# ATTACHMENT N-3
# IDAHO POWER COMPANY'S 2013 INTEGRATED RESOURCE PLAN (DOCKET LC 58)



# 2013
## Integrated Resource Plan

June 2013

IDAHO POWER®
An IDACORP Company

# 2013

# Integrated Resource Plan

## 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.

## SAFE HARBOR STATEMENT

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

**June 2013**

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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.

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 visits the Hemingway Substation.

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

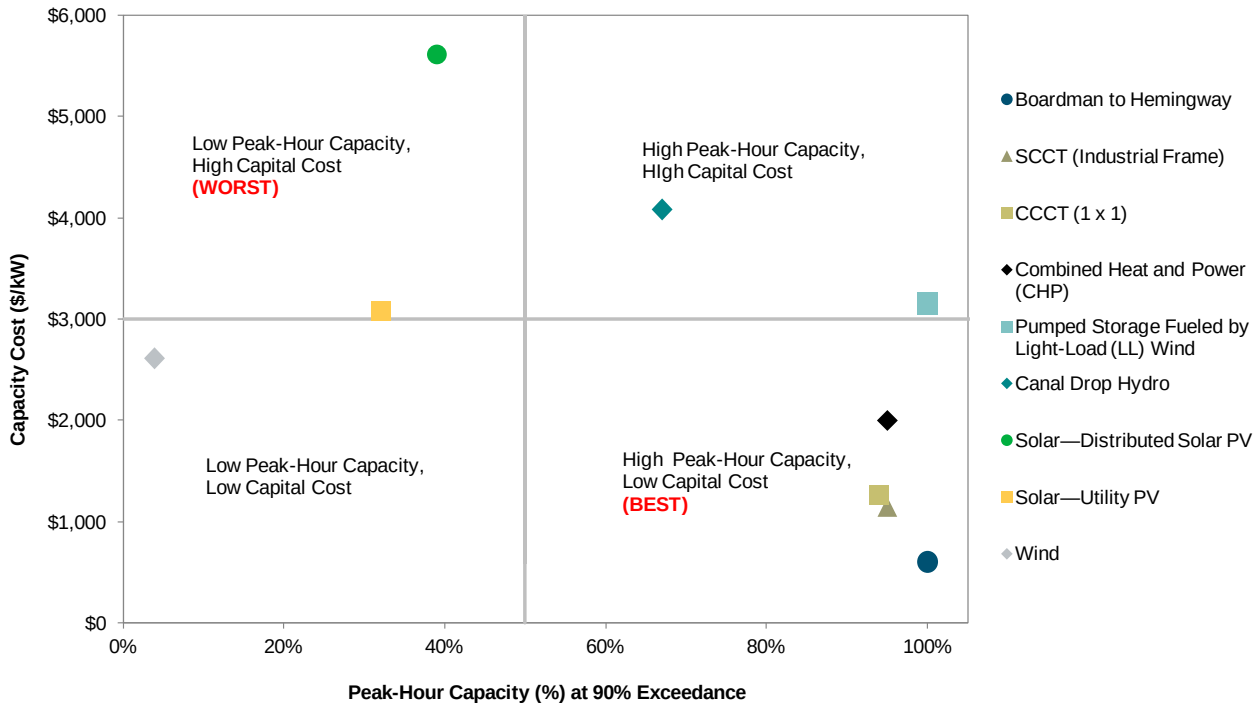



**Figure 1.1 Capacity cost of new supply-side resources**

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.

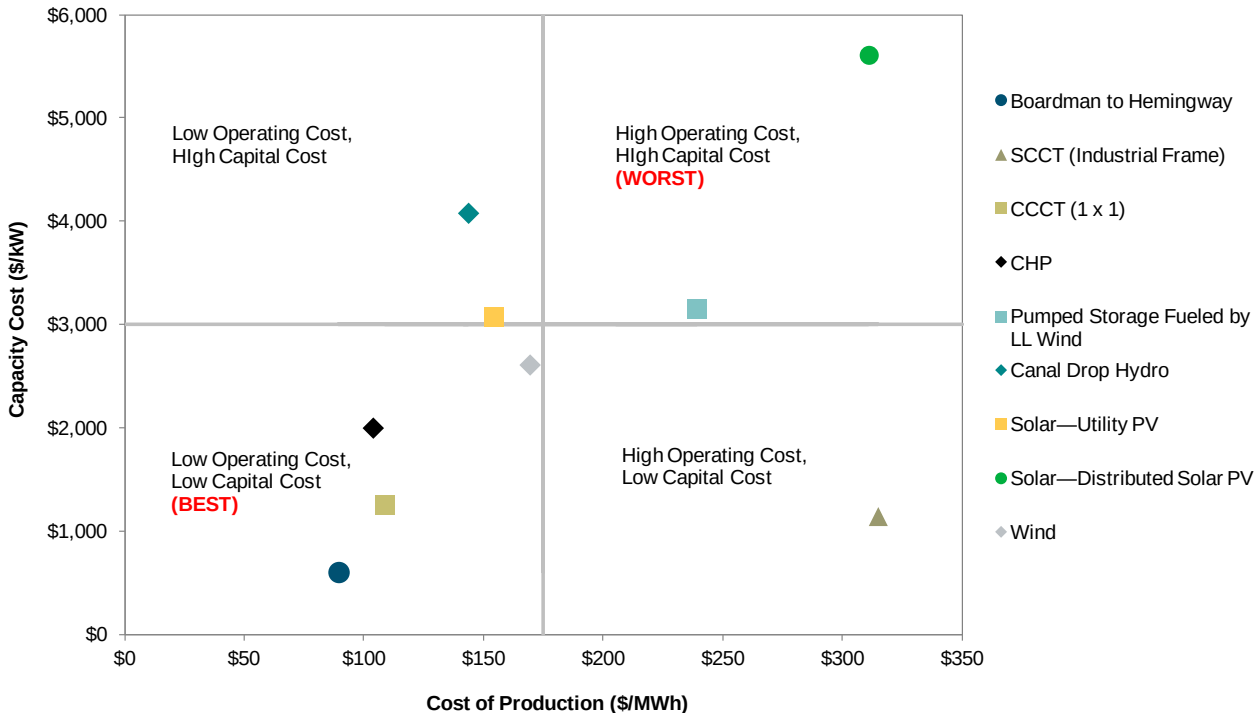



**Figure 1.2 Energy cost of new supply-side resources**

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 37$^{th}$ lowest emitter of $CO_2$ per MWh produced and the 35$^{th}$ 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 58$^{th}$ 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**

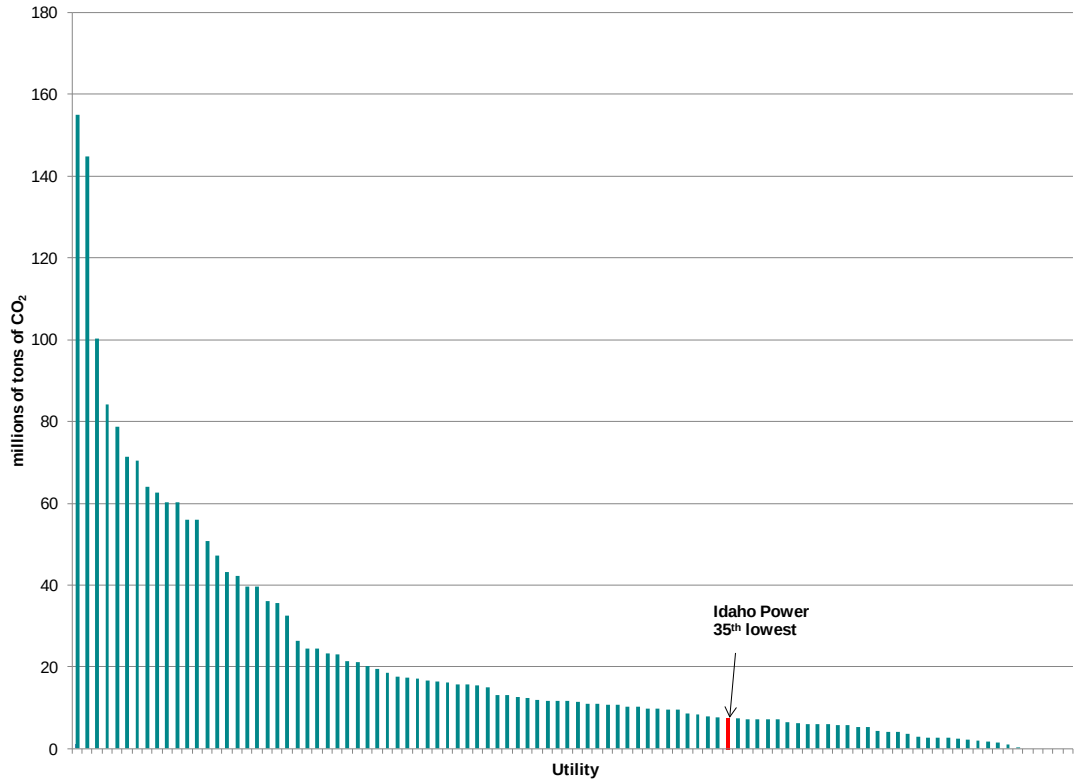



**Figure 1.4 $CO_2$ emissions of the largest 100 utilities**

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.

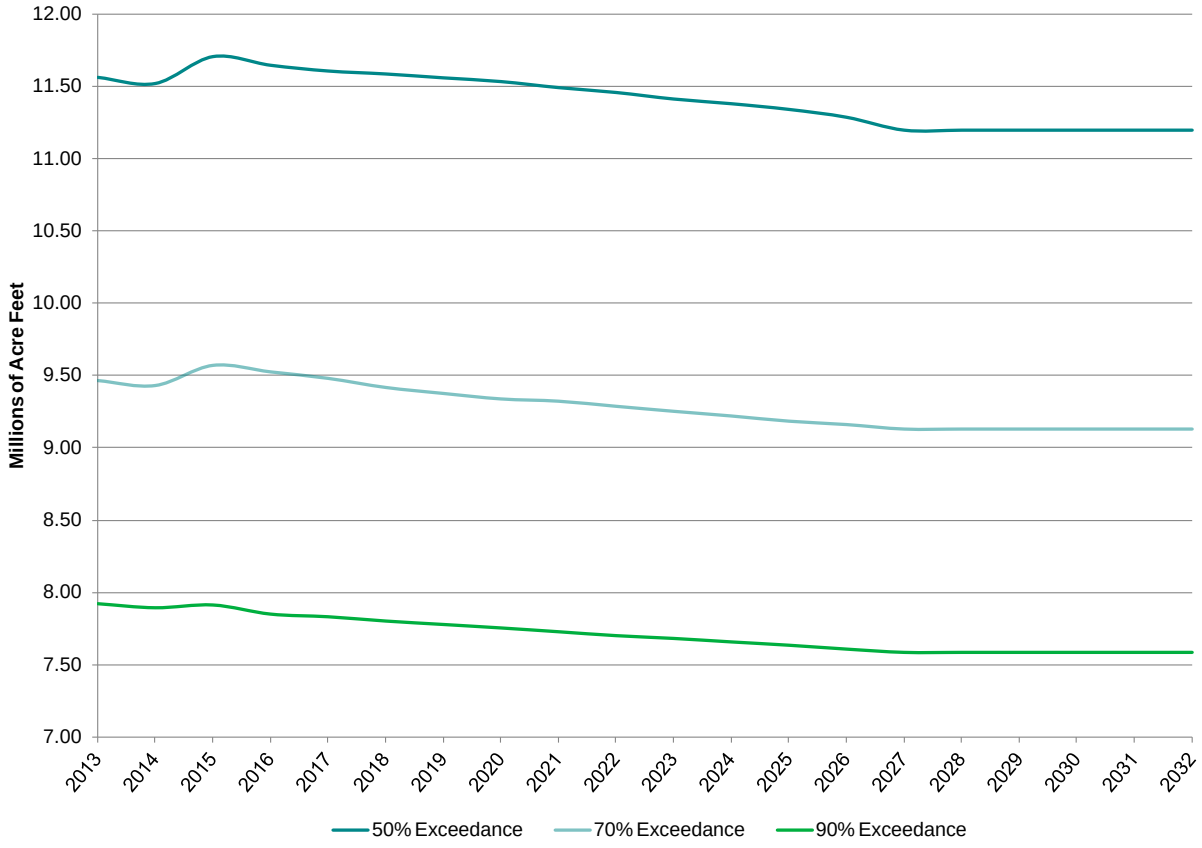



**Figure 2.1 Brownlee total annual inflow—forecasted flows, 2013–2032**

## 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.

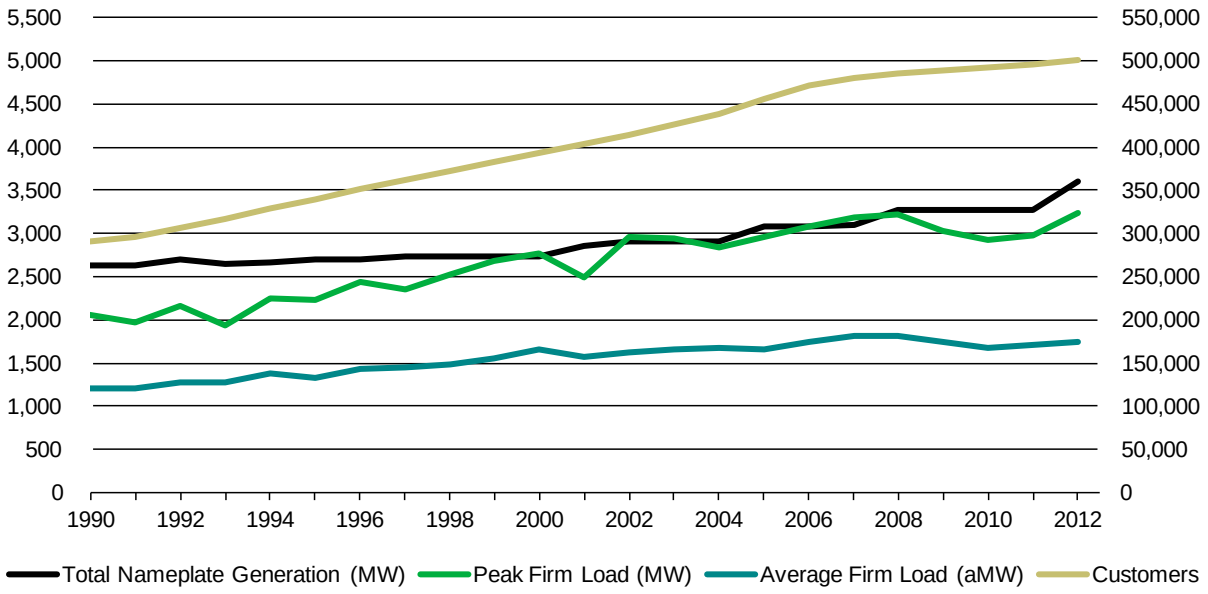



**Figure 3.1 Historical capacity, load, and customer data**

**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.

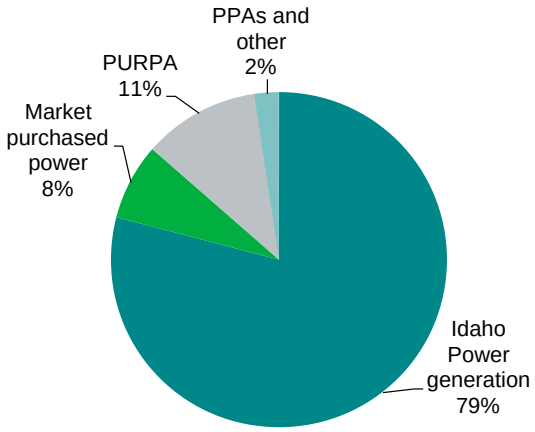



**Figure 3.2 2012 energy sources by type**

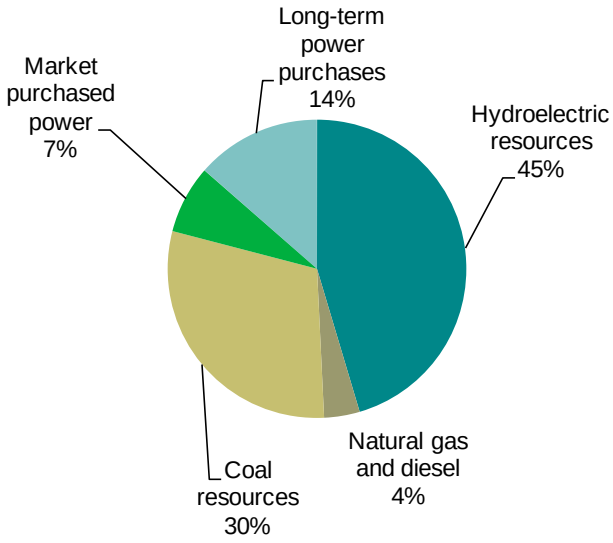



**Figure 3.3 2012 energy sources**

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.

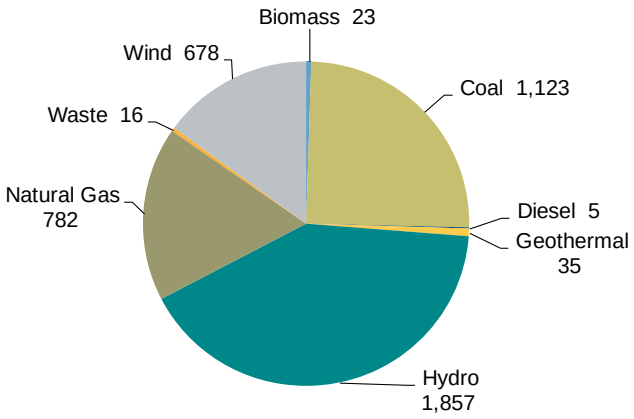



**Figure 3.4 2012 Idaho Power system nameplate (MW) (owned resources plus PPAs)**

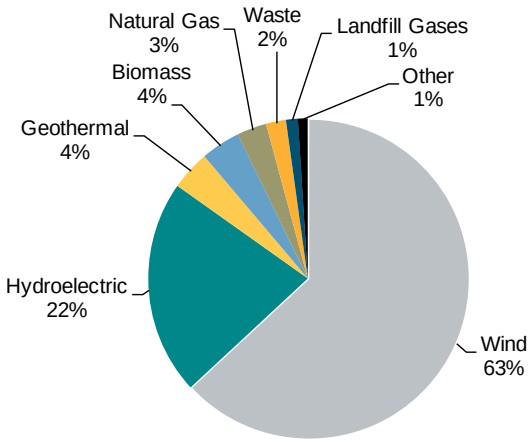



**Figure 3.5 2012 long-term power purchases by resource type**

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.

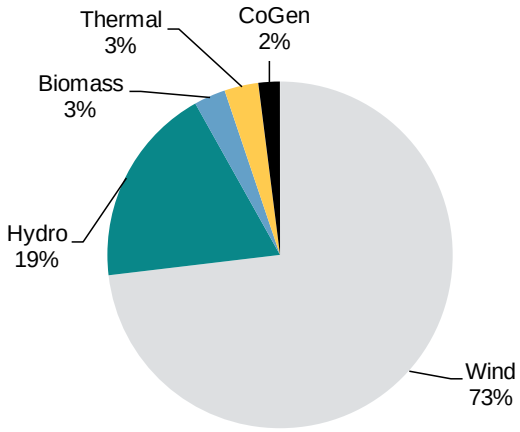



**Figure 3.6 PURPA contracts by resource type**

## 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.

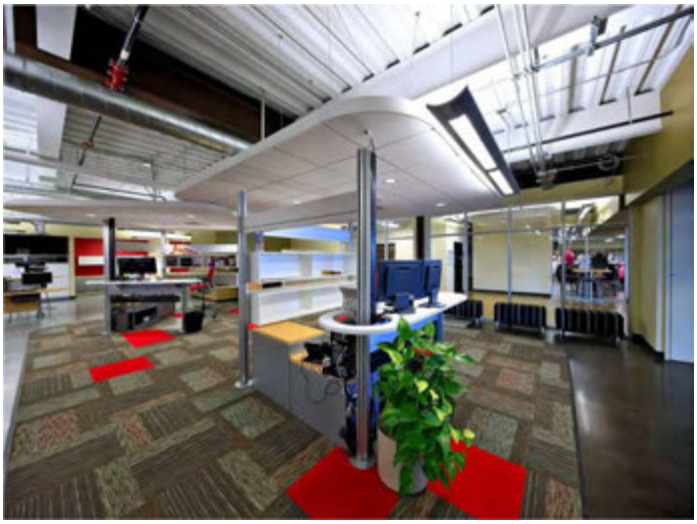
In July 2010, FERC issued a license amendment for the project. The license amendment allows two years to begin construction and five years to complete the project. The company requested and received a two-year extension from FERC on May 1, 2012, that requires construction to commence by July 1, 2014. 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.

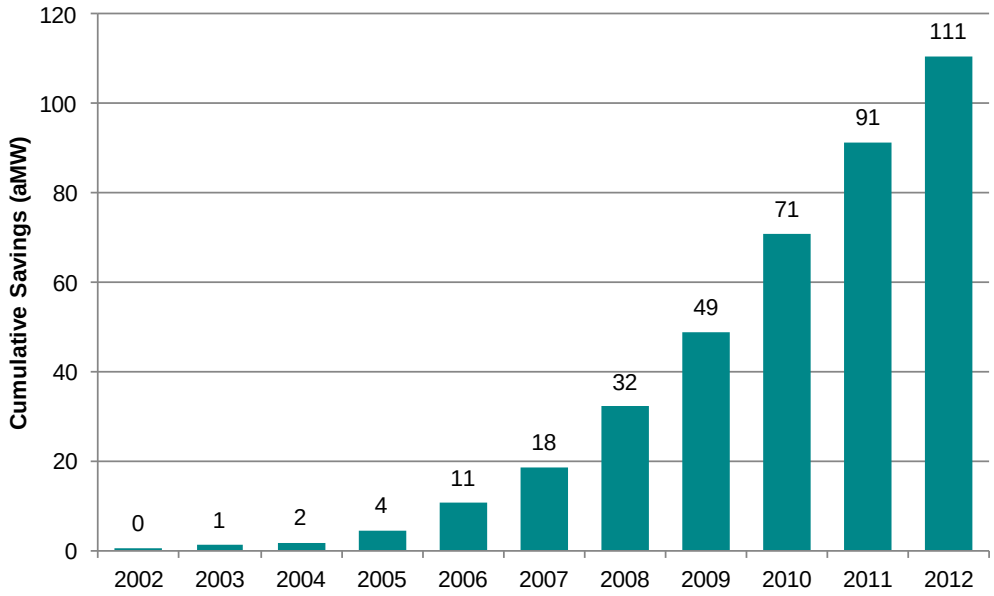



**Figure 4.1 Cumulative energy efficiency savings, 2002–2012 (aMW)**

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.

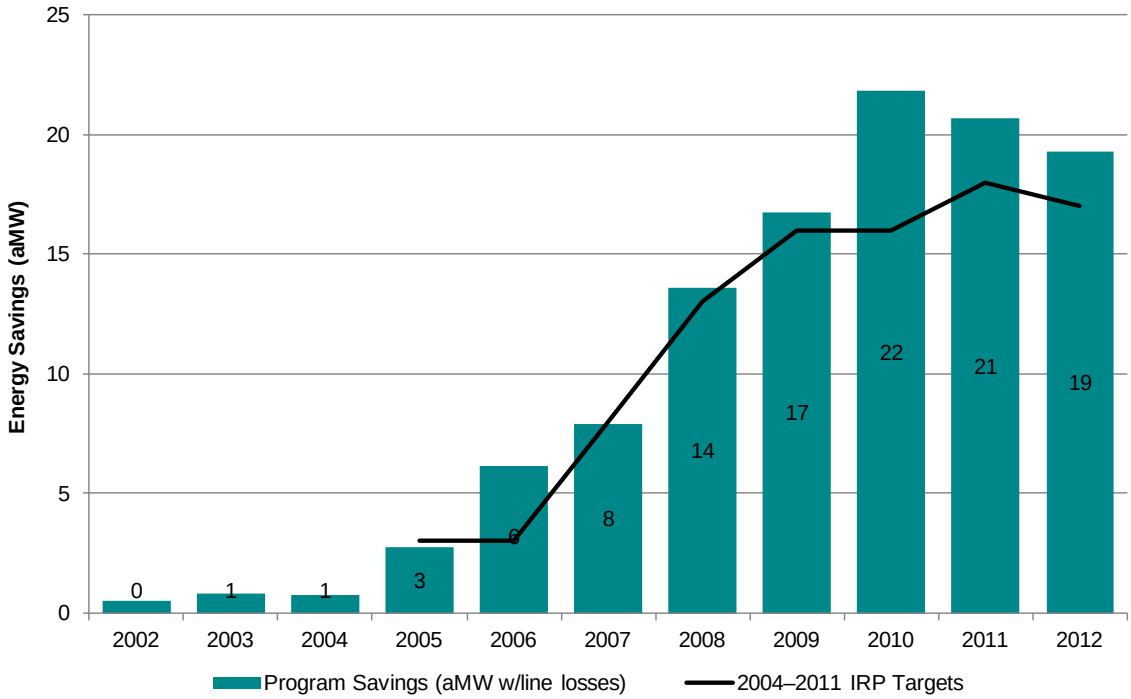



**Figure 4.2 Annual energy efficiency savings and IRP targets, 2002–2012 (aMW)**

## 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.

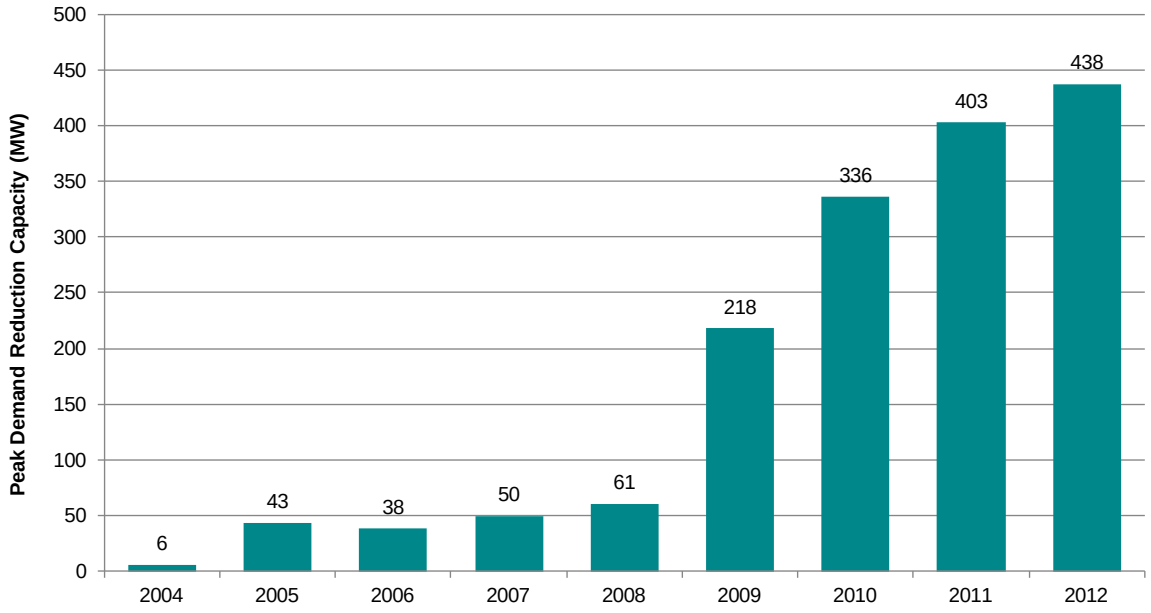



**Figure 4.3 Demand response peak reduction capacity, 2004–2012 (MW)**

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.

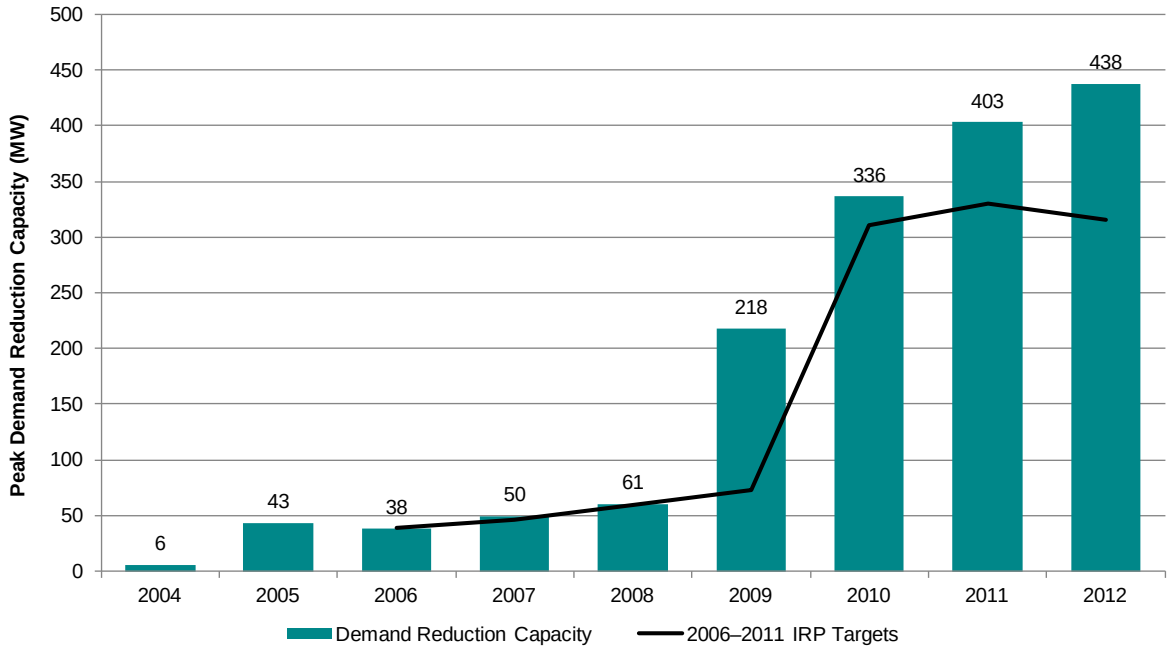



**Figure 4.4 Demand response peak reduction capacity with IRP targets, 2004–2012 (MW)**

## 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.

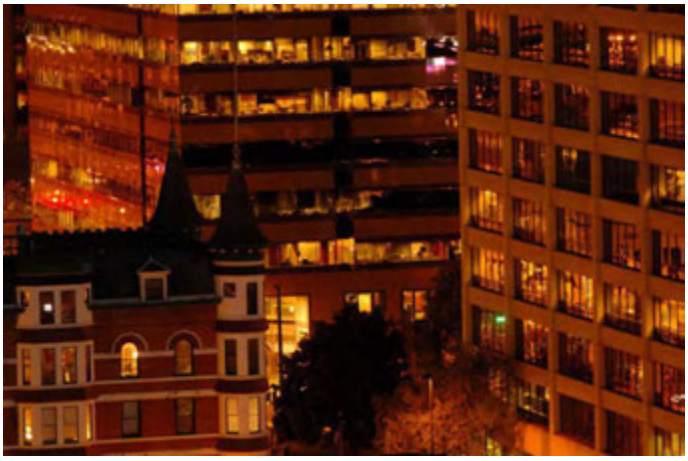
The actual savings from the current CVR implementation are not significant enough to be incorporated into the IRP load and resource balance forecast.

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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 70$^{th}$-percentile and 90$^{th}$-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 70$^{th}$-percentile and 90$^{th}$-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.

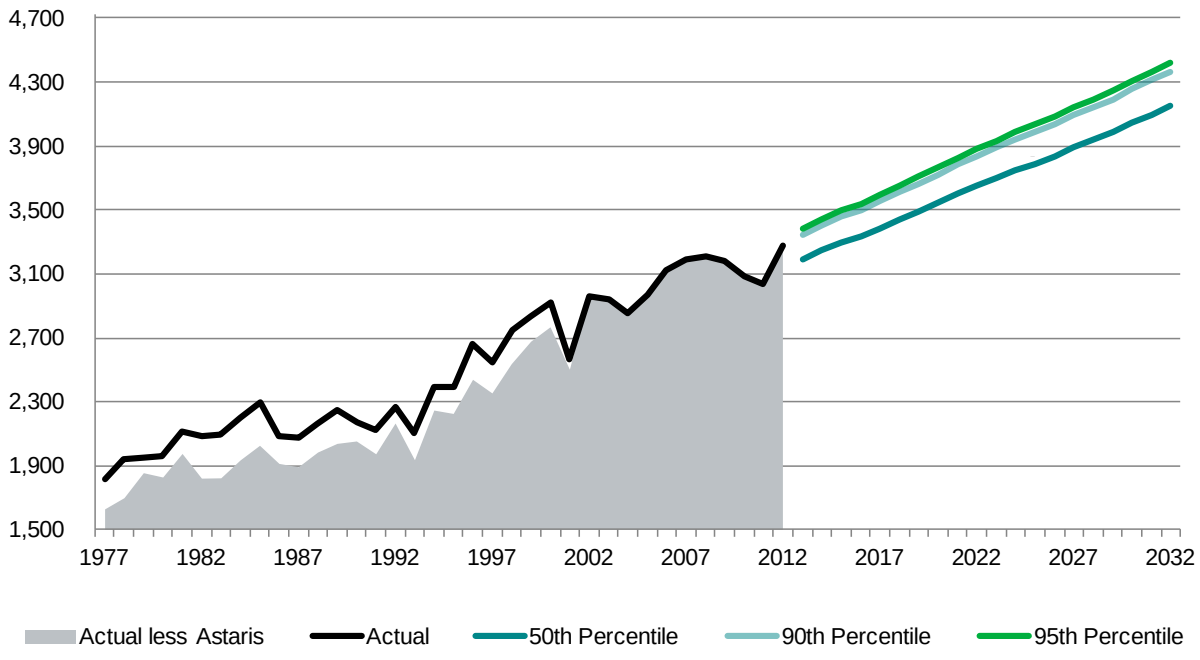



**Figure 5.1 Peak-hour load-growth forecast (MW)**

**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.

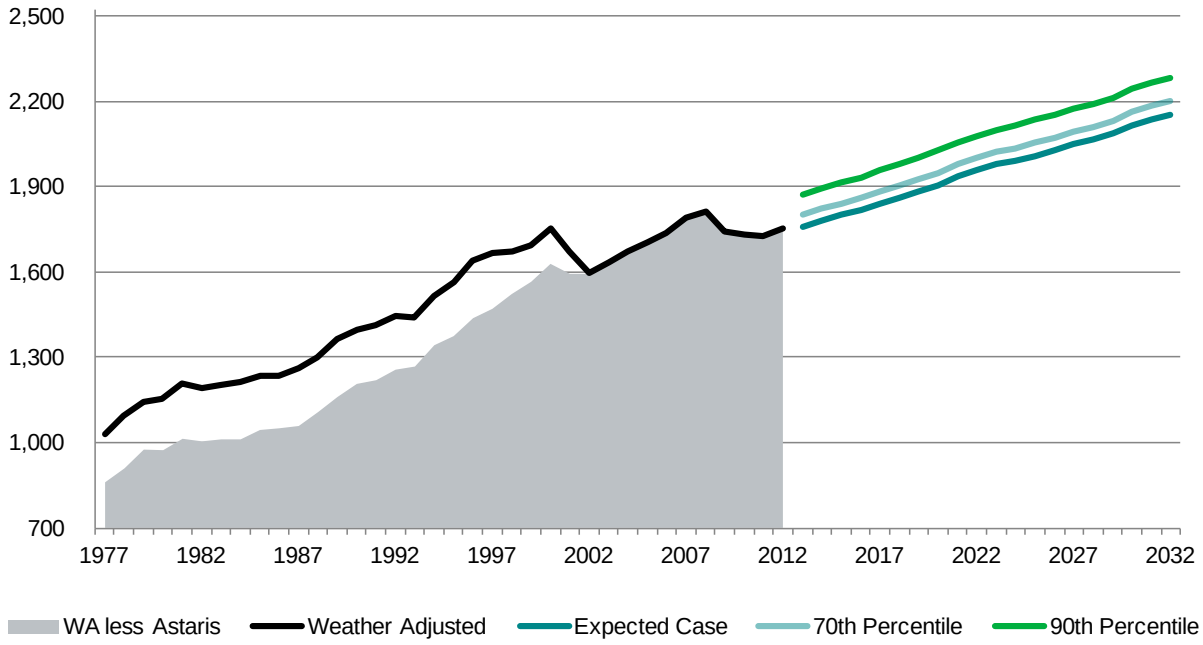



**Figure 5.2 Average monthly load-growth forecast (aMW)**

**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 70th-percentile forecast as the basis for monthly average-energy planning in the IRP. The 70th-percentile forecast is based on 70th-percentile weather to forecast average monthly load, 70th-percentile water to forecast hydroelectric generation, and 95th-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 70$^{th}$-percentile streamflow conditions for the Snake River Basin as the basis for the projections of monthly average hydroelectric generation. The 70$^{th}$ 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 90$^{th}$-percentile streamflow conditions to project peak-hour hydroelectric generation. The 90$^{th}$ percentile means streamflows are expected to exceed the planning criteria 90 percent of the time and to be worse than the planning criteria only 10 percent of the time.

The practice of basing hydroelectric generation forecasts on worse-than-median streamflow conditions was initially adopted in the 2002 IRP in response to suggestions that Idaho Power

use more conservative water planning criteria as a method of encouraging the acquisition of sufficient firm resources to reduce reliance on market purchases. However, Idaho Power continues to prepare hydroelectric generation forecasts for 50th-percentile (median) streamflow conditions because the median streamflow condition is still used for rate-setting purposes and other analyses.

Idaho Power uses two primary models for forecasting future flows for the IRP. The Snake River Planning Model (SRPM) is used to determine surface-water flows, and the Enhanced Snake Plain Aquifer Model (ESPAM) is used to determine the effect of various aquifer management practices on Snake River reach gains. The two models are used in combination to produce a normalized hydrologic record for the Snake River Basin from 1928 through 2009. The record is normalized to account for specified conditions relating to Snake River reach gains, water-management facilities, irrigation facilities, and operations. The 50th-, 70th-, and 90th-percentile streamflow forecasts are derived from the normalized hydrologic record. Further discussion of flow modeling for the 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 70th-percentile year in 2010 is identical to a 70th-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 90th-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 50$^{th}$, 70$^{th}$, and 90$^{th}$ 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.

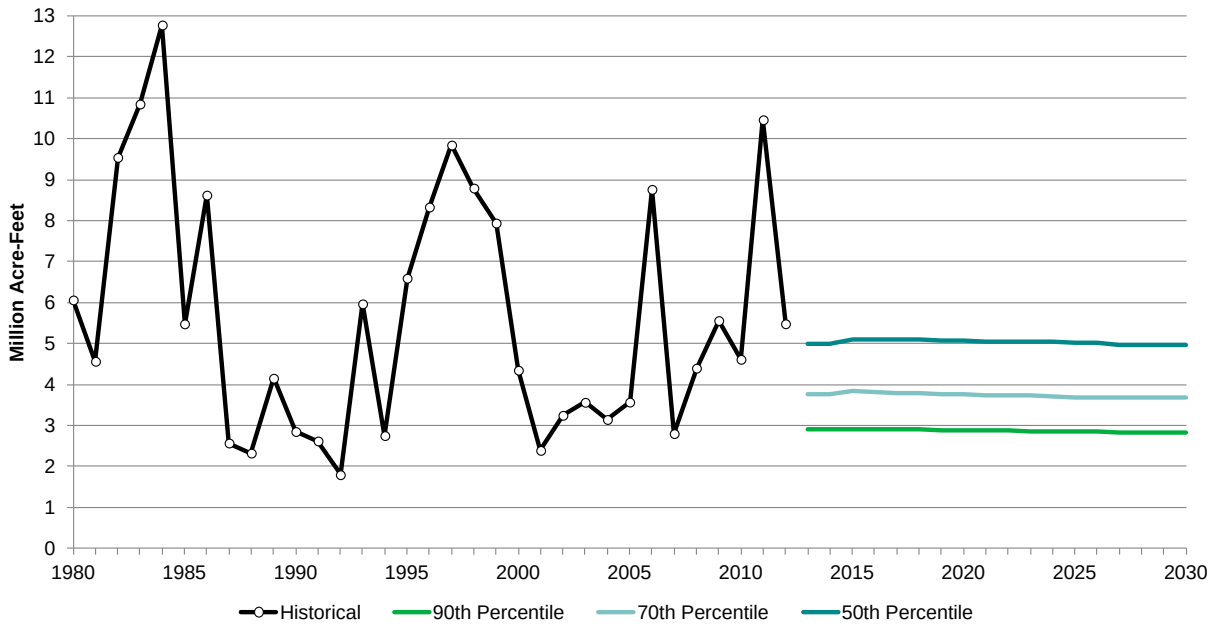



**Figure 5.3 Brownlee historical and forecast inflows**

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.

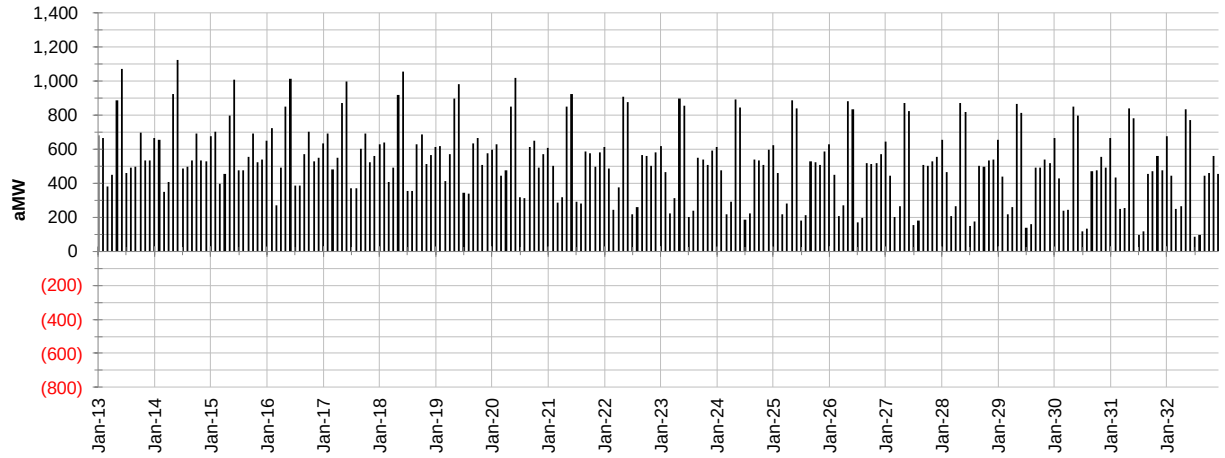



**Figure 5.4 Monthly average-energy surpluses and deficits with existing and committed resources and existing DSM (70th-percentile water and 70th-percentile load)**

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.

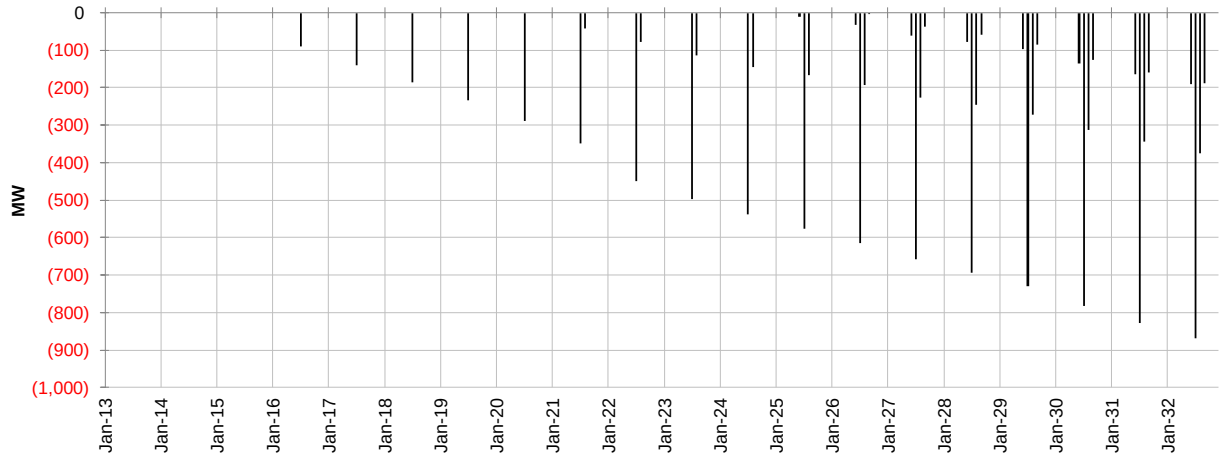



**Figure 5.5 Monthly peak-hour deficits without existing and committed resources and existing DSM (90th-percentile water and 95th-percentile load)**

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.

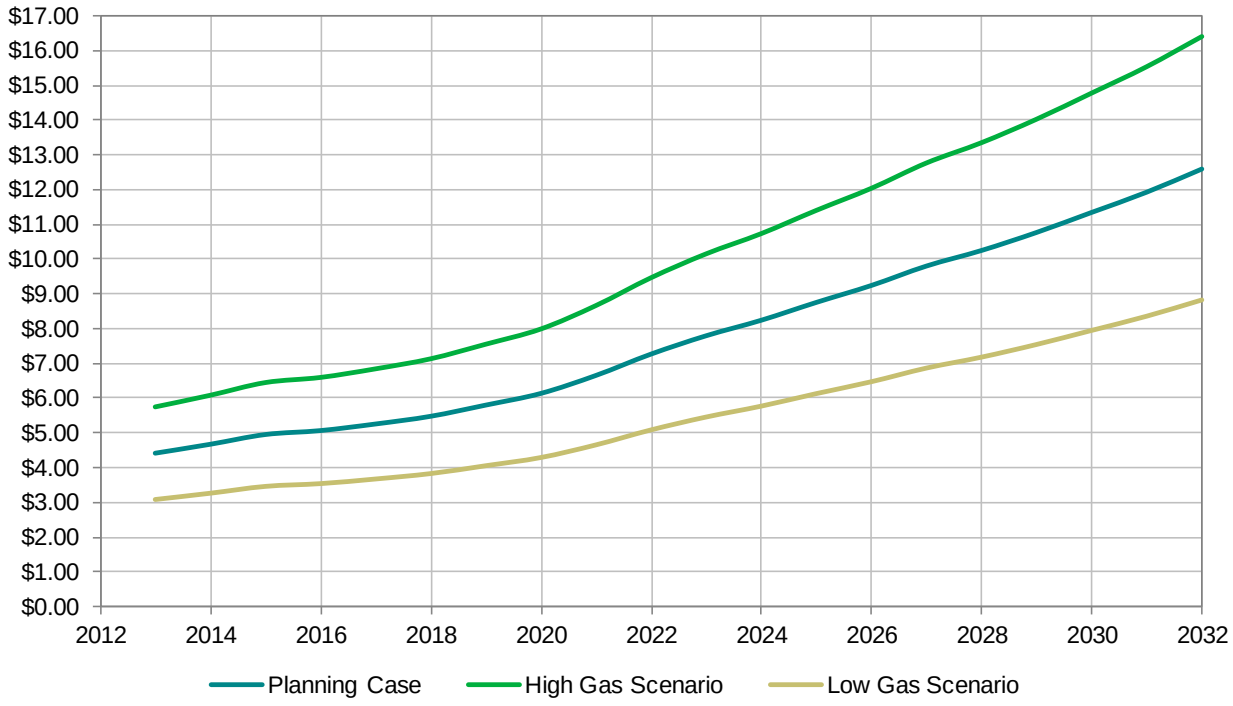



**Figure 5.6 Henry Hub Price Forecast—EIA *Annual Energy Outlook 2012* (nominal dollars)**

# 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.

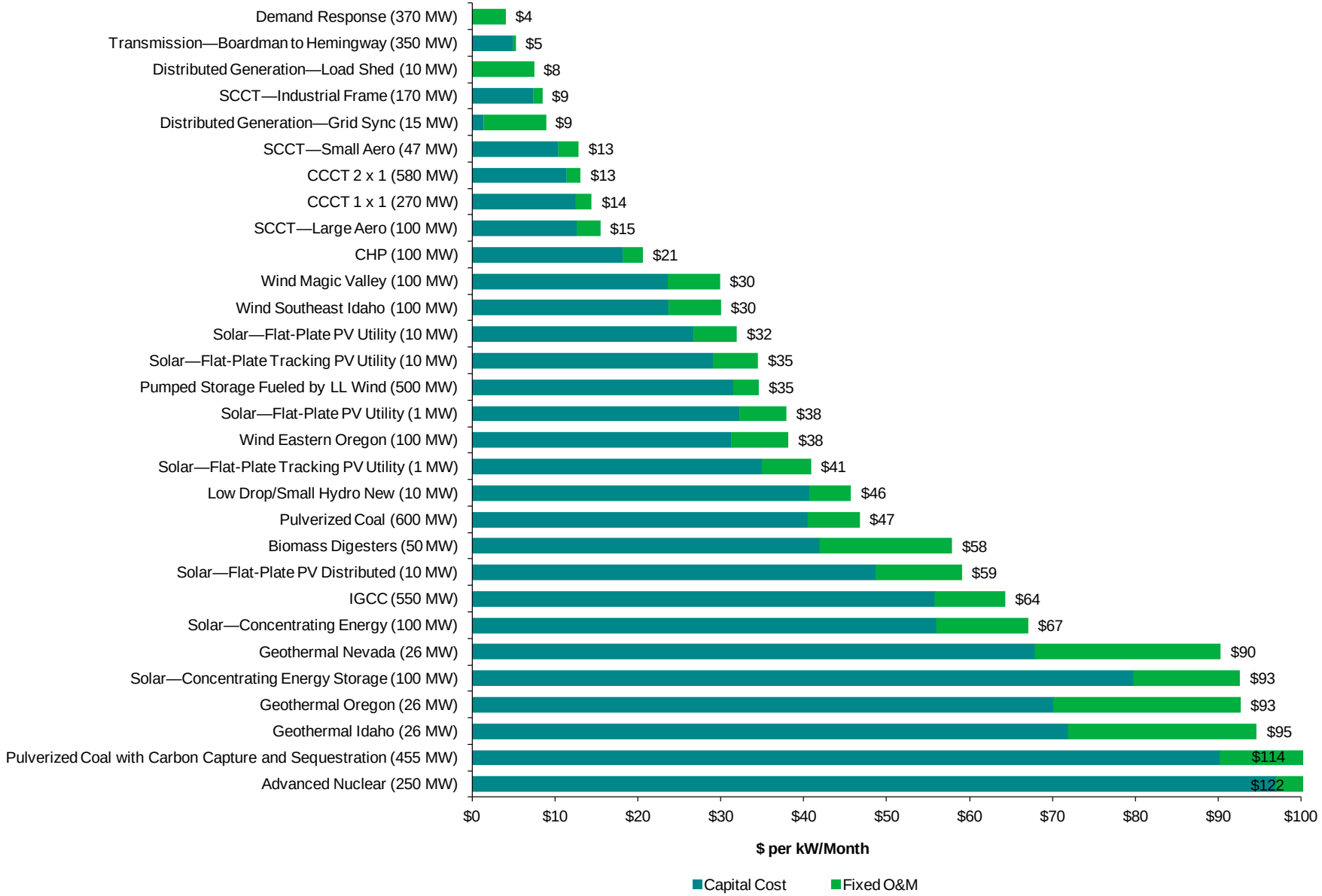



**Figure 5.7 30-year levelized capacity (fixed) costs**

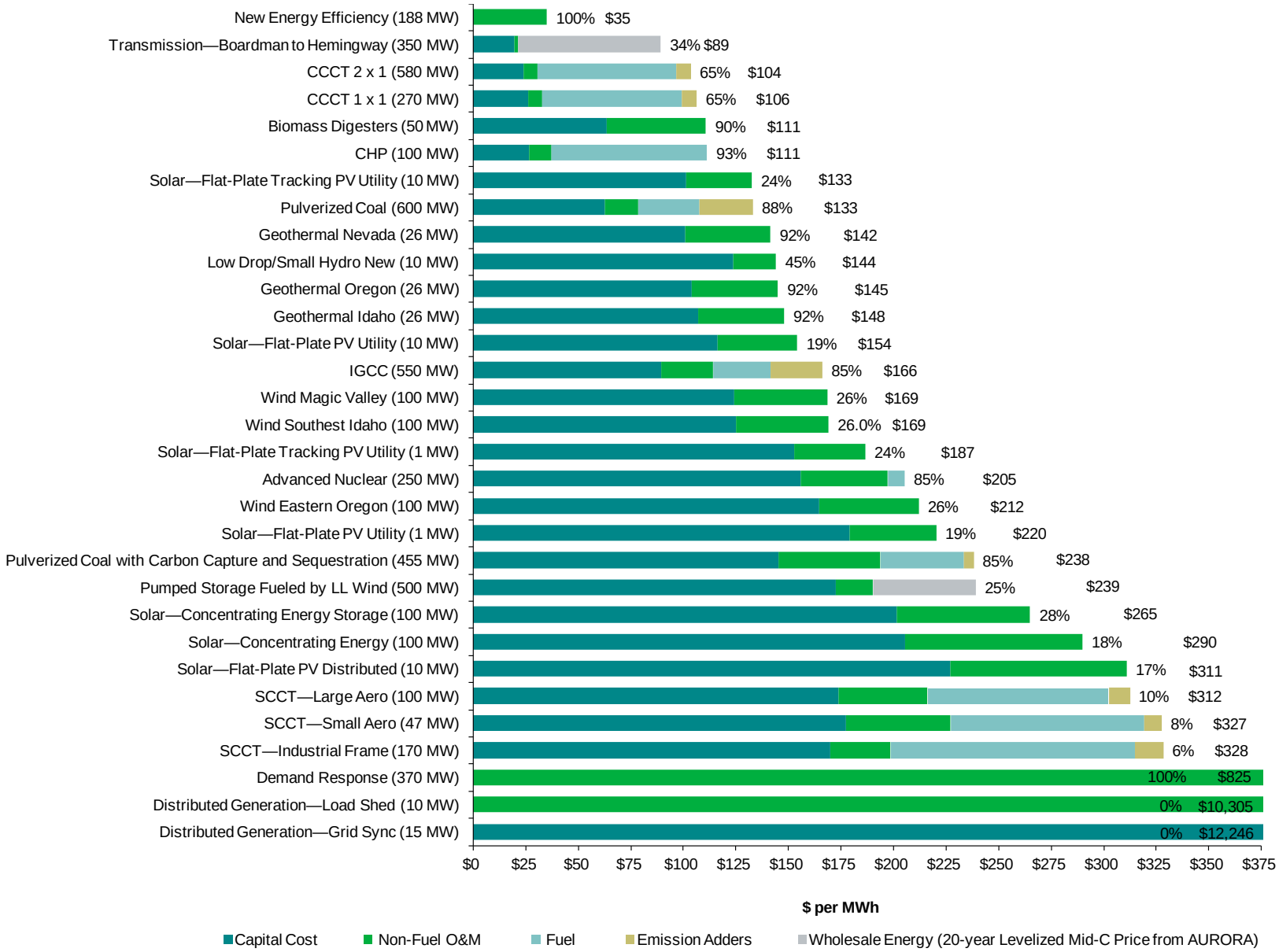



**Figure 5.8 30-year levelized cost of production (at stated capacity factors)**

## 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.

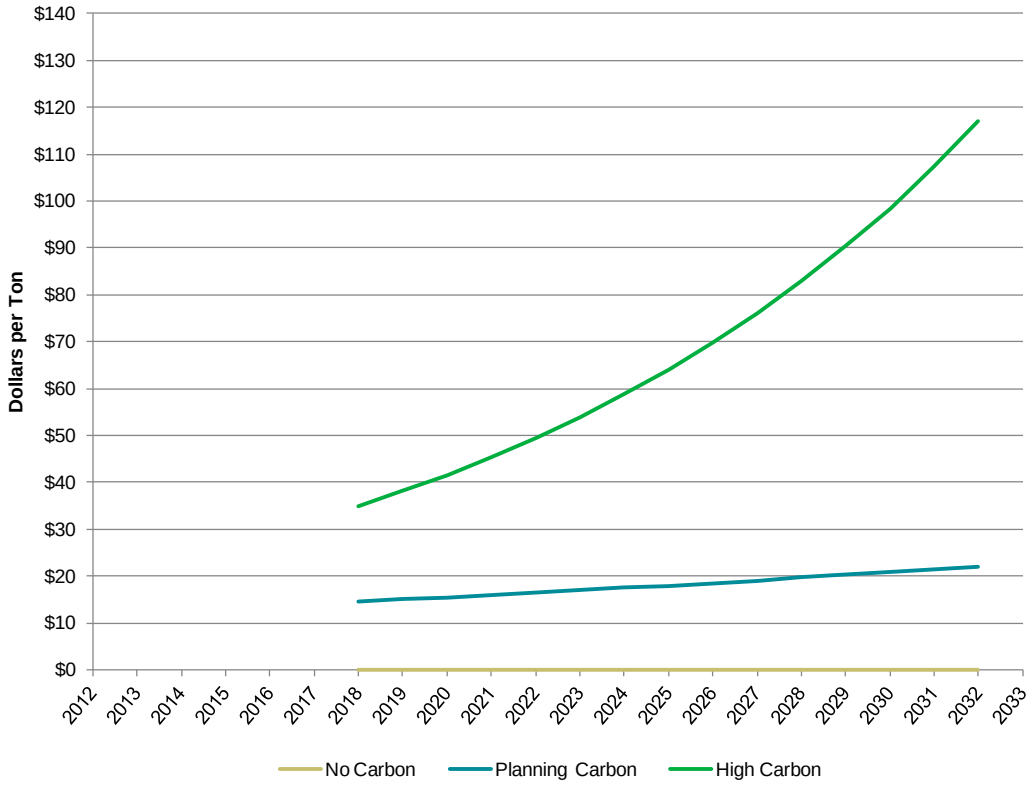



**Figure 5.9 2013 IRP carbon adder**

**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.

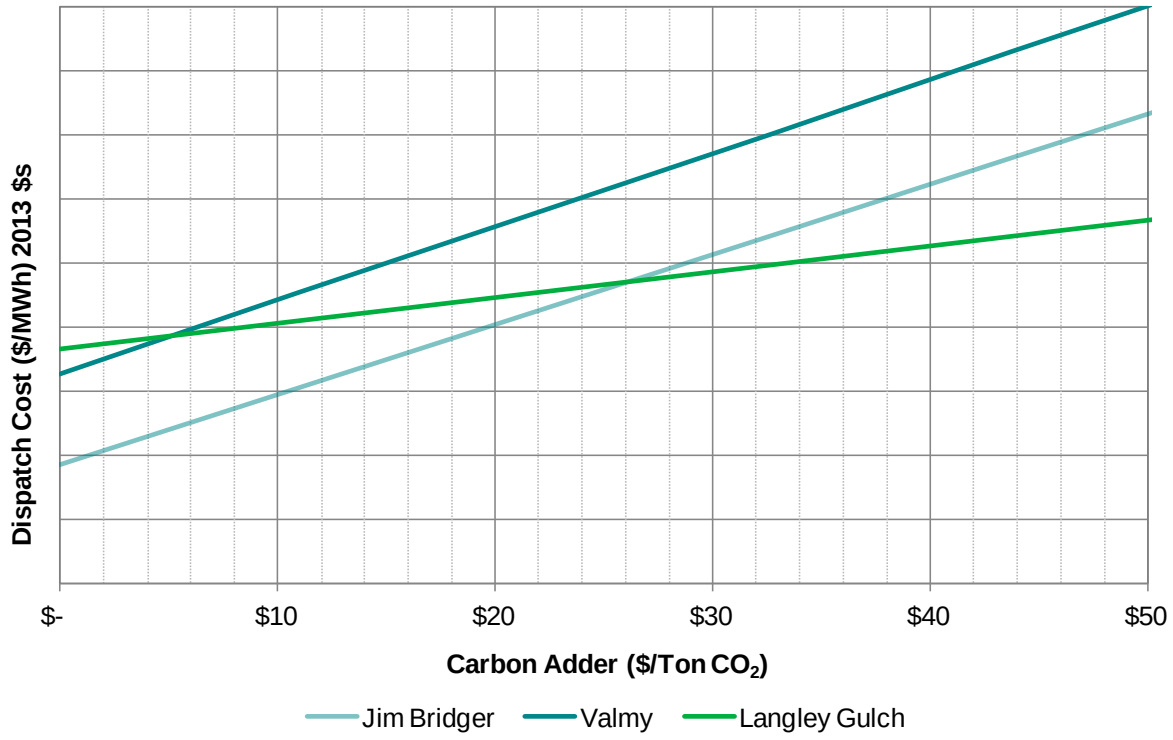



**Figure 5.10 Dispatch costs, 2020**

# 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.

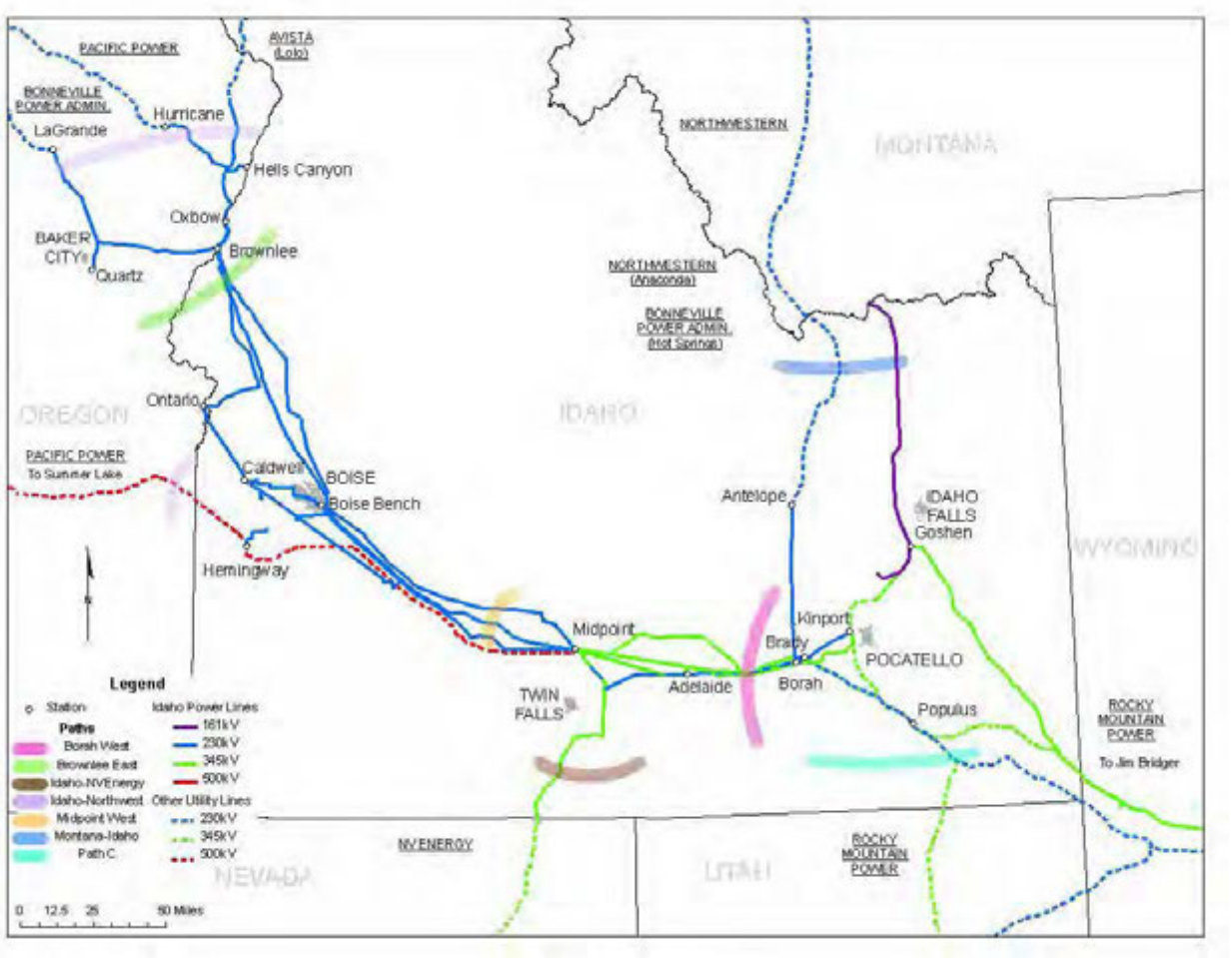



**Figure 6.1 Idaho Power transmission system map**

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<br>200 winter/500 summer | 400<br>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.

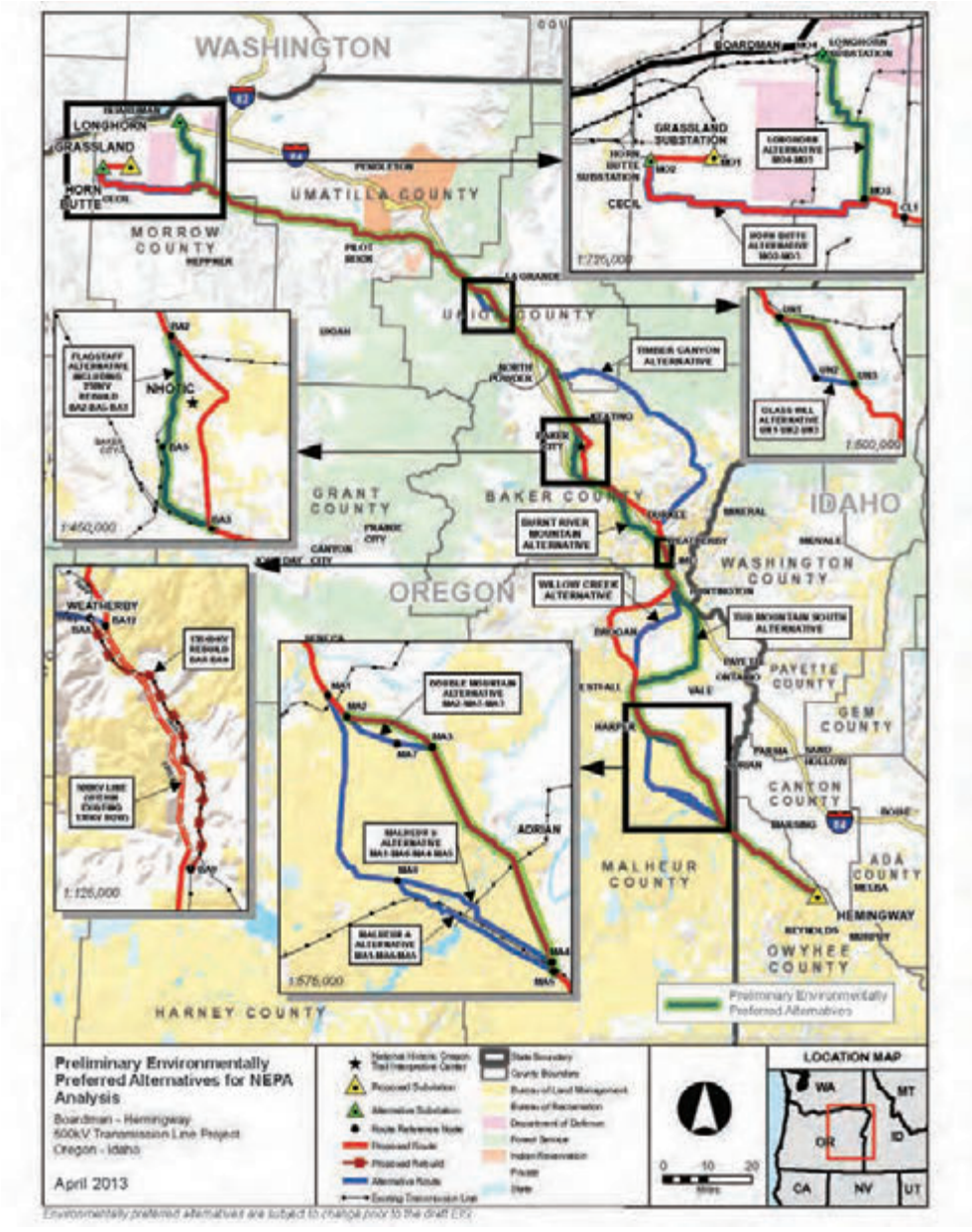



**Figure 6.2 Boardman to Hemingway routes with the BLM preliminary environmentally preferred route**

## 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.

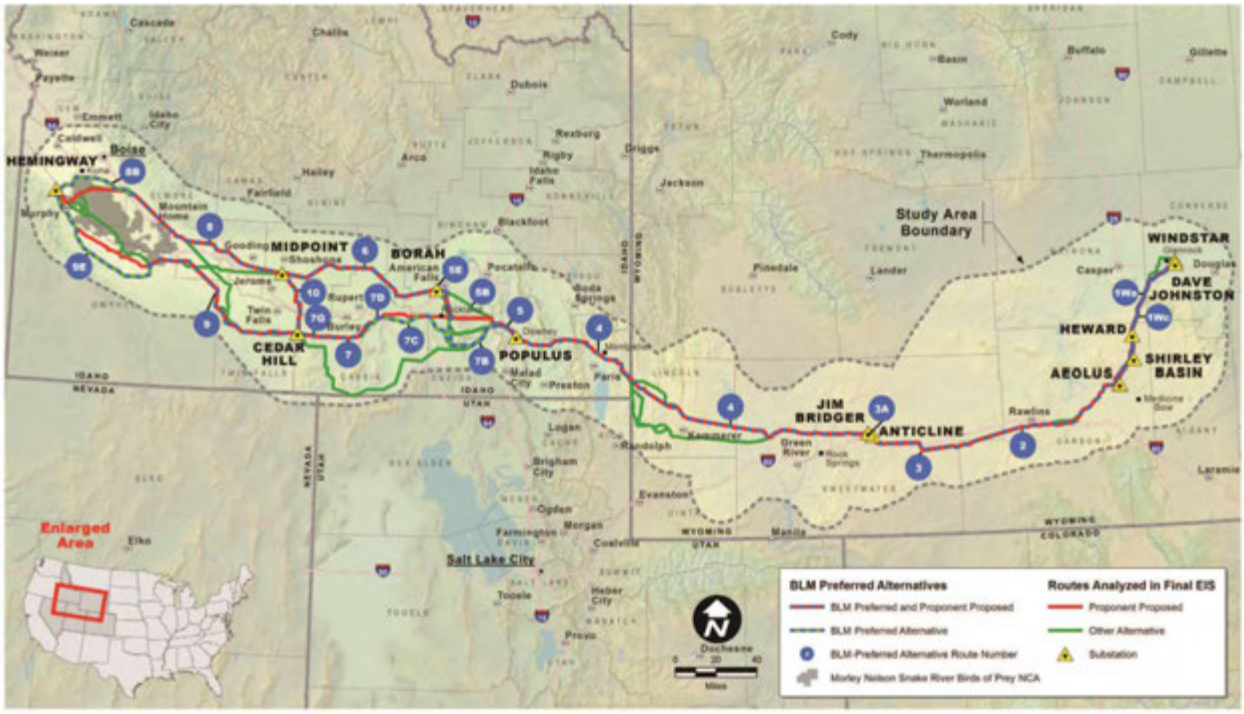



**Figure 6.3 Gateway West Map**

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.

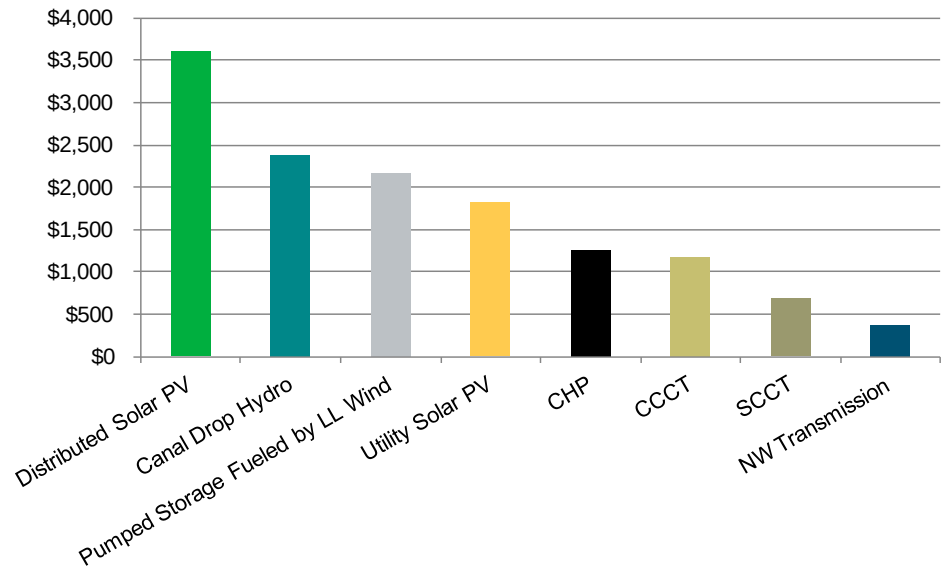



**Figure 7.1 Relative costs per delivered on-peak kW**

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.

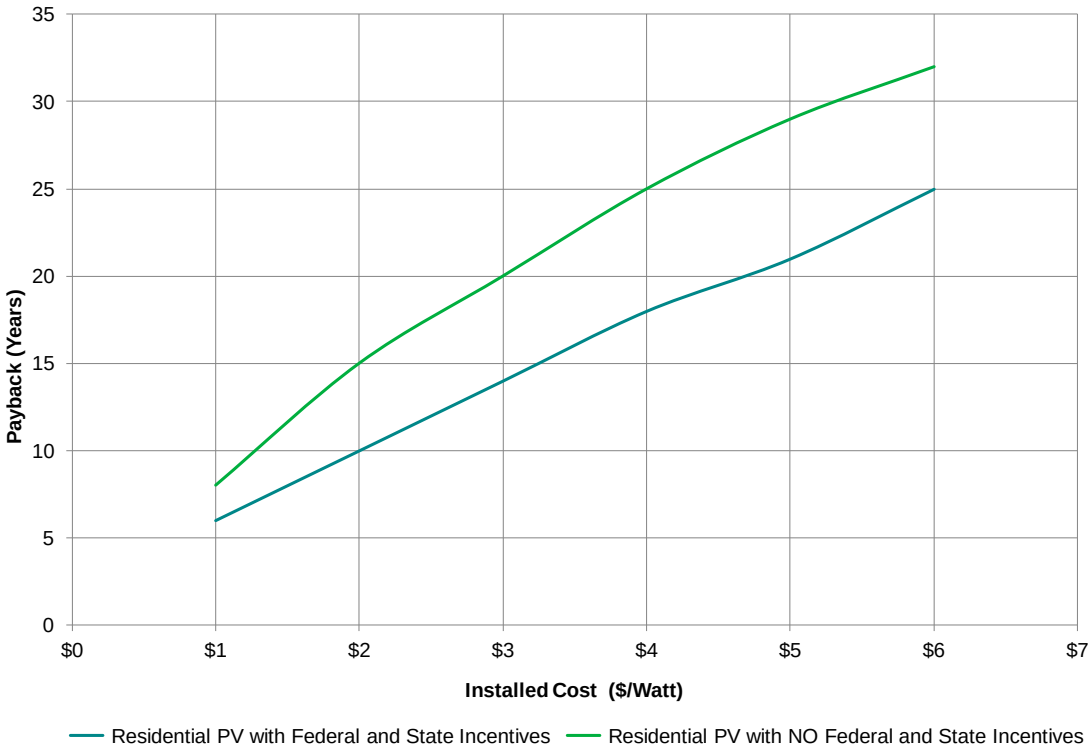



**Figure 7.2 Solar generation recovery period**

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 | | Low | Scenario | Scenario |
| Resource Alternative | High | Low | High | Low | Water | 6 | 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 90$^{th}$-percentile water and 95$^{th}$-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

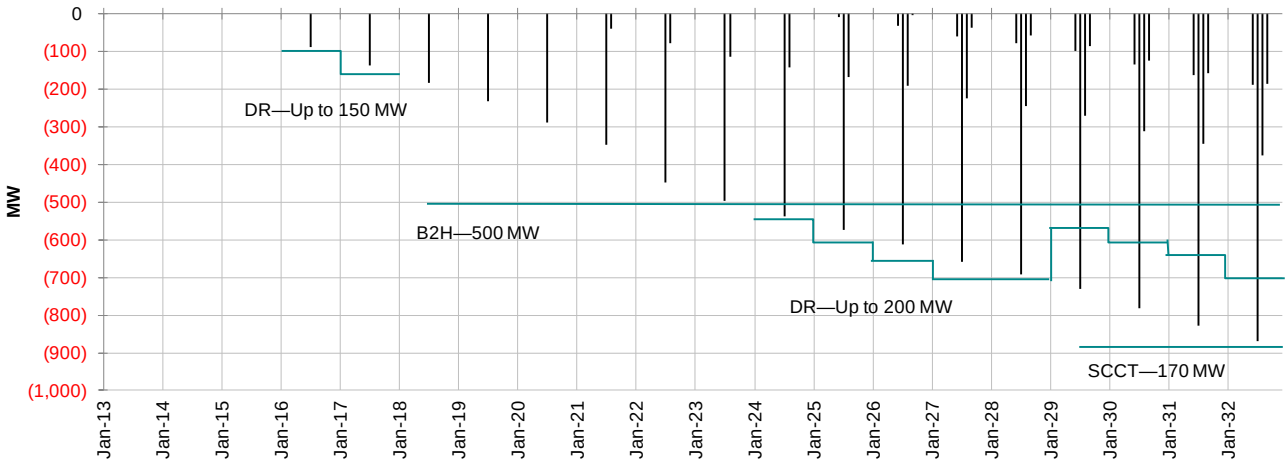



**Figure 8.1 Resource portfolio 1**

**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

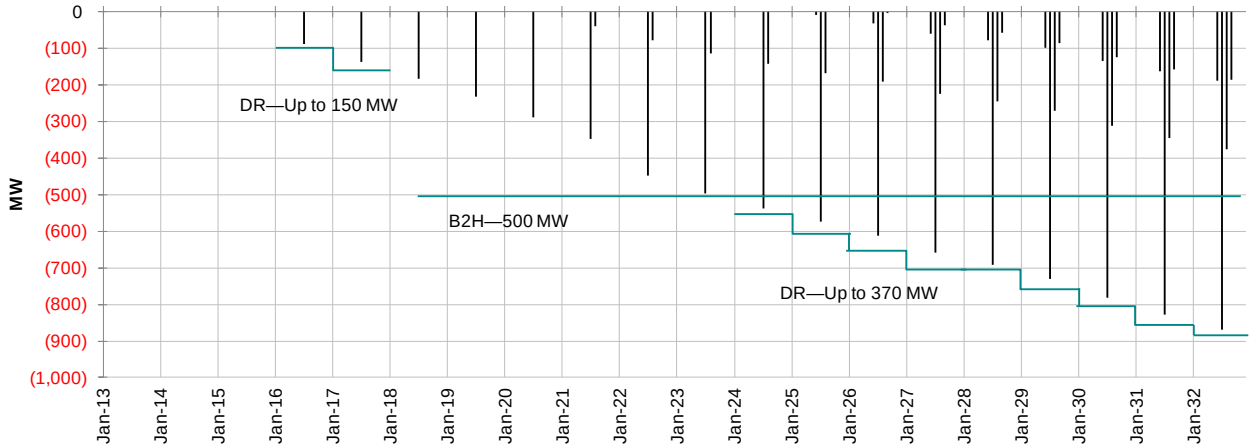



**Figure 8.2 Resource portfolio 2**

**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

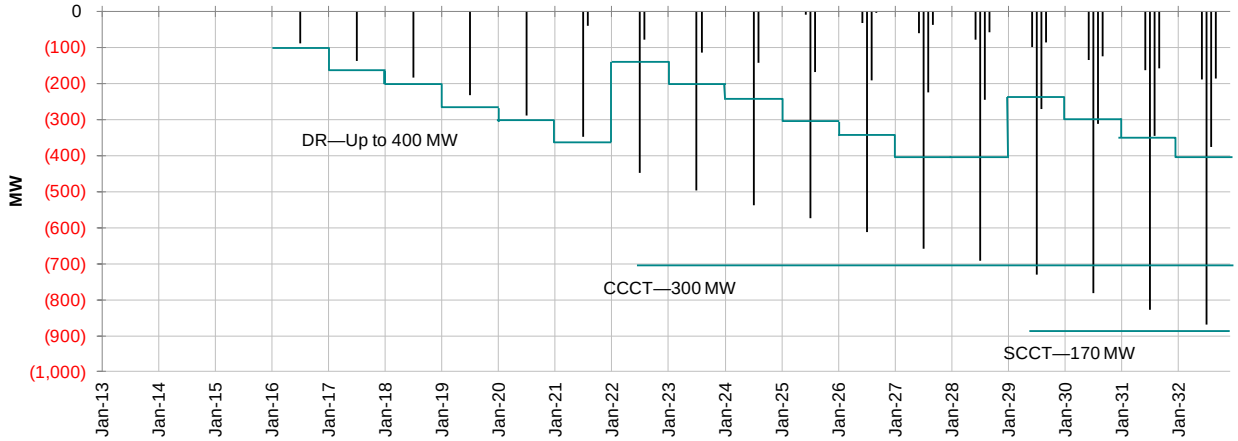



**Figure 8.3 Resource portfolio 3**

**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

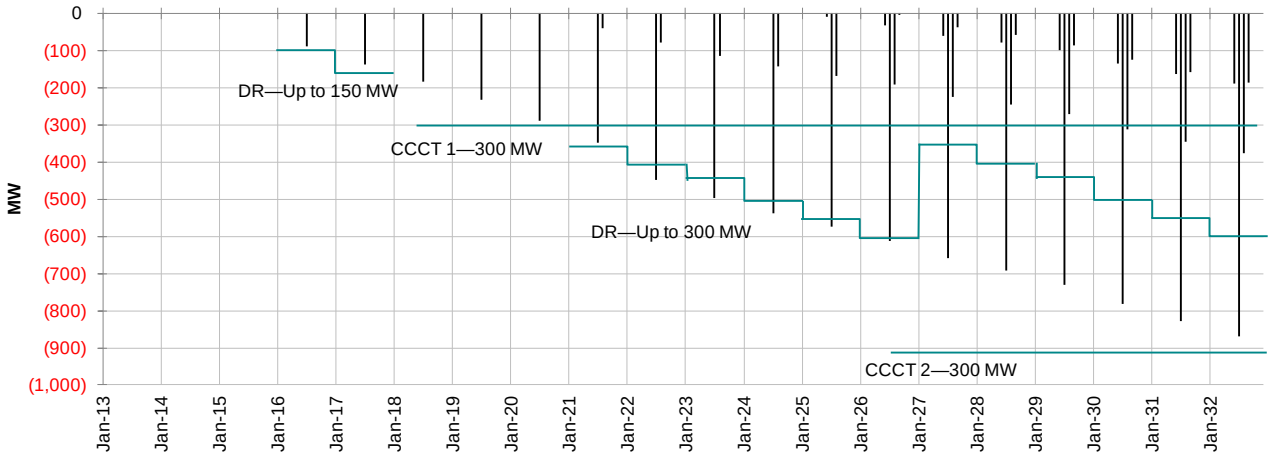



**Figure 8.4 Resource portfolio 4**

**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

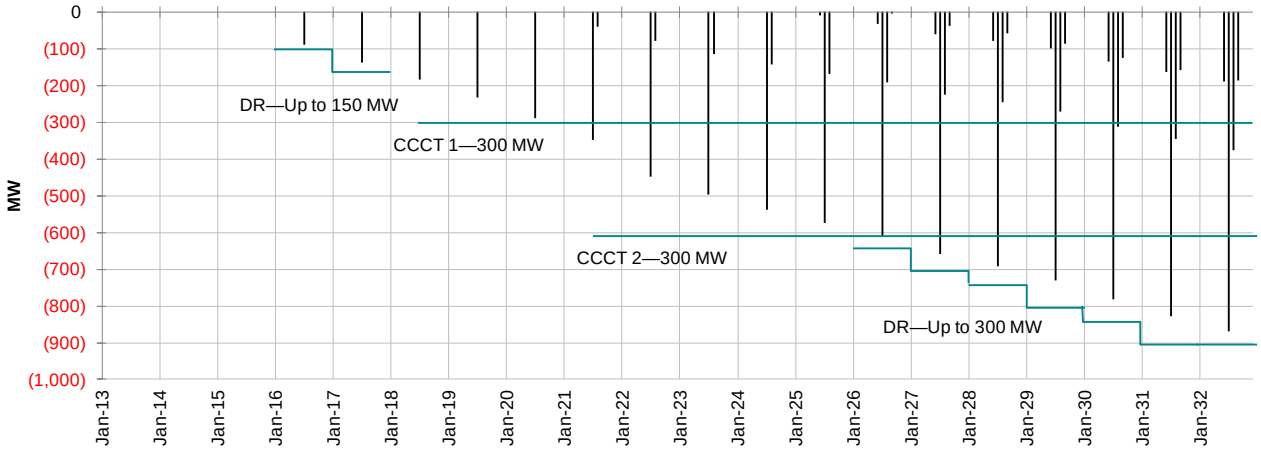



**Figure 8.5 Resource portfolio 5**

**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 90$^{th}$-percentile water and 95$^{th}$-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.

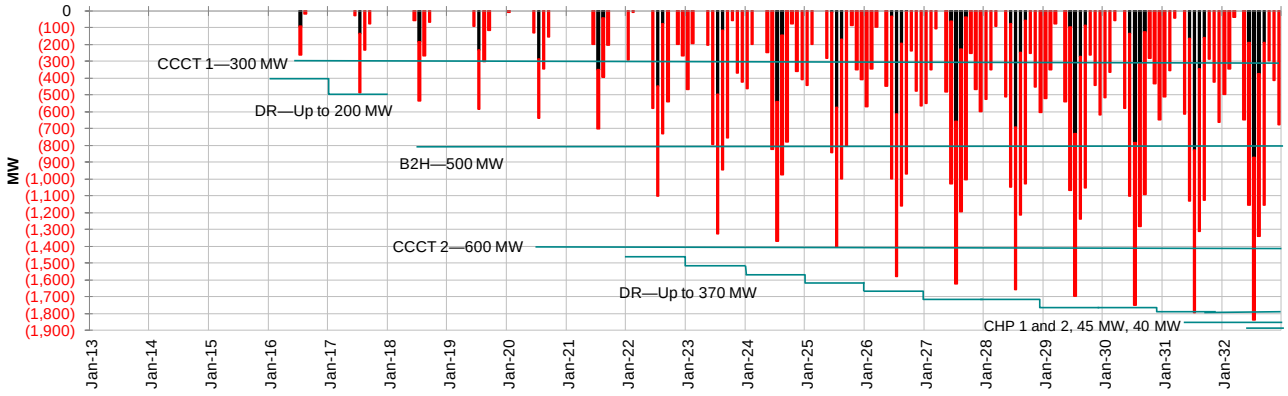



**Figure 8.6 Resource portfolio 6**

**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.

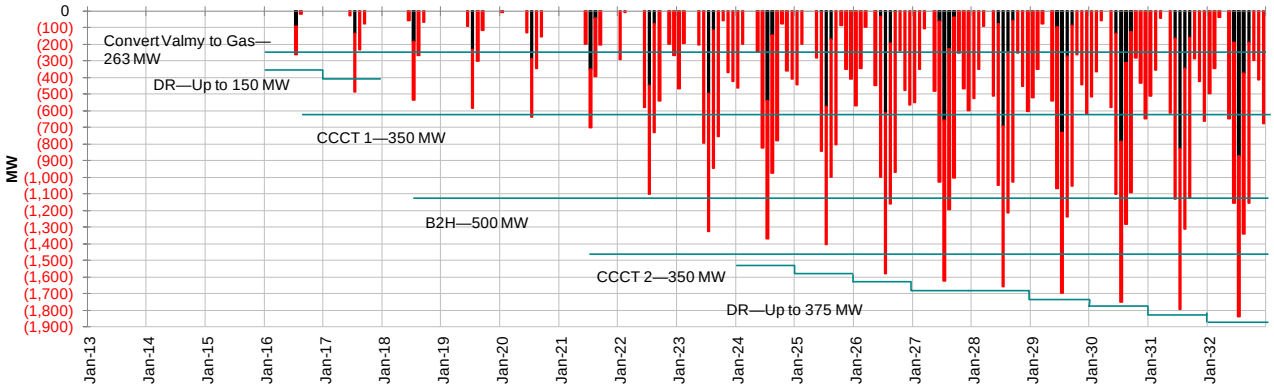



**Figure 8.7 Resource portfolio 7**

**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).

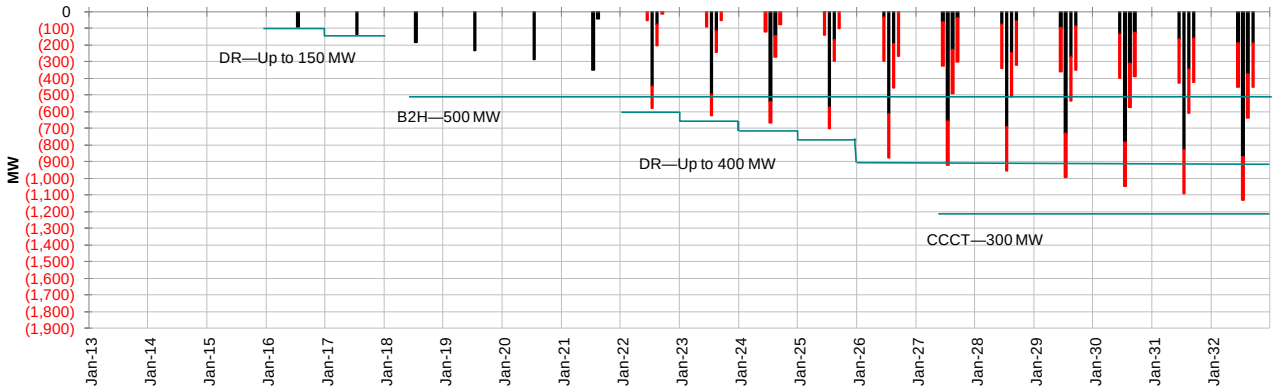



**Figure 8.8 Resource portfolio 8**

**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.

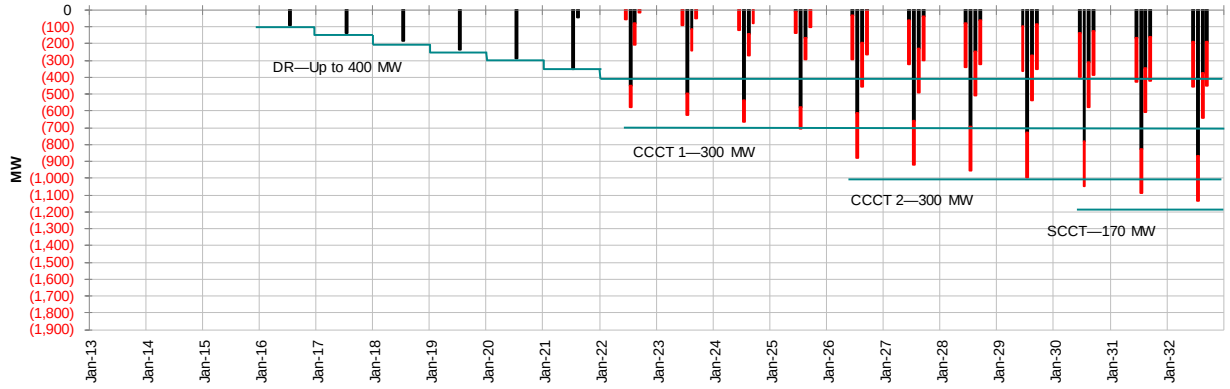



**Figure 8.9 Resource portfolio 9**

**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)**

| Portfolio | Variable Costs | Fixed Costs | | | | Summary | | |
|---|---|---|---|---|---|---|---|---|
| | Operating[1] (Aurora) | New Resources[2] | New Natural Gas Pipeline Capacity Charge | Demand Response | Total | Total Portfolio Costs | Lowest Cost Rank | Lowest Cost Relative Difference |
| (1) | (2) | (3) | (4) | (5) | (6) (3)+(4)+(5) | (7) (2)+(6) | (8) | (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.

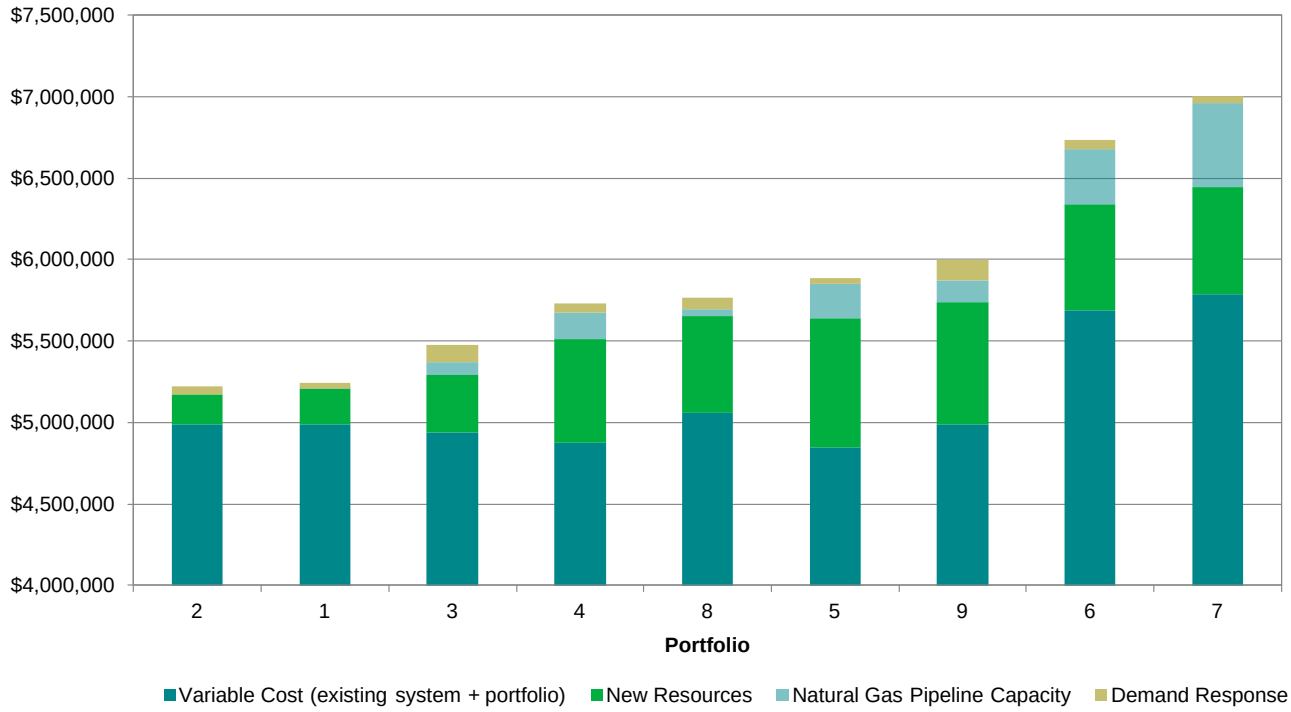



**Figure 9.1 Total portfolio costs, NPV 2013–2032 (2013 dollars, 000s)**

# 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.

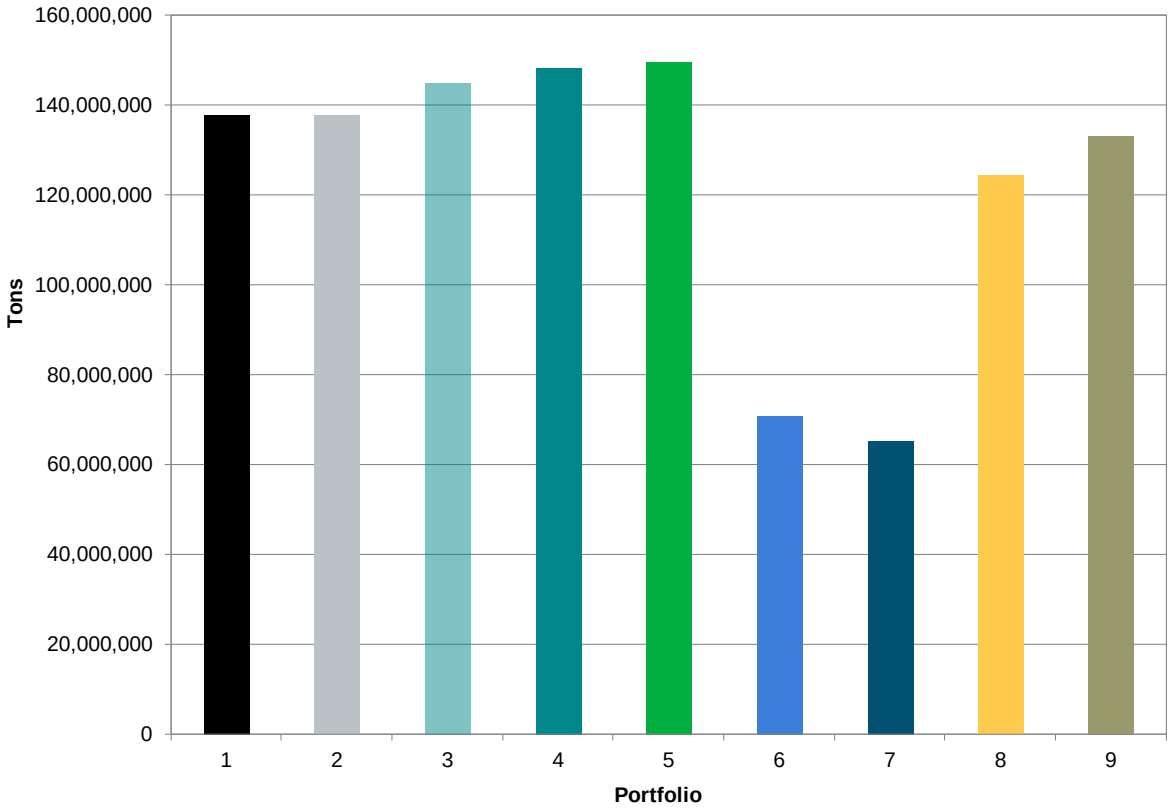



**Figure 9.2 Total $CO_2$ emissions for 2013–2032**

## *$NO_x$ 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.

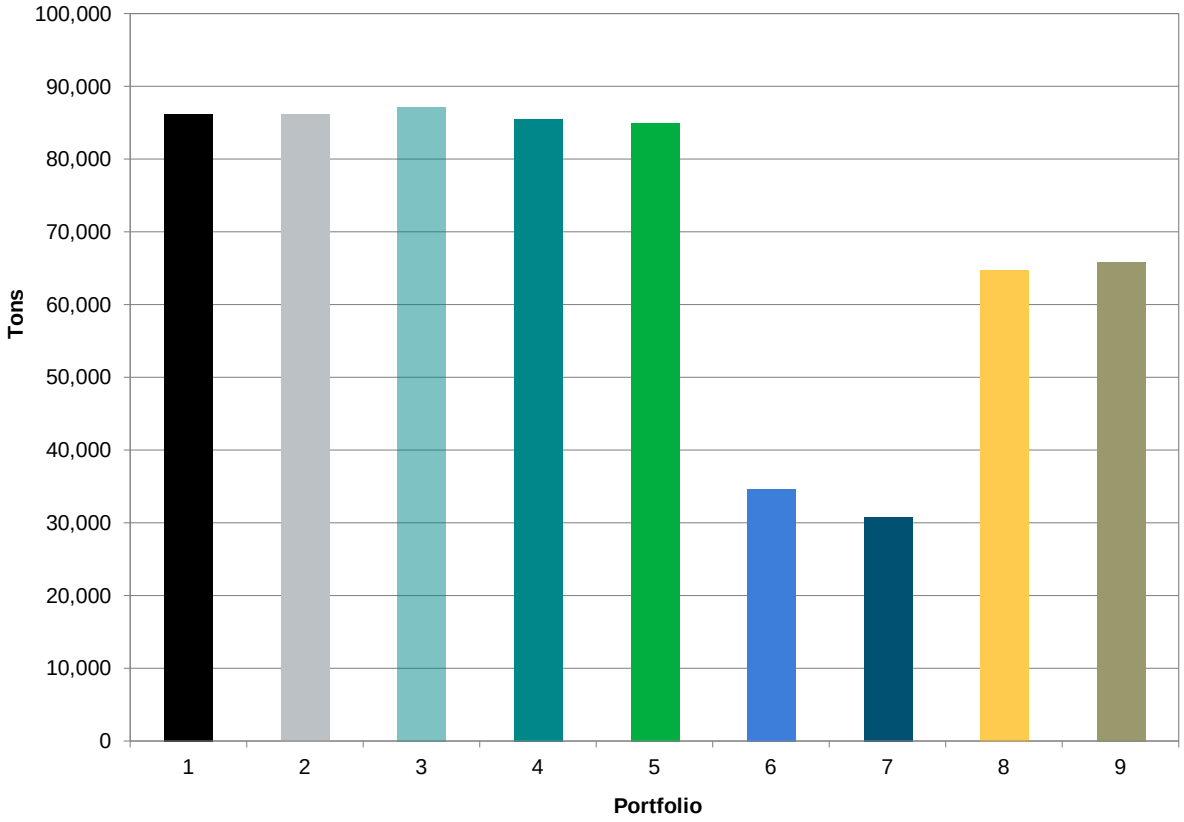



**Figure 9.3 Total $NO_x$ emissions for 2013–2032**

## *$SO_2$ 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.

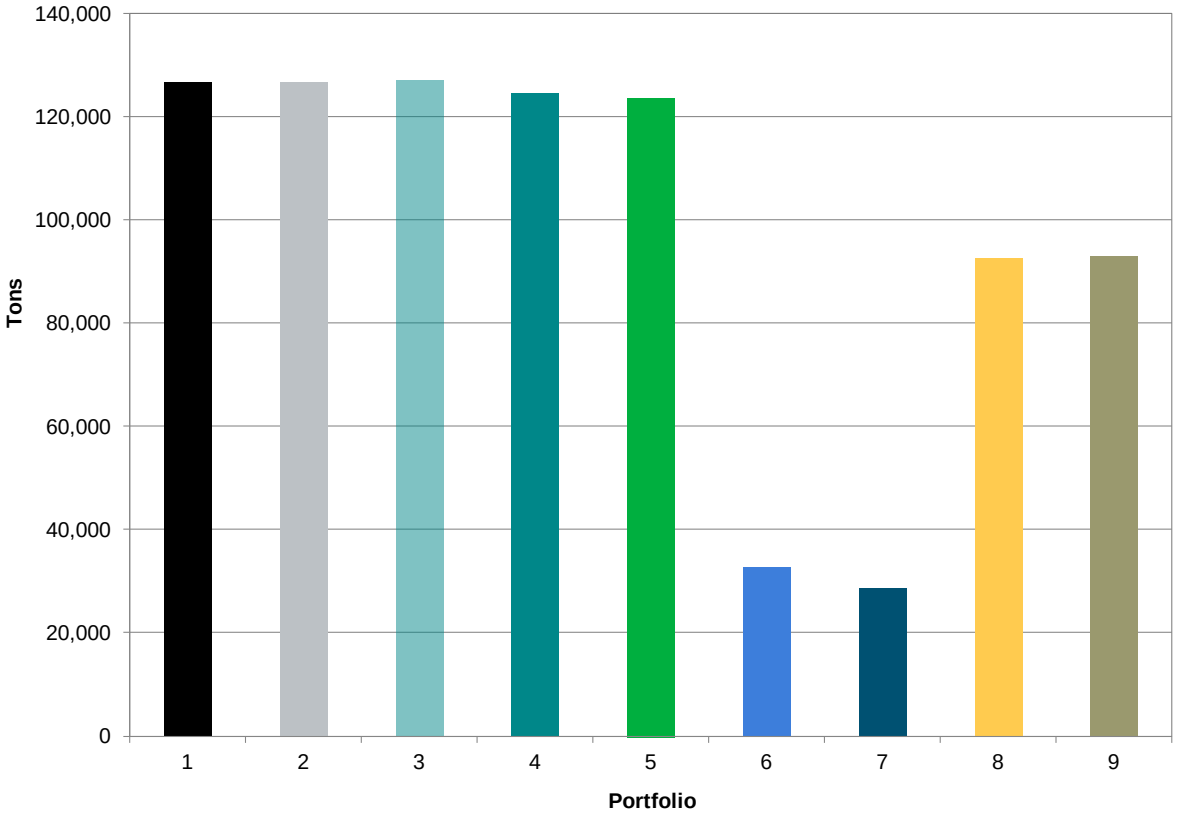



**Figure 9.4 Total $SO_2$ emissions for 2013–2032**

## *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.

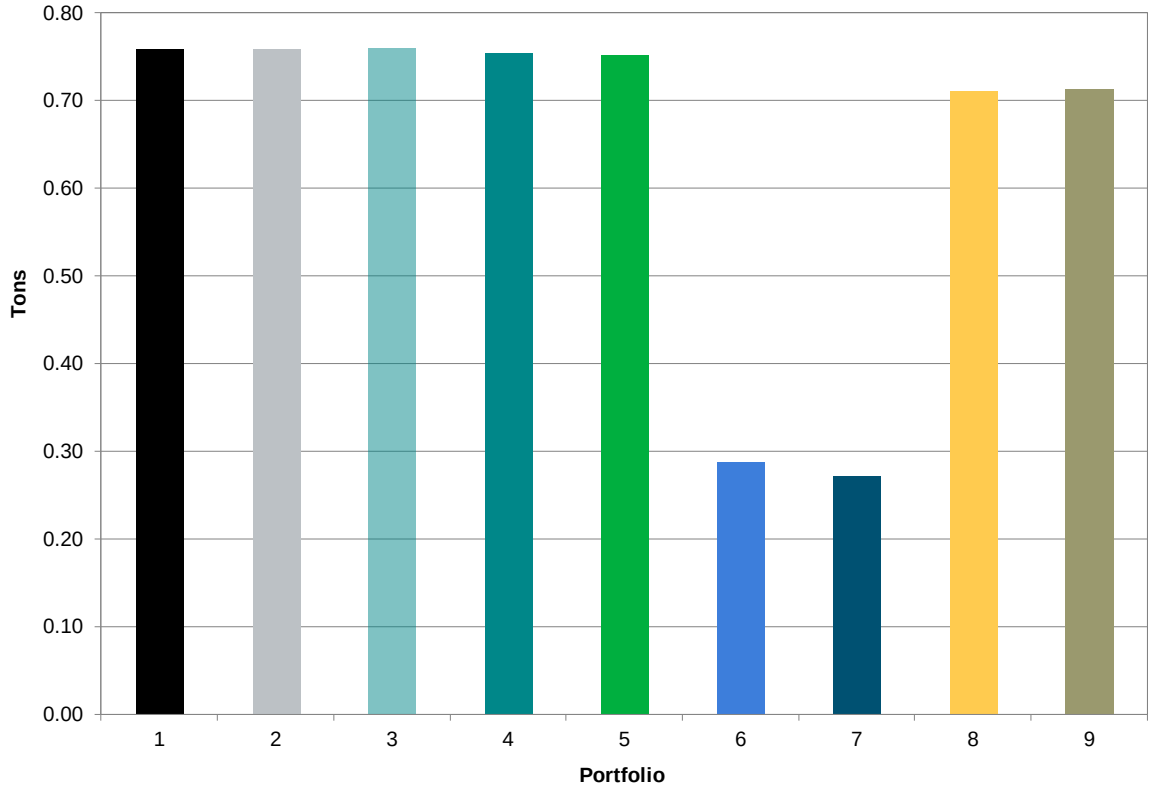



**Figure 9.5 Total Hg emissions for 2013–2032**

## 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.

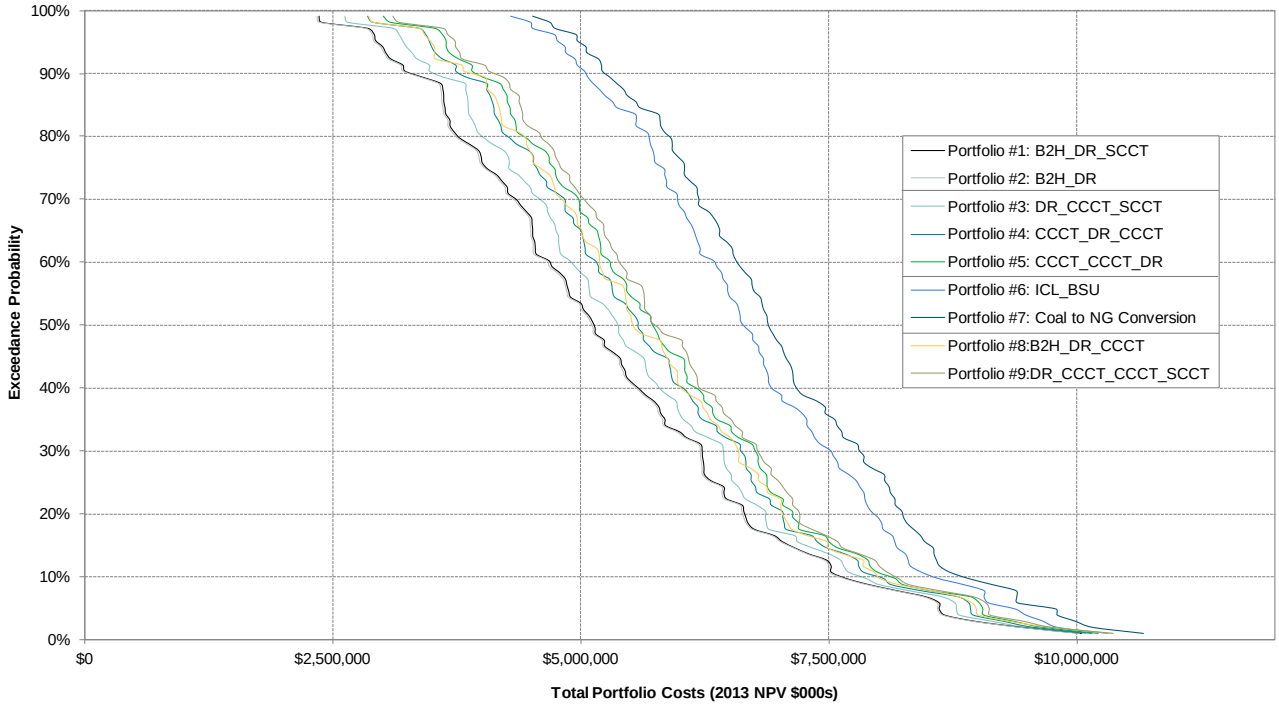



**Figure 9.6 Portfolio stochastic analysis**

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.

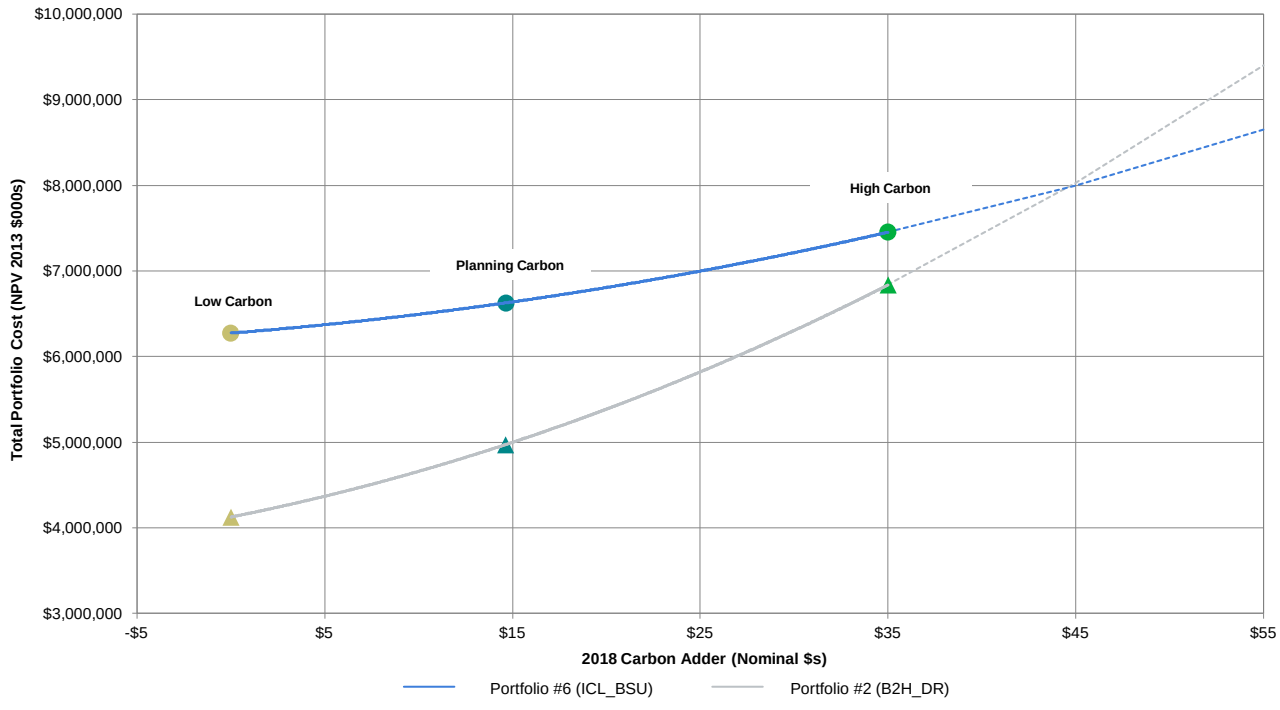



**Figure 9.7 Stochastic-based carbon-adder tipping point**

## 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.

[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.

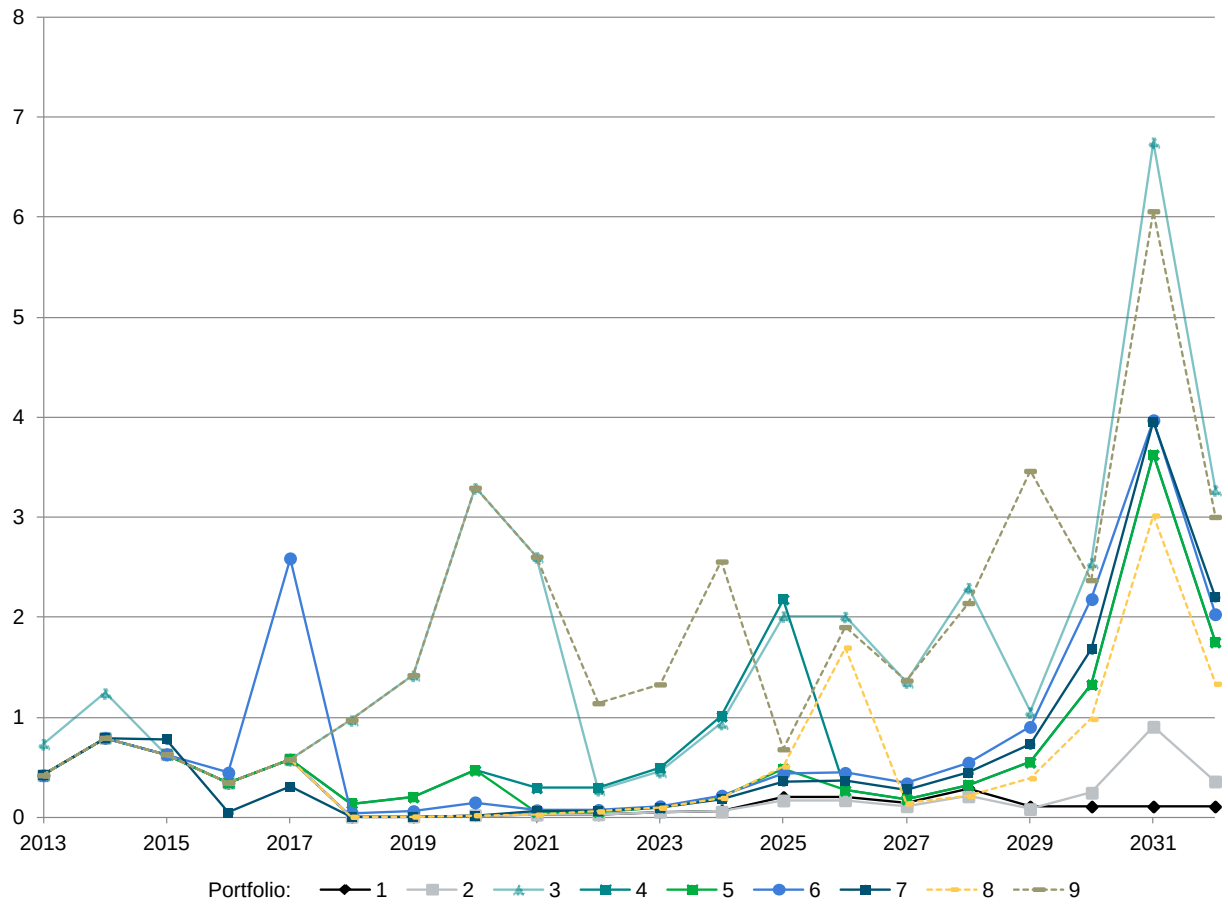



**Figure 9.8 LOLE (hours per year)**

## 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.

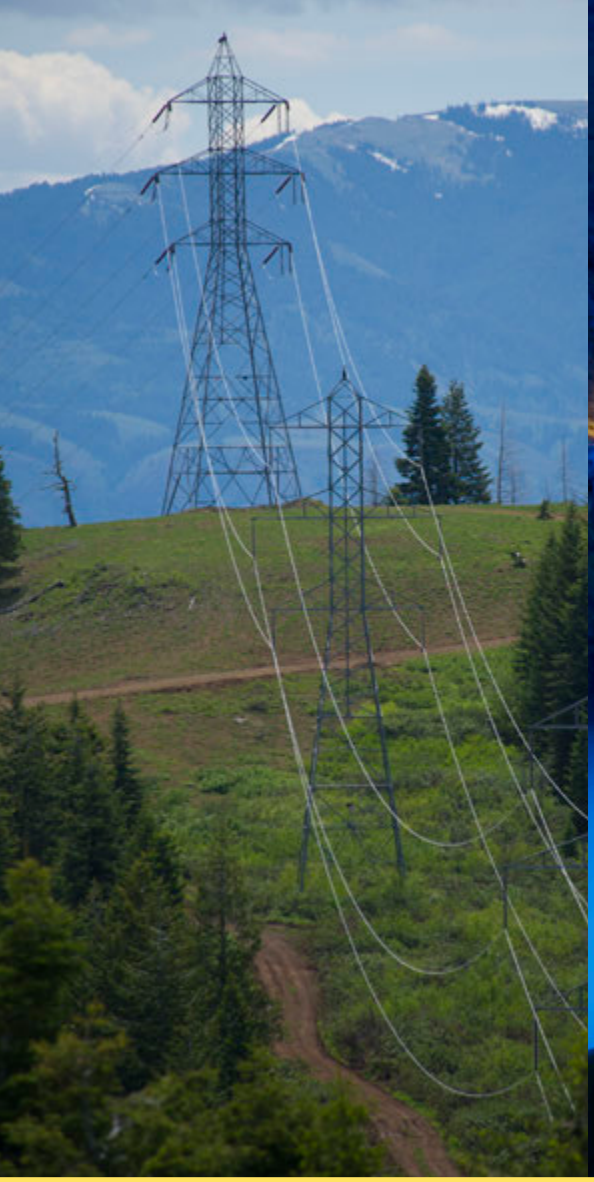
Idaho Power treated the Boardman to Hemingway Transmission line as an uncommitted resource in the 2006, 2009, 2011, and 2013 IRPs. The analysis included as part of the 2013 IRP indicates that it is time for Idaho Power, the transmission line partners, and the various regulatory and governmental agencies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

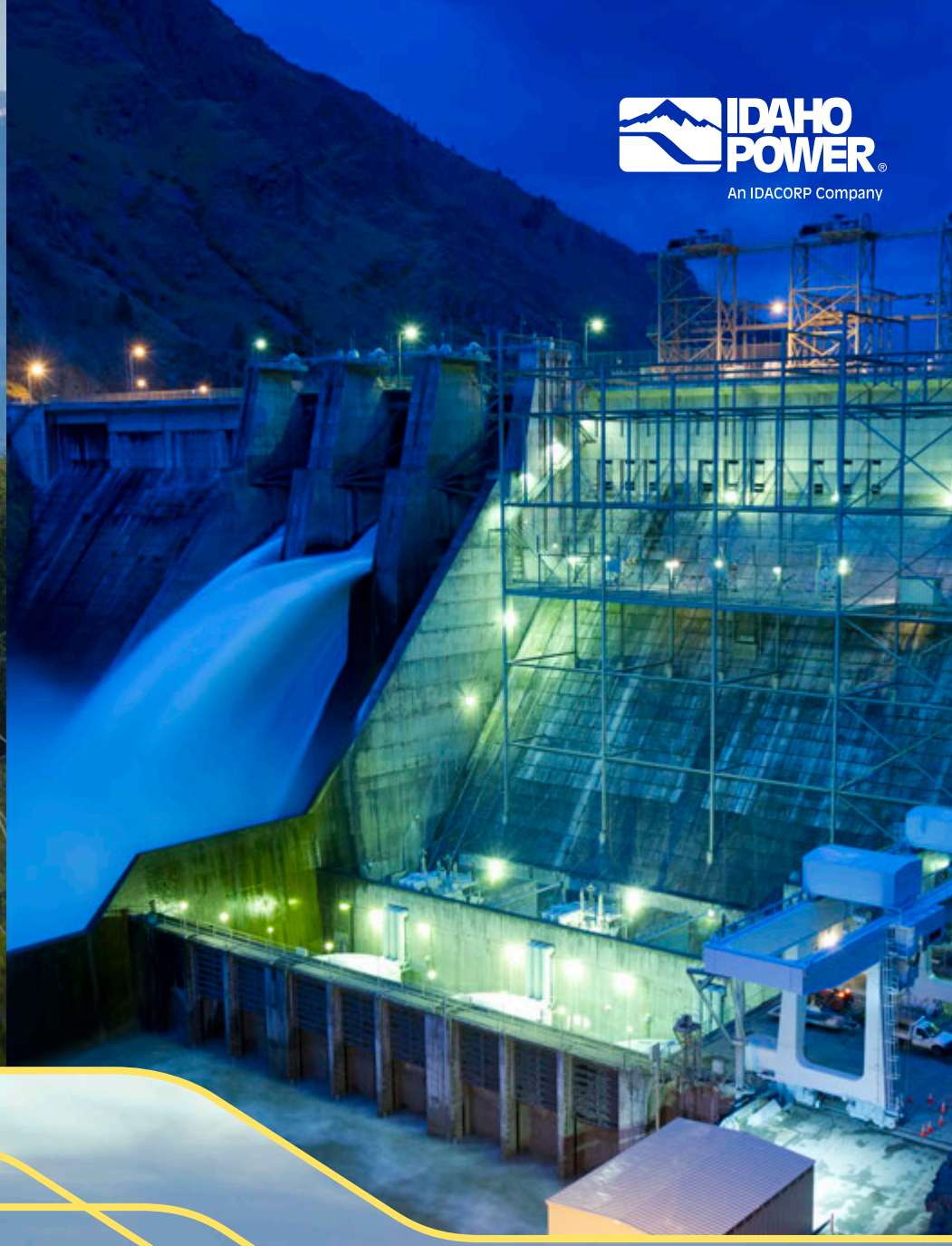
The company's demand response programs will be used throughout the planning period to meet resource needs. The level of demand response capacity available will be based on the deficits identified through the IRP process or on operational needs identified between IRP cycles. The demand response programs 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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IDAHO POWER®
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# 2013 Integrated Resource Plan

## APPENDIX A

# Sales and Load Forecast

June 2013

# 2013

# Integrated Resource Plan

## APPENDIX A

# Sales and Load Forecast


## 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.


## SAFE HARBOR STATEMENT

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

**June 2013**

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# INTRODUCTION

Idaho Power has prepared *Appendix A—Sales and Load Forecast* as an appendix to its *2013 Integrated Resource Plan* (IRP). The sales and load forecast is Idaho Power's best estimate of the future demand for electricity within the company's service area. The forecast covers the 20-year period from 2013 through 2032.

The expected-case monthly average load forecast represents Idaho Power's estimate of the most probable outcome for load growth during the planning period and is based on the most recent economic forecast for Idaho Power's service area. However, the actual path of future electricity sales will not follow the exact path suggested by the expected-case load forecast. Therefore, four additional load forecasts were prepared, two that provide a range of possible load growths due to economic uncertainty and two that address the load variability associated with abnormal weather. The high- and low-growth scenarios provide a range of possible load growths over the planning period due to variable economic, demographic, and other non-weather-related influences. The high-growth and low-growth scenarios were prepared based on statistical analyses to empirically reflect uncertainty inherent in the load forecast. The 70$^{th}$-percentile and 90$^{th}$-percentile load forecast scenarios were developed to assist Idaho Power in reviewing the resource requirements that would result from higher loads due to more adverse weather conditions.

The expected-case load forecast assumes median temperatures and median rainfall. Because actual loads can vary significantly depending on weather conditions, two alternative scenarios were considered: a 70$^{th}$-percentile average load forecast and 90$^{th}$-percentile average load forecast. The 70$^{th}$-percentile load forecast assumes monthly loads that can be exceeded in 3 out of 10 years (30% of the time). The 90$^{th}$-percentile load forecast assumes monthly loads that can be exceeded in 1 out of 10 years (10% of the time).

In the expected-case scenario, Idaho Power's system load is forecast to increase to 2,154 average megawatts (aMW) in the year 2032 from the 2013 forecast load of 1,759 aMW. The expected-case forecast system load growth rate averages 1.1 percent per year over the 20-year planning period (2013–2032). In the more critical 70$^{th}$-percentile load forecast used for resource planning, the system load is forecast to reach 2,201 aMW by 2032. The Idaho Power system peak load (95$^{th}$ percentile) is forecast to grow to 4,418 megawatts (MW) in the year 2032 from the actual system summer peak of 3,245 MW that occurred on Thursday, July 12, 2012, at 4:00 p.m. In the expected-case scenario, the Idaho Power system peak increases at an average growth rate of 1.4 percent per year over the 20-year planning period (2013–2032). The number of Idaho Power active retail customers is expected to increase from the December 2012 level of 500,000 customers to over 667,000 customers at year-end 2032.

This year's economic forecast was 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 *Appendix A—Sales and Load Forecast*. The national, state, metropolitan statistical area (MSA), and county econometric projections are tailored to Idaho Power's service area using an in-house economic forecast model and database. Specific demographic projections are also developed for the service

area from national and local census data. National economic drivers from Moody's Analytics were also used in the development of *Appendix A—Sales and Load Forecast*.

Economic growth assumptions influence several classes of service growth rates. The number of households in Idaho is projected to grow at an annual average rate of 1.2 percent during the forecast period. The growth in the number of households within individual counties in Idaho Power's service area differs from statewide household growth patterns. Service area households are derived from county-specific household forecasts. The number of households, incomes, employment projections, economic output, real retail electricity prices, and customer consumption patterns are used to develop load projections.

In addition to the economic assumptions used to drive the expected-case forecast scenario, several specific assumptions were incorporated into the forecasts of the individual sectors. Further discussion of the assumptions is presented in the sections of this report pertaining to the individual sectors.

The future load impacts of implemented and committed Idaho Power energy efficiency demand-side management (DSM) programs are considered within *Appendix A—Sales and Load Forecast*. These programs and their expected impacts are addressed in more detail in Idaho Power's *Demand-Side Management 2012 Annual Report*. This report is Appendix B to the 2013 IRP.

During the 20-year forecast horizon, there could be major changes in the electric utility industry, such as carbon regulations and subsequent higher electricity prices impacting future electricity demand. In addition, the price and volatility of substitute fuels, such as natural gas, may also impact future demand for electricity. The high degree of uncertainty associated with such changes is reflected in the economic high- and low-load growth scenarios previously described. The impact of carbon legislation on the load forecast is reflected in retail electricity prices, which are a driver in the major sector sales forecasting model. The alternative sales and load scenarios of *Appendix A—Sales and Load Forecast* were prepared under the assumption that Idaho Power will continue to serve all customers in its franchised service area during the planning period.

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

# 2013 IRP Sales and Load Forecast

## Average Load

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 reflected in the economic forecast used for the 2011 IRP was determined too optimistic in terms of a rapid recovery from the recession. The updated variables driving the 2013 forecast reflect this recent performance. The stalled recovery in the national and, to a lesser extent, 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 to date. Longer-term, higher-retail electricity price assumptions that incorporate estimates of assumed carbon legislation serve to decrease the forecast of average loads, especially in the second 10 years of the forecast period.

Significant factors and considerations that influenced the outcome of the 2013 IRP load 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 new 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 this 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 Demands

Peak-day temperatures and the growth in average loads drive the peak forecasting model regressions. The peak forecast results and comparisons with previous forecasts differ for a number of reasons that 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 82 MW of peak demand originally anticipated are excluded from this sales and load forecast.

- As referenced previously, the 2011 IRP sales and load forecast included a new customer referred to as "Special" that failed to materialize. For the 2013 IRP, Idaho Power has assumed this "Special" contract will not come on-line, and the 60 MW of peak demand originally anticipated is excluded from this sales and load forecast.

- The 2013 IRP peak-demand forecast considers the impact of committed and implemented energy efficiency DSM programs on peak demand.

- The 2013 IRP peak-demand forecast model explicitly excludes the impact of demand response programs to establish peak impacts to effectively plan for demand response and supply-side resources in meeting peak demand. Demand response programs impacts are accounted for in the IRP load and resource balance as a reduction in peak demand.

- The peak model develops peak-scenario impacts based on historical probabilities of peak-day temperatures at the $50^{th}$, $90^{th}$, and $95^{th}$ percentiles of occurrence for each month of the year.

- Historical peak-demand data is considered in the peak-model regressions. Based on a historical comparison of percentiles, the July 2002, July 2003, June 2005, and July 2005 peak-day temperatures were near the $100^{th}$ percentile, and their addition to the regression models impacted forecast results. More recently, all-time system peaks were reached in July 2007, June 2008, and July 2012 and were incorporated into the peak forecast model regressions.

- Idaho Power continues to use a median peak-day temperature driver in lieu of an average peak-day temperature driver. The median peak-day temperature has a 50-percent probability of being exceeded. Peak-day temperatures are not normally distributed and can be skewed by one or more extreme observations as referred to in the previous bulleted item; therefore, the median temperature better reflects expected temperatures within the context of probabilistic percentiles. The weighted average peak-day temperature drivers are calculated over the 1982 to 2011 time period (the most recent 30 years).

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# OVERVIEW OF THE FORECAST

The sales and load forecast is constructed by developing a separate forecast for each sales category. Independent sales forecasts are prepared for each of the major customer classes: residential, commercial, irrigation, and industrial. Individual energy and peak-demand forecasts are developed for special-contract customers, including Micron Technology, Inc.; Simplot Fertilizer Company (Simplot Fertilizer); the Idaho National Laboratory (INL); and Hoku Materials. These four special-contract customers are combined into a single forecast category labeled additional firm load. Last, the contract off-system category represents long-term contracts to supply firm energy and demand to off-system customers. At this time, there are no long-term contracts. The assumptions for each of the individual categories are described in greater detail in the respective sections.

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

Loss factors are determined by Idaho Power's Distribution Planning department. The annual average energy loss coefficients are multiplied by the calendar-month load, yielding the system load, including losses.

The peak-load forecast was prepared in conjunction with the 2013 sales forecast. Idaho Power has two distinct peak periods: 1) a winter peak, resulting from space-heating demand that normally occurs in December, January, or February; and 2) a larger summer peak that normally occurs in late June or July. The summer peak generally occurs when extensive air conditioning (A/C) use coincides with significant irrigation demand.

Peak loads are forecast using 12 regression equations and are a function of average peak-day temperatures, the historical monthly average load, and precipitation (summer only). The peak forecast uses statistically derived peak-day temperatures based on the most recent 30 years of climate data for each month. Peak loads for the INL, Micron Technology, and Simplot Fertilizer are forecast based on a historical analysis and contractual considerations.

The primary external factors in the forecast are macroeconomic and demographic data. Moody's Analytics provides the macroeconomic forecasts. The national, state, MSA, and county economic and demographic projections are tailored to Idaho Power's service area using an economic database developed by an outside consultant. Specific demographic projections are also developed for the service area from national and local census data.

## Fuel Prices

Fuel prices, in combination with service-area economic drivers, impact long-term trends in electricity sales. Changes in relative fuel prices can also have significant impacts on the future

demand for electricity. The sales and load forecast is also influenced by the estimated impact of proposed carbon legislation on retail electricity prices. The carbon-impacted retail electricity prices move higher throughout the forecast period, reducing future electricity sales. Class level and economic-sector-level regression models were used to identify the relationships between real historical electricity prices and historical electricity sales. The estimated coefficients from these models were used as drivers in the individual sales forecast models.

Short-term and long-term nominal electricity price increases are generated internally from Idaho Power financial models. The United States (US) Energy Information Administration (EIA) provides the forecasts of long-term changes in nominal natural gas prices. The nominal price estimates are adjusted for projected inflation by applying the appropriate economic deflators to arrive at real fuel prices. The projected average annual growth rates of fuel prices in nominal and real terms (adjusted for inflation) are presented in Table 1. The growth rates shown are for residential fuel prices and can be used as a proxy for fuel-price growth rates in the commercial, industrial, and irrigation sectors.

**Table 1. Residential fuel-price escalation (2013–2032) (average annual percent change)**

| | Nominal | Real* |
|---|---|---|
| Electricity—2013 IRP | 3.2% | 1.3% |
| Electricity—2011 IRP | 1.5% | (0.1%) |
| Natural Gas | 3.2% | 1.3% |

* Adjusted for inflation

Figure 1 illustrates the average electricity price paid by Idaho Power's residential customers over the historical period 1972 to 2012 and over the forecast period 2013 to 2032. Both nominal and real prices are shown. In the 2013 IRP, nominal electricity prices are expected to climb to nearly 17 cents per kilowatt-hour (kWh) by the end of the forecast period in 2032. Real electricity prices (inflation adjusted) are expected to increase over the forecast period at an average rate of 1.3 percent annually. In the 2011 IRP, nominal electricity prices were assumed to slowly climb to nearly 13 cents per kWh by 2032, and real electricity prices (inflation adjusted) were expected to remain flat over the forecast period at an average rate of -0.1 percent annually. The impact of the higher real electricity price forecast on the 2013 IRP load forecast serves to slow the growth in electricity sales, especially in the last 10 years of the forecast period.

The electricity price forecast used to prepare the sales and load forecast in the 2013 IRP reflected 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 yielded 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.

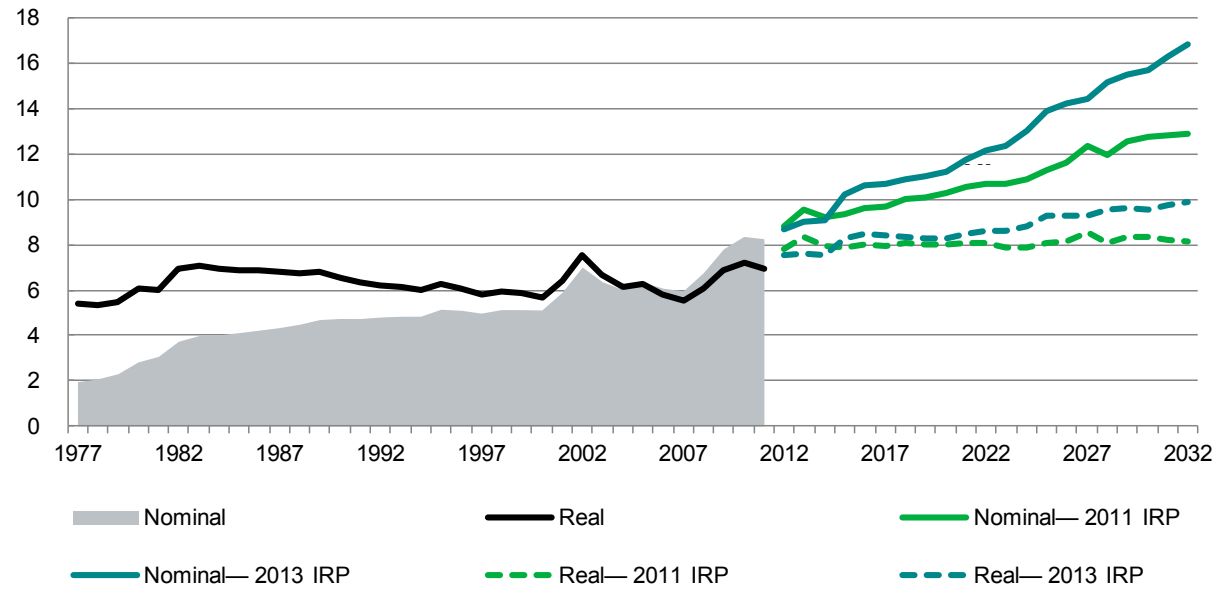



**Figure 1. Forecast residential electricity prices (cents per kWh)**

Electricity prices for Idaho Power customers increased significantly in 2001 and 2002 because of the power cost adjustment (PCA) impact on rates, a direct result of the western US energy crisis of 2000 and 2001. Prior to 2001, Idaho Power's electricity prices were historically quite stable. From 1990 to 2000, electricity prices rose only 8 percent overall, an annual average compound growth rate of 0.8 percent annually.

Figure 2 illustrates the average natural gas price paid by Intermountain Gas Company's residential customers over the historical period 1970 to 2011 and forecast prices from 2012 to 2032. Natural gas prices remained stable and flat throughout the 1990s before moving sharply higher in 2001. Since spiking in 2001, natural gas prices moved downward for a couple of years before moving sharply upward in 2004 through 2006. The collapse in natural gas prices that began in 2009 led to much lower prices in 2010 and 2011. Nominal natural gas prices are expected to rise slowly through 2014, then more rapidly throughout the remainder of the forecast period until nearly doubling at an average rate of 3.2 percent per year. Real natural gas prices (adjusted for inflation) are expected to increase over the same period at an average rate of 1.3 percent annually.

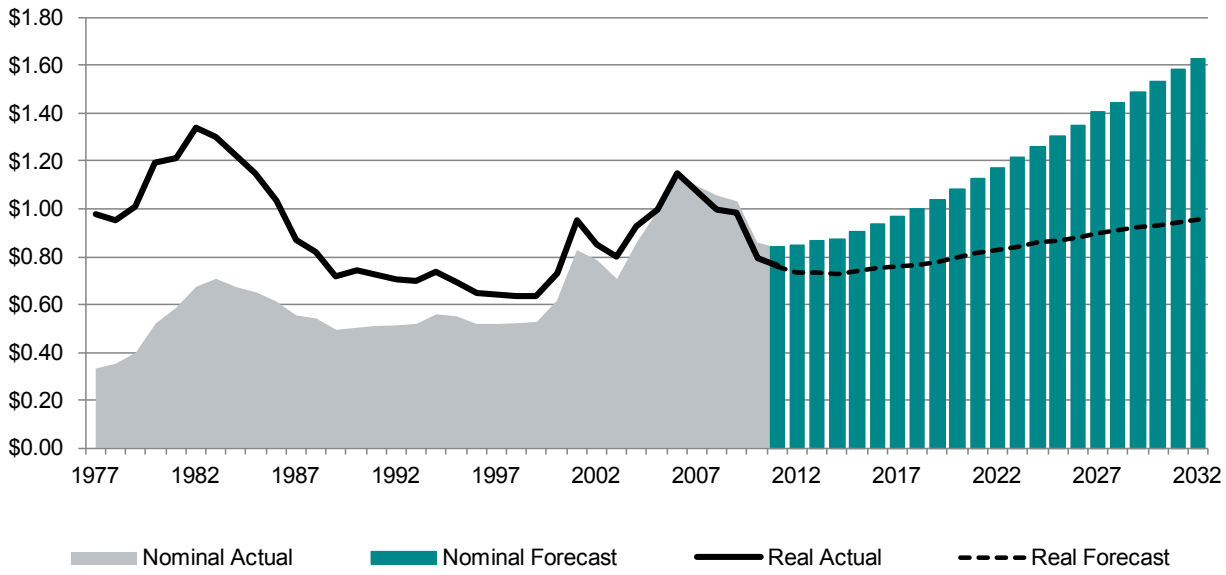



**Figure 2. Forecast residential natural gas prices (dollars per therm)**

If future natural gas price increases outpace electricity price increases, the operating costs of space heating and water heating with electricity would become more advantageous when compared to that of natural gas. However, in the 2013 IRP price forecast, the long-term growth rates of electricity and natural gas prices are nearly identical.

## Electric Vehicles

The load forecast includes an update of the impact of plug-in electric vehicles on the system load. The 2011 IRP forecast model relied heavily on the forecast methodologies of the Electric Power Research Institute (EPRI) and Oak Ridge National Laboratory. At the time, these models did not have actual consumer adoption data or most recent domestic fuel supply impacts of advanced technologies in crude oil production. The 2013 IRP electric-vehicle forecast update integrates service area vehicle registration data with updated technological and economic variables impacting adoption, as well as vehicle charging behavior. This update also integrates the fuel and technology forecasts of the Department of Energy's (DOE) National Energy Model (NEM).

The Idaho Power vehicle share forecast is based on a Bass diffusion model of adoption as informed by actual vehicle registration. Load impacts from adoption are derived from assumptions of battery-only and hybrid plug-in shares evident from historical registration data and informed by NEM forecasts. The combined vehicle forecast represents just over 4 percent of new vehicle sales in the service area at the end of the planning period. Battery-only vehicles represent 15 percent of the total, and the updated forecast model reflects a much slower adoption rate than anticipated in the 2011 forecast. The all-electric share is consistent with the DOE Annual Energy Outlook (AEO) 2013 update that forecasts all-electric vehicles at less than 1 percent of sales in 2040.

The resulting impact on the load forecast is about 1 aMW in 2020, reaching approximately 4 aMW at the end of the forecast period in 2032. The load impacts were allocated to the residential and commercial sales forecasts using an 80/20 split, respectively.

Idaho Power continues to capture consumer behavioral data and other salient market information associated with electric-vehicle adoption to improve the forecasting model in future forecasts.

# Forecast Probabilities

## *Load Forecasts Based on Weather Variability*

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

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

Maximum load occurs when the highest recorded levels of heating degree days (HDD) are assumed in winter and the highest recorded levels of cooling and growing degree days (CDD and GDD) combined with the lowest recorded level of precipitation are assumed in summer. Conversely, the minimum load occurs when the lowest recorded levels of HDD are assumed in winter and the lowest recorded levels of CDD and GDD, combined with the highest level of precipitation, are assumed in summer.

For example, at the Boise Weather Service office, the median HDD in December from 1982 to 2011 (the most recent 30 years) was 1,039. The 70$^{th}$-percentile HDD is 1,074 and would be exceeded in 3 out of 10 years. The 90$^{th}$-percentile HDD is 1,291 and would be exceeded in 1 out of 10 years. The 100$^{th}$-percentile HDD (the coldest December over the 30 years) is 1,619 and occurred in December 1985. This same concept was applied in each month throughout the year in only the weather-sensitive customer classes: residential, commercial, and irrigation.

In the 70$^{th}$-percentile residential and commercial load forecasts, temperatures in each month were assumed to be at the 70$^{th}$ percentile of HDD in wintertime and at the 70$^{th}$ percentile of CDD in summertime. In the 70$^{th}$-percentile irrigation load forecast, GDD were assumed to be at the 70$^{th}$ percentile and precipitation at the 30$^{th}$ percentile, reflecting drier-than-median weather. The 90$^{th}$-percentile load forecast was similarly constructed.

Idaho Power loads are highly dependent on weather, and these two scenarios allow the careful examination of load variability and how it may impact future resource requirements. It is

important to understand that the probabilities associated with these forecasts apply to any given month. To assume temperatures and precipitation would maintain a 70th-percentile or 90th-percentile level continuously, month after month throughout an entire year, would be much less probable. Monthly forecast numbers are evaluated for resource planning, and caution should be used in interpreting the meaning of the annual average load figures being reported and graphed for the 70th-percentile or 90th-percentile forecasts.

Table 2 summarizes the load scenarios prepared for the 2013 IRP. Three average load scenarios were prepared based on a statistical analysis of the historical monthly weather variables listed. The probability associated with each average load scenario is also indicated in the table. In addition, three peak-demand scenarios were prepared based on a statistical analysis of historical peak-day average temperatures, and the probability associated with each peak-demand scenario is also indicated in Table 2.

**Table 2. Average load and peak-demand forecast scenarios**

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

The analysis of resource requirements is based on the 70th-percentile average load forecast coupled with the 95th-percentile peak-demand forecast to provide a more adverse representation of the average load and peak demand to be considered. In other Idaho Power planning, such as the preparation of the financial forecast or the operating plan, the expected-case (50th percentile) average-load forecast and the 90th-percentile peak-demand forecast are typically used.

## *Load Forecasts Based on Economic Uncertainty*

The expected-case load forecast is based on the most recent economic forecast for Idaho Power's service area and represents Idaho Power's most probable outcome for load growth during the planning period. The expected-case load forecast reflects the integration of existing energy efficiency DSM program effects as a reduction to the average load forecast. In addition, retail electricity prices also impact the growth in electricity sales long term.

Two additional load forecasts for the Idaho Power service area were prepared. The forecasts provide a range of possible load growths for the 2013 to 2032 planning period due to high and low economic and demographic conditions. The high- and low-economic-growth scenarios were prepared based on a statistical analysis to empirically reflect the uncertainty inherent in the load forecast. The average growth rates for the high- and low-growth scenarios were derived from the historical distribution of one-year growth rates over the past 25 years (1987–2011).

The estimated probabilities for the three load scenarios are reported in Table 2. The standard deviation observed during the historical time period is used to estimate the dispersion around the expected-case scenario. The probability estimates assume the expected forecast is the median growth path (i.e., there is a 50-percent probability the actual growth rate will be less than the expected-case growth rate and a 50-percent chance the actual growth rate will be greater than the expected-case growth rate). In addition, the probability estimates assume the variation in growth rates will be equivalent to the variation in growth rates observed over the past 25 years (1987–2011). The high- and low-case load forecasts also reflect the integration of existing energy efficiency DSM program effects as a reduction to the average load wintertime forecasts.

Two types of probability estimates are reported in Table 3. The first probability, the probability of exceeding, shows the likelihood that the actual load growth will be greater than the projected growth rate in the specified scenario. For example, over the next 20 years, there is a 10-percent probability the actual growth rate will exceed the growth rate projected in the high scenario; conversely, there is a 10-percent chance the actual growth rate will fall below that of the low scenario. In other words, over a 20-year period, there is an 80-percent probability that the actual growth rate of system load will fall between the growth rates projected in the high and low scenarios. The second probability estimate, the probability of occurrence, indicates the likelihood that the actual growth will be closer to the growth rate specified in that scenario than to the growth rate specified in any other scenario. For example, there is a 26-percent probability the actual growth rate will be closer to the high scenario than to any of the other forecast scenarios for the entire 20-year planning horizon. Probabilities for shorter, 1-year, 5-year, and 10-year time periods are also shown in Table 3.

**Table 3. Forecast probabilities**

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

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

Idaho Power system load projections are reported in Table 4 and pictured in Figure 3. The expected-case system load-forecast growth rate averages 1.1 percent per year over the 20-year planning period. The low scenario projects the system load will increase at an average rate of 0.6 percent per year throughout the forecast period. The high scenario projects load growth of 1.5 percent per year. Idaho Power has experienced both the high- and low-growth rates in the past. These scenario forecasts provide a range of projected growth rates that cover

approximately 80 percent of the probable outcomes as measured by Idaho Power's historical experience.

**Table 4. System load growth (aMW)**

| Growth | 2013 | 2017 | 2022 | 2032 | Annual Growth Rate 2013–2032 |
|---|---|---|---|---|---|
| Low | 1,738 | 1,760 | 1,826 | 1,949 | 0.6% |
| Expected | 1,759 | 1,842 | 1,956 | 2,154 | 1.1% |
| High | 1,829 | 1,972 | 2,145 | 2,447 | 1.5% |

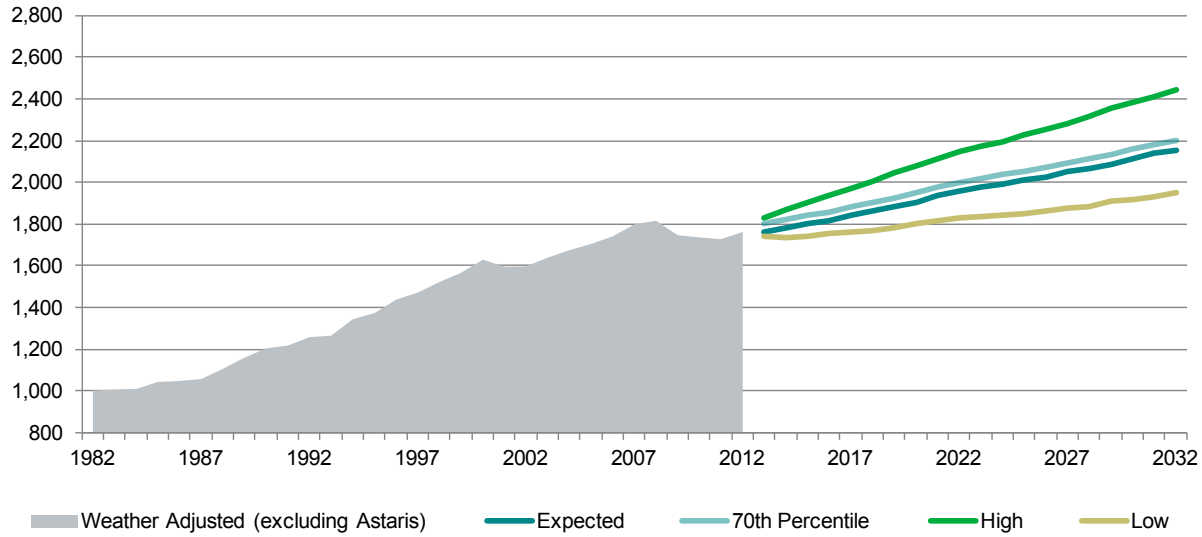



**Figure 3. Forecast system load (aMW)**

# RESIDENTIAL

The expected-case residential load is forecast to increase from 574 aMW in 2013 to 704 aMW in 2032, an average annual compound growth rate of 1.1 percent. In the 70th-percentile scenario, the residential load is forecast to increase from 590 aMW in 2013 to 724 aMW in 2032, matching the expected-case residential growth rate. The residential load forecasts are reported in Table 5 and shown graphically in Figure 4.

**Table 5. Residential load growth (aMW)**

| Growth | 2013 | 2017 | 2022 | 2032 | Annual Growth Rate 2013–2032 |
|---|---|---|---|---|---|
| 90th Percentile | 623 | 649 | 687 | 763 | 1.1% |
| 70th Percentile | 590 | 614 | 650 | 724 | 1.1% |
| Expected Case | 574 | 597 | 632 | 704 | 1.1% |

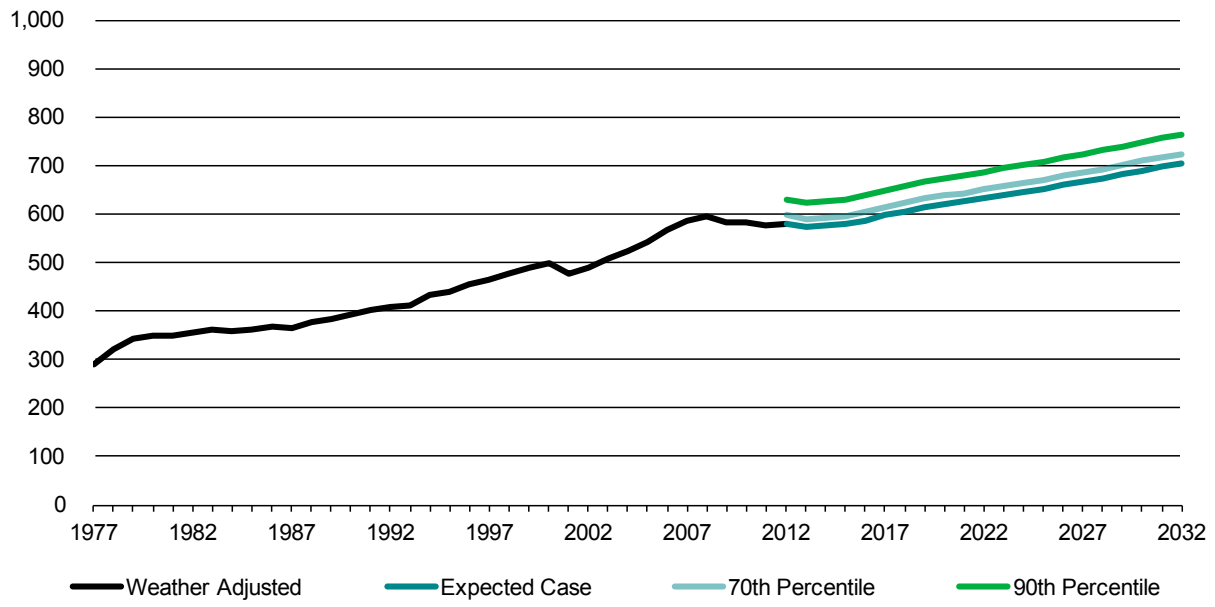



**Figure 4. Forecast residential load (aMW)**

Sales to residential customers made up 33 percent of Idaho Power's system sales in 1982 and 36 percent of system sales in 2012. The residential customer proportion of system sales is forecast to be approximately 36 percent in 2032. There were 416,000 residential customers as of December 2012. The number of residential customers is projected to increase to approximately 554,000 by December 2032. The relative customer proportions of Idaho Power's system electricity sales are shown in Figure 15.

The average sales per residential customer were 13,700 kWh in 1977. Average sales increased to over 14,800 kWh per residential customer in 1979 before declining to 13,200 kWh in 2001. In 2002 and 2003, residential use per customer dropped dramatically—over 500 kWh per

customer from 2001—the result of two years of significantly higher electricity prices combined with a weak national and service-area economy. The reduction in electricity prices in June 2003 and a recovery in the service-area economy caused residential use per customer to stabilize and rise through 2007. However, the recession in 2008 and 2009, combined with conservation programs designed to reduce electricity use served to slow the growth in residential use per customer. The average sales per residential customer are expected to slowly decline to approximately 11,200 kWh per year in 2032. Average annual sales per residential customer are shown in Figure 5.

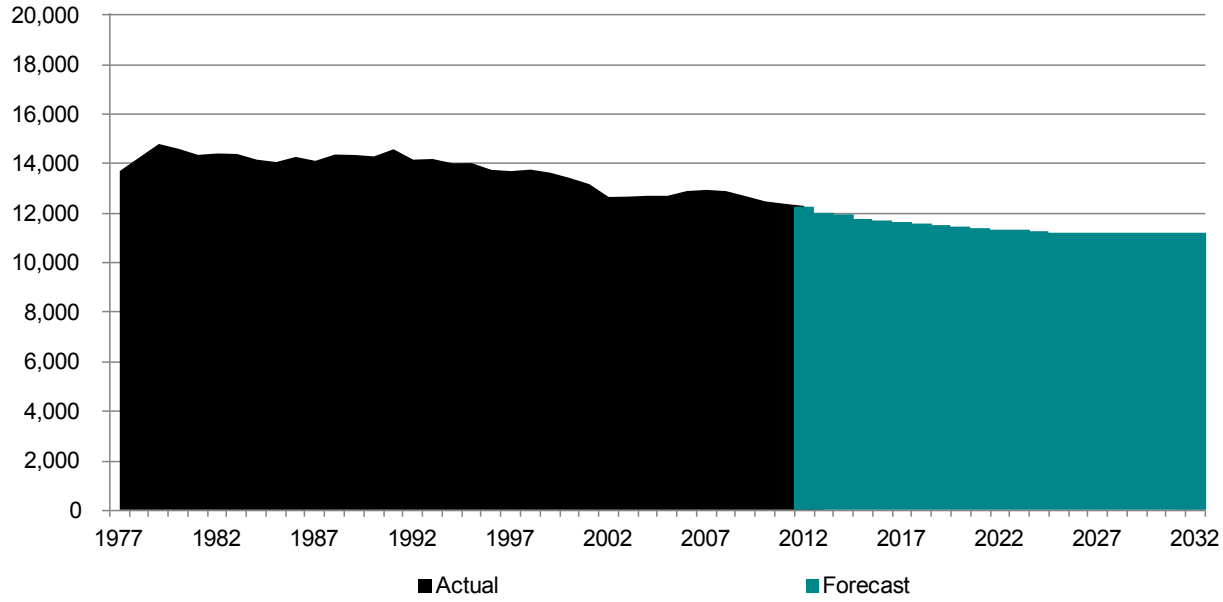



**Figure 5. Forecast residential use per customer (weather-adjusted kWh)**

The residential-use-per-customer forecast is based on a forecast of the number of residential customers and an econometric analysis of residential-sector sales. The number of residential customers being added each year is a direct function of the number of new service-area households as derived from Moody's Analytics June 2012 forecast of county housing stock and demographic data. The residential-customer forecast for 2013 to 2032 shows an average annual growth rate of 1.5 percent.

The residential sales forecast equation considers several factors affecting electricity sales to the residential sector. Residential sales are a function of HDD (wintertime), CDD (summertime), the number of service-area households as derived from Moody's Analytics forecasts of county housing stock, the real price of electricity, and the real price of natural gas. The forecast of residential use per customer is arrived at by dividing the residential sales forecast, which considers the impact of forecast DSM, by the residential-customer forecast.

# COMMERCIAL

The commercial category is primarily made up of Idaho Power's small general-service and large general-service customers. Other schedules considered part of the commercial category are unmetered general-service, street-lighting service, traffic-control signal-lighting service, and dusk-to-dawn customer lighting.

In the expected-case scenario, the commercial load is projected to increase from 446 aMW in 2013 to 549 aMW in 2032. The average annual compound-growth rate of the commercial load is 1.1 percent during the forecast period. As referred to previously, the forecast does not include an assumption for growth from new customers that deviate from historical business failure and startup parameters. As summarized in Table 6, the commercial load in the 70$^{th}$-percentile scenario is projected to increase from 451 aMW in 2013 to 556 aMW in 2032. The commercial load forecasts are illustrated in Figure 6.

**Table 6. Commercial load growth (aMW)**

| Growth | 2013 | 2017 | 2022 | 2032 | Annual Growth Rate 2013–2032 |
|---|---|---|---|---|---|
| 90$^{th}$ Percentile | 463 | 485 | 510 | 572 | 1.1% |
| 70$^{th}$ Percentile | 451 | 472 | 496 | 556 | 1.1% |
| Expected Case | 446 | 466 | 490 | 549 | 1.1% |

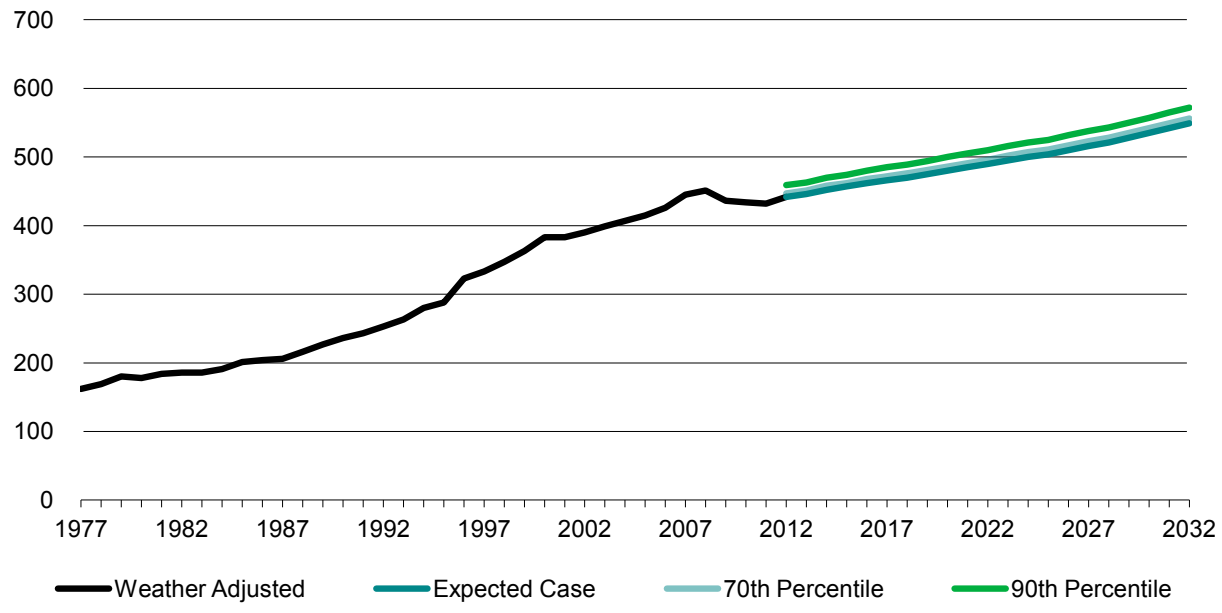



**Figure 6. Forecast commercial load (aMW)**

As of December 2012, Idaho Power had 66,000 commercial customers. The number of commercial customers is expected to increase at an average annual growth rate of 1.6 percent, reaching 90,200 customers by 2032. Commercial customers consumed nearly 17 percent of Idaho Power system sales in 1982 and nearly 28 percent of system sales in 2012.

The commercial customer proportion of system sales is projected to remain at 28 percent of system sales by 2032. The relative customer proportions of Idaho Power's system electricity sales are shown in Figure 15.

The average consumption per commercial customer increased to a record 67,300 kWh in 2001. However, two years of significantly higher electricity prices combined with a weak national and service-area economy caused a setback in the growth of commercial use per customer beginning in 2002. The reduction in electricity prices in June 2003 and a recovery in the service-area economy slowed the rate of decline in commercial use per customer through 2007. However, a severe recession in 2008 and 2009 caused commercial use per customer to drop considerably. After flattening out from 2010 to 2012, commercial use per customer is projected to rise slowly through 2014 as the economy recovers, then continue its downward trend. The primary reasons for the long-term decline are higher retail electricity prices due to generating plant additions and DSM program impacts on energy sales. The average consumption per commercial customer is expected to decrease to approximately 53,500 kWh in 2032. The forecast average annual use per commercial customer is shown in Figure 7.

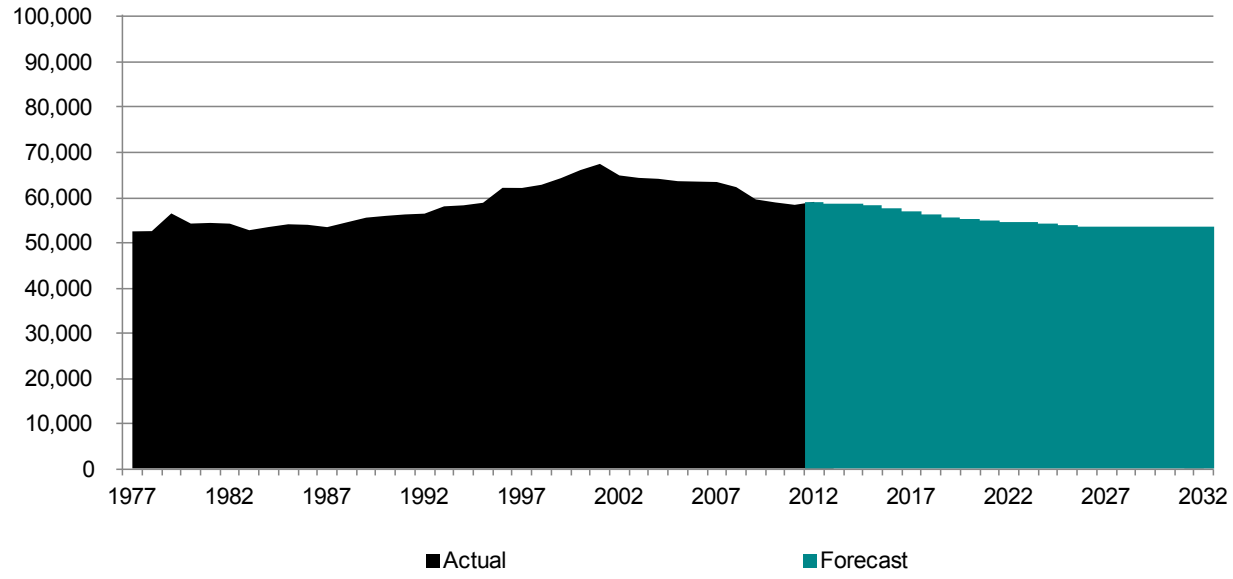



**Figure 7. Forecast commercial use per customer (weather-adjusted kWh)**

The commercial-use-per-customer forecast is based on a forecast of the number of commercial customers and an econometric analysis of commercial-sector sales. The number of commercial customers being added each year is a direct function of the number of new residential customers being added. Additionally, the number of residential customers being added is a direct function of the number of new service-area households as derived from Moody's Analytics June 2012 economic forecast of county housing stock and demographic data. The commercial-customer forecast for 2013 to 2032 shows an average annual growth rate of 1.6 percent.

The commercial-sales forecast equation considers several factors affecting electricity sales to the commercial sector. Commercial sales are a function of HDD (wintertime); CDD (summertime); the number of service-area households and service-area employment as derived from

Moody's Analytics forecasts; and the real price of electricity. The commercial-use-per-customer forecast is arrived at by dividing the commercial sales forecast, which considers the impacts of forecast DSM, by the commercial-customer forecast.

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# IRRIGATION

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

Throughout the forecast period, the expected-case irrigation load is forecast to remain flat at 200 aMW from 2013 to 2032, an average annual compound growth rate of 0 percent. The expected-case, 70th-percentile, and 90th-percentile scenarios forecast no growth in irrigation load from 2013 to 2032. In the 70th-percentile scenario, irrigation load is projected to be 215 aMW in 2013 and 215 aMW in 2032. The individual irrigation load forecasts are reported in Table 7 and Figure 8, which illustrates the poorer economic conditions and dramatic reduction in land put into production in the mid-1980s.

**Table 7. Irrigation load growth (aMW)**

| Growth | 2013 | 2017 | 2022 | 2032 | Annual Growth Rate 2013–2032 |
|---|---|---|---|---|---|
| 90th Percentile | 235 | 235 | 236 | 235 | 0.0% |
| 70th Percentile | 215 | 215 | 216 | 215 | 0.0% |
| Expected Case | 200 | 200 | 202 | 200 | 0.0% |

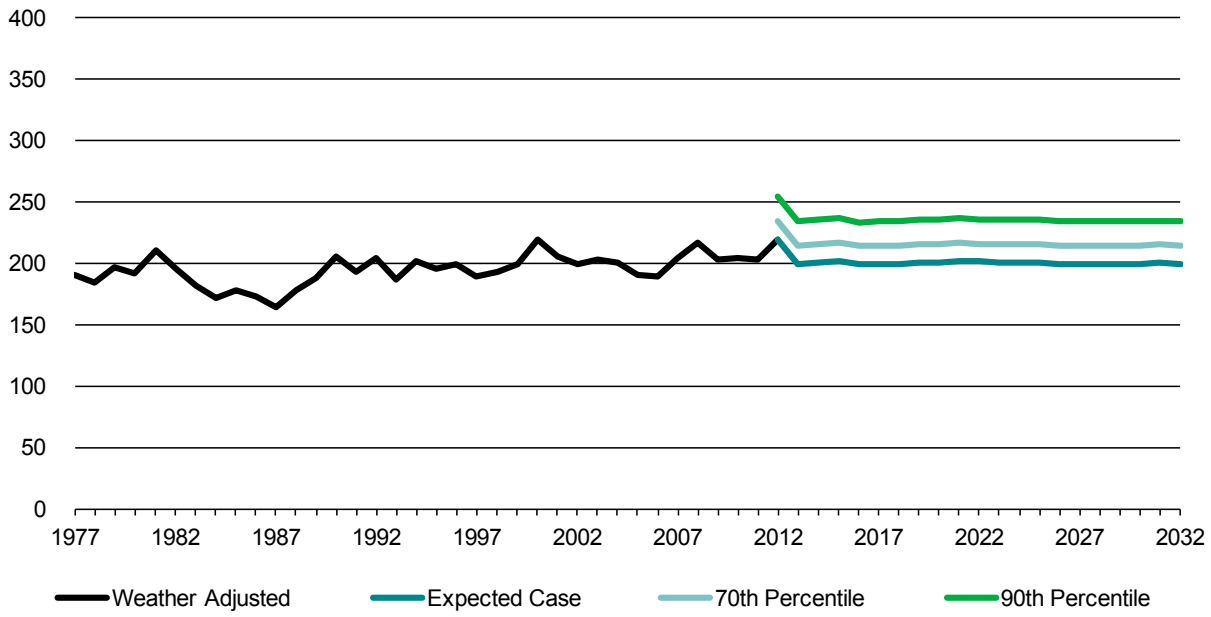



**Figure 8. Forecast irrigation load (aMW)**

It is important to understand that the annual average loads in Table 7 and Figure 8 are calculated using the 8,760 hours in a typical year. In the highly seasonal irrigation sector, over 97 percent of the annual energy is billed during the six months from May through October, and nearly half of

the annual energy is billed in just two months, July and August. During the summer, hourly irrigation loads can exceed 800 MW. In a normal July, irrigation pumping accounts for roughly 25 percent of the energy consumed during the hour of the annual system peak and 30 percent of the energy consumed during July for general business sales. The monthly forecast load figures are being evaluated for resource planning purposes, not the annual average loads.

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 planting patterns. Farmers have taken advantage of the commodities market by planting increasing levels of acreage. After 2015, the sales forecast is slightly lower than the previous IRP forecast, primarily due to higher electricity prices influencing demand. The conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to farmers trying to reduce labor costs, explains most of the increased energy consumption in recent years.

The 2013 irrigation sales forecast model considers several factors affecting electricity sales to the irrigation class, including temperature; precipitation; spring rainfall; *Moody's Gross Product: Agriculture, for Idaho*; *Moody's Producer Price Index: Prices Received by Farmers, All Farm Products*; and the real price of electricity. Considerations were made for the unusually low electricity consumption in the 2001 crop year due to the voluntary load-reduction program.

In early 2001, wholesale electricity prices reached unprecedented levels; Idaho Power, in an attempt to minimize reliance on the market, developed a voluntary load-reduction program that paid irrigators to reduce their electricity consumption in 2001. The voluntary load-reduction program was effective and resulted in a 30-percent, or approximately 500,000-megawatt-hour (MWh), reduction in 2001 irrigation sales. The 2001 irrigation sales and corresponding loads have been adjusted upward by 499,319 MWh to reflect a more normal 2001 irrigation season.

Actual irrigation electricity sales have grown from the 1970 level of 816,000 MWh to a peak amount of 1,990,000 MWh in 2000. Idaho Power projects no growth in irrigated acres in the service area and limited growth in sprinkler irrigation or conversion to sprinkler irrigation.

Irrigation sales represented about 18 percent of weather-normalized Idaho Power system sales in 1982 and reached a maximum proportion of 20 percent of Idaho Power system sales in 1977. In 2012, the irrigation proportion of system sales was 14 percent due to the much higher relative growth in other customer classes. By 2032, irrigation customers are projected to consume less than 10 percent of Idaho Power system sales. The irrigation customer load proportion is shown in Figure 15.

In 1980, Idaho Power had about 10,850 active irrigation accounts. By 2012, the number of active irrigation accounts had increased to 18,675 and is projected to be nearly 23,000 at the end of the planning period in 2032.

Since 1988, Idaho Power has experienced some growth in the number of irrigation customers, but very little, if any, growth in total electricity sales (weather-adjusted) to this sector. The number of customers has increased because customers are converting previously furrow-irrigated land to sprinkler-irrigated land. However, the conversion rate is low, and the kWh use per customer is substantially lower than the average existing Idaho Power irrigation

customer. This is because water for furrow irrigation is gravity-drawn from canals and not pumped from deep, groundwater wells.

Bell Rapids, a large, high-lift cooperative irrigation company that irrigated about 25,000 acres from 1970 to 2004, was Idaho Power's largest irrigation customer. The Bell Rapids combined accounts included more than 40 irrigation service points that accounted for approximately 3 to 4 percent of Idaho Power's annual irrigation sales. In early 2005, the State of Idaho purchased the water rights from Bell Rapids, which resulted in the loss of Bell Rapids as an irrigation customer. Prior to 2005, Bell Rapids consumed, on average, 55,000 MWh annually.

In the future, factors related to the conjunctive management of ground and surface water and the possible litigation associated with the resolution will require consideration. Depending on the resolution of these issues, irrigation sales may be impacted.

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# INDUSTRIAL

The industrial category is made up of Idaho Power's large power service (Schedule 19) customers with monthly metered demands between 1,000 kilowatts (kW) and 20,000 kW. In 1975, Idaho Power had about 70 industrial customers, which represented about 10 percent of Idaho Power's system sales. By December 2012, the number of industrial customers had risen to 116, representing approximately 16 percent of system sales. Special contracts are addressed in the Additional Firm Load section of this document.

In the expected-case forecast, industrial load grows from 267 aMW in 2013 to 367 aMW in 2032, an average annual growth rate of 1.7 percent (Table 8). As a general rule, industrial loads are not weather sensitive, and the forecasts in the 70$^{th}$ and 90$^{th}$-percentile scenarios are identical to the expected-case industrial-load scenario. The industrial load forecast is pictured in Figure 9.

**Table 8. Industrial load growth (aMW)**

| Growth | 2013 | 2017 | 2022 | 2032 | Annual Growth Rate 2013–2032 |
|---|---|---|---|---|---|
| Expected Case | 267 | 294 | 319 | 367 | 1.7% |

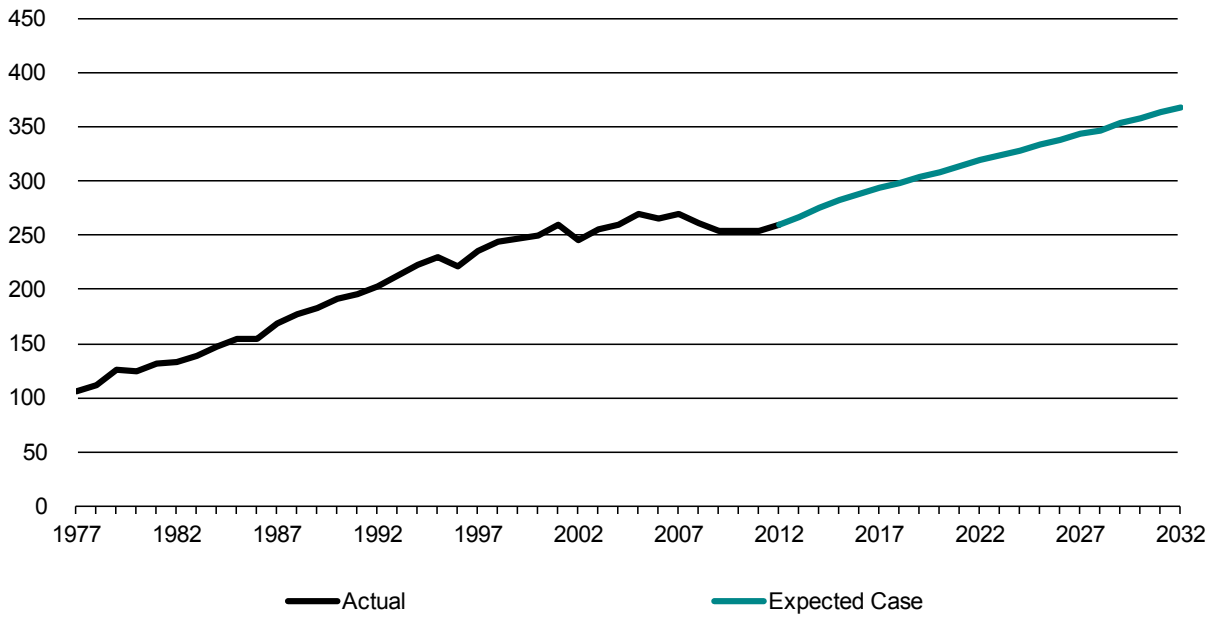



**Figure 9. Forecast industrial load (aMW)**

The industrial energy forecast is based on the most recent (June 2012) national, state, MSA, and county economic forecasts from Moody's Analytics and the resulting derived economic forecast for Idaho Power's service area.

Since rate tariff definitions do not correspond with economic activity types, Idaho Power's Schedule 19 customers were categorized, and their historical electricity sales were summarized by economic activity. This is also true for the large commercial loads, so Schedule 9 primary and transmission customers' energy sales were also included for forecasting purposes and later recombined with the commercial-sector sales forecast. The appropriate employment series (or population time series) were matched to each economic sector or industry group. Regression models were developed for 16 industry groups to determine the relationship between historical electricity sales and historical employment, population, and/or other relevant explanatory variables. The estimated coefficients from the industry group regression models were then applied to the appropriate employment, population, and other relevant drivers, which resulted in the escalation of electricity sales to the various industry groups over time.

Figure 10 illustrates the 2012 industrial electricity consumption by industry group. By far, the largest share of electricity was consumed by the food manufacturing sector (47%); followed by other industry groups (17%); health care (7%); and computer and electronic product manufacturing, education, and other manufacturing (each representing 6%). As Figure 10 shows, several other industry groups make up the remaining share of the 2012 industrial electricity consumption.

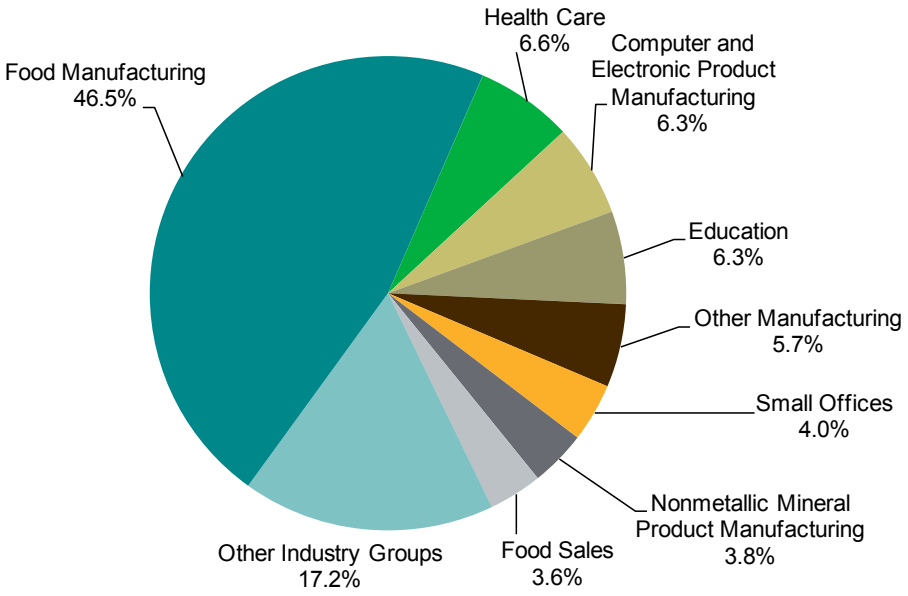



**Figure 10. Industrial electricity consumption by industry group (based on 2012 figures)**

# 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 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. These special-contract customers are Micron Technology, Simplot Fertilizer, the INL, and Hoku Materials. The contract with Raft River expired on September 30, 2011.

In the expected-case forecast, additional firm load is expected to increase from 115 aMW in 2013 to 143 aMW in 2032, an average growth rate of 1.1 percent per year over the planning period (Table 9). The additional firm load energy and demand forecasts in the 70$^{th}$ and 90$^{th}$-percentile scenarios are identical to the expected-load growth scenario. The scenario of projected additional firm load is illustrated in Figure 11.

**Table 9. Additional firm load growth (aMW)**

| Growth | 2013 | 2017 | 2022 | 2032 | Annual Growth Rate 2013–2032 |
|---|---|---|---|---|---|
| Expected Case | 115 | 121 | 140 | 143 | 1.1% |

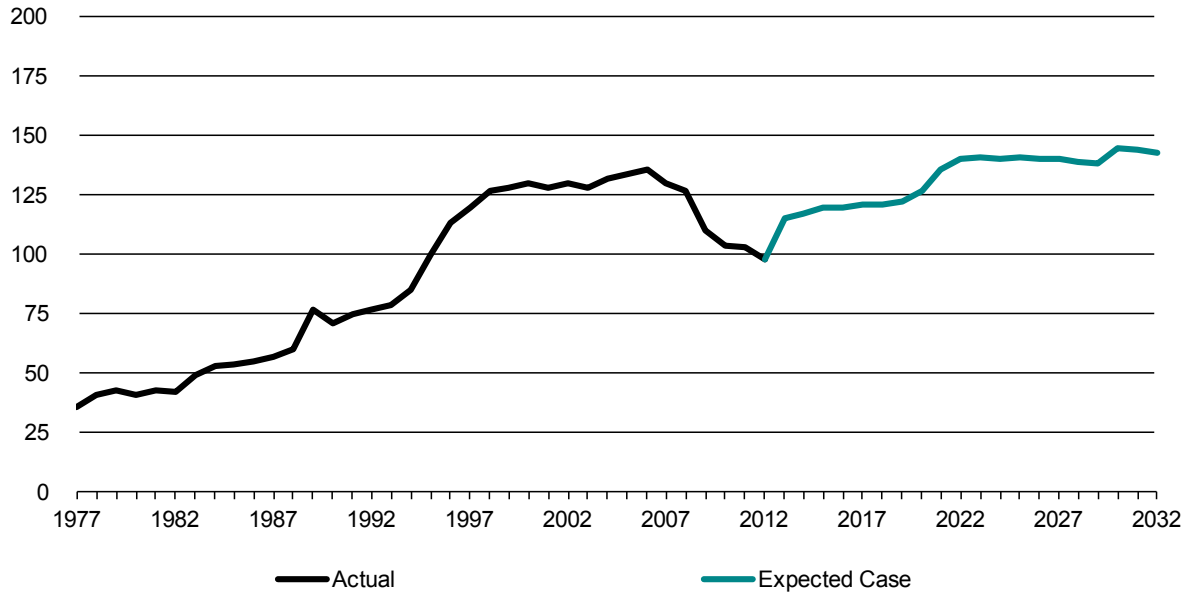



**Figure 11. Forecast additional firm load (aMW)**

## Micron Technology

Micron Technology represents Idaho Power's largest electric load for an individual customer and employs approximately 5,000 workers in the Boise MSA. The company operates its research and development fabrication facility in Boise and performs a variety of other activities, including product design and support, quality assurance, systems integration and related manufacturing, corporate, and general services. Micron Technology's electricity use is 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. The primary driver of long-term electricity sales growth at Simplot Fertilizer is Moody's Analytics forecast of gross product in the pesticide, fertilizer, and other agricultural chemical manufacturing segment for the Pocatello MSA.

## Idaho National Laboratory

The 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 execute on its contract to take service under the special-contract tariff. For the 2013 IRP, Idaho Power has assumed that Hoku Materials will not come on-line, and the 74 aMW of energy and 82 MW of peak demand originally anticipated are excluded from 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 (August 2010), several interested parties had taken significant steps toward the 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, since the 2011 IRP, the likelihood of the new large load diminished. For the 2013 IRP, 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 excluded from this sales and load forecast.

# COMPANY SYSTEM PEAK

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

The all-time system summer peak demand was 3,245 MW, recorded on Thursday, July 12, 2012, at 4:00 p.m. The previous summer peak demand was 3,214 MW and occurred on Monday, June 30, 2008, at 3:00 p.m. The summer system peak load growth accelerated from 1998 to 2008 as a record number of residential and commercial customers were added to the system and A/C became standard in nearly all new residential homes and new commercial buildings.

In the 90th-percentile forecast, the system summer peak load is expected to increase from 3,344 MW in 2013 to 4,365 MW in the year 2032, an average growth rate of 1.4 percent per year over the planning period (Table 10). In the 95th-percentile forecast, the system summer peak load is expected to increase from 3,382 MW in 2013 to 4,418 MW in 2032. The three scenarios of projected system summer peak load are illustrated in Figure 12. The 2001 summer peak was dampened by the nearly 30-percent curtailment in irrigation load due to the 2001 voluntary load-reduction program.

**Table 10. System summer peak load growth (MW)**

| Growth | 2013 | 2017 | 2022 | 2032 | Annual Growth Rate 2013–2032 |
|---|---|---|---|---|---|
| 95th Percentile | 3,382 | 3,596 | 3,881 | 4,418 | 1.4% |
| 90th Percentile | 3,344 | 3,555 | 3,835 | 4,365 | 1.4% |
| 50th Percentile | 3,189 | 3,387 | 3,651 | 4,147 | 1.4% |

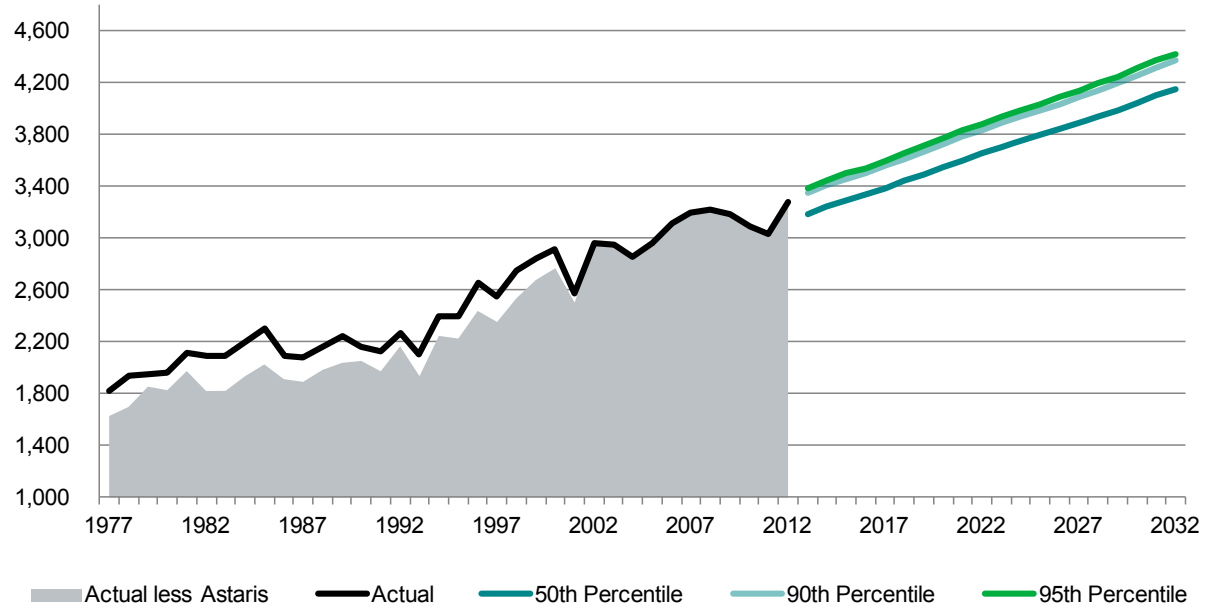



**Figure 12. Forecast system summer peak (MW)**

The all-time system winter peak demand was 2,528 MW, reached on Thursday, December 10, 2009, at 8:00 a.m. As shown in Figure 13, the historical system winter peak load is much more variable than the summer system peak load. This is because the variability of peak-day temperatures in winter months is far greater than the variability of peak-day temperatures in summer months. The wider spread of the winter peak forecast lines in Figure 13 illustrates the higher variability associated with winter peak-day temperatures.

In the 90th-percentile forecast, the system winter peak load is expected to increase from 2,585 MW in 2013 to 3,020 MW in 2032, an average growth rate of 0.8 percent per year over the planning period (Table 11). In the 95th-percentile forecast, the system winter peak load is expected to increase from 2,683 MW in 2013 to 3,118 MW in 2032, an average growth rate of 0.8 percent per year over the planning period (Table 11). The three scenarios of projected system winter peak load are illustrated in Figure 13.

**Table 11. System winter peak load growth (MW)**

| Growth | 2013 | 2017 | 2022 | 2032 | Annual Growth Rate 2013–2032 |
|---|---|---|---|---|---|
| 95th Percentile | 2,683 | 2,765 | 2,901 | 3,118 | 0.8% |
| 90th Percentile | 2,585 | 2,668 | 2,803 | 3,020 | 0.8% |
| 50th Percentile | 2,301 | 2,384 | 2,520 | 2,737 | 0.9% |

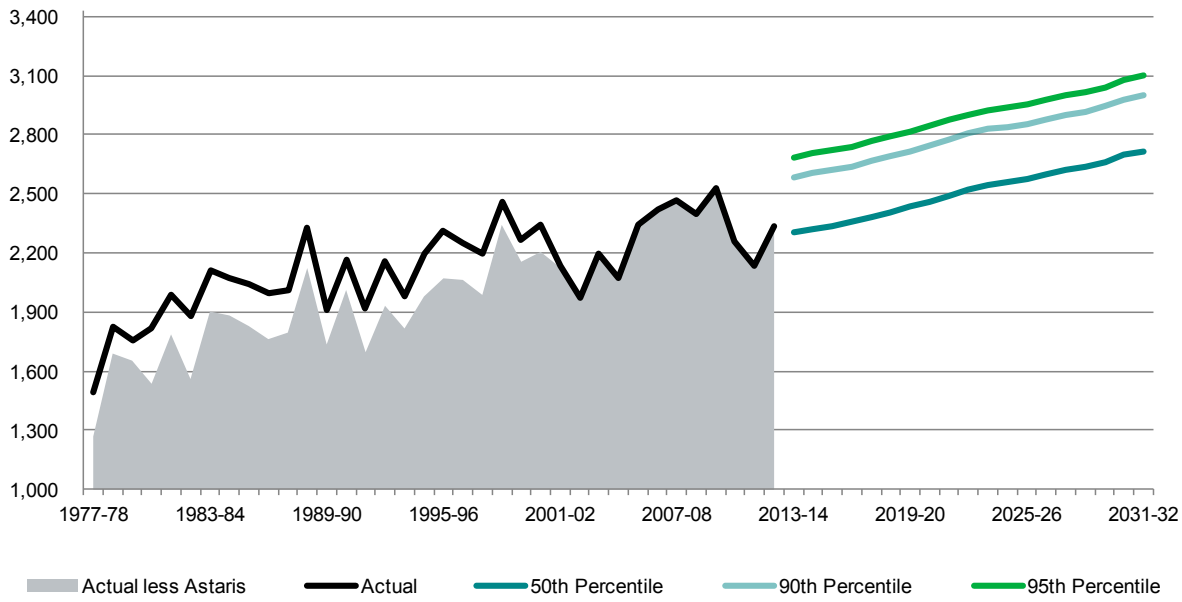



**Figure 13. Forecast system winter peak (MW)**

# COMPANY SYSTEM LOAD

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

The expected-case system load forecast is based on the most recent Moody's Analytics economic forecast for the nation, state, MSAs, and counties in the service area and represents Idaho Power's most probable load growth during the planning period. The expected-case forecast system load growth rate averages 1.1 percent per year from 2013 to 2032. Company system load projections are reported in Table 12 and shown in Figure 14.

In the expected-case forecast, the company system load is expected to increase from 1,759 aMW in 2013 to 2,154 aMW in 2032. In the 70$^{th}$-percentile forecast, the company system load is expected to increase from 1,800 aMW in 2013 to 2,201 aMW by 2032, an average growth rate of 1.1 percent per year over the planning period (Table 12).

**Table 12. System load growth (aMW)**

| Growth | 2013 | 2017 | 2022 | 2032 | Annual Growth Rate 2013–2032 |
|---|---|---|---|---|---|
| 90$^{th}$ Percentile | 1,872 | 1,959 | 2,078 | 2,284 | 1.1% |
| 70$^{th}$ Percentile | 1,800 | 1,884 | 2,000 | 2,201 | 1.1% |
| Expected Case | 1,759 | 1,842 | 1,956 | 2,154 | 1.1% |

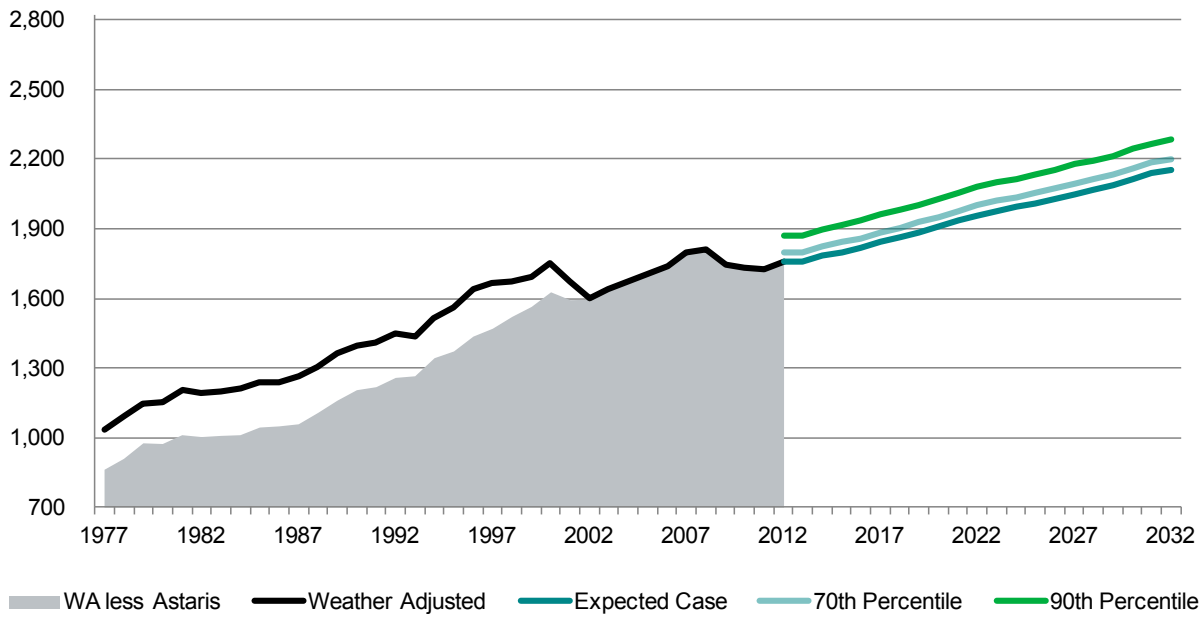



**Figure 14. Forecast system load (aMW)**

The Astaris elemental phosphorous plant (previously FMC) was located at the western edge of Pocatello, Idaho. Although no longer a customer of Idaho Power, Astaris has been Idaho Power's largest individual customer and, in some past years, averaged nearly 200 aMW each month. In April 2002, the special contract between Astaris and Idaho Power was terminated. Without the dampening effects of Astaris on historical system load growth, the system load more accurately portrays the underlying general business growth trend within the service area.

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

The composition of system company electricity sales by year is shown in Figure 15. Residential sales are forecast to be nearly 23 percent higher in 2032, gaining 1.1 million MWh over 2013. Commercial sales are also expected to be 23 percent higher or 0.9 million MWh above 2013 followed by industrial (38 percent higher or 0.9 million additional MWh) and irrigation (only 0.2 percent higher in 2032 than 2013). Electricity sales to Astaris ended in April 2002.

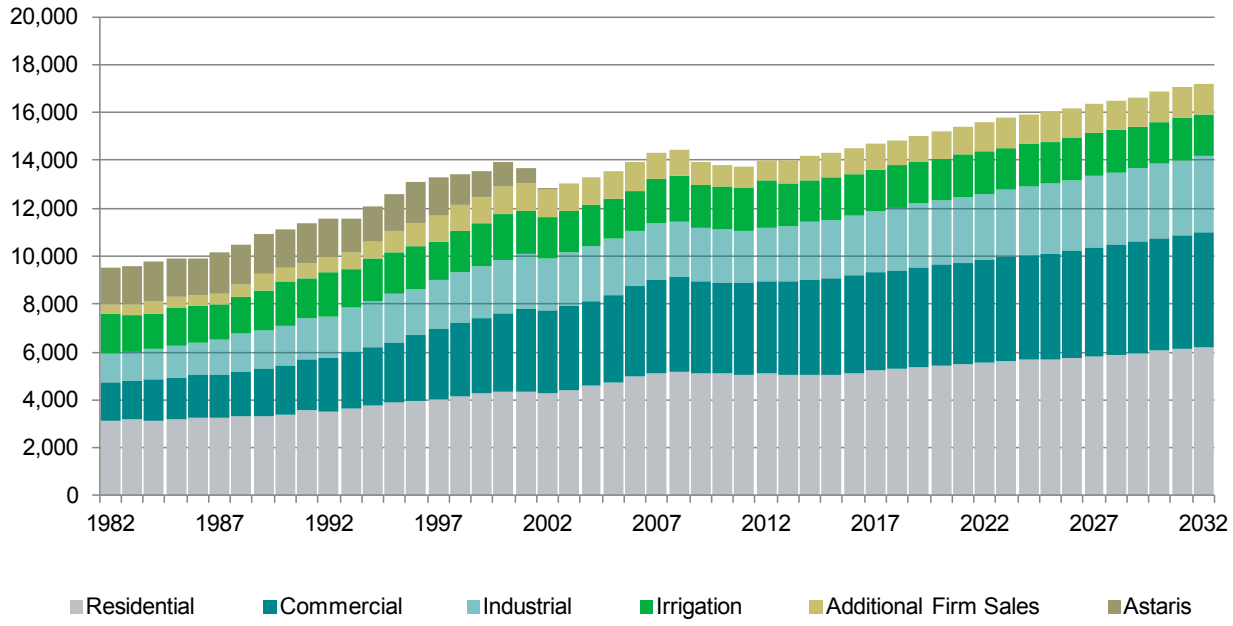



**Figure 15. Composition of system company electricity sales (thousands of MWh)**

The additional firm load category (which represents sales to Micron Technology, Simplot Fertilizer, and the INL) is forecast to grow by 24 percent from 2013 to 2032.

# CONTRACT OFF-SYSTEM LOAD

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

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

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# ENERGY EFFICIENCY AND DEMAND RESPONSE

Energy efficiency and demand response impacts are treated differently in the forecasting and planning process. Energy efficiency impacts (reductions) are explicitly integrated into the forecast models. Demand response impacts are explicitly *excluded* from the forecast models; the impacts of demand response are modeled in the load and resource balance as a supply-side resource for reducing peak-demand periods.

## Energy Efficiency

Energy efficiency influences on past and future load consist of utility programs, statutory codes, and manufacturing standards for appliances, equipment, and building materials that reduce energy consumption. As the influence of statutory codes and manufacturing standards on residential and commercial customers has increased in importance relative to utility programs, Idaho Power forecast models have been modified to ensure they capture these influences. Specifically, the models capture the physical flow of energy-efficient products through shipment data to resellers and installers. The source for this data is the DOE (the data also serves as input to the DOE NEM), and the data is refined by Itron for utility-specific applications. This data captures energy-efficient installations regardless of the source (e.g., programs, standards, and codes). However, Idaho Power closely monitors the assumptions and impacts of DOE data to ensure the model correctly captures all energy-efficiency impacts.

Efficiency data for industrial and irrigation customers is not directly surveyed and collected by the DOE; therefore, the models for efficiency impacts have been developed using a methodology established in Itron's white paper, "Incorporating DSM into the Load Forecast".[1] This approach develops statistical methods to recognize efficiency trends from historical utility acquisition, recognizing that historical trends are embedded in the actual sales data (which serves as the basis for the sector's forecast). Trends associated with future acquisitions from these existing programs (and their cumulative impacts) are similarly developed to compare with historical trends. If there is a significant change in future trends (i.e., trends unseen by the regression model of historical actual energy and conservation trends), the forecast output is adjusted to realize the trend change embedded in the regression output.

Regardless of the method, efficiency impacts from the models are compared to sister utility acquisitions to ensure the models are correctly capturing all energy savings.

Energy savings from energy efficiency programs are typically measured and reported at the point of delivery (customer's meter). Therefore, energy efficiency savings are increased by the amount of energy lost in transmitting the electricity from the generation source to the customer's meter.

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[1] Stuart McMenamin and Mark Quan. *Incorporating DSM into the Load Forecast*. Itron, https://www.itron.com/na/PublishedContent/Incorporating%20DSM%20into%20the%20Load%20Forecast.pdf (accessed February 3, 2011).

The influence of new efficiency programs is not typically prepared in time to be available for input into the forecast models. Therefore, the impacts of the new programs are accounted for in the IRP load and resource balance prior to determining the need for additional supply-side resources. The forecast performance of existing and new energy efficiency and demand response programs is shown in the load and resource balance in *Appendix C—Technical Appendix*. In the next planning cycle, the impact of new committed programs will be considered when updating the individual class-level sales forecasts.

## Demand Response

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

Demand response programs are treated as supply-side resources in the 2013 IRP and are not incorporated into the sales and load forecast. In the load and resource balance, the forecast of existing demand response programs is subtracted from the peak-hour load forecast prior to accounting for existing supply-side resources. Likewise, the performance of new demand response programs is accounted for prior to determining the need for additional supply-side resources. Because energy efficiency programs also result in a reduction to peak demand, there is a component of peak-hour load reduction integrated into the sales and load forecast. This provides a consistent treatment of both types of programs, as energy efficiency programs are considered in the sales and load forecast while all demand response programs are included in the load and resource balance.

A thorough description of each of the energy efficiency and demand response programs is included in *Appendix B—Demand Side Management 2012 Annual Report*.

## Appendix A1. Historical and Projected Sales and Load

### Residential Load

**Historical Residential Sales and Load, 1972–2012 (weather adjusted)**

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1972 | 145,208 | – | 10,959 | 1,591 | – | 184 |
| 1973 | 152,957 | 5.3% | 11,537 | 1,765 | 10.9% | 203 |
| 1974 | 160,151 | 4.7% | 12,066 | 1,932 | 9.5% | 223 |
| 1975 | 167,622 | 4.7% | 12,955 | 2,172 | 12.4% | 250 |
| 1976 | 175,720 | 4.8% | 13,455 | 2,364 | 8.9% | 271 |
| 1977 | 184,561 | 5.0% | 13,686 | 2,526 | 6.8% | 290 |
| 1978 | 194,650 | 5.5% | 14,235 | 2,771 | 9.7% | 321 |
| 1979 | 202,982 | 4.3% | 14,779 | 3,000 | 8.3% | 342 |
| 1980 | 209,629 | 3.3% | 14,585 | 3,057 | 1.9% | 348 |
| 1981 | 213,579 | 1.9% | 14,339 | 3,063 | 0.2% | 349 |
| 1982 | 216,696 | 1.5% | 14,395 | 3,119 | 1.9% | 356 |
| 1983 | 219,849 | 1.5% | 14,375 | 3,160 | 1.3% | 363 |
| 1984 | 222,695 | 1.3% | 14,146 | 3,150 | (0.3%) | 357 |
| 1985 | 225,185 | 1.1% | 14,049 | 3,164 | 0.4% | 363 |
| 1986 | 227,081 | 0.8% | 14,256 | 3,237 | 2.3% | 368 |
| 1987 | 228,868 | 0.8% | 14,097 | 3,226 | (0.3%) | 366 |
| 1988 | 230,771 | 0.8% | 14,352 | 3,312 | 2.7% | 378 |
| 1989 | 233,370 | 1.1% | 14,336 | 3,346 | 1.0% | 383 |
| 1990 | 238,117 | 2.0% | 14,277 | 3,400 | 1.6% | 393 |
| 1991 | 243,207 | 2.1% | 14,566 | 3,542 | 4.2% | 402 |
| 1992 | 249,767 | 2.7% | 14,146 | 3,533 | (0.3%) | 408 |
| 1993 | 258,271 | 3.4% | 14,172 | 3,660 | 3.6% | 412 |
| 1994 | 267,854 | 3.7% | 14,002 | 3,750 | 2.5% | 434 |
| 1995 | 277,131 | 3.5% | 14,004 | 3,881 | 3.5% | 438 |
| 1996 | 286,227 | 3.3% | 13,734 | 3,931 | 1.3% | 455 |
| 1997 | 294,674 | 3.0% | 13,682 | 4,032 | 2.6% | 463 |
| 1998 | 303,300 | 2.9% | 13,744 | 4,169 | 3.4% | 476 |
| 1999 | 312,901 | 3.2% | 13,620 | 4,262 | 2.2% | 488 |
| 2000 | 322,402 | 3.0% | 13,407 | 4,322 | 1.4% | 500 |
| 2001 | 331,009 | 2.7% | 13,160 | 4,356 | 0.8% | 476 |
| 2002 | 339,764 | 2.6% | 12,637 | 4,294 | (1.4%) | 488 |
| 2003 | 349,219 | 2.8% | 12,653 | 4,419 | 2.9% | 507 |
| 2004 | 360,462 | 3.2% | 12,686 | 4,573 | 3.5% | 524 |
| 2005 | 373,602 | 3.6% | 12,684 | 4,739 | 3.6% | 543 |
| 2006 | 387,707 | 3.8% | 12,878 | 4,993 | 5.4% | 568 |
| 2007 | 397,286 | 2.5% | 12,924 | 5,135 | 2.8% | 585 |
| 2008 | 402,520 | 1.3% | 12,875 | 5,182 | 0.9% | 594 |
| 2009 | 405,144 | 0.7% | 12,672 | 5,134 | (0.9%) | 584 |
| 2010 | 407,551 | 0.6% | 12,461 | 5,078 | (1.1%) | 582 |
| 2011 | 409,786 | 0.5% | 12,363 | 5,066 | (0.2%) | 577 |
| 2012 | 413,610 | 0.9% | 12,274 | 5,077 | 0.2% | 581 |

**Residential Load**

**Projected Residential Sales and Load, 2013–2032**

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2013 | 417,852 | 1.0% | 12,025 | 5,025 | (1.0%) | 574 |
| 2014 | 422,850 | 1.2% | 11,954 | 5,055 | 0.6% | 577 |
| 2015 | 429,685 | 1.6% | 11,783 | 5,063 | 0.2% | 579 |
| 2016 | 438,746 | 2.1% | 11,695 | 5,131 | 1.3% | 587 |
| 2017 | 448,379 | 2.2% | 11,644 | 5,221 | 1.8% | 597 |
| 2018 | 457,313 | 2.0% | 11,588 | 5,299 | 1.5% | 606 |
| 2019 | 465,250 | 1.7% | 11,545 | 5,371 | 1.4% | 614 |
| 2020 | 472,652 | 1.6% | 11,480 | 5,426 | 1.0% | 620 |
| 2021 | 479,844 | 1.5% | 11,412 | 5,476 | 0.9% | 626 |
| 2022 | 486,853 | 1.5% | 11,363 | 5,532 | 1.0% | 632 |
| 2023 | 493,741 | 1.4% | 11,342 | 5,600 | 1.2% | 640 |
| 2024 | 500,509 | 1.4% | 11,294 | 5,653 | 0.9% | 646 |
| 2025 | 507,171 | 1.3% | 11,235 | 5,698 | 0.8% | 651 |
| 2026 | 513,749 | 1.3% | 11,230 | 5,769 | 1.2% | 659 |
| 2027 | 520,202 | 1.3% | 11,230 | 5,842 | 1.3% | 667 |
| 2028 | 526,553 | 1.2% | 11,199 | 5,897 | 0.9% | 674 |
| 2029 | 532,781 | 1.2% | 11,197 | 5,966 | 1.2% | 682 |
| 2030 | 538,901 | 1.1% | 11,211 | 6,042 | 1.3% | 690 |
| 2031 | 544,944 | 1.1% | 11,203 | 6,105 | 1.0% | 697 |
| 2032 | 550,883 | 1.1% | 11,189 | 6,164 | 1.0% | 704 |

## Commercial Load

### Historical Commercial Sales and Load, 1972–2012 (weather adjusted)

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1972 | 22,585 | – | 46,141 | 1,042 | – | 120 |
| 1973 | 23,286 | 3.1% | 48,145 | 1,121 | 7.6% | 128 |
| 1974 | 24,096 | 3.5% | 49,028 | 1,181 | 5.4% | 136 |
| 1975 | 25,045 | 3.9% | 51,217 | 1,283 | 8.6% | 147 |
| 1976 | 26,034 | 3.9% | 52,513 | 1,367 | 6.6% | 157 |
| 1977 | 27,112 | 4.1% | 52,416 | 1,421 | 3.9% | 162 |
| 1978 | 27,831 | 2.7% | 52,476 | 1,460 | 2.8% | 169 |
| 1979 | 28,087 | 0.9% | 56,389 | 1,584 | 8.4% | 180 |
| 1980 | 28,797 | 2.5% | 54,145 | 1,559 | (1.6%) | 178 |
| 1981 | 29,567 | 2.7% | 54,286 | 1,605 | 2.9% | 184 |
| 1982 | 30,167 | 2.0% | 54,127 | 1,633 | 1.7% | 186 |
| 1983 | 30,776 | 2.0% | 52,676 | 1,621 | (0.7%) | 186 |
| 1984 | 31,554 | 2.5% | 53,383 | 1,684 | 3.9% | 191 |
| 1985 | 32,418 | 2.7% | 53,989 | 1,750 | 3.9% | 201 |
| 1986 | 33,208 | 2.4% | 53,869 | 1,789 | 2.2% | 204 |
| 1987 | 33,975 | 2.3% | 53,357 | 1,813 | 1.3% | 206 |
| 1988 | 34,723 | 2.2% | 54,409 | 1,889 | 4.2% | 216 |
| 1989 | 35,638 | 2.6% | 55,451 | 1,976 | 4.6% | 227 |
| 1990 | 36,785 | 3.2% | 55,844 | 2,054 | 3.9% | 236 |
| 1991 | 37,922 | 3.1% | 56,164 | 2,130 | 3.7% | 243 |
| 1992 | 39,022 | 2.9% | 56,339 | 2,198 | 3.2% | 253 |
| 1993 | 40,047 | 2.6% | 57,951 | 2,321 | 5.6% | 263 |
| 1994 | 41,629 | 4.0% | 58,181 | 2,422 | 4.4% | 280 |
| 1995 | 43,165 | 3.7% | 58,742 | 2,536 | 4.7% | 288 |
| 1996 | 44,995 | 4.2% | 62,048 | 2,792 | 10.1% | 323 |
| 1997 | 46,819 | 4.1% | 62,019 | 2,904 | 4.0% | 333 |
| 1998 | 48,404 | 3.4% | 62,722 | 3,036 | 4.6% | 347 |
| 1999 | 49,430 | 2.1% | 64,191 | 3,173 | 4.5% | 363 |
| 2000 | 50,117 | 1.4% | 65,975 | 3,306 | 4.2% | 383 |
| 2001 | 51,501 | 2.8% | 67,339 | 3,468 | 4.9% | 383 |
| 2002 | 52,915 | 2.7% | 64,788 | 3,428 | (1.1%) | 390 |
| 2003 | 54,194 | 2.4% | 64,243 | 3,482 | 1.6% | 399 |
| 2004 | 55,577 | 2.6% | 64,042 | 3,559 | 2.2% | 407 |
| 2005 | 57,145 | 2.8% | 63,517 | 3,630 | 2.0% | 415 |
| 2006 | 59,050 | 3.3% | 63,425 | 3,745 | 3.2% | 426 |
| 2007 | 61,640 | 4.4% | 63,336 | 3,904 | 4.2% | 445 |
| 2008 | 63,492 | 3.0% | 62,200 | 3,949 | 1.2% | 451 |
| 2009 | 64,151 | 1.0% | 59,488 | 3,816 | (3.4%) | 436 |
| 2010 | 64,421 | 0.4% | 58,820 | 3,789 | (0.7%) | 434 |
| 2011 | 64,921 | 0.8% | 58,285 | 3,784 | (0.1%) | 432 |
| 2012 | 65,599 | 1.0% | 58,941 | 3,866 | 2.2% | 442 |

## Commercial Load

### Projected Commercial Sales and Load, 2013–2032

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2013 | 66,489 | 1.4% | 58,657 | 3,900 | 0.9% | 446 |
| 2014 | 67,430 | 1.4% | 58,737 | 3,961 | 1.6% | 452 |
| 2015 | 68,612 | 1.8% | 58,249 | 3,997 | 0.9% | 457 |
| 2016 | 70,122 | 2.2% | 57,661 | 4,043 | 1.2% | 462 |
| 2017 | 71,686 | 2.2% | 56,953 | 4,083 | 1.0% | 466 |
| 2018 | 73,199 | 2.1% | 56,250 | 4,117 | 0.9% | 470 |
| 2019 | 74,579 | 1.9% | 55,754 | 4,158 | 1.0% | 475 |
| 2020 | 75,873 | 1.7% | 55,392 | 4,203 | 1.1% | 480 |
| 2021 | 77,131 | 1.7% | 55,025 | 4,244 | 1.0% | 485 |
| 2022 | 78,357 | 1.6% | 54,730 | 4,288 | 1.0% | 490 |
| 2023 | 79,565 | 1.5% | 54,520 | 4,338 | 1.2% | 495 |
| 2024 | 80,754 | 1.5% | 54,202 | 4,377 | 0.9% | 500 |
| 2025 | 81,925 | 1.4% | 53,864 | 4,413 | 0.8% | 504 |
| 2026 | 83,082 | 1.4% | 53,741 | 4,465 | 1.2% | 510 |
| 2027 | 84,220 | 1.4% | 53,642 | 4,518 | 1.2% | 516 |
| 2028 | 85,343 | 1.3% | 53,466 | 4,563 | 1.0% | 521 |
| 2029 | 86,450 | 1.3% | 53,429 | 4,619 | 1.2% | 528 |
| 2030 | 87,540 | 1.3% | 53,470 | 4,681 | 1.3% | 535 |
| 2031 | 88,619 | 1.2% | 53,491 | 4,740 | 1.3% | 542 |
| 2032 | 89,685 | 1.2% | 53,547 | 4,802 | 1.3% | 549 |

## Irrigation Load

### Historical Irrigation Sales and Load, 1972–2012 (weather adjusted)

| Year | Maximum Active Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1972 | 7,815 | – | 132,292 | 1,034 | – | 118 |
| 1973 | 8,341 | 6.7% | 141,030 | 1,176 | 13.8% | 134 |
| 1974 | 8,971 | 7.6% | 147,698 | 1,325 | 12.6% | 151 |
| 1975 | 9,480 | 5.7% | 153,957 | 1,460 | 10.2% | 167 |
| 1976 | 9,936 | 4.8% | 155,406 | 1,544 | 5.8% | 176 |
| 1977 | 10,238 | 3.0% | 163,266 | 1,672 | 8.3% | 191 |
| 1978 | 10,476 | 2.3% | 154,006 | 1,613 | (3.5%) | 184 |
| 1979 | 10,711 | 2.2% | 161,705 | 1,732 | 7.4% | 197 |
| 1980 | 10,854 | 1.3% | 155,740 | 1,690 | (2.4%) | 192 |
| 1981 | 11,248 | 3.6% | 164,533 | 1,851 | 9.5% | 211 |
| 1982 | 11,312 | 0.6% | 151,369 | 1,712 | (7.5%) | 196 |
| 1983 | 11,133 | (1.6%) | 142,865 | 1,591 | (7.1%) | 182 |
| 1984 | 11,375 | 2.2% | 132,933 | 1,512 | (4.9%) | 172 |
| 1985 | 11,576 | 1.8% | 134,849 | 1,561 | 3.2% | 178 |
| 1986 | 11,308 | (2.3%) | 134,121 | 1,517 | (2.8%) | 173 |
| 1987 | 11,254 | (0.5%) | 128,532 | 1,446 | (4.6%) | 165 |
| 1988 | 11,378 | 1.1% | 137,237 | 1,561 | 7.9% | 178 |
| 1989 | 11,957 | 5.1% | 137,982 | 1,650 | 5.7% | 188 |
| 1990 | 12,340 | 3.2% | 146,128 | 1,803 | 9.3% | 206 |
| 1991 | 12,484 | 1.2% | 135,557 | 1,692 | (6.2%) | 193 |
| 1992 | 12,809 | 2.6% | 140,744 | 1,803 | 6.5% | 205 |
| 1993 | 13,078 | 2.1% | 125,294 | 1,639 | (9.1%) | 187 |
| 1994 | 13,559 | 3.7% | 130,325 | 1,767 | 7.8% | 202 |
| 1995 | 13,679 | 0.9% | 125,349 | 1,715 | (3.0%) | 196 |
| 1996 | 14,074 | 2.9% | 123,944 | 1,744 | 1.7% | 199 |
| 1997 | 14,383 | 2.2% | 115,552 | 1,662 | (4.7%) | 190 |
| 1998 | 14,695 | 2.2% | 114,918 | 1,689 | 1.6% | 193 |
| 1999 | 14,912 | 1.5% | 117,715 | 1,755 | 3.9% | 200 |
| 2000 | 15,253 | 2.3% | 126,625 | 1,931 | 10.0% | 220 |
| 2001 | 15,522 | 1.8% | 116,328 | 1,806 | (6.5%) | 206 |
| 2002 | 15,840 | 2.0% | 110,674 | 1,753 | (2.9%) | 200 |
| 2003 | 16,020 | 1.1% | 110,784 | 1,775 | 1.2% | 203 |
| 2004 | 16,297 | 1.7% | 108,574 | 1,769 | (0.3%) | 201 |
| 2005 | 16,936 | 3.9% | 98,823 | 1,674 | (5.4%) | 191 |
| 2006 | 17,062 | 0.7% | 97,105 | 1,657 | (1.0%) | 189 |
| 2007 | 17,001 | (0.4%) | 105,867 | 1,800 | 8.6% | 205 |
| 2008 | 17,428 | 2.5% | 109,360 | 1,906 | 5.9% | 217 |
| 2009 | 17,708 | 1.6% | 100,337 | 1,777 | (6.8%) | 203 |
| 2010 | 17,846 | 0.8% | 99,895 | 1,783 | 0.3% | 204 |
| 2011 | 18,292 | 2.5% | 97,124 | 1,777 | (0.3%) | 203 |
| 2012 | 18,675 | 2.1% | 103,703 | 1,937 | 9.0% | 220 |

## Irrigation Load

### Projected Irrigation Sales and Load, 2013–2032

| Year | Maximum Active Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2013 | 18,890 | 1.2% | 92,719 | 1,751 | (9.6%) | 200 |
| 2014 | 19,142 | 1.3% | 92,074 | 1,762 | 0.6% | 201 |
| 2015 | 19,396 | 1.3% | 91,204 | 1,769 | 0.4% | 202 |
| 2016 | 19,645 | 1.3% | 89,128 | 1,751 | (1.0%) | 199 |
| 2017 | 19,899 | 1.3% | 87,928 | 1,750 | (0.1%) | 200 |
| 2018 | 20,152 | 1.3% | 87,142 | 1,756 | 0.4% | 200 |
| 2019 | 20,404 | 1.3% | 86,281 | 1,760 | 0.2% | 201 |
| 2020 | 20,655 | 1.2% | 85,477 | 1,766 | 0.3% | 201 |
| 2021 | 20,909 | 1.2% | 84,582 | 1,769 | 0.2% | 202 |
| 2022 | 21,160 | 1.2% | 83,429 | 1,765 | (0.2%) | 202 |
| 2023 | 21,413 | 1.2% | 82,407 | 1,765 | 0.0% | 201 |
| 2024 | 21,664 | 1.2% | 81,620 | 1,768 | 0.2% | 201 |
| 2025 | 21,917 | 1.2% | 80,447 | 1,763 | (0.3%) | 201 |
| 2026 | 22,172 | 1.2% | 79,028 | 1,752 | (0.6%) | 200 |
| 2027 | 22,423 | 1.1% | 78,263 | 1,755 | 0.2% | 200 |
| 2028 | 22,675 | 1.1% | 77,568 | 1,759 | 0.2% | 200 |
| 2029 | 22,926 | 1.1% | 76,458 | 1,753 | (0.3%) | 200 |
| 2030 | 23,180 | 1.1% | 75,656 | 1,754 | 0.0% | 200 |
| 2031 | 23,434 | 1.1% | 75,013 | 1,758 | 0.2% | 201 |
| 2032 | 23,684 | 1.1% | 74,129 | 1,756 | (0.1%) | 200 |

## Industrial Load

### Historical Industrial Sales and Load, 1972–2012 (weather adjusted)

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1972 | 56 | – | 10,944,714 | 615 | – | 71 |
| 1973 | 63 | 12.3% | 10,889,056 | 687 | 11.7% | 79 |
| 1974 | 65 | 2.2% | 11,464,249 | 739 | 7.6% | 84 |
| 1975 | 71 | 10.5% | 11,014,121 | 785 | 6.1% | 91 |
| 1976 | 73 | 3.0% | 11,681,540 | 858 | 9.3% | 99 |
| 1977 | 85 | 15.1% | 10,988,826 | 929 | 8.3% | 106 |
| 1978 | 99 | 17.6% | 9,786,753 | 972 | 4.7% | 111 |
| 1979 | 109 | 9.6% | 9,989,158 | 1,087 | 11.8% | 126 |
| 1980 | 112 | 2.7% | 9,894,706 | 1,106 | 1.7% | 125 |
| 1981 | 118 | 5.7% | 9,718,723 | 1,148 | 3.9% | 132 |
| 1982 | 122 | 3.5% | 9,504,283 | 1,162 | 1.2% | 133 |
| 1983 | 122 | (0.3%) | 9,797,522 | 1,194 | 2.7% | 138 |
| 1984 | 124 | 1.5% | 10,369,789 | 1,282 | 7.4% | 147 |
| 1985 | 125 | 1.2% | 10,844,888 | 1,357 | 5.9% | 155 |
| 1986 | 129 | 2.7% | 10,550,145 | 1,357 | (0.1%) | 155 |
| 1987 | 134 | 4.1% | 11,006,455 | 1,474 | 8.7% | 169 |
| 1988 | 133 | (1.0%) | 11,660,183 | 1,546 | 4.9% | 177 |
| 1989 | 132 | (0.6%) | 12,091,482 | 1,594 | 3.1% | 183 |
| 1990 | 132 | 0.2% | 12,584,200 | 1,662 | 4.3% | 191 |
| 1991 | 135 | 2.5% | 12,699,665 | 1,719 | 3.4% | 196 |
| 1992 | 140 | 3.4% | 12,650,945 | 1,770 | 3.0% | 203 |
| 1993 | 141 | 0.5% | 13,179,585 | 1,854 | 4.7% | 212 |
| 1994 | 143 | 1.7% | 13,616,608 | 1,948 | 5.1% | 223 |
| 1995 | 120 | (15.9%) | 16,793,437 | 2,021 | 3.7% | 230 |
| 1996 | 103 | (14.4%) | 18,774,093 | 1,934 | (4.3%) | 221 |
| 1997 | 106 | 2.7% | 19,309,504 | 2,042 | 5.6% | 235 |
| 1998 | 111 | 4.6% | 19,378,734 | 2,145 | 5.0% | 244 |
| 1999 | 108 | (2.3%) | 19,985,029 | 2,160 | 0.7% | 247 |
| 2000 | 107 | (0.8%) | 20,433,299 | 2,191 | 1.5% | 250 |
| 2001 | 111 | 3.5% | 20,618,361 | 2,289 | 4.4% | 260 |
| 2002 | 111 | (0.1%) | 19,441,876 | 2,156 | (5.8%) | 246 |
| 2003 | 112 | 1.0% | 19,950,866 | 2,234 | 3.6% | 255 |
| 2004 | 117 | 4.3% | 19,417,310 | 2,269 | 1.5% | 259 |
| 2005 | 126 | 7.9% | 18,645,220 | 2,351 | 3.6% | 270 |
| 2006 | 127 | 1.0% | 18,255,385 | 2,325 | (1.1%) | 265 |
| 2007 | 123 | (3.6%) | 19,275,551 | 2,366 | 1.8% | 270 |
| 2008 | 119 | (3.1%) | 19,412,391 | 2,308 | (2.4%) | 261 |
| 2009 | 124 | 4.0% | 17,987,570 | 2,224 | (3.6%) | 254 |
| 2010 | 121 | (2.0%) | 18,404,875 | 2,232 | 0.3% | 254 |
| 2011 | 120 | (1.1%) | 18,586,468 | 2,229 | (0.1%) | 254 |
| 2012 | 115 | (4.2%) | 19,746,525 | 2,269 | 1.8% | 260 |

## Industrial Load

### Projected Industrial Sales and Load, 2013–2032

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2013 | 116 | 0.9% | 20,123,969 | 2,334 | 2.9% | 267 |
| 2014 | 117 | 0.9% | 20,531,410 | 2,402 | 2.9% | 275 |
| 2015 | 118 | 0.9% | 20,904,644 | 2,467 | 2.7% | 282 |
| 2016 | 121 | 2.5% | 20,855,283 | 2,523 | 2.3% | 288 |
| 2017 | 121 | 0.0% | 21,229,207 | 2,569 | 1.8% | 294 |
| 2018 | 123 | 1.7% | 21,215,736 | 2,610 | 1.6% | 298 |
| 2019 | 124 | 0.8% | 21,400,507 | 2,654 | 1.7% | 303 |
| 2020 | 125 | 0.8% | 21,591,980 | 2,699 | 1.7% | 308 |
| 2021 | 126 | 0.8% | 21,777,074 | 2,744 | 1.7% | 314 |
| 2022 | 128 | 1.6% | 21,782,963 | 2,788 | 1.6% | 319 |
| 2023 | 130 | 1.6% | 21,787,965 | 2,832 | 1.6% | 324 |
| 2024 | 131 | 0.8% | 21,953,791 | 2,876 | 1.5% | 328 |
| 2025 | 131 | 0.0% | 22,268,240 | 2,917 | 1.4% | 333 |
| 2026 | 133 | 1.5% | 22,264,535 | 2,961 | 1.5% | 338 |
| 2027 | 133 | 0.0% | 22,596,372 | 3,005 | 1.5% | 343 |
| 2028 | 135 | 1.5% | 22,573,943 | 3,047 | 1.4% | 347 |
| 2029 | 136 | 0.7% | 22,727,071 | 3,091 | 1.4% | 353 |
| 2030 | 138 | 1.5% | 22,713,855 | 3,135 | 1.4% | 358 |
| 2031 | 139 | 0.7% | 22,862,159 | 3,178 | 1.4% | 363 |
| 2032 | 140 | 0.7% | 23,014,399 | 3,222 | 1.4% | 367 |

**Additional Firm Sales and Load***

**Historical Additional Firm Sales and Load, 1972–2012**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 1972 | 284 | – | 32 |
| 1973 | 291 | 2.3% | 33 |
| 1974 | 282 | (2.9%) | 32 |
| 1975 | 314 | 11.2% | 36 |
| 1976 | 289 | (8.1%) | 33 |
| 1977 | 311 | 7.8% | 36 |
| 1978 | 357 | 14.8% | 41 |
| 1979 | 373 | 4.4% | 43 |
| 1980 | 360 | (3.5%) | 41 |
| 1981 | 376 | 4.6% | 43 |
| 1982 | 368 | (2.4%) | 42 |
| 1983 | 425 | 15.6% | 49 |
| 1984 | 466 | 9.6% | 53 |
| 1985 | 471 | 1.1% | 54 |
| 1986 | 482 | 2.4% | 55 |
| 1987 | 502 | 4.2% | 57 |
| 1988 | 530 | 5.6% | 60 |
| 1989 | 671 | 26.5% | 77 |
| 1990 | 625 | (6.9%) | 71 |
| 1991 | 661 | 5.8% | 75 |
| 1992 | 680 | 2.9% | 77 |
| 1993 | 689 | 1.3% | 79 |
| 1994 | 741 | 7.5% | 85 |
| 1995 | 878 | 18.6% | 100 |
| 1996 | 989 | 12.6% | 113 |
| 1997 | 1,048 | 6.0% | 120 |
| 1998 | 1,113 | 6.2% | 127 |
| 1999 | 1,122 | 0.8% | 128 |
| 2000 | 1,143 | 1.9% | 130 |
| 2001 | 1,118 | (2.1%) | 128 |
| 2002 | 1,139 | 1.9% | 130 |
| 2003 | 1,120 | (1.7%) | 128 |
| 2004 | 1,157 | 3.3% | 132 |
| 2005 | 1,175 | 1.6% | 134 |
| 2006 | 1,189 | 1.2% | 136 |
| 2007 | 1,141 | (4.0%) | 130 |
| 2008 | 1,114 | (2.4%) | 127 |
| 2009 | 965 | (13.4%) | 110 |
| 2010 | 907 | (6.0%) | 104 |
| 2011 | 906 | 0.0% | 103 |
| 2012 | 862 | (4.8%) | 98 |

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

**Additional Firm Sales and Load***

**Projected Additional Firm Sales and Load, 2013–2032**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 2013 | 1,010 | 17.1% | 115 |
| 2014 | 1,025 | 1.5% | 117 |
| 2015 | 1,053 | 2.7% | 120 |
| 2016 | 1,053 | 0.1% | 120 |
| 2017 | 1,062 | 0.8% | 121 |
| 2018 | 1,060 | (0.3%) | 121 |
| 2019 | 1,068 | 0.8% | 122 |
| 2020 | 1,115 | 4.4% | 127 |
| 2021 | 1,193 | 7.0% | 136 |
| 2022 | 1,229 | 3.0% | 140 |
| 2023 | 1,234 | 0.4% | 141 |
| 2024 | 1,231 | (0.2%) | 140 |
| 2025 | 1,234 | 0.2% | 141 |
| 2026 | 1,228 | (0.5%) | 140 |
| 2027 | 1,228 | 0.0% | 140 |
| 2028 | 1,217 | (0.9%) | 139 |
| 2029 | 1,212 | (0.5%) | 138 |
| 2030 | 1,268 | 4.6% | 145 |
| 2031 | 1,262 | (0.5%) | 144 |
| 2032 | 1,257 | (0.4%) | 143 |

*Includes Micron Technology, Simplot Fertilizer, and the INL

**Company System Load (excluding Astaris)**

**Historical Company System Sales and Load, 1972–2012 (weather adjusted)**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 1972 | 4,566 | – | 577 |
| 1973 | 5,040 | 10.4% | 635 |
| 1974 | 5,461 | 8.4% | 690 |
| 1975 | 6,012 | 10.1% | 760 |
| 1976 | 6,422 | 6.8% | 810 |
| 1977 | 6,858 | 6.8% | 863 |
| 1978 | 7,174 | 4.6% | 910 |
| 1979 | 7,776 | 8.4% | 977 |
| 1980 | 7,773 | 0.0% | 974 |
| 1981 | 8,043 | 3.5% | 1,012 |
| 1982 | 7,994 | (0.6%) | 1,004 |
| 1983 | 7,991 | 0.0% | 1,009 |
| 1984 | 8,095 | 1.3% | 1,012 |
| 1985 | 8,303 | 2.6% | 1,045 |
| 1986 | 8,382 | 0.9% | 1,050 |
| 1987 | 8,462 | 1.0% | 1,059 |
| 1988 | 8,839 | 4.5% | 1,108 |
| 1989 | 9,237 | 4.5% | 1,161 |
| 1990 | 9,544 | 3.3% | 1,206 |
| 1991 | 9,744 | 2.1% | 1,219 |
| 1992 | 9,985 | 2.5% | 1,259 |
| 1993 | 10,163 | 1.8% | 1,266 |
| 1994 | 10,628 | 4.6% | 1,344 |
| 1995 | 11,030 | 3.8% | 1,373 |
| 1996 | 11,390 | 3.3% | 1,437 |
| 1997 | 11,688 | 2.6% | 1,471 |
| 1998 | 12,151 | 4.0% | 1,522 |
| 1999 | 12,472 | 2.6% | 1,565 |
| 2000 | 12,895 | 3.4% | 1,628 |
| 2001 | 13,037 | 1.1% | 1,594 |
| 2002 | 12,771 | (2.0%) | 1,596 |
| 2003 | 13,030 | 2.0% | 1,637 |
| 2004 | 13,327 | 2.3% | 1,673 |
| 2005 | 13,568 | 1.8% | 1,703 |
| 2006 | 13,909 | 2.5% | 1,739 |
| 2007 | 14,346 | 3.1% | 1,796 |
| 2008 | 14,460 | 0.8% | 1,813 |
| 2009 | 13,917 | (3.8%) | 1,744 |
| 2010 | 13,789 | (0.9%) | 1,734 |
| 2011 | 13,762 | (0.2%) | 1,725 |
| 2012 | 14,011 | 1.8% | 1,760 |

**Company System Load (including Astaris)**

| Historical Company System Sales and Load, (1972–2012) (weather adjusted) | | | | Astaris Sales and Load (1972–2002) (weather adjusted) | | |
|---|---|---|---|---|---|---|
| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) | Astaris Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
| 1972 | 6,385 | – | 794 | 1,819 | – | 207 |
| 1973 | 6,685 | 4.7% | 832 | 1,645 | (9.6%) | 188 |
| 1974 | 7,104 | 6.3% | 887 | 1,643 | (0.1%) | 188 |
| 1975 | 7,569 | 6.6% | 946 | 1,557 | (5.3%) | 178 |
| 1976 | 7,997 | 5.6% | 998 | 1,575 | 1.2% | 179 |
| 1977 | 8,276 | 3.5% | 1,033 | 1,418 | (10.0%) | 162 |
| 1978 | 8,716 | 5.3% | 1,094 | 1,542 | 8.8% | 176 |
| 1979 | 9,170 | 5.2% | 1,144 | 1,395 | (9.6%) | 159 |
| 1980 | 9,286 | 1.3% | 1,155 | 1,513 | 8.5% | 172 |
| 1981 | 9,677 | 4.2% | 1,208 | 1,634 | 8.0% | 186 |
| 1982 | 9,548 | (1.3%) | 1,191 | 1,554 | (4.9%) | 177 |
| 1983 | 9,600 | 0.5% | 1,202 | 1,610 | 3.6% | 184 |
| 1984 | 9,796 | 2.0% | 1,215 | 1,701 | 5.7% | 194 |
| 1985 | 9,917 | 1.2% | 1,239 | 1,614 | (5.1%) | 184 |
| 1986 | 9,935 | 0.2% | 1,236 | 1,554 | (3.7%) | 177 |
| 1987 | 10,154 | 2.2% | 1,262 | 1,692 | 8.9% | 193 |
| 1988 | 10,474 | 3.2% | 1,303 | 1,635 | (3.4%) | 186 |
| 1989 | 10,940 | 4.4% | 1,365 | 1,703 | 4.2% | 194 |
| 1990 | 11,149 | 1.9% | 1,398 | 1,604 | (5.8%) | 183 |
| 1991 | 11,353 | 1.8% | 1,412 | 1,609 | 0.3% | 184 |
| 1992 | 11,555 | 1.8% | 1,446 | 1,570 | (2.4%) | 179 |
| 1993 | 11,600 | 0.4% | 1,438 | 1,437 | (8.4%) | 164 |
| 1994 | 12,048 | 3.9% | 1,514 | 1,420 | (1.2%) | 162 |
| 1995 | 12,597 | 4.6% | 1,561 | 1,567 | 10.4% | 179 |
| 1996 | 13,079 | 3.8% | 1,639 | 1,689 | 7.8% | 192 |
| 1997 | 13,315 | 1.8% | 1,666 | 1,628 | (3.6%) | 186 |
| 1998 | 13,424 | 0.8% | 1,674 | 1,273 | (21.8%) | 145 |
| 1999 | 13,523 | 0.7% | 1,691 | 1,051 | (17.4%) | 120 |
| 2000 | 13,949 | 3.1% | 1,754 | 1,054 | 0.3% | 120 |
| 2001 | 13,695 | (1.8%) | 1,673 | 658 | (37.5%) | 75 |
| 2002 | 12,782 | (6.7%) | 1,597 | 11 | (98.3%) | 1 |
| 2003 | 13,030 | 1.9% | 1,637 | 0 | (100.0%) | 0 |
| 2004 | 13,327 | 2.3% | 1,673 | 0 | 0.0% | 0 |
| 2005 | 13,568 | 1.8% | 1,703 | 0 | 0.0% | 0 |
| 2006 | 13,909 | 2.5% | 1,739 | 0 | 0.0% | 0 |
| 2007 | 14,346 | 3.1% | 1,796 | 0 | 0.0% | 0 |
| 2008 | 14,460 | 0.8% | 1,813 | 0 | 0.0% | 0 |
| 2009 | 13,917 | (3.8%) | 1,744 | 0 | 0.0% | 0 |
| 2010 | 13,789 | (0.9%) | 1,734 | 0 | 0.0% | 0 |
| 2011 | 13,762 | (0.2%) | 1,725 | 0 | 0.0% | 0 |
| 2012 | 14,011 | 1.8% | 1,760 | 0 | 0.0% | 0 |

**Company System Load**

**Projected Company System Sales and Load, 2013–2032**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 2013 | 14,020 | 0.1% | 1,759 |
| 2014 | 14,205 | 1.3% | 1,782 |
| 2015 | 14,348 | 1.0% | 1,800 |
| 2016 | 14,502 | 1.1% | 1,818 |
| 2017 | 14,684 | 1.3% | 1,842 |
| 2018 | 14,842 | 1.1% | 1,862 |
| 2019 | 15,011 | 1.1% | 1,883 |
| 2020 | 15,208 | 1.3% | 1,906 |
| 2021 | 15,426 | 1.4% | 1,934 |
| 2022 | 15,603 | 1.1% | 1,956 |
| 2023 | 15,769 | 1.1% | 1,977 |
| 2024 | 15,905 | 0.9% | 1,992 |
| 2025 | 16,025 | 0.8% | 2,009 |
| 2026 | 16,176 | 0.9% | 2,028 |
| 2027 | 16,348 | 1.1% | 2,049 |
| 2028 | 16,483 | 0.8% | 2,065 |
| 2029 | 16,640 | 1.0% | 2,087 |
| 2030 | 16,879 | 1.4% | 2,116 |
| 2031 | 17,043 | 1.0% | 2,137 |
| 2032 | 17,201 | 0.9% | 2,154 |

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IDAHO POWER®
An IDACORP Company



# 2013 Integrated Resource Plan

## APPENDIX B

# Demand-Side Management

## 2012 ANNUAL REPORT

**March 15, 2013**

# 2013

# Integrated Resource Plan

## APPENDIX B

# Demand-Side Management

## 2012 ANNUAL REPORT

**March 15, 2013**

IDAHO POWER®

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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.


## SAFE HARBOR STATEMENT

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


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# LIST OF SUPPLEMENTS

Supplement 1: Cost-Effectiveness
Supplement 2: Evaluation
NEEA Market Effects Evaluations (included on CD with Supplement 2)

# GLOSSARY OF ACRONYMS

aMW—Average Megawatt

A/C—Air Conditioning/Air Conditioners

ACB, Inc.—Advertising Checking Bureau, Inc.

ADM—ADM Associates, Inc.

AMI—Advanced Metering Infrastructure

ARRA—*American Reinvestment and Recovery Act of 2008*

B/C—Benefit/Cost

BCA—Building Contractors Association

BCASEI—Building Contractors Association of Southeast Idaho

BCASWI—Building Contractors Association of Southwestern Idaho

BCW—Boise Center West

BOMA—Building Owners and Managers Association

BOP—Builder Option Package

BPA—Bonneville Power Administration

CAES—Center for Advanced Energy Studies

CAP—Community Action Partnership

CAPAI—Community Action Partnership Association of Idaho, Inc.

CAIS—Certified Agricultural Irrigation Specialist

CBSA—Commercial Building Stock Assessment

CEERI—CAES Energy Efficiency Research Initiative

CEI—Continuous Energy Improvement

CEL—Cost-Effective Limit

CEU—Continuing Education Unit

CFL—Compact Fluorescent Lamp/Light

CHQ—Corporate Headquarters (Idaho Power)

CID—Certified Irrigation Designer

CIS—Customer Information System

COP—Coefficient of Performance

CR—Customer Representative (field staff)

CR&EE—Customer Research and Energy Efficiency Department

CSR—Customer Service Representative (call center)

DHP—Ductless Heat Pump

DOE—Department of Energy

DSM—Demand-Side Management

DSR—Demand-Side Resource

EA4—EA4 Energy Audit Program

EA5—EA5 Energy Audit Program

EEAG—Energy Efficiency Advisory Group

EECBG—Energy Efficiency Conservation Block Grant

EISA—*Energy Independence and Security Act of 2007*

EM&V—Evaluation, Measurement, and Verification

EnerNOC Solutions—EnerNOC Utility Solutions Consulting

ETO—Energy Trust of Oregon

EPA—Environmental Protection Agency

EUAT—Energy-Use Advisory Tool

FCA—Fixed-Cost Adjustment

$ft^2$—Square Feet

GMPG—Green Motors Practice Group

GWh—Gigawatt-hour

H&CE—Heating & Cooling Efficiency Program

HEM, LLC—Home Energy Management, LLC

hp—Horsepower

HPWH—Heat Pump Water Heater

HPS—Home Performance Specialist

HSPF—Heating Seasonal Performance Factor

HVAC—Heating, Ventilation, and Air Conditioning

IDL—Integrated Design Lab (in Boise)

IECC—International Energy Conservation Code

INL—Idaho National Laboratory

IOER—Idaho Office of Energy Resources

IP—Internet Protocol

IPMVP—International Performance Measurement and Verification Protocol

IPUC—Idaho Public Utilities Commission

IRP—Integrated Resource Plan

IRPAC—Integrated Resource Plan Advisory Council

IRS—Internal Revenue Service

iSTEM—Idaho Science, Technology, Engineering and Mathematics

IT—Information Technology

JACO—JACO Environmental, Inc.

kW—Kilowatt

kWh—Kilowatt-hour

LED—Light-Emitting Diode

LEEF—Local Energy Efficiency Funds

LIHEAP—Low Income Home Energy Assistance Program

MEF—Modified Energy Factor

MOU—Memorandum of Understanding

MHAFB—Mountain Home Air Force Base

MPER—Market Progress Evaluation Report

MW—Megawatt

MWh—Megawatt-hour

MVBA—Magic Valley Builders Association

NEEM—Northwest Energy Efficient Manufactured

NEEA—Northwest Energy Efficiency Alliance

NEMA—National Electrical Manufacturers Association

NPCC—Northwest Power and Conservation Council

NWRRC—Northwest Regional Retail Collaborative

OPUC—Public Utility Commission of Oregon

OSV—On-Site Verification

PCA—Power Cost Adjustment

PCT—Participant Cost Test

PECI—Portland Energy Conservation, Inc.

PLC—Power-Line Carrier

PSA—Public-Service Announcement

PTCS—Performance Tested Comfort System

QA—Quality Assurance

QC—Quality Control

RAP—Resource Action Programs

R&D—Research and Development

RBSA—Residential Building Stock Assessment

RETAC—Regional Emerging Technologies Advisory Committee

RFP—Request for Proposal

Rider—Idaho Energy Efficiency Rider and Oregon Energy Efficiency Rider

RIM—Ratepayer Impact Measure Test

ROCEE—Refrigerator Operator Coaching for Energy Efficiency

RPAC—*Regional Portfolio Advisory Committee*

RTF—Regional Technical Forum

SCCT—Simple-Cycle Combustion Turbine

SCO—State-Certifying Organization

SEE—Students for Energy Efficiency

SEER—Seasonal Energy Efficiency Ratio

SEM—Strategic Energy Management

SGIS—Smart Grid Investment Grant

SIR—Savings-to-Investment Ratio

SRVBCA—Snake River Valley Building Contractors Association

T-5HO—T-5 High Output

TRC—Total Resource Cost

TVP—Time-Variant Pricing

VFD—Variable-Frequency Drive

UC—Utility Cost

UES—Unit Energy Savings

US—United States

USA—Utility Service Agreement

W—Watt

WAQC—Weatherization Assistance for Qualified Customers

# EXECUTIVE SUMMARY

The pursuit of cost-effective energy efficiency is a primary objective for Idaho Power. Energy efficiency and demand response provide economic and operational benefits to the company and its customers. The enhancement of information and programs ensures customers' opportunities to learn about their energy use and participate in programs.

In 2012, Idaho Power focused energy efficiency activities on program analysis, energy savings, demand reductions, and improvements and expansion of its current programs. Idaho Power initiated several impact evaluations conducted by third-party consultants. The company also sponsored numerous activities under its customer education initiatives to improve customers' energy intelligence and to educate them about the company's energy efficiency programs. To identify additional energy-savings measures, Idaho Power conducted a new energy efficiency potential study in conjunction with its *2013 Integrated Resource Plan* (IRP). Also in 2012, the See ya later, refrigerator® program reached a milestone when it picked up its 10,000$^{th}$ unit.

Total expenditures from all funding sources on demand-side management (DSM)-related activities increased about 7 percent, from almost $46.3 million in 2011 to $49.3 million in 2012. This funding now comes from several sources outside the Idaho and Oregon Energy Efficiency Riders. Idaho incentives from the company's demand response programs are recovered through the annual power cost adjustment (PCA), and Idaho incentives for its industrial energy efficiency program, Custom Efficiency, are capitalized similar to a supply-side resource.

Although on target for savings achieved for the IRP, Idaho Power's annual energy savings from its energy efficiency activities slightly decreased in 2012. Reduced energy savings in 2012 were caused partially by Idaho Power's and the region's increased evaluation, measurement, and verification (EM&V) activities, which generally reduce savings estimates. The amount of energy saved was enough to power over 13,000 average homes served by Idaho Power. From Idaho Power's energy efficiency programs alone (excluding Northwest Energy Efficiency Alliance [NEEA] savings), the savings decreased 7 percent, from 163,315 megawatt-hours (MWh) in 2011 to 152,486 MWh in 2012. Annual energy savings for 2011, including the revised NEEA savings, were 183,862 MWh. In 2012, these savings decreased slightly to 170,228 MWh.

In 2012, Idaho Power celebrated 10 years of energy efficiency and demand response activity funded under the Idaho Energy Efficiency Rider (Idaho Rider). In those 10 years, the company realized a cumulative annual savings of over 1 million MWh savings. This is enough energy to power a city of 85,000 average residences. The demand-reduction capacity for Idaho Power's demand response programs in 2012 was over 438 megawatts (MW). This represents over 13 percent of Idaho Power's new record system peak of 3,245 MW set in 2012.

The *Demand-Side Management 2012 Annual Report* provides a review of the company's DSM activities and finances throughout 2012 and outlines Idaho Power's plans for DSM activities. This report also satisfies the reporting requirements set out in the Idaho Public Utilities Commission's (IPUC) Order Nos. 29026 and 29419, as well as the Memorandum of Understanding (MOU) signed by IPUC staff and Idaho investor-owned utilities in January 2010.

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# INTRODUCTION

Idaho Power's *Demand-Side Management 2012 Annual Report* provides a review of the financial and operational performance of Idaho Power's demand-side management (DSM) activities and initiatives for 2012. In 2012, Idaho Power offered energy efficiency and demand response programs to all customer sectors and sponsored numerous activities under its customer education initiatives to improve customers' energy intelligence and to educate them about reducing their electricity consumption.

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 its demand response programs as determined through the Integrated Resource Plan (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 and through outreach and education. Idaho Power endeavors to implement identical programs in its Idaho and Oregon service areas.

Customer participation in Idaho Power's energy efficiency and demand response programs continues to remain strong, provide substantial energy savings, and increase demand-reduction capacity. The energy savings exclusively from Idaho Power's energy efficiency programs in 2012 were 152,486 megawatt-hours (MWh). In 2012, the amount of energy saved from its programs was enough to power more than 13,000 average homes served by Idaho Power for one year.

Demand reduction available from the demand response programs increased in 2012. Combined, the Irrigation Peak Rewards, FlexPeak Management, and A/C Cool Credit programs resulted in an estimated summer peak reduction capacity of 438 megawatts (MW).

Idaho Power uses the same report structure each year in a continuing effort to fulfill the objectives of the Memorandum of Understanding (MOU) signed on January 25, 2010 by Idaho Power, Idaho Public Utilities Commission (IPUC) staff, and Idaho's other investor-owned utilities. The report consists of the main document and two supplements. *Supplement 1: Cost Effectiveness* shows all of the standard cost-effectiveness tests for Idaho Power programs and includes a table that reports expenses by funding source and cost category (Table 2). In 2012, the company continued its commitment to third-party evaluation activities. Included in *Supplement 2: Evaluation* are copies of all of Idaho Power's 2012 evaluations, evaluations conducted by its regional partners, customer surveys and reports, Idaho Power's evaluation plans, general energy efficiency research, and demand response research. In 2012, all Idaho Power energy efficiency programs were cost effective, except the company's weatherization programs for income-qualified customers and 52 individual measures in various programs. The majority of these measures have been discontinued, and the remaining measures will be reviewed in 2013.

The cost-effectiveness analysis of Idaho Power's demand response programs showed all three demand response programs to be cost-effective over the life of each program. This analysis uses a program life of a 20-year planning period for the A/C Cool Credit and Irrigation Peak Rewards programs and a 10-year planning period for the FlexPeak Management program. For this report, based on the future uncertainty of these programs and because the IPUC has not issued an order in IPUC Case No. IPC-E-12-29, Idaho Power used the assumptions from the information known prior to the filing to temporarily suspend the A/C Cool Credit and Irrigation Peak Rewards programs. The cost-effectiveness analysis for the FlexPeak Management program is still based on a 10-year life. The cost-effectiveness models were updated to include 2012 expenses and demand reduction, as well as 2013 budgeted expenses and forecasted performance.

## DSM Programs

The programs within Idaho Power's energy efficiency and demand response portfolio are offered to all major customer sectors: residential, commercial, industrial, and irrigation. The commercial and industrial energy efficiency programs are made available to customers in either sector.

Idaho Power groups its DSM activities in four categories: energy efficiency, demand response, market transformation, and other programs and activities. The other programs and activities are generally designed to provide customer outreach and education concerning the efficient use of electricity. All of these activities are coordinated to advance Idaho Power's continued commitment to pursue all cost-effective energy efficiency, all prudent demand response, and to enhance customer satisfaction.

Figures 1 through 3 show the demand-reduction capacity, historic energy savings, and DSM expenses.

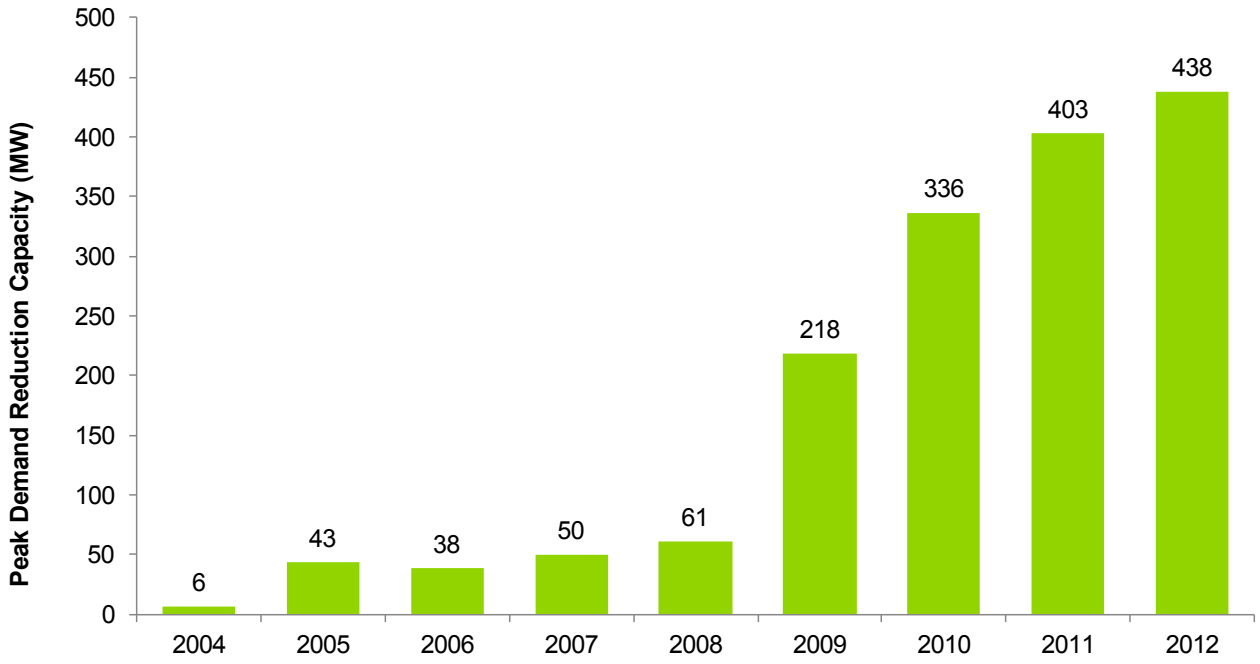



Figure 1. Peak demand-reduction capacity 2004–2012 (MW)

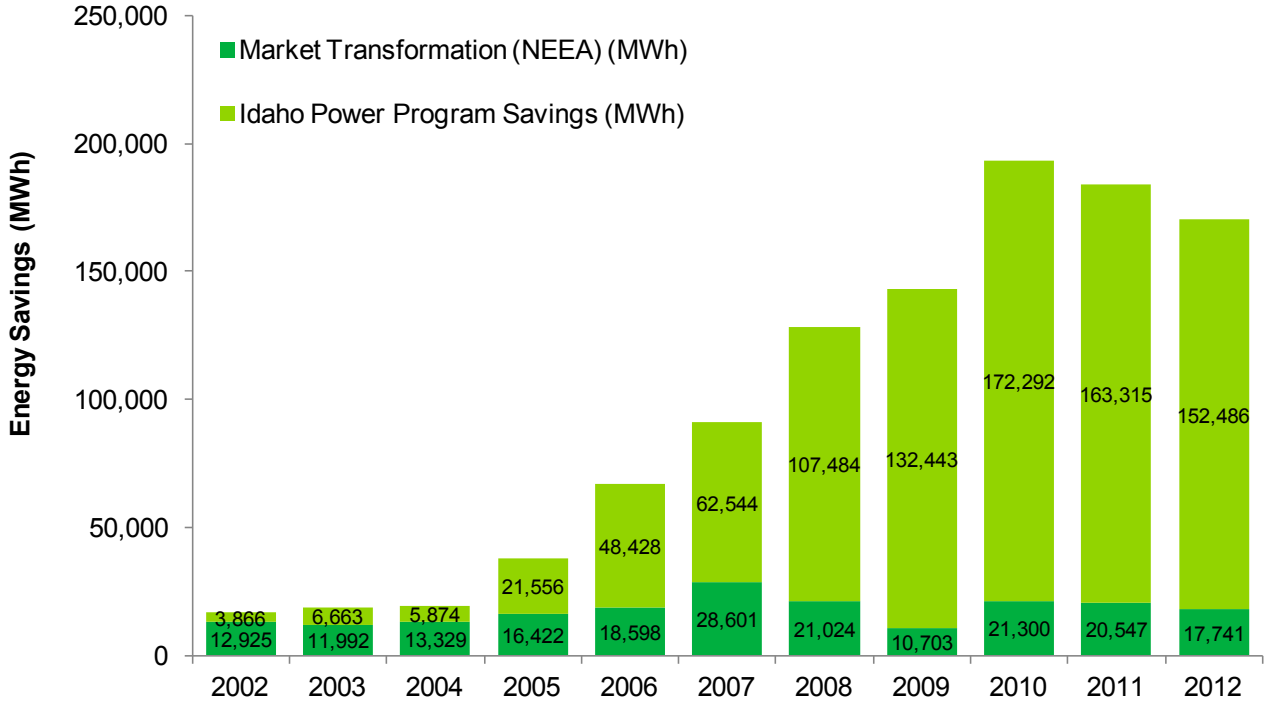



Figure 2. Annual energy savings 2002–2012 (MWh)

Note: 2012 market-transformation savings (NEEA) are preliminary.

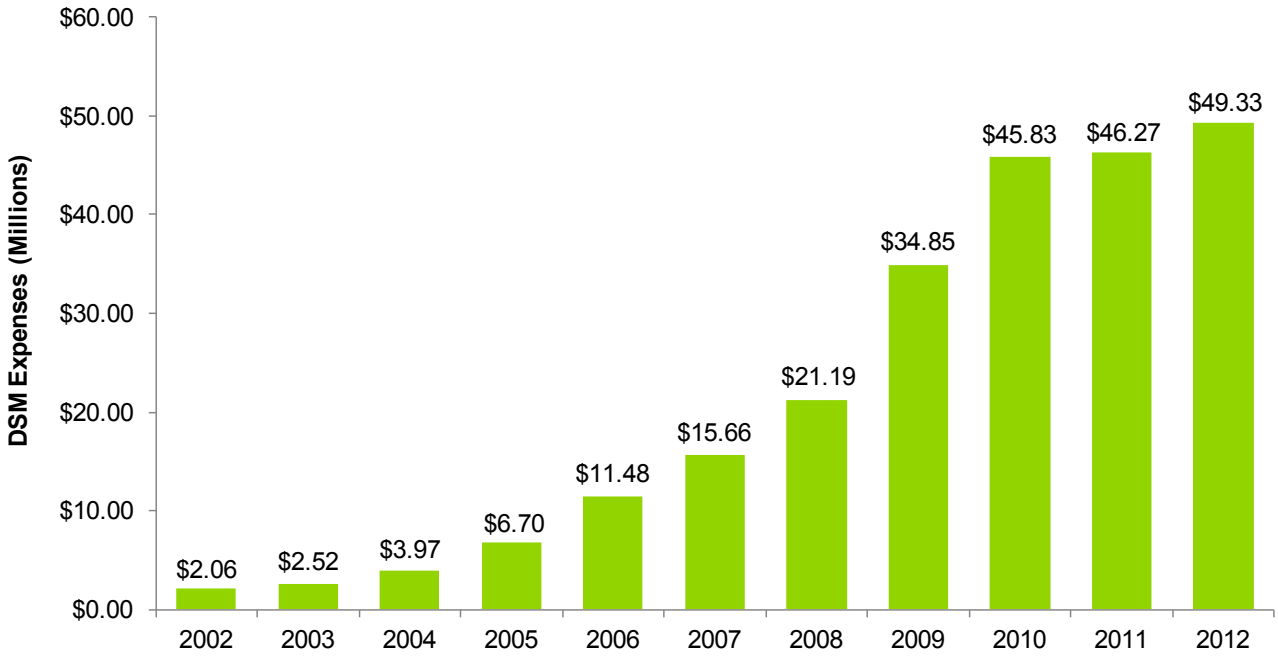



Figure 3. DSM expense history 2002–2012 from all sources (millions of dollars)

## Demand Response Programs

The goal of demand response at Idaho Power is to minimize or delay the need to build new supply-side resources. The company estimates future capacity shortfalls through the IRP planning process, then plans programs to mitigate these shortfalls. Demand response programs are measured by the amount of demand reduction, in MW, available to the company during system peak periods. In 2012, Idaho Power operated three demand response programs: the A/C Cool Credit program for residential customers, the FlexPeak Management program for commercial/industrial customers, and the Irrigation Peak Rewards program for irrigation customers.

Research efforts in 2012 included a continued investigation into the need for demand response, as well as how to measure its value. Idaho Power also continued to examine and refine program dispatch criteria. Idaho Power contracted with Portland Energy Conservation, Inc. (PECI), to conduct a research project for the A/C Cool Credit program to optimize the use of this program by more accurately estimating the available demand reduction in advance of dispatching this program. In 2012, the company, based on PECI's research plan, used the A/C Cool Credit program 13 times, with a goal of capturing various cycling strategies at various temperature bins, allowing PECI to create a regression model to estimate demand reduction.

The FlexPeak Management program was used four times during summer 2012. These events did not incur any marginal costs for the company and were successful in keeping the participants familiar and engaged with the program while verifying the accuracy of EnerNOC, Inc.'s, weekly nominations. Although Idaho experienced fairly extreme weather conditions in summer 2012, there was no need to dispatch the Irrigation Peak Rewards program, which was not economical to operate considering the variable payment necessary to use this program. Idaho Power hit a new all-time system peak of 3,245 MW at 4:00 p.m. on July 12, 2012. Both the A/C Cool Credit and FlexPeak Management programs were dispatched at 4:00 p.m. on this day, successfully preventing the system peak from increasing after 4:00 p.m., as it would have otherwise done.

Idaho Power's IRP determines the company's forecasted need for energy resources while balancing reliability, cost, environmental concerns, and efficiency. The plan is developed with the assistance of the company's customers and other stakeholders and is reviewed and updated every two years. In 2012, Idaho Power began the analytical portion of the 2013 IRP and commenced its regular meetings with the Integrated Resource Plan Advisory Council (IRPAC).

In fall 2012, the company's IRP analysis demonstrated there were 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 Irrigation Peak Rewards, A/C Cool Credit, and FlexPeak Management programs have been available to meet that need. However, the most recent analysis from the 2013 IRP indicates no peak-hour shortages until 2016. This 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. Based on the results of this analysis, on December 21, 2012, Idaho Power filed Case No. IPC-E-12-29 with the IPUC, requesting a temporary suspension of the A/C Cool Credit and Irrigation Peak Rewards programs. The FlexPeak Management program will continue to be available in 2013. This temporary suspension will allow the company to work with stakeholders to identify the best long-term solution for its demand response programs.

## Energy Efficiency Programs

Energy efficiency programs focus on reducing energy usage by identifying homes, buildings, equipment, or components where an energy-efficient design, replacement, or repair can achieve energy savings. These programs are available to all customer sectors in Idaho Power's service area. Project measures range from entire residential or commercial building construction to appliance replacement. Savings from these programs are measured in terms of kilowatt-hour (kWh) or MWh savings. These programs usually supply energy savings throughout the year. Idaho Power's energy efficiency offerings include programs in residential and commercial new construction (lost-opportunity savings), residential and commercial retrofit applications, and irrigation and industrial systems improvement or replacement.

## Market Transformation

Market transformation is a method of achieving energy savings through engaging and influencing large national and regional companies and organizations. These organizations influence the design of energy efficiency into products, services, and practices that improves their energy efficiency. Idaho Power achieves market-transformation savings primarily through its participation in the Northwest Energy Efficiency Alliance (NEEA).

## Other Programs and Activities

Other programs and activities represent a range of small projects that are typically research, development, and education oriented. This category includes the Residential Energy Efficiency Education Initiative, Easy Savings Program, Commercial Educational Initiative, Local Energy Efficiency Funds (LEEF), Residential Economizer Project Study, and Boise City Home Audit Project. These programs enable Idaho Power to offer support for projects and educational opportunities not normally covered under existing programs.

Table 1 provides a list of the DSM programs and their respective sectors, operational category, the state each was available in 2012, and associated energy savings.

Table 1. 2012 DSM, sectors, programs, operational type, and energy savings/demand reduction

| Program by Sector | Operational Type | State | Savings |
|---|---|---|---|
| **Residential** | | | |
| A/C Cool Credit | Demand Response | ID/OR | 44.9 MW |
| Ductless Heat Pump Pilot | Energy Efficiency | ID/OR | 445 MWh |
| Energy Efficient Lighting | Energy Efficiency | ID/OR | 16,709 MWh |
| Energy House Calls | Energy Efficiency | ID/OR | 1,192 MWh |
| ENERGY STAR® Homes Northwest | Energy Efficiency | ID/OR | 537 MWh |
| Heating & Cooling Efficiency Program | Energy Efficiency | ID/OR | 689 MWh |
| Home Improvement Program | Energy Efficiency | ID | 457 MWh |
| Home Products Program | Energy Efficiency | ID/OR | 887 MWh |
| Oregon Residential Weatherization | Energy Efficiency | OR | 12 MWh |
| Rebate Advantage | Energy Efficiency | ID/OR | 187 MWh |
| Residential Energy Efficiency Education Initiative | Other Programs and Activities | ID/OR | n/a |
| See ya later, refrigerator® | Energy Efficiency | ID/OR | 1,576 MWh |
| Weatherization Assistance for Qualified Customers | Energy Efficiency | ID/OR | 648 MWh |
| Weatherization Solutions for Eligible Customers | Energy Efficiency | ID | 258 MWh |
| **Commercial/Industrial** | | | |
| Building Efficiency | Energy Efficiency | ID/OR | 20,450 MWh |
| Commercial Education Initiative | Other Programs and Activities | ID/OR | n/a |
| Easy Upgrades | Energy Efficiency | ID/OR | 41,569 MWh |
| FlexPeak Management | Demand Response | ID/OR | 52.8 MW |
| Oregon Commercial Audits | Energy Efficiency | OR | n/a |
| Custom Efficiency | Energy Efficiency | ID/OR | 54,253 MWh |
| **Irrigation** | | | |
| Irrigation Efficiency Rewards | Energy Efficiency | ID/OR | 12,617 MWh |
| Irrigation Peak Rewards | Demand Response | ID/OR | 339.9 MW |
| **All Sectors** | | | |
| Northwest Energy Efficiency Alliance | Market Transformation | ID/OR | 17,741 MWh |

## Program Performance

In 2012, annual energy savings slightly decreased compared to 2011. The saving difference varied by sector. Energy savings for the residential sector decreased by 24 percent to 23,597 MWh. The commercial sector energy savings increased by 23 percent to 62,019 MWh, and the industrial sector energy savings decreased by 20 percent to 54,253 MWh. Energy savings for the irrigation sector decreased by 10 percent to 12,617 MWh. The reduction in savings in the residential sector was due, in part, to new lower deemed-savings amounts approved by the Regional Technical Forum (RTF) and Idaho Power making some programs available only for electrically heated homes. Some of the energy-savings reduction in the industrial sector and the increase in the commercial sector were due to programmatic changes. The overall reduced energy savings in 2012 may be caused, in part, by Idaho Power's and the region's increased evaluation, measurement, and verification (EM&V) activities. Additional energy savings continue to be realized through market-transformation partnership activities with NEEA.

Customer participation remained strong in most of the existing programs during the year. The number of projects completed under the Building Efficiency and Easy Upgrades programs increased by 33 percent

and 6 percent, respectively. Participation in Rebate Advantage increased by 40 percent, from 25 homes in 2011 to 35 homes in 2012. The number of homes completed under the ENERGY STAR® Homes Northwest program increase by 33 percent. The projects completed under the Irrigation Efficiency Rewards program increased slightly by 3 percent, from 880 projects in 2011 to 908 projects in 2012.

A few programs were big contributors to overall energy savings. Although the Custom Efficiency program had reduced savings compared to 2011, the program accounted for 32 percent of Idaho Power's energy savings from programs, resulting in an estimated 54,253 MWh of savings. The Easy Upgrades program in the commercial sector provided 24 percent, or 41,569 MWh, of estimated energy savings. In the residential sector, the Energy Efficient Lighting program saved 16,709 MWh, accounting for 10 percent of overall energy savings.

Table 2 shows the 2012 annual energy savings, percent of energy usage, number of customers, and average megawatt (aMW) savings associated with each of the DSM program categories. The table also provides a comparison of the 2012 contribution of each sector in terms of energy usage and its respective size in the number of customers. Unless otherwise noted, all energy savings presented in this report are measured or estimated at the customer's meter, excluding line losses.

Table 2. 2012 program sector summary and energy usage/savings/demand reduction

| | Energy Efficiency Program Impacts[a] | | | | Idaho Power System Sales | | |
|---|---|---|---|---|---|---|---|
| | Program Expenses | Energy Savings (kWh) | Average Energy (aMW) | Peak Load Reduction (MW)[b] | Sector Total (MWh) | Percentage of Energy Usage | Number of Customers |
| Residential | $ 6,337,777 | 23,597,363 | 2.7 | 44.9 | 5,052,302 | 35.83% | 416,020 |
| Commercial | 6,954,795 | 62,018,709 | 7.1 | 7.1 | 3,869,314 | 27.44% | 65,920 |
| Industrial | 7,092,581 | 54,253,106 | 6.2 | 60.4 | 3,131,650 | 22.21% | 116 |
| Irrigation | 2,373,201 | 12,617,164 | 1.4 | 343.0 | 2,048,435 | 14.53% | 19,045 |
| Market Transformation | 3,379,756 | 17,741,430 | 2.0 | n/a | n/a | n/a | n/a |
| Other Programs and Activities | 692,062 | n/a | n/a | n/a | n/a | n/a | n/a |
| **Total Direct Program Expenses** | **$26,830,172** | **170,227,773** | **19.0** | **455.0** | **14,101,701** | **100.00%** | **501,101** |

[a] Energy, average energy, and expense data have been rounded to the nearest whole unit, which may result in minor rounding differences.
[b] This includes peak load reduction from both demand response and energy efficiency programs.

## 2012 Activities

In 2012, Idaho Power continued to expand its DSM programs to increase participation and energy savings. Many activities in 2012 revolved around evaluation and research to make DSM programs more effective and the savings gained from these programs more reliable. The company also completed a third-party energy efficiency potential study and a non-participant survey for the residential, commercial, and irrigation sectors.

Although not directly related to Idaho Power's DSM activities, the company has continued to install and configure its new Customer Information System (CIS), made possible under a matching grant from the Smart Grid Investment Grant (SGIG). This project should be complete with migration to the new CIS by mid-2013. This installation has and will affect some of the company's DSM program activities because any changes related to the company's billing system cannot occur until the system is implemented. Information technology (IT) resources for other projects have also been dramatically constrained during the conversion.

Idaho Power collaborated with the City of Boise to finalize the Boise City Home Audit Project. Additionally, the company continued to fund and collaborate with the Integrated Design Lab (in Boise) (IDL) and participate with NEEA's Ductless Heat Pump (DHP) Pilot.

During 2012, Idaho Power continued its contractual participation in NEEA under the 2011 to 2014 agreement. NEEA's efforts in the northwest impact Idaho Power's customers by encouraging regional market transformation. Idaho Power representatives participated in several NEEA committees and in several NEEA events.

Idaho Power also continued to help fund and participate in the RTF and used the results from the RTF's research in program development and cost-effectiveness analyses. Beginning in 2012, a representative from Idaho Power was a member of the RTF Policy Advisory Committee. This committee provides policy recommendations on how to best meet the needs of stakeholders while maintaining the independent technical model of the RTF. Additionally, Idaho Power staff participated in numerous sub-committees.

On March 15, 2012, Idaho Power filed Case No. IPC-E-12-15, a request for the IPUC to designate Idaho Power's expenditure of $35,623,321 in Idaho Energy Efficiency Rider (Idaho Rider) funds and $7,018,385 in Custom Efficiency incentive expenses as prudently incurred expenses in 2012. Through the discovery process, Idaho Power found that $345 had been inadvertently charged to the Idaho Rider that should have been charged to the Oregon Energy Efficiency Rider (Oregon Rider). The company subsequently modified its request for prudency to $35,622,976 in Idaho Rider expenses, for a total request of $42,641,361. The company included copies of the *Demand-Side Management 2011 Annual Report* along with *Supplement 1: Cost-Effectiveness* and *Supplement 2: Evaluation* in its filing. On October 22, 2012, the IPUC issued Order No. 32667. In this order, the IPUC found that the company had prudently incurred $41,942,123.50, including $34,923,738.50 in Rider expenses and $7,018,385 in Custom Efficiency incentive expenses in 2011. The commission declined to decide the reasonableness of $89,601 of Idaho Power labor-related expense increases for Rider funded employees and denied Rider funding for $82,855.50 in A/C Cool Credit incentive payments to customers. On November 13, 2012, Idaho Power filed a petition for reconsideration in Case No. IPC-E-12-15. In this filing and subsequent filings, the company asked for reconsideration on an accounting adjustment of $526,781 and $89,601 in labor-related expenses. On December 11, 2012, the commission issued Order No. 32690, in which they found it reasonable to grant the company reconsideration of the accounting-related adjustment but again declined to decide the reasonableness of the company's labor-related expense increase until the company provided evidence from which the commission might better assess the reasonableness of those expenses. As a result of these orders, the company has credited the Idaho Rider account 254201 by $82,855.50 and placed $89,601 in reserve account 253000 until prudency can be determined. These prudency filings and Idaho Power's DSM activities are designed to comply with the agreed principles set forth in the MOU for Prudency Determination of DSM Expenditures.

## Energy Efficiency Advisory Group

Formed in 2002, the Energy Efficiency Advisory Group (EEAG) provides input on formulating and implementing energy efficiency and demand-reduction programs funded by the Rider. Currently, the EEAG consists of 14 members from Idaho Power's service area and the Pacific Northwest. Members represent a cross section of customers from the residential, industrial, commercial, and irrigation sectors, as well as representatives for seniors, low-income individuals, environmental organizations, state agencies, public utility commissions, and Idaho Power.

The EEAG met three times in 2012: February 22, July 19, and November 6. Additionally, a webinar was held on December 5 and a conference call was held on December 14. During these meetings, Idaho Power discussed and requested recommendations on new program proposals, marketing methods, and specific measure details; provided a status of the Rider funding and expenses; updated ongoing programs and projects; and supplied general information on DSM issues. Idaho Power relies on input from the EEAG to provide a customer and public interest review of energy efficiency and demand response programs and expenses. The minutes from the 2012 EEAG meetings, the webinar on December 5, and the December 14 conference call are included in *Supplement 2: Evaluation*.

During the July 19 EEAG meeting, EEAG members and Idaho Power staff engaged in an interactive session to review the structure and content of EEAG meetings. A summary of this discussion and suggestions was provided in a memo dated August 3, 2012, and sent to all members. In subsequent meetings, and after review of the original order by the IPUC that created EEAG, the members affirmed their desire to meet quarterly for all-day, in-person sessions to review DSM activities. Additional teleconferences and/or webinars may supplement the quarterly meetings. The members also requested that time be allocated for the audience to ask questions throughout the presentations and discussions and that guest speakers be used when appropriate to the subject matter. Finally, members will be given an opportunity to suggest agenda items and will receive presentation materials one week in advance of the meeting. The company has implemented many of the EEAG members' recommendations to increase the effectiveness of EEAG meetings. Additionally, Idaho Power continues to address recommendations from the IPUC received in Case No. IPC-E-12-15 and confirmed by Order No. 32667. A copy of the revised memo can be found in *Supplement 2: Evaluation*.

At the November 6 EEAG meeting, Idaho Power presented and discussed four residential initiatives: Home Energy Audits, Shade Tree Pilot, Student Energy Efficiency Kits, and Solar Thermal Hot Water measure. All initiatives except the Solar Thermal Hot Water measure received positive feedback and support from EEAG. Idaho Power plans on launching the following three initiatives in 2013.

The new Home Energy Audits program is based, in part, on the Boise City Home Audit Project that Idaho Power and the City of Boise undertook previously using *American Recovery and Reinvestment Act of 2008* (ARRA) funding. This new program will allow all-electric residential customers to select a home performance specialist (HPS) from a list of preferred providers and have the HPS perform an audit of their home. The audit will include a blower door test, a visual inspection of the crawl space and attic, and a collection of data regarding the home and its energy use. Homeowners will receive a report with specific recommendations for their home and information on programs that may help with the cost of energy efficiency improvements. Preparations are underway for a program launch during third quarter 2013.

Idaho Power, along with local stakeholders, is exploring a shade-tree program for the Treasure Valley. Using results from a state-sponsored urban tree-canopy study and online planting resources developed by the Arbor Day Foundation, the Shade Tree Pilot will encourage strategic planting of trees to reduce residential energy use. Properly planted shade trees save energy in the summer by reducing cooling costs. Trees provide measureable economic and environmental benefits, including enhanced air quality, storm water quality, and property values. Utility shade-tree programs throughout the country report energy savings, high participant satisfaction, and enhanced public images related to environmental stewardship. The Shade Tree Pilot is being developed for implementation in fall 2013, and results will be reviewed for full program development in 2014.

Idaho Power plans to build on the success of its previous Students for Energy Efficiency (SEE) Program (2009–2011) by implementing a new Student Energy Efficiency Kits program. The new

program will target elementary school students in grades four through six. The project plan includes the delivery of 2,500 kits to students attending schools in Idaho Power's service area during spring semester 2013 and another 2,500 kits in the fall. Participating classrooms will be identified by Idaho Power's community education representatives. Once enrolled, one of two vendors selected through a competitive request for proposal (RFP) process will facilitate the delivery of the curriculum, take-home energy kits, and feedback materials directly to the school. Spring kit delivery will begin on approximately April 1, 2013, and reporting for the spring enrollment will be complete in July 2013. Fall kit delivery will begin in September 2013, with reporting complete in early 2014. At the end of 2013, Idaho Power intends to gather feedback from all stakeholders to capture lessons learned and determine whether or not to continue the program in 2014.

In addition to EEAG, Idaho Power solicits further customer input through meeting directly with stakeholder groups in the residential, commercial, industrial, and irrigation customer sectors. Idaho Power has also enhanced its relationships with trade allies, trade organizations, and regional groups committed to increasing the use of energy efficiency programs and measures to reduce electricity load.

## Regulatory Initiatives

Idaho Power believes there are three essential components of an effective regulatory model for DSM: 1) the timely recovery of DSM program costs, 2) the removal of financial disincentives, and 3) the availability of financial incentives. A description of this overall DSM business model was provided in Case No. IPC-E-10-27, which was filed with the IPUC on October 22, 2010.

Since 2002, Idaho Power has recovered most DSM program costs through the Rider, with the intended result of providing a more timely recovery of DSM costs. To address the removal of financial disincentives, Idaho Power has tested the effects of a fixed-cost adjustment (FCA) mechanism in a five-year pilot initiative. In 2011, the FCA pilot completed year five and the company filed Case No. IPC-E-11-19 with the IPUC requesting to convert the FCA to an ongoing and permanent rate schedule. On March 30, 2012, the IPUC approved the FCA mechanism as a permanent program for the residential and small general-service customers. The IPUC also directed Idaho Power to file a proposal within six months to adjust the FCA to address the capture of changes in load not related to energy efficiency programs. On September 28, 2012, the company filed its Compliance Filing in response to the IPUC's directive. On January 31, 2013, the IPUC issued Final Order No. 32731, directing that the FCA mechanism continue unchanged.

Idaho Power is working toward the third component of the overall DSM regulatory model. As part of Case No. IPC-E-10-27, the IPUC issued Order No. 32245 on May 17, 2011, allowing Idaho Power to account for customer incentives paid through the Custom Efficiency program as a regulatory asset beginning on January 1, 2011. On October 31, 2012, the company filed Case No. IPC-E-12-24, requesting the authority to include 2011 Custom Efficiency program incentive payments in rates and to establish a mechanism to annually update rates for future payments. This mechanism would provide Idaho Power an opportunity to earn an authorized rate of return on its investments in demand-side resources (DSR). As of December 31, 2012, proceedings relating to this case are ongoing.

## DSM Expenditures

Funding for DSM programs in 2012 came from several sources. The Rider funds are collected directly from customers on their monthly bills. For 2012, the Idaho Rider was 4 percent of base-rate revenues. The 2012 Oregon Rider was 3 percent of base-rate revenues. Beginning in 2011, Idaho Power was

allowed to account for incentives paid through the Custom Efficiency program as a regulatory asset in Idaho. Additionally beginning in 2012, Idaho related demand response program incentives were paid through the power cost adjustment (PCA) mechanism. Other energy efficiency and demand response-related expenses not funded through the Rider, including costs for administration and overhead, are included as part of Idaho Power's ongoing operation and maintenance costs.

Total DSM expenses funded from all sources were $49.3 million in 2012. At the beginning of 2012, the Idaho Rider negative balance was about $5.3 million, and by January 1, 2013, the positive balance was $4 million. This reduction in the Idaho Rider negative balance and accrual of a positive balance was accomplished through the filings described in the Regulatory Initiatives section. At the beginning of the year, the Oregon Rider negative balance was approximately $3.5 million, and by year-end, the negative balance was $3.9 million.

Table 3 shows the total expenditures funded by the Idaho Rider ($25,739,189); the Oregon Rider ($1,382,330); and Idaho Power base rates ($22,205,341). The Idaho Power base rates category includes Idaho Custom Efficiency program incentives, Idaho Power demand response incentives, and operation and maintenance costs, separated by expense category.

Table 3. 2012 funding source and energy impact

| Funding Source | Expenses | MWh Savings |
|---|---|---|
| Idaho Rider | $ 25,739,188 | 164,781 |
| Oregon Rider | 1,382,330 | 4,771 |
| Idaho Power Base Rates | 22,205,341 | 676 |
| **Total** | **$ 49,326,859** | **170,228** |

Table 4 and Figure 4 indicate 2012 DSM program expenditures by category. The expenses in the Materials & Equipment category are primarily for A/C Cool Credit ($3,300,000). The Other Expense category includes marketing ($397,800), program evaluation ($214,000), and program training ($115,800). The Purchased Services category includes payments made to NEEA and third-party contractors who help deliver Idaho Power's programs, such as M2M Communication Corp. for Irrigation Peak Rewards; EnerNOC for FlexPeak Management; JACO Environmental, Inc. (JACO), for See ya later, refrigerator®; Honeywell for A/C Cool Credit; Evergreen Consulting for Easy Upgrades; and contractors for Weatherization Assistance for Qualified Customers (WAQC) and Weatherization Solutions for Eligible Customers.

Table 4. 2012 DSM program expenditures by category

| | Total | % of Total |
|---|---|---|
| Incentive Expense | $ 30,848,941 | 62% |
| Labor/Administrative Expense | 3,490,392 | 7% |
| Materials & Equipment | 3,308,304 | 7% |
| Other Expense | 532,733 | 1% |
| Purchased Services | 11,146,489 | 23% |
| **Total 2012 DSM Program Expenditures by Category** | **$ 49,326,859** | **100%** |

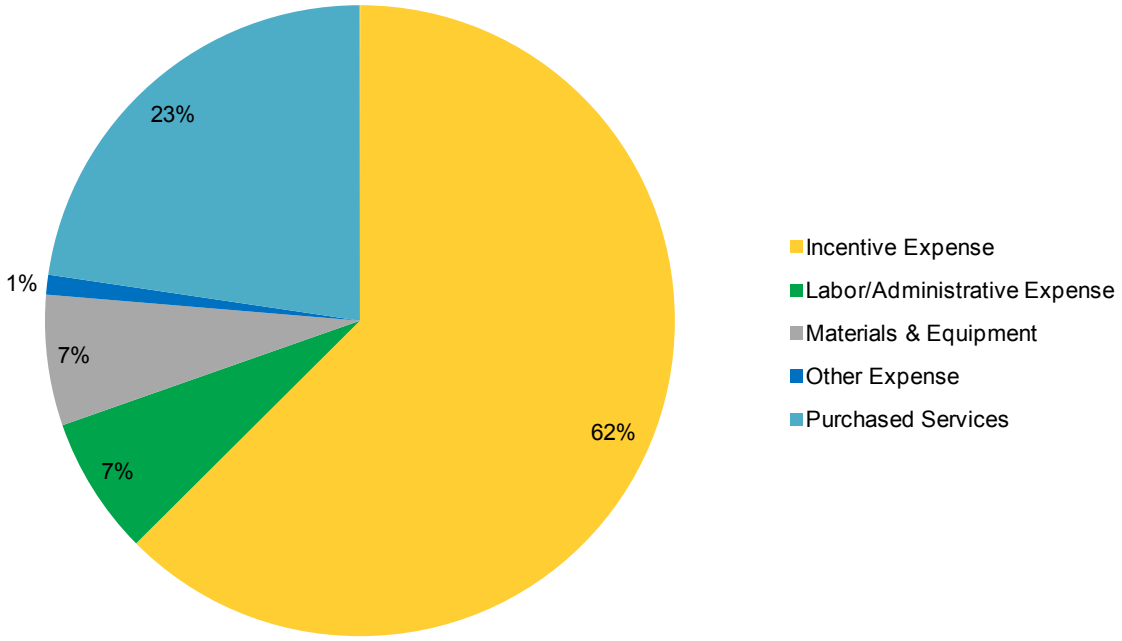



Figure 4. 2012 DSM program expenditures by category

Table 5 and Figure 5 describe the amount and percentage of incentives paid by segment and sector. There are two incentive segments—demand response (DR) and Energy Efficiency (EE)—and three sectors—Residential, Commercial/Industrial, and Irrigation. The incentives listed are funded by the Idaho Rider, Oregon Rider, the Custom Efficiency regulatory asset, the Idaho PCA mechanism, and Idaho Power base rates. Market transformation-related payments made to NEEA and payments made to third-party community action partners under the WAQC program are not included in the incentive amounts.

Table 5. 2012 DSM program incentives by segment and sector

| | Sector Total | % of Total |
|---|---|---|
| DR—Residential | $ 759,544 | 2% |
| DR—Commercial/Industrial | 2,905,642 | 9% |
| DR—Irrigation | 11,011,193 | 36% |
| EE—Irrigation | 2,043,829 | 7% |
| EE—Residential | 2,143,235 | 7% |
| EE—Commercial/Industrial | 11,985,498 | 39% |
| **Total Incentive Expense** | **$ 30,848,941** | **100%** |

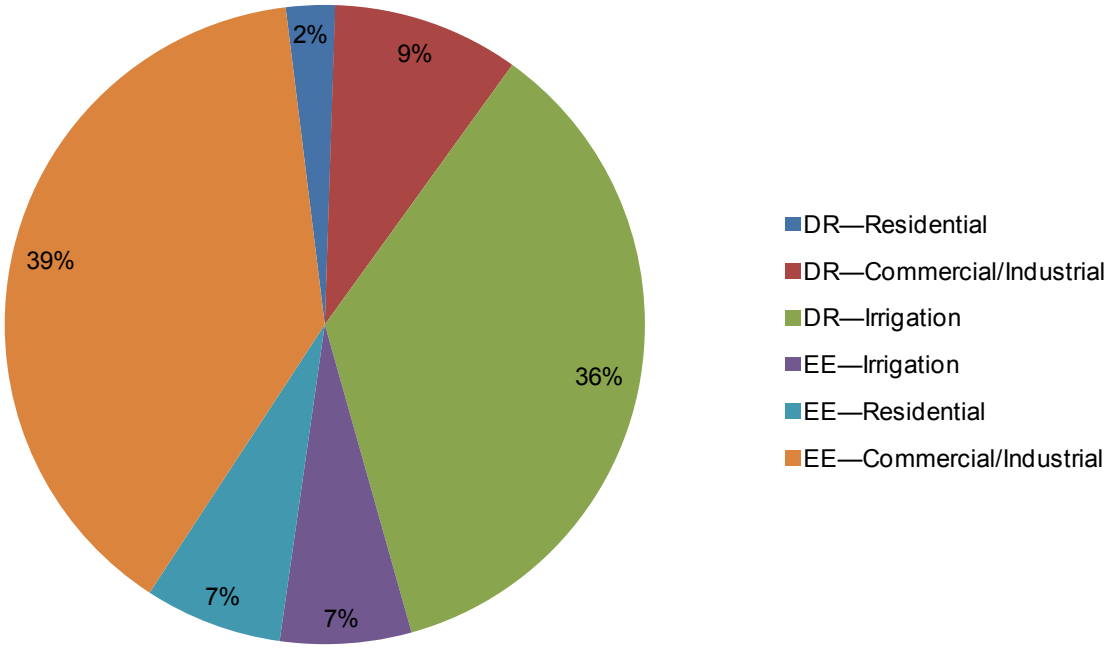



Figure 5. 2012 DSM program incentives by segment and sector

## Marketing

With technology rapidly advancing, marketing choices are no longer as simple as placing a print advertisement or distributing a press release. Now marketing is a mosaic that also includes social media, multimedia, community events, online advertising, and owned media.

To meet the demands, a new marketing specialist was added to the energy efficiency team at Idaho Power in April 2012. Adding this position allowed for new marketing ideas and a more balanced workload for two specialists.

Idaho Power marketing staff continually research academic and industry best practices to stay current on marketing theory and tactics. Successful marketing approaches from inside and outside the utility industry are studied and evaluated to determine if they are appropriate for marketing Idaho Power's energy efficiency programs.

Below is a high-level summary of new marketing communication tactics developed and implemented during 2012.

To increase Idaho Power's communication with small and medium commercial customers, the company launched the first biannual *Energy at Work* commercial newsletter. The goal of this newsletter is to provide pertinent and useful information to a customer segment with limited time. The summer 2012 edition is available to download on Idaho Power's business energy efficiency web page. Topics in this edition include the following:

- Energy Efficiency: Good for Business and Your Health
- T-12 Lamps are So Yesterday

- 2011 Commercial Energy Efficiency Program Recap
- Planning for a Successful Energy Efficiency Project
- Four Steps to An Energy-Saving Business Strategy

A video about the DHP Pilot was produced in the first half of 2012 using customer testimonials to explain why people choose DHPs and the benefits for electrically-heated homes. This video is available on Idaho Power's DHP Pilot's web page http://www.idahopower.com/EnergyEfficiency/Residential/Programs/ductlessHeatPumps/default.cfm. The video also was uploaded to YouTube and received 5,200 views in approximately one year.

Planning for an Easy Upgrades program online advertising campaign began in the fall and winter of 2012 to increase participation in the program. An animated advertisement was developed to target commercial businesses, with a planned launch date of January 2, 2013. The advertisement targets specific professions and industries within Idaho Power's service area. Idaho Power staff will review weekly reports to monitor click-through rates (the number of times a user clicks on the advertisement, taking them to a corresponding web page) and make adjustments as needed over the course of the three-month campaign.

Two movie theater advertisements, one for the Home Improvement Program and one for both ducted and DHPs, were produced using in-house resources and shown at Regal Cinema theaters in Nampa and Boise. The advertisements ran for eight weeks during June and July 2012. The number of individual advertisements shown totaled 12,544, and the number of total projected impressions was 695,376; total projected impressions are the anticipated number of times an advertisement will be displayed or viewed, giving customers a certain number of potential exposures to a message or an "opportunity-to-see." The more times a message is viewed, particularly within a shorter time frame, the more likely customers will take action. To maximize the usability of the two movie theater advertisements, both advertisements were uploaded to YouTube and the Home Improvement Program advertisement was posted on the program's Idaho Power web page.

At the November 6 EEAG meeting, an Idaho Power Corporate Communications department representative solicited information from EEAG regarding changes to the company's monthly customer newsletter, *Connections*. Discussions covered reducing the number of energy efficiency bill inserts and instead creating energy efficiency-focused *Connections* editions. EEAG members offered suggestions and support for adding more energy efficiency information in the newsletter. In July 2013, *Connections* will specifically focus on the company's energy efficiency programs.

In January 2013, Idaho Power produced a print advertisement campaign featuring a New Year's theme and a number of Idaho Power's energy efficiency programs. The advertisement ran for two weeks in daily and weekly newspapers throughout Idaho Power's service area.

Facebook and Yahoo! behavioral-targeted advertisements are being used to expand Idaho Power's online presence. Idaho Power staff track these online marketing campaigns through reports that show the number of impressions (number of times a person is exposed to a message), click-through rates, and reach (geographic dispersion of the message). These reports will help inform subsequent marketing decisions.

The following additional metrics are used to determine if marketing tactics are successful.

- Trade ally/contractor feedback
- Customer comments via the Idaho Power call center, email, and customer representatives (CR)
- Qualitative and quantitative survey results
- Customer inquiries and customer awareness of programs
- Web Trends data reports

## Program Evaluation

Evaluation of the company's DSM programs is integral in providing accurate and transparent program savings results and is a key component in Idaho Power's commitment to continuous program improvement.

Most program evaluations and primary research is contracted through third-party entities by means of a competitive bid process managed by Idaho Power's Procurement department. When appropriate, an internal analysis is conducted and managed by Idaho Power's Energy Efficiency Research and Analysis team.

In 2012, Idaho Power completed third-party impact evaluations on the following six programs: Heating & Cooling Efficiency (H&CE) Program; See ya later, refrigerator®; WAQC; Weatherization Solutions for Eligible Customers; Building Efficiency; and Easy Upgrades. Additionally, a third-party process evaluation of the A/C Cool Credit program and a 20-year all-sector energy efficiency potential study were completed.

Two third-party primary research projects were conducted in 2012. The A/C Cool Credit research project delivered a predictive model for future use in determining the value of curtailments at various temperatures and cycling strategies. The Irrigation Efficiency Rewards research project determined the estimated unit energy savings for measures deemed out of compliance by the RTF.

Internal program impact reports were completed by Customer Relations and Energy Efficiency staff for the FlexPeak Management and Irrigation Peak Rewards programs. The *Weatherization Assistance for Qualified Customers 2011 Annual Report* was completed in 2012 and filed with the IPUC on April 1, 2012.

Copies of the final reports from evaluations and research performed in 2012 and the *Weatherization Assistance for Qualified Customers 2011 Annual Report* are included in *Supplement 2: Evaluation*.

## Customer Satisfaction

In 2012, based on surveys conducted in 2011, Idaho Power received the highest customer satisfaction with business customers among western midsized utilities according to J.D. Power and Associates *2012 Electric Utility Business Customer Satisfaction Study*. In 2013, based on surveys conducted in 2012, Idaho Power's satisfaction among business customers decreased by 6 percent overall. Fifty-five percent of the business customer respondents in this study indicated they are aware of Idaho Power's energy efficiency programs, and those customers are more satisfied with Idaho Power than the

customers who are unaware of the programs. The awareness of Idaho Power's energy efficiency programs not only affects the customer's overall satisfaction with the company but also his/her satisfaction with corporate citizenship.

Since 1995, Idaho Power has employed an independent third-party research vendor to conduct customer relationship surveys to measure the overall customer relationship and satisfaction with Idaho Power. The survey measures the satisfaction of a number of aspects of the customer's relationship with Idaho Power, including energy efficiency at a very high level. However, the intent of this survey is not to measure all aspects of any or all energy efficiency programs offered by Idaho Power.

The 2012 results of Idaho Power's quarterly customer relationship survey continued to show slight but steady improvement. Customers' positive perception of Idaho Power's energy efficiency efforts increased from 39 percent in early 2003, when energy efficiency-related questions were added to the survey, to 60 percent in late 2012. Idaho Power continues to expand its customer satisfaction measurement activities, which enable Idaho Power to identify actionable areas for improvement. Figure 6 depicts quarterly growth in the number of customers who indicated Idaho Power met or exceeded their needs concerning energy efficiency efforts encouraged by Idaho Power.

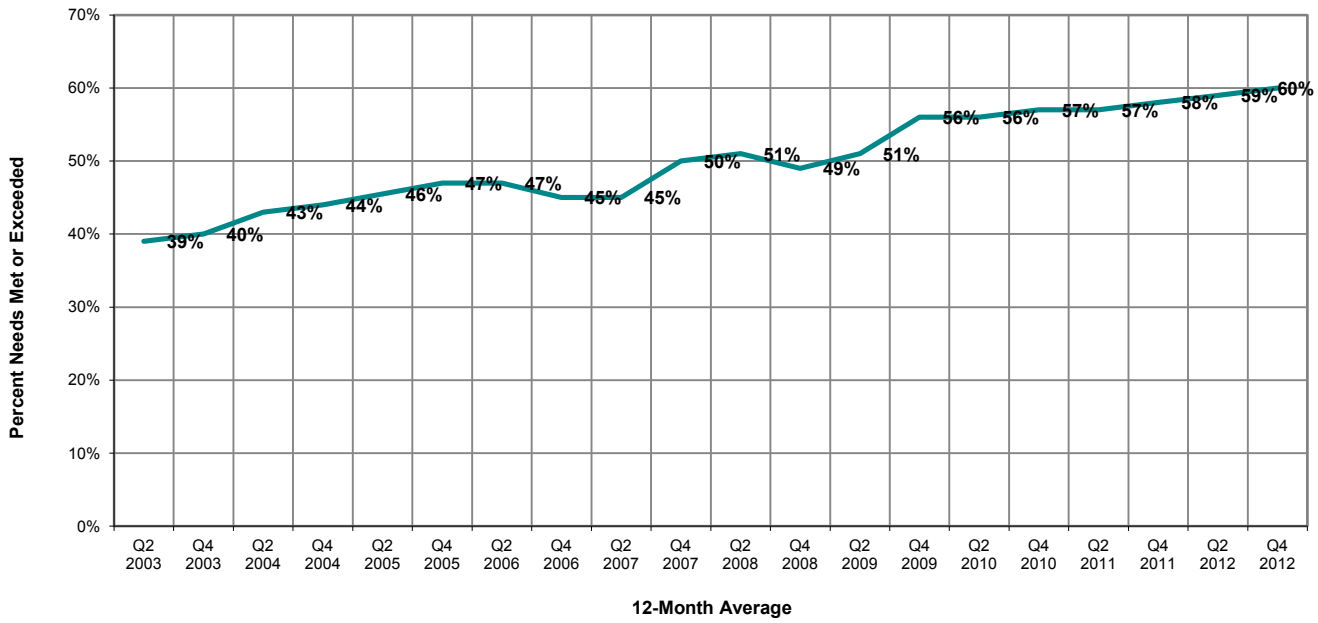



Figure 6. Percent of customers whose needs are met or exceeded by Idaho Power's energy efficiency efforts

Three questions related to energy efficiency programs in the general relationship survey were added in 2010 and continued in the 2012 survey: 1) Have you participated in any of Idaho Power's energy efficiency programs?, 2) Which energy efficiency program did you participate in?, and 3) Overall, how satisfied are you with the energy efficiency program? In 2012, overall, 35 percent of the survey respondents across all sectors indicated they have participated in at least one Idaho Power energy efficiency program. Of survey respondents who have participated in at least one Idaho Power energy efficiency program, 90 percent are "very" or "somewhat" satisfied with the program.

Qualitative research in the form of focus groups and one-on-one customer interviews measured customer satisfaction with the Building Efficiency program in 2012. This research provided guidance for

program modification and marketing. Results from this research are presented in the program descriptions in this report under Building Efficiency.

Due to a concern of over-surveying program participants or "survey fatigue," and because the measures and specifics of most program designs do not change annually, Idaho Power has determined it is in the best interest of customers and program operations not to survey most program participants annually. To ensure meaningful research in the future, Idaho Power has determined that program research will be done periodically (every two to three years), unless there have been major program changes. If aspects of the program change significantly, a satisfaction survey will likely be warranted subsequent to the change.

## Cost-Effectiveness

Idaho Power considers cost-effectiveness of primary importance in the design, implementation, and tracking of energy efficiency and demand response programs. In the past, most of Idaho Power's energy efficiency and demand response programs were preliminarily identified through the IRP process. Because of Idaho Power's diversified portfolio of programs, in the 2011 IRP, most of the new potential for energy efficiency in Idaho Power's service area is based on additional measures to be added to programs rather than new programs. The process in the IRP remains the same for determining if measures should be adopted as it was for program inclusion. Specific cost-effective programs or energy-saving measures are screened by sector to determine if the levelized cost of these programs or measures is less than supply-side resource alternatives. If they are shown to be less costly than supply side resources from a levelized-cost perspective, the hourly shaped energy savings is subsequently included in the IRP as a resource.

Prior to the actual implementation of energy efficiency or demand response programs, Idaho Power performs a cost-effectiveness analysis to assess whether a specific potential program design will be cost effective from the perspective of Idaho Power and its customers. Incorporated into these models are inputs from various sources in order to use the most current and reliable information available. When possible, Idaho Power leverages the experiences of other utilities in the region or throughout the country to help identify specific program parameters.

Idaho Power's goal is for all programs to have benefit/cost (B/C) ratios greater than 1 for the total resource cost (TRC) test, utility cost (UC) test, and participant cost test (PCT) at the program level and the measure level where appropriate. An exception to the measure level cost-effectiveness is when there is interaction between measures. Idaho Power may launch a pilot or a program to evaluate estimates or assumptions in the cost-effectiveness analysis. Following the implementation of a program, cost-effectiveness analyses are reviewed as new inputs from the actual program activity become available, such as actual program expenses, savings, or participation levels. If measures or programs are determined not to be cost effective after implementation, the program or measures are reexamined, including input provided from the company's EEAG.

Appendix 4 contains the UC and TRC B/C ratios using actual cost information over the life of each program through 2012. These B/C ratios are provided as a measure of cost-effectiveness for all Idaho Power energy efficiency or demand response programs currently being offered where energy savings and demand reduction are realized. As done in 2011, the actual historic savings and expenses were not discounted; only the value of the ongoing savings going forward are discounted to reflect today's dollars. A complete description of Idaho Power's methodology, input assumptions, sources, and results is presented in *Supplement 1: Cost-Effectiveness*.

In 2012, all three of the company's demand response programs were cost effective from a long-term perspective. Since this report is focused on cost-effectiveness for 2012 and with the final order pending on IPC-E-12-29, Idaho Power did not change the forecast of future expenses and program performance of its demand response programs. The Irrigation Peak Rewards and FlexPeak Management programs were shown to be cost effective from the one-year perspective for 2012. The A/C Cool Credit program was determined not to be cost-effective on a one-year perspective for 2012 because of the additional expense of replacing the paging switches with Advanced Metering Infrastructure (AMI)-compatible switches. All but two of Idaho Power's energy efficiency programs were cost effective from the UC, TRC, and PCT perspectives. WAQC and Weatherization Solutions for Eligible Customers programs are shown to be not cost-effective from the TRC and UC perspective. This was due to the lower estimated savings per home that resulted from the impact evaluation conducted by D&R International, Ltd. Fifty-two measures within programs were not cost effective from the UC or TRC perspective. Of those 52 measures, 40 were measures that were removed from the program offerings in 2012. Eleven measures will be reviewed and possibly modified in 2013. One measure will be removed in 2013. The specific cost-effectiveness ratios are included in *Supplement 1: Cost-Effectiveness*.

While verifying 2012 ENERGY STAR Homes Northwest program incentives for this report, Idaho Power found that 10 incentives out of 410 were paid to builders who submitted applications for ENERGY STAR gas-heated homes that were initiated in 2011. Since non-electrically heated ENERGY STAR Homes Northwest applicants with building permits dated after December 31, 2010, were excluded from this program in 2011, these 10 incentives should not have been paid. The total incentives paid for the 10 homes were $4,000. Gas-heated homes were excluded from the program because, as shown in *Supplement 1: Cost-Effectiveness*, gas-heated ENERGY STAR homes are not cost effective from the TRC perspective; however, they are cost-effective from the UC perspective, and the program remains cost-effective with the inclusion of the costs and savings from the gas-heated homes. In 2013, the fuel-type field in Idaho Power's database code was changed to allow only heat pump as the heating type. The code was changed on the incentive field to reflect electrically heated homes. These changes will prevent gas-heated homes from being given incentives in the future. Also in 2013, the incentive payment processes have been changed to provide a more thorough review of participant applications prior to payment.

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

## Future Plans

Many of Idaho Power's DSM programs are selected for implementation through Idaho Power's biennial IRP planning process. The IRP is a public document that details Idaho Power's strategy for economically maintaining the adequacy of its power system into the future. The IRP process balances reliability, cost, risk, environmental concerns, and efficiency in developing a preferred portfolio of future resources that meets the specific energy needs of Idaho Power's customers. In 2013, Idaho Power plans to increase participation in, and energy savings from, existing energy efficiency programs and initiatives. The company will continue to explore new potential, such as efficient measures for multiple-family dwellings. The company will continue to modify programs and measures and update energy savings and cost data to ensure all of its programs remain cost effective. With the filing and acknowledgement of the 2013 IRP, Idaho Power will have a new set of commission-acknowledged DSM alternative costs with which to analyze its energy efficiency programs. The company will conduct research and analysis to determine the effects of these new costs on the cost-effectiveness of its programs. Additionally, the company will continue to expand and enhance its research and EM&V projects included in the evaluation plan in *Supplement 2: Evaluation*.

## DSM Annual Report Structure

The structure of Idaho Power's *Demand-Side Management 2012 Annual Report* remains mostly unchanged from the 2011 report. It aligns with the reporting requirements included in the MOU with the IPUC staff and Idaho's other investor-owned utilities.

This main *Demand-Side Management 2012 Annual Report* is organized primarily by the customer sectors residential, commercial/industrial, and irrigation. Each sector has a description, which is followed by information regarding programs in that sector. Each program description includes a chart containing 2012 and 2011 program metrics in tabular format, followed by a general description, 2012 activities, cost-effectiveness, customer satisfaction/evaluation, and 2013 plans. Each program section contains detailed information relating to program changes and the reasoning behind those changes, including information on cost-effectiveness and evaluation. Following the sector and program sections of the report are descriptions of Idaho Power's activities in market transformation, other programs and activities, and Idaho Power's regulatory initiatives. Appendices 1 through 5 following the written sections contain tabular information on 2012 expenses and savings and supply historic information for all energy efficiency programs and demand response activities at Idaho Power.

Historically, Idaho Power divided its service area into five regions: 1) Canyon, consisting primarily of Canyon and Gem counties; 2) Western, consisting of the company's Oregon jurisdiction and Adams, Valley, and Payette counties; 3) Capital, consisting of Boise, Mountain Home, and the surrounding area; 4) Southern, consisting of the Twin Falls and Sun Valley area; and 5) Eastern, consisting of the Pocatello, Blackfoot, and Salmon areas.

Idaho Power currently divides its service area into three geographic regions: 1) Canyon–West, which combines the former Canyon and Western regions; 2) Capital, which retains the same geographic area; and 3) South–East, which combines the former Southern and Eastern regions. Because of the historical geographic demarcations, the five historical regions are often referred to throughout this report.

Appendices 1 through 5 remain generally unchanged in form and contain financial, energy savings, demand reduction, levelized costs, and program life B/C ratios from the UC and the TRC perspectives. Appendix 5 contains detailed financial and energy-savings information separated by Idaho Power's two jurisdictions, Idaho and Oregon.

Included again this year are two supplements and an attached CD. *Supplement 1: Cost Effectiveness* contains detailed annual cost-effectiveness information by program and energy-saving measures, as well as detailed financial information separated by expense category and jurisdiction. Provided in Supplement 1 are the B/C ratios from the UC, TRC, ratepayer impact measure test (RIM), and PCT perspectives. As of 2011, Idaho Power is using the alternate DSM costs and other financial inputs from Idaho Power's 2011 IRP. These inputs are used in cost-effective analyses for 2011 and forward.

*Supplement 2: Evaluation* contains Idaho Power's evaluation plans, copies of completed program evaluation reports, research reports, and reports created by Idaho Power or third parties. A CD containing market progress evaluation reports (MPER) and other reports provided by NEEA is attached to Supplement 2.

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# RESIDENTIAL SECTOR OVERVIEW

## Description

Idaho Power serves a population of slightly over one million people. Of this overall population, at the end of 2012 the company was serving 416,020 residential customers in its Idaho and Oregon service areas. During 2012, Idaho Power added 4,533 residential customers, a significant increase of residential customers compared to 2,733 in 2011. The growth in residential customers is the largest increase of residential customers over the past five years. This positive trend points towards a decrease in economic uncertainty, with more housing starts occurring in the company's service area. However, it is important to keep this growth rate in perspective from the standpoint that at its highest growth rate, Idaho Power was adding over 15,000 residential customers per year. In 2012, the residential segment represented 35.8 percent of Idaho Power's total electricity usage.

During 2012, after three consecutive years without hitting a system peak, Idaho Power hit its new system peak of 3,245 MW on July 12 at 4:00 p.m. The previous system peak of 3,214 MW was on Monday, June 30, 2008, at 3:00 p.m. In 2012, the Idaho Power service area experienced higher than normal summer temperatures and a summer high temperature of 108 degrees on July 12, 2012. A/C Cool Credit and FlexPeak Management demand response programs were dispatched on July 12, helping reduce what would have been a higher system peak. The company also had a low system winter peak during 2012. The all-time winter peak for Idaho Power of 2,528 MW occurred on Thursday, December 10, 2009, at 8:00 a.m. The winter system peak during 2012 was only 2,133 MW on Wednesday, December 19, at 8:00 a.m. All of these factors contributed to a of 1.4-percent decrease in residential system sales from 2011 to 2012. However, when the system sales data is weather adjusted, this decrease is only 0.2 percent. Idaho Power continued its education and promotion of energy efficiency programs and information to all residential customers. These tasks and activities contributed to increased program participation and continued strong customer satisfaction results.

# Programs

Table 6. 2012 residential program summary

| Program | Participants | Total Cost | | Savings | |
|---|---|---|---|---|---|
| | | Utility | Resource | Annual Energy (kWh) | Peak Demand (MW) |
| **Demand Response** | | | | | |
| A/C Cool Credit | 36,454 homes | $ 5,727,994 | $ 5,727,994 | n/a | 44.9 |
| **Total** | | **$ 5,727,994** | **$ 5,727,994** | | **44.9** |
| **Energy Efficiency** | | | | | |
| Ductless Heat Pump Pilot | 127 homes | $ 159,867 | $ 617,833 | 444,500 | |
| Energy Efficient Lighting | 925,460 bulbs | 1,126,836 | 2,407,355 | 16,708,659 | |
| Energy House Calls | 668 homes | 275,884 | 275,884 | 1,192,039 | |
| ENERGY STAR® Homes Northwest | 410 homes | 453,186 | 871,310 | 537,447 | |
| Heating & Cooling Efficiency Program | 141 projects | 182,281 | 676,530 | 688,855 | |
| Home Improvement Program | 840 homes | 385,091 | 812,827 | 457,353 | |
| Home Products Program | 16,675 appliances/fixtures | 659,032 | 817,924 | 887,222 | |
| Oregon Residential Weatherization | 5 homes | 4,516 | 11,657 | 11,985 | |
| Rebate Advantage | 35 homes | 37,241 | 71,911 | 187,108 | |
| See ya later, refrigerator® | 3,176 refrigerators/freezers | 613,146 | 613,146 | 1,576,426 | |
| Weatherization Assistance for Qualified Customers | 238 homes/non-profits | 1,370,141 | 1,819,945 | 648,304 | |
| Weatherization Solutions for Eligible Customers | 141 homes | 1,070,556 | 1,070,556 | 257,466 | |
| **Total** | | **$ 6,337,777** | **$10,066,879** | **23,597,363** | |

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

Programs available to residential customers include 1 demand response program, 12 energy efficiency programs, and 1 energy efficiency educational initiative. Residential efficiency programs include Energy House Calls; Rebate Advantage; ENERGY STAR® Homes Northwest; Home Products Program; Home Improvement Program; Energy Efficient Lighting; WAQC; Weatherization Solutions for Eligible Customers; DHP Pilot; Oregon Residential Weatherization; H&CE Program; and See ya later, refrigerator®.

Idaho Power markets its residential energy efficiency programs through many promotional methods including, but not limited to, bill inserts, bill messages, print advertisements, radio and television commercials, billboards, retail events, customer visits, and participation in home and garden shows as well as fairs.

Presentations to community groups and businesses continued to be a major emphasis during 2012. Idaho Power customer and community education representatives made hundreds of presentations in communities served by the company.

Idaho Power conducts the Burke Customer Relationship survey each year. This survey showed 53 percent of residential survey respondents in 2012 indicated Idaho Power is meeting or exceeding their needs with information on how to save energy or reduce their bill.

Sixty-one percent of residential respondents indicated Idaho Power is meeting or exceeding their needs by encouraging energy efficiency with its customers. Overall, 45 percent of Idaho Power residential customers surveyed in 2012 indicated Idaho Power is meeting or exceeding their needs in offering

energy efficiency programs, while 26 percent of the residential survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of the residential survey respondents who have participated in at least one Idaho Power energy efficiency program, 83 percent are “very” or “somewhat” satisfied with the program.

# A/C Cool Credit

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (participants) | 36,454 | 37,728 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | 44.9 | 24.0 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $4,804,566 | $2,781,553 |
| Oregon Energy Efficiency Rider | $92,810 | $114,989 |
| Idaho Power Funds | $830,618 | $0 |
| Total Program Costs—All Sources | $5,727,994 | $2,896,542 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Benefit/Cost Ratio | n/a | n/a |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.33 | |
| Total Resource Benefit/Cost Ratio | 1.33 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

## *Description*

A/C Cool Credit is a voluntary, dispatchable demand response program for residential customers. Using communication hardware and software, Idaho Power cycles participants' central air conditioners (A/C) or heat pumps off and on via a direct-load control device installed on the A/C unit. This program enables Idaho Power to reduce system peaking requirements during times when summer peak load is high. Idaho Power may cycle participants' A/C for up to 40 hours each month in June, July, and August. In return, participants receive a $7 per-month credit on their Idaho Power bill during July, August, and September.

Customers' A/Cs are controlled using two types of switches that communicate either by power-line carrier (PLC) or radio paging signals. A switch is installed on each customer's A/C unit and allows Idaho Power to cycle the customer's A/C during a cycling event. AMI switches use PLC communication, which provides the communication backbone for these switches. Since the implementation of Idaho Power's AMI project, the company installed the AMI switches wherever possible on new A/C Cool credit participants' A/C units in an effort to eliminate the use of radio paging signal switches.

In 2012, Idaho Power decided to replace existing radio-controlled paging switches with AMI switches due to declining radio paging coverage. There were approximately 23,500 paging switches in the field at the start of 2012. The company successfully negotiated with its third-party installation vendor to reduce the cost to replace the switches and worked with the switch supplier, Aclara®, to reduce the lead time to secure the necessary switches. This switch replacement project began in spring 2012. The project was originally planned to take approximately 18 months beginning in March 2012 and finishing in

June 2013. Switches in areas where paging coverage had been discontinued were replaced first and were replaced by June 15, 2012. Due to Idaho Power's filing of IPUC Case No. IPC-E-12-29 to temporarily suspend the program, the switch replacement project was discontinued in December 2012. At the end of 2012, approximately 7,640 radio-controlled paging switches were still on the system and 28,539 AMI switches were in the program.

## 2012 Activities

In 2012, Idaho Power contracted with PECI to conduct a research project for the A/C Cool Credit program. PECI's goals were to: 1) verify that savings can be estimated using AMI data, 2) verify that the adaptive algorithm embedded in the switches was working as designed, 3) create a predictive model for planning purposes, 4) estimate the kW reduction at various temperature and cycling strategies, and 5) test customer comfort impacts of higher cycling strategies to find optimum curtailment strategies that maximize kW results while minimizing customer comfort impacts.

To obtain the necessary data to complete this research and develop a predictive model, PECI needed observations of different curtailment strategies at different temperatures with corresponding baseline days where no curtailments occurred. The baseline days provided comparative information to ensure the impact on a curtailment day was fully attributed to the program. Overall, this curtailment research approach was a departure from previous years, where resources were called based on the perceived system need and value.

Based on PECI's research strategy and available days where the temperature matched the research design, there were 13 cycling events in 2012. One cycling event was in June, six events were in July, and six events were in August. Most events lasted from 4:00 p.m. to 7:00 p.m. For two events, participants were divided into two groups, with one group cycling from 4:00 p.m. to 7:00 p.m. and the second group cycling from 5:00 p.m. to 8:00 p.m. One hundred percent cycling, where the paging switches completely turn off the A/C units, was tested twice for one hour each time from 5:00 p.m. to 6:00 p.m.

Prior to the 2012 cycling season, the program specialist convened a working group to manage the complex nature of the cycling events required by the study. This working group included leaders and staff from the Customer Research & Energy Efficiency (CR&EE) department and representatives of Idaho Power's Metering department, who are responsible for configuring the dispatch software used by the AMI switches. The variables that needed configuration included three geographic areas, eight cycling percentages, and four time intervals that needed to be developed for two types of AMI switches.

This working group monitored the events and acted to address cycling issues as they occurred throughout the summer. After the cycling season, this group updated program process flow charts and provided input to PECI's Start-Up Checklist provided in their process evaluation report.

In 2012, due to the low switch inventory and the lead-time necessary to obtain switches, the company determined it would be best to use the available switches to replace paging switches and reduce marketing activities. The limited marketing methods used included a bill insert, follow-up letters for a cause-related effort, and a few small direct-mail campaigns.

The cause-related marketing approach used the last few years, consisting of partnering with the Idaho Foodbank and the Oregon Food Bank–Southeast Oregon Services, was updated and expanded to offer more choices for potential participants. The promotion started in mid-October 2011 and continued

through February 2012. Customers enrolling during this limited-time offer and having a switch installed chose between a $20 contribution made to the participant's local food bank and a $20 gift card to a retailer or restaurant of their choice. For 2012, this marketing approach yielded 315 new A/C Cool Credit enrollments. Gift card fulfillment was administered by a third party.

The criteria used for creating new participant solicitation lists were further refined in 2012 as part of a continuing endeavor to focus targeting efforts. Previous criteria included July energy use over 500 kWh; July use 15 percent or greater than April use; Idaho and Oregon residential customers in Ada, Bannock, Bingham, Canyon, Elmore, Gem, Gooding, Jerome, Malheur, Payette, Power, Twin Falls, and Washington counties; an active Utility Service Agreement (USA); "receive marketing" indicator yes; not an existing program participant; premise type is a house; no known landlord; and no duplicates. In 2012, a criterion was added to include 5 kW of demand, or more, for July. The mailing list was further refined to remove any miscellaneous accounts that met the above criteria but did not make sense to include, such as outbuildings, wells, religious facilities, estate accounts, or those managed by a third party.

Since the paging provider discontinued paging service to the Mountain Home Air Force Base (MHAFB), the company could not cycle the switches located in this area in 2012. The financial incentives previously paid to the MHAFB were discontinued. The company explored the option of partnering with the MHAFB to add additional paging equipment at the MHAFB; however, it was not possible to complete the contracts in time for the 2012 cycling season. As of the date of this publishing, a solution to use the paging switches on the MHAFB has not been determined.

## Cost-Effectiveness

The B/C analysis for the A/C Cool Credit program is based on a 20-year model that uses financial and DSM alternate-cost assumptions from the most recent IRP. As published in the 2011 IRP, for peaking alternatives, such as demand response programs, a 170-MW simple-cycle combustion turbine (SCCT) is used as an avoided resource cost.

Because the 2013 IRP process has indicated a lack of near-term capacity deficits, on December 21, 2012, Idaho Power filed a proposal with the IPUC to temporarily suspend two of its demand response programs, A/C Cool Credit and Irrigation Peak Rewards, for 2013. A settlement workshop was held in February 2013 with Idaho Power and interested stakeholders to discuss plans for the 2013 cycling season. The stipulation agreed to in that settlement workshop was filed on February 14, 2013. Idaho Power will meet with stakeholders and interested parties in workshops to further discuss future changes and identify the best long-term solutions for 2014 and beyond.

For this report, based on the future uncertainty of these programs and because the IPUC has not issued an order in the IPC-E-12-29 case, Idaho Power used the assumptions from the information known prior to the filing to temporarily suspend the A/C Cool Credit program for its cost-effective analysis. The cost-effectiveness models were updated to include 2012 expenses and demand reduction, as well as 2013 budgeted expenses and forecasted performance. Under these assumptions, the A/C Cool Credit program had a lifecycle TRC ratio of 1.33 and a one-year TRC ratio of 0.68. See *Supplement 1: Cost-Effectiveness* for details on the cost-effectiveness assumptions and data.

## Customer Satisfaction and Evaluations

As mentioned earlier, in 2012, Idaho Power contracted with PECI to conduct research on the A/C Cool Credit program to determine optimal curtailment strategies to meet cost-effectiveness targets and develop a predictive model that correlates weather forecasts with achievable kW load shifts from curtailment events. The results of this research showed that: 1) AMI data for evaluation is more reliable, accurate, and cost-effective than data loggers; 2) the embedded adaptive algorithm is operating as intended, although was only used once during the research period; 3) customer comfort is only minimally affected by higher cycling strategies and indoor temperature increase during events within the range expected for load control programs; and 4) the data from this research enabled PECI to create a predictive model that can be used for planning purposes.

The PECI research also demonstrated that the A/C Cool Credit program can achieve 1.09 kW per participant demand reduction when the weather is sufficiently hot and the cycling strategy is set appropriately. The research noted that on the July 2 event, one set of switches did not respond as expected. The event was intended to be a one-hour curtailment at 100 percent at a temperature of less than 90 degrees. The temperature rose above 90 degrees, which was outside the parameters recommended by PECI, thus the event was canceled. The paging switches and one set of the AMI switches responded; however, the other set of the AMI switches did not stop cycling when the event was cancelled. A change had been made to the scheduling software on Friday, June 29, and the Monday, July 2 event was the first event that occurred after this change was made. Upon investigating and working with the vendor, a coding error was found in the third-party software. Idaho Power developed an interim solution for future use. The vendor is aware of the situation and is working to develop a more permanent solution. The report also makes note that for the event on July 11, only one set of the AMI switches received the signal to dispatch. Idaho Power investigated and found a configuration setting that needed to be changed. This setting was corrected and tested before the event on the following day, July 12. All the switches responded correctly for that event.

Idaho Power also contracted with PECI to provide a process evaluation and program readiness plan. The objective of this evaluation was to document and evaluate the current program processes, identify best practices, and provide recommendations for improvement where applicable. The readiness plan was created to ensure interdepartmental coordination and program readiness prior to the 2012 curtailment season.

The process evaluation report indicated that the program has a high customer satisfaction rate, low churn rate, and a successful relationship with the delivery partner, Honeywell, Inc. PECI also noted that the program has operated successfully due to the continuity in program knowledge from the program specialist and the diligence of internal stakeholders.

PECI recommends: 1) determine appropriate metrics for measuring response rates to marketing campaigns; 2) more focus on customer retention; 3) clearly define roles, responsibilities, and accountability to increase collaboration between marketing and program staff; 4) incorporate pre-season testing of field equipment; and 5) more consistent messaging regarding program guidelines. Copies of both of these reports are included in *Supplement 2: Evaluation*.

## 2013 Strategies

The 2013 activities for this program hinge on the results of the company's proposal in IPC-E-12-29 to temporarily suspend the A/C Cool Credit program for the 2013 season and upcoming workshops on how to proceed with demand response programs for 2014 and beyond. The proposed suspension will

provide Idaho Power an opportunity to work with stakeholders to determine how this program might best serve customers and the company in the future. The company believes the filing is a prudent step to avoid expenses associated with the program until the company's planning process determines the future of the A/C Cool Credit program and the demand response programs in general. Because of this pending proposal, switch replacements were discontinued in December 2012. Approximately 15,564 paging switches have been replaced, and approximately 7,640 remain in the field.

# Ductless Heat Pump Pilot

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 127 | 131 |
| Energy Savings (kWh) | 444,500 | 458,500 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $153,017 | $183,260 |
| Oregon Energy Efficiency Rider | $6,850 | $7,923 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $159,867 | $191,183 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.024 | $0.028 |
| Total Resource Benefit/Cost Ratio | $0.094 | $0.081 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 4.22 | |
| Total Resource Benefit/Cost Ratio | 1.44 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2009 | |

## *Description*

Idaho Power joined the Northwest DHP Pilot project in 2009 and implemented the pilot throughout its service area. The company extended the project as an Idaho Power DHP pilot through 2012. A main goal of the Northwest DHP Pilot project is to promote DHP technology as an energy-saving alternative for customers who primarily heat their homes with electricity. In 2012, Idaho Power offered customers a $750 incentive payment to participate.

The program targets homes heated with electric zonal systems. Typically, these homes do not have air ducting and therefore cannot easily have a forced-air heat pump system installed. This provides the opportunity to encourage the use of DHPs. The types of electric zonal systems in the targeted homes include baseboards, ceiling cables, and wall-mounted units. Homes heated with fossil fuel forced-air systems or electric forced-air systems do not qualify. Qualifications include having one DHP indoor unit installed in the main living area of the home, since this is where most occupants spend the majority of their time.

Other Northwest DHP Pilot goals are to identify how much energy this technology saves to determine an RTF deemed-savings amount and to obtain customer satisfaction and behavior patterns regarding the units.

Field monitoring of selected homes throughout the Pacific Northwest, an analysis of billing data, and other evaluations occurred from 2009 through mid-2011. Data was analyzed during the second half of 2011 and continued through 2012. An impact and process evaluation field metering report was published in 2012 by NEEA. NEEA will complete a billing analysis report, cost-effectiveness report,

and the final summary report in early 2013. Details about the regional DHP effort can be found at the project website at www.goingductless.com and www.neea.org.

## 2012 Activities

Idaho Power used several marketing methods during 2012 to promote the pilot. Examples include participating in trade shows with a working demo unit, advertising in 10 newspapers, sending direct-mail letters, and adding bill inserts. The use of social-media websites continued in 2012 to increase DHP Pilot awareness. Additional marketing materials included descriptions of customers' experiences with the program posted as *Success Stories* on the Idaho Power website. Copies of the two DHP Pilot 2012 *Success Stories* are provided in *Supplement 2: Evaluation*.

Expanding the network of participating contractors remained a key growth strategy for the DHP Pilot. The goal was to support contractors currently in the DHP Pilot while adding new contractors. To accelerate the expansion of the participating contractor network, Idaho Power provided 15 DHP Pilot orientation training sessions to participating and prospective contractors. Expansion strategies resulted in the addition of 12 companies to the list of participating contractors, a 22 percent increase over 2011.

To hasten the residential adoption of the DHP technology in the Idaho Power service area, a key strategy was to communicate with other tiers of the supply chain. In the Idaho Power service area, there are several wholesalers supplying DHPs to the contractors. The program specialist met with several of these wholesalers to provide them the ability to promote DHPs to their contracting customers and to share helpful information. NEEA provided additional marketing and contractor training support for the DHP Pilot.

Idaho Power and other northwestern utilities participated in a 2012 NEEA-sponsored marketing campaign for DHPs conducted from September through December. Residents in the Idaho Power service area were targeted for the campaign using radio, television, and social-media website advertisements.

## Cost-Effectiveness

In 2012, the RTF reaffirmed support for a provisional annual-savings estimate based on the installation of one indoor-unit installation until the full pilot analysis is completed in early 2013. The qualifying unit should be installed consistent with the pilot guidelines, including at least one ton of heating capacity and using an inverted driven compressor. The deemed savings per unit is estimated at 3,500 annual kWh until the pilot analysis is completed. Regardless of prior cooling, the type of electric-resistance heat the DHP was displacing, or the climate zone in which the unit is located, the RTF has only deemed one savings amount. Participant costs for the TRC estimate were calculated by averaging one-unit installations that occurred in Idaho Power's service area in 2012. The average installation cost was $4,358, which was an increase over the 2011 average cost of $3,407. Using the RTF-deemed savings, this program is shown to be cost effective. For details see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

As part of the DHP Pilot, Idaho Power conducted on-site verifications (OSV) at completed installations in Idaho Power's service area to ensure the installations complied with program requirements. The OSVs were beneficial for customers and the contractors. The inspector provided information to customers regarding maximizing the benefits of their DHP. The contractors received feedback from the

inspector and reviewed the installation requirements of the DHP Pilot. Ten percent of the installations received on-site verifications in 2012.

In 2012, NEEA provided two reports to update the DHP pilot. The following are report highlights. These reports are included on the CD accompanying *Supplement 2: Evaluation*.

### Report E12-237, released May 2012

This report focuses on the detailed metering portion of the evaluation. Ecotope, Inc., installed metering equipment on a total of 95 homes selected from the participants in the DHP Pilot project. The metered sites were analyzed to develop the determinants of energy savings of the DHP systems as they operated across a variety of climates and occupants. The results of this report contribute to a more comprehensive understanding of DHP performance and its applicability as an energy efficiency measure in the Northwest. The metering results indicate supplemental heat from other fuels has less overall impact on savings than originally expected. The analysis also strongly indicates that increased indoor temperatures result in lower savings. The use of a DHP in place of baseboard heaters is far less sensitive to the characteristics of the home than would be expected in a conventional heating system. Other findings suggest the occupant's acceptance of this equipment is good and their satisfaction is uniform.
The amount of DHP cooling energy measured in the study was about 7 percent of the total value of heating savings. The cooling energy value was considered insignificant when compared to the heating savings value. Therefore, the cooling energy usage was not factored into the net impact of the equipment.

### Report E12-245, released October 2012

This report is the second MPER of NEEA's Northwest DHP Initiative. The report presents evaluation findings based on 1) telephone surveys of households that purchased DHPs through the initiative, 2) telephone surveys of other general-population households, and 3) in-depth interviews with Northwest utilities that support the initiative, DHP manufacturers/distributors, and installers. The report includes current data on the DHP market in the Northwest. The report findings suggest that multimedia marketing should be continued. Word-of-mouth marketing is a tactic that should be incented as well.
The distributors should also be encouraged to promote DHPs that can perform well in extremely low outdoor temperatures. The report also suggests that banks and financial institutions be encouraged to offer financing for DHPs.

## *2013 Strategies*

Idaho Power will sponsor and provide training sessions and orientations to the DHP Pilot program for new and existing contractors to assist them in meeting program requirements and further their product knowledge.

Expanding the network of participating contractors remains a key strategy for the DHP Pilot. The goal is to support contractors currently in the DHP Pilot while adding new contractors. Performance of the DHP Pilot is substantially dependent on the success of the contractor's ability to promote and leverage the DHP Pilot. Frequent individual contractor meetings will be held in 2013. The program specialist, along with Idaho Power CRs, will arrange these meetings.

To promote the residential adoption of the DHP technology in Idaho Power's service area, the strategy includes communicating with the complete supply chain. To accelerate the wholesaler's ability to increase contractor awareness of DHPs and the DHP Pilot, the program specialist will meet with the wholesalers and share helpful information.

Traditional and new marketing methods will be used in 2013 to reach the target audience. Knowing contractors are a vital marketing asset, contractor visits will be made in the first half of 2013 to better understand how Idaho Power can support them in promoting the DHP Pilot program, as well as the H&CE Program. Specifically, Idaho Power will discuss the helpfulness and usability of a contractor portal housed on Idaho Power's website. The portal will provide contractors with access to predesigned and approved marketing collateral materials. These materials will include specific areas or fields contractors can customize with their specific business name, address, and phone number. The creation of this contractor portal will be based on contractor feedback.

Also planned for 2013 are online behavioral advertisements, print advertisements, and direct-mail pieces targeted to customers who have high electric winter usage, as well as customers who have moved into a new home, which research has shown have a higher likelihood to make home upgrades. Behavioral advertisements refer to advertisements posted on websites based on an individual's recent web behavior. For example, if someone views a major automobile company's website, automobile advertisements will pop up on other unrelated websites viewed because the Internet Protocol (IP) address of the viewer's searches is tracked.

# Energy Efficient Lighting

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (bulbs) | 925,460 | 1,039,755 |
| Energy Savings (kWh) | 16,708,659 | 19,694,381 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,110,329 | $1,668,328 |
| Oregon Energy Efficiency Rider | $16,507 | $50,805 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $1,126,836 | $1,719,133 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.012 | $0.015 |
| Total Resource Benefit/Cost Ratio | $0.025 | $0.024 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 4.47 | |
| Total Resource Benefit/Cost Ratio | 3.05 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2002 | |

## *Description*

The Energy Efficient Lighting program strives for residential energy savings through the replacement of less-efficient lighting with more-efficient technology. According to the *NEEA 2011 Residential Building Stock Assessment: Single-Family Characteristics and Energy Use* study, the average Idaho home has 63 bulb sockets. The *2010 Idaho Power End Use* study shows 88 percent of customers have less than 20 compact fluorescent bulbs installed, indicating there is still potential to install more energy-efficient bulbs. Changing these bulbs represents a low-cost, easy way for all customers to achieve energy savings.

ENERGY STAR® qualified compact fluorescent lamps (CFL) are an alternative to standard incandescent light bulbs that result in saved money, energy, and time. Bulbs come in a variety of wattages, colors, and styles, including bulbs for three-way lights and dimmable fixtures. ENERGY STAR bulbs use up to 75 percent less energy and last up to 10 times longer than incandescent bulbs.

## *2012 Activities*

In 2012, the Energy Efficient Lighting program provided more than two-thirds of all energy savings derived from residential energy efficiency customer programs. This contribution is expected to decline in future years as CFL penetration rates increase and more efficient lighting standards are enforced.

The Energy Efficiency Lighting program follows a markdown model that provides incentives directly to the manufacturers or retailers with savings passed onto the customer at the point of purchase. The benefits of this model are low administration costs, the availability of products to the customer, and the ability to provide an incentive for specific products.

In 2012, Idaho Power again participated in the Bonneville Power Administration (BPA) Simple Steps, Smart Savings™ promotion focusing on ENERGY STAR specialty and spiral bulbs. Fluid Market Strategies managed the promotion. Fluid Market Strategies is responsible for retailer and manufacturer contracts, marketing materials at the point of purchase, and for providing support and training to retailers. Additional marketing by Idaho Power included the utility website, events, and presentations to customers.

CFL fixtures are an option under the BPA's Simple Steps, Smart Savings markdown promotion. In 2012, Idaho Power dropped light fixtures from the Home Products Program and added them as a measure to the Simple Steps, Smart Savings promotion under the Energy Efficient Lighting program. However, no sales of fixtures were reported in 2012 under this promotion.

Additional 2012 program activities included direct distribution and retailer education events. Idaho Power has a small, direct-distribution program where bulbs are given directly to customers at appropriate venues. The idea is, if given a free bulb, customers might try CFLs for the first time or be encouraged to replace additional lamps. Guidelines for approved venues and the direct distribution effort have been developed to ensure customer fairness.

During 2012, Idaho Power participated in six retailer events with large national retailers. Retailer events were designed to communicate directly to customers at the point of sale. Idaho Power staff set up tables with light displays at the entrances of stores and answered questions about CFLs.

The Energy Efficient Lighting program was one of three Idaho Power programs that sponsored the local, semi-professional basketball team, the Idaho Stampede, at the team's Green Week games in April. As part of the promotion, Idaho Power ran a 30-second public-service announcement (PSA) on energy-efficient lighting that aired at two Idaho Stampede home games. The announcement was posted to Idaho Power's website and to YouTube. At the two Idaho Stampede games, the promotion included a light bulb demonstration using a bicycle to power incandescent and CFL bulbs. Sixty-eight people rode the bike at the games and learned firsthand how much less electricity CFL blubs use compared to incandescent bulbs.

Three presentations were developed for use by Idaho Power staff focusing on lighting basics, outdoor lighting, and holiday lighting. A lighting-basics presentation was given at the Ada County Extension office and the Idaho Green Expo.

In 2012, Idaho Power began participating in the Northwest Regional Retail Collaborative (NWRRC) facilitated by NEEA and following work by the Western Regional Utility Network. Both the NWRRC and the Network seek to develop collaborative approaches to working with manufactures and retailers to increase the uptake of energy-efficient products in the retail market.

In 2012, Idaho Power began researching the transition of the Energy Efficient Lighting program to a more comprehensive retailer markdown program that would include additional product categories. Barriers include retailer point-of-sale system limitations. Groups like the NWRRC provide a forum to identify and work toward addressing these types of barriers.

## Cost-Effectiveness

In 2012, the RTF updated several assumptions for specialty CFL bulbs. The change to baseline and efficient wattage assumptions, though minimal, did contribute to the decrease in savings. The RTF reviewed studies and took into consideration the changes in bulb efficiency standards from the

*Energy Independence and Security Act of 2007* (EISA), as well as regional sales data. Additionally, there was a change to the hours-of-use assumptions for various lamp types and storage rates that further contributed to the decrease in savings. Despite the change, the measures still remain cost effective. The savings for spiral bulbs remained unchanged. For detailed cost-effectiveness assumptions, metrics, and sources, see *Supplement 1: Cost-Effectiveness*.

## 2013 Strategies

Idaho Power will continue to participate in Simple Steps, Smart Savings through 2013. Marketing for this program will continue to include point-of-purchase signs at the retailer managed by Fluid Market Strategies. Idaho Power will also promote the program through its website, events, and presentations.

Idaho Power will continue to distribute limited quantities of bulbs directly to customers at appropriate public energy efficiency events and continue to participate in retailer educational events. An evaluation will be made based on the cost to put CFLs in new-customer welcome packets. Customer education regarding savings of time and energy from these improved products will continue.

The company will monitor the market and emerging technologies. Light-emitting diode (LED) light bulbs are on display at many major retailers. As of December 2012, there were over 1,300 products on the ENERGY STAR criteria list for LED replacement bulbs. Seventy-five percent are reflectors. Market prices for LED products are significantly higher than CFLs and EISA-compliant halogens.[1] Idaho Power will continue to evaluate the price, availability, savings, and technology of LED lighting to determine if it should be included in the future.

Idaho Power will also participate in the NWRRC. Participation in the NWRRC will help facilitate research into transitioning the Energy Efficient Lighting program to a more comprehensive retailer-markdown program with additional product categories.

In 2013, Idaho Power plans to do a third-party process evaluation of the Energy Efficient Lighting program.

[1] Example: An ENERGY STAR qualified, 60-watt (W) equivalent A-lamp LED equivalent by Phillips retails between $25.45 and $38.50 according to Consumer Reports at http://www.consumerreports.org/cro/home-garden/home-improvement/lightbulbs/lightbulb-ratings/models/overview/philips-ambientled-12-5w-12e26a60-60w-409904-99040398.htm.

# Energy House Calls

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 668 | 881 |
| Energy Savings (kWh) | 1,192,039 | 1,214,004 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $272,666 | $447,229 |
| Oregon Energy Efficiency Rider | $3,217 | $36,146 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $275,884 | $483,375 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.016 | $0.027 |
| Total Resource Benefit/Cost Ratio | $0.016 | $0.027 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 3.05 | |
| Total Resource Benefit/Cost Ratio | 3.05 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2002 | |

## *Description*

The Energy House Calls program helps manufactured and mobile homeowners with electric heating reduce electricity use by improving the home's efficiency. This program provides free duct-sealing and additional efficiency measures to Idaho Power customers living in Idaho or Oregon in a manufactured or mobile home using an electric furnace or heat pump.

Services and products offered through the Energy House Calls program include duct testing and sealing according to Performance Tested Comfort System (PTCS) standards set by the RTF and adopted by the BPA; installing a CFL bulb; providing two furnace filters, along with replacement instructions; testing water heater temperatures for the proper setting; and distributing energy efficiency educational materials for manufactured home occupants. The value of the service to the customer is dependent on the complexity of the repair, although services are provided free to participants. The typical cost range of the average service call is $325 to $550. Idaho Power provides the customer with the sub-contractor contact information. Customers access the service and schedule an appointment by directly calling one of the recognized, certified sub-contractors specially trained to provide these services in their region.

## *2012 Activities*

Energy House Calls serviced 592 manufactured homes during 2012, resulting in 1,192,039 kWh savings. Seventy-six percent of the homes serviced were located in the Treasure Valley. Twenty-four percent were outside the Treasure Valley, with 11 percent in Eastern Idaho and 13 percent in Southern Idaho. Quality-assurance (QA) checks were conducted on 5 percent of the homes serviced in the program. Idaho Power coordinates the sub-contractors performing local weatherization and

energy efficiency services, processes sub-contractor paperwork, and pays sub-contractors directly for work performed.

Marketing campaigns included a bill insert sent to all Idaho Power residential customers, a program brochure used by Idaho Power representatives in the field and at Idaho Power-sponsored events, and a direct-mail postcard. The direct-mail postcards were sent to all customers identified as living in a manufactured home. Feedback from Idaho Power sub-contractors indicated the direct-mail postcards yielded the most amount of interest in the program. This was the most effective form of marketing.

During summer 2012, Idaho Power employees marketed the Energy House Calls program to managers and residents of mobile home parks in Twin Falls, Pocatello, and Chubbuck. Marketing efforts included distributing marketing material, leaving door hangers, and answering customer questions and inquiries. Marketing materials informed customers their inquiries would be forwarded to the appropriate contractor.

Idaho Power field staff CRs and call-center customer service representatives (CSR) are educated about the program and will continue to promote it to qualified customers.

## Cost-Effectiveness

Duct-sealing deemed savings for manufactured homes were revised in spring 2012 by the RTF to bring the measure into compliance with current guidelines. The measure definition was also updated to reflect different manufactured home styles.

The baseline pre- and post-supply duct leakage were analyzed by the RTF as part of the comprehensive measure review during 2012, and the results were reported at the October 2012 RTF meeting. The baseline duct leakage increased from a previous 15 percent to 20 percent, which corresponds to more duct leakage being found in existing homes, resulting in increased savings from duct sealing. The increased baseline leakage is consistent with data collected from Idaho Power projects. The updated savings were provided along with new measure definitions splitting out savings by either single-wide manufactured homes and double-wide or triple-wide manufactured homes. Annual savings reported for 2012 were assigned by the home's heat source, the existence of central A/C (electric furnace with and without A/C) or a heat pump, and the home's climate zone. For more detailed information about the cost-effectiveness savings and assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

To monitor QA in 2012, third-party verifications were conducted by Momentum, LLC on approximately 5 percent of the participant homes, resulting in 33 home inspections. The final round of QA results is being analyzed during first quarter 2013 and appears to be consistent with those conducted earlier in the year, which were very positive. Verifications were selected at random. The verification included a visual review of the reported information, as well as a blower door test to verify the results submitted by the sub-contractor.

## 2013 Strategies

Plans for the upcoming year include continuing the direct-mail campaign throughout the Idaho Power service area to increase market penetration. Based off low response rates in the Eastern and Southern regions, there are concerns the market may be reaching saturation. Possible reasons for the lack of participation include an imperfect mailing list and the difficulty in identifying manufactured homes on the Idaho Power billing system. Idaho Power updated the mailing list used for the direct-mail letters in

2012 and plans to do the same in 2013. The list is generated from homes designated as manufactured or mobile on Idaho Power's CIS and is analyzed for homes that appear to use electric heat, based on kWh use during winter and summer months. The company will also continue to explore low-cost and effective methods of marketing this program to all residential customers believed to have electrically heated manufactured homes. This form of marketing may yield additional word-of-mouth promotion to potential program participants. Less broad-based outreach efforts will continue via CRs and limited-income outreach entities.

# ENERGY STAR® Homes Northwest

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 410 | 308 |
| Energy Savings (kWh) | 537,447 | 728,030 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $450,727 | $255,405 |
| Oregon Energy Efficiency Rider | $2,458 | $4,357 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $453,186 | $259,762 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.046 | $0.020 |
| Total Resource Benefit/Cost Ratio | $0.089 | $0.051 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 3.77 | |
| Total Resource Benefit/Cost Ratio | 2.51 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

## *Description*

ENERGY STAR® Homes Northwest is a regionally coordinated initiative supported by a partnership between Idaho Power and NEEA to improve and promote the construction of energy-efficient homes using guidelines set forth by the United States (US) Environmental Protection Agency (EPA). This program targets the lost-opportunity energy savings and summer-demand reduction that results by increasing the efficiency of the residential-building envelope and air delivery system above current building codes and building practices. An ENERGY STAR certified home is a home that has been inspected and tested by an independent, third-party ENERGY STAR rater to meet the stringent ENERGY STAR requirements. This third-party rater is hired by the builder to perform these duties.

The ENERGY STAR Homes Northwest residential construction program promotes homes that are electrically heated and are at least 15 percent more energy efficient than those built to standard Idaho code. The program specifications for ENERGY STAR Homes Northwest are verified by independent, third-party HPS and are certified by the Washington State University Extension Energy Program, an organization that conducts the certification inspections throughout the state of Idaho and for the EPA. The homes are more efficient, comfortable, and durable than standard homes constructed according to Idaho building codes.

Homes that earn the ENERGY STAR label include six required specifications. The specifications found in all ENERGY STAR certified homes are 1) effective insulation, 2) high-performance windows, 3) air-tight construction and sealed ductwork, 4) energy-efficient lighting, 5) ENERGY STAR qualified appliances, and 6) efficient heating and cooling equipment.

In 2012, builders involved in ENERGY STAR Homes Northwest received a $1,000 incentive per home built to the Northwest Builder Option Package (BOP) electrically heated homes standard. Builders who entered their homes in a Parade of Homes received the standard $1,000 incentive plus an additional $500 incentive to encourage builders to construct ENERGY STAR homes.

The Idaho Power program collaborates with many local entities for program promotion, including ENERGY STAR Homes Northwest and builders. A large part of the program's role in 2012 was to provide marketing materials and conduct education and training activities for residential new construction industry partners.

## 2012 Activities

As the housing market slowly started to improve throughout the Idaho Power service area in 2012, the ENERGY STAR Homes Northwest program showed an increase in ENERGY STAR Homes certified from 308 in 2011 to 410 in 2012.

Idaho Power conducted numerous ENERGY STAR promotional activities during 2012. The company presented energy efficiency awards at the Building Contractors Association of Southwestern Idaho (BCASWI) Parade of Homes awards banquet. In addition, the company maintained a presence in the building industry by supporting many of the building contractors associations (BCA) throughout Idaho Power's service area. Specifically, the company participated in the BCASWI Builder's Expo, the Snake River Valley Building Contractors Association (SRVBCA) Builder's Expo, the Magic Valley Builders Association Parade of Homes (MVBA), the BCASWI Parade of Homes, SRVBCA Parade of Homes, the Building Contractors Association of Southeast Idaho (BCASEI) Parade of Homes, and the Idaho BCA Convention. Idaho Power joined with Northwest ENERGY STAR for a minor sponsorship of the 2012 St. Jude Dream Home®. The Dream Home was a certified, electrically heated, ENERGY STAR home. Northwest ENERGY STAR secured the donation of the heat pump. Idaho Power produced a bill insert, sent to all residential customers in the Idaho Power service area, promoting ENERGY STAR homes and highlighting the 2012 Dream Home.

Other marketing projects involved adding a message about this program to residential customers' electric bills. These bill messages encouraged Idaho Power customers to visit ENERGY STAR certified homes in their local Parade of Homes events.

## Cost-Effectiveness

There were no changes to RTF deemed-savings values for single family ENERGY STAR homes during 2012. In fall 2012, the RTF produced deemed annual savings for multi-family ENERGY STAR homes using a blended prototype of low-rise, multi-family dwelling types that included a townhome design. The modeled multi-family ENERGY STAR home prototype included a range of homes sizes between 950 to 1,500 square feet ($ft^2$). The average size of a townhome in the program in 2012 was 925 $ft^2$, which falls within the RTF-modeled prototype range. The annual deemed savings for the townhome are approximately one-third the annual savings of a traditional detached single-family home and vary depending on the climate zone between 599 and 770 kWh annual savings. Since 396 out of 410 ENERGY STAR homes given incentives by Idaho Power in 2012 were townhome style homes and did not fit the traditional single-family home, the company applied the new updated savings to all townhomes.

While verifying 2012 ENERGY STAR Homes Northwest program incentives for this report, Idaho Power found 10 incentives, out of a total of 410, that were inadvertently paid to builders who submitted applications for ENERGY STAR gas-heated homes. Since non-electrically heated ENERGY STAR Homes Northwest homes with building permits dated after December 31, 2010, were excluded from this program in 2011, these 10 incentives should not have been paid. The costs and savings are included in the cost-effectiveness analysis, and although the company has determined that gas-heated homes are not cost-effective, the program remains cost-effective. For more detailed information about the cost-effectiveness savings, sources, calculations, and assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

The HPS works with builders to ensure the ENERGY STAR homes are compliant with the Northwest electric-only BOP. Along with verifying the installation of building components and equipment through on-site inspections, prior to being certified, the home must pass a blower door test, air-duct leakage test, and combustion back-draft tests.

The state-certifying organization (SCO) performs QA. The Washington State University Energy Extension Program is under contract with NEEA to perform QA and technical assistance duties within Idaho. For QA purposes, 10 percent of homes certified in the ENERGY STAR Homes Northwest program are reviewed by the Washington State University Energy Extension Program. This is a technical verification of the homes. All of the homes randomly chosen for QA in Idaho Power's service area passed the QA inspection process.

## 2013 Strategies

As in 2012, builders involved in ENERGY STAR Homes Northwest during 2013 will receive a $1,000 incentive per home built to the Northwest BOP, electric-only standards in Idaho Power's service area. Builders showcasing their electric-only home in a BCA Parade of Homes event will receive the standard $1,000 incentive plus an additional $500 parade marketing incentive.

Idaho Power plans to continue marketing efforts to help sell ENERGY STAR homes, including educating consumers, Realtors, and appraisers about the benefits and features of ENERGY STAR homes. Results will be influenced by the housing market's potential improvements. These marketing efforts include Parade of Homes advertisements in parade magazines for the BCASWI, SRVBCA, MVBA, and the Building Contractor Association of Eastern Idaho. Bill inserts will be sent to all residential customers in April and May. In addition, bill messaging is planned in June, July, and August to support the various BCA Parade of Homes events throughout Idaho Power's service area.

In 2013, changes were made in Idaho Power's database and payment review process to prevent incentives to be paid for gas-heated ENERGY STAR homes. The fuel-type field in Idaho Power's database code was changed to allow only heat pump as the heating type. Also, the code was changed on the incentive field to reflect electrically heated homes. Also in 2013, the incentive payment processes have been changed to provide a more thorough review of participant applications prior to payment.

In 2013, Idaho Power plans to conduct a third-party process evaluation of the ENERGY STAR Homes Northwest program.

# Heating & Cooling Efficiency Program

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 141 | 130 |
| Energy Savings (kWh) | 688,855 | 733,405 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $175,483 | $188,876 |
| Oregon Energy Efficiency Rider | $6,798 | $6,894 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $182,281 | $195,770 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.018 | $0.018 |
| Total Resource Benefit/Cost Ratio | $0.066 | $0.056 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 3.49 | |
| Total Resource Benefit/Cost Ratio | 1.78 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2007 | |

## *Description*

The H&CE Program provides incentives for the purchase and proper installation of qualified heating and cooling equipment to residential customers.

The objective of the program is to acquire energy savings by providing customers with energy-efficient alternatives for electric space heating. Incentive payments are provided to residential customers and heating, ventilation, and air conditioning (HVAC) participating contractors who install eligible equipment. The eligible measures in 2012 included air-source heat pumps, open-loop water-source heat pumps, and evaporative coolers.

Heating and A/C companies authorized by Idaho Power as participating contractors for the program are required to perform all installations, with the exception of evaporative coolers, which can be self-installed. The program continued through 2012 with the same portfolio of incentives as in 2011.

## *2012 Activities*

The H&CE Program's list of measures and incentives during 2012 included the following:

- Air-source heat pump customer incentives for replacing an existing air-source heat pump with a new air-source heat pump were $200 for minimum efficiency 8.2 heating seasonal performance factor (HSPF) and $250 for minimum efficiency 8.5 HSPF.

- Customer incentives for replacing an existing electric, oil, or propane heating system with a new air-source heat pump were $300 for minimum efficiency 8.2 HSPF and $400 for minimum

efficiency 8.5 HSPF. Participating homes with oil or propane heating systems must have been located in areas where natural gas was unavailable.

- Incentives for customers or builders of new construction installing an air-source heat pump in a new home were $300 for minimum efficiency 8.2 HSPF and $400 for minimum efficiency 8.5 HSPF.

- The open-loop water-source heat pump customer incentive for replacing an existing air-source heat pump with a new open-loop water-source heat pump was $500 for minimum efficiency 3.5 coefficient of performance (COP).

- The customer incentive for replacing an existing electric, oil, or propane heating system with a new open-loop water-source heat pump was $1,000 for minimum efficiency 3.5 COP. Participating homes with oil or propane heating systems must have been located in areas where natural gas was unavailable.

- The incentive for customers with new construction installing an open-loop water-source heat pump in a new home was $1,000 for minimum efficiency 3.5 COP.

- The evaporative-cooler customer incentive was $150.

The expanding of Idaho Power's network of participating contractors remained a key growth strategy for the program. Idaho Power's goal was to support contractors currently in the program, while adding new contractors. The company held meetings with several prospective contractors to support this strategy. Six companies were added in 2012 to Idaho Power's list of participating contractors, doubling the number added from 2011.

Idaho Power held training sessions for contractors in September that provided general instructions on heat pumps and program guidelines. For a company to be eligible to join the program as a participating contractor, they must have attended this training. Fourteen technicians from eight companies attended the sessions in 2012. These training sessions remain an important part of the program because the training creates opportunities to invite additional contractors into the program.

Several marketing tactics were used during 2012 to reach customers. Examples include print advertising in newspapers, direct-mail, bill inserts, and trade shows. The use of social-media websites continued in 2012 to increase program awareness. Additional marketing materials included descriptions of customers' experiences with the program posted as *Success Stories* on Idaho Power's website. Copies of the two H&CE Program 2012 *Success Stories* are provided in *Supplement 2: Evaluation*.

To increase contractor participation in the program, stronger relationships with the equipment wholesalers was necessary. In Idaho Power's service area, there are several major wholesalers supplying heat pumps to the contractors. The program specialist met with such wholesalers to provide them with the ability to promote the program with their contracting customers and share helpful information.

Idaho Power uses Honeywell, Inc., a third-party contractor, to review the incentive applications and perform OSVs. This contractor provides direct support to participating contractors and the residential program participants. Honeywell offers local assistance through representative visits to contractors at their businesses as needed. Using a program database via a portal developed by Idaho Power, Honeywell reviews and submits incentive applications for Idaho Power payment. This allows

Idaho Power to maintain the database within the company's system, which is secure yet accessible to the third-party contractor.

On the national level, a 2011 federal tax credit for heat pumps contained in section 25C of the Internal Revenue Service (IRS) tax code was not renewed for 2012.

## Cost-Effectiveness

The savings for heat pumps installed under the H&CE Program consists of both savings for the increased efficiency of the equipment and savings resulting from quality installation, including proper unit sizing, controls settings, and commissioning. While the core savings of air-source heat pumps were not updated or changed by the RTF during 2012, other measures currently not deemed by the RTF, including lower-tier savings heat pumps, evaporative A/Cs, and geothermal heat pumps savings sources were reviewed to ensure they were consistent with the current regional work done by the RTF. For 2012, participant costs' averages used for the cost-effectiveness analysis were calculated using Idaho Power-specific project data instead of relying on regional averages.

There were no changes in 8.5 HSPF air-source heat pump annual savings for 2012 when customers were displacing electric furnaces. Additional equipment savings were claimed in 2012 in cases were customers' equipment performance exceeded an HSPF rating of 9. An additional 115 to 128 annual kWh were claimed depending on the customer's climate zone.

The previous savings for evaporative coolers (swamp cooler) were based on the 2009 potential study and on a generic prototype evaporative cooler that was not differentiated between a direct or indirect cooler design. Indirect cooler designs have specialized equipment that pre-cools the air before the evaporation process occurs, which substantially increases the savings and equipment costs. The few incentives that Idaho Power paid for evaporative coolers were for the direct-cooler design that pushed direct outside air into the cooler with no pre-treatment. The savings were reduced from an annual savings rate 1,300 kWh over a seasonal energy efficiency ratio (SEER) 13 code central A/C to between 300 and 400 annual kWh depending on whether the cooler was installed in a multi-family manufactured home or single-family home. For more detailed information about the cost-effectiveness savings, sources, calculations, and assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Idaho Power contracted with The Cadmus Group, Inc., to conduct an impact evaluation of 2011 savings results. The evaluation report indicated that most measures were installed in compliance with PTCS commissioning, controls, and sizing standards. Tracked data was complete and accurate, and ex-ante energy savings were a reasonable but needed refinement. The program ex-post realized savings rate was 94 percent as compared to ex-ante estimates.

The Cadmus Group, Inc., recommends the following: 1) program staff continue to collect detailed data on each project to refine individual project savings estimates, 2) perform a saturation study to determine intent to convert to all-electric heating and cooling, and 3) consider the promotion of on-bill financing to make a heat pump more attractive to customers. A copy of the complete report is included in *Supplement 2: Evaluation*.

The program performed random OSVs on 14 completed installations in the Idaho Power service area, resulting in 10 percent of the total applicants. These OSVs verified the information submitted on the paperwork matched what was installed at customers' sites. Overall, the OSV results were favorable with

respect to the contractors. The program specialist continues to work with contractors to help them understand the importance of accurate documentation.

## 2013 Strategies

There will be two changes to the program in 2013. The first change is the removal of measures involving air-source heat pumps below 8.5 HSPF. The measures include replacing an existing air-source heat pump, electric resistance, oil, or propane heating system with a new minimum 8.2 HSPF air-source heat pump. The primary reason for removing these measures is that the heat pump market has been slowly transforming to more efficient, higher HSPF heat pumps. In the last several years, only about 3.5 percent of all applications received in this program have been for units below 8.5 HSPF, rendering an incentive unnecessary.

The second change is to increase the incentive from $400 to $800 when replacing an electric-resistance heating system with an air-source heat pump having a minimum of 8.5 HSPF. Idaho Power made this change to increase the participation of this measure and to focus the program on higher efficiency measures. The incremental installed cost of a new heat pump is approximately $3,000. Idaho Power has evaluated the cost-effectiveness of this measure with an $800 incentive, and this measure continues to be cost effective.

Idaho Power will sponsor and provide training to new and existing contractors in the program to assist them in meeting program requirements and further their product knowledge. Sessions will be held at both local wholesaler and Idaho Power facilities.

Expanding the network of participating contractors remains a key strategy for the program. The goal is to support contractors currently in the program while adding new contractors. The performance of the program is substantially dependent on the success of the contractors' abilities to promote and leverage the measures offered in the program. Frequent individual meetings will be held with contractors in 2013. The program specialist, along with Idaho Power CRs, will arrange the discussions.

To increase participation in the program in the Idaho Power service area, the program specialist will work to strengthen relationships with equipment wholesalers. To accelerate the wholesalers' abilities to increase contractor awareness of the program, the program specialist will meet with the wholesalers and share information.

Numerous marketing methods will be used in 2013 to reach the target audience. Knowing contractors are a vital marketing asset, contractor visits will be made in the first half of 2013 to better understand how Idaho Power can support them in promoting the H&CE Program, as well as the DHP Pilot. During the visits with contractors, the marketing specialist and the program specialist will specifically discuss the helpfulness and usability of a new contractor portal housed on Idaho Power's website. The portal will provide contractors access to pre-designed and approved marketing collateral materials. These materials will include specific areas or fields contractors can customize with their business name, address, and phone number. The creation of this contractor portal will be based on contractor feedback.

Also planned for 2013 are online behavioral advertisements, print advertisements, and direct-mail pieces to targeted customers who have high electric winter usage and who have moved into a new home. Research has shown new home buyers are more likely to make home upgrades in the first two years of ownership.

In 2013, Idaho Power plans to do a third-party process evaluation of the H&CE Program.

# Home Improvement Program

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 840 | 2,275 |
| Energy Savings (kWh) | 457,353 | 917,519 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $385,091 | $666,041 |
| Oregon Energy Efficiency Rider | $0 | $0 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $385,091 | $666,041 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.044 | $0.038 |
| Total Resource Benefit/Cost Ratio | $0.093 | $0.155 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 3.15 | |
| Total Resource Benefit/Cost Ratio | 1.21 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho | |
| Program Inception | 2008 | |

## *Description*

The Home Improvement Program offers incentives to homeowners for upgrading insulation in electrically heated homes. The program's list of measures and incentives in 2012 consisted of the following:

- Customer incentives for attic insulation, wall insulation, under-floor insulation, and required prescriptive air- and duct-sealing.
- Customer incentives to Idaho residential customers in the Idaho Power service area for additional insulation professionally installed was 15 cents per square foot for attic insulation, 50 cents per square foot for wall and under-floor insulation, and 30 cents per linear foot for air- and duct-sealing.
- Existing attic insulation must be an R-20 or less to qualify, and the final R-Value must meet the local energy code. Idaho Power's service area consists of climate zones 5 and 6, resulting in an R-38 requirement for climate zone 5 and R-49 requirement for climate zone 6.
- The existing insulation level in walls must be R-5 or less, and the final R-Value must be R-19.
- The existing insulation level of under-floor must be R-5 or less, and the final R-Value must be R-30.

On April 1, 2012, the program transitioned from an open contractor program to a participating contractor program. Participating contractors must successfully complete a two-day contractor training

course administered by Fluid Market Strategies. Customers must use a participating contractor to qualify for the Idaho Power incentive.

Also on April 1, 2012, the program transitioned from being a fuel-neutral program to an electrically heated home program. To qualify for an incentive under this program, the home must be a single-family home, including duplexes and townhomes. The home must have an electric heating system serving at least 80 percent of the home's conditioned floor area. The heating system can be a permanently installed electric furnace, heat pump, or electric zonal heating system. Insulation must be professionally installed between conditioned and unconditioned space by an insulation contractor. On April 1, 2012, wall insulation, under-floor insulation, and required prescriptive air- and duct-sealing were added to the program.

## 2012 Activities

Due to the increased complexity of the program requirements, Idaho Power brought the outsourced, third-party incentive processing back in house. All Home Improvement Program incentive applications are now processed by Idaho Power staff.

Various marketing techniques were employed in 2012. Movie theater advertising ran during June, July, and August in the Boise, Nampa, Pocatello, and Cascade markets. A small-market print advertising campaign ran in November and December. An informational bill insert ran in October, and a direct-mail letter targeted to electrically heated customers was sent out in November. All of these marketing activities resulted in increased customer inquiries regarding program details and provided opportunities for customer education.

## Cost-Effectiveness

*Supplement 1: Cost-Effectiveness* contains cost-effectiveness information for attic, wall, and floor insulation measures broken out by customers' electric heating source equipment type, R-value change, climate zone, and presence of central A/C if applicable. Additionally, the cost-effectiveness results in *Supplement 1: Cost-Effectiveness* are shown for the Home Improvement Program attic insulation measures phased out in the first trimester of 2013. These measures included previously available incentives for customers with central A/C, regardless of heating fuel type.

Although the RTF reviewed 2011 attic insulation measures for compliance and RTF guidelines during 2012, no changes were made to deemed annual savings values. Deemed-savings values specific to Idaho Power's climate zones were published by the RTF in October 2011, including cooling savings based on the RTF's deemed savings for single-family home weatherization published in July 2011.

A change in the Idaho Power cost-effectiveness analysis for 2012 was the inclusion of the RTF specifications requiring homes to be adequately air-sealed, including air ducts, prior to the installation of attic and floor insulation. Idaho Power included the costs of the $0.30-per-linear-foot incentive offered to program participants who needed to have air- and duct-sealing done to align with the updated guidelines. When calculating the TRC, the installed costs were averaged across attic and floor insulation projects, including costs to air- and duct-seal to assess cost-effectiveness. The additional project costs had minimal impacts to participant costs and the overall cost-effectiveness of project costs per square foot, staying consistent with the RTF deemed participant cost estimates. For more detailed information about the cost-effectiveness calculations and assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

For QA purposes, third-party contractors randomly reviewed 10 percent of all insulation jobs completed in the Home Improvement Program. With the addition of the new program requirements in April 2012, these QA contractors also performed in-progress QA to assist and educate the contractors on the new program requirements, particularly the air- and duct-sealing requirements. Of the 80 QA inspections completed in 2012, two issues concerning post-insulation depth were reported and corrected.

One voluntary marketing question, inquiring how the customer heard about the program, was added to the program incentive application form. Of the 840 applications, 196 customers answered the marketing question. Ninety-two customers (47%) heard about the program from an insulation contractor, while 66 customers (34%) heard about the program from an Idaho Power bill insert. Twenty-six customers (13%) received a referral from a friend or acquaintance, eight customers (4%) heard about the program from the Idaho Power website, and four customers (2%) heard about the program from a newspaper advertisement.

## 2013 Strategies

In February 2013, Idaho Power plans to add an energy-efficient-windows measure to the Home Improvement Program. Windows being replaced must be single-pane wood frame, single-pane metal frame, or double-pane metal frame. As with all other Home Improvement Program measures, only electrically heated homes qualify for an incentive.

In addition, beginning in February 2013, manufactured homes meeting all program qualifications will be eligible for all Home Improvement Program incentives.

Numerous marketing activities are planned for 2013. A new program brochure and web page update are planned for February 2013, in conjunction with program additions and updates. Informational bill inserts are planned for February and April. Targeted direct-mail letters are planned for April and October. Facebook advertisements in high-electric-usage areas are planned for January and September. Print advertisements in select rural areas are planned for February.

# Home Products Program

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (appliances/fixtures) | 16,675 | 15,896 |
| Energy Savings (kWh) | 887,222 | 1,485,326 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $640,098 | $619,764 |
| Oregon Energy Efficiency Rider | $18,829 | $18,559 |
| Idaho Power Funds | $105 | $0 |
| Total Program Costs—All Sources | $659,032 | $638,323 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.061 | $0.034 |
| Total Resource Benefit/Cost Ratio | $0.075 | $0.080 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 2.26 | |
| Total Resource Benefit/Cost Ratio | 1.40 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2008 | |

## *Description*

The Home Products Program provides an incentive payment to Idaho and Oregon residential customers for purchasing ENERGY STAR® qualified appliances. Appliances and products with ENERGY STAR must meet higher, stricter efficiency criteria than federal standards. In 2012, the measures and related incentives included ENERGY STAR qualified clothes washers ($50), refrigerators ($30), and freezers ($20). Program participation is a simple process for customers, who have two options to submit their application: They may complete a mail-in incentive application and submit it with an itemized copy of the sales receipt or submit an online application, offered through Idaho Power's processing vendor's website, and upload or mail in the receipt. If the purchase qualifies, the customer receives an incentive check by mail.

The Home Products Program also includes promotions using retailer markdowns and retailer/manufacturer incentives. Markdowns reduce retail-end prices to the customer at the point of purchase. Retailer/manufacturer incentives drive the manufacture, distribution, and promotion of more energy-efficient consumer products at the retail level. This mid/upstream incentive model is potentially anticipated to be powerful in changing markets when incentive dollars are small per product but the product category has a high volume of sales. "Upstream and midstream incentives offer the advantage that incentive amounts can sometimes be lower, as market partners may need less 'convincing' to make or sell efficient technologies."[2]

[2] http://www.epa.gov/cleanenergy/documents/suca/program_incentives.pdf.

One measure offered through the retailer markdown model is low-flow showerheads. Low-flow showerheads are part of the Simple Steps, Smart Savings™ markdown promotion administered by the BPA. Simple Steps, Smart Savings is coordinated by Fluid Market Strategies.

Idaho Power works in collaboration with NEEA on the Consumer Electronics Energy Forward Campaign program. This program provides a direct incentive to manufactures for producing the most energy-efficient televisions available. NEEA manages advertising, sales support, and in-store promotions for the program.

## 2012 Activities

Marketing the Home Products Program to customers occurs primarily through retail outlets. Idaho Power provides information to store managers and employees through training sessions at store staff meetings and through periodic visits by various Idaho Power representatives. In addition to brochures, fixture hang-tags and static clings—small, sticky decals—were distributed to nearly 80 retailers for placement on qualifying products. The prominent focus for using hang-tags and clings was to highlight the respective incentive amounts and eligible products.

In 2012, Idaho Power continued outsourcing the processing of applications for the Home Products Program to Advertising Checking Bureau, Inc. (ACB, Inc.), a third-party vendor. Participants have the option of online or paper applications. Both methods require the customer submit a copy of the sales receipt to confirm the product purchase. If submitting the application online, customers have the option of uploading their receipt, or mailing it in, along with a copy of their web page confirmation.

Idaho Power promoted the program to residential customers via retail store salespeople, bill stuffers, community promotions, Idaho Power field staff, and other outreach activities. During 2012, two bill inserts detailing the program were mailed to all residential customers. The spring (April) insert was shared with the Rebate Advantage program. The holiday bill insert (November) was shared with the DHP Pilot program.

As a result of findings from the 2011 impact evaluation completed by ADM Associates, Inc. (ADM), it was determined that ceiling fans, ceiling fan light kits, and LED light fixtures no longer met cost effectiveness requirements. Thus, these three products, along with CFL fixtures, were removed from the list of eligible products, effective March 1, 2012.

CFL fixtures are an option under the BPA's Simple Steps, Smart Savings markdown promotion. In 2012, Idaho Power evaluated including CFL fixtures in its administration of the Simple Steps, Smart Savings promotion. Due to different incentive structures and lower administration costs, CFL light fixture incentives are cost effective if delivered under the Simple Steps, Smart Savings markdown model. Therefore, in March 2012, light fixture incentives for select fixtures were added as a measure to the Simple Steps, Smart Savings promotion under the Energy Efficient Lighting program. However, no sales for fixtures were reported in 2012 under this promotion.

An option on the application allows customers to donate their entire incentive to Project Share, an energy assistance program where Idaho Power partners with the Salvation Army. In 2012, Home Products Program participants donated $190 to this cause. A Project Share donation thank-you card created specifically for the Home Products Program was sent to customers who donated their incentive.

NEEA created a marketing campaign for the Energy Forward campaign in fall 2012 to promote energy-efficient televisions. The campaign objectives were to drive sales of Energy Forward televisions at partner retail stores, provide retailers, utilities, and manufacturers with additional channels of promotion; increase retailer and utility engagement and partnership in the promotion of Energy Forward televisions; and increase consumer awareness and adoption of Energy Forward televisions.
The campaign included a sweepstakes hosted through the Energy Forward Facebook page located at www.Facebook.com/EnergyEfficientElectronics. Northwest residents could win Energy Forward televisions, tickets to college football games, and a grand prize of a VIP tailgate party in each of the four Northwest states—Idaho, Montana, Oregon, and Washington.

The campaign in Idaho generated 218 contest entries. Best Buy and Sears stores participated as full campaign partners, which included additional sales associate trainings and educational and campaign-related point of purchase material in all Best Buy and Sears stores. NEEA also secured discounted rates for in-store broadcasts of the *Energy Forward Most Efficient* video on televisions screens in the consumer electronics sections of Best Buy, Costco, Sam's Club, Sears, and Wal-Mart.

Through the Home Products Program, Idaho Power paid 16,675 incentives during 2012, resulting in 887,222 kWh savings. Incentives were issued for approximately 6,338 clothes washers, 4,497 refrigerators, 461 freezers, 285 light fixtures, 7 ceiling fans, 2 ceiling fan light kits, and 5,085 showerheads.

## Cost-Effectiveness

In 2011, ADM reviewed the savings for each measure. ADM reduced the annual savings estimate for ceiling fans from 159.36 kWh to 59 kWh. The savings for ceiling fan light kits were based on the number of CFLs in each kit. In 2011, the RTF reduced the annual savings for CFLs from 24 kWh to 16 kWh. Additionally, ADM confirmed the RTF's assumptions and lower savings regarding LED light fixtures. As a result of these changes, the measures were determined not to be cost effective and were removed from the program in March 2012.

In 2012, the RTF updated the savings for clothes washers and freezers. For clothes washers, the RTF looked at the impact of the new federal standards and the efficiency levels of clothes washers readily available in the Pacific Northwest market. The RTF also updated the savings assumptions on annual loads of laundry using the research from the recent Residential Building Stock Assessment (RBSA) conducted by NEEA. As a result of this work, the baseline efficiency for clothes washers increased and the savings decreased. For programs like Idaho Power's that do not restrict the modified energy factor (MEF), the annual savings decreased from 122 kWh to 37 kWh, which has made the measure not cost effective. In the 2011 impact evaluation, ADM recommended applying the RTF's breakouts for clothes washer savings by MEFs; however, due to a measure definition change by the RTF, Idaho Power has applied the wide-ranging ENERGY STAR clothes washer savings for any type of domestic hot water heating system and any dryer type. As before, Idaho Power adjusted the savings downwards to reflect the electric hot-water heater and electric dryer saturation in the Idaho Power service area. The adjustment is based on information from the *2010 Home Energy Survey*.

The RTF updated the baseline for freezers based on sales data from the region and data from the California Energy Commission database. As a result of the review, savings for freezers decreased slightly; however, the measure life was extended from 20 years to 22 years. Freezers remain cost effective.

Due to the lower savings attributed to clothes washers, the program's overall administrative costs per kWh increased from $0.118 to $0.342 per kWh. As a result, two refrigerator measures are shown to have a TRC of 0.99. Idaho Power expects to incur lower administrative costs in 2013 once clothes washers are removed from the program, which will increase the cost-effectiveness of the measures within the program. There were no changes to the savings assumptions that drive the cost-effectiveness of refrigerators and low-flow showerheads. For detailed information for all measures within the Home Products Program, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Information gathered from a question on the incentive application form indicated salespeople are a proven, effective avenue for marketing the program. Ninety-one percent of the responses indicated customers learned about the incentive program through salespeople. Three percent learned from in-store materials (brochures); 3 percent from one of two Idaho Power bill inserts sent to all residential customers; and 3 percent from the Idaho Power website, newspaper/radio, or referral.

A customer satisfaction survey is scheduled for the Home Products Program in 2013.

## 2013 Strategies

Due to changes in the baseline threshold used to calculate energy savings, clothes washers will be discontinued, effective March 31, 2013. On February 15, 2013, Idaho Power filed Oregon Advice No. 13-03 with the Public Utility Commission of Oregon (OPUC) to remove clothes washers from the list of eligible appliances offered to Oregon customers through the Home Products Program. With the removal of the clothes washer incentives, several methods will be used to notify customers. Letters were mailed to all retailers in January 2013 to alert them of the changes. New table tents were created for distribution to all retailers in early February for display. These will inform customers of the removal of the clothes washer incentive and that they need to purchase their clothes washer before March 31, 2013, to qualify for the incentive. To announce the changes to the program, the Idaho Power website home page will be updated for February and March and an online advertising campaign will target potential purchasers. Idaho Power staff will visit retailers during February and March to discuss the changes and answer questions. Idaho Power will continually review potential products for addition to the program during 2013 and beyond.

The marketing strategy for 2013 will remain similar to 2012, with only minimal adjustments and updates as needed. Bill stuffers, in-store brochures, hang-tags, and clings will be the primary marketing avenues. Online banner advertisements and keyword search terms will be added as a new media effort. Idaho Power will research if company billboards would be effective for the program. As a result of the removal of clothes washers, new brochures will be created and distributed to all retailers before April 1, 2013.

The company expects participation for 2013 to decrease significantly with the removal of clothes washers from the list of eligible products. In 2012, clothes washers accounted for more than half of applications received. In 2013, Idaho Power will explore transitioning the light fixtures and showerheads to a more comprehensive retailer markdown program and explore additional product categories for this type of program model.

# Oregon Residential Weatherization

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 5 | 8 |
| Energy Savings (kWh) | 11,985 | 21,908 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $0 | $0 |
| Oregon Energy Efficiency Rider | $4,051 | $6,690 |
| Idaho Power Funds | $465 | $1,236 |
| Total Program Costs—All Sources | $4,516 | $7,926 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.022 | $0.021 |
| Total Resource Benefit/Cost Ratio | $0.056 | $0.027 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 3.88 | |
| Total Resource Benefit/Cost Ratio | 1.55 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Oregon | |
| Program Inception | 1980 | |

## *Description*

Idaho Power offers free energy audits for electrically heated customer homes within the Oregon service area. This is a statutory program offered under Oregon Schedule 78. Upon a customer's request, an Idaho Power CR visits the home to analyze it for energy efficiency opportunities. An estimate of costs and savings for specific measures is given to the customer. Customers may choose either a cash incentive or a 6.5-percent interest loan for a portion of the costs for weatherization measures.

## *2012 Activities*

During May, Idaho Power sent every Oregon residential customer an informational brochure about energy audits and home weatherization financing. Eight Oregon customers responded. Each customer returned a card from the brochure indicating interest in a home energy audit, weatherization loan, or incentive payment. Eight audits and responses to customer inquiries to the program were completed, with five incentives paid.

Idaho Power issued five rebates totaling $1,722 for 11,985 kWh savings. All rebates and related savings were attributed to the addition of new windows, ceiling insulation, and floor insulation. There were no loans made through this program during 2012.

## *Cost-Effectiveness*

The Oregon Residential Weatherization program is a statutory program as provided for in Oregon Schedule 78. The cost-effectiveness of this program is defined within this schedule. Pages 3 and 4 of the schedule list the measures determined to be cost effective and the required measure-life cycles for

specific measures. This schedule also includes the cost-effective limit (CEL) for measure lives of 7, 15, 25, and 30 years.

Five projects were completed under this program in 2012. Projects consisted of increasing attic and floor insulation and putting in new windows. The projects combined for an annual energy savings of 11,985 kWh at a levelized TRC per kWh of 5.6 cents over the 30-year measure life as defined by the Oregon Schedule 78. The CEL for insulation (30-year measure life) is $1.09 per annual kWh saved and $0.95 per annual kWh for new windows (25-year measure life) is. Since the actual levelized cost of energy savings for the 2012 projects was 3.4 cents from the TRC perspective, these projects are considered cost effective.

## 2013 Strategies

Plans for the upcoming year include notifying customers in their May bill about the program. Idaho Power will complete requested audits and fulfill all cost-effective rebate and loan applications.

# Rebate Advantage

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 35 | 25 |
| Energy Savings (kWh) | 187,108 | 159,325 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $34,926 | $59,241 |
| Oregon Energy Efficiency Rider | $2,316 | $4,228 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $37,241 | $63,469 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.012 | $0.024 |
| Total Resource Benefit/Cost Ratio | $0.024 | $0.033 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 8.71 | |
| Total Resource Benefit/Cost Ratio | 3.87 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

## *Description*

Idaho Power residential customers who purchase a new, all-electric ENERGY STAR® qualified manufactured home in 2012 and sited it in Idaho Power's service area were eligible for a $500 rebate through the Rebate Advantage program. Salespersons received a $100 incentive for each qualified home they sold.

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

The Rebate Advantage program helps Idaho Power customers with the initial costs associated with purchasing a new, energy-efficient ENERGY STAR qualified manufactured home. This enables the homebuyer to enjoy the long-term benefit of lower electric bills and greater comfort provided by these homes. In addition, Idaho Power encourages sales consultants to discuss energy efficiency with their customers during the sales process.

## *2012 Activities*

During 2012, Idaho Power paid 35 incentives on new manufactured homes, which accounted for 187,108 annual kWh savings. Despite three dealerships closing in 2012, the number of incentives processed increased by 40 percent over 2011.

Marketing strategies used in 2012 included maintaining the Google AdWords campaign, a billboard campaign, and one bill insert. The program specialist, marketing specialist, and Idaho Power field staff visited numerous dealerships throughout the company's service area over the summer to answer any questions and notify them of a planned incentive increase, effective 2013.

Idaho Power continued to support dealerships in 2012 by providing them with Rebate Advantage brochures and applications as needed. CRs visited these dealerships to distribute material, promote the program, and answer salespersons' questions.

## Cost-Effectiveness

No changes occurred to the assumptions that drive the cost-effectiveness for ENERGY STAR manufactured homes. All cost-effective analyses were based on the January 2011 approval decision by the RTF. The measures remained cost-effective for 2012. The measure is currently under review by the RTF and will be updated in 2013. For details, see *Supplement 1: Cost-Effectiveness*.

## 2013 Strategies

The Rebate Advantage incentive amounts for customers and salespeople will double in 2013. Customers who purchase an all-electric ENERGY STAR manufactured home will receive a $1,000 incentive. Salespersons will receive a $200 incentive for each qualified home they sell. This new rebate offsets the cost of the ENERGY STAR enhancements and is designed to offset a greater portion of the cost differential between these homes and non-ENERGY STAR homes. This program remains cost effective with the increased incentive levels.

In early 2013, a bill insert will be mailed to all residential customers to inform them of the change in the incentive amount. The new posters and brochures that were created and distributed in 2012 to all local dealerships to promote the increase in the incentive amount will continue to be used throughout 2013. Idaho Power continues to explore new marketing methods and promote the program using internal resources and externally at the dealership level. CRs will enhance relationships with dealerships by visiting each dealership, offering program support, answering questions, and distributing materials. The interaction of local Idaho Power staff with the local dealers reemphasizes the importance of promoting the benefits of ENERGY STAR qualified homes and products.

Idaho Power will continue to examine additional marketing strategies directed at the end consumer. These will include the continuation and revision, as needed, of the Google AdWords campaign and additional bill inserts sent to all residential customers. This strategy may be shared with the Home Products Program, as done in 2012. Strategies may include other banner-type promotional materials at the physical dealerships. Participation in this option will be determined by direct contact with the dealerships to determine how many show interest in having the banner displayed at their dealership. In addition, new research from the upcoming *2013 Manufactured Home Market Facts Report* by Foremost® Insurance will be used to determine the best marketing strategies.

# See ya later, refrigerator®

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (refrigerators/freezers) | 3,176 | 3,449 |
| Energy Savings (kWh) | 1,576,426 | 1,712,423 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $596,167 | $634,967 |
| Oregon Energy Efficiency Rider | $16,979 | $19,426 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $613,146 | $654,393 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.046 | $0.046 |
| Total Resource Benefit/Cost Ratio | $0.046 | $0.046 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.70 | |
| Total Resource Benefit/Cost Ratio | 1.70 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2009 | |

## *Description*

The See ya later, refrigerator® program acquires energy savings through the removal of qualified refrigerators and stand-alone freezers in residential homes throughout Idaho Power's service area. Each application is screened upon enrollment by Idaho Power to determine whether each refrigerator or freezer unit under consideration meets all program eligibility requirements, including the requirement that a unit must be residential-grade, a minimum of 10 cubic feet as measured using inside dimensions, no larger than 30 cubic feet, and in working condition. Customers receive a $30 incentive check mailed after the removal of the unit. The program targets older, extra units for maximum savings.

Idaho Power contracts with JACO to provide most services for this program, including customer service and scheduling, unit pickup, unit recycling, reporting, marketing assistance, and incentive payments. Idaho Power provides participant confirmation, supplemental marketing, and internal program administration.

## *2012 Activities*

In July 2012, the See ya later, refrigerator® program reached a milestone when it picked up its 10,000$^{th}$ unit. Idaho Power invited local media to watch the unit get unloaded from the collection truck to a trailer used to haul units to the recycling facility in Salt Lake City, Utah. The story was picked up by several television stations.

Idaho Power continued to offer See ya later, refrigerator® participants, upon enrollment, the option to receive their $30 incentive or donate it to Project Share. Project Share is an energy assistance program in partnership with the Salvation Army. The program helps customers who need help paying for energy

services, including fuel bills and furnace repairs. In 2012, 2.7 percent of Idaho Power's See ya later, refrigerator® participants chose this option, raising $2,610 for Project Share.

In 2012, program staff visited the JACO recycling facility in Salt Lake City. According to the contract terms, JACO is responsible for dismantling and properly recycling or disposing of parts of each unit. This trip confirmed the contract conditions were being met.

The program continued to use a variety of marketing channels including bill inserts, direct mail, Valpak®, and promotion at events. In 2012, the program tested a new marketing avenue, cinema advertising at a theater in Nampa, ID. Idaho Power developed a 30-second spot that aired 5,824 times.

The See ya later, refrigerator® program was one of three programs that sponsored the Idaho Stampede's Green Week games. The promotion included highlighting Idaho Power's energy efficiency programs at two home games through announcements, posters, and staffed displays providing attendees the opportunity to talk with Idaho Power employees about energy efficiency. As part of the promotion, Idaho Power ran a 30-second PSA regarding See ya later, refrigerator®, which aired at both home games. Idaho Power posted the PSA to its website and YouTube.

The program also tested different types of direct-mail in 2012. In January and April, letters were sent to customers encouraging enrollment in the program. In June, a magnet mailer was sent. All mailings used market segmentation to create the mailing list. In the April and June mailings, the lists were further refined using total energy use and length-of-time as customers. By evaluating energy use, homes with extremely low use (and therefore unlikely to have a secondary appliance) were removed. By evaluating length-of-time as customer, the mailing targeted those customers identified by market research as more likely to participate in this program.

## Cost-Effectiveness

No changes occurred to the assumptions that drive the cost-effectiveness of the two measures that are part of this program, which include the decommissioning of secondary freezers and refrigerators. All cost-effective analyses are based on the RTF's approval decision dated July 2010. Both program measures remained cost effective in 2012.

Refrigerator and freezer recycling measures were reviewed by the RTF during the year as part of the comprehensive review of most residential measures and RTF guideline updates. Savings and measure-life estimates were updated by the RTF late in 2012 and will be included in the claimed savings in 2013. For details, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

In 2012, Idaho Power considered the recommendations provided by the 2011 process evaluation conducted for the program by ADM. The evaluation included two recommendations. The first recommendation was to continue researching "existing retailer involvement in the program." Idaho Power continues to track referrals through retailers. The goal of the program is to collect secondary units and remove them from customer homes. Energy savings are maximized when the unit is removed and not replaced. In 2012, 67 percent of participants that reported hearing about the program through retailers also indicated they intended to replace the unit. This is compared to 49 percent of all program participants that indicated they intended to replace the unit. Since retailer referrals have a higher replacement rate, resulting in lower energy savings, marketing through retailers is not a preferred approach at this time.

The second recommendation was to monitor customer understanding of program requirements. Anecdotal comments in the evaluation suggested some participants may not always understand the purpose of the program or eligibility requirements. Idaho Power continues to include major program requirements on its marketing materials to enhance customers' understanding of program parameters. Idaho Power also emphasizes the energy-saving benefits of the program on its marketing materials. In addition, JACO's call center and online enrollment process include screening to ensure program requirements are met.

Idaho Power contracted with ADM to conduct an impact evaluation of 2011 savings results. ADM noted the program appears to be running smoothly with an ex-post realization rate of 95 percent as compared to ex-ante estimates.

The ADM report also indicated the JACO screening process is mostly preventing ineligible units from entering the program. Also, the current RTF-approved unit energy savings (UES) values were correctly applied as ex-ante estimates, and the parameters supporting those values appear applicable to the Idaho Power program.

ADM recommended Idaho Power continue to actively monitor the RTF UES list of measures for deemed-savings updates since, although appliance decommissioning measures are RTF approved, they were listed as "under review" at the time of the publication of the evaluation. These measures are subject to change as updates to the estimation procedures and/or data sources are made. A copy of the complete report is included in *Supplement 2: Evaluation*.

JACO tracks individual statistics for each unit collected, including information on how customers heard about the program and when customers enrolled. Statistics about the unit collected include the age of the unit, its location on the customer's property, and other data.

The 2012 unit data showed that 22 percent of units the program picked up were stand-alone freezers, and 78 percent of the units were refrigerators. Fifty-seven percent of the units were secondary, 28 percent were primary, and 14 percent were unknown. This shows slight improvement in the collection of secondary units over 2011. The average vintage of units collected was 1986, with 57 percent of the units manufactured from 1965 to 1990, generally the least efficient years of manufacture. In 2011, 64 percent of units were of this vintage, suggesting the program is still collecting older units.

The program reclaims or recycles up to 95 percent of the components of each unit collected. In 2012, this translated into over 417,676 pounds of materials. Reclaimed materials may include oils or refrigerants that can be distilled, then reused.

JACO and Idaho Power also track data related to the marketing effectiveness of the program. Results of customer tracking information indicate 49 percent of customers reported learning of the program through bill inserts that ran in February, May, August, and October 2012. A portion of these customers reporting bill inserts may refer to the article that appeared in the *Customer Connection* newsletter in the September bill. Eighteen percent of customers reported learning of the program through a friend or neighbor. Other word-of-mouth activities, such as events, account for an additional one percent of signups.

In 2012, direct-mail was used three times and resulted in 6 percent of the enrollments. Direct-mail is sent to a subset of customers. Idaho Power market-segmentation data and national research show participants in utility refrigerator recycling programs are likely to have common characteristics, including older, empty-nesters, smaller households, homeowners, single-family homes, and higher

incomes. Nielsen's PRIZM segmentation software was used to identify customers with these characteristics. In addition to the segmentation software, two other criteria were applied to list: energy use and length of time in the home. As older refrigerators can use up to 1,400 kWh per year, homes with very low energy use were considered unlikely to have a second unit and removed from the list. Second, the length of time in the home may correlate to age. As likely participants are older, the length of time in the home was applied on top of the segmentation criteria.

Although appliance retailers also refer customers to the program, Idaho Power does not pursue this marketing channel. The program focuses on the removal of secondary units rather than replacing existing units. Retailers sell new units to replace older units. In addition, a retailer selling a new unit will usually pick up and recycle the old one.

Newspaper advertisements comprise 3 percent of enrollments. Newspaper advertisements ran one to two times per month for seven months in regional publications throughout the Idaho Power service area. Eighty-one percent of customers who enrolled used the toll-free telephone number, and 19 percent used the online enrollment form. Idaho Power uses the customer information that JACO collects and the surveys from Idaho Power evaluations to target future marketing efforts and increase the effectiveness of marketing while reducing the cost.

Figure 7 indicates information sources and the percentage of customers reporting hearing about the program through particular sources. The Other category includes sources such as community event, repeat customer, truck advertisement, and unknown sources.

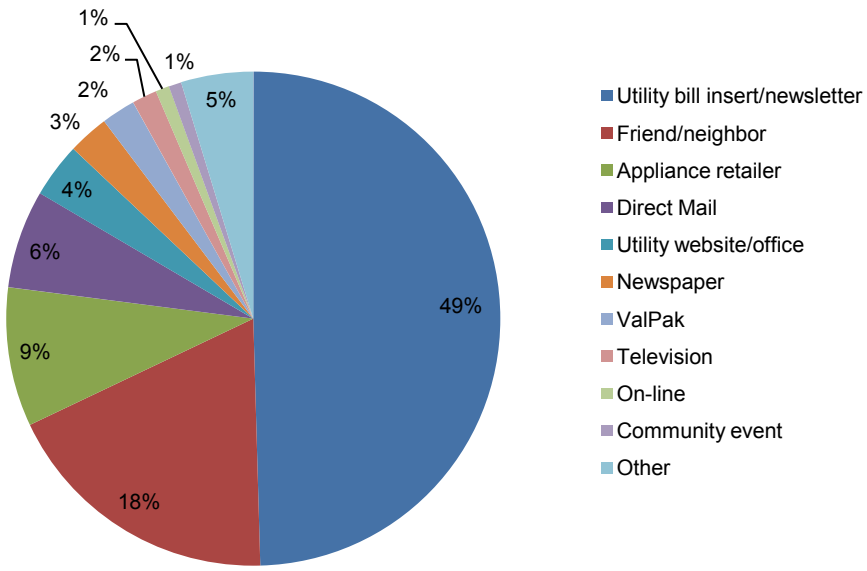



Figure 7. How customers heard about See ya later, refrigerator®

## 2013 Strategies

Idaho Power plans to continue implementing the program and managing the contract with JACO.

The marketing plan for 2013 includes a continued focus on a variety of channels, including bill inserts, newspaper advertisements, and customer newsletters. Digital media pay-per-click advertisements will be

on Google all year. The company will continue promotions at energy efficiency and community outreach events and on the Idaho Power website. A program process evaluation conducted by ADM in 2011 indicated that 52 percent of program participants reported convenience was the aspect of the program that provided them the most value. Therefore, new messaging will be developed and tested with a group of Idaho Power customers, focusing on the convenience aspect of the program as a motivation.

# Weatherization Assistance for Qualified Customers

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes/non-profits) | 238 | 287 |
| Energy Savings (kWh) | 648,304 | 2,783,648 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $0 | $0 |
| Oregon Energy Efficiency Rider | $0 | $0 |
| Idaho Power Funds | $1,370,141 | $1,324,415 |
| Total Program Costs—All Sources | $1,370,141 | $1,324,415 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.129 | $0.029 |
| Total Resource Benefit/Cost Ratio | $0.172 | $0.042 |
| **Program Life Benefit/Cost Ratios**[a] | | |
| Utility Benefit/Cost Ratio | 4.39 | |
| Total Resource Benefit/Cost Ratio | 2.84 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 1989 | |

[a] The 2012 one-year B/C ratios are 0.84 for the UC and 0.71 for the TRC.

## *Description*

The WAQC program provides funding to install weatherization measures in qualified owner-occupied and rental homes that are electrically heated. In 2012, qualified households included those with incomes up to 200 percent of the federal poverty-level guidelines. Energy efficiency enhancements allow qualified families to maintain a comfortable home environment while saving energy and money otherwise spent on heating, cooling, and lighting. Participants receive energy efficiency education to help save energy in their homes. Funding is also provided for the weatherization of buildings that house non-profit organizations who serve special-needs populations. In compliance with IPUC Order No. 29505, Idaho Power funds the Community Action Partnership (CAP) agencies to administer the WAQC program in its service area.

WAQC is modeled after the US Department of Energy (DOE) Weatherization Program. The DOE program is managed through Health and Human Services offices in Idaho and by the Oregon Housing and Community Services in Oregon. While Idaho Power funds the WAQC program, CAP agencies in Idaho Power's service area serve as the administrators of the WAQC program. Federal funds are allocated to the Idaho Department of Health and Welfare (IDHW) and Oregon Housing and Community Services, then to CAP agencies based on US Census data of qualifying household incomes within each CAP agency's geographic area. The CAP agencies oversee local weatherization crews and contractors, providing services and measures that improve energy efficiency of the homes. WAQC funding allows these state agencies to leverage their federal weatherization dollars and serve more residents by supplementing federal Low Income Home Energy Assistance Program (LIHEAP) weatherization funds.

Energy-saving home measures provided by this program include upgrades to windows, doors, wall insulation, ceiling insulation, floor insulation, infiltration, ducts, water heaters, pipes, furnace tune-ups, furnace modification, furnace replacement, and CFLs. The Idaho Weatherization Assistance Program calculates savings with the EA5 energy audit program (EA5). Idaho implemented the upgrade from the EA4 energy audit program (EA4) to the EA5 in September 2011. By January 2012, all agencies began using the EA5 to report savings. Consistent with the Idaho Weatherization Assistance Program, WAQC offers several measures that have costs but do not save energy or for which savings cannot be measured. Included in this category are health and safety, vents, furnace repair, and home energy audits. Health and safety measures are necessary to ensure weatherization activities do not cause unsafe situations in a customer's home or compromise a household's existing indoor air quality. Other non-energy-savings measures are allowed under this program to help facilitate the effective performance of those measures yielding energy savings.

Energy-saving measures provided to non-profit buildings under this program include upgrades to windows, doors, wall insulation, ceiling insulation, floor insulation, infiltration, ducts, water heaters, pipes, furnace tune-ups, furnace modification, furnace replacement, and CFLs. Non-profit building measures that have costs but do not save energy or for which savings cannot be measured are health and safety, vents, furnace repair, and energy audits.

For more details on the WAQC program, view the most recent regulatory report, *Weatherization Assistance for Qualified Customers 2011 Annual Report*, April 1, 2012, located in *Supplement 2: Evaluation*.

## 2012 Activities

During 2012, CAP agencies weatherized 224 electrically heated homes in Idaho and 10 in Oregon, totaling 234 weatherized homes. Four Idaho buildings housing non-profit organizations that serve special-needs populations were weatherized in 2012.

On February 15, 2012, IPUC staff filed Case No. GNR-E-12-01, Cost-Effectiveness and Funding of Low Income Weatherization Programs. As part of this case, IPUC staff sponsored workshops from March 19 to 20, 2012, to discuss investor-owned utility weatherization programs. Also discussed at the workshops was the need for an appropriate funding level for low-income weatherization programs and an overall program design. IPUC staff filed a report on October 23, 2013, providing recommendations on funding, cost-effectiveness, and the low-income energy conservation education programs. Notice of the IPUC decision meeting on January 28, 2013, reports that the IPUC took this case into private deliberation, and Idaho Power is awaiting an order.

## Cost-Effectiveness

In 2012, D&R International, Ltd., conducted an impact evaluation under contract with Idaho Power. This study resulted in significantly lower realized energy savings for the WAQC program, which led to lower cost-effectiveness ratios in 2012 as compared to 2011. For this report's cost-effectiveness calculations, the company used D&R International's average annual energy savings of 2,684 kWh per home that resulted from the billing analysis of 2011 weatherized homes. This is in contrast to an average of 9,103-kWh annual savings as reported by the EA4 in 2011. Since the D&R International report did not give a per-unit savings amount for non-profit building weatherized under the WAQC program, these four project savings were adjusted by applying the overall program 29-percent realization rate from the evaluation. Even though the WAQC program used the EA5 in 2012, the company believes the average annual saving per home estimate provided by D&R International is applicable because the

weatherization activities have not changed and the reported savings from the EA5 are similar to the EA4. The company also adopted the recommendations included in the IPUC staff's report from Case No. GNR-E-12-01 for the cost-effectiveness calculations for the WAQC program when possible. The results of this cost-effective analysis showed a TRC ratio of 0.71 and a UC ratio of 0.84. The details of the cost-effectiveness calculations are included in *Supplement 1: Cost Effectiveness*.

## Customer Satisfaction and Evaluations

Idaho Power used independent third-party verification companies across its service area to randomly check 5 percent of the weatherization jobs submitted for payment by the program. These QA inspectors verify installed measures in homes of participating customers, as well as discuss the program with these customers. Home verifiers visited 39 homes for feedback about the program. When asked how much customers learned about saving electricity, 26 answered they learned "a lot" or "some." When asked about how many ways they tried to save electricity, 29 responded "a lot" or "some."

The Idaho Power program specialist participates in the Idaho state peer-review process, which involves representatives from the CAP agencies, Community Action Partnership Association of Idaho, Inc. (CAPAI), and the IDHW reviewing homes weatherized by each of the CAP agencies. Results show that all CAP agency weatherization departments are weatherizing in accordance with federal guidelines.

Additionally, the DOE audits the state agencies each year. The DOE audits include field work, as well as paperwork and billing audits and show that the Idaho State Weatherization Assistance Program is in compliance with DOE standards.

Idaho Power contracted with D&R International to conduct an impact evaluation of 2011 savings results and to estimate the usefulness of the DOE-approved EA4 calculation methodology, as used in 2011, for ex-ante savings estimates. D&R International used the results of billing regression models and savings outputs from EA4 to provide ex-post savings estimates resulting in a 29-percent savings realization rate as compared to ex-ante estimates.

D&R International noted in the final report that EA4, as it was implemented for this program, over-estimates and does not provide an accurate prediction of energy savings as EA4 does not rank multiple measures and focuses on heating load while not calculating cooling load. The report also indicated there are no savings during the summer months due to the added electrical load created by the installation of heat pumps, which provide added cooling load during this time.

D&R International recommended converting to the use of the DOE-approved EA5, which ranks heating measures and duct improvements by the savings-to-investment ratio (SIR) and evaluates architectural measures prior to evaluating improvements to heating, the duct system, and building repairs. D&R International also recommends improving EA5 using bin weather data rather than straight heating degree day methodology. A copy of the complete report is included in *Supplement 2: Evaluation*.

## 2013 Strategies

In 2013, Idaho Power plans to issue an RFP to conduct research and analysis on the current audit program, EA5, used by the CAP agencies to administer the WAQC program. The company hopes to compare the savings estimated by the EA5 to the results from other residential and commercial audit tools. Idaho Power will also require the contractor to compare the modeled savings estimates to the deemed savings for weatherization measures as determined by the RTF and other reliable sources. This research, along with the pending order in the GNR-E-12-01 case from the IPUC, will help

determine future modifications to the company's low-income weatherization programs. In 2013, Idaho Power also plans to conduct a third-party process evaluation of the WAQC program.

The company will continue its involvement with the State of Idaho's Policy Advisory Council that serves as an oversight group for weatherization activities in Idaho. Through this forum, Idaho Power participates in the weatherization policy for the State of Idaho. The council will continue to review state grant applications.

Idaho Power plans to selectively market WAQC throughout 2013. The program is promoted at resource fairs, community special-needs populations' service provider meetings, and CAP agency functions in an attempt to reach customers who may benefit from the program. The Idaho Power web page for WAQC will be updated with new graphics and expanded copy. Marketing for this program is conducted in cooperation with weatherization managers to ensure a manageable response level at the agencies.

# Weatherization Solutions for Eligible Customers

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 141 | 117 |
| Energy Savings (kWh) | 257,466 | 1,141,194 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,048,461 | $774,254 |
| Oregon Energy Efficiency Rider | $0 | $(2,306) |
| Idaho Power Funds | $22,094 | $16,200 |
| Total Program Costs—All Sources | $1,070,556 | $788,148 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.254 | $0.042 |
| Total Resource Benefit/Cost Ratio | $0.254 | $0.042 |
| **Program Life Benefit/Cost Ratios**[a] | | |
| Utility Benefit/Cost Ratio | 1.47 | |
| Total Resource Benefit/Cost Ratio | 1.47 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho | |
| Program Inception | 2008 | |

[a] The 2012 one-year B/C ratios are 0.43 for the UC and 0.47 for the TRC.

## *Description*

Weatherization Solutions for Eligible Customers is an energy efficiency program designed to serve Idaho Power residential customers who are slightly above poverty level and, therefore, do not financially qualify for the company's weatherization assistance program, WAQC. The measures in the program and the methods of delivery mirror WAQC. The installation of energy efficiency measures and repairs are allowed as long as the improvements have a SIR of 1 or higher. The amount spent on each home is limited to an annual average per home. Homes considered for this program are electrically heated and either owned or rented. If rented, the landlord's permission is needed, along with an agreement to maintain the unit's current rent for a minimum of one year.

Idaho customers eligible for this program earn income just above the federal poverty level. They typically do not have expendable income to participate in other residential energy efficiency programs, and they live in similar housing as WAQC customers.

## *2012 Activities*

The 2012 program ended the year with 141 weatherization jobs completed. Qualifying customers for the year earned an income between 175 percent and 250 percent of the federal poverty level. The program served customers in Idaho Power's Southern, Western, Eastern, and Capital service areas.

Table 7 shows the number of jobs and costs associated with measures installed in homes called production costs. Also shown are job average costs and total payments to contractors for the year.

Table 7. 2012 weatherization solutions financial breakdown

| Contractor | Number of Jobs | Production Costs | Average Job Cost* | Administrative Payment to Contractor | Total Payment |
|---|---|---|---|---|---|
| Energy Zone | 63 | $ 454,545 | $ 7,215 | $ 45,455 | $ 500,000 |
| Home Energy Management | 41 | 272,900 | 6,656 | 27,290 | 300,190 |
| Power Savers | 20 | 106,461 | 5,323 | 10,646 | 117,107 |
| Savings Around Power | 17 | 87,450 | 5,144 | 8,745 | 96,195 |
| **Total** | **141** | **$ 921,356** | **$ 6,534** | **$ 92,136** | **$ 1,013,492** |

* Average Job Cost is calculated based on the direct cost of installed measures without the administration adder.

Marketing of the program was done several ways in 2012. All four contractors advertised the program in their regions with program flyers and door hangers distributed by contractors throughout mobile-home parks and at specific property-management offices. Flyers were also left with previous customers to spread information about the program to families and friends who might qualify. Word of mouth continued to be an effective marketing tool for the program in 2012. Several articles about the program were featured in various local publications and at an Idaho Power booth at weatherization conferences.

## Cost-Effectiveness

In 2012, D&R International, Ltd., conducted an impact evaluation of the Weatherization Solutions for Eligible Customers program under contract with Idaho Power. This study resulted in significantly lower energy savings estimates for this program, which led to lower cost-effectiveness ratios in 2012 as compared to 2011. For this report's cost-effectiveness calculations, the company used D&R International's average annual energy savings of 1,826 kWh per home that resulted from the billing analysis of 2011 weatherized homes. This is in contrast to an average of 9,754-kWh annual savings per home as reported by the EA4 in 2011. This is a realization rate of 19 percent of the savings reported under the EA4. The company also adopted the recommendations included in the IPUC staff's report from Case No. GNR-E-12-01 for the cost-effectiveness calculations for the Weatherization Solutions for Eligible Customers program when possible. The results of this cost-effective analysis showed a TRC ratio of 0.47 and a UC ratio of 0.43. Since the evaluation did not calculate an average measure level saving or realization rate by measure for this report, Idaho Power is not including measure level cost-effectiveness in this report, a change from previous reports. The details of the cost-effectiveness calculations are included in *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

In 2012, the program contractors conducted a customer satisfaction survey. Questionnaires were given to customers after the contractor completed the job. Of the 141 participants, 89 customers provided written feedback about the work done and about energy conservation in their home. Each response complimented the work crew and expressed thanks for the program. These contractor surveys include high-level questions and are administered by the contractors, not by Idaho Power.

Idaho Power hired independent third-party verification companies across its service area to randomly check weatherization jobs submitted for payment by the program. These QA inspectors verify installed measures in homes of participating customers and discuss the program with these customers. Of the 141 jobs completed in 2012, verifiers visited 25 homes for feedback about the program. When these 25 customers were asked how much they learned about saving electricity during weatherization, 16 answered from the choices offered that they learned "a lot" or "some." When asked about how many ways they tried to save electricity in their home, 21 responded "a lot" or "some." This customer

feedback is collected as a part of the actual job verification. The documents containing individual customer information include these two questions.

Idaho Power contracted with D&R International to conduct an impact evaluation of 2011 savings results and to estimate the usefulness of the DOE-approved EA4 calculation methodology currently used for ex-ante savings estimates. D&R International used the results of billing regression models and savings outputs from EA4 to provide ex-post savings estimates, resulting in a 19-percent savings realization rate as compared to ex-ante estimates.

D&R International noted in the final report that EA4, as it was implemented for this program, over-estimates and does not provide an accurate prediction of energy savings as EA4 does not rank multiple measures and focuses on heating load and does not calculate cooling load. The report also indicated there are no savings during the summer months due to the added electrical load created by the installation of heat pumps, which provide added cooling load during this time.

D&R International recommended converting to the use of DOE-approved EA5, which ranks heating measures and duct improvements by the SIR and evaluates architectural measures prior to evaluating improvements to heating, the duct system, and building repairs. D&R International also recommends improving EA5 using bin weather data rather than straight heating degree day methodology. A copy of the complete report is included in *Supplement 2: Evaluation*.

## 2013 Strategies

In 2013, Idaho Power plans to issue an RFP to conduct research and analysis on the current audit program, EA5, used by the contractors to administer the Weatherization Solutions for Eligible Customers program. The company hopes to compare the saving estimated by the EA5 to the results from other residential and commercial audit tools. Idaho Power also will require the contractor to determine per-measure savings for this program and compare them to the deemed savings for weatherization measures as determined by the RTF and other reliable sources. This research, along with the pending order in Case No. GNR-E-12-01 from the IPUC, will help determine future modifications to the company's low-income weatherization programs. Additionally, Idaho Power plans to conduct a third-party process evaluation of the Weatherization Solutions for Eligible Customers program in 2013.

In 2013, Idaho Power plans to offer this program to Idaho Power customers in the Southern, Eastern, Western, and Capital regions. Weatherization Solutions for Eligible Customers anticipates weatherizing 165 homes through the program in 2013.

Home Energy Management, LLC (HEM, LLC) is under contract to weatherize approximately 40 homes in Idaho Power's Southern region; Energy Zone, LLC is under contract to weatherize approximately 50 homes in Idaho Power's Western region; and Savings Around Power is contracted to weatherize approximately 25 homes in the Eastern region. Power Savers, serving Idaho Power's Capital region, is under contract to weatherize approximately 50 homes.

An annual allowable average cost of $7,200 per home will be used again in 2013. Contractors will be paid 10 percent of the production costs per home as an administrative fee. All measures that provide energy savings will meet the minimum SIR when applied through the state-approved energy audit. Each total job will also meet the minimum SIR requirements.

Eligible customers will include Idaho Power customers who heat their homes electrically and earn an income between 175 percent and 250 percent of the federal poverty level. Customers who are either

purchasing or renting their homes may be eligible. As in 2011 and 2012, the identification of potential participants will be made through several means. Energy Assistance/LIHEAP applicants at CAP agencies who do not meet WAQC income qualifications are sent denial letters. Program contractors will use this list of denied customers at CAP agencies to market the Weatherization Solutions for Eligible Customers program. Contractors will distribute flyers and door hangers explaining the program and qualifying guidelines to customers heating their homes electrically.

Idaho Power's plans to market the Weatherization Solutions for Eligible Customers program throughout 2013. Direct-mail letters proved successful in 2012, and these targeted mailings will continue along with bill inserts and online advertisements. The web page for the program will be updated with new graphics and expanded copy. Marketing for this program is conducted in close cooperation with contractors to ensure the marketing activity is done at a level each contractor is able to service in a timely manner.

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# COMMERCIAL/INDUSTRIAL SECTOR OVERVIEW

## Description

Idaho Power's commercial and industrial sector consists of over 65,857 customers. In 2012, the commercial sector's number of new customers increased by 683, an increase of 1 percent over 2011. The energy usage of commercial customers varies from a few kWh each month to several hundred thousand kWh per month. The commercial sector represents 27.4 percent of Idaho Power's total electricity usage.

The industrial customers and special-contract sector are Idaho Power's largest individual energy consumers. There are approximately 116 industrial customers. These customers can use millions of kWh a month and account for 22.2 percent of Idaho Power's total electricity usage.

The Custom Efficiency program continued to represent the highest total energy savings among commercial and industrial programs in 2012, with a total savings of 54,253 MWh. The Building Efficiency program saw the highest percentage increase among commercial and industrial programs, with annual savings increasing by 105 percent over 2011. Combined, the programs experienced a 4.54 percent increase in the number of completed projects over 2012. Overall, energy savings decreased less than 1 percent compared to 2011. Table 8 shows a summary of savings and expenses from the three commercial and industrial energy efficiency programs and one demand response program.

## Programs

Table 8. 2012 commercial/industrial program summary

| | | Total Cost | | Savings | |
|---|---|---|---|---|---|
| **Program** | **Participants** | **Utility** | **Resource** | **Annual Energy (kWh)** | **Peak Demand (MW)** |
| **Demand Response** | | | | | |
| FlexPeak Management | 102 sites | $ 3,009,822 | $ 3,009,822 | n/a | 52.8 |
| **Total** | | **$ 3,009,822** | **$ 3,009,822** | | **52.8** |
| **Energy Efficiency** | | | | | |
| Building Efficiency | 84 projects | $ 1,592,572 | $ 8,204,883 | 20,450,037 | 2.3 |
| Easy Upgrades | 1,838 projects | 5,349,753 | 9,245,297 | 41,568,672 | 4.7 |
| Custom Efficiency | 126 projects | 7,092,581 | 12,975,629 | 54,253,106 | 7.6 |
| **Total** | | **$ 14,034,906** | **$ 30,425,809** | **116,271,815** | **14.6** |

Note: See Appendix 3 for notes on methodology and column definitions.

Three major programs targeting different energy efficiency projects are available to commercial/industrial customers in the company's Idaho and Oregon service areas. Easy Upgrades offers a menu of typical retrofit measures with prescriptive incentive amounts for lighting, HVAC, motors, the building shell, plug loads, and food-service equipment. These energy-saving measures give customers the option of choosing the best selections for incorporating energy efficiency into their business. The Building Efficiency program is available for new construction projects and large remodels. These projects typically capture lost-opportunity savings. This program continues to be successful, incorporating qualified energy-saving improvements for lighting, cooling, building shells, and energy control options. Participants in the Easy Upgrades program can receive incentives of up to $100,000 per site per year for approved, completed projects. There are no incentive caps on Building Efficiency- and Custom Efficiency-approved and completed projects. The Custom Efficiency

program offers financial incentives for large commercial and industrial energy users undertaking more complex projects to improve the efficiency of their electrical systems or processes.

Incentive levels are 70 percent of the project cost or 12 cents per kWh for first-year savings, whichever is less. Idaho Power continues to offer the Oregon Commercial Audits program to medium and small commercial customers.

FlexPeak Management, a demand response program, is offered to Idaho and Oregon commercial and industrial customers. Idaho Power contracted with EnerNOC, Inc., a third-party aggregator, to reduce peak demand at critical times. EnerNOC, in turn, contracts directly with Idaho Power's commercial and industrial customers to achieve demand reduction.

2012 proved to be another challenging, rewarding, and successful year for Idaho Power's commercial and industrial energy efficiency programs. Custom Efficiency awarded the single largest incentive in the program's history to a chilled water economizer project designed to save approximately 10 million kWh annually. Building Efficiency experienced substantial growth in both the number of completed projects and energy savings. Easy Upgrades also experienced growth in both the number of completed projects and energy savings. These are remarkable accomplishments considering the economic environment Idaho Power's business customers continue to navigate. The commercial and industrial programs continued to develop and strengthen Idaho Power's strategic partnerships. These partnerships include the IDL, engineering and architectural firms, a vast network of trade allies, and most importantly, Idaho Power customers. Training and education continued to be an important aspect of the company's programs in 2012. Trade ally meetings included training on lighting design and technologies. Custom Efficiency continued to offer a host of industrial training sessions that were well attended. Finally, Building Efficiency sponsored a number of outreach training sessions conducted by the IDL.

The Green Rewind offering is available to Idaho Power's agricultural, commercial, and industrial customers. The sectors' combined 42 Green Rewind motors achieved a total annual savings of 84,193 kWh in 2012, with 19 commercial/industrial sector motors contributing 54,154 kWh per year and 23 irrigation sector motors contributing 30,039 kWh per year.

Twenty-one service centers in Idaho Power's service area have the necessary equipment and training to participate in the Green Rewind offering. An estimated 1,200 motor rewinds are occurring annually within these service centers. Currently, eight service centers have signed on as Green Motors Practice Group (GMPG) members. The GMPG also will expand the number of service centers participating in the GMPG's Green Motors Initiative, leading to market transformation and additional southern Idaho and eastern Oregon kWh savings.

Motor service centers are paid $2 per horsepower (hp) for each National Electrical Manufacturers Association (NEMA) Standard hp-rated motor between 15 and 5,000 hp for industrial uses and 25 to 5,000 hp for agricultural uses that receive a verified Green Rewind. The GMPG requires all service centers to sign and adhere to the GMPG Annual Member Commitment Quality Assurance agreement. The GMPG follows up with a quality check and QA.

In 2012, Idaho Power entered into the third year of a three-year contract with the IDL to meet the following objectives:

- Educate architects, engineers, and other design and construction professionals about energy efficiency topics through an in-firm summer series. This series was expanded in 2011 and 2012 to include firms outside the Treasure Valley.

- Facilitate the Idaho Building Simulation Users' Group to improve the energy efficiency-related simulation skills of local design and engineering professionals.

- Support Idaho Power employees in promoting energy efficiency and providing Idaho Power's customers with up-to-date and accurate information regarding energy efficiency technologies and best practices.

- Create a hands-on demonstration and training area for electrical contractors to learn the necessary skills to successfully install and commission daylight-harvesting lighting control systems.

- Review daylight photo-control incentives to improve the quality and performance of installed systems.

- Develop and maintain a measurement equipment tool loan library, including a web-based equipment tool loan-tracking system.

- Stimulate market awareness of energy use in buildings to promote energy efficiency by working with commercial real estate brokers or owners in the development of metrics to be used in the sale or lease of commercial property.

- Promote aggressive energy efficiency on new construction and major renovation projects in the Idaho Power service area.

- Promote improved energy efficiency in existing convenience stores in the Idaho Power service area.

- Provide measurement and verification services to investigate actual energy savings compared to computer simulation modeled savings or pre- and post-renovation/retrofit conditions.

Expanding on some of the prior year's results, the following objectives were added in 2012:

- Conduct a review of documents associated with the Building Efficiency program's application for incentives along with site inspections on a random percentage of projects to validate whether noted systems and components have been installed.

- Provide the design community with additional spreadsheet-style calculation tools to analyze the feasibility and capacity of various passive cooling design strategies (an expansion of prior climate design resource efforts.)

- Increase both the general public and design community literacy about how different classifications of commercial buildings consume energy and the metrics associated with these data.

- Investigate multi-family new construction and retrofit best practices for utility incentive programs and to investigate the potential for new program incentives.

Phase I of the Idaho Office of Energy Resources (IOER) K–12 Energy Efficiency Project for public schools in Idaho Power's service area concluded December 2012. The project invested federally provided funds into energy efficiency projects in public school buildings within Idaho Power's service

area. In July 2011, Idaho Power entered into an agreement with the IOER that provided for the accumulation and reinvestment of energy efficiency incentive payments from Idaho Power's qualified energy efficiency programs for K–12 projects. These accumulated incentives will be used for additional cost-effective energy efficiency projects that meet current Idaho Power program requirements implemented in public school buildings within Idaho Power's service area and will be referred to as Phase II projects. The agreement will result in achieving a higher level of energy efficiency in public school buildings than either Idaho Power or the IOER could achieve with their individual programs. Phase II projects are anticipated to begin in mid-2013 and conclude in late 2014.

During the November 6 EEAG meeting, the Idaho Power commercial/industrial energy efficiency program leader discussed how the Building Efficiency program is researching expanded measure offerings for new construction and major remodel projects for multi-family dwellings. Research is being performed on the energy savings and the cost-effectiveness of various energy-savings measures that would be included in the Building Efficiency program. If the research is favorable and measures are cost effective, new measure offerings could be added to the program in 2013. EEAG was generally supportive of researching multi-family measure offerings.

Customer satisfaction research by sector includes the Idaho Power quarterly customer relationship surveys that ask questions about customer perceptions related to Idaho Power's energy efficiency programs. Fifty-six percent of Idaho Power's large commercial and industrial customers surveyed in 2012 for the Burke Customer Relationship survey indicated Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Fifty percent of survey respondents indicated Idaho Power was meeting or exceeding their needs with information on how to save energy or reduce their bill. Sixty-six percent of respondents indicated Idaho Power was meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 79 percent of the large commercial and industrial survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of the large commercial and industrial survey respondents who have participated in at least one Idaho Power energy efficiency program, 93 percent are "very" or "somewhat" satisfied with the program.

The results from surveying Idaho Power's small business customers indicated 42 percent of these customers said Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Fifty-one percent of survey respondents indicated Idaho Power was meeting or exceeding their needs with information on how to save energy or reduce their bill. Fifty percent of respondents indicated Idaho Power was meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 21 percent of the small business survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of small business survey respondents who have participated in at least one Idaho Power energy efficiency program, 94 percent are "very" or "somewhat" satisfied with the program.

In 2013, Idaho Power is anticipating adding at least two new initiatives within the Custom Efficiency program. Impact evaluations conducted on Building Efficiency and Easy Upgrades will be finalized in early 2013. Program specialists will be analyzing the findings from these reports and will adjust programs as needed. Training, education, and outreach will continue to be a focus aimed at driving projects. Additionally, the company will analyze ways to improve Idaho Power programs based on customer and trade ally feedback, as well as internally driven research.

# Building Efficiency

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 84 | 63 |
| Energy Savings (kWh) | 20,450,037 | 11,514,641 |
| Demand Reduction (MW) | 2.3 | 0.9 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,579,121 | $1,277,422 |
| Oregon Energy Efficiency Rider | $13,451 | $14,003 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $1,592,572 | $1,291,425 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.007 | $0.010 |
| Total Resource Benefit/Cost Ratio | $0.036 | $0.026 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 6.50 | |
| Total Resource Benefit/Cost Ratio | 2.56 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2004 | |

## *Description*

The Building Efficiency program enables customers in Idaho Power's service area to apply energy-efficient design features and technologies that would otherwise be lost opportunities for savings to their projects. The program offers a menu of measures and incentives for lighting, cooling, building shell, and control-efficiency options. Customers involved in the construction of new buildings or construction projects with significant additions, remodels, or expansions are eligible to receive incentives. Commercial and industrial customers taking service under, or who will take service under, Schedule 7 (Small General Service), Schedule 9 (Large General Service), Schedule 19 (Large Power Service), or special-contract customers are eligible to participate. Program marketing is targeted toward architects, engineers, and other design professionals.

Fourteen measures are offered through this program and include interior-light load reduction, exterior-light load reduction, daylight photo controls, occupancy sensors, high-efficiency exit signs, premium-efficiency HVAC units, additional HVAC-unit efficiency bonuses, efficient chillers, air-side economizers, a reflective roof treatment, high-performance windows, energy- management control systems, demand-controlled ventilation, and variable-frequency drives (VFD).

Idaho Power is a primary sponsor of the IDL, which provides technical assistance and training seminars to local architects, engineers, and designers. Some of this activity is coordinated and supported through NEEA's BetterBricks® program. The Building Efficiency program sponsors the biannual BetterBricks awards held in Boise. The BetterBricks awards recognize leaders whose work supports the design and operations of high-performance buildings and their commitment to energy efficiency. The Building Efficiency program also sponsors technical lunch-and-learn sessions geared to educate design

professionals and the Idaho Building Simulation Users' Group. The Idaho Building Simulation Users' Group is designed to improve the energy efficiency-related simulation skills of local design and engineering professionals.

## 2012 Activities

The Building Efficiency program completed 84 projects, resulting in 20,450,037 kWh in annual energy savings in Idaho. Overall, the program increased kWh savings almost 78 percent over 2011. The dramatic increase in energy savings for 2012 was impacted by some large, multi-year construction projects being completed for qualified program incentives. Examples include regional hospitals in Twin Falls and Pocatello. Additionally, design professionals have become more familiar with the program in recent years. In 2012, vinyl construction banners were produced for the first time and installed at a building site to publicly showcase the building was being "built with energy efficiency in mind."

The Building Efficiency program was last modified in 2011, although the cap of $100,000 on Idaho projects was removed in 2012. Also in 2012, an impact evaluation was completed, focus groups were held with architects and engineers, and in-depth interviews were conducted with building owners to gain feedback on the program. Based on the outcome of these activities, minor changes will be made to the program in mid-2013 once all recommendations have been evaluated thoroughly. New construction and major renovation project design and construction life is much longer than small retrofits and requires consistency in program measures and operation. Program consistency reduces confusion for customers with long construction and project timelines.

Technical training and assistance continue to be important in educating design professionals in energy efficiency design for new construction and major renovations. Influencing a project early in the design phase will have the most impact and least amount of lost opportunity. Twenty-one technical training lunches were completed in 2012, with 235 attendees, including architects, engineers, interior designers, and project managers. Technical training sessions were held in Boise, Twin Falls, Pocatello, Idaho Falls, and Ketchum. Topics included Integrated Design Principals, Energy Benchmarking and Energy Goal Setting, Daylight In Buildings: Schematic Design Methods, Daylighting: Getting the Details Right, Multi-Zone Demand Control Ventilation Systems, Climate Responsive Design: Tools and Methods, Advanced Envelope Construction, Radiant System Design Considerations, High-Performance Classrooms, Role-of-Life Cycle Cost Assessment in Integrated Design, Center for Advanced Energy Studies and Integrated Design, and Commissioning. The Building Efficiency program, in conjunction with the Custom Efficiency program, sponsored 12 training sessions, with 145 attendees for the Building Simulations User Group through the IDL. Additionally, Idaho Power was a sponsor of the American Institute of Architects 2030 Challenge held in Boise. The 2030 Challenge was a 10-session learning course designed to educate architects, engineers, and other design professionals on integrated design practices in new construction. Approximately 40 design professionals were enrolled in the program. The 10 sessions started in fall 2011 and concluded in spring 2012.

Additional *Success Stories* were added to the Idaho Power website in 2012, with one specific to new construction titled *Idaho Power Helps Motorcycle Parts Manufacturer Keep Jobs at Home*. Copies of the 2012 *Success Stories* are provided in *Supplement 2: Evaluation*.

Building Efficiency has teamed up with the Building Owners and Managers Association (BOMA) and NEEA to offer a Kilowatt Crackdown™ competition for office buildings over 15,000 $ft^2$ located in the Treasure Valley. The initial sign-up closed on December 31, 2012. Over 40 buildings signed up to participate in the year-long competition, which includes benchmarking their building in

ENERGY STAR® Portfolio Manager—an interactive energy-management tool that allows tracking and assessing of energy and water consumption—and implementing low-cost and no-cost efficiency measures in their building throughout 2013. Participating buildings have access to an energy coach, scoping audit of their building, and education opportunities. The purpose of this commercial building energy competition is to facilitate and educate businesses on wise energy use. The competition will continue through the beginning of 2014. Idaho Power is contributing marketing and technical expertise to help ensure the success of the competition. At the November 6 EEAG meeting, Idaho Power provided an update on the Kilowatt Crackdown competition in the Treasure Valley market. Idaho Power also sponsors the American Society of Architects Honor awards, the BetterBricks awards, the Smart Growth awards, and the Association of Idaho Cities Annual Conference.

At the November 6 EEAG meeting, Idaho Power also discussed the work being done regarding multi-family dwellings. Building Efficiency is researching expanded measure offerings for new construction and major remodel projects for multi-family dwellings. Research is being performed on the energy savings and cost-effectiveness of various energy-savings measures that would be included in the Building Efficiency program. If the research shows the measures are cost effective, new measure offerings could be added to the program in 2013.

## Cost-Effectiveness

For 2012, the Idaho Power incentive structure remained consistent with the 2011 program.

To calculate energy savings, the Building Efficiency program verifies the incremental efficiency of each measure over a code or standard-practice installation baseline. Savings are calculated through two main methods. When available, savings are calculated using actual measurement parameters for both the measure at code and at efficiency. The other method for calculating savings in the program is based on industry standard assumptions when precise measurements are unavailable. Since Building Efficiency is a prescriptive program and the measures are being installed in new buildings, there are no baselines of previous measureable kWh usage in the building. Therefore, industry standard assumptions from the International Energy Conservation Code (IECC) are used to calculate the savings achieved over how the building would have used energy absent of efficiency measures. In 2012, ADM conducted an impact evaluation of the 2011 program savings. The report recommended a revision to the prescriptive formulas used to estimate the reported savings in three measures. The revised formula has been applied to the 2012 savings results. The program remains cost effective.

Building Efficiency incentives are based on a variety of methods depending on the measure type. Incentives are calculated mainly through a dollar-per-unit equation using square footage, tonnage, operating hours, or kW reduction as the unit being used. For 2012, Idaho Power's incentive structure remained consistent with the 2011 program. Complete measure level details for cost-effectiveness can be found in *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Idaho Power contracted with ADM to conduct an impact evaluation of 2011 savings results. The evaluation report indicates that, overall, the Building Efficiency program does a good job ensuring rebated energy efficiency equipment efficiencies are above those mandated by applicable building code. The 2011 program savings realization rate was estimated to be 73 percent as compared to ex-ante estimates.

The report identified two areas that contributed to over 40 percent of the reduction in the ex-post savings adjustment, which included 1) errors in ex-ante prescriptive formulas used to estimate savings for some HVAC equipment and controls and 2) baseline definition issues that redefined subsets of measures as baseline equipment. Some equipment installed as upgrades were actually required as part of code.

ADM recommends 1) the revision of prescriptive formulas used to estimate savings for air-side economizers, energy-management system building controls, and demand-control ventilation; 2) making prescriptive algorithms more rigorous; 3) making each algorithm more specific to the application for which it is applicable; 4) select a larger number of HVAC controls and VFD projects for detailed application review to screen for potential code or baseline issues; and 5) update the application to include specific applications for which VFDs will not qualify for incentives. A revised version of the impact evaluation report was received after the printing of *Supplement 2: Evaluation*. These revisions do not materially change the results of the evaluation. A copy of the complete report is included in *Supplement 2: Evaluation*. A copy of the revised report is available on request.

In 2012, Idaho Power contracted with Market Decisions Corporation to provide participant focus groups with architects, engineers, and designers and to conduct phone interviews with building owners and operators to gain feedback on the Building Efficiency program. Two in-person two-hour focus groups were held with 14 architects, engineers, or designers in attendance. Ten 30-minute in-depth phone interviews were conducted with building owners and operators. Participants were asked a series of questions by a Market Decisions Corporation moderator and asked to candidly share their experience and satisfaction with the Building Efficiency program.

As a qualitative study, the following key findings only reflect the general thoughts of those that participated in the research groups and are not representative of the entire program. Overall, the research participants are "highly satisfied" with the program. Architects and engineers are familiar with all program incentives and owners are familiar with the incentives applicable to their projects. The architects and engineers typically bring the Building Efficiency program to the owner's attention during the project's design phase. All research participants also expressed a high level of satisfaction with the pre-application process and Idaho Power staff engagement during their projects. A copy of the report can be found in *Supplement 2: Evaluation*.

Building Efficiency continued random installation verification on 10 percent of projects in 2012. The purpose of these verifications was to confirm program guidelines and requirements were adequately facilitating participants to provide accurate and precise information with regard to energy efficiency measure installations. The IDL completed on-site field verifications on 9 of the 84 projects, which encompasses approximately 10 percent of the total completed projects in the program. Out of the nine projects verified, eight projects were installed with only minor or no discrepancies compared to how they were declared. The minor discrepancies resulted in a total increase of energy-efficient measures. Only one project was installed with less energy-efficient measures than were declared. Random project installation verification will continue in 2013.

## 2013 Strategies

The Building Efficiency program will make program updates in mid-2013 once the impact evaluation and focus group research has been evaluated. Research is currently being conducted on multi-family construction. The outcome of the research may lead to additional Building Efficiency offerings in the multi-family sector. A future filing with the OPUC regarding mid-2013 program changes would include the removal of the $100,000 cap on Building Efficiency projects in Oregon. The Building Efficiency

program will continue to perform random post-project verifications on a minimum of 10 percent of completed projects.

The Building Efficiency program will continue to sponsor technical training through the IDL. Technical trainings will continue to address the energy efficiency education needs of design professionals in the Boise, Pocatello, Twin Falls, and Sun Valley markets. Additionally, the program will continue to support organizations focused on promoting energy efficiency in commercial construction. Idaho Power hopes to replicate the vinyl construction banners publicly showcasing buildings as "built with energy efficiency in mind" across a number of energy-efficient buildings in the coming year. The feasibility and value of advertising in specific trade publications will be determined in 2013.

In 2013, Idaho Power plans to contract with a third-party to conduct a research project for the Building Efficiency program that will evaluate existing and new measures for the program.

# Custom Efficiency Program

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 126 | 166 |
| Energy Savings (kWh)[a] | 54,253,106 | 67,979,157 |
| Demand Reduction (MW) | 7.6 | 7.8 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $923,050 | $413,959 |
| Oregon Energy Efficiency Rider | $115,866 | $1,385,613 |
| Idaho Power Funds | $6,053,665 | $6,984,239[b] |
| Total Program Costs—All Sources | $7,092,581 | $8,783,811 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.012 | $0.012 |
| Total Resource Benefit/Cost Ratio | $0.021 | $0.026 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 7.48 | |
| Total Resource Benefit/Cost Ratio | 3.31 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

[a] Includes kWh savings from Green Rewind.
[b] Capitalized incentive payments per IPUC Order No. 32245.

## *Description*

The Custom Efficiency program targets energy savings by implementing customized energy efficiency projects at customers' sites. The program is an opportunity for commercial and industrial customers in Idaho and Oregon to lower their electrical usage and receive a financial incentive by completing energy efficiency projects. Incentives reduce customers' payback periods for projects that might not be completed otherwise. Program offerings include training and education regarding energy efficiency, energy auditing services for project identification and evaluation, and financial incentives for project implementation.

Interested customers submit applications to Idaho Power for potential projects that have been identified by a third-party consultant, Idaho Power, or by the customer as applicable to the facility. Idaho Power engineers work with customers and vendors to gather sufficient information to support the energy-savings calculations.

Project implementation begins after Idaho Power reviews and approves an application and an agreement finalizing the terms and conditions of the applicant's and Idaho Power's obligations. In some cases, large, complex projects may take as long as two years to be completed. Often, Idaho Power conducts follow-up or post-inspection validation via third-party engineering firms on projects of this nature. Every project is verified post-completion by Idaho Power staff or an Idaho Power contractor. All lighting projects are pre- and post-inspected by an Idaho Power contractor or an Idaho Power representative. Incentive levels for the Custom Efficiency program remained at 70 percent of the project cost, or 12 cents per kWh for first-year savings, whichever is less.

## 2012 Activities

Custom Efficiency experienced another successful year in 2012. A total of 126 projects were completed by 110 customers, including four Oregon projects from four customers. Custom Efficiency awarded the single largest incentive in the program's history to a chilled water economizer project designed to save approximately 10 million kWh annually. Program energy savings decreased in 2012 by 20 percent over 2011, from 67,979 MWh to 54,253 MWh. The decrease in program energy savings was a result of several factors: 2012 was a presidential election year and customers mentioned they were hesitant to move forward with large projects until after the election was determined. This, along with general economic uncertainty, impacted the 2012 numbers. Also, the program may have reached some saturation through maturation, as nearly 90 percent of the large-power service customers have submitted an application for a project through 2012. Finally, with the high percentage of industrial customers that have completed projects in the program, deeper energy savings with be challenging to achieve. There were 137 approved applications for active projects at the end of 2012, representing 64,034 MWh of savings. Table 9 indicates the program's 2012 annual energy savings by primary project measures.

Table 9. 2012 Custom Efficiency annual energy savings by primary project measure

| Program Summary by Measure | Number of Projects | KWh Saved |
|---|---|---|
| Lighting | 63 | 20,107,218 |
| HVAC | 6 | 11,885,602 |
| CFL | 19 | 5,321,048 |
| Refrigeration | 15 | 5,319,400 |
| Motors | 3 | 2,289,748 |
| Compressed Air | 4 | 2,228,709 |
| Pump | 2 | 1,425,757 |
| Fan | 9 | 1,380,649 |
| VFDs | 3 | 951,665 |
| Green Rewind | 19 | 54,154 |
| Other | 2 | 3,289,155 |
| **Total** | **126**[a] | **54,253,106** |

[a] Does not include Green Rewind projects.

Key components in facilitating customer implementation of energy efficiency projects are facility energy auditing, customer technical training, and education services. Because the link between energy audits and the completion of projects is historically significant, Idaho Power reevaluated its current offerings and strengthened them where appropriate. It is anticipated, effective by the second quarter of 2013, that detailed audits will go from 50 percent reimbursement or $10,000, whichever is less, to 75 percent reimbursement or $12,500. Scoping audit details did not change in 2012.

Technical training and education continue to be important in helping Idaho Power industrial customers identify where they may have energy efficiency opportunities within their facilities. The training is coordinated by the NEEA Industrial Training Project, and Idaho Power is a co-sponsor. Idaho Power also co-funds the trainings, which allows twice the trainings in Idaho Power service area. Additionally, Idaho Power covers the cost of each customer's subsidized attendance in the classroom-based training sessions. A total of nine technical classroom-based training sessions were completed in 2012. Four of these classes were two-day classes, and the rest were one-day classes. Topics included compressed air, chilled water systems and cooling towers, pump systems, VFDs,

data-center efficiency, energy management, and industrial refrigeration. A schedule of training events is posted on Idaho Power's website.

The level of attendance remained high in 2012, with 171 Idaho Power-sponsored seats filled with 146 end-use customers and various Idaho Power staff, consultants, and trade allies. Customer feedback indicated average overall satisfaction levels over 97 percent.

There were two training sessions outside of the Idaho Power service area attended by Idaho Power customers. One was a pump certification training in Eugene, Oregon, attended by two Idaho Power customers. The second was a conveyance systems training in Portland, Oregon, attended by one customer. The conveyance system training is planned to be offered within Idaho Power's service area in 2013.

Additionally, 2012 encompassed Phase II of the Webinar Pilot Plan coordinated by NEEA. Twelve webinars were presented free to all attendees. Topics included VFDs; lighting; data centers; energy-management topics, including developing an energy plan, investment analysis energy management for industrial customers, and energy auditing and troubleshooting. There were 50 Idaho Power region seats filled with end-use customers and multiple Idaho Power personnel and consultants attending the webinar recordings. Idaho Power posted the recordings and PDFs on the newly established training page on the Idaho Power website.

Figure 8 shows the number of Idaho Power-sponsored attendee seats filled as compared to other utility companies for the 2012 in-class NEEA industrial trainings. This figure uses data from ECOVA™'s summary of the trainings provided in the *NEEA Regional Industrial Training Update, December 2012*, included in *Supplement 2: Evaluation*.

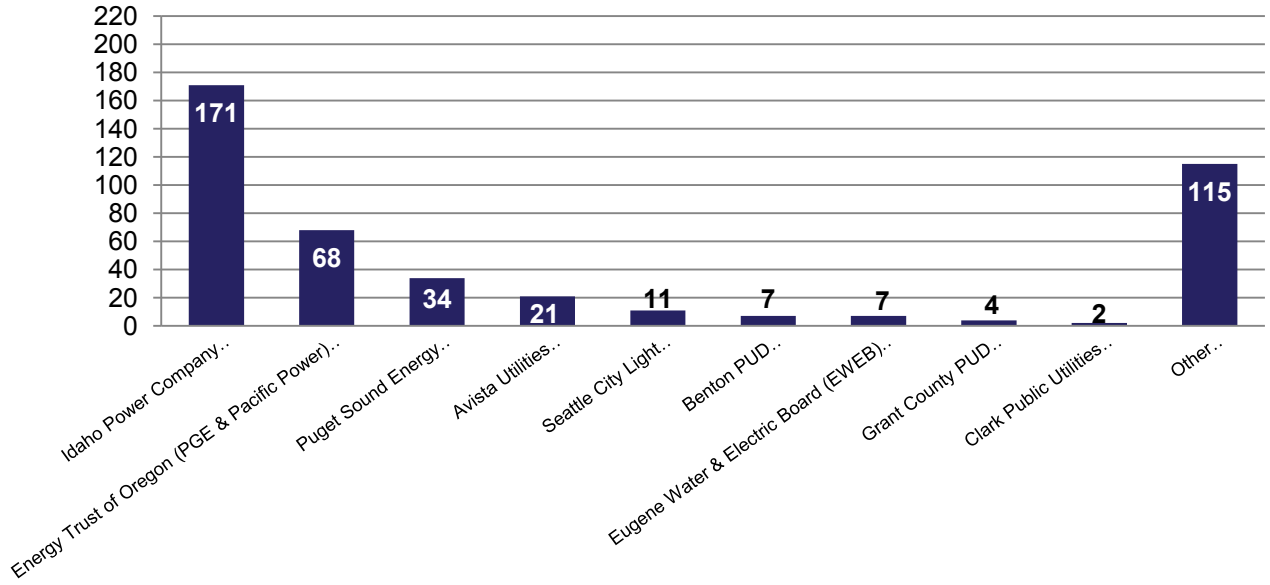



Figure 8. NEEA chart of attendees (seats filled) by attendee sponsor[3]

[3] Data source: *NEEA Regional Industrial Training Update, December 2012*.

As stated in the sector overview, Green Rewind is available to Idaho Power's Custom Efficiency customers. This measure maintains the motor's original efficiency and ensures an efficient use of electricity to run the motor. There were 19 Green Rewind motors in the commercial/industrial sector in 2012, contributing 54,154 kWh in annual savings.

The Custom Efficiency program has achieved a high service-area penetration rate. As stated previously, through 2012, nearly 90 percent of the large-power service customers have submitted applications for a project. Idaho Power engineers have met with the remaining viable Rate 19 and special-contract customers to discuss energy efficiency programs and opportunities within customer facilities.

In 2012, the Idaho Power CR&EE department filled a summer internship position with a Boise State University mechanical engineering student. A Custom Efficiency engineer served as the intern mentor. The intern was involved with many aspects of the day-to-day program operation including, but not limited to, measurement and verification of energy efficiency aspects related to Custom Efficiency program lighting projects, attendance at customer meetings related to energy efficiency, familiarization, and communication of all three commercial incentive programs, calculation and review of energy-saving projects, exposure to program marketing and planning activities, and administrative work related to the Custom Efficiency program. Another internship will be offered in summer 2013 and will involve activities similar to the 2012 internship. These internships are important mechanisms that help drive work-force development in the energy efficiency profession.

Early in 2012, the Custom Efficiency staff noticed that program energy savings were trending downward with respect to the prior few years. Several utilities in the region started to implement behavioral, strategic energy management, maintenance-related, energy coaching, resource conservation manager, and other non capital-intensive programs. Thus, Custom Efficiency engineers investigated the potential of bringing some of these offerings to Idaho Power as part of the Custom Efficiency program offerings. Three separate offerings were developed in 2012 and have been budgeted for in 2013. These include 1) Refrigeration Operator Coaching for Energy Efficiency (ROCEE), 2) Small Industrial or Custom Efficiency Express, and 3) Strategic Energy Management (SEM).

## Cost-Effectiveness

All projects submitted through the Custom Efficiency program must meet cost-effectiveness requirements, which include TRC, UC, and PCT tests from a project perspective. The program requires all costs related to the energy efficiency implementation and energy-savings calculations are gathered and submitted with the program application. Payback is calculated with and without incentives, along with the estimated dollar savings for installing energy efficiency measures. As the project progresses, any changes to the project are used to recalculate energy savings and incentives before the incentives are paid to the participant. To aid in gathering or verifying the data required to conduct cost-effectiveness and energy-savings calculations, third-party engineering firms are sometimes used via a scoping audit, detailed audit, or engineering measurement, and verification services available under the Custom Efficiency program. Details for cost-effectiveness are in *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Each project in the Custom Efficiency program is thoroughly reviewed to ensure energy savings are achieved. Idaho Power engineering staff or a third-party consultant calculates the energy savings. Through the verification process, end-use measure information, project photographs, and project costs are collected.

On many projects, and especially larger and more complex projects, Idaho Power or a third-party consultant conducts on-site power monitoring and data collection before and after project implementation. The measurement and verification process helps ensure the achievement of projected energy savings. Verifying applicants' information confirms that demand reduction and energy savings are obtained and are within program guidelines. If changes in scope take place in a project, a recalculation of energy savings and incentive amounts occurs based on the actual installed equipment and performance. The measurement and verification reports provided to Idaho Power include a verification of energy savings, costs, estimates of measure life, and any final recommendations to ensure the persistence of savings.

Because the customers who participate in the Custom Efficiency program are some of Idaho Power's largest customers, program managers or major customer representatives solicit customer satisfaction feedback for the Custom Efficiency program. This is authenticated in customers' willingness to participate in the Custom Efficiency program posting the customers' *Success Stories* on the Idaho Power website. In 2012, six new *Success Stories* describing 2012 projects were posted on the company's website. An example of a *Success Story* posted in 2012, titled *Idaho Power incentives help Ballard Dairy and Cheese bring the kids back to their family operation*, refers to a project Ballard Dairy and Cheese completed early in 2012. Idaho Power provided $28,604 in incentives for energy efficiency upgrades that reduced costs and is expected to save over $12,000 in annual utility bills. The owner said, "We had help from the Small Business Administration and the USDA, too, but we really couldn't have done it without Idaho Power's assistance." Copies of the 2012 *Success Stories* are provided in *Supplement 2: Evaluation*.

## 2013 Strategies

Both the Custom Efficiency and Easy Upgrades programs offer lighting incentives to commercial and industrial customers. In 2013, Idaho Power will continue to make program changes to lighting projects within both Custom Efficiency and Easy Upgrades to be as consistent with each program as possible. Better alignment of the incentives between the two programs will lessen program confusion and potentially increase participant satisfaction. One significant change occurring to lighting projects in 2013 will be the addition of allowing incentives for existing T-8 lighting to more efficient technology, T-8 to LED case lighting, and T-8/T-5HO to reduced wattage T-8/T-5HO.

Early in 2013, detailed audits will go from a 50 percent reimbursement or $10,000, whichever is less, to a 75 percent reimbursement or $12,500, while scoping audits will be revised to have a $3,500 maximum, up from $3,000 in 2012.

In 2013, Idaho Power will conduct customer satisfaction research on the Custom Efficiency program. The actual methodology for the research is under review. Research will be conducted late in the year.

Custom Efficiency plans to launch three new program offerings in 2013 aimed at expanding support for customers implementing energy efficiency within their facilities. The first program, tentatively titled Small Industrial or Custom Efficiency Express, is planned for launch in the third quarter of 2013. It is designed to address the smaller compressed air, pump and fan VFDs (other than HVAC and irrigation), cold storage doors, and small refrigeration projects that do not justify the study costs associated with a typical large and/or complex custom project. The program offering will be administrated by Cascade Energy Engineering and will leverage vendor relationships, incorporate simplified analysis tools, and streamline the incentive process. This offering has not officially been named yet. The second Custom Efficiency program offering anticipated for launch in March 2013 is the ROCEE. This offering will provide highly relevant hands-on energy efficiency training to key individuals whose actions have a

direct bearing on the energy performance of energy-intensive systems. Using services provided by NEEA and Cascade Energy Engineering, this offering will engage 6 to 10 large customer facilities to reduce energy associated with their refrigeration systems. The third program offering under development, SEM, will provide training and incentives to program-offering participants focused on low-cost or no-cost measures that may be more behavioral or operations and maintenance-related. Due to concerns with the persistence of savings and/or measure life, these types of projects have historically not been eligible for incentives. However, with a new SEM program offering, these concerns can be addressed appropriately, leading to an increased energy savings potential within the program. The Small Industrial, ROCEE, and SEM program offerings were described to EEAG at the November 6 meeting, resulting in favorable comments from EEAG members.

In 2013, Idaho Power plans to continue expanding the Custom Efficiency program through a number of activities and through continued development of strategic partnerships. These activities will include direct marketing of the Custom Efficiency program by Idaho Power major CRs to further educate customers on Idaho Power energy efficiency programs, identify potential ways the customer can reduce energy costs, and drive program participation. Idaho Power will continue to provide site visits and energy audits for project identification; technical training for customers; funding for detailed energy audits for larger, complex projects; and delivery of NEEA-sponsored energy improvement practices to customers. Additionally, program staff will continue to engage and support the Center for Advanced Energy Studies (CAES), the IDL, and the Industrial Assessment Center.

Each year, the company designs and pays for a "Top 10" advertisement that appears in the *Idaho Business Review*. This advertisement publicly congratulates companies that had the most energy savings throughout the year. *Success Stories* will continue to be written and produced throughout 2013. These stories focus on businesses that took advantage of Idaho Power's Custom Efficiency program and the resulting benefits. *Success Stories* are posted on Idaho Power's website as PDFs so the highlighted businesses can print and use them to publicize their energy-efficient projects. In addition to these success stories, Idaho Power assists with public-relations opportunities, creating certificates for display within the building and having an Idaho Power representative speak at press events.

# Easy Upgrades

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 1,838 | 1,732 |
| Energy Savings (kWh) | 41,568,672 | 38,723,073 |
| Demand Reduction (MW) | 4.7 | 4.4 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $5,150,422 | $4,598,019 |
| Oregon Energy Efficiency Rider | $199,331 | $121,447 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $5,349,753 | $4,719,466 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.012 | $0.011 |
| Total Resource Benefit/Cost Ratio | $0.020 | $0.022 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 7.57 | |
| Total Resource Benefit/Cost Ratio | 3.29 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2007 | |

## *Description*

The Easy Upgrades program encourages commercial and industrial customers in Idaho and Oregon to implement energy efficiency retrofits by offering customer incentives. Eligible measures cover a variety of energy-saving opportunities in lighting, HVAC, building shells, VFDs, plug loads, and food-service equipment. Easy Upgrades is one of the company's largest programs. A complete list of the measures offered through the Easy Upgrades program is included in *Supplement 1: Cost-Effectiveness*.

Idaho Power commercial and industrial customers taking service under Rate Schedule 7 (Small General Service), Rate Schedule 9 (Large General Service), Rate Schedule 19 (Large Power Service), and special-contract customers are eligible. For projects with expected incentive payments of more than $1,000 or that contain VFDs or non-standard lighting measures, applicants must submit a pre-approval application prior to initiating the project. In those cases, the customer or contractor completes the pre-approval application and submits it with the required documentation. For projects not requiring pre-approval, customers may elect to skip the pre-approval application process and submit their payment application and accompanying documentation. Under the Easy Upgrades program, customers may assign their incentive payment to a third party (e.g., their contractor or supplier), as approved by Idaho Power.

## *2012 Activities*

Easy Upgrades experienced strong program participation in 2012. The number of completed projects increased by 6 percent over 2011, and energy savings increased by 7 percent.

Several process-improvement activities were implemented in 2012. A written program procedures manual was developed, a non-lighting verification protocol was put in place, and work was undertaken to expand program reporting capability. To provide quicker project turnaround, and in anticipation of an increase in project applications submitted to the program, Idaho Power hired an additional contract employee to assist with application processing. Trade allies experienced and appreciated the improved turnaround.

The program conducted eight lighting trade ally program information workshops across the Idaho Power service area. In addition, three technical lighting classes were offered to trade allies and two lighting classes were given for Idaho Power CRs. Two of the three technical classes qualified for continuing education credits for eligible, licensed trade allies. For the first time, the program held technical and program information classes in McCall. The program was well received, resulting in increased project submissions from that area. A total of 362 people received lighting information/education from the Easy Upgrades program in 2012.

In addition to the formal training classes held, program staff and Idaho Power CRs visited trade allies in the field, at the trade ally's business, or at a customer location to further educate them on program criteria and to respond to their inquiries.

Significant field time was spent visiting lighting trade allies throughout the Idaho Power service area. The program experienced a lull in application submissions mid-year, and trade ally outreach was used to help ameliorate that issue. Over 75 visits were made for the purposes of strengthening relationships; encouraging program participation; increasing knowledge of the Easy Upgrades program; receiving trade ally feedback about the market, the program, and their experiences; and learning how the program can better support trade allies (including where to focus training efforts in the future). Visits targeted electrical supply businesses and electrical contractors who were fairly new to the Easy Upgrades program. The upswing in project submissions post trade ally visits was noticeable.

An Easy Upgrades program specialist participated as a member of the NEEA Northwest Regional Strategy for Commercial Lighting Energy Efficiency development group. This group formed through collaboration with stakeholders to identify opportunities and strategic needs to support the region's success in commercial lighting. This strategic report will be finalized and presented to the NEEA Regional Portfolio Advisory Committee (RPAC) in January 2013. Implementation of the approved regional strategy is proposed to begin shortly thereafter.

Idaho Power continued to contract with Evergreen Consulting Group, LLC to provide ongoing lighting specialist expertise, project support, and trade ally training. Two lighting specialists provided support in trade ally outreach, as well as trade ally training. Idaho Power contracted with Honeywell, Inc., to perform non-lighting project reviews and pre- and post-project inspections.

To ensure projects participating in the program met program specifications and to verify conditions in the field were as stated on the program application, the Easy Upgrades program conducted pre- and post-inspections on numerous projects throughout 2012. The majority of inspections performed (1,030) were for lighting projects and consisted of 453 pre-inspections and 577 post-inspections. Seventy-three non-lighting projects received inspections, of which 19 were pre-inspections and 54 were post-inspections.

Program site inspections resulted in a variety of findings. The field conditions proved an exact match to the information on the application in many instances. For projects where discrepancies were found, incentive payments were adjusted to reflect actual field conditions, anywhere from lowering or

increasing the incentive amount to denying the project incentive altogether. Examples of lighting discrepancies included fixture count and fixture type differences. Examples of non-lighting inspections not matching the project applications included facility square-footage differences; projects not meeting program criteria, such as insulating an unconditioned space; and projects that applied for one measure, but the actual project pertains to a different measure. Program management used inspection findings to identify areas for program improvement and modification and for trade ally training opportunities.

In addition to verifying that the information provided on the incentive application matched conditions in the field, the inspections provided an opportunity for Easy Upgrades to receive feedback from customers and trade allies about their projects and the program. Customers shared how their energy-efficient upgrade benefited their business. They also appreciated the inspections and viewed them as value added. In many cases, inspections resulted in identifying additional retrofit opportunity that resulted in increased energy savings for customers and Idaho Power. A frequent comment heard from trade allies was that knowing Idaho Power had inspectors verifying projects randomly in the field increased the accuracy of project information submitted to the program.

To advance energy savings and quality lighting design, Idaho Power was one of four utilities that participated with NEEA in the regional Comprehensive Lighting Pilot. The pilot concluded in the second quarter of 2012. The purpose of the pilot was to provide valuable information regarding the program design, level of incentives, and program support needed to achieve success in securing projects with increased energy savings using a comprehensive approach. Easy Upgrades program staff await NEEA's evaluation report of the pilot expected February 2013.

## Cost-Effectiveness

In 2012, Idaho Power made several small adjustments to the measure offerings in the program. The lighting tool was updated to accept electronic T-12 ballasts. An initial analysis was conducted to see if the lighting measures shown in the tool would remain cost effective with the addition of the electronic T-12 ballasts. While the savings decreased slightly, it was shown to still be cost effective based on the average input watts and hours of operation. The actual savings for each lighting project are calculated based on existing light fixtures, the replacement light fixtures, and hours of operation.

NEMA Premium Efficiency general purpose motors were removed from the program in 2012. The motors are now the federal standard. The VFD measures listed on the Motors and HVAC worksheets were moved to one new worksheet.

In the *Demand-Side Management 2011 Annual Report*, Idaho Power listed several measures it planned to remove, change, or update in 2012. The company anticipated making these changes to the non-lighting measures of the program after the completion of the impact evaluation. However, due to the timing of results from the impact evaluation, the changes to the program have been postponed to 2013. Additionally, Idaho Power is currently working with a contractor to review selected non-lighting measures in the program and to provide updated deemed values to use going forward. Currently, most deemed-savings values for non-lighting measures come from the *Demand-Side Management Potential Study* conducted by Nexant, Inc., in 2009; however, Idaho Power uses data from the RTF for a dozen measures.

As part of a comprehensive review of all deemed measures, the RTF reviewed and updated the savings for commercial ENERGY STAR® refrigerators and freezers in October 2012. Because of the change in federal efficiency standards and the very high level of ENERGY STAR market penetration, the baseline changed and the savings decreased causing the measures to no longer be cost-effective. Five incentives

for solid or glass door ENERGY STAR refrigerators and freezers of varying sizes were paid an Easy Upgrades program incentive in 2012. Idaho Power will review the measure in 2013 and determined what changes needed to be made. The remaining RTF measures have either not been updated or have not changed significantly to impact cost-effectiveness.

For current, detailed cost-effectiveness assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

An example of a satisfied customer is indicated in a *Success Story* posted on Idaho Power's website in 2012, *Upgrading its lighting gives Dominick's Quick Print whiter whites, brighter colors, and more cheerful employees*. This story describes how Joe Dominick, owner/manager/president of Dominick's Quick Print in Ontario, Oregon (and mayor of Ontario), was considering a lighting upgrade for his print shop. His electrician told him about the Idaho Power Easy Upgrades incentive program to help ease his worries about potential expenses. "I gulped when he first told me the cost," Joe said, "but when he told me that Idaho Power's incentive program could cut the cost by 65 percent, that got my attention. That made the project possible." Through Idaho Power's Easy Upgrades program, this small business owner changed out all 41 of his T-12 light fixtures to efficient T-8 fixtures, resulting in an estimated 7,586 kWh savings per year. A copy of this *Success Story* is provided in *Supplement 2: Evaluation*.

Idaho Power contracted with ADM to conduct an impact evaluation of 2011 savings results. This evaluation showed that lighting projects, which represented approximately 57 percent of 2011 savings, had a realization rate of 101 percent, while non-lighting projects had a realization rate of 33 percent. The overall realization rate was 72 percent as compared to ex-ante estimates.

The performance of VFD and HVAC controls (specifically programmable thermostat measures), accounted for approximately 80 percent of the reduction in ex-post savings due to the high volatility in savings potential and difficulty in estimating measure savings using deemed estimates.

ADM recommends the use of a partially deemed approach using a stipulated formula with site-specific inputs along with tables of deemed inputs to reduce the variance in realized savings for all VFD measure savings estimates. In addition, they recommend increasing the volume of projects receiving a detailed review of the project scope and measure applicability for both VFD and HVAC controls. A copy of the complete report is included in *Supplement 2: Evaluation*.

## 2013 Strategies

Several measure changes will be implemented in 2013. The program expects to offer incentives for qualifying T-8 lamps to reduced wattage T-8 lamps, T-5 High Output (T-5HO) lamps to reduced-wattage T-5HO lamps, screw-in metal halide lamps, and T-8 to LED refrigeration/case lighting. Incentives for permanent fixture decommissioning will also be offered as a way to encourage proper lighting design.

The program expected to undertake an evaluation of the non-lighting measures in 2012 similar to the extensive review of lighting measures conducted in 2011. However, with the program impact evaluation slated for mid-year 2012, Idaho Power postponed the non-lighting measure review until after receipt of the impact evaluation to incorporate its findings. Based on the results of the impact evaluation, the following recommendations were provided:

- Use custom calculations for large projects involving VFDs or for projects involving VFDs in process applications.
- Perform a thorough review of the project scope and affected equipment. This recommendation has particular applicability to the energy-management system controls and economizer measures.
- Consider applying interactive factors to lighting savings.
- Consider adopting a concurrent evaluation paradigm.

A review of these recommendations and a plan of action (or reason for no action) are targeted for completion in the first quarter of 2013.

Increased trade ally and customer training will be a focus for the program in 2013. Lighting 101 and lighting controls classes, both with continuing education credits, will be offered throughout the company service area. These classes will be offered in Salmon, a first for that area. Additionally, Easy Upgrades will secure American Institute of Architects CEUs and promote the lighting classes to the design community.

The program will expand beyond its lighting classes and offer technical training for trade allies and customers with in-house technical staff in the areas of VFDs and HVAC/controls.

Due to the success of the focused trade ally visits in 2012 and because the majority of customers participating in the program first learned about the program from trade allies, Easy Upgrades will continue to invest time and effort in trade ally visits across the Idaho Power service area. The purposes for these trade ally visits is noted in the previous 2012 Activities section.

Marketing outreach efforts targeted at small to medium customers will increase in 2013 to better inform/educate customers of the Easy Upgrades program and the various incentives offered. This marketing outreach will include a variety of strategies: direct-mail letters, articles in the company monthly customer newsletter, internet banner advertisements, articles and advertorials in local papers and/or local chamber of commerce newsletters, biannual commercial newsletters, and other tactics as identified throughout the year.

Results from the NEEA Northwest Regional Strategy for Commercial Lighting Energy Efficiency group will be evaluated, and Idaho Power will participate in the various aspects of the strategy it determines to be applicable to Idaho Power's market, program strategy, and goals.

Results from the NEEA Comprehensive Lighting Pilot evaluation will be reviewed, and opportunities for program implementation will be evaluated.

Idaho Power participated in regional discussions regarding the Standards for General Service Fluorescent Lamps protocol that became effective July 14, 2012. Due to the extensive T-12 lamp inventory and manufacturers continuing to produce T-12 lamps that meet the exception clause of the new ruling, Idaho Power will continue offering T-12 to T-8 incentives throughout 2013. Idaho Power discussed this at the July 19, 2012, EEAG meeting. Members were unanimously supportive of continuing to offer incentives for T-12 retrofit projects.

Idaho Power is aware of the RTF Lighting Protocols being drafted and will monitor these protocol outcomes to determine their applicability to the Easy Upgrades program.

In 2013, Idaho Power plans to contract with a third-party consultant to evaluate existing and new measures for the program.

# FlexPeak Management

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (sites) | 102 | 111 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | 52.8 | 58.8 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $98,973 | $1,954,850 |
| Oregon Energy Efficiency Rider | $150,489 | $102,880 |
| Idaho Power Funds | $2,760,360 | $0 |
| Total Program Costs—All Sources | $3,009,822 | $2,057,730 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Benefit/Cost Ratio | n/a | n/a |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.22 | |
| Total Resource Benefit/Cost Ratio | 1.22 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2009 | |

## *Description*

FlexPeak Management is a voluntary demand response program available in Idaho and Oregon service areas designed for Idaho Power's industrial and large commercial customers capable of reducing their electrical energy loads for short periods during summer peak days. The program objective is to reduce the demand on Idaho Power's system during peak times through customers' voluntary electrical-use reduction. The program is active June 1 to August 31 between 2:00 p.m. and 8:00 p.m. on non-holiday weekdays. Customers receive notification of a demand-reduction event two hours prior to the start of the event, and events last between two and four hours. Reduction events may be called a maximum of 60 hours per season.

In November 2008, EnerNOC, Inc., was selected through a competitive RFP process to implement the program. Idaho Power entered into a five-year contract with EnerNOC in February 2009. In May 2009, the IPUC approved the contract in Order No. 30805. In June 2010, the program was approved by the OPUC in Order No. 10-206.

EnerNOC is responsible for developing and implementing all marketing plans, securing all participants, installing and maintaining all equipment behind Idaho Power's meter used to reduce demand, tracking participation, and reporting results to Idaho Power. Idaho Power initiates demand response events by notifying EnerNOC, who then supplies the requested load reduction to the Idaho Power system.

EnerNOC meets with prospective customers to identify their potential to reduce electrical energy load during active program hours with minimal impact to their business operations. Customers initially enroll in the program by entering into a contract with EnerNOC. EnerNOC then installs energy-monitoring

equipment at the customer site, simulates a demand response event to ensure customer satisfaction and performance, and officially enrolls the facility in the program.

Each week during the active season, EnerNOC commits a demand-reduction level in MW to Idaho Power that EnerNOC is obligated to meet during a demand-reduction event. EnerNOC is subject to financial penalties for failing to reach the committed MW reduction.

When Idaho Power anticipates the need for capacity, it notifies EnerNOC of the date and time of the event. Idaho Power has access to near real-time energy-usage data and can continuously monitor the success of the demand-reduction event in aggregate. Customers can also continuously monitor their demand-reduction performance using their individual, near real-time energy-usage data through EnerNOC's proprietary software. This metering data and software is available to participating customers throughout the year.

## 2012 Activities

There were no changes to the program in 2012. During the first week of the program, EnerNOC committed to provide a meter-level reduction of 30.5 MW. This weekly commitment, or nomination, was comprised of 99 facility sites, of which 96 participated in the program in 2011 and 3 facility sites were added in 2012. The weekly nomination at the end of the season was 38.8 MW and comprised of 101 facility sites.

EnerNOC was contractually obligated to commit to provide at least 35 MW of reduction for each week in 2012. Their weekly commitments ranged from 29.6 MW to 38.8 MW. Four of the first five weekly commitments were below the 35 MW minimum; therefore, EnerNOC was subject to a penalty for those weeks. The remaining 10 weeks of the season they were above the 35 MW minimum and did not receive a penalty. Their commitment peaked in August at 38.8 MW.

Idaho Power called four demand response events for the FlexPeak Management program in 2012. One event occurred in June, two in July, and one in August. EnerNOC successfully exceeded the committed MW reduction in two of the four events. For the other two events, EnerNOC did not reach their committed MW reduction; performances were 91 percent and 87 percent of the committed levels. The highest hourly reduction achieved was in July at 54.2 MW (47.9 MW at the meter), which exceeded the target reduction of 35 MW for summer 2012.

## Cost-Effectiveness

The B/C analysis for the FlexPeak Management program is based on a 10-year model that uses financial and DSM alternate-cost assumptions from the most recent IRP. As published in the 2011 IRP, for peaking alternatives, such as demand response programs, a 170-MW SCCT is used as an avoided resource cost.

Because the 2013 IRP process has indicated a lack of near-term capacity deficits, on December 21, 2012, Idaho Power filed a proposal with the IPUC to temporarily suspend two of its demand response programs, A/C Cool Credit and Irrigation Peak Rewards, for 2013. A settlement workshop was held in February 2013 with Idaho Power and interested stakeholders to discuss plans for the 2013 cycling season. The settlement workshop led to a stipulation that was filed on February 14, 2013. FlexPeak Management was not included in the original filing due the company's contractual obligation to EnerNOC; however, Idaho Power intends to meet with all stakeholders in workshops to further discuss future changes and identify the best long-term solutions for 2014 and beyond. At the time this

report was written, Idaho Power was negotiating with EnerNOC on potential contract amendments aimed at reducing overall program costs for 2013. Because these negotiations are ongoing, the company conducted the cost-effectiveness analysis using the same cost and benefit assumptions it has in the past and used the 2013 budgeted expenses and forecasted performance, only updating 2012 actual demand reductions and costs.

Because demand response programs are analyzed over their program life, the analysis includes historical program demand reduction and expenses, as well as forecasted program activity. The program is analyzed over a 10-year program life because the 5-year contract with EnerNOC includes an option to extend the contract for another five years.

This analysis is updated annually with actual B/Cs. For the FlexPeak Management program, the benefits are based on measured demand reduction at the participant's meter. The costs include the fees paid to EnerNOC and Idaho Power administration for the program. The 2012 cost-effective analysis demonstrated the FlexPeak Management program has a TRC ratio of 1.22 from a long-term perspective and a TRC ratio of 1.21 for 2012. *Supplement 1: Cost-Effectiveness* contains details on the cost-effectiveness assumptions and data.

## Customer Satisfaction and Evaluations

EnerNOC sent a post-event survey via email after the first event in June 2012 to 195 participants representing all the sites enrolled in the event. Eighteen participants responded, for a 9-percent response rate. When asked how prepared they felt for the demand response event on a scale of 1 to 10, 10 being "fully prepared," the average response was 8.4. When asked how likely they were to recommend EnerNOC to a peer or business partner on a scale of 1 to 10, 10 being "definitely will," the average response was 8.6. When asked how clear the initial notification they received from EnerNOC was on the day of the event on a scale of 1 to 10, 10 being "very clear," the average response was 8. When asked how satisfied they were with how EnerNOC managed the demand response event on a scale of 1 to 10, 10 being "very satisfied," the average response was 8.3.

EnerNOC sent a second post-event survey via email after the August 2012 event to 201 participants, again representing all the sites enrolled in the event. Twenty-one participants responded, for a 10 percent response rate. When asked how prepared they felt for the demand response event on a scale of 1 to 10, 10 being "fully prepared," the average response was again 8.4. When asked how likely they were to recommend EnerNOC to a peer or business partner on a scale of 1 to 10, 10 being "definitely will," the average response was 8. When asked how clear the initial notification they received from EnerNOC was on the day of the event on a scale of 1 to 10, 10 being "very clear," the average response was 8. When asked how satisfied they were with how EnerNOC managed the demand response event on a scale of 1 to 10, 10 being "very satisfied," the average response was 8.1. A summary of the results is in *Supplement 2: Evaluation*. Also included in the supplement is the *FlexPeak Management Annual Report*.

## 2013 Strategies

The 2013 peak season will be the final season of Idaho Power's current contract with EnerNOC. EnerNOC is contractually obligated to commit to provide at least 35 MW of reduction for each week of the active season in 2013. EnerNOC plans to conduct a post-season customer satisfaction survey for the 2012 season during the first quarter of 2013. The results will be made available to Idaho Power. Idaho Power will continue to evaluate the best use of the program to meet the program objectives,

maximize the benefit to Idaho Power's system, and refine internal criteria to call demand-reduction events.

In 2013, Idaho Power plans to conduct a third-party process evaluation of the FlexPeak Management program and produce an internal report, including 2013 activities, demand reduction, and a cost-effectiveness analysis summary.

# Oregon Commercial Audits

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (audits) | 14 | 12 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $0 | $0 |
| Oregon Energy Efficiency Rider | $12,470 | $13,597 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $12,470 | $13,597 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Benefit/Cost Ratio | n/a | n/a |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | |
| Total Resource Benefit/Cost Ratio | n/a | |
| **Program Characteristics** | | |
| Program Jurisdiction | Oregon | |
| Program Inception | 1983 | |

## *Description*

The Oregon Commercial Audits program identifies opportunities for commercial building owners to achieve energy savings. This is a statutory program offered under Oregon Rate Schedule No. 82. Through this program, free energy audits provide evaluations and educational services to customers. Annual mailings to each customer in the commercial sector communicate program benefits and offerings.

## *2012 Activities*

Idaho Power sent out its annual mailing to approximately 3,400 Oregon commercial customers in August 2012. Customers were notified of the availability of no-cost energy audits and were provided with the Idaho Power publication *Saving Energy Dollars*. Fourteen customers requested an audit, with five audits completed by Idaho Power and nine completed by a third-party contractor.

Idaho Power contracts with EnerTech Services to perform the third-party portion of requested audits. Energy audits include a review of the customers past billing data and an inspection of the building shell, HVAC equipment, operating schedules if available, and lighting systems. Additionally, specific business operating practices that can be incorporated to improve energy use are discussed. During the audits, customers receive Idaho Power energy efficiency program information.

## *Cost-Effectiveness*

As previously stated, the Oregon Commercial Audits program is a statutory program offered under Oregon Schedule 82. Since the required parameters of the Commercial Energy Audit Program are

specified in Oregon Schedule 82 and the company abides by these specifications, this program is deemed to be cost effective. Idaho Power claims no energy savings from this program.

## Customer Satisfaction and Evaluations

The value of an audit is the identification of actual savings opportunities in the customer's facility. Audits provide the opportunity to discuss utility incentives available to customers who install qualifying energy efficiency measures. Both activities can lead to energy efficiency projects being undertaken. Customers are generally pleased with the audit process. This is especially true when the business owner is fully engaged in the audit. Business owners can make the decisions to change operating practices or make capital improvements designed to use energy wisely. Additionally, the audits help identify energy-saving opportunities that may not be obvious to the business owner.

## 2013 Strategies

The Oregon Commercial Audits program will continue to be an important avenue for Idaho Power to help customers identify energy-saving opportunities. The audits help pinpoint favorable energy-saving actions that customers may pursue through customer behavioral changes or potential capital projects, such as replacing inefficient lighting. Additionally, the audit process will be used to introduce customers to Idaho Power's energy efficiency incentive programs. The program will be marketed through the annual customer notification.

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# IRRIGATION SECTOR OVERVIEW

## Description

The irrigation sector is composed of agricultural customers operating water pumping or water delivery systems to irrigate agricultural crops or pasturage. The end-use equipment primarily consists of agricultural irrigation pumps and center pivots. This customer group does not include water pumping for non-agricultural purposes, such as the irrigation of lawns, parks, cemeteries, golf courses, or domestic water supply.

In December 2012, the active and inactive irrigation service locations totaled 19,045 system-wide. This was an increase of 1 percent compared to 2011, primarily due to the addition of service locations for pumps and pivots to convert land previously furrow-irrigated to sprinkler irrigation systems. Irrigation customers accounted for 2,048,435 MWh of energy usage in 2012, which was up from 2011 by 22.4 percent due to the hotter, dryer summer. This sector represented 14.5 percent of Idaho Power's total electricity usage and about 25 percent of peak demand in the summer. Energy usage for this sector has not grown significantly in many years; however, there is substantial yearly variation in usage due primarily to the impact of weather on customer irrigation needs.

Idaho Power offers two programs to the irrigation sector: 1) Irrigation Peak Rewards, a demand response program designed to provide a system peak resource, and 2) Irrigation Efficiency Rewards, an energy efficiency program designed to encourage the replacement or improvement of inefficient systems and components. Idaho Power also pays incentives to customers participating in the Green Rewind offering in which motor service centers are paid $2 per hp for each NEMA Standard hp-rated motor between 25 hp and 5,000 hp for agricultural uses that receives a verified Green Rewind. Participation in Green Rewind ensures the motor's original efficiency is maintained if it is rewound at an approved service center.

The Irrigation Peak Rewards program had 340 MW of available demand-reduction capacity for summer 2012, an increase of almost 20 MW, or a 6.2-percent increase over 2011 summer's program capacity. For the 2012 season, 2,433 service points were enrolled, compared to 2,342 in 2011, representing a 3.9-percent increase.

The Irrigation Efficiency Rewards program, in operation since 2003, saw its annual savings decrease by 1,363 MWh to 12,617 MWh compared to 2011 reported savings. The savings decrease in 2012 was primarily due to fewer larger projects being done in 2012. During 2012, irrigation customers contributed 30,039 kWh per year of energy savings from 23 motors participating in Green Rewind.

Table 10 summarizes the overall expenses and program performance for both the energy efficiency and demand response programs provided to irrigation customers.

# Programs

Table 10. 2012 irrigation program summary

| Program | Participants | Total Cost | | Savings | |
|---|---|---|---|---|---|
| | | Utility | Resource | Annual Energy (kWh) | Peak Demand (MW) |
| **Demand Response** | | | | | |
| Irrigation Peak Rewards | 2,433 service points | $12,423,364 | $12,423,364 | n/a | 339.9 |
| **Total** | | **$12,423,364** | **$12,423,364** | **n/a** | **339.9** |
| **Energy Efficiency** | | | | | |
| Irrigation Efficiency Rewards | 908 projects | $ 2,373,201 | $11,598,185[a] | 12,617,164 | 3.1 |
| **Total** | | **$ 2,373,201** | **$11,598,185** | **12,617,164** | **3.1** |

[a] See Appendix 3 for notes on methodology and column definitions.

Each year, the company conducts a customer relationship survey. Overall, 54 percent of Idaho Power irrigation customers surveyed in 2012 for the Burke Customer Relationship survey indicated Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Fifty-five percent of survey respondents indicated Idaho Power is meeting or exceeding their needs with information on how to save energy or reduce their bill. Sixty-six percent of respondents indicated Idaho Power is meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 29 percent of the irrigation survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of irrigation survey respondents who have participated in at least one Idaho Power energy efficiency program, 88 percent are “very” or “somewhat” satisfied with the program.

# Irrigation Efficiency Rewards

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 908 | 880 |
| Energy Savings (kWh)[a] | 12,617,164 | 13,979,833 |
| Demand Reduction (MW) | 3.1 | 3.8 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,978,729 | $2,153,613 |
| Oregon Energy Efficiency Rider | $360,689 | $176,619 |
| Idaho Power Funds | $33,782 | $30,072 |
| Total Program Costs—All Sources | $2,373,201 | $2,360,304 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.022 | $0.020 |
| Total Resource Benefit/Cost Ratio | $0.110 | $0.113 |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 4.66 | |
| Total Resource Benefit/Cost Ratio | 1.76 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

[a] Includes kWh savings from Green Rewind.

## *Description*

The Irrigation Efficiency Rewards program encourages energy-efficient equipment use and design in irrigation systems. Qualified irrigators in Idaho Power's Idaho and Oregon service area can receive financial incentives and reduce their electricity usage. Incentives for the Irrigation Efficiency Rewards program help customers recover a portion of the costs of installing a new, more efficient irrigation system and energy-efficient improvements to existing systems.

Two options help meet the needs for major or minor changes on new or existing systems. The Custom Incentive Option addresses extensive retrofits of existing systems or new irrigation systems, providing component upgrades and large-scale improvements. For new systems, the incentive is 25 cents per the first year of kWh saved above standard installation methods, not to exceed 10 percent of the total project cost. For existing system upgrades, the incentive is 25 cents per the first year of kWh saved, or $450 per kW demand reduction, whichever is greater, but not to exceed 75 percent of the total project cost. The qualifying energy efficiency measures include any hardware changes that result in a reduction of the potential kWh usage of an irrigation system.

Idaho Power reviews, analyzes, and makes recommendations on each application. On each completed project, before final payment, all project information is reviewed. Prior usage history, actual invoices, and, in most situations, post-usage demand data are available to verify savings and incentives.

The Menu Incentive Option covers a significant portion of the costs of repairing and replacing specific components that help the irrigation system use less energy. This option is designed for systems in which

small maintenance upgrades provide energy savings from 11 separate measures. These measures include the following:

- New flow-control nozzles
- Replacement of worn brass or plastic nozzles
- Rebuilt or new impact sprinklers
- Rebuild kits for wheel-line levelers
- New low-pressure or rotating-type sprinklers
- New low-pressure regulators
- New drains, riser caps, and gaskets
- New wheel line hubs
- New pivot gooseneck and drop tube
- Leaky pipe repair
- New center pivot base boot gasket

Payments are calculated on predetermined average kWh savings per component.

Participation in Green Rewind is an opportunity that enables customers to maintain the motor's original efficiency and ensures an efficient use of electricity to run the motor. Motor service centers are paid $2 per hp for each NEMA Standard hp-rated motor between 25 and 5,000 hp that receives a verified Green Rewind. The RTF approved the Green Motors Practices rewinding as an energy efficiency measure and approved a table of deemed savings for industrial and agricultural applications.

In addition to incentives, the program offers customer education, training, and irrigation-system assessments. Idaho Power agricultural representatives sponsor, coordinate, conduct, and present educational workshops for irrigation customers, providing expert information and training across Idaho Power's service area. Energy audits conducted by Idaho Power agricultural representatives evaluate prospective customers' potential savings. Agricultural representatives from Idaho Power also engage agricultural irrigation equipment dealers in training sessions, increasing their awareness of the program and promoting it through the irrigation equipment distribution channels. Marketing efforts include direct mailings, advertisements in agricultural publications, and participation in agricultural workshops and conferences. Idaho Power's agricultural representatives are funded approximately 30 percent by the Idaho and Oregon Riders and 70 percent from base rates.

## 2012 Activities

Of the 908 irrigation efficiency projects completed in 2012, 790 were associated with the Menu Incentive Option, providing an estimated 7,015 MWh of energy savings and 1.37 MW of demand reduction. The Custom Incentive Option had 118 projects, of which 65 were new irrigation systems and 53 were on existing systems. This option provided 5,572 MWh of energy savings and 1.7 MW of

demand reduction for the year. Also during 2012, irrigation customers contributed 30,039 kWh of energy savings from 23 motors participating in the Green Rewind opportunity.

In June 2012, with approval from the EEAG and OPUC (Tariff Advice No. 12-09), Idaho Power changed the Menu Incentive Option for new or rebuilt wheel-line levelers to only rebuilt wheel-line levelers or rebuild kits. This change came about because the cost of a new wheel-line leveler made this measure not cost effective.

Idaho Power agricultural representatives, the program specialist, and the agricultural engineer participated in training that maintains their Certified Irrigation Designer (CID) and Certified Agricultural Irrigation Specialist (CAIS) certifications. This training allows Idaho Power to maintain its high level of expertise in the irrigation industry and is sponsored by the nationally based Irrigation Association.

Idaho Power continued to market the program by varying the location of workshops and offering new presentations to irrigation customers. In 2012, Idaho Power provided six workshops promoting the Irrigation Efficiency Rewards program throughout the service area. Approximately 260 customers attended workshops in Blackfoot, Burley, Twin Falls, Grand View, and Nampa. Idaho Power also accepted invitations to present the program at three workshops sponsored by agricultural groups in Idaho Falls, Gooding, and Nampa. Exhibitor booths were displayed at regional agricultural trade shows, including the Eastern and Western Idaho Agriculture Expos, the Agri-Action Ag show, the Treasure Valley Irrigation Conference, and the Idaho Irrigation Equipment Association show and conference.

## Cost-Effectiveness

Each application under the Custom Incentive Option received by Idaho Power undergoes an assessment to estimate the energy savings that will be achieved through a customer's participation in the program. To estimate the effectiveness of a project, Idaho Power uses a service point's previous five years of electricity usage history and, based on the specific equipment to be installed, calculates the estimated post-installation energy consumption of the system. The company also verifies the completion of the system design through aerial photographs, maps, and field visits by Idaho Power agricultural representatives to ensure the irrigation system is used in the manner the documentation describes.

Each application under the Menu Incentive Option received by Idaho Power also undergoes an assessment to ensure savings are achieved. Payments are calculated on predetermined average kWh savings per measure. In some cases, the energy savings estimated in the Menu Incentive Option are adjusted downward to reflect how the components are actually being used. No changes occurred to the assumptions that drive the cost-effectiveness of the measures that are part of this program.

All cost-effective analyses were based on the savings approved by the RTF in January 2010. The measures were reviewed for compliance with the new RTF savings guidelines in 2011 and were determined to be out of compliance. In 2012, the RTF approved of a plan to bring the measure back into compliance with the guidelines. Idaho Power will meet with the RTF in early 2013 to evaluate the research done by the University of Idaho to study the savings impacts of the measures provided in the Menu Incentive Option.

Based on the available deemed savings from the RTF, nearly all the measures offered under the Menu Incentive Option are cost effective. The rebuilt and new wheel-line levelers were shown not to be cost effective in 2010. After reviewing the measure, it was determined that the cost of the new

wheel-line levelers was negatively impacting the cost-effectiveness of the measure. In 2012, the measure was modified to include only rebuilt wheel-line levelers in the program's offerings.

For details on the cost-effectiveness assumptions for the Menu Incentive Option, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

At the February 2012 EEAG meeting, Idaho Power discussed the plan of partnering with the University of Idaho to research the Menu Incentive Option measures of the Irrigation Efficiency Rewards program to gather more information about menu measures. A sub-committee of the RTF will review the research and present aspects of the study to the RTF in 2013.

In 2012, Idaho Power contracted with the University of Idaho to conduct research regarding the Irrigation Efficiency Rewards program Menu Incentive Option. This research evaluated energy savings associated with the repairing of leaks and worn components listed in the Menu Incentive Option. The final report is included in *Supplement 2: Evaluation*.

## 2013 Strategies

Marketing plans for 2013 include conducting 7 to 10 customer-based irrigation workshops. Additionally, Idaho Power program specialists, agriculture representatives, and an agriculture engineer will attend five regional trade shows. These workshops and trade shows enable discussions between Idaho Power representatives, the company's customers, irrigation dealers, and trade allies while continually educating them about irrigation best practices, the program, and ways to participate. Each year, workshops are conducted in different local areas. Subjects and presentations are updated to offer new ideas.

Idaho Power is reviewing the program regarding measures offered in the Menu Incentive Option. The research provided by the University of Idaho will be presented to the RTF in early 2013. The results of this research project will help determine changes to the program in future years and validate energy savings attributed to the replacement of irrigation components offered in the Menu Incentive Option.

A 2013 media plan has been created aimed at increasing the impact of advertising on this program. In addition, the effectiveness of online advertisements will be evaluated with this target audience. A database of irrigation dealers and vendors is also being developed for direct-mail purposes. Irrigation dealers and vendors are a key component to the successful marketing of the program; therefore, direct mailings containing the most up-to-date program information, brochures, and dealer specific meetings ensure correct program promotion.

# Irrigation Peak Rewards

| | 2012 | 2011 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (service points) | 2,433 | 2,342 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | 339.9 | 320.0 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,309,107 | $11,790,216 |
| Oregon Energy Efficiency Rider | $95,863 | $254,013 |
| Idaho Power Funds | $11,018,394 | $41,993 |
| Total Program Costs—All Sources | $12,423,364 | $12,086,222 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Benefit/Cost Ratio | n/a | n/a |
| **Program Life Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.79 | |
| Total Resource Benefit/Cost Ratio | 1.72 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2004 | |

## *Description*

Idaho Power's Irrigation Peak Rewards program is a voluntary program available to all Idaho and Oregon agricultural irrigation customers. The purpose of the program is to minimize or delay the need to build new supply-side resources. The program pays irrigation customers a financial incentive for the ability to turn off specified irrigation pumps with the use of one or more load control devices during the program season of June 15 through August 15.

In 2012, all Idaho Power irrigation customers taking service under Schedule 24 in both Idaho and Oregon were eligible, and participants chose between three options: 1) the Electric Timer Option, 2) an Automatic Dispatch Option that allows Idaho Power to remotely turn off participants' pumps, or 3) a Manual Dispatch Option designed for large-service locations with 1,000 hp or greater that allows participating customers, after being notified by Idaho Power, to choose which pumps to manually turn off during a load control event.

Participants in the Manual Dispatch Option are required to nominate the amount of kW they are enrolling in the program by June 1 of the program year. Participants in the Electronic Timer Option can choose to have all irrigation pumps on a single, metered service point turned off one, two, or three times per week. Interruptions occur from 4:00 p.m. to 8:00 p.m., and Idaho Power determines the specific weekday or weekdays to schedule the interruption of all pumps at each service point. Installation fees between $250 and $500 are applied to participating service locations less than 75 hp. For customers participating in the dispatch options, load control events could occur up to four hours per day, up to 15 hours per week, but no more than 60 hours per season. For 2012, dispatchable load control events could happen between 1:00 p.m. and 9:00 p.m. on weekdays and Saturday. Customers who choose to

participate until 9:00 p.m. receive a higher variable incentive for events. A control device attached to the customer's individual pump electrical panels allows Idaho Power to remotely control the pumps. Installation fees between $500 and $1,000 were applied to participating service points with less than 50 hp depending on the option customers chose.

The incentive structure includes a fixed and variable incentive payment. A customer's fixed incentive appears as a bill credit that sums the demand credit and energy credit for the interruption option selected and applies to a customer's monthly bills. The variable incentive is a summary of all load control event kWh multiplied by the variable incentive credit paid in the form of a check within 45 days of the end of the program season. Credits are prorated for periods when reading/billing cycles do not align with the program season dates from June 15 to August 15. All customer incentives participating in the Electric Timer Option, Automatic Dispatch Option, or Manual Dispatch Options are calculated using Idaho Power meter billing data. In addition, Manual Dispatch Option customers' incentives are calculated using interval metering data and nominated kW. Installation fees and opt-out penalties are completed through manual bill adjustments. Incentives, determined from interval meter data for service points classified as large-service locations, are completed through a manual process, and customers received the incentives in the form of a check in 2012. The incentives offered are listed in Table 11.

Table 11. Option incentives

| Dispatchable Interruption Option Incentives | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Fixed Incentive Payment | | | | Variable Incentive Payment | | |
| Dispatchable Option | Demand Credit ($/billing kW) | | Energy Credit ($/billing kWh) | | Standard Interruption Variable[a] | | Extended Interruption Variable[b] |
| **Options 1, 2, and 3** | $5.00 | **and** | $0.019 | **plus** | $0.159 | **or** | $0.209 |

[a] Energy Credit: 4 hours between 1–8 p.m. ($/event kWh)
[b] Energy Credit: 4 hours between 1–9 p.m. ($/event kWh)

| Electronic Timer Option Incentives | | | |
|---|---|---|---|
| Option | Demand Credit ($ per billing kW) | | Energy Credit ($ per billing kWh) |
| **Timer Option Incentives** | | | |
| One weekday | $3.15 | | |
| Two weekdays | $4.65 | **plus** | $0.002 |
| Three weekdays | $4.65 | **plus** | $0.007 |

Under the rules of the Automatic and Manual Dispatch Options, participants have the ability to opt out of dispatch events five times per service point. Each opt-out incurs a fee of $1 per kW based on the current month's billing kW, which may be prorated to correspond with the dates of program operation and are completed through manual bill adjustments.

## 2012 Activities

Participation in this program was strong in 2012. Service points increased by 91, a 3.9-percent increase over 2011. Most of the challenges surrounding communication with some dispatch devices that occurred in prior years were resolved. In 2012, the program had the potential to achieve a maximum peak load reduction of approximately 340 MW. This represents a 6-percent increase from 2011, even though the company did not solicit new participants. Of all eligible irrigation service locations, approximately 13 percent participated in the program. In 2012, there were 2,433 metered service points enrolled in the program, with approximately 3.4 percent enrolled in the Electric Timer Option, 95.1 percent enrolled in the Automatic Dispatch Option, and 1.5 percent in the Manual Dispatch Option.

Idaho Power attempted to distribute the Electric Timer Option participating service points evenly throughout each weekday based on cumulative demand-reduction potential. However, due to service-point size variability, enrollment opt-outs, and other variables, the load reduction could not be exactly balanced. All participants in the Automatic and Manual Dispatch Options were grouped into five regional areas to be dispatched on each scheduled event day. Table 12 shows the MW reduction achieved daily on a week-by-week basis.

Table 12. Total program daily MW reduction without distribution losses using realization rates

| Measure | Monday | Tuesday | Wednesday | Thursday | Friday |
|---|---|---|---|---|---|
| June 15 | n/a | n/a | n/a | n/a | 3.1 |
| June 18–22 | 4.2 | 4.0 | 3.9 | 4.2 | 3.3 |
| June 25–29 | 4.2 | 4.0 | 3.9 | 339.9[a] | 3.3 |
| July 2–6 | 4.0 | 3.8 | 3.7 | 3.9 | 3.1 |
| July 9–13 | 4.0 | 3.8 | 3.7 | 320.7[b] | 3.1 |
| July 16–20 | 3.5 | 3.3 | 3.2 | 3.5 | 2.7 |
| July 23–27 | 3.5 | 3.3 | 3.2 | 3.5 | 2.7 |
| July 30–August 3 | 3.2 | 3.1 | 3.0 | 3.2 | 2.5 |
| August 6–10 | 3.2 | 3.1 | 3.0 | 3.2 | 2.5 |
| August 13–15 | 3.2 | 3.1 | 3.0 | n/a | n/a |

[a] The shaded cell reflects the estimated MW load reduction capacity available through the program.
[b] The shaded cell is Idaho Power's peak load day and reflects the estimated MW load reduction capacity available through the program.

Although the load reduction provided by the Irrigation Peak Rewards program was available to Idaho Power throughout the 2012 program season, dispatching the program was unnecessary. This was due to resources being able to meet system peak demands, low energy prices, and lack of system emergencies during the summer. Under the program's variable incentive design, taking into account both the extended interruption incentive and program realization rates, the program had an approximate dispatch price of $240 per MWh, which would total about $300,000 per event if all customers were interrupted for four hours. The program would be used if the company could not meet its peak needs with other resources, if hourly energy prices were greater than the dispatch cost of the program, or to avert a system emergency.

In February 2012, a customer mailing was sent to irrigation customers who participated in the program in 2011. The mailing included a program explanation, a program application, contract agreement, the program's incentive structure, a list of the customer's eligible service points, and an incentive estimate for each program option. Customers that had not participated in the program and did not receive the initial mailing but requested to participate were sent the same information.

Idaho Power did not market the program in 2012 but did provide program information at six workshops throughout the service area. Approximately 260 customers attended workshops in Blackfoot, Burley, Twin Falls, Grand View, and Nampa. The company also accepted invitations to present the program at three workshops sponsored by agricultural groups in Idaho Falls, Gooding, and Nampa. Exhibitor booths, where company representatives were available to answer questions, were displayed at regional agricultural trade shows, including the Eastern and the Western Idaho Agriculture Expos, the Agri-Action Ag show, the Treasure Valley Irrigation Conference, and the Idaho Irrigation Equipment Association show and conference. Additionally, numerous one-on-one conversations with Idaho Power agriculture representatives familiarized customers with the technology and program details.

At the July 2012 EEAG meeting, Idaho Power presented the concept of changing the Irrigation Peak Rewards program to have three or four interruption events included in the fixed portion of the incentive customers receive. This would mean the program would not have to pay the variable incentive for these events. The events would be used primarily for customer awareness of what happens when events are called. It was discussed that without these included events the program could go multiple years without initiating any load control events. EEAG members were generally accepting of the concept.

## Cost-Effectiveness

The B/C analysis for the Irrigation Peak Rewards program is based on a 20-year model that uses financial and DSM alternate-cost assumptions from the most recent IRP. As published in the 2011 IRP, for peaking alternatives, such as demand response programs, a 170-MW SCCT is used as an avoided resource cost.

Because the 2013 IRP process has indicated a lack of near-term capacity deficits, on December 21, 2012, Idaho Power filed a proposal with the IPUC to temporarily suspend two of its demand response programs, A/C Cool Credit and Irrigation Peak Rewards for 2013. A settlement workshop was held in February 2013 with Idaho Power and interested stakeholders to discuss plans for the 2013 cycling season. The stipulation was filed on February 14, 2013. Idaho Power intends to meet with all stakeholders in workshops to further discuss future changes and identify the best long-term solutions for 2014 and beyond.

Demand response programs are analyzed over the program life, this includes historical program demand reduction and expenses, as well as forecasted program activity. Because of the uncertainty of the program costs and because an order in the IPC-E-12-29 case is pending, for this report, the company conducted its cost-effectiveness analysis using the information know prior to the filing to temporarily suspend the Irrigation Peak Rewards program in 2013. The costs and demand capacity for 2012 were included with the forecast demand reduction and costs based on the 2013 budget and expected results. The Irrigation Peak Rewards program had a TRC ratio of 1.72. From a one-year perspective, the Irrigation Peak Rewards program had a TRC ratio of 2.4. See *Supplement 1: Cost-Effectiveness* for details on the cost-effectiveness assumptions and data.

## Customer Satisfaction and Evaluations

Each year, Idaho Power produces an internal annual report for the Irrigation Peak Rewards program. This report includes a load reduction analysis, cost-effectiveness, and program changes. A copy is included in *Supplement 2: Evaluation*.

## 2013 Strategies

As referenced previously, on December 21, 2012, Idaho Power filed Case No. IPC-E-12-29 with the IPUC to temporarily suspend the Irrigation Peak Rewards program for the 2013 season. The 2013 IRP is under development, and the IRP analysis indicates there will not be a need for demand response programs like the Irrigation Peak Rewards program during 2013. The proposed temporary suspension of Irrigation Peak Rewards will allow Idaho Power to work with stakeholders to determine the future course of action for its demand response programs. Idaho Power has proposed to continue to maintain the load control devices currently in place until further direction indicates otherwise.

Idaho Power plans to also file with the OPUC to suspend the program for 2013.

# MARKET TRANSFORMATION

## Northwest Energy Efficiency Alliance

NEEA encourages and supports cost-effective market-transformation efforts in Idaho, Oregon, Washington, and Montana. Through partnerships with local utilities, NEEA motivates the marketplace adoption of energy-saving services and technologies and encourages regional education and marketing platforms. NEEA provides training and marketing resources across residential, commercial, and industrial sectors. Idaho Power accomplishes market transformation in its service area through membership and coordinated activities with NEEA. 2012 was the third year of NEEA's current, five-year plan.

NEEA performs several MPERs on various energy efficiency efforts each year. In addition to the MPERs, NEEA provides market-research reports for energy efficiency initiatives throughout the Pacific Northwest. Each of the reports applicable to Idaho is included in the NEEA Market Effects Evaluations in *Supplement 2: Evaluation*.

In 2012, Idaho Power energy efficiency staff served on NEEA's Board of Directors, attended advisory meetings, served on sub-committees, and participated in NEEA-sponsored studies and research.

### *Commercial and Industrial NEEA Activities in Idaho*

NEEA continued to provide support for commercial energy efficiency activities in Idaho in 2012. This included partial funding of the IDL and local BetterBricks® trainings and workshops. Idaho Power's commercial sector programs Building Efficiency and Easy Upgrades are designed to leverage NEEA, the IDL, and BetterBricks activities.

In the industrial sector, NEEA continued its efforts to embed Continuous Energy Improvement (CEI) in small- to medium-sized businesses defined as less than 250 employees per site. CEI is a multi-year strategic effort designed to improve energy efficiency in the industrial sector. Prior CEI efforts focused on two regional industries considered heavy energy users: 1) the food processing industry and 2) the pulp and paper industry. Participants achieve cost savings through the adoption of energy-efficient business practices. CEI provides expert support, resources, and services, supplying companies with the training and tools for making energy efficiency a core business value. This effort is supported by providing technical knowledge to organizations and to Idaho Power customers collaborating on energy efficiency implementation. NEEA has a demonstration project for the agricultural sector taking place in Idaho. The project will provide information on control systems and variable-rate irrigation to improve overall efficiency.

Technical training and education continue to be important in helping Idaho Power's industrial customers identify where they may have energy efficiency opportunities within their facilities. Nine technical training classes were completed in 2012. Topics included compressed air, chilled water systems and cooling towers, pumping systems, VFDs, industrial refrigeration, data-center efficiency, and energy-management systems. The level of attendance at these classes remains high, with 171 participants attending the workshops.

In the commercial sector, NEEA has been working with utilities and lighting trade allies to develop a comprehensive lighting program. Idaho Power was one of four utilities that participated in the regional Comprehensive Lighting Pilot. The pilot concluded in the second quarter of 2012. NEEA has also been working to secure a pilot project in Idaho for their Existing Building Renewal initiative. This initiative is

aimed at developing and testing new industry tools for commercial property owners engaging in deep energy retrofits.

## Residential NEEA Activities in Idaho

NEEA supported a variety of residential programs and associated activities in Idaho Power's service area in 2012.

Among Idaho Power's programs, NEEA is directly involved in providing additional funding and support for ENERGY STAR® Homes Northwest, the DHP Pilot, the Residential Economizer study, and the Consumer Electronics Energy Forward campaign.

NEEA provides ENERGY STAR Homes Northwest builder and contractor training, manages the regional-homes database, develops regional marketing campaigns, and coordinates the various building specifications and requirements with the EPA and utilities in Idaho, Montana, Oregon, and Washington. Most of these activities are managed through a third-party implementer hired by NEEA.

In June, Idaho Power partnered with NEEA to promote the 2012 St. Jude Dream Home®. The Dream Home was a certified, electrically heated, ENERGY STAR home featuring a state-of-the-art DHP. NEEA secured the donation of the DHP from the manufacturer. An Idaho Power bill insert promoted the ENERGY STAR qualified Dream Home, and NEEA donated an ENERGY STAR flat-screen television to be used as a raffle prize.

NEEA has coordinated the DHP pilot research project since 2009, which includes data collection, design, results analysis, savings calculations, and ongoing promotional activities. The goal of the pilot is to encourage the adoption of these products while displacing the use of existing electric-resistance zonal heating systems in homes. NEEA created and launched a regional marketing program in 2012, conducted from September through December. The goal of the program was to increase consumer awareness of DHPs. The promotion included the use of social media, as well as radio, television, and newspaper advertising. Idaho Power currently offers a $750 cash incentive for qualified homeowners who install a qualified DHP system.

NEEA coordinated a residential Heat Pump Water Heater (HPWH) research project in the Northwest region that started approximately three years ago. A goal of the project is to promote the adoption of higher-efficiency water heaters over units built with only electric-resistance heat. Another goal is to provide a business case to the DOE by April 2016 encouraging the DOE to modify the 2020 federal standards and test methods for domestic electric water heaters. Water heaters built with only electric-resistance heat will not meet the proposed modified standard. The research project includes data collection, design, analysis, savings calculations, and marketing activities. NEEA's promotion offers a $1,000 rebate through June 2013 to residential homeowners who have certain HPWHs installed. The promotion requires the HPWH to be installed by a contractor trained by NEEA. In 2012, NEEA trained 18 contractors in the Idaho Power service area. NEEA also arranged for a HPWH discount program to be offered through Sears, a national appliance retailer, using 30 of their stores in the Northwest. Discounts were made available to homeowners who purchased certain HPWHs. Idaho Power participated in a HPWH summit in Portland in June 2012. The goal of the summit was to increase collaboration and cohesion with all regional utilities and other stakeholders.

In 2012, an Idaho Power residential program specialist participated on the selection committee for the HPWH Model Validation & Process Evaluation. This study strives to provide energy-savings data through the installation of HPWHs and data-logging equipment in residential homes. The committee

scored contractor bids and selected the contractor Evergreen Economics to provide the HPWH Model Validation and Process Evaluation. Evaluation data will be compared to energy-savings data generated by the RTF's computer modeling created specifically for this study.

Idaho Power's partnership with NEEA's Consumer Electronics Energy Forward Campaign continued in 2012. The Energy Forward campaign highlighted the most energy-efficient televisions available. Retailers who represent more than 80 percent of televisions sold in the Northwest partnered with NEEA to promote Energy Forward televisions, including Best Buy, Costco, Kmart, Sam's Club, Sears, and Wal-Mart. Although final 2012 numbers are not yet available, as of late 2012, approximately 37 percent of televisions sold in the region were Energy Forward-qualified.

NEEA developed and launched a number of marketing tactics, including a fall marketing campaign to drive sales of qualifying televisions and engage national retailers in the promotion of these televisions. The campaign was a sweepstakes in which consumers could enter to win one of four "VIP tailgates" at a home game (one in each state of Idaho, Montana, Oregon, and Washington) or a chance to win weekly sub-prizes like Energy Forward televisions. Best Buy, Sears, and ENERGY STAR were campaign sponsors, and NEEA conducted public relations, advertising, social media, and online promotional tactics, including promotional packages with universities.

NEEA also launched a marketing campaign on October 1 with Best Buy, Sears, and ENERGY STAR as campaign sponsors. The primary objectives of the campaign were to increase retailer participation in promoting Energy Forward Most Efficient televisions, increase sales associates' awareness of them, and increase sales associates' ability to communicate qualifying television benefits to consumers leading into Black Friday. Mass consumer outreach via public relations, paid media, social media, community events, and partner outreach enticed retail partners to participate in the campaign and also helped increase consumer awareness and demand leading into the busiest shopping season of the year. NEEA representatives maintained retail partnerships by visiting each store at various times throughout the year, setting up point-of-purchase materials, and educating the sales staff.

Idaho Power has also participated in NEEA's Residential Advisory Committee meetings and activities throughout 2012 and served on the advisory team to contribute to ongoing improvements of Conduit, a regional online community for energy efficiency program managers in the Pacific Northwest. The goal of Conduit is to expedite the delivery and adoption of energy efficiency programs and activities. NEEA launched the website in May 2011. Conduit houses a library, discussion forums, and collaboration space. Similar to Facebook in features and benefits, Conduit is a space for energy efficiency professionals to congregate and share ideas, concerns, and questions. It is open to trade allies, state agencies, regulators, research institutions, and utility professionals. Additionally, two members of the residential programs team attended NEEA's annual conference, Connections Northwest, which provided updates on NEEA-sponsored programs and research, as well as valuable networking opportunities with other utility program managers.

An Idaho Power residential program specialist participated on the Regional Emerging Technologies Advisory Committee (RETAC) during 2012. The committee reviewed and updated the RETAC charter to effectively integrate the charter with other committees such, as the RPAC. Another RETAC committee purpose was to develop a 2013 plan to support the charter and member needs. The 2012 portfolio of emerging technologies under review at NEEA was discussed. Idaho Power and other utilities participating in RETAC reported on the energy efficiency projects the utility companies were interested in or had investigated.

In 2012, an Idaho Power residential program specialist participated on the National Energy Efficiency Technology Road Mapping Summit committee. The purpose of the committee was to revise current technology characteristics and the research and development (R&D) associated with the individual residential and commercial technology roadmaps contained in the Roadmap Portfolio. The Roadmap Portfolio helps guide and prioritize the regional investigation of technologies. The portfolio contains many technologies, along with the specific drivers, capability gaps, characteristics, and R&D programs associated with each technology. Idaho Power participated in revisions to the HVAC technology roadmap. The prioritization of all residential and commercial roadmaps is to be completed by March 2013.

An Idaho Power residential specialist was involved in 2012 with the NWRRC. This collaborative is a forum to evaluate and coordinate regional retail strategy. The first official meeting as a collaborative was held on November 27, 2012, at the Puget Sound Energy office in Olympia, Washington. Activities included a presentation to NEEA's Portfolio Committee, approval and adaption of Charter and Working Agreements, and the development of a scoping process for 20 potential measures identified for review at subsequent meetings.

## Other NEEA Activities in Idaho

Over the last two years, Idaho Power's energy efficiency analysts participated in two committees to collect basic information on building stock and energy use of buildings throughout the Pacific Northwest. The results of the studies help form the future regional planning efforts. In 2011, NEEA moved forward with the RBSA. With the RBSA, customers from households in Washington, Oregon, Idaho, and parts of Montana were selected randomly to participate in a phone survey. A subset of those customers was then selected to participate in an on-site survey and, in some cases, a more in-depth energy review of the home. The *Single-Family Characteristics and Energy Use Report* was released in September 2012. The *Manufactured Home Characteristics and Energy Use Report* was published in January 2013. The multi-family report is expected to be released in 2013. Organizations, such as the RTF, have begun to revise measure saving using updated assumptions from the RBSA.

In addition to the RBSA, NEEA began work on the Commercial Building Stock Assessment (CBSA). An Idaho Power energy efficiency analyst participated in the RFP selection committee and the Sampling Priorities Working Group. Work on the CBSA will continue throughout 2013, with a final report expected in 2014.

Idaho Power is a participant in NEEA's Cost Effectiveness Advisory Committee. This committee meets three to four times a year to review NEEA cost-effectiveness models, assumptions, and, ultimately, energy-savings estimates. Idaho Power also participates in NEEA's Northwest Research Group. This group meets throughout the year to catalogue and coordinate energy efficiency research projects regionally.

## NEEA Funding

In 2012, Idaho Power began the third year of the 2010 to 2014 Regional Energy Efficiency Initiative Agreement with NEEA. Per this agreement, Idaho Power is committed to fund NEEA based on a quarterly estimate of expenses up to the five-year total direct funding amount of $16.5 million in support of NEEA's implementation of market-transformation programs in Idaho Power's service area. Of this amount in 2012, 100 percent was funded through the Idaho and Oregon Riders.

In 2012, Idaho Power paid $3,379,756 to NEEA. The Idaho jurisdictional share of the payments was $3,210,768, while $168,988 was paid for the Oregon jurisdiction. Other expenses associated with NEEA activities, such as administration and travel, were paid by Idaho Power.

For this report, NEEA provides Idaho Power an early estimate of its annual savings for the previous year. In the *Demand-Side Management 2011 Annual Report*, the NEEA savings reported were 16,109 MWh. The revised estimate included in this report for 2011 NEEA savings is 20,547 MWh. Preliminary estimates reported by NEEA for 2012 indicate that Idaho Power's share of regional market-transformation MWh savings for 2012 is 17,741 MWh, or 2 aMW. Idaho Power relies on NEEA to report the energy savings and other benefits of NEEA's regional portfolio of initiatives. For further information about NEEA, visit their website at www.nwalliance.org.

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# OTHER PROGRAMS AND ACTIVITIES

## Residential Energy Efficiency Education Initiative

Idaho Power recognizes the value of general energy efficiency awareness and education in creating behavioral change and customer demand for, and satisfaction with, its programs. The Residential Energy Efficiency Education Initiative's goal is to promote energy efficiency to the residential sector. This goal is achieved by creating and delivering educational materials and programs that increase Idaho Power's energy efficiency program participation and result in wise and informed choices regarding energy use.

The Residential Energy Efficiency Education Initiative continued to lead the production and distribution of the 2012 energy efficiency guides.

The first *Winter Energy Efficiency Guide*, designed specifically around content applicable for homes with electric heat, was distributed to 187,114 customers with their newspapers in January. The *Summer Energy Efficiency Guide* circulation increased to 222,313 due to additional newspaper subscriptions, insertion into the *Boise Weekly* magazine, and an extra 800 copies for hand delivery by Idaho Power representatives to locations, such as senior centers. The *Summer Energy Efficiency Guide*, inserted into newspapers on May 20, focused on ways to save money and make wise use of electricity during the cooling season. To get information out well in advance of the heating season, a third energy efficiency guide was published and distributed on November 11. This guide introduced tools and checklists to assist customers in getting the most savings per dollar invested in energy-related upgrades. It also suggested low and no-cost ways to increase comfort and manage bills while maintaining equipment and planning for future improvements.

During 2012, Idaho Power changed the style of the energy efficiency guides and incorporated a more consistent look and feel, including a catalog identification number to facilitate subsequent in-house printings. These process improvements allowed the company to increase the shelf-life and begin to build a library of flexible resources at a minimal cost. In 2012, 1,405 additional guides were distributed as educational handouts at energy efficiency presentations and events. About 10 percent of customers who requested *30 Simple Things You Can Do To Save Energy* also requested one or more of the energy efficiency guides.

In 2012, Idaho Power continued to build its social-media presence. Compared to this time last year, Facebook fans nearly doubled to just over 3,600, and Idaho Power's Twitter following quadrupled to 800 users. The company continued to leverage both channels to communicate information about Idaho Power energy efficiency programs, incentives, and events. Idaho Power's YouTube channel also saw increased activity; the 45 videos currently posted generated 13,500 views, of which 5,500 came from Idaho Power's educational video on DHPs. Across all channels, content was timed to align with print and broadcast campaigns so as to reinforce the message and heighten customer awareness. Additionally, Idaho Power's Energy Efficiency Program managers responded to 362 web inquiries with detailed written answers.

The Residential Energy Efficiency Education Initiative distributed energy efficiency messages through a variety of other communication methods during 2012. Increased customer awareness of energy-saving ideas was accomplished via continued distribution of the 96-page book *30 Simple Things You Can Do To Save Energy*, a joint publishing project between Idaho Power and The Earthworks Group. During the year, 8,707 English and 1,008 Spanish copies were distributed directly to customers via community events and local libraries; by CRs during in-home visits; by participating contractors in the

Home Improvement Program, Energy House Calls, H&CE Program, Boise Home Audit Project, and See ya later, refrigerator® program; through direct web requests; and in response to inquiries received by Idaho Power's customer service center. Of the books distributed in 2012, 1,106 were mailed directly to customers at their request, including 1,087 sent to customers who contacted Idaho Power's Customer Service Center with questions about how to reduce energy use and 19 in response to direct requests received through Idaho Power's website. Idaho Power also mailed 876 copies of the informational brochure *Practical Ways to Manage Your Electricity Bill* to customers who called specifically with concerns about high bills.

Idaho Power continues to recognize that educated employees are effective advocates for Idaho Power's energy efficiency programs. To keep employees informed and up to date, Idaho Power conducted its annual energy efficiency awareness campaign in March. Activities during 2012 included weekly articles in internal publications to engage employees in learning more about Idaho Power's programs and wise energy use. A texting competition was implemented and employees were encouraged to text answers to weekly questions focused on energy efficiency. Posters for display in Idaho Power's offices and distribution of wearable buttons encouraging employees to become "Energy Efficiency Rock Stars" rounded out the month.

Although the formal partnership with the Idaho Commission for Libraries expired in June 2011, the Kill A Watt™ Meter Program remained active in 2012. With this commitment complete, Idaho Power reached out to local libraries to assist with the continued promotion of the program. Idaho Power developed a travelling, interactive table display for individual library use to create buzz and interest around the Kill A Watt kits. All participating libraries received an invitation to schedule the display. Eight libraries responded and three displays moved amongst the libraries throughout the summer and fall.

Idaho Power took the lead in strengthening the energy education partnership with secondary school educators through continued participation on the Idaho Science, Technology, Engineering and Mathematics (iSTEM) Steering Committee. In 2012, twenty teachers completed the 3-day, 2-credit professional development seminar facilitated by Idaho Power and co-sponsored by Intermountain Gas and the Idaho National Lab (INL).

Other energy education partnerships included working with the IDL in late autumn to offer two residential-focused training seminars in the BetterBricks® series. Twenty-four participants attended the session titled "Advanced Insulation Techniques" and 16 attended "The People Side of Sustainability." Both sessions had two off-site participants that attended via live video streaming. Videotapes of the seminars are available for download from the IDL's website. The workshops averaged 15 post-lecture downloads in 2012. Idaho Power continued its co-sponsorship of the "Sustainable Energy Sustainable Homes" lecture series. The eight workshops, facilitated by local trade experts, provided information and expertise to encourage energy efficiency upgrades. Attendance increased from an average of 12 participants per session in 2011 to an average of 18 participants per session in 2012. Idaho Power continued to partner with the City of Hailey on the educational portion of their Hailey Community Climate Challenge grant by participating in the delivery of seven workshops during the year.

In addition to these activities, Idaho Power continued sponsorship of the fifth annual Idaho Green Expo in June. As part of Idaho Power's commitment to the Expo, the company sponsored a direct-mail effort to increase participation and publicize the new location. Data from Idaho Power's 2010 and 2011 Green Expo Surveys was mined to determine the best Treasure Valley homeowners to include. Two-for-one coupons were provided the week prior to the Expo to 26,000 targeted participants. The Idaho Power Expo booth consisted of a "Summer of '78" theme, where participants were encouraged to set their

summertime thermostats to 78 degrees and given other stay-cool tips. In addition to sharing this message at the booth, Idaho Power partnered with six other sustainably minded organizations to sponsor a broad educational activity that used text messaging to engage attendees and their families for the length of their expo visit. The activity exceeded expectations with 186 unique individuals, representing 6 percent of total expo attendees, choosing to play. Together, they texted 3,093 correct answers to the specified telephone number. On average, these 186 players texted 17 correct answers each and thus received 34 pieces of valuable information during their expo visit. The regional director for the vendor, who processed the text messages, stated, "These results are quite fantastic. In a typical setting I would estimate 1.5 percent to 2 percent participation. You all have tripled that. Great effort!"

For the third year running, Idaho Power partnered with GreenWorks Idaho to develop and administer an exit survey, resulting in 342 completed surveys. The Green Expo participant profiles will be used to further improve messaging and goals and increase an understanding of Idaho Power's return-on-investment for future sponsorship of this event. It will also be used for tracking energy efficiency-related trends among expo attendees. Thirty percent of this year's survey participants reported having received an energy efficiency incentive payment from Idaho Power, up from 21 percent in 2011. The survey summary is provided in *Supplement 2: Evaluation*.

In September 2012, Idaho Power participated in the St. Luke's Women's Show for the fifth consecutive year. The event continues to be important due to the size of the audience and because its demographic component aligns with Idaho Power's residential energy efficiency target audience. Numerous marketing research studies have shown the people most likely to participate in energy efficiency programs tend to be females with higher education and income levels than the general population. This target audience aligns well with individuals who attend this event.

Idaho Power requested booth visitors complete an in-depth survey. The survey was redesigned in 2012 based on results from the previous two years' surveys to gather key market data and establish a baseline regarding attitudes toward energy-efficient and sustainable behaviors. Another improvement with the 2012 survey was that participants were given the opportunity to complete an online survey prior to the show through the show sponsor. This resulted in a more positive experience in completing the survey for many, since there were frequently waiting lines in previous years. In total, the company collected 670 completed surveys, exceeding the target of 400. The opportunity to complete the survey online shortened the waiting line at the booth and resulted in 274 of the 670 survey respondents completing the survey from a remote location.

Although the respondents are not a random sample, key findings from the Women's Show survey indicated Idaho Power's ENERGY STAR® Homes Northwest continues to be the most recognized energy efficiency program, with most respondents (77%) indicating they were "aware of" the program. Respondents also indicated awareness of other ENERGY STAR branded programs and the See ya later, refrigerator® program. Energy House Calls was the least recognized program, with a majority of respondents (65%) indicating they had "never heard of" the program. The Home Products Program and A/C Cool Credit program were most identified by participants as a program they had participated in.

Of the Women's Show participants that completed the survey (98% female), the majority said they review and pay the monthly bills in their home and are the primary decision makers for managing thermostats, purchasing light bulbs and fixtures, and making appliance and electronics purchases. However, less than half of respondents indicated they are the primary decision maker for home upgrades, such as adding insulation.

When asked if they had plans to reduce their electricity consumption, less than 8 percent indicated they had no plans to do so. Forty-three percent indicated they were already taking some action, while 49 percent indicated they were either currently exploring ways or starting to take some action to reduce electricity use. Of the actions presented, turning lights off when leaving the room, adjusting thermostats up two degrees in the summer, and replacing incandescent light bulbs with CFLs were the most likely behavioral changes respondents would take to save money and to positively impact the environment. Respondents were slightly more inclined to reduce their water heater temperature 10 degrees and participate in the A/C Cool Credit program for positive environmental benefits than cost savings.

Idaho Power further increased its energy efficiency presence in the community by providing energy efficiency and program information through 171 outreach activities, including events, presentations, trainings, and other outreach activities. As part of process improvement accomplishments, the Outreach Tracking System, the database that records educational and outreach activities, again received some enhancements for additional metrics. In 2012, a special effort was made to increase the quantity and quality of post-event feedback recorded in the database. At the conclusion of 2012, 71 percent of events taking place during the year had some post-event documentation recorded in the system.

In addition to the outreach activities noted previously, Idaho Power field staff throughout Idaho Power's service area delivered another 176 presentations to local organizations addressing energy efficiency programs and wise energy use. In 2012, the Community Education team provided 92 presentations on *The Power to Make a Difference* to 2,690 people. More specifically, 53 of these presentations were to students, and 29 of them were community presentations. The breakdown of attendance was 1,539 students and 1,151 community members. The community education representatives and other staff members also completed 42 senior citizen presentations on energy efficiency programs and shared information about saving energy to a total of 1,473 seniors in the company service area.

The Residential Energy Efficiency Education Initiative continued to provide energy efficiency tips in response to media inquiries and other needs of Idaho Power's Corporate Communications department. The initiative staff supplied information for various Idaho Power publications, such as *News Scans, Green Power Newsletter*, *A/C Cool Credit Newsletter*, *Customer Connections*, and Idaho Power's Facebook page. Additionally, the initiative worked with the Energy-Use Advisory Tool (EUAT) team to provide appropriate tips and suggestions for the account manager enhancements implemented in March. One of the major goals of this web enhancement was to educate customers and encourage behavioral change by linking specific energy-related behaviors and choices to their monetary consequences. Time-of-Day promotional materials and calculators were also created with energy efficiency suggestions from the initiative.

During 2013, the initiative's goals are to increase program participation and promote education and energy-saving ideas that result in energy-efficient and conservation-oriented behaviors and choices. Based on guidance from EEAG, plans for 2013 include more opportunities to educate and influence young people regarding wise energy use and continued work with Idaho Power program specialists, partners, and participating contractors to influence behavioral change, particularly when energy efficiency upgrades are made. Energy efficiency educational materials and channels will continue to be evaluated and either developed or revised, as necessary, to increase customer reach, improve distribution, and enhance presentation opportunities. Beginning in 2013, two issues of *Customer Connections* (the monthly newsletter included in customer bills) will be devoted entirely to energy efficiency. Idaho Power will continue to actively evaluate existing data to determine how future research and data collection may be improved to further the Residential Energy Efficiency Education Initiative's goals.

## Easy Savings Program

As a result of IPUC Case No. IPC-E-08-10 under Order Nos. 30722 and 30754, Idaho Power committed to fund energy efficiency education for customers receiving energy assistance through the federal LIHEAP and provides $125,000 to be paid to CAP agencies in the Idaho Power service area on a prorated basis. In addition, this order specified that Idaho Power provide educational information for households that heat their homes with electricity provided by Idaho Power.

Three main desired outcomes of the Easy Savings Program are to educate recipients about saving energy in their homes to use energy wisely, to allow hands-on experience while installing a low-cost measure, and to reduce the energy burden for energy assistance/LIHEAP applicants.

In past years, the primary target for the program was households applying for energy assistance that did not qualify for weatherization prioritization. Households that were targeted through the Easy Savings Program generally did not include elderly or disabled individuals or families with children that are already prioritized for other Idaho Power weatherization services. For the 2011 to 2012 program, the priority status for weatherization assistance exclusion was removed. Customers with priority status for weatherization are now eligible to receive Easy $avings® program kits.

Each provided kit contained the following low-cost/no-cost energy saving items:

- CFLs (13 W and 18 W)
- Hot-water temperature card and refrigerator thermometer
- Rope caulk and outlet draft stoppers
- Kitchen faucet aerator and high-efficiency showerhead
- LED nightlight and reminder magnets for the laundry
- *Quick Start Guide* to installation
- Survey inquiring about the installation experience and actions taken to reduce energy use

All educational materials are printed in English and Spanish. Returned surveys are used to track the effectiveness of the program. Tracking is done via a kit/survey unique numbering system.

In August 2012, Idaho Power placed an order with the Easy Savings Program vendor, Resource Action Programs (RAP), for a two-year supply of kits. This allowed time for the regional CAP agencies to receive kits and ready them for distribution by the beginning of the LIHEAP season, which begins on November 1 each year and ends the following March, depending on funding availability.

Fulfilling the payment requirements for program years 2011 to 2012, $250,000 were sent by Idaho Power to CAP agency executive directors in each region. Each agency used 30 percent of the agency's allotment to cover expenses for administering the program at their agency. An order for 4,255 kits was placed in August 2012. Kits were shipped from the vendor and received at agencies in October 2012 for distribution to customers. The goal is to have all kits distributed prior to November 2013.

Between October 2012 and December 31, 2012, 850 kits were distributed to Idaho Power customers approved to receive energy assistance benefits on their Idaho Power bills. A participant survey inquiring about installation experiences and actions taken to reduce energy use was included in the kits. Tracking was done via a kit/survey numbering system. Returned surveys were used to track the educational impact of the program.

Of the 850 surveys distributed, 126 completed surveys were received back from customers describing their experience in installing kit items in their homes. The survey included questions about whether the customer took specific actions to reduce energy use as a result of receiving the kit, as well as questions confirming the installation of kit items.

Ninety-one percent of household respondents reported they have, or will, lower their heat during the day, and 82 percent reported they will lower their heat at night. Eighty-two percent of the households reported installing both CFLs provided, and another 12 percent said they installed one of the CFLs provided. Seventy-nine percent of the households reported installing the high-efficiency showerhead.

Overall, survey results show that over 58 percent of the households that received the kits and returned a survey installed five or more kit items. Seventy-four percent of the respondent households reported learning a lot about saving energy and money in their home after completing the *Easy Savings Quick Start Guide*. Copies of the survey and survey results can be found in *Supplement 2: Evaluation*.

Gift certificates valued at $100 each will be provided by CAPAI to encourage survey completion on the remaining 3,405 kits. A drawing from all returned surveys will be held in 2013. Five households will win a $100 gift certificate. Upon anticipated completion of kit distribution in October 2013, Idaho Power and CAPAI will consider changes for the program in 2014.

## Commercial Education Initiative

Since 2008, the Commercial Education Initiative has informed and educated commercial customers regarding energy efficiency, increased awareness of and participation in existing commercial energy efficiency and demand response programs, and enhanced customer satisfaction regarding the company's energy efficiency initiatives. A major strength of the initiative is the emphasis on building strategic relationships. The program specialist works closely with Idaho Power CRs assigned to commercial market segments to capitalize on their established relationships with customers.

The initiative oversees the distribution of informational materials and works directly with trade allies and other market players who, in turn, support and promote Idaho Power's energy efficiency programs. Routinely, individual site visits are conducted to educate customers on energy-savings opportunities at their business. Additionally, these site visits serve as training opportunities for field staff, raising their knowledge for future site visits.

In 2012, Idaho Power carried out its plan to capitalize on effective customer projects by posting on Idaho Power's website six *Success Stories* highlighting customers' 2012 energy efficiency projects. Copies of the 2012 *Success Stories* are provided in *Supplement 2: Evaluation*.

Raising the knowledge level of commercial customers in the wise use of energy in their daily operations is important to the continued success of Idaho Power's commercial energy efficiency programs. The Commercial Education Initiative works with and supports multiple stakeholders and organizations to increase customers' energy efficiency knowledge. Examples of key stakeholders include the IDL; BOMA; US Green Building Council; and American Society of Heating, Refrigeration,

and Air-Conditioning Engineers. Through funding provided by Idaho Power, the IDL performs several tasks aimed at increasing the energy efficiency knowledge of architects, engineers, trade allies, and customers. Specific activities include sponsoring a building-simulation users group, conducting lunch-and-learn sessions held at various design and engineering firms, and offering a tool loan library. Customers also have access to equipment that enables them to measure and monitor energy consumption on various systems within their operation.

In 2012, the Commercial Education Initiative sought further opportunities to assist small communities interested in learning more about energy efficiency. The initiative continued to conduct site visits, used the Equipment Efficiency Specification Sheets, and distributed target market information tip sheets. Additionally, Idaho Power offered assistance to colleges providing energy-related technical education.

Plans for 2013 include 1) working with Idaho Power marketing specialists to increase customer awareness of the company's energy efficiency programs and their specific offerings, 2) coordinating training opportunities for CRs to increase their energy expertise, and 3) refining tools that allow customers to perform a cursory evaluation of their own facilities to identify energy efficiency opportunities and determine if a more in-depth evaluation or audit is needed. Customer support via facility walk-throughs and site-specific efficiency guidance will continue. Idaho Power will continue working with key stakeholders to provide outreach and training opportunities. In a partnership with NEEA and BOMA, Idaho Power is piloting an energy-savings competition for commercial office buildings. Similar competitions have successfully been held in Seattle, Washington, and Portland, Oregon. Branded as the Kilowatt Crackdown™, the goal of the competition is to help participants raise their energy awareness and increase building performance community wide. The Kilowatt Crackdown will be a beneficial educational opportunity for participants.

## Local Energy Efficiency Funds

The purpose of LEEF is to provide modest funding for short-term projects and activities that do not fit within other categories of energy efficiency programs but that still provide energy savings or a defined benefit to the promotion of energy-efficient behaviors or activities.

Idaho Power received four applications for LEEF in 2012. Projects included 1) the installation of computerized controllers on existing engine-block heaters in a bus yard, 2) the use of a solar thermal system to heat a residence in Idaho City, 3) the installation of a programmable logic controller on manufacturing ovens to reduce peak demand, and 4) the construction of an energy-efficient micro-home for demonstration purposes.

For each of these projects, Idaho Power convened a working group of engineers and cost-effectiveness analysts to review the application, request additional information, and perform a cost-effectiveness analysis. None of the projects were funded for the reasons stated below.

Three of the projects did not meet cost-effectiveness tests for various reasons. The committee found that less expensive timers would achieve the same savings as the proposed controllers for the block heaters. The residence in Idaho City planned to have a pellet stove for backup heat, so the primary heat source was not going to be electric. The manufacturing ovens proposal shifted use, but the existing peak period was not during Idaho Power's peak demand period, and there were no proposed energy savings associated with the proposal. The micro-home project was specific to the 2012 Green Expo trade show, and the application was received too late for the completion of funding and construction prior to the show. However, funding was put into the Residential Energy Efficiency Education Initiative budget in 2013 to complete a similar project that could be used for demonstration purposes.

## Residential Economizer Project Study

In 2011, a Residential Economizer Project Study was initiated involving the installation of 19 economizers into residential houses. An economizer draws cool, outside evening air into the A/C system of a house. Its purpose is to reduce the summer cooling energy required to cool the house. The reduction of cooling energy is derived from the reduced run time of the A/C mechanical system. Data collection devices were used to capture energy and temperature values in the houses fitted with these systems. The data was collected during summer 2011. It was analyzed by Idaho Power and third parties to determine potential energy savings. The installation of data-logging equipment, field monitoring, and the energy analysis report was performed by the IDL.

In early 2012, with the advice of EEAG, it was determined that securing additional data during summer 2012 would be beneficial when combined with data collected the prior year. Twenty-two additional houses were fitted with economizers and data-logging equipment. Twelve of the houses data logged in 2011 were also data logged in 2012. Ongoing progress was reported in February and July 2012 EEAG meetings. All 34 houses were analyzed at the end of 2012. The final report from the IDL is due after December 2012.

NEEA has been involved with the study since its beginning in 2011. The 2012 results will be shared with them. In 2011, NEEA planned to contribute to four study reports. Three of the studies were completed in 2011. These three include the baseline energy study, the contractor survey, and the customer survey. NEEA will review the 2012 results to determine if the fourth report, the market-transformation report, will be necessary based on factors including reported energy savings.

## Regional Technical Forum

The BPA and the Northwest Power and Conservation Council (NPCC) established the RTF in 1999. Since 2004, Idaho Power has supported the RTF by providing annual financial support, regularly attending monthly meetings, and participating on various sub-committees.

The forum's purpose is to advise the BPA, the NPCC, the region's utilities, and organizations, including NEEA and the Energy Trust of Oregon (ETO), on technical matters related to energy efficiency and renewable-resources development. Activities include the development of standardized protocols for verifying and evaluating energy savings and tracking conservation and renewable resource goals. Providing feedback and suggestions for improving the effectiveness of regional energy efficiency and renewable-resource development programs are additional activities of the RTF. The RTF also recommends a list of eligible conservation measures and the estimated savings associated with those measures. Idaho Power uses the information provided by the RTF when conducting research and analysis on new and current measures. The RTF meets monthly to review and provide comments on analyses and other materials prepared by the NPCC, BPA staff, and RTF contractors. Idaho Power uses the savings estimates and calculations provided by the RTF when applicable to the Idaho climate zones and load characteristics. In 2012, Idaho Power staff participated in all of the RTF's meetings and was involved in various sub-committees, such as the RTF Policy Advisory Committee. Idaho Power is also working with the RTF to bring the "out-of-compliance" irrigation hardware measures into compliance. The company partnered with the University of Idaho to conduct field testing of various irrigation components during the 2012 growing season. The research will be presented to the RTF in early 2013.

Since 2010, the RTF has been working toward developing a set of operative guidelines to describe the RTF's methods to select, develop, and maintain measure savings, costs, and other benefits. The guidelines were completed and adopted in 2012. In the meantime, the RTF has spent the past two

years reviewing previously deemed measures and determining its compliance to the new guidelines. A measure may fall under one of the four measure categories and one of the four measure statuses.

Measure categories include proven, provisional, planning, and small-saver savings. Proven savings meet the highest quality and reliability standards. Provisional savings estimates are those the RTF conditionally approves and requires additional data collection. It must be possible to obtain the data necessary to meet the proven quality of standards. Planning savings do not meet the quality of standards of the provisional or proven categories; however, these measures may be needed for the regional program operators. A data-collection plan must be developed that can bring the measure to the provisional or proven category. Small savers are measures that have savings too small to necessitate the resources needed to bring the measure to proven or provisional quality of standards.

Measure statuses include active, under review, de-activated, and out-of-compliance. The active measure status is when the measure's source data is current and contains reliable savings.

Prior to a measure's sunset date, a measure may change its status to under review if new sources of data become available. The measure's savings will be reviewed and may be re-estimated. A de-activated measure status refers to when the sunset date for a measure has passed and new savings estimates have not been approved. A measure may be de-activated if new findings invalidate the measure savings. Out-of-compliance measures are those measures that do not comply with one or more of the requirements from the guidelines. Once the RTF determines a measure is out of compliance, a plan to bring the measure into compliance must be approved within a year. This status is applicable to measures approved prior to June 1, 2011.

## Boise City Home Audit Project

In 2011, Idaho Power and the City of Boise partnered to create a limited-term, residential energy audit project that installed low-cost energy-saving measures and identified additional efficiency improvements. The City of Boise received ARRA funding from the DOE Energy Efficiency Conservation Block Grant (EECBG). At the end of 2011, a portion of the funds remained, and the project was extended to provide for an additional 226 home audits.

The home audit extension in 2012 resembled the original project. Idaho Power contracted with HPSs to perform the energy audits and installation of measures. The energy audit included a blower door test, a visual inspection of the crawl space and attic, and a collection of data regarding the home and its energy use. Potential low-cost energy-saving measures that could be installed in each home included limited sealing of air leaks, such as mastic around the furnace unit; installing CFLs; insulating water pipes that are three feet or less between the water heater and the structure; and installing water heater blankets. The audit included instructing customers on a variety of items, including the replacement of their furnace filter and how to lower the temperature on their water heater.

Participating customers paid $49 for the audit and installation of measures, with the remaining cost covered by the EECBG funds. Energy audits of this type normally cost $300 or more, not including the measures, materials, and labor. The cost of the materials potentially installed at each home was approximately $100.

After the audit was complete, homeowners received a report and were provided information on programs that could assist them with the costs of implementing additional measures, including information on the City of Boise's Home Improvement Loan Program.

The target audience for this project was Boise residential customers living in single-family, site-built homes under 3,000 $ft^2$. The homes had to be owner-occupied year-round. The target was for 25 percent of participating homes to be all-electric.

Participants were recruited through direct-mail. In 2012, six small batches of recruitment letters were mailed for a total of 12,342 letters, with a response rate of 2.3 percent. Customers who were interested in participating in the project were directed to a website to complete an application. Those who either did not have internet access or were uncomfortable with filling out the application online were able to call and have their application taken over the phone. Participants were selected on a first-come, first-served basis.

The three energy auditors from the original project were selected to continue with the extension. Audits were randomly and evenly distributed between the three auditors.

Of the 225 audited homes, 182 homes (81%) were heated by gas, two homes (1%) were heated by oil, and 41 (18%) were heated by electricity. The average age of the homes in the 2012 project extension was 37.6 years old.

Home sizes ranged from 913 $ft^2$ to 3,176 $ft^2$. The average home size was 1,933 $ft^2$. Although the recommended maximum home size was 3,000 $ft^2$, a few homes over this size were completed. Table 13 shows the 2012 number of participating homes by ranges of square-foot increments.

Table 13. Number of participating homes by size

| Home Size | Count |
|---|---|
| 700–1000 $ft^2$ | 4 |
| 1001–1500 $ft^2$ | 63 |
| 1501–2000 $ft^2$ | 53 |
| 2001–2500 $ft^2$ | 66 |
| 2501–3000 $ft^2$ | 31 |
| 3001–3328 $ft^2$ | 9 |

Homes were located throughout the Boise city limits, with larger amounts of recruitment letters mailed in those zip codes reported to have a higher percentage of electrically heated homes. Table 14 compares the 2012 number of participating homes per zip code that heat by using electricity, gas, or oil.[2]

Table 14. Number of participating homes by zip code and heating source

| Zip Code | Electric | Gas | Oil | Total |
|---|---|---|---|---|
| 83702 | 7 | 19 | 1 | 27 |
| 83703 | 7 | 6 | 0 | 13 |
| 83704 | 8 | 52 | 0 | 60 |
| 83705 | 5 | 9 | 0 | 14 |
| 83706 | 8 | 29 | 0 | 37 |
| 83709 | 3 | 25 | 0 | 28 |
| 83712 | 1 | 10 | 1 | 12 |
| 83713 | 3 | 23 | 0 | 26 |
| 83714 | 0 | 1 | 0 | 1 |
| 83716 | 0 | 8 | 0 | 8 |

When performing an audit, the HPS determined which available measures were appropriate for the home, and, if the homeowner approved, those measures were installed. Table 15 lists by heating source and quantity of items installed in participating homes in 2012.

Table 15. Measures installed in participating homes by heat source

| | Quantity | Gas Home | Electric Home | Other |
|---|---|---|---|---|
| CFLs | 776 | | | |
| Water heater blankets | | 4 | 1 | |
| Pipe insulation | | 79 | 13 | 1 |
| Mastic | | 55 | 11 | 1 |

Once an audit was complete, the information obtained by the auditor was entered into a database. A personalized report was created and mailed to each participant detailing what was found at the home, what measures were installed, and further energy efficiency recommendations.

A survey was sent after the participant received their personalized report and allowed time for participant action regarding suggested energy efficiency actions. The survey gathered data on immediate actions the participant initiated following the audit and short-term actions they planned to take at a future date. It also inquired about reasons for inaction, such as expenses or difficulty finding a contractor. A copy of the survey is included in *Supplement 2: Evaluation*.

Idaho Power contracted the IDL and the City of Boise to provide an impact evaluation of the Boise City Home Audit Pilot. Using ARRA funds, energy audits were conducted and low-cost energy efficiency measures were installed at 650 homes located in Boise. The audits took place from late 2010 through summer 2011 and identified additional energy efficiency measures for future consideration by the customer.

The final report indicated that the average savings per home from direct install measures was 308 kWh in electricity and 3 therms in natural gas per year. Based on the average residential consumption in Idaho Power's service area, this represents a 2.4-percent reduction in annual electricity consumption. Although these savings estimates were to be originally calibrated using utility billing data, according to the International Performance Measurement and Verification Protocol (IPMVP), savings were not large enough to accurately differentiate from historical billing data.

The cost-effectiveness analysis conducted under IDLs assumptions indicates that this program, with installed measures for dual-fuel homes, would only be cost-effective under the PCT. The analysis shows that this program with the same installed measures for electrically heated homes would be cost effective under the UCT and TRC. A copy of the complete report is included in *Supplement 2: Evaluation*.

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# REGULATORY INITIATIVES

Idaho Power believes there are three essential components of an effective regulatory model for DSM: 1) the timely recovery of DSM program costs, 2) the removal of financial disincentives, and 3) the availability of financial incentives. A description of this overall DSM business model was provided in Case No. IPC-E-10-27 filed with the IPUC on October 22, 2010, and is described in more detail below.

Since 2002, Idaho Power has recovered most its DSM program costs through the Rider with the intended result of providing a more timely recovery of DSM costs. In addition, since January 1, 2012, funding of Idaho customer incentives of demand response programs is now included in base rates and tracked in the annual PCA mechanism. On December 30, 2011, the IPUC issued Order No. 32426 in General Rate Case No. IPC-E-11-08 that approved including $11.3 million of demand response incentive payments as part of base rates. As of June 1, 2012, Idaho Power is including in the PCA an amount to true-up actual demand response incentive expenses for the previous year if the amount is different than the $11.3 million in base rates.

To address the removal of financial disincentives, Idaho Power tested the effects of an FCA mechanism in a five-year pilot initiative. In 2011, the FCA completed its fifth year in pilot status. As part of the 2011 General Rate Case No. IPC-E-11-08, Idaho Power requested the FCA become permanent. The IPUC decided the FCA should be addressed in a separate case. On October 19, 2011, the company filed Case No. IPC-E-11-19 with the IPUC. The case requested to convert the FCA to an ongoing and permanent rate schedule. On March 30, 2012, the IPUC issued Order No. 32505, approving the FCA mechanism as a permanent program for the residential and small general-service customers. The IPUC also directed Idaho Power to file a proposal within six months to adjust the FCA to address the capture of changes in load not related to energy efficiency programs. On September 28, 2012, the company submitted its Compliance Filing, requesting the IPUC issue an order authorizing either the continued use of the existing FCA methodology, without change, or in the alternative, a modified methodology that introduces a symmetrical cap on the calculated FCA balance based on the change in the annual energy consumption per customer of plus or minus 2 percent from the historical average. On January 31, 2013, the IPUC issued Final Order No. 32731, directing the FCA mechanism continue unchanged.

Idaho Power is working toward the third component of the overall DSM regulatory model. As part of Case No. IPC-E-10-27, the IPUC issued Order No. 32245 on May 17, 2011, allowing Idaho Power to account for Idaho customer incentives paid through the Custom Efficiency program as a regulatory asset beginning January 1, 2011. On October 31, 2012, the company filed Case No. IPC-E-12-24, requesting the authority to include 2011 Custom Efficiency program incentive payments in rates and to establish a mechanism to annually update rates for future payments. This mechanism would provide Idaho Power an opportunity to earn an authorized rate of return on its investments in DSRs. As of December 31, 2012, proceedings relating to this case are ongoing.

## Fixed-Cost Adjustment

Under the FCA, rates are adjusted annually up or down to recover or refund the difference between the fixed costs authorized by the IPUC and the fixed costs Idaho Power actually received the previous year through energy sales. This mechanism removes the financial disincentive that exists when Idaho Power invests in energy efficiency and demand response resources designed to reduce customer usage. The FCA is limited to the residential and small general-service customer classes in recognition of the

fact that, for these customers, a high percentage of fixed costs are recovered through their volumetric energy charges.

During the five-year period in which the FCA Schedule 54 was in a pilot status, Idaho Power made strong progress toward improving and enhancing its efforts to promote energy efficiency and DSM activities. The company increased the number of energy efficiency and demand response programs it offers and substantially increased both its investment in DSM activities and the MWh savings obtained through these activities. Results from the first five years of the pilot indicated the true-up mechanism was working as intended.

As stated previously, on March 30, 2012, the IPUC issued Order No. 32505, approving the FCA mechanism as a permanent program for the residential and small general-service customers.

On May 8, 2012, the IPUC issued Order No. 32544, approving the company's request to implement FCA rates for fixed-cost deferrals in 2011. Beginning June 1, 2012, the company implemented an overall rate adjustment of 0.28 percent to residential and small general-service customers to collect a combined $10.3 million in under-collected fixed costs. Residential customers experienced a rate increase of 0.0227 cents/kWh, while small general-service customers experienced an increase of 0.0324 cents/kWh. The rate adjustments will result in a collection of an additional $1 million over the then-current billed amounts and will be in place until May 31, 2013.

## Custom Efficiency Incentive Recovery

On October 31, 2012, the company filed Case No. IPC-E-12-24 requesting authority to include Custom Efficiency program Idaho incentive payments in rates. Previously, on May 17, 2011, the IPUC in Order No. 32245 had authorized Idaho Power to account for Custom Efficiency program incentive payments as a regulatory asset.

In the October 31, 2012, filing, Idaho Power requested the following of the IPUC: Recognize the 2011 Custom Efficiency incentive amounts as "used and useful"; begin recovery of these amounts in rates on June 1, 2013; specify the company's rate of return as the carrying charge for the regulatory asset account prior to amortization; specify a four-year amortization period for the regulatory asset; acknowledge that the unamortized portion of the regulatory asset will earn the company's rate of return, allow the company to institute annual spring filings for this process; and authorize the implementation of Schedule 56. The incremental annual revenue requested in the filing is $2,949,340, with a requested rate change effective date of June, 1, 2013, to coincide with other anticipated rate changes associated with the annual PCA and the annual FCA.

## Energy Efficiency Rider—Prudence Determination of Expenditures

On March 15, 2012, Idaho Power filed Case No. IPC-E-12-15 with the IPUC requesting an order finding that the company had prudently incurred $42,641,706 (later adjusted to $42,641,361) in DSM expenses in 2011. This adjusted number included $35,622,976 in Idaho Rider expenses and $7,018,385 in Custom Efficiency program incentive expenses. The filing included three reports: *Demand-Side Management 2011 Annual Report*, *Supplement 1: Cost Effectiveness*, and *Supplement 2: Evaluation*. Supplement 2 included *NEEA Market Effects Evaluations*. In Final Order No. 32667, dated October 22, 2012, and Reconsideration Order No. 32690, dated December 11, 2012, the IPUC approved in part and denied in part Idaho Power's request. In these orders, the IPUC approved $42,468,904.50 in 2011 DSM expenditures, including $35,450,519.50 in Idaho Rider expenses and $7,018,385 in Custom Efficiency

program incentives, as prudently incurred expenses. The IPUC disallowed the recovery of $82,855.50 for incentives paid to participants of the A/C Cool Credit program who did not receive a signal to cycle even though Idaho Power thought they were being cycled. In addition, the IPUC declined to decide the reasonableness of Idaho Power's 2011 Rider-funded, labor-related expense increase until the company provides further information.

## Cost-Effectiveness and Funding of Low-Income Weatherization

On February 15, 2012, the IPUC issued a notice that opened Case No. GNR-E-12-01 and scheduled a public workshop from March 19 to 20, 2012. This case was initiated in part because both Rocky Mountain Power and Avista Utilities had recently conducted evaluations of their low-income programs and found them not to be cost effective. In 2012, Idaho Power began an evaluation of their low-income program. In addition, CAPAI asked the IPUC to increase funding for low-income programs in both Idaho Power's and Rocky Mountain Power's service areas. In this case, utilities, interested persons, and IPUC staff were to explore in greater detail issues related to the funding, implementation, and evaluation of utility low-income weatherization and energy conservation education programs. IPUC staff, utilities, CAPAI, and CAP agencies participated in the March workshop.

On October 23, 2012, IPUC staff issued their draft *Report on Low Income Weatherization and Energy Conservation Education Programs*. In this draft report, IPUC staff set out their suggested criteria for consideration when increased funding is being deliberated. IPUC staff also provided recommendations and comments on cost-effective calculations and procedures, as well as utility funding level considerations. Parties to the case, including the three Idaho investor-owned electric utilities, provided reply comments in November 2012. Idaho Power, in its comments, emphasized that low-income program funding should be based on the need exhibited by qualified weatherization customers. A proposed methodology was provided in Idaho Power's comments. On December 7, 2012, IPUC staff filed reply comments. An IPUC order is still anticipated in this case.

## Demand Response Programs Suspension

On December 21, 2012, Idaho Power filed Case No. IPC-E-12-29, requesting a temporary suspension of two of its three demand response programs, A/C Cool Credit and Irrigation Peak Rewards. The temporary suspension was requested because the current load and resource balance being used to develop the 2013 IRP does not show a peak-hour deficit in the near term, making these programs unnecessary in 2013. This temporary suspension will allow the company to work with stakeholders to identify the best long-term solution for these programs. The temporary suspension of the two demand response programs and their associated incentive payments would result in reduced costs for all Idaho Power customers in the form of a reduction in the 2013 to 2014 PCA that will be updated June 1, 2013. Before making this filing, Idaho Power convened a special meeting of EEAG on December 14, 2012, to review the issues and solicit member input. The group understood the rational for the filing; however, concerns were expressed about the impact on program participants and about how these program changes integrate in the IRP planning process. The temporary suspension of the programs requested in the filing will provide time to work with stakeholders on the redesign of the programs. The company requested the IPUC issue an order by March 1, 2013.

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# CONTINUED COMMITMENT

Every year, Idaho Power enhances its commitment to provide DSM programs that offer broader opportunities for Idaho Power's customers to manage their energy and demand use. Idaho Power also continues its effort to make its own facilities more energy efficient and to find ways to promote energy efficiency in its communities and with its employees. A review of specific efforts is listed in the following sections.

## Continued Expansion and Broad Availability of Energy Efficiency and Demand Response Programs

In 2012, Idaho Power broadened the marketing efforts and portfolio of programs offered to customers. Programs continue to add service areas where they are available to customers and continue to add new measures for customer participation. This expansion of programs and offerings helps ensure more customers each year have the opportunity to participate in programs. Some highlights for 2012 are as follows:

- Custom Efficiency awarded the single largest incentive in the program's history, on a chilled water economizer project designed to save approximately 10 million kWh annually.
- The See ya later, refrigerator® program reached a milestone when it picked up its 10,000th unit.
- In the education arena, the first *Winter Energy Efficiency Guide*, designed specifically around content applicable for homes with electric heat, was distributed to 187,114 customers with their newspapers in January. The *Summer Energy Efficiency Guide* circulation increased to 222,313.
- The network of participating contractors for the DHP Pilot expanded in 2012. To accelerate the expansion of the participating contractor network, Idaho Power provided 15 DHP Pilot orientation trainings to participating and prospective contractors. Expansion strategies resulted in the addition of 12 companies to the list of participating contractors, a 22-percent increase over 2011.
- The first biannual *Energy at Work* commercial newsletter was launched by the company. The goal of the newsletter is to provide pertinent and useful information to a customer segment with limited time.
- Idaho Power increased its use of online and social marketing, including an Easy Upgrades online advertising campaign and targeted behavioral advertisements on Facebook and Yahoo!.
- The Weatherization Solutions for Eligible Customers program expanded its service area into the Boise area through a new trade ally called Power Savers.
- In May 2012, Idaho Power issued its inaugural sustainability report: *Balance*. This report highlighted the company's continuing efforts to operate in a manner that supports financial, environmental, and social stewardship.
- In 2012, based on surveys conducted in 2011, Idaho Power received the highest customer satisfaction with business customers among western midsized utilities according to J.D. Power and Associates *2012 Electric Utility Business Customer Satisfaction Study*.

## Building-Code Improvement Activity

Since 2005, the State of Idaho has been on a cycle of adopting a state-specific version of the IECC. The most recent example of this was the adoption of the 2009 IECC that became effective in Idaho on January 1, 2011. The 2012 IECC was published in 2012, and the Idaho Building Code Board took public comments on whether or not to pursue a similar code update for Idaho based on the latest IECC. Idaho Power is participating in these ongoing meetings and monitoring the situation to assess where support may be offered. The Idaho Building Code Board has convened another Energy Codes Collaborative in 2013 to revise the current energy code in Idaho.

Idaho Power also contributed to the *Idaho Residential Energy Code Compliance* study commissioned by NEEA in 2012. This report is measuring Idaho's level of compliance with energy codes as required by the 2009 ARRA, which mandates that states receiving these funds achieve 90-percent compliance with target codes by 2017. The report describes the study of Idaho residential compliance with the amended version of the 2009 IECC. The report, included in *Supplement 2: Evaluation*, indicates a relatively high compliance by builders with the residential energy code in Idaho and suggests the overall 90-percent compliance rate has already been achieved, although some measures, such as wall insulation and lighting, are below that rate.

## Promotion of Energy Efficiency through Electricity Rate Design

Idaho Power continues to support a policy of gradually moving all customers into rates designed to reflect their cost of service, provide cost-based price signals, and encourage the wise and efficient use of energy.

On January 19, 2012, Idaho Power filed Tariff Advice No. 12-02 to expand Schedule 05, Time-of-Day Pilot Plan, to Idaho customers while at the same time suspend Schedule 04, Energy Watch plan. Idaho Power proposed to expand Energy Watch plan at a later time. Included in the Advice filing, which later became Case No. IPC-E-12-05, was a report titled *2012 Time-Variant Pricing (TVP) Implementation Plan*. The overall goal of this implementation plan was to "utilize the new AMI system to offer customers a choice of pricing plans while providing them with better tools to manage their energy usage, to provide the company with the opportunity to further study the effects of a time-variant rate on customers' usage, and to help shape the company's future communication efforts." The company also planned to evaluate the impact of this new rate plan on its revenues and costs. The Time-of-Day pricing structure was designed to send price signals to customers that more closely reflect the costs of serving those customers. The plan provides participants the opportunity to move their usage from higher-priced time periods to lower-priced time periods and possibly lower their bills. On March 27, 2012, the IPUC issued Order No. 32499 and approved the proposed changes to the tariffs and directed Idaho Power to file a report analyzing the *2012 TVP Implementation Plan* results to IPUC staff prior to further revising its TVP tariffs.

Idaho Power set up a study to determine changes in energy usage caused by changes in participants' behavior in response to the new rate structure. A target market was determined and, throughout spring and summer 2012, participants were solicited by a weekly direct-mail effort. Potential participants were encouraged to visit Idaho Power's website (http://www.idahopower.com/TOD) to evaluate their usage under the different plan options and to make an educated decision regarding which plan was best for them. Over 126,000 customers were solicited. The direct-mail solicitation process ended in September. As of the end of 2012, over 1,500 customers signed up to become Time-of-Day plan participants. Through late 2012 and early 2013, Idaho Power will evaluate initial study findings and will file its report with the IPUC in spring 2013.

## Third-Party, Independent Verification

Idaho Power recognizes that the timely, credible, and transparent evaluation of all its DSM programs is critical in ensuring maximum program performance and the accurate reporting of program energy savings. Third-party contractors are used to provide primary research and impact, process, and market evaluations. These evaluations and research help ensure programs are being administered effectively and best-practice specifications are met. Reports from these evaluations provide valuable recommendations for program improvement and validate energy savings achieved through the company's DSM programs.

In 2012, impact evaluations were completed by third-party contractors on the following six DSM programs: Building Efficiency; Easy Upgrades; H&CE Program; See ya later, refrigerator®; Weatherization Solutions for Eligible Customers; and WAQC. A process evaluation was completed for the A/C Cool Credit program. Primary research was conducted on the Irrigation Efficiency Rewards and A/C Cool Credit programs. Copies of the reports can be found in *Supplement 2: Evaluation*.

In addition, Idaho Power uses third-party contractors to perform QA and OSVs for most programs. The H&CE Program, Home Improvement Program, ENERGY STAR® Homes Northwest, Easy Upgrades, and Building Efficiency programs use third-party contractors to perform QA or OSVs on approximately 10 percent of completed customer projects. The Energy House Calls and WAQC programs contract with third-party experts to perform QA analyses on approximately 5 percent of customer completed projects.

Throughout 2012, Idaho Power participated with NEEA to conduct several third-party assessments. These studies included the Residential Building Stock Assessment, an evaluation of the Northwest DHP Initiative, assessment of four Residential Consumer Electronics products, and several market effects evaluations in the residential, commercial, and industrial sectors. Copies of these reports can be found in *Supplement 2: Evaluation*.

The company also funds and participates in the RTF. The RTF is an advisory committee that was created in 1999 to develop regional standards and for the establishment of deemed savings derived from energy efficiency programs and measures. Idaho Power uses the RTF as a source for information regarding energy efficiency programs and measures and uses the RTF databases to provide deemed-savings estimates for many of the energy efficiency measures implemented as part of the company's DSM programs.

It is anticipated that in 2013, Idaho Power will contract with third-party evaluators to complete process evaluations for the Energy Efficient Lighting, ENERGY STAR Homes Northwest, H&CE Program, Weatherization Solutions for Eligible Customers, WAQC, Easy Upgrades, and FlexPeak Management programs. The *2010–2013 Evaluation Plan* can be found in *Supplement 2: Evaluation*.

### *Energy Efficiency Potential Study*

Idaho Power contracted with EnerNOC Utility Solutions Consulting (EnerNOC Solutions) to provide an analysis of the technical, economic, and achievable energy efficiency over the next 20 years in the company's service area. In addition, EnerNOC Solutions provided an executable dynamic model that supports the potential study and allows for the testing of sensitivity. EnerNOC Solutions also updated load profiles by sector, program, and end use. Because of their disproportionate energy use, special-contract customer potential was analyzed separately. The achievable energy efficiency potential by sector is shown as follows:

- Residential achievable potential projects: 189,469 MWh in 2017, or approximately 21.6 aMW. This level of potential is equivalent to 3.5 percent of the residential baseline projection for that year. By 2032, the cumulative achievable projection savings are 701,104 MWh, 10.8 percent of the baseline projection. A copy of the complete report is included in *Supplement 2: Evaluation*.

- Commercial achievable potential projects: 194,418 MWh, or approximately 22.2 aMW, of energy savings in 2017, which corresponds to 5.2 percent of the commercial baseline projection for that year. By 2032, the cumulative achievable projection savings are 633,771 MWh, 13.9 percent of baseline projection. A copy of the complete report is included in *Supplement 2: Evaluation*.

- Industrial achievable potential projects: 174,526 MWh, or approximately 19.9 aMW, of energy savings in 2017, which corresponds to 18 percent of the industrial baseline projection for that year. By 2032, the cumulative achievable projection savings are 488,465 MWH, 12.8 percent of baseline projection. A copy of the complete report is included in *Supplement 2: Evaluation*.

- Irrigation achievable potential projects: 36,360 MWh, or approximately 4.2 aMW, of energy savings in 2017, which corresponds to 6.8 percent of the irrigation baseline projection for that year. By 2032, the cumulative achievable projection savings are 229,821 MWh, 11.3 percent of baseline projection. A copy of the complete report is included in *Supplement 2: Evaluation*.

Achievable potential across the residential, commercial, industrial, and irrigation sectors is projected to be 594,772 MWh, or 67.9 aMW, in 2017 and increases to 234.4 aMW by 2032. This represents 4.3 percent of the baseline projection in 2017 and 12.2 percent in 2032. By 2032, achievable potential offsets 12.2 percent of the growth in the baseline projection. A copy of the complete report is included in *Supplement 2: Evaluation*.

## Idaho Power's Internal Energy Efficiency Commitment

Idaho Power's continued commitment toward promoting energy efficiency extends beyond encouraging, providing incentives, and educating its customers.

At the annual shareholders meeting held in May 2012, IDACORP, Inc., and Idaho Power issued the inaugural sustainability report: *Balance*. This report highlighted the company's continuing efforts to operate in a manner that supports financial, environmental, and social stewardship. The sustainability report featured articles highlighting the company's long-standing commitment to operating in a sustainable manner, including groundbreaking raptor protection programs and innovative methods to gather and analyze data in waterways supporting company operations. IDACORP plans to issue its second sustainability report in May 2013.

The Idaho Power Green Team championed sustainable activities conducted by Idaho Power and its employees. In 2012, projects included coordinating monthly Green Bag educational seminars, supporting company-wide alternative transportation efforts, and implementing a project at the company café to compost the organic portion of its wastes.

Idaho Power's corporate headquarters (CHQ) continued to participate in the strategic elimination of power loads during peak use through the FlexPeak Management program. In August 2010, Idaho Power entered into an agreement with EnerNOC, Inc., to enroll the CHQ in FlexPeak Management—Idaho Power's commercial/industrial demand response program. EnerNOC enlists and contracts with Idaho Power's commercial and industrial customers to voluntarily reduce their electricity use primarily

during times of Idaho Power system peaks. EnerNOC provides participants with auditing assistance, energy-monitoring software, demand-reduction performance monitoring, coaching, and other related services. EnerNOC works closely with its program participants to estimate their reduction potential accurately. Unlike other program participants, Idaho Power does not receive any financial incentives to participate.

In 2012, Idaho Power committed to reduce its electrical consumption by 100 kW during demand-reduction events. The CHQ participated in all four of the FlexPeak events, which were initiated in June, July, and August. The average reduction achieved by the facility across the four events was 425 kW. The CHQ exceeded the committed reduction in all events. The maximum hourly reduction was 775 kW, achieved in July. Reductions were mostly obtained by turning off lights, adjusting A/C set-points, decreasing fan speeds, and curtailing elevator use. The facility reduction plan in place could be executed at any time to reduce electricity use if necessary.

In 2012, Idaho Power began an aggressive lighting retrofit in several of its facilities. This included upgraded lighting at eight of its hydroelectric power plants, the CHQ building, and two operations centers. Total projected first-year electrical savings were approximately 562,100 kWh. These savings should continue for 10 to 12 years.

Changes at the power plants included replacing magnetic ballasts and T-12 lamps with more efficient electronic ballasts and T-8 lamps. At the Hells Canyon Dam, external mercury vapor fixtures were replaced with LED fixtures.

Energy-efficient T-8 lighting was installed in all of the CHQ's hallways, basement, loading dock, stairwells, restrooms, coffee rooms, copy rooms, first/second floor light wall, electrical rooms, data rooms, and penthouse. Efficient electronic ballasts and lamps replaced the inefficient magnetic ballasts and lamps. Wall-, ceiling-, or fixture-mounted occupancy sensors were installed as appropriate. Halogen art display fixtures were retrofitted with LED lamps. In elevator shafts and pump rooms, CFLs replaced incandescent lamps.

The lighting retrofit and space remodel at the Payette Operations Center continued during 2012 with the removal of T-12 lighting, installation of T-8 lighting retrofit packages, and a decrease in cubicle heights to 53 inches for improved natural lighting. In addition, the Boise Center West (BCW) project installed dimmable LED lighting fixtures throughout the new data center.

In 2013, the BCW project will incorporate several energy-efficient attributes. Plans include using indirect clerestory windows, placing Dyson hand-insertion electric air dryers and water-saving features within the restrooms.

During 2012, planning continued for the 2013 installation of a new energy-efficient chilled water system for the CHQ. Although remodeling of the CHQ (carpets, blinds, lighting upgrade, paint, and new lowered cube height) was postponed for one year, the company anticipates continuing this project through 2016. Sub-station lighting retrofits were initiated in 2012 and will continue to be a focal point through at least 2020.

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# APPENDICES

This report includes five appendices. Appendix 1 contains financial information for 2012, showing the beginning balance, ending balance, and the expenditures for the Idaho and Oregon Riders, Idaho Custom Efficiency incentive payments, and NEEA payments and credits. Appendix 2 also contains financial information showing expenses by funding source for each of Idaho Power's energy efficiency and demand response programs or activities. Appendix 3 shows participation, UC, TRC, energy and demand savings, measure life, and levelized costs for Idaho Power's current energy efficiency programs and activities for 2012. Appendix 4 shows similar data as Appendix 3 but also includes data for past years' program performance and B/C ratios from the utility and TRC perspectives for active programs. Appendix 5 contains program savings and costs separated into Idaho Power's Idaho and Oregon jurisdictions and by funding source. In these appendices, the data has been rounded to the nearest whole unit, which may result in minor rounding differences.

Additional information is contained in the supplements provided in separate documents in two formats. *Supplement 1: Cost-Effectiveness* contains detailed cost-effectiveness information by program and energy-savings measure. Provided in Supplement 1 are the B/C ratios from the UC, TRC, RIM, and PCT perspectives. The *2012 DSM Detailed Expenses by Program* table reports expenses by funding source and separates the company's DSM expenses by expense type, incentive expenses, labor/administration, materials, other expenses, and purchased services. *Supplement 2: Evaluation* contains copies of Idaho Power's third-party evaluations and reports. A CD is attached in Supplement 2 and contains copies of *NEEA Market Effects Evaluations*. A searchable, linked table with the title, study manager, evaluation type, and other information are included with each supplement.

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## **Appendix 1.** Idaho Rider, Oregon Rider, Idaho Custom Efficiency, and NEEA funding balances

| | | |
|---|---|---|
| **Idaho Energy Efficiency Rider** | | |
| 2012 Beginning Balance | $ | (5,321,997) |
| 2012 Funding plus Accrued Interest | | 35,101,807 |
| **Total 2012 Funds** | | **29,779,810** |
| 2012 Expenses | | (25,822,044) |
| 2011 AC Cool Credit Disallowance | | 82,856 |
| **2012 Year-End Balance** | **$** | **4,040,622** |
| **Oregon Energy Efficiency Rider** | | |
| 2012 Beginning Balance | $ | (3,537,441) |
| 2012 Funding plus Accrued Interest | | 1,004,836 |
| **Total 2012 Funds** | | **(2,532,605)** |
| 2012 Expenses | | (1,382,330) |
| **2012 Year-End Balance** | **$** | **(3,914,935)** |
| **Idaho Custom Efficiency Incentives** | | |
| 2012 Beginning Balance Accrued Incentives | $ | (7,018,385) |
| 2012 Beginning Balance Accrued Interest | | (212,339) |
| **2012 Total Beginning Balance** | **$** | **(7,230,724)** |
| 2012 Incentives Accrued | | (6,019,222) |
| 2012 Interest Accrued | | (836,255) |
| **2012 Year-End Balance** | **$** | **(14,086,201)** |
| **NEEA Payments and Escrow Credit Funds Balance** | | |
| 2012 Idaho Power Contractual Obligation[a] | $ | 3,379,756 |
| **2012 Year-End Balance** | **$** | **3,379,756** |

[a] Idaho Power shall prepay estimated expenses quarterly, where the amount shall be amortized over the respective quarter. Funding of NEEA, approved by IPUC Order 31080 dated 5/12/10. Reconciliation between the estimated expenditures and the actual expenditures for the quarter will be completed 30 days after the quarter end or by March 1 for year-end. A true-up of the variance will be included in the next quarter's invoice, not to exceed 125 percent of its five-year total direct-funding contribution.

## **Appendix 2.** 2012 DSM expenses by funding source (dollars)

| Sector/Program | Idaho Rider | Oregon Rider | Idaho Power | Total Program |
|---|---|---|---|---|
| **Energy Efficiency/Demand Response** | | | | |
| **Residential** | | | | |
| A/C Cool Credit[a] | $ 4,804,566 | $ 92,810 | $ 830,618 | **$ 5,727,994** |
| Ductless Heat Pump Pilot | 153,017 | 6,850 | 0 | **159,867** |
| Energy Efficient Lighting | 1,110,329 | 16,507 | 0 | **1,126,836** |
| Energy House Calls | 272,666 | 3,217 | 0 | **275,884** |
| ENERGY STAR® Homes | 450,727 | 2,458 | 0 | **453,186** |
| Heating & Cooling Efficiency Program | 175,483 | 6,798 | 0 | **182,281** |
| Home Improvement Program | 385,091 | 0 | 0 | **385,091** |
| Home Products Program | 640,098 | 18,829 | 105 | **659,032** |
| Oregon Residential Weatherization | 0 | 4,051 | 465 | **4,516** |
| Rebate Advantage | 34,926 | 2,316 | 0 | **37,241** |
| See Ya Later Refrigerator | 596,167 | 16,979 | 0 | **613,146** |
| Weatherization Assistance for Qualified Customers | 0 | 0 | 1,370,141 | **1,370,141** |
| Weatherization Solutions for Eligible Customers | 1,048,461 | 0 | 22,094 | **1,070,556** |
| **Commercial/Industrial** | | | | |
| Building Efficiency | 1,579,121 | 13,451 | 0 | **1,592,572** |
| Comprehensive Lighting | 64,094 | 0 | 0 | **64,094** |
| Easy Upgrades | 5,150,422 | 199,331 | 0 | **5,349,753** |
| FlexPeak Management[a] | 98,973 | 150,489 | 2,760,360 | **3,009,822** |
| Oregon Commercial Audit | 0 | 12,470 | 0 | **12,470** |
| Custom Efficiency[b] | 923,050 | 115,866 | 6,053,665 | **7,092,581** |
| **Irrigation** | | | | |
| Irrigation Efficiency Rewards | 1,978,729 | 360,689 | 33,782 | **2,373,201** |
| Irrigation Peak Rewards[a] | 1,309,107 | 95,863 | 11,018,394 | **12,423,364** |
| **Energy Efficiency/Demand Response Total** | **$ 20,775,027** | **$ 1,118,975** | **$ 22,089,624** | **$ 43,983,625** |
| **Market Transformation** | | | | |
| NEEA[c] | 3,210,768 | 168,988 | 0 | **3,379,756** |
| **Market Transformation Total** | **$ 3,210,768** | **$ 168,988** | **$ 0** | **$ 3,379,756** |
| **Other Programs and Activities** | | | | |
| **Residential** | | | | |
| Residential Economizer Pilot[d] | 93,593 | (101) | 0 | **93,491** |
| Residential Energy Efficiency Education Initiative | 165,919 | 8,819 | 0 | **174,738** |
| **Commercial** | | | | |
| Commercial Energy Efficiency Education Initiative | 70,099 | 3,689 | 0 | **73,788** |
| **Other** | | | | |
| Energy Efficiency Direct Program Overhead | 271,622 | 14,329 | 0 | **285,951** |
| **Other Programs and Activities Total** | **$ 601,233** | **$ 26,736** | **$ 0** | **$ 627,968** |
| **Indirect Program Expenses** | | | | |
| Residential Overhead | 172,819 | 9,051 | 0 | **181,869** |
| Commercial/Industrial/Irrigation Overhead | 171,673 | 9,096 | 7,784 | **188,554** |
| Energy Efficiency Accounting and Analysis | 898,944 | 47,050 | 142,241 | **1,088,236** |
| Energy Efficiency Advisory Group | 2,710 | 142 | 0 | **2,853** |
| Special Accounting Entries[e] | (93,985) | 2,291 | (34,308) | **(126,002)** |
| **Indirect Program Expenses Total** | **$ 1,152,161** | **$ 67,631** | **$ 115,718** | **$ 1,335,509** |
| **Totals** | **$ 25,739,188** | **$ 1,382,330** | **$ 22,205,341** | **$ 49,326,859** |

[a] Per order 32426 the IPUC determined that IPC may recover 100 percent of its Idaho demand response incentives through the PCA mechanism.
[b] Idaho Custom Efficiency incentives, Idaho Power balance of $6,053,665, not included in base rates for 2012.
[C] NEEA Funding addressed in IPUC per Order No. 31080, dated May 12, 2010. 2013 annual expense expected at $3.8 million (see footnote, Appendix 1 for additional information).
[d] Residential Economizer 2011 Oregon Rider balance of $101 was reclassified to Idaho Rider in 2012.
[e] Special Accounting Entries, Idaho Power accrual amount of ($34,146), not included in base rates for 2012.

## **Appendix 3.** 2012 DSM program activity

| Program | Participants | Total Costs | | Savings | | Measure Life (Years) | Nominal Levelized Costs[a] | |
|---|---|---|---|---|---|---|---|---|
| | | Utility[b] | Resource[c] | Annual Energy (kWh) | Peak Demand[d] (MW) | | Utility ($/kWh) | Total Resource ($/kWh) |
| **Demand Response** | | | | | | | | |
| A/C Cool Credit | 36,454 homes | $ 5,727,994 | $ 5,727,994 | n/a | 44.9 | n/a | n/a | n/a |
| Irrigation Peak Rewards[1] | 2,177 service points | 12,423,364 | 12,423,364 | n/a | 339.9 | n/a | n/a | n/a |
| FlexPeak Management | 102 sites | 3,009,822 | 3,009,822 | n/a | 52.8 | n/a | n/a | n/a |
| **Total** | | **$ 21,161,180** | **$ 21,161,180** | **n/a** | **437.6** | | | |
| **Energy Efficiency** | | | | | | | | |
| **Residential** | | | | | | | | |
| Ductless Heat Pump Pilot | 127 homes | 159,867 | 617,833 | 444,500 | | 20 | $ 0.024 | $ 0.094 |
| Energy Efficient Lighting | 925,460 bulbs | 1,126,836 | 2,407,355 | 16,708,659 | | 5 | 0.012 | 0.025 |
| Energy House Calls | 668 homes | 275,884 | 275,884 | 1,192,039 | | 18 | 0.016 | 0.016 |
| ENERGY STAR® Homes Northwest | 410 homes | 453,186 | 871,310 | 537,447 | | 35 | 0.046 | 0.089 |
| Heating & Cooling Efficiency Program | 141 projects | 182,281 | 676,530 | 688,855 | | 20 | 0.018 | 0.066 |
| Home Improvement Program | 840 insulation projects | 385,091 | 812,827 | 457,353 | | 45 | 0.044 | 0.093 |
| Home Products Program | 16,675 appliances/fixtures | 659,032 | 817,924 | 887,222 | | 14 | 0.061 | 0.075 |
| Oregon Residential Weatherization | 5 home | 4,516 | 11,657 | 11,985 | | 30 | 0.022 | 0.022 |
| Rebate Advantage | 35 homes | 37,241 | 71,911 | 187,108 | | 25 | 0.012 | 0.024 |
| See ya later, refrigerator® | 3,176 refrigerators/freezers | 613,146 | 613,146 | 1,576,426 | | 8 | 0.046 | 0.046 |
| Weatherization Assistance for Qualified Customers | 238 homes/non-profits | 1,370,141 | 1,819,945 | 648,304 | | 25 | 0.129 | 0.172 |
| Weatherization Solutions for Eligible Customers | 141 homes | 1,070,556 | 1,070,556 | 257,466 | | 25 | 0.254 | 0.254 |
| **Sector Total** | | **$ 6,337,777** | **$ 10,066,879** | **23,597,363** | | **9** | **$ 0.029** | **$ 0.046** |
| **Commercial** | | | | | | | | |
| Building Efficiency | 84 projects | 1,592,572 | 8,204,883 | 20,450,037 | 2.3 | 12 | 0.007 | 0.036 |
| Easy Upgrades | 1,838 projects | 5,349,753 | 9,245,297 | 41,568,672 | 4.7 | 12 | 0.012 | 0.020 |
| Oregon Commercial Audits | 14 audits | 12,470 | 12,470 | | | | | |
| **Sector Total** | | **$ 6,954,795** | **$ 17,462,650** | **62,018,709** | **7.1** | **12** | **$ 0.010** | **$ 0.025** |
| **Industrial** | | | | | | | | |
| Custom Efficiency[2] | 126 projects | 7,092,581 | 12,975,629 | 54,253,106 | 7.6 | 12 | 0.012 | 0.021 |
| **Sector Total** | | **$ 7,092,581** | **$ 12,975,629** | **54,253,106** | **7.6** | **12** | **$ 0.012** | **$ 0.021** |
| **Irrigation** | | | | | | | | |
| Irrigation Efficiency Rewards[3] | 908 projects | 2,373,201 | 11,598,185 | 12,617,164 | 3.1 | 8 | 0.022 | 0.110 |
| **Sector Total** | | **$ 2,373,201** | **$ 11,598,185** | **12,617,164** | **3.1** | **8** | **$ 0.022** | **$ 0.110** |

## **Appendix 3.** 2012 DSM program activity (continued)

| Program | Participants | Total Costs | | Savings | | Measure Life (Years) | Nominal Levelized Costs[a] | |
|---|---|---|---|---|---|---|---|---|
| | | Utility[b] | Resource[c] | Annual Energy (kWh) | Peak Demand[d] (MW) | | Utility ($/kWh) | Total Resource ($/kWh) |
| **Market Transformation** | | | | | | | | |
| Northwest Energy Efficiency Alliance[4] | | $ 3,379,756 | $ 3,379,756 | 17,741,430 | | | | |
| **Other Programs and Activities** | | | | | | | | |
| **Residential** | | | | | | | | |
| Residential Economizer | | 93,491 | 93,491 | | | | | |
| Residential Energy Efficiency Education Initiative | | 174,738 | 174,738 | | | | | |
| **Commercial** | | | | | | | | |
| Commercial Education Initiative | | 73,788 | 73,788 | | | | | |
| Comprehensive Lighting[5] | | 64,094 | 64,094 | | | | | |
| **Other** | | | | | | | | |
| Energy Efficiency Direct Program Overhead | | 285,951 | 285,951 | | | | | |
| Local Energy Efficiency Funds | | | | | | | | |
| **Total Program Direct Expense** | | **$ 47,991,350** | **$ 77,336,341** | **170,227,773** | **455.3** | | | |
| Indirect Program Expenses | | 1,335,509 | | | | | | |
| **Total DSM Expense** | | **$ 49,326,859** | | | | | | |

[a] Levelized Costs are based on financial inputs from Idaho Power's 2011 IRP and calculations include line-loss adjusted energy savings.

[b] The Total Utility Cost is all cost incurred by Idaho Power to implement and manage a DSM program.

[c] The total resource cost (TRC) is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.

[d] Summer Peak Demand is reported where program MW reduction is documented. Demand response program reductions are reported with 13-percent peak loss assumptions.

[1] Peak demand represents enrolled capacity of the program during summer 2012.

[2] Custom Efficiency savings includes 19 Green Motors participants totaling 54,154 kWh of annual savings, but not in project totals.

[3] Irrigation Efficiency includes 23 Green Motors participants totaling 36,039 kWh of annual savings, not counted in project totals.

[4] Savings are preliminary estimates provided by NEEA.

[5] Comprehensive Lighting annual savings of 447,620 kWh from 6 projects are included in Easy Upgrades savings totals. For the combined cost-effectiveness analysis, see Easy Upgrades in Supplement 1.

## **Appendix 4.** Historical DSM expense and performance 2002–2012

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/ Cost Ratios[b]: Utility | Program Life Benefit/ Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Demand Response** | | | | | | | | | | | |
| A/C Cool Credit | | | | | | | | | | | |
| 2003 | 204 | $ 275,645 | $ 275,645 | | | 0.0 | | | | | |
| 2004 | 420 | 287,253 | 287,253 | | | 0.5 | | | | | |
| 2005 | 2,369 | 754,062 | 754,062 | | | 3.1 | | | | | |
| 2006 | 5,369 | 1,235,476 | 1,235,476 | | | 6.3 | | | | | |
| 2007 | 13,692 | 2,426,154 | 2,426,154 | | | 12.2 | | | | | |
| 2008 | 20,195 | 2,969,377 | 2,969,377 | | | 25.5 | | | | | |
| 2009 | 30,391 | 3,451,988 | 3,451,988 | | | 38.5 | | | | | |
| 2010 | 30,803 | 2,002,546 | 2,002,546 | | | 39.0 | | | | | |
| 2011 | 37,728 | 2,896,542 | 2,896,542 | | | 24.0 | | | | | |
| 2012 | 36,454 | 5,727,994 | 5,727,994 | | | 44.9 | | | | | |
| **Total** | | **$ 22,027,036** | **$ 22,027,036** | | | | | | | **1.33** | **1.33** |
| FlexPeak Management | | | | | | | | | | | |
| 2009 | 33 | 528,681 | 528,681 | | | 19.3 | | | | | |
| 2010 | 60 | 1,902,680 | 1,902,680 | | | 47.5 | | | | | |
| 2011 | 111 | 2,057,730 | 2,057,730 | | | 58.8 | | | | | |
| 2012 | 102 | 3,009,822 | 3,009,822 | | | 52.8 | | | | | |
| **Total** | | **$ 7,498,913** | **$ 7,498,913** | | | | | | | **1.22** | **1.22** |
| Irrigation Peak Rewards | | | | | | | | | | | |
| 2004 | 58 | 344,714 | 344,714 | | | 5.6 | | | | | |
| 2005 | 894 | 1,468,282 | 1,468,282 | | | 40.3 | | | | | |
| 2006 | 906 | 1,324,418 | 1,324,418 | | | 31.8 | | | | | |
| 2007 | 947 | 1,615,881 | 1,615,881 | | | 37.4 | | | | | |
| 2008 | 897 | 1,431,840 | 1,431,840 | | | 35.1 | | | | | |
| 2009 | 1,512 | 9,655,283 | 9,655,283 | | | 160.2 | | | | | |
| 2010 | 2,038 | 13,330,826 | 13,514,246 | | | 249.7 | | | | | |
| 2011 | 2,342 | 12,086,222 | 12,086,222 | | | 320.0 | | | | | |
| 2012 | 2,433 | 12,423,364 | 12,423,364 | | | 339.9 | | | | | |
| **Total** | | **$ 53,680,830** | **$ 53,864,250** | | | | | | | **1.79** | **1.72** |

## **Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Savings and Demand Reduction: Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Efficiency** | | | | | | | | | | | |
| Ductless Heat Pump Pilot | | | | | | | | | | | |
| 2009 | 96 | $ 202,005 | $ 451,605 | 409,180 | 0.05 | | 18 | $ 0.031 | $ 0.086 | | |
| 2010 | 104 | 189,231 | 439,559 | 364,000 | 0.04 | | 20 | 0.044 | 0.103 | | |
| 2011 | 131 | 191,183 | 550,033 | 458,500 | 0.05 | | 20 | 0.028 | 0.081 | | |
| 2012 | 127 | 159,867 | 617,833 | 444,500 | 0.05 | | 20 | 0.024 | 0.094 | | |
| **Total** | **458** | **$ 742,286** | **$ 2,059,030** | **1,676,180** | | | **20** | **$ 0.036** | **$ 0.105** | **4.22** | **1.44** |
| Energy Efficiency Packets | | | | | | | | | | | |
| 2002 | 2,925 | 755 | 755 | 155,757 | 0.02 | | 7 | 0.001 | 0.001 | | |
| **Total** | **2,925** | **$ 755** | **$ 755** | **155,757** | | | **7** | **$ 0.001** | **$ 0.001** | | |
| Energy Efficient Lighting | | | | | | | | | | | |
| 2002 | 11,618 | 243,033 | 310,643 | 3,299,654 | 0.38 | | 7 | 0.012 | 0.015 | | |
| 2003 | 12,662 | 314,641 | 464,059 | 3,596,150 | 0.41 | | 7 | 0.014 | 0.021 | | |
| 2004 | | | | | | | | | | | |
| 2005 | 43,760 | 73,152 | 107,810 | 1,734,646 | 0.20 | | 7 | 0.007 | 0.010 | | |
| 2006 | 178,514 | 298,754 | 539,877 | 6,302,794 | 0.72 | | 7 | 0.008 | 0.014 | | |
| 2007 | 219,739 | 557,646 | 433,626 | 7,207,439 | 0.82 | | 7 | 0.012 | 0.017 | | |
| 2008 | 436,234 | 1,018,292 | 793,265 | 14,309,444 | 1.63 | | 7 | 0.011 | 0.013 | | |
| 2009 | 549,846 | 1,207,366 | 1,456,796 | 13,410,748 | 1.53 | | 5 | 0.020 | 0.024 | | |
| 2010 | 1,190,139 | 2,501,278 | 3,976,476 | 28,082,738 | 3.21 | | 5 | 0.020 | 0.031 | | |
| 2011 | 1,039,755 | 1,719,133 | 2,764,623 | 19,694,381 | 2.25 | | 5 | 0.015 | 0.024 | | |
| 2012 | 925,460 | 1,126,836 | 2,407,355 | 16,708,659 | 1.91 | | 5 | 0.012 | 0.025 | | |
| **Total** | **4,607,727** | **$ 9,060,131** | **$ 13,254,530** | **114,346,653** | | **0.0** | **5** | **$ 0.017** | **$ 0.025** | **4.47** | **3.05** |
| Energy House Calls | | | | | | | | | | | |
| 2002 | 17 | 26,053 | 26,053 | 25,989 | 0.00 | | 20 | 0.082 | 0.082 | | |
| 2003 | 420 | 167,076 | 167,076 | 602,723 | 0.07 | | 20 | 0.023 | 0.023 | | |
| 2004 | 1,708 | 725,981 | 725,981 | 2,349,783 | 0.27 | | 20 | 0.025 | 0.025 | | |
| 2005 | 891 | 375,610 | 375,610 | 1,775,770 | 0.20 | | 20 | 0.017 | 0.017 | | |
| 2006 | 819 | 336,701 | 336,701 | 777,244 | 0.09 | | 20 | 0.035 | 0.035 | | |
| 2007 | 700 | 336,372 | 336,372 | 699,899 | 0.08 | | 20 | 0.039 | 0.039 | | |
| 2008 | 1,099 | 484,379 | 484,379 | 883,038 | 0.10 | | 20 | 0.045 | 0.045 | | |
| 2009 | 1,266 | 569,594 | 569,594 | 928,875 | 0.11 | | 20 | 0.052 | 0.052 | | |

## **Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Savings and Demand Reduction: Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Efficiency** | | | | | | | | | | | |
| Energy House Calls | | | | | | | | | | | |
| 2010 | 1,602 | $ 762,330 | $ 762,330 | 1,198,655 | 0.14 | | 20 | $ 0.054 | $ 0.054 | | |
| 2011 | 881 | 483,375 | 483,375 | 1,214,004 | 0.14 | | 20 | 0.027 | 0.027 | | |
| 2012 | 668 | 275,884 | 275,884 | 1,192,039 | 0.14 | | 18 | 0.016 | 0.016 | | |
| **Total** | **10,071** | **$ 4,543,355** | **$ 4,543,355** | **11,648,019** | | | **18** | **$ 0.034** | **$ 0.034** | **3.05** | **3.05** |
| ENERGY STAR® Homes Northwest | | | | | | | | | | | |
| 2003 | | 13,597 | 13,597 | 0 | | | | | | | |
| 2004 | 44 | 140,165 | 335,437 | 101,200 | 0.01 | 0.1 | 25 | 0.103 | 0.246 | | |
| 2005 | 200 | 253,105 | 315,311 | 415,600 | 0.05 | 0.4 | 25 | 0.045 | 0.056 | | |
| 2006 | 439 | 469,609 | 602,651 | 912,242 | 0.10 | 0.9 | 25 | 0.038 | 0.049 | | |
| 2007 | 303 | 475,044 | 400,637 | 629,634 | 0.07 | 0.6 | 25 | 0.056 | 0.047 | | |
| 2008 | 254 | 302,061 | 375,007 | 468,958 | 0.05 | 0.6 | 25 | 0.048 | 0.059 | | |
| 2009 | 474 | 355,623 | 498,622 | 705,784 | 0.08 | 1.1 | 25 | 0.039 | 0.055 | | |
| 2010 | 630 | 375,605 | 579,495 | 883,260 | 0.10 | | 25 | 0.033 | 0.051 | | |
| 2011 | 308 | 259,762 | 651,249 | 728,030 | 0.08 | | 32 | 0.020 | 0.051 | | |
| 2012 | 410 | 453,186 | 871,310 | 537,447 | 0.06 | | 35 | 0.046 | 0.089 | | |
| **Total** | **3,062** | **$ 3,097,757** | **$ 4,643,317** | **5,382,155** | | | **35** | **$ 0.039** | **$ 0.058** | **3.77** | **2.51** |
| Heating & Cooling Efficiency Program | | | | | | | | | | | |
| 2006 | | 17,444 | 17,444 | | | | | | | | |
| 2007 | 4 | 488,211 | 494,989 | 1,595 | 0.00 | | 18 | 27.344 | 27.710 | | |
| 2008 | 359 | 473,551 | 599,771 | 561,440 | 0.06 | | 18 | 0.073 | 0.092 | | |
| 2009 | 349 | 478,373 | 764,671 | 1,274,829 | 0.15 | | 18 | 0.034 | 0.054 | | |
| 2010 | 217 | 327,669 | 1,073,604 | 1,104,497 | 0.13 | | 20 | 0.025 | 0.083 | | |
| 2011 | 130 | 195,770 | 614,523 | 733,405 | 0.08 | | 20 | 0.018 | 0.056 | | |
| 2012 | 141 | 182,281 | 676,530 | 688,855 | 0.08 | | 20 | 0.018 | 0.066 | | |
| **Total** | **1,200** | **$ 2,163,300** | **$ 4,241,532** | **4,364,621** | | | **20** | **$ 0.041** | **$ 0.080** | **3.49** | **1.78** |

## **Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/ Cost Ratios[b]: Utility | Program Life Benefit/ Cost Ratios[b]: Total Resource | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Efficiency** | | | | | | | | | | | | |
| Home Improvement Program | | | | | | | | | | | | |
| 2008 | 282 | $ 123,454 | $ 157,866 | 317,814 | 0.04 | | 25 | $ 0.029 | $ 0.037 | | | |
| 2009 | 1,188 | 321,140 | 550,148 | 1,338,876 | 0.15 | | 25 | 0.019 | 0.032 | | | |
| 2010 | 3,537 | 944,716 | 2,112,737 | 3,986,199 | 0.46 | | 45 | 0.016 | 0.035 | | | |
| 2011 | 2,275 | 666,041 | 2,704,816 | 917,519 | 0.10 | | 45 | 0.038 | 0.155 | | | |
| 2012 | 840 | 385,091 | 812,827 | 457,353 | 0.05 | | 45 | 0.044 | 0.093 | | | |
| **Total** | **8,122** | **$ 2,440,442** | **$ 6,338,394** | **7,017,761** | | | **45** | **$ 0.022** | **$ 0.058** | **3.15** | **1.21** | 2 |
| Home Products Program | | | | | | | | | | | | |
| 2007 | | 9,275 | 9,275 | 0 | | | | | | | | |
| 2008 | 3,034 | 250,860 | 468,056 | 541,615 | 0.06 | | 15 | 0.044 | 0.082 | | | |
| 2009 | 9,499 | 511,313 | 844,811 | 1,638,038 | 0.19 | | 15 | 0.031 | 0.051 | | | |
| 2010 | 16,322 | 832,161 | 1,025,151 | 1,443,580 | 0.16 | | 15 | 0.057 | 0.070 | | | |
| 2011 | 15,896 | 638,323 | 1,520,977 | 1,485,326 | 0.17 | | 15 | 0.034 | 0.080 | | | |
| 2012 | 16,675 | 659,032 | 817,924 | 887,222 | 0.10 | | 14 | 0.061 | 0.075 | | | |
| **Total** | **61,426** | **$ 2,900,964** | **$ $4,686,194** | **5,995,781** | | | **14** | **$ 0.048** | **$ 0.078** | **2.26** | **1.40** | |
| Oregon Residential Weatherization | | | | | | | | | | | | |
| 2002 | 24 | (662) | 23,971 | 4,580 | | | 25 | 0.010 | 0.389 | | | |
| 2003 | | (943) | | | | | | | | | | 3 |
| 2004 | 4 | 1,057 | 1,057 | | | | | | | | | |
| 2005 | 4 | 612 | 3,608 | 7,927 | 0.00 | | 25 | 0.006 | 0.034 | | | |
| 2006 | | 4,126 | 4,126 | | | | | | | | | 4 |
| 2007 | 1 | 3,781 | 5,589 | 9,971 | 0.00 | | 25 | 0.028 | 0.042 | | | |
| 2008 | 3 | 7,417 | 28,752 | 22,196 | 0.00 | | 25 | 0.025 | 0.096 | | | |
| 2009 | 1 | 7,645 | 8,410 | 2,907 | 0.00 | | 25 | 0.203 | 0.223 | | | |
| 2010 | 1 | 6,050 | 6,275 | 320 | 0.00 | | 30 | 0.011 | 0.062 | | | |
| 2011 | 8 | 7,926 | 10,208 | 21,908 | 0.00 | | 30 | 0.021 | 0.027 | | | |
| 2012 | 5 | 4,516 | 11,657 | 11,985 | 0.00 | | 30 | 0.022 | 0.056 | | | |
| **Total** | **51** | **$ 41,525** | **$ 103,653** | **81,794** | | | **30** | **$ 0.036** | **$ 0.089** | **3.88** | **1.55** | 5 |

## **Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/ Cost Ratios[b]: Utility | Program Life Benefit/ Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Efficiency** | | | | | | | | | | | |
| Rebate Advantage | | | | | | | | | | | |
| 2003 | 73 | $ 27,372 | $ 79,399 | 227,434 | 0.03 | | 45 | $ 0.008 | $ 0.022 | | |
| 2004 | 105 | 52,187 | 178,712 | 332,587 | 0.04 | | 45 | 0.010 | 0.034 | | |
| 2005 | 98 | 46,173 | 158,462 | 312,311 | 0.04 | | 45 | 0.009 | 0.032 | | |
| 2006 | 102 | 52,673 | 140,289 | 333,494 | 0.04 | | 45 | 0.010 | 0.027 | | |
| 2007 | 123 | 89,269 | 182,152 | 554,018 | 0.06 | | 45 | 0.010 | 0.021 | | |
| 2008 | 107 | 90,888 | 179,868 | 463,401 | 0.05 | | 45 | 0.012 | 0.025 | | |
| 2009 | 57 | 49,525 | 93,073 | 247,348 | 0.03 | | 25 | 0.015 | 0.029 | | |
| 2010 | 35 | 39,402 | 66,142 | 164,894 | 0.02 | | 25 | 0.018 | 0.031 | | |
| 2011 | 25 | 63,469 | 85,044 | 159,325 | 0.02 | | 25 | 0.024 | 0.033 | | |
| 2012 | 35 | 37,241 | 71,911 | 187,108 | 0.02 | | 25 | 0.012 | 0.024 | | |
| **Total** | **760** | **$ 548,199** | **$ 1,235,052** | **2,981,920** | | | **25** | **$ 0.014** | **$ 0.031** | **8.71** | **3.87** |
| See ya later, refrigerator® | | | | | | | | | | | |
| 2009 | 1,661 | 305,401 | 305,401 | 1,132,802 | 0.13 | | 8 | 0.041 | 0.041 | | |
| 2010 | 3,152 | 565,079 | 565,079 | 1,567,736 | 0.18 | | 8 | 0.054 | 0.054 | | |
| 2011 | 3,449 | 654,393 | 654,393 | 1,712,423 | 0.20 | | 8 | 0.046 | 0.046 | | |
| 2012 | 3,176 | 613,146 | 613,146 | 1,576,426 | 0.18 | | 8 | 0.046 | 0.046 | | |
| **Total** | **11,438** | **$ 2,138,019** | **$ 2,138,019** | **5,989,387** | | | **8** | **$ 0.052** | **$ 0.052** | **1.70** | **1.70** |
| Weatherization Solutions for Eligible Customers | | | | | | | | | | | |
| 2008 | 16 | 52,807 | 52,807 | 71,680 | 0.01 | | 25 | 0.057 | 0.057 | | |
| 2009 | 41 | 162,995 | 162,995 | 211,719 | 0.02 | | 25 | 0.059 | 0.059 | | |
| 2010 | 47 | 228,425 | 228,425 | 313,309 | 0.04 | | 25 | 0.056 | 0.056 | | |
| 2011 | 117 | 788,148 | 788,148 | 1,141,194 | 0.13 | | 25 | 0.042 | 0.042 | | |
| 2012 | 141 | 1,070,556 | 1,070,556 | 257,466 | 0.03 | | 25 | 0.254 | 0.254 | | |
| **Total** | **362** | **$ 2,302,931** | **$ 2,302,931** | **1,995,368** | | | **25** | **$ 0.086** | **$ 0.086** | **1.47** | **1.47** |
| Window AC Trade-Up Pilot | | | | | | | | | | | |
| 2003 | 99 | 6,687 | 10,492 | 14,454 | | | 12 | 0.051 | 0.079 | | |
| **Total** | **99** | **$ 6,687** | **$ 10,492** | **14,454** | | | **12** | **$ 0.051** | **$ 0.079** | | |

## **Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential—Weatherization Assistance for Qualified Customers (WAQC)** | | | | | | | | | | | |
| WAQC—Idaho | | | | | | | | | | | |
| 2002 | 197 | $ 235,048 | $ 492,139 | | | | | | | | |
| 2003 | 208 | 228,134 | 483,369 | | | | | | | | |
| 2004 | 269 | 498,474 | 859,482 | 1,271,677 | 0.15 | | 25 | $ 0.0290 | $ 0.050 | | |
| 2005 | 570 | 1,402,487 | 1,927,424 | 3,179,311 | 0.36 | | 25 | 0.0330 | 0.045 | | |
| 2006 | 540 | 1,455,373 | 2,231,086 | 2,958,024 | 0.34 | | 25 | 0.0370 | 0.056 | | |
| 2007 | 397 | 1,292,930 | 1,757,105 | 3,296,019 | 0.38 | | 25 | 0.0290 | 0.040 | | |
| 2008 | 439 | 1,375,632 | 1,755,749 | 4,064,301 | 0.46 | | 25 | 0.0250 | 0.032 | | |
| 2009 | 427 | 1,260,922 | 1,937,578 | 4,563,832 | 0.52 | | 25 | 0.0210 | 0.033 | | |
| 2010 | 373 | 1,205,446 | 2,782,597 | 3,452,025 | 0.39 | | 25 | 0.0260 | 0.060 | | |
| 2011 | 273 | 1,278,112 | 1,861,836 | 2,648,676 | 0.30 | | 25 | 0.0360 | 0.053 | | |
| 2012 | 228 | 1,321,927 | 1,743,863 | 621,464 | 0.02 | | 25 | 0.1590 | 0.210 | | |
| **Total** | **3,921** | **$ 11,554,485** | **$ 17,832,228** | **26,055,329** | | | **25** | **$ 0.0330** | **$ 0.051** | **4.36** | **2.83** |
| WAQC—Oregon | | | | | | | | | | | |
| 2002 | 31 | 24,773 | 47,221 | 68,323 | 0.01 | | 25 | 0.0270 | 0.051 | | |
| 2003 | 29 | 22,255 | 42,335 | 102,643 | 0.01 | | 25 | 0.0160 | 0.031 | | |
| 2004 | 17 | 13,469 | 25,452 | 28,436 | 0.00 | | 25 | 0.0350 | 0.067 | | |
| 2005 | 28 | 44,348 | 59,443 | 94,279 | 0.01 | | 25 | 0.0350 | 0.047 | | |
| 2006 | | | | | | | 25 | | | | |
| 2007 | 11 | 30,694 | 41,700 | 42,108 | 0.00 | | 25 | 0.0540 | 0.074 | | |
| 2008 | 14 | 43,843 | 74,048 | 73,841 | 0.01 | | 25 | 0.0400 | 0.068 | | |
| 2009 | 10 | 33,940 | 46,513 | 114,982 | 0.01 | | 25 | 0.0230 | 0.031 | | |
| 2010 | 27 | 115,686 | 147,712 | 289,627 | 0.03 | | 25 | 0.0300 | 0.038 | | |
| 2011 | 14 | 46,303 | 63,981 | 134,972 | 0.02 | | 25 | 0.0260 | 0.035 | | |
| 2012 | 10 | 48,214 | 76,083 | 26,840 | 0.00 | | 25 | 0.1340 | 0.212 | | |
| **Total** | **191** | **$ 423,525** | **$ 624,488** | **976,051** | | | **25** | **$ 0.0323** | **$ 0.048** | **4.26** | **2.89** |
| WAQC—BPA Supplemental | | | | | | | | | | | |
| 2002 | 75 | 55,966 | 118,255 | 311,347 | 0.04 | | 25 | 0.0130 | 0.028 | | |
| 2003 | 57 | 49,895 | 106,915 | 223,591 | 0.03 | | 25 | 0.0170 | 0.036 | | |
| 2004 | 40 | 69,409 | 105,021 | 125,919 | 0.01 | | 25 | 0.0410 | 0.062 | | |
| **Total** | **172** | **$ 175,270** | **$ 330,191** | **660,857** | | | **25** | **$ 0.0200** | **$ 0.037** | **6.73** | **3.57** |
| **WAQC—All Total** | | **$ 12,153,280** | **$ 18,786,907** | **27,692,237** | | | **25** | **0.0330** | **0.051** | **4.39** | **2.84** |

**Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Commercial** | | | | | | | | | | | |
| Air Care Plus Pilot | | | | | | | | | | | |
| 2003 | 4 | $ 5,764 | $ 9,061 | 33,976 | | | 10 | $ 0.021 | $ 0.033 | | |
| 2004 | | 344 | 344 | | | | | | | | |
| **Total** | **4** | **$ 6,108** | **$ 9,405** | **33,976** | | | **10** | **$ 0.022** | **$ 0.034** | | |
| Building Efficiency Program | | | | | | | | | | | |
| 2004 | | 28,821 | 28,821 | | | | | | | | |
| 2005 | 12 | 194,066 | 233,149 | 494,239 | 0.06 | 0.2 | 12 | 0.043 | 0.052 | | |
| 2006 | 40 | 374,008 | 463,770 | 704,541 | 0.08 | 0.3 | 12 | 0.058 | 0.072 | | |
| 2007 | 22 | 669,032 | 802,839 | 2,817,248 | 0.32 | 0.5 | 12 | 0.015 | 0.040 | | |
| 2008 | 60 | 1,055,009 | 1,671,375 | 6,598,123 | 0.75 | 1.0 | 12 | 0.017 | 0.028 | | |
| 2009 | 72 | 1,327,127 | 2,356,434 | 6,146,139 | 0.70 | 1.3 | 12 | 0.024 | 0.043 | | |
| 2010 | 70 | 1,509,682 | 3,312,963 | 10,819,598 | 1.24 | 0.9 | 12 | 0.016 | 0.035 | | |
| 2011 | 63 | 1,291,425 | 3,320,015 | 11,514,641 | 1.31 | 0.9 | 12 | 0.010 | 0.026 | | |
| 2012 | 84 | 1,592,572 | 8,204,883 | 20,450,037 | 2.33 | 0.6 | 12 | 0.007 | 0.036 | | |
| **Total** | **423** | **$ 8,041,743** | **$ 20,394,250** | **59,544,566** | | | **12** | **$ 0.015** | **$ 0.038** | **6.50** | **2.56** |
| Easy Upgrades | | | | | | | | | | | |
| 2006 | | 31,819 | 31,819 | | | | | | | | |
| 2007 | 104 | 711,494 | 1,882,035 | 5,183,640 | 0.59 | 0.8 | 12 | 0.015 | 0.040 | | |
| 2008 | 666 | 2,992,261 | 10,096,627 | 25,928,391 | 2.96 | 4.5 | 12 | 0.013 | 0.043 | | |
| 2009 | 1,224 | 3,325,505 | 10,076,237 | 35,171,627 | 4.02 | 6.1 | 12 | 0.011 | 0.032 | | |
| 2010 | 1,535 | 3,974,410 | 7,655,397 | 35,824,463 | 4.09 | 7.8 | 12 | 0.013 | 0.024 | | |
| 2011 | 1,732 | 4,719,466 | 9,519,364 | 38,723,073 | 4.42 | 4.4 | 12 | 0.011 | 0.022 | | |
| 2012 | 1,838 | 5,349,753 | 9,245,297 | 41,568,672 | 4.75 | 4.8 | 12 | 0.012 | 0.020 | | |
| **Total** | **7,099** | **$ 21,104,708** | **$ 48,506,776** | **182,399,866** | | | **12** | **$ 0.013** | **$ 0.029** | **7.57** | **3.29** |
| Holiday Lighting | | | | | | | | | | | |
| 2008 | 14 | 28,782 | 73,108 | 259,092 | 0.03 | | 10 | 0.014 | 0.035 | | |
| 2009 | 32 | 33,930 | 72,874 | 142,109 | 0.02 | | 10 | 0.031 | 0.066 | | |
| 2010 | 25 | 46,132 | 65,308 | 248,865 | 0.03 | | 10 | 0.024 | 0.034 | | |
| 2011 | 6 | 2,568 | 2,990 | 66,189 | 0.01 | | 10 | 0.004 | 0.005 | | |
| **Total** | **77** | **$ 111,412** | **$ 214,280** | **716,255** | | | **10** | **$ 0.019** | **$ 0.037** | **3.70** | **1.92** |

## **Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Savings and Demand Reduction: Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Commercial** | | | | | | | | | | | |
| Oregon Commercial Audit | | | | | | | | | | | |
| 2002 | 24 | $ 5,200 | $ 5,200 | | | | | | | | |
| 2003 | 21 | 0 | 4,000 | | | | | | | | |
| 2004 | 7 | 0 | 0 | | | | | | | | |
| 2005 | 7 | 5,450 | 5,450 | | | | | | | | |
| 2006 | 6 | | | | | | | | | | |
| 2007 | | 1,981 | 1,981 | | | | | | | | |
| 2008 | | 58 | 58 | | | | | | | | |
| 2009 | 41 | 20,732 | 20,732 | | | | | | | | |
| 2010 | 22 | 5,049 | 5,049 | | | | | | | | |
| 2011 | 12 | 13,597 | 13,597 | | | | | | | | |
| 2012 | 14 | 12,470 | 12,470 | | | | | | | | |
| **Total** | **154** | **$ 64,537** | **$ 68,537** | | | | | | | | |
| Oregon School Efficiency | | | | | | | | | | | |
| 2005 | | 86 | 86 | | | | | | | | |
| 2006 | 6 | 24,379 | 89,771 | 223,368 | 0.03 | | 12 | $ 0.012 | $ 0.044 | | |
| **Total** | **6** | **$ 24,465** | **$ 89,857** | **223,368** | | | **12** | **$ 0.012** | **$ 0.044** | | |
| **Industrial** | | | | | | | | | | | |
| Custom Efficiency | | | | | | | | | | | |
| 2003 | | 1,303 | 1,303 | | | | | | | | |
| 2004 | 1 | 112,311 | 133,441 | 211,295 | 0.02 | | 12 | 0.058 | 0.069 | | |
| 2005 | 24 | 1,128,076 | 3,653,152 | 12,016,678 | 1.37 | | 12 | 0.010 | 0.033 | | |
| 2006 | 40 | 1,625,216 | 4,273,885 | 19,211,605 | 2.19 | | 12 | 0.009 | 0.024 | | |
| 2007 | 49 | 3,161,866 | 7,012,686 | 29,789,304 | 3.40 | 3.6 | 12 | 0.012 | 0.026 | | |
| 2008 | 101 | 4,045,671 | 16,312,379 | 41,058,639 | 4.69 | 4.8 | 12 | 0.011 | 0.044 | | |
| 2009 | 132 | 6,061,467 | 10,848,123 | 51,835,612 | 5.92 | 6.7 | 12 | 0.013 | 0.024 | | |
| 2010 | 223 | 8,778,125 | 17,172,176 | 71,580,075 | 8.17 | 9.5 | 12 | 0.014 | 0.027 | | |
| 2011 | 166 | 8,783,811 | 19,830,834 | 67,979,157 | 7.76 | 7.8 | 12 | 0.012 | 0.026 | | |
| 2012 | 126 | 7,092,581 | 12,975,629 | 54,253,106 | 6.19 | 7.6 | 12 | 0.012 | 0.021 | | |
| **Total** | **862** | **$ 40,790,426** | **$ 92,213,608** | **347,935,471** | | | **12** | **$ 0.013** | **$ 0.029** | **7.48** | **3.31** |

## **Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/ Cost Ratios[b]: Utility | Program Life Benefit/ Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Irrigation** | | | | | | | | | | | |
| Irrigation Efficiency Program | | | | | | | | | | | |
| 2003 | 2 | $ 41,089 | $ 54,609 | 36,792 | 0.00 | 0.0 | 15 | $ 0.106 | $ 0.141 | | |
| 2004 | 33 | 120,808 | 402,978 | 802,812 | 0.09 | 0.4 | 15 | 0.014 | 0.048 | | |
| 2005 | 38 | 150,577 | 657,460 | 1,012,883 | 0.12 | 0.4 | 15 | 0.014 | 0.062 | | |
| 2006 | 559 | 2,779,620 | 8,514,231 | 16,986,008 | 1.94 | 5.1 | 8 | 0.024 | 0.073 | | |
| 2007 | 816 | 2,001,961 | 8,694,772 | 12,304,073 | 1.40 | 3.4 | 8 | 0.024 | 0.103 | | |
| 2008 | 961 | 2,103,702 | 5,850,778 | 11,746,395 | 1.34 | 3.5 | 8 | 0.026 | 0.073 | | |
| 2009 | 887 | 2,293,896 | 6,732,268 | 13,157,619 | 1.50 | 3.4 | 8 | 0.026 | 0.077 | | |
| 2010 | 753 | 2,200,814 | 6,968,598 | 10,968,430 | 1.25 | 3.3 | 8 | 0.030 | 0.096 | | |
| 2011 | 880 | 2,360,304 | 13,281,492 | 13,979,833 | 1.60 | 3.8 | 8 | 0.020 | 0.113 | | |
| 2012 | 908 | 2,373,201 | 11,598,185 | 12,617,164 | 1.44 | 3.1 | 8 | 0.022 | 0.110 | | |
| **Total** | **5,837** | **$ 16,425,973** | **$ 62,755,370** | **93,612,009** | | | **8** | **$ 0.026** | **$ 0.098** | **4.66** | **1.76** |
| **Other Programs** | | | | | | | | | | | |
| Building Operator Training | | | | | | | | | | | |
| 2003 | 71 | 48,853 | 48,853 | 1,825,000 | 0.21 | | 5 | 0.006 | 0.006 | | |
| 2004 | 26 | 43,969 | 43,969 | 650,000 | 0.07 | | 5 | 0.014 | 0.014 | | |
| 2005 | 7 | 1,750 | 4,480 | 434,167 | 0.05 | | 5 | 0.001 | 0.002 | | |
| **Total** | **104** | **$ 94,572** | **$ 97,302** | **2,909,167** | | | **5** | **$ 0.007** | **$ 0.007** | | |
| Commercial Education Initiative | | | | | | | | | | | |
| 2005 | | 3,497 | 3,497 | | | | | | | | |
| 2006 | | 4,663 | 4,663 | | | | | | | | |
| 2007 | | 26,823 | 26,823 | | | | | | | | |
| 2008 | | 72,738 | 72,738 | | | | | | | | |
| 2009 | | 120,584 | 120,584 | | | | | | | | |
| 2010 | | 68,765 | 68,765 | | | | | | | | |
| 2011 | | 89,856 | 89,856 | | | | | | | | |
| 2012 | | 73,788 | 73,788 | | | | | | | | |
| **Total** | | **$ 460,714** | **$ 460,714** | | | | | | | | |

## **Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | | Levelized Costs[a] | | Program Life Benefit/ Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost[c] | Resource Cost[d] | Annual Energy (kWh) | Average Energy[e] (aMW) | Peak Demand[f] (MW) | Measure Life (Years) | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Other Programs** | | | | | | | | | | | |
| Comprehensive Lighting | | | | | | | | | | | |
| 2011 | | $ 2,404 | $ 2,404 | | | | | | | | |
| 2012 | | 64,094 | 64,094 | | | | | | | | |
| **Total** | | **$ 66,498** | **$ 66,498** | | | | | | | | |
| Distribution Efficiency Initiative | | | | | | | | | | | |
| 2005 | | 21,552 | 43,969 | | | | | | | | |
| 2006 | | 24,306 | 24,306 | | | | | | | | |
| 2007 | | 8,987 | 8,987 | | | | | | | | |
| 2008 | | (1,913) | (1,913) | | | | | | | | |
| **Total** | | **$ 52,932** | **$ 75,349** | | | | | | | | |
| DSM Direct Program Overhead | | | | | | | | | | | |
| 2007 | | 56,909 | 56,909 | | | | | | | | |
| 2008 | | 169,911 | 169,911 | | | | | | | | |
| 2009 | | 164,957 | 164,957 | | | | | | | | |
| 2010 | | 117,874 | 117,874 | | | | | | | | |
| 2011 | | 210,477 | 210,477 | | | | | | | | |
| 2012 | | 285,951 | 285,951 | | | | | | | | |
| **Total** | | **$ 1,006,079** | **$ 1,006,079** | | | | | | | | |
| Other C&RD and CRC BPA | | | | | | | | | | | |
| 2002 | | 55,722 | 55,722 | | | | | | | | |
| 2003 | | 67,012 | 67,012 | | | | | | | | |
| 2004 | | 108,191 | 108,191 | | | | | | | | |
| 2005 | | 101,177 | 101,177 | | | | | | | | |
| 2006 | | 124,956 | 124,956 | | | | | | | | |
| 2007 | | 31,645 | 31,645 | | | | | | | | |
| 2008 | | 6,950 | 6,950 | | | | | | | | |
| **Total** | | **$ 495,654** | **$ 495,654** | | | | | | | | |

**Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Savings and Demand Reduction: Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Other Programs** | | | | | | | | | | | |
| Residential Economizer Pilot | | | | | | | | | | | |
| 2011 | | $ 101,713 | $ 101,713 | | | | | | | | |
| 2012 | | 93,491 | 93,491 | | | | | | | | |
| **Total** | | **$ 195,204** | **$ 195,204** | | | | | | | | |
| Residential Education Initiative | | | | | | | | | | | |
| 2005 | | 7,498 | 7,498 | | | | | | | | |
| 2006 | | 56,727 | 56,727 | | | | | | | | |
| 2007 | | | | | | | | | | | |
| 2008 | | 150,917 | 150,917 | | | | | | | | |
| 2009 | | 193,653 | 193,653 | | | | | | | | |
| 2010 | | 222,092 | 222,092 | | | | | | | | |
| 2011 | | 159,645 | 159,645 | | | | | | | | |
| 2012 | | 174,738 | 174,738 | | | | | | | | |
| **Total** | | **$ 965,270** | **$ 965,270** | | | | | | | | |
| Solar 4R Schools | | | | | | | | | | | |
| 2009 | | 42,522 | 45,522 | | | | | | | | |
| **Total** | | **$ 42,522** | **$ 45,522** | | | | | | | | |
| Local Energy Efficiency Fund | | | | | | | | | | | |
| 2003 | 56 | 5,100 | 5,100 | | | | | | | | |
| 2004 | | 23,449 | 23,449 | | | | | | | | |
| 2005 | 2 | 14,896 | 26,756 | 78,000 | 0.01 | | 10 | $ 0.024 | $ 0.042 | | |
| 2006 | 480 | 3,459 | 3,459 | 19,027 | 0.00 | | 7 | 0.009 | 0.009 | | |
| 2007 | 1 | 7,520 | 7,520 | 9,000 | 0.00 | | 7 | 0.135 | 0.135 | | |
| 2008 | 2 | 22,714 | 60,100 | 115,931 | 0.01 | 0.0 | 15 | 0.019 | 0.049 | | |
| 2009 | 1 | 5,870 | 4,274 | 10,340 | 0.00 | 0.0 | 12 | 0.064 | 0.047 | | |
| 2010 | 1 | 251 | 251 | | 0.00 | 0.0 | | | | | |
| 2011 | 1 | 1,026 | 2,052 | 2,028 | | | 30 | 0.036 | 0.071 | | |
| **Total** | **544** | **$ 84,285** | **$ 132,961** | **234,326** | | | **14** | **$ 0.037** | **$ 0.058** | **2.95** | **1.87** |

## **Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/ Cost Ratios[b]: Utility | Program Life Benefit/ Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Market Transformation** | | | | | | | | | | | |
| NEEA | | | | | | | | | | | |
| 2002 | | $ 1,286,632 | $ 1,286,632 | 12,925,450 | 1.48 | | | | | | |
| 2003 | | 1,292,748 | 1,292,748 | 11,991,580 | 1.37 | | | | | | |
| 2004 | | 1,256,611 | 1,256,611 | 13,329,071 | 1.52 | | | | | | |
| 2005 | | 476,891 | 476,891 | 16,422,224 | 1.87 | | | | | | |
| 2006 | | 930,455 | 930,455 | 18,597,955 | 2.12 | | | | | | |
| 2007 | | 893,340 | 893,340 | 28,601,410 | 3.27 | | | | | | |
| 2008 | | 942,014 | 942,014 | 21,024,279 | 2.40 | | | | | | |
| 2009 | | 968,263 | 968,263 | 10,702,998 | 1.22 | | | | | | |
| 2010 | | 2,391,217 | 2,391,217 | 21,300,366 | 2.43 | | | | | | |
| 2011 | | 3,108,393 | 3,108,393 | 20,547,192 | 2.35 | | | | | | |
| 2012 | | 3,379,756 | 3,379,756 | 17,741,430 | 2.03 | | | | | | |
| **Total** | | **$ 16,926,319** | **$ 16,926,319** | **193,183,955** | | | | | | | |
| Consumer Electronic Initiative | | | | | | | | | | | |
| 2009 | | 160,762 | 160,762 | | | | | | | | |
| **Total** | | **$ 160,762** | **$ 160,762** | | | | | | | | |
| **Annual Totals** | | | | | | | | | | | |
| 2002 | | 1,932,520 | 2,366,591 | 16,791,100 | 1.92 | 0.0 | | | | | |
| 2003 | | 2,566,228 | 3,125,572 | 18,654,343 | 2.12 | 0.0 | | | | | |
| 2004 | | 3,827,213 | 4,860,912 | 19,202,780 | 2.19 | 6.6 | | | | | |
| 2005 | | 6,523,348 | 10,383,577 | 37,978,035 | 4.34 | 44.3 | | | | | |
| 2006 | | 11,174,181 | 20,950,110 | 67,026,303 | 7.65 | 44.4 | | | | | |
| 2007 | | 14,896,816 | 27,123,018 | 91,145,357 | 10.40 | 58.5 | | | | | |
| 2008 | | 20,213,216 | 44,775,829 | 128,508,579 | 14.67 | 74.9 | | | | | |
| 2009 | | 33,821,062 | 53,090,852 | 143,146,365 | 16.34 | 236.6 | | | | | |
| 2010 | | 44,643,541 | 69,164,744 | 193,592,637 | 22.10 | 357.7 | | | | | |
| 2011 | | 44,877,117 | 79,436,532 | 183,861,776 | 20.99 | 419.6 | | | | | |
| 2012 | | 47,991,352 | 77,411,652 | 170,227,773 | 19.43 | 453.6 | | | | | |
| **Total Direct Program** | | **$ 232,466,593** | **$ 392,689,390** | **1,070,135,047** | | | | | | | |

## **Appendix 4.** Historical DSM expense and performance 2002–2012 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Indirect Program Expenses** | | | | | | | | | | | |
| DSM Overhead and Other Indirect | | | | | | | | | | | |
| 2002 | | $ 128,855 | | | | | | | | | |
| 2003 | | (41,543) | | | | | | | | | |
| 2004 | | 142,337 | | | | | | | | | |
| 2005 | | 177,624 | | | | | | | | | |
| 2006 | | 309,832 | | | | | | | | | |
| 2007 | | 765,561 | | | | | | | | | |
| 2008 | | 980,305 | | | | | | | | | |
| 2009 | | 1,025,704 | | | | | | | | | |
| 2010 | | 1,189,310 | | | | | | | | | |
| 2011 | | 1,389,135 | | | | | | | | | |
| 2012 | | 1,335,509 | | | | | | | | | |
| **Total** | | **$ 7,402,629** | | | | | | | | | |
| **Total Expenses** | | | | | | | | | | | |
| 2002 | | 2,061,375 | | | | | | | | | |
| 2003 | | 2,524,685 | | | | | | | | | |
| 2004 | | 3,969,550 | | | | | | | | | |
| 2005 | | 6,700,972 | | | | | | | | | |
| 2006 | | 11,484,013 | | | | | | | | | |
| 2007 | | 15,662,377 | | | | | | | | | |
| 2008 | | 21,193,521 | | | | | | | | | |
| 2009 | | 34,846,766 | | | | | | | | | |
| 2010 | | 45,832,851 | | | | | | | | | |
| 2011 | | 46,266,252 | | | | | | | | | |
| 2012 | | 49,326,859 | | | | | | | | | |
| **Total 2002–2012** | | **$ 239,869,220** | | | | | | | | | |

[a] Levelized Costs are based on financial inputs from IPC's 2009 IRP and calculations include line-loss adjusted energy savings.

[b] Program life B/C ratios are provided for active programs only.

[c] The Total Utility Cost is all cost incurred by IPC to implement and manage a DSM program.

[d] The total resource cost (TRC) is the total expenditures for a DSM program from the point of view of IPC and its customers as a whole.

[e] Average Demand = Annual Energy/8,760 annual hours.

[f] Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season. Peak demand reduction for demand response programs is reported at the generation level assuming 13-percent peak line losses.

[1] Peak MW achieved based on mid-week load reduction schedule.

[2] B/C ratios reflect impacts of the 28-percent realization rate for years 2008–2010 from the ADM 2011 impact evaluation.

[3] Utility cost reflects collected funds on previous bad loan write-offs.

[4] Utility cost reflects only audit and administration costs, there was no further activity in 2006.

[5] Levelized cost calculation includes bad loan write-off expense and funds collected from previously written off loans.

[6] Beginning in 2005, BPA funds were no longer applied to CAP agency payments.

[7] Oregon statutory program. The company does not monitor customer implementation of audit recommendations and thus does not estimate savings for this program. Audit expense not involving outside contractor services are booked to general customer service.

[8] Measure life is weighted life (based on energy savings) of custom option (15 years) and menu options (5 years).

[9] Savings are preliminary estimates provided by NEEA.

## **Appendix 5.** 2012 DSM program activity by state jurisdiction

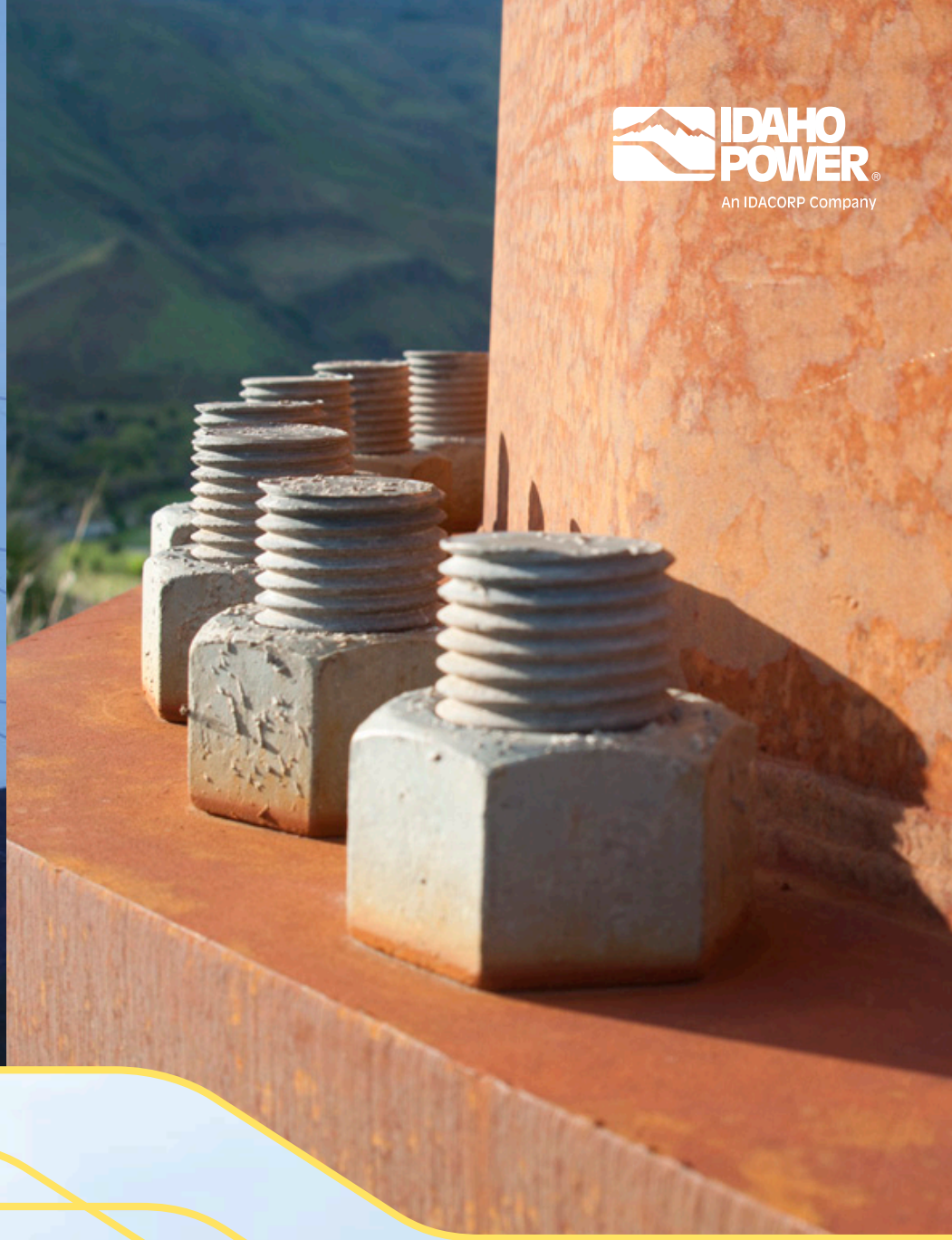
| Program | Idaho Participants | Idaho Utility Costs | Idaho Demand Reduction/ Annual Energy Savings | Oregon Participants | Oregon Utility Costs | Oregon Demand Reduction/ Annual Energy Savings |
|---|---|---|---|---|---|---|
| **Demand Response** | | | **(MW)** | | | **(MW)** |
| A/C Cool Credit | 35,969 homes | $ 5,635,184 | 44.3 | 482 homes | $ 92,810 | 0.6 |
| Irrigation Peak Rewards | 2,396 service points | 12,325,148 | 338.0 | 37 service points | 98,216 | 1.6 |
| FlexPeak Management | 97 sites | 2,859,333 | 41.2 | 5 sites | 150,489 | 11.6 |
| **Total** | | **$ 20,819,664** | **423.5** | | **$ 341,515** | **13.9** |
| **Energy Efficiency** | | | **(kWh)** | | | **(kWh)** |
| **Residential** | | | | | | |
| Ductless Heat Pump Pilot | 122 homes | 153,017 | 427,000 | 5 homes | 6,850 | 17,500 |
| Energy Efficient Lighting | 913,397 bulbs | 1,110,329 | 16,496,129 | 12,063 bulbs | 16,507 | 212,530 |
| Energy House Calls | 620 homes | 272,666 | 1,122,497 | 48 homes | 3,217 | 69,542 |
| ENERGY STAR® Homes Northwest | 410 homes | 450,727 | 537,447 | 0 homes | 2,458 | 0 |
| Heating & Cooling Efficiency Program | 136 projects | 175,483 | 669,607 | 5 projects | 6,798 | 19,248 |
| Home Improvement Program | 840 insulation projects | 385,091 | 457,353 | 0 insulation projects | 0 | 0 |
| Home Products Program | 16,194 appliances/fixtures | 640,203 | 858,202 | 481 appliances/fixtures | 18,829 | 29,019 |
| Oregon Residential Weatherization | 0 home | 0 | 0 | 5 home | 4,516 | 11,985 |
| Rebate Advantage | 33 homes | 34,926 | 173,414 | 2 homes | 2,316 | 13,694 |
| See ya later, refrigerator® | 3,106 refrigerators/freezers | 596,167 | 1,546,075 | 61 refrigerators/freezers | 16,979 | 30,351 |
| Weatherization Assistance for Qualified Customers | 228 homes/non-profits | 1,321,927 | 621,464 | 10 homes/non-profits | 48,214 | 26,840 |
| Weatherization Solutions for Eligible Customers | 141 homes | 1,070,556 | 257,466 | 0 homes | 0 | 0 |
| **Sector Total** | | **$ 6,211,092** | **23,166,654** | | **$ 126,684** | **430,709** |
| **Commercial** | | | | | | |
| Building Efficiency | 84 projects | 1,579,121 | 20,450,037 | 0 projects | 13,451 | 0 |
| Easy Upgrades | 1,787 projects | 5,150,422 | 40,656,743 | 51 projects | 199,331 | 911,929 |
| Oregon Commercial Audits | 0 audits | 0 | 0 | 14 audits | 12,470 | 0 |
| **Sector Total** | | **$ 6,729,543** | **61,106,780** | | **$ 225,252** | **911,929** |
| **Industrial** | | | | | | |
| Custom Efficiency | 122 projects | 6,976,700 | 53,137,995 | 4 projects | 115,881 | 1,115,111 |
| **Sector Total** | | **$ 6,976,700** | **53,137,995** | | **$ 115,881** | **1,115,111** |
| **Irrigation** | | | | | | |
| Irrigation Efficiency Rewards | 869 projects | 2,010,822 | 11,163,948 | 39 projects | 362,378 | 1,453,216 |
| **Sector Total** | | **$ 2,010,822** | **11,163,948** | | **$ 362,378** | **1,453,216** |

## **Appendix 5.** 2012 DSM program activity by state jurisdiction (continued)

| Program | Idaho | | | Oregon | | |
|---|---|---|---|---|---|---|
| | Participants | Utility Costs | Demand Reduction/ Annual Energy Savings | Participants | Utility Costs | Demand Reduction/ Annual Energy Savings |
| **Market Transformation** | | | **(kWh)** | | | **(kWh)** |
| Northwest Energy Efficiency Alliance[1] | | $ 3,210,768 | 16,854,359 | | $ 168,988 | 887,072 |
| **Other Programs and Activities** | | | | | | |
| **Residential** | | | | | | |
| Residential Economizer Project | | 93,593 | | | (101) | |
| Residential Energy Efficiency Education Initiative | | 165,919 | | | 8,819 | |
| **Commercial** | | | | | | |
| Commercial Education Initiative | | 70,099 | | | 3,689 | |
| Comprehensive Lighting | | 64,094 | | | | |
| **Other** | | | | | | |
| Energy Efficiency Direct Program Overhead | | 271,622 | | | 14,329 | |
| **Total Program Direct Expense** | | **$ 46,623,916** | | | **$ 1,367,435** | |
| Indirect Program Expense | | 1,260,377 | | | 75,132 | |
| **Total Annual Savings** | | | **165,429,736** | | | **4,798,037** |
| **Total DSM Expense** | | **$ 47,884,293** | | | **$ 1,442,567** | |

[1] Savings are preliminary estimates provided by NEEA. Oregon is credited with 5 percent of annual NEEA savings.





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# 2013 Integrated Resource Plan

## APPENDIX C

## Technical Report

June 2013

# 2013

# Integrated Resource Plan

## APPENDIX C

# Technical Report


## 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.


## SAFE HARBOR STATEMENT

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

**June 2013**

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# INTRODUCTION

*Appendix C–Technical Appendix* contains supporting data and explanatory materials used to develop Idaho Power's *2013 Integrated Resource Plan* (IRP).

The main document, the IRP, contains a full narrative of Idaho Power's resource planning process. Additional information regarding the 2013 IRP sales and load forecast is contained in *Appendix A–Sales and Load Forecast,* and details on Idaho Power's demand-side management efforts are explained in *Appendix B–Demand-Side Management 2012 Annual Report*. The IRP, including the three appendices, was filed with the Idaho and Oregon public utility commissions in June 2013.

For information or questions concerning the resource plan or the resource planning process, contact Idaho Power:

Idaho Power—Resource Planning

1221 West Idaho Street

Boise, Idaho 83702

208-388-2623

irp@idahopower.com

# IRP ADVISORY COUNCIL

Idaho Power has involved representatives of the public in the IRP planning process since the early 1990s. This public forum has come to be known as the IRP Advisory Council. The IRP Advisory Council generally meets monthly during the development of the IRP 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.

As part of preparing the 2013 IRP, Idaho Power hosted a field trip covering the distribution and transmission system and the natural gas power generation. Idaho Power also hosted 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. Idaho Power values these opportunities to convene, and the IRP Advisory Council members and the public have made significant contributions to this plan.

Idaho Power believes working with members of the IRP Advisory Council and the public is very rewarding, and the IRP is better because of the public involvement. Idaho Power and the members of the IRP Advisory Council recognize that outside perspective is valuable, but also recognize that final decisions on the IRP are made by Idaho Power.

## List of Advisory Council Members

### Customer Representatives

Agricultural Representative.....Sid Erwin
Boise State University.....John Gardner
Idaho National Laboratory.....Kurt Myers
Micron.....John Velikoff
Simplot.....Don Sturtevant

### Public Interest Representatives

Boise Metro Chamber of Commerce.....Ray Stark
Idaho Conservation League.....Ben Otto
Idaho Department of Commerce.....Gynii Gilliam
Idaho Office of Energy Resources.....John Chatburn
Idaho State House of Representatives.....Representative Brent Crane
Idaho State Senate.....Senator Russ Fulcher
Idaho Technology Council.....Jay Larsen
Northwest Power and Conservation Council.....Shirley Lindstrom
Northwest Power and Conservation Council.....Jim Yost
Oil and Gas Industry Advisor.....David Hawk
University of Idaho Integrated Design Lab.....Kevin Van Den Wymelenberg
Water Issues Advisor.....Vince Alberdi

### Regulatory Commission Representatives

Idaho Public Utilities Commission.....Bryan Lanspery
Public Utility Commission of Oregon.....Brittany Andrus

# IRP Advisory Council Meeting Schedule and Agenda

| Meeting Dates | | Agenda Items |
|---|---|---|
| 2012 | Thursday, August 16 | Background and Process<br>Explanation of the IRP Process<br>Summary of 2012 Summer Peak Load Season<br>Preliminary Resources to Include in the Resource Stack<br>DSM Potential Study<br>Recent Transmission Issues<br>Boardman to Hemingway Update |
| 2012 | Thursday, September 6 | Thermal Fuels and Associated Issues<br>Natural Gas Price Forecast and Transportation<br>Coat and Gas Unit Forecast<br>Renewable Energy Credit<br>Carbon Adder and Proposed Federal Legislation<br>CSPP Forecast |
| 2012 | Wednesday, October 10 | Field Trip to Langly Gulch and Hemingway Substation |
| 2012 | Thursday, October 11 | Hydro Resources and Issues, Customer Load<br>Water Issues<br>Hydro Forecast<br>Load Forecast<br>DSM Program Forecast |
| 2012 | Thursday, November 15 | 2011 IRP Update<br>Environmental Compliance Cost Study<br>Boardman to Hemingway Update<br>Load Forecast<br>Natural Gas Price Forecast<br>DSM Update |
| 2012 | Friday, November 30 | Portfolio Design Workshop |
| 2012 | Thursday, December 13 | Portfolio Modeling Review<br>Portfolio Workshop Review<br>Load and Resource Balance<br>Resource Cost Summary<br>Portfolio Modeling Plan<br>Aurora Model Overview<br>Conservation Voltage Reduction |
| 2013 | Thursday, January 17 | Meeting Canceled |
| 2013 | Thursday, February 21 | 2011 IRP Update Filing and Resource Analysis<br>Coal Study Results<br>Boardman to Hemingway Update<br>Preliminary Resource Analysis<br>Idaho Power Response to Hurricane Sandy |
| 2013 | Thursday, March 14 | Risk Analysis Methods<br>Resource Alternatives Risk Analysis<br>Preliminary Resource Portfolio Analysis<br>Hells Canyon Relicensing |

| Meeting Dates | | Agenda Items |
|---|---|---|
| 2013 | Thursday, April 11 | Risk Analysis Results<br>Resource Portfolio Risk Analysis<br>2013 Water Year Projections<br>DSM Annual Report |
| 2013 | Thursday, May 9 | Risk Analysis Results (continued)<br>Questions from the April Meeting Concerning the Resource Portfolio Risk Analysis<br>Results from the Two Resource Portfolios that Retire the North Valmy Coal Plant |
| 2013 | Thursday, June 6 | Conclusion<br>Draft IRP Document<br>IRP Public Presentation Review<br>Energy Imbalance Market<br>Summer 2013 Preparedness |

# PUBLIC POLICY ISSUES

## Greenhouse Gas Emissions

### *Climate Change and the Regulation of Greenhouse Gas Emissions*

#### Overview

Long-term climate change could significantly affect Idaho Power's business in a variety of ways, including:

- Changes in temperature and precipitation could affect customer demand and energy loads
- Extreme weather events could increase service interruptions, outages, maintenance costs, and the need for additional backup systems, and can affect the supply of, and demand for, electricity and natural gas, which may impact the price of energy commodities
- Changes in the amount and timing of snowpack and stream flows could adversely affect hydroelectric generation
- Legislative and/or regulatory developments related to climate change could affect plants and operations, including restrictions on the construction of new generation resources, the expansion of existing resources, or the operation of generation resources in general
- Consumer preference for, and resource planning decisions requiring, renewable or low greenhouse gas (GHG)-emitting sources of energy could impact usage of existing generation sources and require significant investment in new generation and transmission infrastructure

Some recent initiatives regarding GHG emissions contemplate market-based compliance programs, such as cap-and-trade programs or emission offsets. However, the regulation of GHG emissions under the CAA could result in GHG emission limits on stationary sources that do not provide market-based compliance options. Such a program could raise uncertainty about the future viability of fossil fuels, specifically coal, as an economical energy source for new and existing electric generation facilities because many new technologies for reducing CO2 emissions from coal, including carbon capture and storage, are still in the development stage and are not yet proven. Emission standards could require significant increases in capital expenditures and operating costs, which may accelerate the retirement of coal-fired units. Due in part to the uncertainty of future GHG regulations, in its 2011 IRP Idaho Power did not include any new conventional coal resources in its resource portfolios.

A variety of factors contribute to the financial, regulatory, and logistical uncertainties related to GHG reductions, including the specific GHG emissions limits, the timing of implementation of these limits, the level of emissions allowances allocated and the level that must be purchased, the purchase price of emissions allowances, the development and commercial availability of technologies for renewable energy and for the reduction of emissions, the degree to which offsets may be used for compliance, provisions for cost containment (if any), the impact on coal and natural gas prices, and cost recovery through rates. Accordingly, Idaho Power cannot predict the effect on its results of operations, financial position, or cash flows of any GHG emission or other global climate change requirements that may be

adopted, although the costs to implement and comply with any such requirements could be substantial. A more detailed discussion of legislative and regulatory developments related to climate change follows.

### National and International GHG Initiatives

There is concern both nationally and internationally about climate change and the possible contribution of GHG emissions to climate change. In support of international efforts to reduce GHG emissions, in January 2010 the Obama Administration pledged to cut GHG emissions in the United States from 2005 levels by 17 percent by 2020 and 80 percent by 2050. Other communications from the Obama Administration have proposed the adoption of a clean energy standard in the U.S., calling for 80 percent of American energy to come from clean sources by 2035. Further, climate change regulation has been a recent priority of the U.S. Congress. In prior legislative sessions, legislation in both the U.S. House and Senate was introduced to enact a comprehensive climate change program, but these attempts were unsuccessful. At the same time, legislation has also been introduced seeking to amend the CAA to prohibit the EPA from promulgating regulations on the emissions of GHGs to address climate change and excluding GHGs from the definition of an "air pollutant" for purposes of addressing climate change. Neither areas of focus have culminated in legislation and have led to greater uncertainty as to the direction of GHG regulation.

At the same time, the EPA has become increasingly active in the regulation of GHGs. The EPA's endangerment finding in 2009 that GHGs threaten public health and welfare resulted in enactment of a series of EPA regulations to address GHG emissions. The EPA has issued final rules regulating GHG emissions under the New Source Review (NSR)/Prevention of Significant Deterioration (PSD) and Title V Operating Permit programs under the CAA. Specifically, in May 2010 the EPA issued the "Tailoring Rule," which set thresholds for GHG emissions that define when permits are required for new and existing industrial facilities. The final rule "tailors" the requirements of these CAA permitting programs to limit which facilities will be required to obtain PSD and Title V permits. Additionally, in December 2010 the EPA issued a series of final regulations for GHG emissions designed to ensure that industrial facilities can obtain CAA permits for GHG emissions, and that facilities emitting GHGs at levels below those established in the Tailoring Rule do not need federal CAA permits. The first phase of the rules took effect in January 2011 and required imposition of Best Available Control Technology (BACT) for GHG emissions if a new major source or modification of an existing major source is projected to result in GHG emissions of at least 75,000 tons per year ($CO_2$ equivalent). In addition, Title V permit renewals or modifications for existing major sources must include applicable requirements relating to GHGs. Lawsuits opposing EPA's endangerment finding and Tailoring Rule were unsuccessful. While the rules are complex, Idaho Power believes that its owned and co-owned generation plants are, as of the date of this report, in compliance with the new GHG Tailoring Rules.

In addition, in April 2012, the EPA proposed New Source Performance Standards (NSPS) limiting $CO_2$ emissions from new electric utility generating units (EGUs) fired by fossil fuels. The proposed requirements, which are limited to new sources, would require new fossil fuel-fired EGUs greater than 25 MW to meet an output-based standard of 1,000 pounds of $CO_2$ per MWh. The EPA did not propose standards of performance for existing EGUs whose $CO_2$ emissions increase as a result of installation of pollution controls for conventional pollutants. While Idaho Power does not expect the new NSPS to impact its existing generation facilities, if promulgated the new rule would impact the cost effectiveness of developing new generation units.

## State and Regional GHG Initiatives

On a regional level, there are a number of initiatives, including the Western Regional Climate Action Initiative, considering market-based mechanisms to reduce GHG emissions. Separately, in August 2007 the Oregon legislature enacted legislation setting goals of reducing GHG levels to 10 percent below 1990 levels by 2020 and at least 75 percent below 1990 levels by 2050. Oregon imposes GHG emission reporting requirements on facilities emitting 2,500 metric tons or more of $CO_2$ equivalent annually. The mechanism was implemented in two phases, with Title V sources and entities with an air discharge permit required to start reporting 2009 emissions in 2010 and all other sources required to start reporting 2010 emissions in 2011. The Boardman coal-fired power plant, in which Idaho Power is a 10-percent owner, is subject to and in compliance with Oregon's GHG reporting requirements.

The State of Idaho has not passed legislation specifically regulating GHGs, but in May 2007 Governor Otter issued Executive Order 2007-05, which directed the Idaho Department of Environmental Quality to work with the state government to implement GHG reductions within each agency, complete a statewide emissions inventory, and provide recommendations to the Governor, among other tasks. Wyoming and Nevada similarly have not enacted legislation to regulate GHG emissions and do not have a reporting requirement, but are members of the Climate Registry, a national, voluntary GHG emission reporting system. The Climate Registry is a collaboration aimed at developing and managing a common GHG emission reporting system across states, provinces, and tribes to track GHG emissions nationally. All states for which Idaho Power has traditional fuel plants operating (i.e., Idaho, Oregon, Wyoming, and Nevada) are members of the Climate Registry.

## Idaho Power's Voluntary GHG Reduction Initiatives

Despite the current absence of a national mandatory GHG reduction program, Idaho Power is engaged in voluntary GHG emission intensity reduction efforts. Also, Idaho Power has voluntarily submitted information to the Carbon Disclosure Project, an independent, not-for-profit organization that claims the largest database of corporate climate change information in the world. Idaho Power's estimated $CO_2$ emission intensity (lbs/MWh) from its generation facilities as submitted to the Carbon Disclosure Project was 672, 1,051, 1,004, 1,097, and 1,150 lbs/MWh for 2011, 2010, 2009, 2008, and 2007, respectively.

In 2010, Idaho Power and Ida-West together ranked as the 37th lowest emitter of $CO_2$ per MWh produced and the $35^{th}$ 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, and other entities using publicly reported 2010 generation and emissions data. According to the report, out of the 100 companies named, Idaho Power and Ida-West together ranked as the $58^{th}$ largest power producer based on fossil fuel, nuclear, and renewable energy facility total electricity generation.

## Public Nuisance-Related Suits for GHGs

In June 2011, the U.S. Supreme Court held that federal courts do not have jurisdiction to hear federal common law nuisance claims relating to GHG emissions because the legal authority to regulate GHGs has been delegated by Congress to the EPA, not to federal courts. The Court did not address, however, whether state common law nuisance claims would also be barred by the federal CAA. Accordingly, the Supreme Court’s decision did not completely eliminate the potential for future nuisance-related suits for GHG emissions.

# Flow Modeling

## Models

Idaho Power uses two primary models for forecasting future flows for the IRP. The Snake River Planning Model (SRPM) is used to forecast surface water flows and the Enhanced Snake Plain Aquifer Model (ESPAM) is used to forecast the impact of various aquifer management practices implemented on the Eastern Snake Plain Aquifer (ESPA). The SRPM was recently updated in late 2012 to include hydrologic conditions for years 1928 through 2009. ESPAM was also recently updated with the release of ESPAM 2.0 in July 2012. Subsequent to the completion of the modeling for the 2013 IRP, a corrected version ESPAM 2.1 was released in late 2012. The ESPAM 2.1 update corrected issues discovered within the model in locations in the Snake River basin above Idaho Falls, Idaho. After reviewing output from the updated version of ESPAM, it was determined that the corrections would have no significant impact on the modeling that had been performed for the 2013 IRP.

Beginning with the 2009 IRP, Idaho Power began running the SRPM and ESPAM as a combined modeling system. The combined model seeks to maximize diversions for aquifer recharge and system conversions without creating additional model irrigation shortages over a modeled reference condition. Idaho Power completed an update to the combined model for the 2013 IRP.

## Model Inputs

The model inputs used in this effort are similar to the inputs used in the 2009 and 2011 IRP but those inputs continued to be refined to reflect future system conditions and management policies. The general inputs to the model are reach declines, weather modification, aquifer recharge, system conversions, and retirement of land from irrigation.

Future reach declines were determined using a variety of statistical analysis. Trend data indicate reach gains into American Falls Reservoir and from Milner Dam to Lower Salmon Falls Dan demonstrated a statistically significant decline for the period of 1981 to 2011. Both reaches declined on average 29 cubic feet per second per month (cfs/month) with declines ranging from 25 to 35 cfs/month for American Falls and 18 to 39 cfs/month for Milner to Lower Salmon Falls. Declines in these two reaches met strict predefined criteria, and were therefore included as inputs into the model.

Weather modification was added to the model at two different levels of development. The existing level of development was added to the model for IRP years 2013 and 2014. For IRP years 2015 and beyond, weather modification was increased to reflect a projected level of a fully built-out program in Eastern Idaho. The amount of weather modification added to each year is based on the total runoff for each year from 1928 through 2009. At full build out the Payette basin increase total discharge by an average of 224,000 acre feet per year (acft/year) and the Upper Snake Basin adds an average of 410,000 acft/year.

Aquifer recharge was added to the model at levels reflected in the 2009 Comprehensive Aquifer Management Plan (CAMP) and the recharge limits included in the Swan Falls Reaffirmation agreement. Nine recharge diversions were modeled across the ESPA with a total maximum diversion of 1,315 cfs. Recharge peaks in IRP year 2019 at approximately 200,000 acft and then slowly declines as diminishing reach gains limit the amount of water available for aquifer recharge.

CAMP targeted a level of system conversion where ground water supplied irrigated land is converted to surface supplied irrigated land. The number of acres modeled and potential water savings was based on data provided by the Idaho Department of Water Resources. The current model assumes a total of 13,683 acres of converted land on the ESPA with a total water savings of 1.4 acft or water per acre of irrigated land (acft/ac), and a maximum of 19,156 acft/year. This number is not solely based on the number of acres idled but also on available water to meet irrigation requirements. The modeled data show conversions reach a peak water savings of 17,600 acft in IRP year 2015. Subsequent reach declines reduce water available for system conversions. In IRP year 2027, water savings declined to 17,100 acft.

The model accounts for approximately 15,410 acres that are currently in the Conservation Reserve Enhancement Program (CREP). These acres are idled under a 15-year contract with the U.S. Department of Agriculture. Each idled acre is credited in the ESPAM model for reducing irrigation withdrawal from the ESPA by 2.0 acft/year. Many of the CREP contracts were initiated in 2006 and are set to retire beginning in 2020. The current model phases out CREP acres over a four-year period and includes no idled acres by IRP year 2024. The reduction in CREP acres further results in reducing the amount of water available for other management activities such as aquifer recharge and system conversions.

## Model Results

The combined model allows for the ability to include future management activities, and the resulting reach gains from those management activities into Idaho Power's 2013 IRP. Management activities, such as recharge and system conversions, do not significantly change the total annual volume of water expected to flow through the Hells Canyon Complex, but instead change the timing and location of reach gains within the system. Other future management activities, such as weather modification and CREP do directly impact the annual volume of water expected through the Hells Canyon Complex as well as the timing and location of gains within the system.

Overall flow through the Hells Canyon Complex increases from IRP year 2013 through 2015 in response to increased weather modification in the Upper Snake River Basin. Flows peak in 2015 with the 50 percent exceedance flows into Brownlee Reservoir as just over 11.5 Million acft/year. In 2027, those flows have declined to approximately 11.25 Million acft/year, with most of the declines attributable to spring discharge in the Milner to Lower Salmon Falls reach.

## 2013 Model Parameters

| IRP Year | Managed Recharge (acft/yr) | | Weather Modification (acft/yr) | | System Conversions (Ac) | CREP (Ac) | Lease Water | Reach Declines (acft/yr) | |
|---|---|---|---|---|---|---|---|---|---|
| | Above American Falls | Below American Falls | Snake River Basin | Payette Basin | | | 740 cfs in August | American Falls Inflows | Below Milner |
| 2013 | 54,500 | 48,400 | 124,000 | 224,000 | 13,683 | 16,684 | Yes | 82,671 | 84,535 |
| 2014 | 66,600 | 48,400 | 124,000 | 224,000 | 13,683 | 16,684 | Yes | 103,338 | 105,669 |
| 2015 | 66,600 | 90,800 | 410,000 | 224,000 | 13,683 | 16,684 | Yes | 124,006 | 126,803 |
| 2016 | 66,600 | 90,800 | 410,000 | 224,000 | 13,683 | 16,684 | No | 144,673 | 147,937 |
| 2017 | 66,600 | 108,900 | 410,000 | 224,000 | 13,683 | 16,684 | No | 165,340 | 169,071 |
| 2018 | 88,200 | 115,000 | 410,000 | 224,000 | 13,683 | 16,684 | No | 186,007 | 190,205 |
| 2019 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 16,684 | No | 206,674 | 211,339 |
| 2020 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 16,684 | No | 227,341 | 232,473 |
| 2021 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 16,684 | No | 248,008 | 253,607 |
| 2022 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 12,513 | No | 268,675 | 274,741 |
| 2023 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 8,342 | No | 289,342 | 295,875 |
| 2024 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 4,171 | No | 310,009 | 317,009 |
| 2025 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 0 | No | 330,676 | 338,143 |
| 2026 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 0 | No | 351,343 | 359,277 |
| 2027 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 0 | No | 372,010 | 380,411 |
| 2028 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 0 | No | 372,010 | 380,411 |
| 2029 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 0 | No | 372,010 | 380,411 |
| 2030 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 0 | No | 372,010 | 380,411 |
| 2031 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 0 | No | 372,010 | 380,411 |
| 2032 | 88,200 | 122,100 | 410,000 | 224,000 | 13,683 | 0 | No | 372,010 | 380,411 |

# SALES AND LOAD FORECAST DATA

## Average Annual Forecast Growth Rates

| | 2013–2018 | 2013–2023 | 2013–2032 |
|---|---|---|---|
| **Sales** | | | |
| Residential Sales | 1.07% | 1.09% | 1.08% |
| Commercial Sales | 1.09% | 1.07% | 1.10% |
| Irrigation Sales | 0.05% | 0.07% | 0.01% |
| Industrial Sales | 2.25% | 1.95% | 1.71% |
| Additional Firm Sales | 0.97% | 2.03% | 1.16% |
| System Sales | 1.15% | 1.18% | 1.08% |
| Total Sales | 1.15% | 1.18% | 1.08% |
| **Loads** | | | |
| Residential Load | 1.08% | 1.09% | 1.08% |
| Commercial Load | 1.08% | 1.07% | 1.10% |
| Irrigation Load | 0.05% | 0.07% | 0.00% |
| Industrial Load | 2.23% | 1.94% | 1.69% |
| Additional Firm Sales | 0.97% | 2.03% | 1.16% |
| System Load Losses | 1.08% | 1.08% | 1.03% |
| System Load | 1.14% | 1.17% | 1.07% |
| Total Load | 1.14% | 1.17% | 1.07% |
| **Peaks** | | | |
| System Peak | 1.54% | 1.52% | 1.41% |
| Total Peak | 1.54% | 1.52% | 1.41% |
| Winter Peak | 0.81% | 0.90% | 0.82% |
| Summer Peak | 1.54% | 1.52% | 1.41% |
| **Customers** | | | |
| Residential Customers | 1.82% | 1.68% | 1.47% |
| Commercial Customers | 1.94% | 1.81% | 1.59% |
| Irrigation Customers | 1.30% | 1.26% | 1.20% |
| Industrial Customers | 1.18% | 1.15% | 0.99% |

# Expected-Case Load Forecast

| Monthly Summary[1] | 1/2013 | 2/2013 | 3/2013 | 4/2013 | 5/2013 | 6/2013 | 7/2013 | 8/2013 | 9/2013 | 10/2013 | 11/2013 | 12/2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 792 | 670 | 567 | 487 | 442 | 467 | 589 | 566 | 461 | 457 | 580 | 806 |
| Commercial | 487 | 444 | 415 | 397 | 403 | 429 | 504 | 491 | 435 | 406 | 428 | 505 |
| Irrigation | 2 | 2 | 2 | 72 | 298 | 524 | 643 | 502 | 295 | 43 | 0 | 1 |
| Industrial | 264 | 266 | 262 | 251 | 254 | 270 | 269 | 273 | 270 | 274 | 273 | 278 |
| Additional Firm | 118 | 116 | 113 | 115 | 110 | 112 | 116 | 116 | 112 | 112 | 120 | 122 |
| Loss | 164 | 146 | 131 | 128 | 148 | 180 | 214 | 195 | 155 | 124 | 135 | 169 |
| **System Load** | 1,828 | 1,644 | 1,491 | 1,451 | 1,655 | 1,982 | 2,336 | 2,143 | 1,728 | 1,416 | 1,537 | 1,882 |
| Light Load | 1,688 | 1,517 | 1,370 | 1,314 | 1,505 | 1,774 | 2,119 | 1,901 | 1,553 | 1,277 | 1,418 | 1,738 |
| Heavy Load | 1,938 | 1,739 | 1,586 | 1,550 | 1,774 | 2,149 | 2,506 | 2,317 | 1,882 | 1,516 | 1,632 | 2,005 |
| **Total Load** | 1,828 | 1,644 | 1,491 | 1,451 | 1,655 | 1,982 | 2,336 | 2,143 | 1,728 | 1,416 | 1,537 | 1,882 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,445 | 2,328 | 2,024 | 1,956 | 2,775 | 3,215 | 3,344 | 3,015 | 2,756 | 2,013 | 2,199 | 2,585 |
| **Total Peak Load** | 2,445 | 2,328 | 2,024 | 1,956 | 2,775 | 3,215 | 3,344 | 3,015 | 2,756 | 2,013 | 2,199 | 2,585 |

| Monthly Summary[1] | 1/2014 | 2/2014 | 3/2014 | 4/2014 | 5/2014 | 6/2014 | 7/2014 | 8/2014 | 9/2014 | 10/2014 | 11/2014 | 12/2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 796 | 671 | 569 | 489 | 445 | 472 | 595 | 571 | 465 | 459 | 582 | 810 |
| Commercial | 494 | 449 | 421 | 403 | 409 | 436 | 512 | 499 | 443 | 412 | 435 | 512 |
| Irrigation | 2 | 2 | 2 | 72 | 300 | 528 | 647 | 505 | 296 | 43 | 0 | 1 |
| Industrial | 272 | 274 | 269 | 259 | 261 | 277 | 277 | 281 | 278 | 282 | 281 | 286 |
| Additional Firm | 121 | 117 | 115 | 117 | 113 | 110 | 118 | 118 | 114 | 114 | 122 | 124 |
| Loss | 166 | 148 | 133 | 129 | 150 | 182 | 217 | 198 | 157 | 125 | 137 | 170 |
| **System Load** | 1,850 | 1,661 | 1,510 | 1,470 | 1,678 | 2,004 | 2,366 | 2,172 | 1,754 | 1,436 | 1,558 | 1,903 |
| Light Load | 1,709 | 1,533 | 1,387 | 1,331 | 1,525 | 1,794 | 2,147 | 1,927 | 1,575 | 1,295 | 1,437 | 1,758 |
| Heavy Load | 1,962 | 1,757 | 1,606 | 1,571 | 1,798 | 2,173 | 2,539 | 2,365 | 1,896 | 1,538 | 1,664 | 2,017 |
| **Total Load** | 1,850 | 1,661 | 1,510 | 1,470 | 1,678 | 2,004 | 2,366 | 2,172 | 1,754 | 1,436 | 1,558 | 1,903 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,474 | 2,346 | 2,047 | 1,981 | 2,822 | 3,261 | 3,403 | 3,059 | 2,800 | 2,034 | 2,222 | 2,606 |
| **Total Peak Load** | 2,474 | 2,346 | 2,047 | 1,981 | 2,822 | 3,261 | 3,403 | 3,059 | 2,800 | 2,034 | 2,222 | 2,606 |

| Monthly Summary[1] | 1/2015 | 2/2015 | 3/2015 | 4/2015 | 5/2015 | 6/2015 | 7/2015 | 8/2015 | 9/2015 | 10/2015 | 11/2015 | 12/2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 796 | 669 | 568 | 490 | 446 | 474 | 599 | 575 | 466 | 460 | 583 | 817 |
| Commercial | 498 | 452 | 424 | 407 | 413 | 441 | 517 | 504 | 448 | 416 | 438 | 517 |
| Irrigation | 2 | 2 | 2 | 73 | 301 | 530 | 649 | 507 | 298 | 43 | 0 | 1 |
| Industrial | 279 | 281 | 277 | 265 | 268 | 285 | 285 | 288 | 286 | 290 | 289 | 293 |
| Additional Firm | 124 | 121 | 119 | 120 | 116 | 113 | 121 | 121 | 117 | 117 | 126 | 128 |
| Loss | 167 | 148 | 134 | 130 | 151 | 183 | 219 | 199 | 158 | 127 | 138 | 172 |
| **System Load** | 1,866 | 1,673 | 1,524 | 1,485 | 1,695 | 2,025 | 2,390 | 2,194 | 1,773 | 1,452 | 1,574 | 1,928 |
| Light Load | 1,723 | 1,544 | 1,400 | 1,345 | 1,541 | 1,812 | 2,168 | 1,947 | 1,593 | 1,310 | 1,453 | 1,781 |
| Heavy Load | 1,979 | 1,770 | 1,621 | 1,587 | 1,827 | 2,180 | 2,564 | 2,389 | 1,917 | 1,555 | 1,681 | 2,044 |
| **Total Load** | 1,866 | 1,673 | 1,524 | 1,485 | 1,695 | 2,025 | 2,390 | 2,194 | 1,773 | 1,452 | 1,574 | 1,928 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,471 | 2,357 | 2,040 | 1,965 | 2,867 | 3,296 | 3,456 | 3,093 | 2,835 | 2,053 | 2,222 | 2,620 |
| **Total Peak Load** | 2,471 | 2,357 | 2,040 | 1,965 | 2,867 | 3,296 | 3,456 | 3,093 | 2,835 | 2,053 | 2,222 | 2,620 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2016 | 2/2016 | 3/2016 | 4/2016 | 5/2016 | 6/2016 | 7/2016 | 8/2016 | 9/2016 | 10/2016 | 11/2016 | 12/2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 805 | 675 | 574 | 495 | 452 | 481 | 610 | 585 | 474 | 465 | 590 | 831 |
| Commercial | 503 | 457 | 429 | 411 | 417 | 446 | 523 | 510 | 454 | 421 | 443 | 523 |
| Irrigation | 2 | 2 | 2 | 72 | 298 | 524 | 643 | 502 | 294 | 43 | 0 | 1 |
| Industrial | 286 | 278 | 283 | 272 | 274 | 291 | 291 | 295 | 292 | 296 | 296 | 298 |
| Additional Firm | 124 | 117 | 119 | 120 | 116 | 113 | 121 | 121 | 117 | 117 | 126 | 128 |
| Loss | 169 | 149 | 135 | 132 | 152 | 185 | 220 | 201 | 160 | 128 | 140 | 175 |
| **System Load** | 1,889 | 1,676 | 1,542 | 1,502 | 1,710 | 2,041 | 2,408 | 2,214 | 1,791 | 1,471 | 1,595 | 1,955 |
| Light Load | 1,745 | 1,547 | 1,417 | 1,361 | 1,554 | 1,826 | 2,185 | 1,964 | 1,609 | 1,327 | 1,472 | 1,806 |
| Heavy Load | 2,014 | 1,772 | 1,632 | 1,606 | 1,844 | 2,197 | 2,600 | 2,394 | 1,937 | 1,585 | 1,694 | 2,073 |
| **Total Load** | 1,889 | 1,676 | 1,542 | 1,502 | 1,710 | 2,041 | 2,408 | 2,214 | 1,791 | 1,471 | 1,595 | 1,955 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,486 | 2,370 | 2,050 | 1,971 | 2,906 | 3,323 | 3,500 | 3,121 | 2,867 | 2,070 | 2,235 | 2,640 |
| **Total Peak Load** | 2,486 | 2,370 | 2,050 | 1,971 | 2,906 | 3,323 | 3,500 | 3,121 | 2,867 | 2,070 | 2,235 | 2,640 |

| Monthly Summary[1] | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 818 | 683 | 582 | 503 | 460 | 491 | 623 | 597 | 483 | 473 | 600 | 845 |
| Commercial | 507 | 460 | 433 | 415 | 421 | 451 | 529 | 516 | 459 | 426 | 447 | 528 |
| Irrigation | 2 | 2 | 2 | 72 | 298 | 524 | 642 | 501 | 294 | 42 | 0 | 1 |
| Industrial | 291 | 293 | 288 | 276 | 279 | 297 | 296 | 300 | 298 | 302 | 301 | 303 |
| Additional Firm | 125 | 122 | 120 | 121 | 117 | 114 | 122 | 122 | 118 | 118 | 127 | 129 |
| Loss | 171 | 152 | 137 | 134 | 154 | 187 | 223 | 203 | 162 | 130 | 142 | 177 |
| **System Load** | 1,915 | 1,711 | 1,562 | 1,522 | 1,729 | 2,063 | 2,435 | 2,240 | 1,814 | 1,491 | 1,617 | 1,982 |
| Light Load | 1,768 | 1,579 | 1,435 | 1,378 | 1,572 | 1,847 | 2,209 | 1,987 | 1,629 | 1,345 | 1,492 | 1,831 |
| Heavy Load | 2,041 | 1,810 | 1,653 | 1,636 | 1,853 | 2,222 | 2,629 | 2,422 | 1,961 | 1,606 | 1,718 | 2,112 |
| **Total Load** | 1,915 | 1,711 | 1,562 | 1,522 | 1,729 | 2,063 | 2,435 | 2,240 | 1,814 | 1,491 | 1,617 | 1,982 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,514 | 2,388 | 2,072 | 1,992 | 2,950 | 3,362 | 3,555 | 3,161 | 2,907 | 2,090 | 2,260 | 2,668 |
| **Total Peak Load** | 2,514 | 2,388 | 2,072 | 1,992 | 2,950 | 3,362 | 3,555 | 3,161 | 2,907 | 2,090 | 2,260 | 2,668 |

| Monthly Summary[1] | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 829 | 690 | 589 | 510 | 467 | 500 | 635 | 609 | 491 | 479 | 608 | 858 |
| Commercial | 511 | 463 | 436 | 418 | 425 | 456 | 534 | 520 | 464 | 430 | 451 | 533 |
| Irrigation | 2 | 2 | 2 | 72 | 299 | 526 | 644 | 503 | 295 | 43 | 0 | 1 |
| Industrial | 296 | 297 | 293 | 281 | 284 | 301 | 301 | 305 | 302 | 307 | 306 | 308 |
| Additional Firm | 125 | 121 | 119 | 121 | 117 | 114 | 122 | 122 | 118 | 118 | 127 | 128 |
| Loss | 173 | 153 | 139 | 135 | 156 | 189 | 225 | 206 | 164 | 131 | 143 | 180 |
| **System Load** | 1,936 | 1,726 | 1,578 | 1,538 | 1,747 | 2,085 | 2,461 | 2,265 | 1,834 | 1,508 | 1,635 | 2,007 |
| Light Load | 1,788 | 1,593 | 1,450 | 1,393 | 1,588 | 1,866 | 2,233 | 2,009 | 1,648 | 1,360 | 1,509 | 1,854 |
| Heavy Load | 2,052 | 1,826 | 1,670 | 1,654 | 1,872 | 2,245 | 2,657 | 2,449 | 1,997 | 1,615 | 1,737 | 2,139 |
| Firm Off-System Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Load** | 1,936 | 1,726 | 1,578 | 1,538 | 1,747 | 2,085 | 2,461 | 2,265 | 1,834 | 1,508 | 1,635 | 2,007 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,536 | 2,402 | 2,088 | 2,009 | 2,993 | 3,400 | 3,609 | 3,199 | 2,944 | 2,107 | 2,279 | 2,691 |
| **Total Peak Load** | 2,536 | 2,402 | 2,088 | 2,009 | 2,993 | 3,400 | 3,609 | 3,199 | 2,944 | 2,107 | 2,279 | 2,691 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 839 | 696 | 595 | 517 | 474 | 508 | 646 | 619 | 498 | 485 | 616 | 868 |
| Commercial | 516 | 466 | 440 | 422 | 429 | 461 | 539 | 526 | 470 | 434 | 455 | 538 |
| Irrigation | 2 | 2 | 2 | 72 | 300 | 527 | 646 | 504 | 296 | 43 | 0 | 1 |
| Industrial | 301 | 303 | 298 | 286 | 288 | 306 | 306 | 310 | 307 | 312 | 311 | 313 |
| Additional Firm | 126 | 122 | 120 | 122 | 117 | 115 | 123 | 123 | 119 | 119 | 128 | 129 |
| Loss | 175 | 154 | 140 | 136 | 157 | 191 | 228 | 208 | 166 | 133 | 145 | 182 |
| **System Load** | 1,958 | 1,742 | 1,595 | 1,555 | 1,765 | 2,107 | 2,488 | 2,291 | 1,856 | 1,526 | 1,655 | 2,032 |
| Light Load | 1,808 | 1,608 | 1,466 | 1,409 | 1,605 | 1,886 | 2,258 | 2,032 | 1,667 | 1,376 | 1,527 | 1,877 |
| Heavy Load | 2,076 | 1,843 | 1,697 | 1,662 | 1,892 | 2,284 | 2,670 | 2,477 | 2,021 | 1,634 | 1,758 | 2,165 |
| **Total Load** | 1,958 | 1,742 | 1,595 | 1,555 | 1,765 | 2,107 | 2,488 | 2,291 | 1,856 | 1,526 | 1,655 | 2,032 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,560 | 2,418 | 2,107 | 2,028 | 3,036 | 3,439 | 3,664 | 3,239 | 2,983 | 2,126 | 2,301 | 2,716 |
| **Total Peak Load** | 2,560 | 2,418 | 2,107 | 2,028 | 3,036 | 3,439 | 3,664 | 3,239 | 2,983 | 2,126 | 2,301 | 2,716 |

| Monthly Summary[1] | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 846 | 699 | 600 | 521 | 478 | 515 | 656 | 628 | 504 | 490 | 622 | 878 |
| Commercial | 521 | 470 | 444 | 427 | 434 | 466 | 545 | 532 | 476 | 439 | 459 | 544 |
| Irrigation | 2 | 2 | 2 | 72 | 301 | 528 | 648 | 506 | 297 | 43 | 0 | 1 |
| Industrial | 306 | 297 | 303 | 290 | 293 | 312 | 312 | 315 | 313 | 317 | 316 | 318 |
| Additional Firm | 132 | 124 | 126 | 127 | 122 | 119 | 127 | 128 | 123 | 124 | 134 | 136 |
| Loss | 177 | 155 | 142 | 138 | 159 | 193 | 230 | 210 | 167 | 135 | 147 | 184 |
| **System Load** | 1,984 | 1,746 | 1,616 | 1,576 | 1,787 | 2,133 | 2,517 | 2,319 | 1,880 | 1,547 | 1,678 | 2,061 |
| Light Load | 1,832 | 1,612 | 1,485 | 1,428 | 1,625 | 1,909 | 2,284 | 2,058 | 1,689 | 1,395 | 1,548 | 1,904 |
| Heavy Load | 2,103 | 1,846 | 1,719 | 1,685 | 1,927 | 2,297 | 2,701 | 2,525 | 2,033 | 1,657 | 1,792 | 2,185 |
| **Total Load** | 1,984 | 1,746 | 1,616 | 1,576 | 1,787 | 2,133 | 2,517 | 2,319 | 1,880 | 1,547 | 1,678 | 2,061 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,588 | 2,436 | 2,129 | 2,048 | 3,084 | 3,481 | 3,722 | 3,281 | 3,024 | 2,148 | 2,326 | 2,745 |
| **Total Peak Load** | 2,588 | 2,436 | 2,129 | 2,048 | 3,084 | 3,481 | 3,722 | 3,281 | 3,024 | 2,148 | 2,326 | 2,745 |

| Monthly Summary[1] | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 829 | 690 | 589 | 510 | 467 | 500 | 635 | 609 | 491 | 479 | 608 | 858 |
| Commercial | 511 | 463 | 436 | 418 | 425 | 456 | 534 | 520 | 464 | 430 | 451 | 533 |
| Irrigation | 2 | 2 | 2 | 72 | 299 | 526 | 644 | 503 | 295 | 43 | 0 | 1 |
| Industrial | 296 | 297 | 293 | 281 | 284 | 301 | 301 | 305 | 302 | 307 | 306 | 308 |
| Additional Firm | 125 | 121 | 119 | 121 | 117 | 114 | 122 | 122 | 118 | 118 | 127 | 128 |
| Loss | 173 | 153 | 139 | 135 | 156 | 189 | 225 | 206 | 164 | 131 | 143 | 180 |
| **System Load** | 1,936 | 1,726 | 1,578 | 1,538 | 1,747 | 2,085 | 2,461 | 2,265 | 1,834 | 1,508 | 1,635 | 2,007 |
| Light Load | 1,788 | 1,593 | 1,450 | 1,393 | 1,588 | 1,866 | 2,233 | 2,009 | 1,648 | 1,360 | 1,509 | 1,854 |
| Heavy Load | 2,052 | 1,826 | 1,670 | 1,654 | 1,872 | 2,245 | 2,657 | 2,449 | 1,997 | 1,615 | 1,737 | 2,139 |
| **Total Load** | 1,936 | 1,726 | 1,578 | 1,538 | 1,747 | 2,085 | 2,461 | 2,265 | 1,834 | 1,508 | 1,635 | 2,007 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,536 | 2,402 | 2,088 | 2,009 | 2,993 | 3,400 | 3,609 | 3,199 | 2,944 | 2,107 | 2,279 | 2,691 |
| **Total Peak Load** | 2,536 | 2,402 | 2,088 | 2,009 | 2,993 | 3,400 | 3,609 | 3,199 | 2,944 | 2,107 | 2,279 | 2,691 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 839 | 696 | 595 | 517 | 474 | 508 | 646 | 619 | 498 | 485 | 616 | 868 |
| Commercial | 516 | 466 | 440 | 422 | 429 | 461 | 539 | 526 | 470 | 434 | 455 | 538 |
| Irrigation | 2 | 2 | 2 | 72 | 300 | 527 | 646 | 504 | 296 | 43 | 0 | 1 |
| Industrial | 301 | 303 | 298 | 286 | 288 | 306 | 306 | 310 | 307 | 312 | 311 | 313 |
| Additional Firm | 126 | 122 | 120 | 122 | 117 | 115 | 123 | 123 | 119 | 119 | 128 | 129 |
| Loss | 175 | 154 | 140 | 136 | 157 | 191 | 228 | 208 | 166 | 133 | 145 | 182 |
| **System Load** | 1,958 | 1,742 | 1,595 | 1,555 | 1,765 | 2,107 | 2,488 | 2,291 | 1,856 | 1,526 | 1,655 | 2,032 |
| Light Load | 1,808 | 1,608 | 1,466 | 1,409 | 1,605 | 1,886 | 2,258 | 2,032 | 1,667 | 1,376 | 1,527 | 1,877 |
| Heavy Load | 2,076 | 1,843 | 1,697 | 1,662 | 1,892 | 2,284 | 2,670 | 2,477 | 2,021 | 1,634 | 1,758 | 2,165 |
| **Total Load** | 1,958 | 1,742 | 1,595 | 1,555 | 1,765 | 2,107 | 2,488 | 2,291 | 1,856 | 1,526 | 1,655 | 2,032 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,560 | 2,418 | 2,107 | 2,028 | 3,036 | 3,439 | 3,664 | 3,239 | 2,983 | 2,126 | 2,301 | 2,716 |
| **Total Peak Load** | 2,560 | 2,418 | 2,107 | 2,028 | 3,036 | 3,439 | 3,664 | 3,239 | 2,983 | 2,126 | 2,301 | 2,716 |

| Monthly Summary[1] | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 846 | 699 | 600 | 521 | 478 | 515 | 656 | 628 | 504 | 490 | 622 | 878 |
| Commercial | 521 | 470 | 444 | 427 | 434 | 466 | 545 | 532 | 476 | 439 | 459 | 544 |
| Irrigation | 2 | 2 | 2 | 72 | 301 | 528 | 648 | 506 | 297 | 43 | 0 | 1 |
| Industrial | 306 | 297 | 303 | 290 | 293 | 312 | 312 | 315 | 313 | 317 | 316 | 318 |
| Additional Firm | 132 | 124 | 126 | 127 | 122 | 119 | 127 | 128 | 123 | 124 | 134 | 136 |
| Loss | 177 | 155 | 142 | 138 | 159 | 193 | 230 | 210 | 167 | 135 | 147 | 184 |
| **System Load** | 1,984 | 1,746 | 1,616 | 1,576 | 1,787 | 2,133 | 2,517 | 2,319 | 1,880 | 1,547 | 1,678 | 2,061 |
| Light Load | 1,832 | 1,612 | 1,485 | 1,428 | 1,625 | 1,909 | 2,284 | 2,058 | 1,689 | 1,395 | 1,548 | 1,904 |
| Heavy Load | 2,103 | 1,846 | 1,719 | 1,685 | 1,927 | 2,297 | 2,701 | 2,525 | 2,033 | 1,657 | 1,792 | 2,185 |
| **Total Load** | 1,984 | 1,746 | 1,616 | 1,576 | 1,787 | 2,133 | 2,517 | 2,319 | 1,880 | 1,547 | 1,678 | 2,061 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,588 | 2,436 | 2,129 | 2,048 | 3,084 | 3,481 | 3,722 | 3,281 | 3,024 | 2,148 | 2,326 | 2,745 |
| **Total Peak Load** | 2,588 | 2,436 | 2,129 | 2,048 | 3,084 | 3,481 | 3,722 | 3,281 | 3,024 | 2,148 | 2,326 | 2,745 |

| Monthly Summary[1] | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 852 | 702 | 603 | 525 | 483 | 521 | 664 | 637 | 510 | 494 | 627 | 887 |
| Commercial | 525 | 473 | 448 | 431 | 438 | 471 | 551 | 538 | 481 | 444 | 464 | 550 |
| Irrigation | 2 | 2 | 2 | 72 | 301 | 529 | 649 | 507 | 297 | 43 | 0 | 1 |
| Industrial | 311 | 313 | 308 | 295 | 298 | 317 | 317 | 320 | 318 | 322 | 321 | 323 |
| Additional Firm | 143 | 138 | 135 | 136 | 130 | 127 | 135 | 135 | 130 | 131 | 144 | 148 |
| Loss | 179 | 157 | 143 | 140 | 161 | 195 | 232 | 213 | 169 | 136 | 149 | 187 |
| **System Load** | 2,012 | 1,785 | 1,639 | 1,600 | 1,811 | 2,160 | 2,548 | 2,349 | 1,906 | 1,570 | 1,705 | 2,095 |
| Light Load | 1,858 | 1,647 | 1,506 | 1,449 | 1,647 | 1,934 | 2,312 | 2,084 | 1,712 | 1,416 | 1,573 | 1,936 |
| Heavy Load | 2,145 | 1,888 | 1,735 | 1,710 | 1,953 | 2,326 | 2,734 | 2,558 | 2,061 | 1,692 | 1,811 | 2,221 |
| **Total Load** | 2,012 | 1,785 | 1,639 | 1,600 | 1,811 | 2,160 | 2,548 | 2,349 | 1,906 | 1,570 | 1,705 | 2,095 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,614 | 2,462 | 2,148 | 2,064 | 3,135 | 3,523 | 3,782 | 3,324 | 3,067 | 2,173 | 2,350 | 2,776 |
| **Total Peak Load** | 2,614 | 2,462 | 2,148 | 2,064 | 3,135 | 3,523 | 3,782 | 3,324 | 3,067 | 2,173 | 2,350 | 2,776 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 859 | 706 | 607 | 530 | 488 | 528 | 674 | 646 | 516 | 498 | 633 | 898 |
| Commercial | 530 | 477 | 452 | 435 | 443 | 477 | 557 | 544 | 487 | 449 | 468 | 556 |
| Irrigation | 2 | 2 | 2 | 72 | 301 | 528 | 648 | 506 | 297 | 43 | 0 | 1 |
| Industrial | 316 | 318 | 313 | 300 | 303 | 322 | 322 | 326 | 323 | 328 | 327 | 328 |
| Additional Firm | 148 | 142 | 139 | 141 | 134 | 131 | 138 | 139 | 134 | 135 | 149 | 153 |
| Loss | 181 | 158 | 145 | 141 | 162 | 196 | 234 | 215 | 171 | 138 | 150 | 189 |
| **System Load** | 2,036 | 1,803 | 1,659 | 1,619 | 1,830 | 2,182 | 2,573 | 2,374 | 1,928 | 1,590 | 1,727 | 2,125 |
| Light Load | 1,881 | 1,664 | 1,524 | 1,466 | 1,664 | 1,953 | 2,335 | 2,106 | 1,732 | 1,434 | 1,594 | 1,963 |
| Heavy Load | 2,170 | 1,907 | 1,755 | 1,731 | 1,973 | 2,350 | 2,778 | 2,567 | 2,085 | 1,713 | 1,835 | 2,253 |
| **Total Load** | 2,036 | 1,803 | 1,659 | 1,619 | 1,830 | 2,182 | 2,573 | 2,374 | 1,928 | 1,590 | 1,727 | 2,125 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,636 | 2,480 | 2,164 | 2,077 | 3,180 | 3,559 | 3,835 | 3,361 | 3,104 | 2,194 | 2,370 | 2,803 |
| **Total Peak Load** | 2,636 | 2,480 | 2,164 | 2,077 | 3,180 | 3,559 | 3,835 | 3,361 | 3,104 | 2,194 | 2,370 | 2,803 |

| Monthly Summary[1] | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 868 | 711 | 613 | 536 | 494 | 536 | 685 | 656 | 523 | 504 | 640 | 908 |
| Commercial | 536 | 481 | 457 | 440 | 448 | 483 | 564 | 550 | 494 | 454 | 473 | 562 |
| Irrigation | 2 | 2 | 2 | 72 | 300 | 528 | 648 | 506 | 297 | 43 | 0 | 1 |
| Industrial | 321 | 323 | 318 | 305 | 308 | 327 | 327 | 331 | 328 | 333 | 332 | 333 |
| Additional Firm | 148 | 143 | 140 | 141 | 135 | 132 | 139 | 139 | 134 | 136 | 150 | 153 |
| Loss | 183 | 160 | 146 | 143 | 164 | 198 | 237 | 217 | 173 | 139 | 152 | 191 |
| **System Load** | 2,058 | 1,819 | 1,676 | 1,636 | 1,848 | 2,204 | 2,599 | 2,399 | 1,949 | 1,608 | 1,747 | 2,149 |
| Light Load | 1,901 | 1,679 | 1,540 | 1,482 | 1,680 | 1,972 | 2,358 | 2,128 | 1,751 | 1,450 | 1,612 | 1,985 |
| Heavy Load | 2,194 | 1,924 | 1,774 | 1,760 | 1,981 | 2,373 | 2,806 | 2,594 | 2,108 | 1,733 | 1,855 | 2,290 |
| **Total Load** | 2,058 | 1,819 | 1,676 | 1,636 | 1,848 | 2,204 | 2,599 | 2,399 | 1,949 | 1,608 | 1,747 | 2,149 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,659 | 2,495 | 2,182 | 2,094 | 3,223 | 3,596 | 3,889 | 3,399 | 3,142 | 2,213 | 2,391 | 2,826 |
| **Total Peak Load** | 2,659 | 2,495 | 2,182 | 2,094 | 3,223 | 3,596 | 3,889 | 3,399 | 3,142 | 2,213 | 2,391 | 2,826 |

| Monthly Summary[1] | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 875 | 714 | 617 | 540 | 499 | 542 | 694 | 665 | 529 | 508 | 645 | 917 |
| Commercial | 540 | 485 | 461 | 444 | 452 | 487 | 569 | 556 | 499 | 459 | 477 | 567 |
| Irrigation | 2 | 2 | 2 | 72 | 301 | 529 | 649 | 507 | 297 | 43 | 0 | 1 |
| Industrial | 326 | 317 | 323 | 310 | 312 | 332 | 332 | 336 | 333 | 338 | 337 | 338 |
| Additional Firm | 148 | 138 | 140 | 141 | 134 | 131 | 139 | 139 | 134 | 135 | 149 | 153 |
| Loss | 185 | 160 | 147 | 144 | 165 | 200 | 239 | 219 | 175 | 141 | 153 | 193 |
| **System Load** | 2,075 | 1,814 | 1,689 | 1,650 | 1,863 | 2,223 | 2,622 | 2,421 | 1,968 | 1,623 | 1,762 | 2,169 |
| Light Load | 1,917 | 1,674 | 1,552 | 1,495 | 1,694 | 1,989 | 2,379 | 2,148 | 1,768 | 1,464 | 1,626 | 2,004 |
| Heavy Load | 2,201 | 1,917 | 1,797 | 1,764 | 1,997 | 2,409 | 2,813 | 2,618 | 2,143 | 1,738 | 1,872 | 2,311 |
| **Total Load** | 2,075 | 1,814 | 1,689 | 1,650 | 1,863 | 2,223 | 2,622 | 2,421 | 1,968 | 1,623 | 1,762 | 2,169 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,668 | 2,502 | 2,186 | 2,096 | 3,263 | 3,630 | 3,939 | 3,433 | 3,176 | 2,228 | 2,399 | 2,840 |
| **Total Peak Load** | 2,668 | 2,502 | 2,186 | 2,096 | 3,263 | 3,630 | 3,939 | 3,433 | 3,176 | 2,228 | 2,399 | 2,840 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 881 | 716 | 620 | 544 | 503 | 548 | 703 | 673 | 534 | 511 | 650 | 927 |
| Commercial | 544 | 487 | 464 | 447 | 455 | 492 | 574 | 561 | 504 | 463 | 481 | 573 |
| Irrigation | 2 | 2 | 2 | 72 | 300 | 528 | 647 | 505 | 297 | 43 | 0 | 1 |
| Industrial | 330 | 333 | 327 | 314 | 317 | 337 | 337 | 341 | 338 | 343 | 342 | 343 |
| Additional Firm | 148 | 143 | 140 | 141 | 135 | 132 | 139 | 140 | 135 | 136 | 150 | 153 |
| Loss | 186 | 162 | 148 | 145 | 166 | 201 | 240 | 221 | 176 | 142 | 155 | 195 |
| **System Load** | 2,091 | 1,841 | 1,701 | 1,663 | 1,876 | 2,238 | 2,640 | 2,439 | 1,984 | 1,637 | 1,777 | 2,193 |
| Light Load | 1,931 | 1,699 | 1,563 | 1,506 | 1,706 | 2,003 | 2,396 | 2,164 | 1,782 | 1,476 | 1,639 | 2,026 |
| Heavy Load | 2,217 | 1,948 | 1,810 | 1,777 | 2,011 | 2,426 | 2,833 | 2,656 | 2,145 | 1,753 | 1,898 | 2,324 |
| **Total Load** | 2,091 | 1,841 | 1,701 | 1,663 | 1,876 | 2,238 | 2,640 | 2,439 | 1,984 | 1,637 | 1,777 | 2,193 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,670 | 2,511 | 2,184 | 2,088 | 3,302 | 3,657 | 3,985 | 3,461 | 3,205 | 2,242 | 2,402 | 2,855 |
| **Total Peak Load** | 2,670 | 2,511 | 2,184 | 2,088 | 3,302 | 3,657 | 3,985 | 3,461 | 3,205 | 2,242 | 2,402 | 2,855 |

| Monthly Summary[1] | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 890 | 721 | 625 | 550 | 509 | 557 | 715 | 684 | 542 | 517 | 657 | 940 |
| Commercial | 549 | 492 | 469 | 452 | 461 | 498 | 581 | 568 | 511 | 468 | 486 | 579 |
| Irrigation | 2 | 2 | 2 | 72 | 298 | 525 | 643 | 502 | 295 | 43 | 0 | 1 |
| Industrial | 335 | 338 | 332 | 319 | 322 | 342 | 342 | 346 | 343 | 348 | 347 | 348 |
| Additional Firm | 147 | 142 | 139 | 140 | 134 | 131 | 139 | 139 | 134 | 135 | 149 | 152 |
| Loss | 188 | 163 | 150 | 146 | 168 | 203 | 242 | 222 | 178 | 143 | 156 | 198 |
| **System Load** | 2,112 | 1,857 | 1,718 | 1,679 | 1,892 | 2,256 | 2,662 | 2,461 | 2,003 | 1,654 | 1,796 | 2,219 |
| Light Load | 1,951 | 1,714 | 1,578 | 1,521 | 1,720 | 2,019 | 2,415 | 2,183 | 1,799 | 1,492 | 1,657 | 2,050 |
| Heavy Load | 2,240 | 1,964 | 1,827 | 1,795 | 2,040 | 2,429 | 2,856 | 2,680 | 2,166 | 1,772 | 1,918 | 2,352 |
| **Total Load** | 2,112 | 1,857 | 1,718 | 1,679 | 1,892 | 2,256 | 2,662 | 2,461 | 2,003 | 1,654 | 1,796 | 2,219 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,691 | 2,525 | 2,199 | 2,102 | 3,343 | 3,688 | 4,034 | 3,494 | 3,240 | 2,259 | 2,421 | 2,879 |
| **Total Peak Load** | 2,691 | 2,525 | 2,199 | 2,102 | 3,343 | 3,688 | 4,034 | 3,494 | 3,240 | 2,259 | 2,421 | 2,879 |

| Monthly Summary[1] | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 900 | 726 | 631 | 556 | 516 | 565 | 727 | 695 | 549 | 523 | 665 | 951 |
| Commercial | 555 | 496 | 475 | 457 | 466 | 505 | 588 | 575 | 518 | 474 | 492 | 586 |
| Irrigation | 2 | 2 | 2 | 72 | 299 | 525 | 644 | 503 | 295 | 43 | 0 | 1 |
| Industrial | 340 | 343 | 337 | 323 | 327 | 347 | 347 | 351 | 348 | 353 | 352 | 353 |
| Additional Firm | 147 | 142 | 139 | 140 | 134 | 131 | 139 | 139 | 134 | 135 | 149 | 152 |
| Loss | 190 | 165 | 151 | 148 | 169 | 205 | 245 | 225 | 180 | 145 | 158 | 200 |
| **System Load** | 2,135 | 1,873 | 1,735 | 1,697 | 1,911 | 2,279 | 2,690 | 2,488 | 2,025 | 1,673 | 1,816 | 2,243 |
| Light Load | 1,972 | 1,728 | 1,594 | 1,537 | 1,737 | 2,039 | 2,440 | 2,207 | 1,819 | 1,509 | 1,675 | 2,072 |
| Heavy Load | 2,275 | 1,981 | 1,837 | 1,814 | 2,060 | 2,454 | 2,886 | 2,709 | 2,190 | 1,803 | 1,928 | 2,378 |
| **Total Load** | 2,135 | 1,873 | 1,735 | 1,697 | 1,911 | 2,279 | 2,690 | 2,488 | 2,025 | 1,673 | 1,816 | 2,243 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,714 | 2,539 | 2,217 | 2,120 | 3,386 | 3,729 | 4,090 | 3,535 | 3,281 | 2,278 | 2,442 | 2,902 |
| **Total Peak Load** | 2,714 | 2,539 | 2,217 | 2,120 | 3,386 | 3,729 | 4,090 | 3,535 | 3,281 | 2,278 | 2,442 | 2,902 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 907 | 729 | 635 | 560 | 521 | 572 | 736 | 704 | 556 | 527 | 670 | 962 |
| Commercial | 560 | 500 | 479 | 462 | 471 | 510 | 594 | 581 | 525 | 479 | 496 | 593 |
| Irrigation | 2 | 2 | 2 | 72 | 299 | 527 | 645 | 504 | 296 | 43 | 0 | 1 |
| Industrial | 345 | 335 | 342 | 328 | 331 | 352 | 352 | 356 | 353 | 358 | 357 | 358 |
| Additional Firm | 146 | 136 | 138 | 139 | 133 | 130 | 138 | 138 | 133 | 134 | 147 | 150 |
| Loss | 192 | 164 | 153 | 149 | 171 | 207 | 247 | 227 | 182 | 146 | 160 | 202 |
| **System Load** | 2,152 | 1,866 | 1,748 | 1,710 | 1,926 | 2,298 | 2,713 | 2,510 | 2,044 | 1,688 | 1,831 | 2,266 |
| Light Load | 1,987 | 1,722 | 1,606 | 1,549 | 1,751 | 2,057 | 2,462 | 2,227 | 1,836 | 1,522 | 1,689 | 2,094 |
| Heavy Load | 2,293 | 1,973 | 1,850 | 1,839 | 2,064 | 2,474 | 2,929 | 2,715 | 2,210 | 1,819 | 1,945 | 2,415 |
| **Total Load** | 2,152 | 1,866 | 1,748 | 1,710 | 1,926 | 2,298 | 2,713 | 2,510 | 2,044 | 1,688 | 1,831 | 2,266 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,721 | 2,548 | 2,220 | 2,120 | 3,427 | 3,763 | 4,141 | 3,570 | 3,316 | 2,293 | 2,449 | 2,918 |
| **Total Peak Load** | 2,721 | 2,548 | 2,220 | 2,120 | 3,427 | 3,763 | 4,141 | 3,570 | 3,316 | 2,293 | 2,449 | 2,918 |

| Monthly Summary[1] | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 916 | 734 | 640 | 566 | 527 | 580 | 748 | 715 | 563 | 533 | 678 | 974 |
| Commercial | 567 | 505 | 484 | 467 | 476 | 517 | 602 | 589 | 532 | 486 | 502 | 600 |
| Irrigation | 2 | 2 | 2 | 72 | 298 | 525 | 643 | 502 | 295 | 43 | 0 | 1 |
| Industrial | 350 | 352 | 347 | 333 | 336 | 357 | 357 | 361 | 358 | 363 | 362 | 363 |
| Additional Firm | 145 | 140 | 137 | 139 | 133 | 130 | 138 | 138 | 133 | 134 | 146 | 149 |
| Loss | 194 | 167 | 154 | 151 | 172 | 209 | 249 | 229 | 184 | 148 | 161 | 205 |
| **System Load** | 2,173 | 1,899 | 1,764 | 1,727 | 1,942 | 2,318 | 2,737 | 2,534 | 2,065 | 1,706 | 1,850 | 2,293 |
| Light Load | 2,007 | 1,753 | 1,621 | 1,564 | 1,766 | 2,074 | 2,483 | 2,248 | 1,855 | 1,538 | 1,706 | 2,119 |
| Heavy Load | 2,304 | 2,009 | 1,868 | 1,857 | 2,082 | 2,496 | 2,955 | 2,741 | 2,248 | 1,827 | 1,965 | 2,443 |
| **Total Load** | 2,173 | 1,899 | 1,764 | 1,727 | 1,942 | 2,318 | 2,737 | 2,534 | 2,065 | 1,706 | 1,850 | 2,293 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,740 | 2,560 | 2,234 | 2,132 | 3,468 | 3,798 | 4,192 | 3,606 | 3,353 | 2,311 | 2,466 | 2,942 |
| **Total Peak Load** | 2,740 | 2,560 | 2,234 | 2,132 | 3,468 | 3,798 | 4,192 | 3,606 | 3,353 | 2,311 | 2,466 | 2,942 |

| Monthly Summary[1] | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 926 | 739 | 646 | 572 | 534 | 589 | 761 | 727 | 571 | 539 | 686 | 986 |
| Commercial | 573 | 510 | 490 | 473 | 483 | 525 | 610 | 597 | 540 | 492 | 508 | 608 |
| Irrigation | 2 | 2 | 2 | 72 | 299 | 525 | 644 | 502 | 295 | 43 | 0 | 1 |
| Industrial | 355 | 357 | 352 | 337 | 341 | 362 | 362 | 366 | 363 | 368 | 367 | 368 |
| Additional Firm | 152 | 147 | 144 | 145 | 138 | 136 | 143 | 143 | 138 | 139 | 154 | 158 |
| Loss | 196 | 169 | 156 | 153 | 174 | 211 | 252 | 232 | 186 | 150 | 164 | 207 |
| **System Load** | 2,205 | 1,924 | 1,790 | 1,752 | 1,968 | 2,347 | 2,771 | 2,568 | 2,093 | 1,731 | 1,879 | 2,329 |
| Light Load | 2,036 | 1,775 | 1,645 | 1,587 | 1,789 | 2,101 | 2,515 | 2,278 | 1,881 | 1,562 | 1,733 | 2,152 |
| Heavy Load | 2,338 | 2,035 | 1,904 | 1,873 | 2,109 | 2,545 | 2,974 | 2,777 | 2,280 | 1,854 | 1,996 | 2,482 |
| **Total Load** | 2,205 | 1,924 | 1,790 | 1,752 | 1,968 | 2,347 | 2,771 | 2,568 | 2,093 | 1,731 | 1,879 | 2,329 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,776 | 2,586 | 2,262 | 2,159 | 3,519 | 3,847 | 4,256 | 3,656 | 3,402 | 2,338 | 2,498 | 2,979 |
| **Total Peak Load** | 2,776 | 2,586 | 2,262 | 2,159 | 3,519 | 3,847 | 4,256 | 3,656 | 3,402 | 2,338 | 2,498 | 2,979 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 934 | 743 | 651 | 578 | 539 | 597 | 772 | 737 | 578 | 544 | 692 | 997 |
| Commercial | 580 | 516 | 496 | 479 | 489 | 532 | 618 | 605 | 548 | 499 | 514 | 616 |
| Irrigation | 2 | 2 | 2 | 72 | 299 | 526 | 645 | 504 | 296 | 43 | 0 | 1 |
| Industrial | 360 | 362 | 356 | 342 | 345 | 367 | 367 | 371 | 368 | 373 | 372 | 374 |
| Additional Firm | 151 | 146 | 143 | 144 | 138 | 135 | 143 | 143 | 138 | 139 | 153 | 156 |
| Loss | 198 | 170 | 157 | 154 | 176 | 213 | 255 | 235 | 188 | 152 | 165 | 210 |
| **System Load** | 2,226 | 1,938 | 1,806 | 1,769 | 1,987 | 2,370 | 2,799 | 2,595 | 2,116 | 1,749 | 1,897 | 2,355 |
| Light Load | 2,055 | 1,789 | 1,659 | 1,602 | 1,806 | 2,121 | 2,540 | 2,302 | 1,901 | 1,578 | 1,750 | 2,175 |
| Heavy Load | 2,349 | 2,050 | 1,921 | 1,891 | 2,117 | 2,570 | 2,987 | 2,825 | 2,273 | 1,873 | 2,015 | 2,484 |
| **Total Load** | 2,226 | 1,938 | 1,806 | 1,769 | 1,987 | 2,370 | 2,799 | 2,595 | 2,116 | 1,749 | 1,897 | 2,355 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,791 | 2,597 | 2,272 | 2,167 | 3,562 | 3,888 | 4,312 | 3,697 | 3,443 | 2,356 | 2,513 | 2,999 |
| **Total Peak Load** | 2,791 | 2,597 | 2,272 | 2,167 | 3,562 | 3,888 | 4,312 | 3,697 | 3,443 | 2,356 | 2,513 | 2,999 |

| Monthly Summary[1] | 1/2032 | 2/2032 | 3/2032 | 4/2032 | 5/2032 | 6/2032 | 7/2032 | 8/2032 | 9/2032 | 10/2032 | 11/2032 | 12/2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 942 | 746 | 655 | 583 | 545 | 605 | 782 | 747 | 585 | 549 | 698 | 1,008 |
| Commercial | 587 | 521 | 502 | 485 | 495 | 539 | 627 | 613 | 557 | 506 | 521 | 625 |
| Irrigation | 2 | 2 | 2 | 72 | 299 | 526 | 644 | 503 | 295 | 43 | 0 | 1 |
| Industrial | 365 | 355 | 361 | 347 | 350 | 372 | 372 | 376 | 373 | 379 | 377 | 379 |
| Additional Firm | 151 | 140 | 142 | 144 | 137 | 135 | 142 | 142 | 137 | 138 | 152 | 156 |
| Loss | 200 | 170 | 159 | 156 | 177 | 215 | 257 | 237 | 190 | 153 | 167 | 212 |
| **System Load** | 2,246 | 1,933 | 1,822 | 1,786 | 2,004 | 2,391 | 2,825 | 2,619 | 2,137 | 1,767 | 1,916 | 2,380 |
| Light Load | 2,074 | 1,784 | 1,674 | 1,617 | 1,822 | 2,140 | 2,563 | 2,324 | 1,920 | 1,594 | 1,768 | 2,199 |
| Heavy Load | 2,370 | 2,055 | 1,928 | 1,909 | 2,147 | 2,575 | 3,014 | 2,852 | 2,296 | 1,904 | 2,025 | 2,511 |
| **Total Load** | 2,246 | 1,933 | 1,822 | 1,786 | 2,004 | 2,391 | 2,825 | 2,619 | 2,137 | 1,767 | 1,916 | 2,380 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,807 | 2,596 | 2,282 | 2,174 | 3,603 | 3,925 | 4,365 | 3,735 | 3,482 | 2,374 | 2,527 | 3,020 |
| **Total Peak Load** | 2,807 | 2,596 | 2,282 | 2,174 | 3,603 | 3,925 | 4,365 | 3,735 | 3,482 | 2,374 | 2,527 | 3,020 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

# Annual Summary

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 5,024,661 | 5,054,545 | 5,063,083 | 5,130,952 | 5,221,061 | 5,299,496 | 5,371,170 | 5,426,100 | 5,476,110 | 5,532,311 |
| Commercial | 3,900,064 | 3,960,646 | 3,996,617 | 4,043,282 | 4,082,719 | 4,117,425 | 4,158,116 | 4,202,778 | 4,244,120 | 4,288,491 |
| Irrigation | 1,751,463 | 1,762,474 | 1,768,998 | 1,750,913 | 1,749,671 | 1,756,095 | 1,760,483 | 1,765,522 | 1,768,531 | 1,765,357 |
| Industrial | 2,334,380 | 2,402,175 | 2,466,748 | 2,523,489 | 2,568,734 | 2,609,536 | 2,653,663 | 2,698,998 | 2,743,911 | 2,788,219 |
| Additional Firm | 1,009,771 | 1,025,200 | 1,052,800 | 1,053,500 | 1,062,300 | 1,059,600 | 1,067,700 | 1,115,100 | 1,193,100 | 1,228,700 |
| **System Sales** | 14,020,339 | 14,205,040 | 14,348,247 | 14,502,137 | 14,684,485 | 14,842,152 | 15,011,132 | 15,208,498 | 15,425,772 | 15,603,078 |
| **Total Sales** | 14,020,339 | 14,205,040 | 14,348,247 | 14,502,137 | 14,684,485 | 14,842,152 | 15,011,132 | 15,208,498 | 15,425,772 | 15,603,078 |
| **Generation Month Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 5,027,296 | 5,055,690 | 5,068,397 | 5,154,035 | 5,227,150 | 5,305,125 | 5,375,632 | 5,447,007 | 5,480,685 | 5,537,710 |
| Commercial | 3,903,440 | 3,962,715 | 3,999,260 | 4,056,500 | 4,084,729 | 4,119,758 | 4,160,664 | 4,216,430 | 4,246,659 | 4,291,303 |
| Irrigation | 1,751,467 | 1,762,477 | 1,768,991 | 1,750,951 | 1,749,674 | 1,756,097 | 1,760,485 | 1,765,562 | 1,768,530 | 1,765,357 |
| Industrial | 2,340,228 | 2,407,744 | 2,471,642 | 2,527,392 | 2,572,253 | 2,613,342 | 2,657,573 | 2,702,871 | 2,747,733 | 2,792,033 |
| Additional Firm | 1,009,771 | 1,025,200 | 1,052,800 | 1,053,500 | 1,062,300 | 1,059,600 | 1,067,700 | 1,115,100 | 1,193,100 | 1,228,700 |
| **System Sales** | 14,032,203 | 14,213,826 | 14,361,089 | 14,542,378 | 14,696,106 | 14,853,922 | 15,022,054 | 15,246,971 | 15,436,707 | 15,615,103 |
| **Total Sales** | 14,032,203 | 14,213,826 | 14,361,089 | 14,542,378 | 14,696,106 | 14,853,922 | 15,022,054 | 15,246,971 | 15,436,707 | 15,615,103 |
| Loss | 1,380,235 | 1,396,630 | 1,408,407 | 1,426,063 | 1,440,637 | 1,456,526 | 1,472,745 | 1,492,086 | 1,505,449 | 1,520,629 |
| **Required Generation** | 15,412,437 | 15,610,455 | 15,769,496 | 15,968,441 | 16,136,743 | 16,310,448 | 16,494,799 | 16,739,057 | 16,942,156 | 17,135,732 |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | |
| Residential | 574 | 577 | 579 | 587 | 597 | 606 | 614 | 620 | 626 | 632 |
| Commercial | 446 | 452 | 457 | 462 | 466 | 470 | 475 | 480 | 485 | 490 |
| Irrigation | 200 | 201 | 202 | 199 | 200 | 200 | 201 | 201 | 202 | 202 |
| Industrial | 267 | 275 | 282 | 288 | 294 | 298 | 303 | 308 | 314 | 319 |
| Additional Firm | 115 | 117 | 120 | 120 | 121 | 121 | 122 | 127 | 136 | 140 |
| Loss | 158 | 159 | 161 | 162 | 164 | 166 | 168 | 170 | 172 | 174 |
| **System Load** | 1,759 | 1,782 | 1,800 | 1,818 | 1,842 | 1,862 | 1,883 | 1,906 | 1,934 | 1,956 |
| Light Load | 1,599 | 1,620 | 1,636 | 1,653 | 1,674 | 1,693 | 1,712 | 1,732 | 1,758 | 1,778 |
| Heavy Load | 1,885 | 1,909 | 1,928 | 1,947 | 1,974 | 1,995 | 2,017 | 2,041 | 2,072 | 2,096 |
| **Total Load** | 1,759 | 1,782 | 1,800 | 1,818 | 1,842 | 1,862 | 1,883 | 1,906 | 1,934 | 1,956 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | |
| **System Peak (1 Hour)** | 3,344 | 3,403 | 3,456 | 3,500 | 3,555 | 3,609 | 3,664 | 3,722 | 3,782 | 3,835 |
| **Total Peak Load** | 3,344 | 3,403 | 3,456 | 3,500 | 3,555 | 3,609 | 3,664 | 3,722 | 3,782 | 3,835 |

| | 2023 | 2024 | 2024 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 5,599,951 | 5,652,900 | 5,698,298 | 5,769,278 | 5,841,976 | 5,896,722 | 5,965,645 | 6,041,626 | 6,104,767 | 6,163,934 |
| Commercial | 4,337,889 | 4,377,042 | 4,412,765 | 4,464,888 | 4,517,788 | 4,562,924 | 4,618,921 | 4,680,777 | 4,740,317 | 4,802,348 |
| Irrigation | 1,764,576 | 1,768,216 | 1,763,156 | 1,752,206 | 1,754,887 | 1,758,862 | 1,752,877 | 1,753,702 | 1,757,850 | 1,755,683 |
| Industrial | 2,832,435 | 2,875,947 | 2,917,139 | 2,961,183 | 3,005,317 | 3,047,482 | 3,090,882 | 3,134,512 | 3,177,840 | 3,222,016 |
| Additional Firm | 1,234,000 | 1,231,300 | 1,234,000 | 1,228,400 | 1,228,300 | 1,217,500 | 1,212,000 | 1,268,000 | 1,262,200 | 1,257,000 |
| **System Sales** | 15,768,851 | 15,905,405 | 16,025,359 | 16,175,955 | 16,348,269 | 16,483,491 | 16,640,325 | 16,878,617 | 17,042,974 | 17,200,980 |
| **Total Sales** | 15,768,851 | 15,905,405 | 16,025,359 | 16,175,955 | 16,348,269 | 16,483,491 | 16,640,325 | 16,878,617 | 17,042,974 | 17,200,980 |
| **Generation Month Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 5,604,321 | 5,673,871 | 5,703,975 | 5,775,094 | 5,846,523 | 5,919,794 | 5,971,741 | 6,046,816 | 6,109,685 | 6,186,758 |
| Commercial | 4,340,155 | 4,390,757 | 4,415,734 | 4,467,902 | 4,520,389 | 4,578,115 | 4,622,430 | 4,684,166 | 4,743,845 | 4,818,548 |
| Irrigation | 1,764,577 | 1,768,253 | 1,763,152 | 1,752,207 | 1,754,889 | 1,758,898 | 1,752,877 | 1,753,704 | 1,757,849 | 1,755,721 |
| Industrial | 2,836,188 | 2,879,500 | 2,920,938 | 2,964,990 | 3,008,954 | 3,051,226 | 3,094,645 | 3,138,249 | 3,181,650 | 3,225,818 |
| Additional Firm | 1,234,000 | 1,231,300 | 1,234,000 | 1,228,400 | 1,228,300 | 1,217,500 | 1,212,000 | 1,268,000 | 1,262,200 | 1,257,000 |
| **System Sales** | 15,779,241 | 15,943,680 | 16,037,799 | 16,188,593 | 16,359,055 | 16,525,533 | 16,653,693 | 16,890,934 | 17,055,229 | 17,243,844 |
| **Total Sales** | 15,779,241 | 15,943,680 | 16,037,799 | 16,188,593 | 16,359,055 | 16,525,533 | 16,653,693 | 16,890,934 | 17,055,229 | 17,243,844 |
| Loss | 1,536,622 | 1,553,151 | 1,561,805 | 1,577,035 | 1,594,124 | 1,611,513 | 1,624,411 | 1,644,521 | 1,661,381 | 1,680,699 |
| **Required Generation** | 17,315,863 | 17,496,832 | 17,599,604 | 17,765,627 | 17,953,179 | 18,137,046 | 18,278,105 | 18,535,456 | 18,716,610 | 18,924,543 |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | |
| Residential | 640 | 646 | 651 | 659 | 667 | 674 | 682 | 690 | 697 | 704 |
| Commercial | 495 | 500 | 504 | 510 | 516 | 521 | 528 | 535 | 542 | 549 |
| Irrigation | 201 | 201 | 201 | 200 | 200 | 200 | 200 | 200 | 201 | 200 |
| Industrial | 324 | 328 | 333 | 338 | 343 | 347 | 353 | 358 | 363 | 367 |
| Additional Firm | 141 | 140 | 141 | 140 | 140 | 139 | 138 | 145 | 144 | 143 |
| Loss | 175 | 177 | 178 | 180 | 182 | 183 | 185 | 188 | 190 | 191 |
| **System Load** | 1,977 | 1,992 | 2,009 | 2,028 | 2,049 | 2,065 | 2,087 | 2,116 | 2,137 | 2,154 |
| Light Load | 1,797 | 1,811 | 1,826 | 1,844 | 1,863 | 1,877 | 1,897 | 1,923 | 1,942 | 1,959 |
| Heavy Load | 2,119 | 2,134 | 2,153 | 2,172 | 2,196 | 2,213 | 2,236 | 2,267 | 2,283 | 2,301 |
| **Total Load** | 1,977 | 1,992 | 2,009 | 2,028 | 2,049 | 2,065 | 2,087 | 2,116 | 2,137 | 2,154 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | |
| **System Peak (1 Hour)** | 3,889 | 3,939 | 3,985 | 4,034 | 4,090 | 4,141 | 4,192 | 4,256 | 4,312 | 4,365 |
| **Total Peak Load** | 3,889 | 3,939 | 3,985 | 4,034 | 4,090 | 4,141 | 4,192 | 4,256 | 4,312 | 4,365 |

# 70th Percentile Load Forecast

| Monthly Summary[1] | 1/2013 | 2/2013 | 3/2013 | 4/2013 | 5/2013 | 6/2013 | 7/2013 | 8/2013 | 9/2013 | 10/2013 | 11/2013 | 12/2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 816 | 698 | 581 | 494 | 457 | 491 | 612 | 579 | 471 | 468 | 592 | 820 |
| Commercial | 496 | 453 | 419 | 402 | 410 | 436 | 510 | 495 | 439 | 409 | 432 | 510 |
| Irrigation | 2 | 2 | 2 | 91 | 352 | 570 | 663 | 517 | 312 | 47 | 0 | 1 |
| Industrial | 264 | 266 | 262 | 251 | 254 | 270 | 269 | 273 | 270 | 274 | 273 | 278 |
| Additional Firm | 118 | 116 | 113 | 115 | 110 | 112 | 116 | 116 | 112 | 112 | 120 | 122 |
| Loss | 168 | 150 | 133 | 131 | 156 | 188 | 219 | 199 | 158 | 126 | 137 | 171 |
| **System Load** | 1,864 | 1,684 | 1,511 | 1,484 | 1,740 | 2,067 | 2,390 | 2,178 | 1,762 | 1,437 | 1,555 | 1,902 |
| Light Load | 1,722 | 1,554 | 1,388 | 1,344 | 1,582 | 1,850 | 2,168 | 1,933 | 1,583 | 1,296 | 1,435 | 1,757 |
| Heavy Load | 1,977 | 1,782 | 1,607 | 1,586 | 1,865 | 2,241 | 2,564 | 2,356 | 1,919 | 1,539 | 1,652 | 2,027 |
| **Total Load** | 1,864 | 1,684 | 1,511 | 1,484 | 1,740 | 2,067 | 2,390 | 2,178 | 1,762 | 1,437 | 1,555 | 1,902 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,505 | 2,384 | 2,092 | 1,971 | 2,805 | 3,264 | 3,382 | 3,027 | 2,778 | 2,026 | 2,267 | 2,683 |
| **Total Peak Load** | 2,505 | 2,384 | 2,092 | 1,971 | 2,805 | 3,264 | 3,382 | 3,027 | 2,778 | 2,026 | 2,267 | 2,683 |

| Monthly Summary[1] | 1/2014 | 2/2014 | 3/2014 | 4/2014 | 5/2014 | 6/2014 | 7/2014 | 8/2014 | 9/2014 | 10/2014 | 11/2014 | 12/2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 820 | 699 | 583 | 496 | 460 | 496 | 618 | 585 | 474 | 470 | 595 | 823 |
| Commercial | 503 | 459 | 425 | 408 | 416 | 444 | 518 | 503 | 447 | 416 | 438 | 517 |
| Irrigation | 2 | 2 | 2 | 91 | 354 | 574 | 667 | 520 | 314 | 48 | 0 | 1 |
| Industrial | 272 | 274 | 269 | 259 | 261 | 277 | 277 | 281 | 278 | 282 | 281 | 286 |
| Additional Firm | 121 | 117 | 115 | 117 | 113 | 110 | 118 | 118 | 114 | 114 | 122 | 124 |
| Loss | 170 | 152 | 135 | 133 | 158 | 190 | 222 | 201 | 160 | 127 | 139 | 172 |
| **System Load** | 1,887 | 1,702 | 1,530 | 1,503 | 1,763 | 2,090 | 2,421 | 2,208 | 1,788 | 1,457 | 1,576 | 1,923 |
| Light Load | 1,743 | 1,570 | 1,406 | 1,362 | 1,603 | 1,871 | 2,197 | 1,959 | 1,606 | 1,314 | 1,454 | 1,777 |
| Heavy Load | 2,001 | 1,800 | 1,627 | 1,607 | 1,889 | 2,266 | 2,598 | 2,404 | 1,933 | 1,561 | 1,683 | 2,039 |
| **Total Load** | 1,887 | 1,702 | 1,530 | 1,503 | 1,763 | 2,090 | 2,421 | 2,208 | 1,788 | 1,457 | 1,576 | 1,923 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,534 | 2,403 | 2,115 | 1,996 | 2,852 | 3,310 | 3,442 | 3,071 | 2,822 | 2,047 | 2,289 | 2,704 |
| **Total Peak Load** | 2,534 | 2,403 | 2,115 | 1,996 | 2,852 | 3,310 | 3,442 | 3,071 | 2,822 | 2,047 | 2,289 | 2,704 |

| Monthly Summary[1] | 1/2015 | 2/2015 | 3/2015 | 4/2015 | 5/2015 | 6/2015 | 7/2015 | 8/2015 | 9/2015 | 10/2015 | 11/2015 | 12/2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 820 | 696 | 582 | 496 | 462 | 499 | 622 | 588 | 476 | 470 | 596 | 831 |
| Commercial | 507 | 462 | 428 | 412 | 420 | 448 | 524 | 508 | 452 | 420 | 442 | 522 |
| Irrigation | 2 | 2 | 2 | 91 | 355 | 576 | 669 | 522 | 315 | 48 | 0 | 1 |
| Industrial | 279 | 281 | 277 | 265 | 268 | 285 | 285 | 288 | 286 | 290 | 289 | 293 |
| Additional Firm | 124 | 121 | 119 | 120 | 116 | 113 | 121 | 121 | 117 | 117 | 126 | 128 |
| Loss | 171 | 152 | 136 | 134 | 160 | 192 | 224 | 203 | 162 | 129 | 140 | 175 |
| **System Load** | 1,903 | 1,714 | 1,544 | 1,519 | 1,780 | 2,112 | 2,445 | 2,231 | 1,807 | 1,473 | 1,593 | 1,949 |
| Light Load | 1,758 | 1,582 | 1,418 | 1,376 | 1,619 | 1,890 | 2,219 | 1,979 | 1,624 | 1,329 | 1,470 | 1,800 |
| Heavy Load | 2,018 | 1,813 | 1,642 | 1,623 | 1,920 | 2,274 | 2,624 | 2,429 | 1,954 | 1,578 | 1,701 | 2,066 |
| **Total Load** | 1,903 | 1,714 | 1,544 | 1,519 | 1,780 | 2,112 | 2,445 | 2,231 | 1,807 | 1,473 | 1,593 | 1,949 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,530 | 2,413 | 2,108 | 1,980 | 2,898 | 3,345 | 3,495 | 3,106 | 2,856 | 2,065 | 2,289 | 2,718 |
| **Total Peak Load** | 2,530 | 2,413 | 2,108 | 1,980 | 2,898 | 3,345 | 3,495 | 3,106 | 2,856 | 2,065 | 2,289 | 2,718 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2016 | 2/2016 | 3/2016 | 4/2016 | 5/2016 | 6/2016 | 7/2016 | 8/2016 | 9/2016 | 10/2016 | 11/2016 | 12/2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 829 | 702 | 588 | 502 | 468 | 507 | 634 | 599 | 483 | 476 | 603 | 845 |
| Commercial | 512 | 466 | 433 | 416 | 425 | 454 | 530 | 514 | 458 | 425 | 447 | 528 |
| Irrigation | 2 | 2 | 2 | 91 | 352 | 570 | 663 | 517 | 312 | 47 | 0 | 1 |
| Industrial | 286 | 278 | 283 | 272 | 274 | 291 | 291 | 295 | 292 | 296 | 296 | 298 |
| Additional Firm | 124 | 117 | 119 | 120 | 116 | 113 | 121 | 121 | 117 | 117 | 126 | 128 |
| Loss | 173 | 153 | 137 | 135 | 161 | 193 | 226 | 205 | 163 | 130 | 142 | 177 |
| **System Load** | 1,927 | 1,717 | 1,562 | 1,536 | 1,797 | 2,129 | 2,465 | 2,251 | 1,826 | 1,492 | 1,614 | 1,976 |
| Light Load | 1,779 | 1,585 | 1,436 | 1,391 | 1,633 | 1,905 | 2,236 | 1,997 | 1,640 | 1,346 | 1,489 | 1,826 |
| Heavy Load | 2,053 | 1,815 | 1,654 | 1,642 | 1,937 | 2,292 | 2,661 | 2,434 | 1,974 | 1,608 | 1,714 | 2,095 |
| **Total Load** | 1,927 | 1,717 | 1,562 | 1,536 | 1,797 | 2,129 | 2,465 | 2,251 | 1,826 | 1,492 | 1,614 | 1,976 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,546 | 2,426 | 2,118 | 1,986 | 2,937 | 3,371 | 3,541 | 3,134 | 2,888 | 2,083 | 2,303 | 2,738 |
| **Total Peak Load** | 2,546 | 2,426 | 2,118 | 1,986 | 2,937 | 3,371 | 3,541 | 3,134 | 2,888 | 2,083 | 2,303 | 2,738 |

| Monthly Summary[1] | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 842 | 711 | 597 | 511 | 477 | 518 | 648 | 612 | 492 | 484 | 613 | 859 |
| Commercial | 517 | 470 | 437 | 420 | 429 | 459 | 535 | 520 | 463 | 430 | 451 | 533 |
| Irrigation | 2 | 2 | 2 | 91 | 352 | 570 | 662 | 517 | 312 | 47 | 0 | 1 |
| Industrial | 291 | 293 | 288 | 276 | 279 | 297 | 296 | 300 | 298 | 302 | 301 | 303 |
| Additional Firm | 125 | 122 | 120 | 121 | 117 | 114 | 122 | 122 | 118 | 118 | 127 | 129 |
| Loss | 175 | 156 | 139 | 137 | 163 | 195 | 228 | 207 | 165 | 132 | 144 | 180 |
| **System Load** | 1,952 | 1,752 | 1,582 | 1,556 | 1,817 | 2,152 | 2,493 | 2,278 | 1,849 | 1,513 | 1,636 | 2,004 |
| Light Load | 1,803 | 1,617 | 1,454 | 1,409 | 1,652 | 1,926 | 2,262 | 2,021 | 1,661 | 1,364 | 1,509 | 1,851 |
| Heavy Load | 2,081 | 1,854 | 1,675 | 1,673 | 1,947 | 2,318 | 2,691 | 2,463 | 1,999 | 1,630 | 1,738 | 2,135 |
| **Total Load** | 1,952 | 1,752 | 1,582 | 1,556 | 1,817 | 2,152 | 2,493 | 2,278 | 1,849 | 1,513 | 1,636 | 2,004 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,574 | 2,445 | 2,139 | 2,007 | 2,982 | 3,410 | 3,596 | 3,174 | 2,929 | 2,103 | 2,328 | 2,765 |
| **Total Peak Load** | 2,574 | 2,445 | 2,139 | 2,007 | 2,982 | 3,410 | 3,596 | 3,174 | 2,929 | 2,103 | 2,328 | 2,765 |

| Monthly Summary[1] | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 853 | 718 | 604 | 518 | 484 | 527 | 661 | 624 | 501 | 490 | 621 | 872 |
| Commercial | 521 | 472 | 440 | 424 | 433 | 463 | 540 | 525 | 468 | 434 | 455 | 538 |
| Irrigation | 2 | 2 | 2 | 91 | 353 | 572 | 665 | 518 | 313 | 47 | 0 | 1 |
| Industrial | 296 | 297 | 293 | 281 | 284 | 301 | 301 | 305 | 302 | 307 | 306 | 308 |
| Additional Firm | 125 | 121 | 119 | 121 | 117 | 114 | 122 | 122 | 118 | 118 | 127 | 128 |
| Loss | 177 | 157 | 141 | 138 | 164 | 197 | 231 | 209 | 167 | 134 | 145 | 182 |
| **System Load** | 1,974 | 1,768 | 1,599 | 1,572 | 1,835 | 2,175 | 2,520 | 2,303 | 1,869 | 1,529 | 1,654 | 2,029 |
| Light Load | 1,823 | 1,631 | 1,469 | 1,424 | 1,668 | 1,946 | 2,286 | 2,043 | 1,679 | 1,379 | 1,526 | 1,874 |
| Heavy Load | 2,093 | 1,870 | 1,692 | 1,691 | 1,966 | 2,342 | 2,720 | 2,491 | 2,036 | 1,638 | 1,757 | 2,162 |
| **Total Load** | 1,974 | 1,768 | 1,599 | 1,572 | 1,835 | 2,175 | 2,520 | 2,303 | 1,869 | 1,529 | 1,654 | 2,029 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,595 | 2,459 | 2,156 | 2,023 | 3,025 | 3,448 | 3,651 | 3,212 | 2,966 | 2,120 | 2,347 | 2,789 |
| **Total Peak Load** | 2,595 | 2,459 | 2,156 | 2,023 | 3,025 | 3,448 | 3,651 | 3,212 | 2,966 | 2,120 | 2,347 | 2,789 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 863 | 724 | 610 | 524 | 491 | 536 | 673 | 635 | 508 | 496 | 629 | 882 |
| Commercial | 525 | 476 | 444 | 428 | 437 | 469 | 546 | 530 | 474 | 438 | 459 | 544 |
| Irrigation | 2 | 2 | 2 | 91 | 354 | 573 | 666 | 520 | 314 | 47 | 0 | 1 |
| Industrial | 301 | 303 | 298 | 286 | 288 | 306 | 306 | 310 | 307 | 312 | 311 | 313 |
| Additional Firm | 126 | 122 | 120 | 122 | 117 | 115 | 123 | 123 | 119 | 119 | 128 | 129 |
| Loss | 179 | 158 | 142 | 140 | 166 | 199 | 233 | 212 | 169 | 135 | 147 | 184 |
| **System Load** | 1,996 | 1,785 | 1,616 | 1,590 | 1,854 | 2,198 | 2,547 | 2,330 | 1,891 | 1,548 | 1,674 | 2,054 |
| Light Load | 1,844 | 1,647 | 1,485 | 1,440 | 1,686 | 1,967 | 2,311 | 2,067 | 1,699 | 1,396 | 1,544 | 1,897 |
| Heavy Load | 2,117 | 1,888 | 1,719 | 1,699 | 1,987 | 2,383 | 2,734 | 2,519 | 2,060 | 1,657 | 1,778 | 2,188 |
| **Total Load** | 1,996 | 1,785 | 1,616 | 1,590 | 1,854 | 2,198 | 2,547 | 2,330 | 1,891 | 1,548 | 1,674 | 2,054 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,620 | 2,474 | 2,175 | 2,042 | 3,068 | 3,487 | 3,707 | 3,251 | 3,005 | 2,139 | 2,368 | 2,814 |
| **Total Peak Load** | 2,620 | 2,474 | 2,175 | 2,042 | 3,068 | 3,487 | 3,707 | 3,251 | 3,005 | 2,139 | 2,368 | 2,814 |

| Monthly Summary[1] | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 870 | 727 | 614 | 529 | 496 | 544 | 683 | 644 | 514 | 501 | 635 | 891 |
| Commercial | 531 | 480 | 449 | 432 | 442 | 474 | 552 | 537 | 480 | 443 | 464 | 550 |
| Irrigation | 2 | 2 | 2 | 91 | 355 | 575 | 668 | 521 | 315 | 48 | 0 | 1 |
| Industrial | 306 | 297 | 303 | 290 | 293 | 312 | 312 | 315 | 313 | 317 | 316 | 318 |
| Additional Firm | 132 | 124 | 126 | 127 | 122 | 119 | 127 | 128 | 123 | 124 | 134 | 136 |
| Loss | 181 | 159 | 144 | 141 | 168 | 202 | 236 | 214 | 171 | 137 | 149 | 186 |
| **System Load** | 2,022 | 1,789 | 1,637 | 1,611 | 1,877 | 2,225 | 2,578 | 2,359 | 1,916 | 1,569 | 1,698 | 2,083 |
| Light Load | 1,868 | 1,651 | 1,504 | 1,459 | 1,706 | 1,991 | 2,339 | 2,093 | 1,721 | 1,415 | 1,566 | 1,924 |
| Heavy Load | 2,144 | 1,891 | 1,741 | 1,722 | 2,023 | 2,396 | 2,766 | 2,568 | 2,072 | 1,680 | 1,813 | 2,208 |
| **Total Load** | 2,022 | 1,789 | 1,637 | 1,611 | 1,877 | 2,225 | 2,578 | 2,359 | 1,916 | 1,569 | 1,698 | 2,083 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,648 | 2,493 | 2,197 | 2,063 | 3,117 | 3,529 | 3,766 | 3,293 | 3,046 | 2,161 | 2,394 | 2,843 |
| **Total Peak Load** | 2,648 | 2,493 | 2,197 | 2,063 | 3,117 | 3,529 | 3,766 | 3,293 | 3,046 | 2,161 | 2,394 | 2,843 |

| Monthly Summary[1] | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 877 | 730 | 617 | 533 | 501 | 550 | 692 | 653 | 520 | 505 | 640 | 901 |
| Commercial | 535 | 484 | 453 | 436 | 446 | 479 | 558 | 542 | 485 | 448 | 468 | 555 |
| Irrigation | 2 | 2 | 2 | 91 | 355 | 575 | 669 | 522 | 315 | 48 | 0 | 1 |
| Industrial | 311 | 313 | 308 | 295 | 298 | 317 | 317 | 320 | 318 | 322 | 321 | 323 |
| Additional Firm | 143 | 138 | 135 | 136 | 130 | 127 | 135 | 135 | 130 | 131 | 144 | 148 |
| Loss | 183 | 161 | 145 | 143 | 170 | 204 | 238 | 216 | 173 | 138 | 150 | 189 |
| **System Load** | 2,051 | 1,828 | 1,660 | 1,635 | 1,901 | 2,253 | 2,609 | 2,389 | 1,942 | 1,592 | 1,725 | 2,117 |
| Light Load | 1,894 | 1,687 | 1,526 | 1,481 | 1,728 | 2,017 | 2,368 | 2,120 | 1,744 | 1,436 | 1,591 | 1,956 |
| Heavy Load | 2,186 | 1,933 | 1,758 | 1,748 | 2,050 | 2,426 | 2,800 | 2,601 | 2,100 | 1,716 | 1,832 | 2,244 |
| **Total Load** | 2,051 | 1,828 | 1,660 | 1,635 | 1,901 | 2,253 | 2,609 | 2,389 | 1,942 | 1,592 | 1,725 | 2,117 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,674 | 2,519 | 2,216 | 2,079 | 3,168 | 3,572 | 3,827 | 3,337 | 3,088 | 2,186 | 2,418 | 2,874 |
| **Total Peak Load** | 2,674 | 2,519 | 2,216 | 2,079 | 3,168 | 3,572 | 3,827 | 3,337 | 3,088 | 2,186 | 2,418 | 2,874 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 884 | 734 | 622 | 537 | 507 | 558 | 702 | 662 | 526 | 509 | 646 | 912 |
| Commercial | 540 | 488 | 457 | 440 | 451 | 485 | 564 | 548 | 492 | 453 | 473 | 562 |
| Irrigation | 2 | 2 | 2 | 91 | 355 | 575 | 668 | 521 | 315 | 48 | 0 | 1 |
| Industrial | 316 | 318 | 313 | 300 | 303 | 322 | 322 | 326 | 323 | 328 | 327 | 328 |
| Additional Firm | 148 | 142 | 139 | 141 | 134 | 131 | 138 | 139 | 134 | 135 | 149 | 153 |
| Loss | 185 | 163 | 147 | 145 | 171 | 205 | 240 | 219 | 175 | 140 | 152 | 191 |
| **System Load** | 2,075 | 1,846 | 1,680 | 1,654 | 1,921 | 2,276 | 2,635 | 2,414 | 1,964 | 1,612 | 1,747 | 2,147 |
| Light Load | 1,917 | 1,703 | 1,543 | 1,498 | 1,746 | 2,037 | 2,391 | 2,142 | 1,764 | 1,454 | 1,611 | 1,984 |
| Heavy Load | 2,212 | 1,953 | 1,778 | 1,768 | 2,071 | 2,451 | 2,845 | 2,611 | 2,123 | 1,737 | 1,855 | 2,276 |
| **Total Load** | 2,075 | 1,846 | 1,680 | 1,654 | 1,921 | 2,276 | 2,635 | 2,414 | 1,964 | 1,612 | 1,747 | 2,147 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,696 | 2,537 | 2,232 | 2,092 | 3,213 | 3,608 | 3,881 | 3,374 | 3,126 | 2,207 | 2,438 | 2,901 |
| **Total Peak Load** | 2,696 | 2,537 | 2,232 | 2,092 | 3,213 | 3,608 | 3,881 | 3,374 | 3,126 | 2,207 | 2,438 | 2,901 |

| Monthly Summary[1] | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 893 | 739 | 627 | 543 | 513 | 566 | 714 | 673 | 533 | 515 | 653 | 922 |
| Commercial | 546 | 492 | 462 | 445 | 456 | 491 | 571 | 555 | 498 | 458 | 478 | 568 |
| Irrigation | 2 | 2 | 2 | 91 | 355 | 574 | 668 | 521 | 315 | 48 | 0 | 1 |
| Industrial | 321 | 323 | 318 | 305 | 308 | 327 | 327 | 331 | 328 | 333 | 332 | 333 |
| Additional Firm | 148 | 143 | 140 | 141 | 135 | 132 | 139 | 139 | 134 | 136 | 150 | 153 |
| Loss | 187 | 164 | 148 | 146 | 173 | 207 | 243 | 221 | 177 | 141 | 154 | 193 |
| **System Load** | 2,097 | 1,862 | 1,697 | 1,672 | 1,940 | 2,298 | 2,662 | 2,440 | 1,985 | 1,630 | 1,766 | 2,171 |
| Light Load | 1,937 | 1,719 | 1,559 | 1,514 | 1,763 | 2,057 | 2,415 | 2,165 | 1,783 | 1,470 | 1,630 | 2,006 |
| Heavy Load | 2,235 | 1,970 | 1,796 | 1,798 | 2,078 | 2,475 | 2,874 | 2,638 | 2,147 | 1,757 | 1,876 | 2,313 |
| **Total Load** | 2,097 | 1,862 | 1,697 | 1,672 | 1,940 | 2,298 | 2,662 | 2,440 | 1,985 | 1,630 | 1,766 | 2,171 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,719 | 2,551 | 2,249 | 2,109 | 3,257 | 3,645 | 3,935 | 3,412 | 3,164 | 2,225 | 2,458 | 2,924 |
| **Total Peak Load** | 2,719 | 2,551 | 2,249 | 2,109 | 3,257 | 3,645 | 3,935 | 3,412 | 3,164 | 2,225 | 2,458 | 2,924 |

| Monthly Summary[1] | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 900 | 742 | 631 | 548 | 519 | 574 | 724 | 682 | 539 | 519 | 658 | 931 |
| Commercial | 551 | 495 | 466 | 449 | 460 | 496 | 576 | 561 | 504 | 463 | 482 | 573 |
| Irrigation | 2 | 2 | 2 | 91 | 355 | 575 | 669 | 522 | 315 | 48 | 0 | 1 |
| Industrial | 326 | 317 | 323 | 310 | 312 | 332 | 332 | 336 | 333 | 338 | 337 | 338 |
| Additional Firm | 148 | 138 | 140 | 141 | 134 | 131 | 139 | 139 | 134 | 135 | 149 | 153 |
| Loss | 188 | 164 | 149 | 147 | 174 | 209 | 245 | 223 | 178 | 143 | 155 | 195 |
| **System Load** | 2,115 | 1,857 | 1,710 | 1,686 | 1,955 | 2,318 | 2,685 | 2,462 | 2,004 | 1,645 | 1,782 | 2,191 |
| Light Load | 1,953 | 1,714 | 1,572 | 1,527 | 1,778 | 2,075 | 2,437 | 2,185 | 1,800 | 1,484 | 1,644 | 2,024 |
| Heavy Load | 2,242 | 1,963 | 1,820 | 1,802 | 2,095 | 2,513 | 2,882 | 2,663 | 2,182 | 1,762 | 1,893 | 2,334 |
| **Total Load** | 2,115 | 1,857 | 1,710 | 1,686 | 1,955 | 2,318 | 2,685 | 2,462 | 2,004 | 1,645 | 1,782 | 2,191 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,728 | 2,558 | 2,254 | 2,111 | 3,298 | 3,679 | 3,987 | 3,445 | 3,198 | 2,240 | 2,467 | 2,938 |
| **Total Peak Load** | 2,728 | 2,558 | 2,254 | 2,111 | 3,298 | 3,679 | 3,987 | 3,445 | 3,198 | 2,240 | 2,467 | 2,938 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 905 | 744 | 634 | 551 | 523 | 580 | 733 | 690 | 545 | 522 | 663 | 941 |
| Commercial | 554 | 498 | 469 | 453 | 464 | 501 | 581 | 566 | 509 | 467 | 485 | 579 |
| Irrigation | 2 | 2 | 2 | 91 | 354 | 574 | 667 | 520 | 314 | 48 | 0 | 1 |
| Industrial | 330 | 333 | 327 | 314 | 317 | 337 | 337 | 341 | 338 | 343 | 342 | 343 |
| Additional Firm | 148 | 143 | 140 | 141 | 135 | 132 | 139 | 140 | 135 | 136 | 150 | 153 |
| Loss | 190 | 166 | 150 | 148 | 175 | 211 | 247 | 225 | 180 | 144 | 157 | 197 |
| **System Load** | 2,130 | 1,885 | 1,723 | 1,699 | 1,969 | 2,334 | 2,705 | 2,481 | 2,020 | 1,659 | 1,796 | 2,215 |
| Light Load | 1,967 | 1,739 | 1,583 | 1,538 | 1,790 | 2,089 | 2,454 | 2,201 | 1,815 | 1,496 | 1,657 | 2,046 |
| Heavy Load | 2,259 | 1,994 | 1,833 | 1,816 | 2,110 | 2,530 | 2,902 | 2,702 | 2,184 | 1,777 | 1,918 | 2,348 |
| **Total Load** | 2,130 | 1,885 | 1,723 | 1,699 | 1,969 | 2,334 | 2,705 | 2,481 | 2,020 | 1,659 | 1,796 | 2,215 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,730 | 2,568 | 2,252 | 2,103 | 3,337 | 3,705 | 4,033 | 3,473 | 3,226 | 2,254 | 2,470 | 2,952 |
| **Total Peak Load** | 2,730 | 2,568 | 2,252 | 2,103 | 3,337 | 3,705 | 4,033 | 3,473 | 3,226 | 2,254 | 2,470 | 2,952 |

| Monthly Summary[1] | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 915 | 749 | 640 | 557 | 530 | 589 | 745 | 702 | 552 | 528 | 670 | 954 |
| Commercial | 560 | 503 | 474 | 458 | 470 | 507 | 589 | 573 | 516 | 473 | 491 | 586 |
| Irrigation | 2 | 2 | 2 | 91 | 353 | 571 | 663 | 517 | 312 | 47 | 0 | 1 |
| Industrial | 335 | 338 | 332 | 319 | 322 | 342 | 342 | 346 | 343 | 348 | 347 | 348 |
| Additional Firm | 147 | 142 | 139 | 140 | 134 | 131 | 139 | 139 | 134 | 135 | 149 | 152 |
| Loss | 192 | 167 | 152 | 150 | 177 | 212 | 249 | 227 | 181 | 146 | 158 | 200 |
| **System Load** | 2,152 | 1,900 | 1,739 | 1,715 | 1,985 | 2,353 | 2,727 | 2,503 | 2,039 | 1,677 | 1,815 | 2,241 |
| Light Load | 1,987 | 1,754 | 1,598 | 1,553 | 1,804 | 2,105 | 2,474 | 2,221 | 1,832 | 1,512 | 1,675 | 2,070 |
| Heavy Load | 2,282 | 2,010 | 1,850 | 1,833 | 2,140 | 2,533 | 2,926 | 2,726 | 2,205 | 1,795 | 1,939 | 2,375 |
| **Total Load** | 2,152 | 1,900 | 1,739 | 1,715 | 1,985 | 2,353 | 2,727 | 2,503 | 2,039 | 1,677 | 1,815 | 2,241 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,751 | 2,581 | 2,267 | 2,117 | 3,379 | 3,737 | 4,083 | 3,506 | 3,262 | 2,272 | 2,489 | 2,977 |
| **Total Peak Load** | 2,751 | 2,581 | 2,267 | 2,117 | 3,379 | 3,737 | 4,083 | 3,506 | 3,262 | 2,272 | 2,489 | 2,977 |

| Monthly Summary[1] | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 924 | 754 | 645 | 564 | 537 | 598 | 758 | 713 | 560 | 534 | 678 | 964 |
| Commercial | 567 | 508 | 480 | 463 | 475 | 514 | 596 | 580 | 523 | 479 | 496 | 592 |
| Irrigation | 2 | 2 | 2 | 91 | 353 | 571 | 664 | 518 | 313 | 47 | 0 | 1 |
| Industrial | 340 | 343 | 337 | 323 | 327 | 347 | 347 | 351 | 348 | 353 | 352 | 353 |
| Additional Firm | 147 | 142 | 139 | 140 | 134 | 131 | 139 | 139 | 134 | 135 | 149 | 152 |
| Loss | 194 | 169 | 153 | 152 | 178 | 215 | 251 | 229 | 183 | 147 | 160 | 202 |
| **System Load** | 2,174 | 1,916 | 1,757 | 1,733 | 2,004 | 2,377 | 2,755 | 2,530 | 2,062 | 1,695 | 1,835 | 2,265 |
| Light Load | 2,008 | 1,768 | 1,614 | 1,570 | 1,822 | 2,127 | 2,500 | 2,245 | 1,852 | 1,529 | 1,693 | 2,092 |
| Heavy Load | 2,317 | 2,027 | 1,859 | 1,852 | 2,161 | 2,559 | 2,957 | 2,755 | 2,230 | 1,827 | 1,949 | 2,401 |
| **Total Load** | 2,174 | 1,916 | 1,757 | 1,733 | 2,004 | 2,377 | 2,755 | 2,530 | 2,062 | 1,695 | 1,835 | 2,265 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,774 | 2,596 | 2,285 | 2,135 | 3,422 | 3,777 | 4,139 | 3,547 | 3,303 | 2,291 | 2,509 | 3,000 |
| **Total Peak Load** | 2,774 | 2,596 | 2,285 | 2,135 | 3,422 | 3,777 | 4,139 | 3,547 | 3,303 | 2,291 | 2,509 | 3,000 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 931 | 757 | 649 | 568 | 542 | 606 | 768 | 723 | 566 | 538 | 683 | 975 |
| Commercial | 572 | 512 | 484 | 467 | 480 | 519 | 602 | 586 | 529 | 484 | 501 | 599 |
| Irrigation | 2 | 2 | 2 | 91 | 354 | 573 | 666 | 519 | 314 | 47 | 0 | 1 |
| Industrial | 345 | 335 | 342 | 328 | 331 | 352 | 352 | 356 | 353 | 358 | 357 | 358 |
| Additional Firm | 146 | 136 | 138 | 139 | 133 | 130 | 138 | 138 | 133 | 134 | 147 | 150 |
| Loss | 195 | 169 | 155 | 153 | 180 | 216 | 254 | 231 | 185 | 149 | 161 | 204 |
| **System Load** | 2,191 | 1,910 | 1,769 | 1,747 | 2,020 | 2,397 | 2,780 | 2,553 | 2,081 | 1,710 | 1,850 | 2,288 |
| Light Load | 2,024 | 1,762 | 1,626 | 1,582 | 1,837 | 2,145 | 2,522 | 2,265 | 1,869 | 1,542 | 1,707 | 2,114 |
| Heavy Load | 2,335 | 2,019 | 1,873 | 1,878 | 2,165 | 2,581 | 3,001 | 2,761 | 2,250 | 1,842 | 1,965 | 2,438 |
| **Total Load** | 2,191 | 1,910 | 1,769 | 1,747 | 2,020 | 2,397 | 2,780 | 2,553 | 2,081 | 1,710 | 1,850 | 2,288 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,781 | 2,605 | 2,288 | 2,135 | 3,463 | 3,812 | 4,191 | 3,582 | 3,337 | 2,306 | 2,517 | 3,016 |
| **Total Peak Load** | 2,781 | 2,605 | 2,288 | 2,135 | 3,463 | 3,812 | 4,191 | 3,582 | 3,337 | 2,306 | 2,517 | 3,016 |

| Monthly Summary[1] | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 940 | 761 | 654 | 574 | 549 | 615 | 781 | 734 | 574 | 543 | 690 | 988 |
| Commercial | 578 | 517 | 489 | 473 | 486 | 526 | 610 | 594 | 537 | 490 | 507 | 607 |
| Irrigation | 2 | 2 | 2 | 91 | 353 | 571 | 664 | 517 | 313 | 47 | 0 | 1 |
| Industrial | 350 | 352 | 347 | 333 | 336 | 357 | 357 | 361 | 358 | 363 | 362 | 363 |
| Additional Firm | 145 | 140 | 137 | 139 | 133 | 130 | 138 | 138 | 133 | 134 | 146 | 149 |
| Loss | 197 | 171 | 156 | 154 | 182 | 218 | 256 | 234 | 187 | 150 | 163 | 207 |
| **System Load** | 2,212 | 1,943 | 1,786 | 1,763 | 2,037 | 2,417 | 2,804 | 2,578 | 2,101 | 1,728 | 1,869 | 2,315 |
| Light Load | 2,043 | 1,793 | 1,641 | 1,597 | 1,852 | 2,163 | 2,545 | 2,287 | 1,888 | 1,558 | 1,724 | 2,139 |
| Heavy Load | 2,346 | 2,055 | 1,890 | 1,896 | 2,183 | 2,603 | 3,028 | 2,788 | 2,288 | 1,850 | 1,985 | 2,467 |
| **Total Load** | 2,212 | 1,943 | 1,786 | 1,763 | 2,037 | 2,417 | 2,804 | 2,578 | 2,101 | 1,728 | 1,869 | 2,315 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,800 | 2,616 | 2,301 | 2,147 | 3,505 | 3,847 | 4,244 | 3,619 | 3,375 | 2,324 | 2,534 | 3,040 |
| **Total Peak Load** | 2,800 | 2,616 | 2,301 | 2,147 | 3,505 | 3,847 | 4,244 | 3,619 | 3,375 | 2,324 | 2,534 | 3,040 |

| Monthly Summary[1] | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 950 | 766 | 660 | 581 | 556 | 625 | 794 | 746 | 582 | 550 | 698 | 1,000 |
| Commercial | 585 | 522 | 496 | 479 | 492 | 534 | 618 | 602 | 545 | 497 | 513 | 615 |
| Irrigation | 2 | 2 | 2 | 91 | 353 | 571 | 664 | 518 | 313 | 47 | 0 | 1 |
| Industrial | 355 | 357 | 352 | 337 | 341 | 362 | 362 | 366 | 363 | 368 | 367 | 368 |
| Additional Firm | 152 | 147 | 144 | 145 | 138 | 136 | 143 | 143 | 138 | 139 | 154 | 158 |
| Loss | 200 | 173 | 158 | 156 | 184 | 221 | 259 | 236 | 189 | 152 | 165 | 210 |
| **System Load** | 2,245 | 1,967 | 1,811 | 1,789 | 2,064 | 2,448 | 2,840 | 2,612 | 2,130 | 1,754 | 1,898 | 2,352 |
| Light Load | 2,073 | 1,815 | 1,664 | 1,620 | 1,876 | 2,191 | 2,577 | 2,317 | 1,914 | 1,581 | 1,751 | 2,172 |
| Heavy Load | 2,380 | 2,081 | 1,927 | 1,912 | 2,212 | 2,654 | 3,047 | 2,824 | 2,320 | 1,878 | 2,016 | 2,506 |
| **Total Load** | 2,245 | 1,967 | 1,811 | 1,789 | 2,064 | 2,448 | 2,840 | 2,612 | 2,130 | 1,754 | 1,898 | 2,352 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,836 | 2,642 | 2,329 | 2,174 | 3,556 | 3,895 | 4,308 | 3,668 | 3,424 | 2,351 | 2,566 | 3,077 |
| **Total Peak Load** | 2,836 | 2,642 | 2,329 | 2,174 | 3,556 | 3,895 | 4,308 | 3,668 | 3,424 | 2,351 | 2,566 | 3,077 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 958 | 770 | 665 | 586 | 562 | 633 | 805 | 757 | 589 | 554 | 705 | 1,011 |
| Commercial | 592 | 527 | 501 | 485 | 499 | 541 | 627 | 610 | 553 | 504 | 519 | 623 |
| Irrigation | 2 | 2 | 2 | 91 | 354 | 572 | 665 | 519 | 313 | 47 | 0 | 1 |
| Industrial | 360 | 362 | 356 | 342 | 345 | 367 | 367 | 371 | 368 | 373 | 372 | 374 |
| Additional Firm | 151 | 146 | 143 | 144 | 138 | 135 | 143 | 143 | 138 | 139 | 153 | 156 |
| Loss | 202 | 174 | 160 | 158 | 185 | 223 | 262 | 239 | 192 | 154 | 167 | 212 |
| **System Load** | 2,265 | 1,981 | 1,827 | 1,806 | 2,083 | 2,472 | 2,868 | 2,639 | 2,153 | 1,771 | 1,917 | 2,377 |
| Light Load | 2,092 | 1,828 | 1,679 | 1,636 | 1,893 | 2,212 | 2,603 | 2,341 | 1,934 | 1,598 | 1,768 | 2,196 |
| Heavy Load | 2,390 | 2,096 | 1,944 | 1,930 | 2,219 | 2,679 | 3,060 | 2,874 | 2,313 | 1,897 | 2,036 | 2,507 |
| **Total Load** | 2,265 | 1,981 | 1,827 | 1,806 | 2,083 | 2,472 | 2,868 | 2,639 | 2,153 | 1,771 | 1,917 | 2,377 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,851 | 2,654 | 2,339 | 2,181 | 3,599 | 3,936 | 4,365 | 3,710 | 3,465 | 2,369 | 2,580 | 3,097 |
| **Total Peak Load** | 2,851 | 2,654 | 2,339 | 2,181 | 3,599 | 3,936 | 4,365 | 3,710 | 3,465 | 2,369 | 2,580 | 3,097 |

| Monthly Summary[1] | 1/2032 | 2/2032 | 3/2032 | 4/2032 | 5/2032 | 6/2032 | 7/2032 | 8/2032 | 9/2032 | 10/2032 | 11/2032 | 12/2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 965 | 773 | 669 | 591 | 568 | 641 | 817 | 767 | 596 | 559 | 710 | 1,021 |
| Commercial | 599 | 533 | 508 | 491 | 505 | 549 | 635 | 619 | 561 | 510 | 526 | 632 |
| Irrigation | 2 | 2 | 2 | 91 | 353 | 572 | 665 | 518 | 313 | 47 | 0 | 1 |
| Industrial | 365 | 355 | 361 | 347 | 350 | 372 | 372 | 376 | 373 | 379 | 377 | 379 |
| Additional Firm | 151 | 140 | 142 | 144 | 137 | 135 | 142 | 142 | 137 | 138 | 152 | 156 |
| Loss | 204 | 174 | 161 | 159 | 187 | 225 | 264 | 241 | 194 | 155 | 169 | 214 |
| **System Load** | 2,286 | 1,977 | 1,843 | 1,822 | 2,100 | 2,493 | 2,894 | 2,664 | 2,174 | 1,789 | 1,935 | 2,402 |
| Light Load | 2,111 | 1,824 | 1,694 | 1,650 | 1,910 | 2,231 | 2,626 | 2,364 | 1,953 | 1,614 | 1,785 | 2,219 |
| Heavy Load | 2,412 | 2,101 | 1,951 | 1,948 | 2,251 | 2,685 | 3,088 | 2,901 | 2,336 | 1,928 | 2,045 | 2,534 |
| **Total Load** | 2,286 | 1,977 | 1,843 | 1,822 | 2,100 | 2,493 | 2,894 | 2,664 | 2,174 | 1,789 | 1,935 | 2,402 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| **System Peak (1 hour)** | 2,867 | 2,652 | 2,349 | 2,189 | 3,642 | 3,973 | 4,418 | 3,748 | 3,504 | 2,387 | 2,594 | 3,118 |
| **Total Peak Load** | 2,867 | 2,652 | 2,349 | 2,189 | 3,642 | 3,973 | 4,418 | 3,748 | 3,504 | 2,387 | 2,594 | 3,118 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2013 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

# Annual Summary

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh)–70th Percentile** | | | | | | | | | | |
| Residential | 5,164,791 | 5,195,891 | 5,206,261 | 5,276,623 | 5,369,337 | 5,450,107 | 5,523,750 | 5,580,441 | 5,632,102 | 5,689,844 |
| Commercial | 3,948,571 | 4,009,836 | 4,046,655 | 4,094,416 | 4,134,995 | 4,170,810 | 4,212,514 | 4,258,123 | 4,300,385 | 4,345,653 |
| Irrigation | 1,881,550 | 1,892,561 | 1,899,085 | 1,881,000 | 1,879,758 | 1,886,182 | 1,890,570 | 1,895,609 | 1,898,618 | 1,895,444 |
| Industrial | 2,334,380 | 2,402,175 | 2,466,748 | 2,523,489 | 2,568,734 | 2,609,536 | 2,653,663 | 2,698,998 | 2,743,911 | 2,788,219 |
| Additional Firm | 1,009,771 | 1,025,200 | 1,052,800 | 1,053,500 | 1,062,300 | 1,059,600 | 1,067,700 | 1,115,100 | 1,193,100 | 1,228,700 |
| **System Sales** | 14,339,064 | 14,525,663 | 14,671,549 | 14,829,029 | 15,015,124 | 15,176,235 | 15,348,197 | 15,548,270 | 15,768,116 | 15,947,860 |
| **Total Sales** | 14,339,064 | 14,525,663 | 14,671,549 | 14,829,029 | 15,015,124 | 15,176,235 | 15,348,197 | 15,548,270 | 15,768,116 | 15,947,860 |
| **Generation Month Sales (MWh)–70th Percentile** | | | | | | | | | | |
| Residential | 5,167,413 | 5,197,036 | 5,211,598 | 5,300,406 | 5,375,457 | 5,455,753 | 5,528,219 | 5,602,024 | 5,636,673 | 5,695,236 |
| Commercial | 3,951,973 | 4,011,934 | 4,049,337 | 4,107,904 | 4,137,048 | 4,173,184 | 4,215,100 | 4,272,056 | 4,302,959 | 4,348,499 |
| Irrigation | 1,881,554 | 1,892,564 | 1,899,078 | 1,881,038 | 1,879,761 | 1,886,184 | 1,890,572 | 1,895,649 | 1,898,617 | 1,895,444 |
| Industrial | 2,340,228 | 2,407,744 | 2,471,642 | 2,527,392 | 2,572,253 | 2,613,342 | 2,657,573 | 2,702,871 | 2,747,733 | 2,792,033 |
| Additional Firm | 1,009,771 | 1,025,200 | 1,052,800 | 1,053,500 | 1,062,300 | 1,059,600 | 1,067,700 | 1,115,100 | 1,193,100 | 1,228,700 |
| **System Sales** | 14,350,940 | 14,534,478 | 14,684,455 | 14,870,240 | 15,026,819 | 15,188,062 | 15,359,163 | 15,587,701 | 15,779,082 | 15,959,913 |
| **Total Sales** | 14,350,940 | 14,534,478 | 14,684,455 | 14,870,240 | 15,026,819 | 15,188,062 | 15,359,163 | 15,587,701 | 15,779,082 | 15,959,913 |
| Loss | 1,414,977 | 1,431,581 | 1,443,654 | 1,461,800 | 1,476,685 | 1,492,948 | 1,509,490 | 1,529,225 | 1,542,768 | 1,558,213 |
| **Required Generation** | 15,765,916 | 15,966,059 | 16,128,108 | 16,332,040 | 16,503,504 | 16,681,010 | 16,868,653 | 17,116,926 | 17,321,850 | 17,518,125 |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | |
| Residential | 590 | 593 | 595 | 603 | 614 | 623 | 631 | 638 | 643 | 650 |
| Commercial | 451 | 458 | 462 | 468 | 472 | 476 | 481 | 486 | 491 | 496 |
| Irrigation | 215 | 216 | 217 | 214 | 215 | 215 | 216 | 216 | 217 | 216 |
| Industrial | 267 | 275 | 282 | 288 | 294 | 298 | 303 | 308 | 314 | 319 |
| Additional Firm | 115 | 117 | 120 | 120 | 121 | 121 | 122 | 127 | 136 | 140 |
| Loss | 162 | 163 | 165 | 166 | 169 | 170 | 172 | 174 | 176 | 178 |
| **System Load** | 1,800 | 1,823 | 1,841 | 1,859 | 1,884 | 1,904 | 1,926 | 1,949 | 1,977 | 2,000 |
| Light Load | 1,636 | 1,657 | 1,673 | 1,690 | 1,712 | 1,731 | 1,750 | 1,771 | 1,797 | 1,818 |
| Heavy Load | 1,928 | 1,953 | 1,972 | 1,992 | 2,019 | 2,040 | 2,063 | 2,087 | 2,119 | 2,143 |
| **Total Load** | 1,800 | 1,823 | 1,841 | 1,859 | 1,884 | 1,904 | 1,926 | 1,949 | 1,977 | 2,000 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | |
| **System Peak (1 Hour)** | 3,382 | 3,442 | 3,495 | 3,541 | 3,596 | 3,651 | 3,707 | 3,766 | 3,827 | 3,881 |
| **Total Peak Load** | 3,382 | 3,442 | 3,495 | 3,541 | 3,596 | 3,651 | 3,707 | 3,766 | 3,827 | 3,881 |

| | 2023 | 2024 | 2024 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh)–70th Percentile** | | | | | | | | | | |
| Residential | 5,758,958 | 5,813,316 | 5,860,061 | 5,932,333 | 6,006,257 | 6,062,171 | 6,132,197 | 6,209,218 | 6,273,351 | 6,333,447 |
| Commercial | 4,395,933 | 4,435,955 | 4,472,534 | 4,525,502 | 4,579,235 | 4,625,191 | 4,681,997 | 4,744,649 | 4,804,978 | 4,867,787 |
| Irrigation | 1,894,663 | 1,898,303 | 1,893,243 | 1,882,293 | 1,884,974 | 1,888,949 | 1,882,964 | 1,883,789 | 1,887,937 | 1,885,770 |
| Industrial | 2,832,435 | 2,875,947 | 2,917,139 | 2,961,183 | 3,005,317 | 3,047,482 | 3,090,882 | 3,134,512 | 3,177,840 | 3,222,016 |
| Additional Firm | 1,234,000 | 1,231,300 | 1,234,000 | 1,228,400 | 1,228,300 | 1,217,500 | 1,212,000 | 1,268,000 | 1,262,200 | 1,257,000 |
| **System Sales** | 16,115,989 | 16,254,821 | 16,376,977 | 16,529,711 | 16,704,083 | 16,841,293 | 17,000,039 | 17,240,168 | 17,406,305 | 17,566,020 |
| **Total Sales** | 16,115,989 | 16,254,821 | 16,376,977 | 16,529,711 | 16,704,083 | 16,841,293 | 17,000,039 | 17,240,168 | 17,406,305 | 17,566,020 |
| **Generation Month Sales (MWh)–70th Percentile** | | | | | | | | | | |
| Residential | 5,763,317 | 5,834,947 | 5,865,721 | 5,938,129 | 6,010,781 | 6,085,880 | 6,138,263 | 6,214,376 | 6,278,234 | 6,356,880 |
| Commercial | 4,398,233 | 4,449,963 | 4,475,535 | 4,528,549 | 4,581,867 | 4,640,688 | 4,685,537 | 4,748,069 | 4,808,536 | 4,884,307 |
| Irrigation | 1,894,665 | 1,898,340 | 1,893,239 | 1,882,294 | 1,884,976 | 1,888,985 | 1,882,964 | 1,883,791 | 1,887,936 | 1,885,808 |
| Industrial | 2,836,188 | 2,879,500 | 2,920,938 | 2,964,990 | 3,008,954 | 3,051,226 | 3,094,645 | 3,138,249 | 3,181,650 | 3,225,818 |
| Additional Firm | 1,234,000 | 1,231,300 | 1,234,000 | 1,228,400 | 1,228,300 | 1,217,500 | 1,212,000 | 1,268,000 | 1,262,200 | 1,257,000 |
| **System Sales** | 16,126,403 | 16,294,050 | 16,389,434 | 16,542,362 | 16,714,878 | 16,884,279 | 17,013,410 | 17,252,484 | 17,418,556 | 17,609,813 |
| **Total Sales** | 16,126,403 | 16,294,050 | 16,389,434 | 16,542,362 | 16,714,878 | 16,884,279 | 17,013,410 | 17,252,484 | 17,418,556 | 17,609,813 |
| Loss | 1,574,463 | 1,591,342 | 1,600,133 | 1,615,595 | 1,632,909 | 1,650,617 | 1,663,620 | 1,683,930 | 1,700,984 | 1,720,590 |
| **Required Generation** | 17,700,866 | 17,885,392 | 17,989,567 | 18,157,957 | 18,347,787 | 18,534,896 | 18,677,030 | 18,936,415 | 19,119,540 | 19,330,402 |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | |
| Residential | 658 | 664 | 670 | 678 | 686 | 693 | 701 | 709 | 717 | 724 |
| Commercial | 502 | 507 | 511 | 517 | 523 | 528 | 535 | 542 | 549 | 556 |
| Irrigation | 216 | 216 | 216 | 215 | 215 | 215 | 215 | 215 | 216 | 215 |
| Industrial | 324 | 328 | 333 | 338 | 343 | 347 | 353 | 358 | 363 | 367 |
| Additional Firm | 141 | 140 | 141 | 140 | 140 | 139 | 138 | 145 | 144 | 143 |
| Loss | 180 | 181 | 183 | 184 | 186 | 188 | 190 | 192 | 194 | 196 |
| **System Load** | 2,021 | 2,036 | 2,054 | 2,073 | 2,094 | 2,110 | 2,132 | 2,162 | 2,183 | 2,201 |
| Light Load | 1,837 | 1,851 | 1,867 | 1,884 | 1,904 | 1,918 | 1,938 | 1,965 | 1,984 | 2,000 |
| Heavy Load | 2,166 | 2,181 | 2,200 | 2,221 | 2,244 | 2,261 | 2,284 | 2,316 | 2,332 | 2,351 |
| **Total Load** | 2,021 | 2,036 | 2,054 | 2,073 | 2,094 | 2,110 | 2,132 | 2,162 | 2,183 | 2,201 |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | |
| **System Peak (1 Hour)** | 3,935 | 3,987 | 4,033 | 4,083 | 4,139 | 4,191 | 4,244 | 4,308 | 4,365 | 4,418 |
| **Total Peak Load** | 3,935 | 3,987 | 4,033 | 4,083 | 4,139 | 4,191 | 4,244 | 4,308 | 4,365 | 4,418 |

# LOAD AND RESOURCE BALANCE DATA

## Monthly Average Energy Load and Resource Balance

| | 1/2013 | 2/2013 | 3/2013 | 4/2013 | 5/2013 | 6/2013 | 7/2013 | 8/2013 | 9/2013 | 10/2013 | 11/2013 | 12/2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 7 | 7 | 7 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 7 | 7 |
| Load Forecast (70th% w/DSM) | (1,864) | (1,684) | (1,511) | (1,484) | (1,740) | (2,067) | (2,390) | (2,178) | (1,762) | (1,437) | (1,555) | (1,902) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 933 | 933 | 806 | 699 | 841 | 915 | 933 | 933 | 933 | 933 | 932 | 933 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 579 | 603 | 595 | 676 | 868 | 703 | 517 | 383 | 436 | 413 | 364 | 469 |
| Hydro (70th%)—Other | 216 | 234 | 215 | 236 | 328 | 337 | 278 | 251 | 224 | 219 | 202 | 208 |
| Shoshone Falls Upgrade (70th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 72 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 795 | 837 | 811 | 912 | 1,195 | 1,040 | 867 | 634 | 660 | 632 | 566 | 677 |
| **CSPP (PURPA)** | 201 | 207 | 212 | 262 | 306 | 297 | 263 | 241 | 247 | 235 | 242 | 199 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange– Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| **Total PPAs** | 62 | 74 | 54 | 54 | 72 | 73 | 75 | 75 | 61 | 43 | 55 | 82 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 205 | 292 | 194 | 264 | 68 | 0 | 0 | 0 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,539 | 2,342 | 1,882 | 1,926 | 2,620 | 3,126 | 2,837 | 2,662 | 2,249 | 2,127 | 2,084 | 2,431 |
| **Monthly Surplus/Deficit** | 675 | 657 | 371 | 442 | 880 | 1,059 | 447 | 483 | 487 | 690 | 529 | 529 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 1 | 2 | 3 | 3 | 3 | 1 | 0 | 0 | 0 |
| Commercial/Industrial | 6 | 6 | 6 | 6 | 6 | 7 | 7 | 7 | 6 | 6 | 6 | 6 |
| Residential | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total New DSM (aMW)** | 6 | 6 | 6 | 7 | 9 | 10 | 10 | 9 | 8 | 7 | 6 | 7 |
| **Monthly Surplus/Deficit** | 682 | 664 | 378 | 449 | 889 | 1,068 | 457 | 493 | 495 | 697 | 535 | 535 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 682 | 664 | 378 | 449 | 889 | 1,068 | 457 | 493 | 495 | 697 | 535 | 535 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2014 | 2/2014 | 3/2014 | 4/2014 | 5/2014 | 6/2014 | 7/2014 | 8/2014 | 9/2014 | 10/2014 | 11/2014 | 12/2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 14 | 14 | 14 | 15 | 16 | 16 | 16 | 16 | 15 | 14 | 14 | 14 |
| Load Forecast (70th% w/DSM) | (1,887) | (1,702) | (1,530) | (1,503) | (1,763) | (2,090) | (2,421) | (2,208) | (1,788) | (1,457) | (1,576) | (1,923) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 933 | 933 | 779 | 668 | 853 | 915 | 932 | 932 | 932 | 932 | 931 | 932 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 575 | 602 | 594 | 673 | 867 | 701 | 516 | 381 | 435 | 410 | 364 | 466 |
| Hydro (70th%)—Other | 215 | 221 | 213 | 228 | 327 | 336 | 278 | 250 | 223 | 219 | 201 | 207 |
| Shoshone Falls Upgrade(70th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 72 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 790 | 823 | 806 | 901 | 1,194 | 1,037 | 865 | 632 | 658 | 629 | 565 | 673 |
| **CSPP (PURPA)** | 203 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange– Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| **Total PPAs** | 62 | 74 | 54 | 54 | 72 | 73 | 75 | 75 | 61 | 43 | 55 | 82 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 230 | 352 | 237 | 277 | 113 | 0 | 0 | 1 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,536 | 2,341 | 1,863 | 1,896 | 2,667 | 3,195 | 2,889 | 2,683 | 2,302 | 2,134 | 2,094 | 2,438 |
| **Monthly Surplus/Deficit** | 650 | 639 | 333 | 392 | 904 | 1,104 | 468 | 475 | 515 | 677 | 518 | 515 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 1 | 4 | 6 | 6 | 5 | 3 | 0 | 0 | 0 |
| Commercial/Industrial | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| Residential | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total New DSM (aMW)** | 13 | 13 | 13 | 14 | 17 | 19 | 20 | 19 | 16 | 14 | 13 | 13 |
| **Monthly Surplus/Deficit** | 663 | 653 | 347 | 407 | 921 | 1,124 | 487 | 494 | 530 | 691 | 531 | 528 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 663 | 653 | 347 | 407 | 921 | 1,124 | 487 | 494 | 530 | 691 | 531 | 528 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2015 | 2/2015 | 3/2015 | 4/2015 | 5/2015 | 6/2015 | 7/2015 | 8/2015 | 9/2015 | 10/2015 | 11/2015 | 12/2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 21 | 21 | 21 | 22 | 24 | 24 | 24 | 23 | 23 | 22 | 21 | 21 |
| Load Forecast (70th% w/DSM) | (1,903) | (1,714) | (1,544) | (1,519) | (1,780) | (2,112) | (2,445) | (2,231) | (1,807) | (1,473) | (1,593) | (1,949) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 932 | 932 | 832 | 648 | 687 | 812 | 932 | 932 | 932 | 932 | 931 | 932 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 582 | 619 | 598 | 715 | 869 | 705 | 516 | 381 | 434 | 418 | 363 | 479 |
| Hydro (70th%)—Other | 218 | 258 | 214 | 259 | 331 | 340 | 278 | 251 | 224 | 221 | 202 | 209 |
| Shoshone Falls Upgrade(70th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 72 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 799 | 877 | 813 | 974 | 1,199 | 1,045 | 865 | 632 | 658 | 639 | 566 | 688 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange– Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| **Total PPAs** | 62 | 74 | 54 | 54 | 72 | 73 | 75 | 75 | 61 | 43 | 55 | 82 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 276 | 342 | 237 | 274 | 147 | 0 | 0 | 15 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,557 | 2,395 | 1,922 | 1,949 | 2,552 | 3,089 | 2,889 | 2,681 | 2,336 | 2,145 | 2,095 | 2,467 |
| **Monthly Surplus/Deficit** | 654 | 681 | 378 | 430 | 771 | 978 | 444 | 450 | 529 | 671 | 502 | 518 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 2 | 6 | 8 | 8 | 7 | 4 | 1 | 0 | 0 |
| Commercial/Industrial | 19 | 19 | 19 | 19 | 19 | 20 | 20 | 20 | 19 | 19 | 19 | 19 |
| Residential | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| **Total New DSM (aMW)** | 20 | 20 | 20 | 21 | 26 | 28 | 29 | 27 | 23 | 20 | 20 | 20 |
| **Monthly Surplus/Deficit** | 673 | 700 | 398 | 451 | 797 | 1,006 | 473 | 478 | 552 | 691 | 521 | 538 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 673 | 700 | 398 | 451 | 797 | 1,006 | 473 | 478 | 552 | 691 | 521 | 538 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2016 | 2/2016 | 3/2016 | 4/2016 | 5/2016 | 6/2016 | 7/2016 | 8/2016 | 9/2016 | 10/2016 | 11/2016 | 12/2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 26 | 26 | 26 | 27 | 29 | 30 | 30 | 29 | 28 | 26 | 26 | 26 |
| Load Forecast (70th% w/DSM) | (1,927) | (1,717) | (1,562) | (1,536) | (1,797) | (2,129) | (2,465) | (2,251) | (1,826) | (1,492) | (1,614) | (1,976) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 932 | 932 | 703 | 686 | 716 | 839 | 938 | 938 | 938 | 938 | 937 | 938 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 581 | 617 | 599 | 712 | 872 | 704 | 515 | 351 | 432 | 416 | 364 | 488 |
| Hydro (70th%)—Other | 218 | 283 | 214 | 261 | 330 | 340 | 277 | 206 | 224 | 221 | 202 | 208 |
| Shoshone Falls Upgrade(70th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 798 | 900 | 813 | 973 | 1,202 | 1,043 | 791 | 556 | 656 | 637 | 566 | 696 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 314 | 342 | 237 | 272 | 178 | 0 | 0 | 34 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,551 | 2,412 | 1,807 | 1,997 | 2,611 | 3,104 | 2,811 | 2,602 | 2,368 | 2,168 | 2,117 | 2,497 |
| **Monthly Surplus/Deficit** | 624 | 694 | 244 | 461 | 815 | 975 | 347 | 351 | 542 | 675 | 504 | 520 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 2 | 7 | 9 | 10 | 8 | 4 | 1 | 0 | 0 |
| Commercial/Industrial | 25 | 24 | 24 | 24 | 25 | 25 | 25 | 25 | 24 | 24 | 24 | 24 |
| Residential | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| **Total New DSM (aMW)** | 27 | 26 | 26 | 28 | 33 | 36 | 37 | 35 | 31 | 27 | 26 | 26 |
| **Monthly Surplus/Deficit** | 651 | 721 | 270 | 489 | 848 | 1,012 | 383 | 386 | 572 | 703 | 530 | 547 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 651 | 721 | 270 | 489 | 848 | 1,012 | 383 | 386 | 572 | 703 | 530 | 547 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 30 | 30 | 30 | 31 | 34 | 35 | 35 | 34 | 33 | 30 | 30 | 30 |
| Load Forecast (70th% w/DSM) | (1,952) | (1,752) | (1,582) | (1,556) | (1,817) | (2,152) | (2,493) | (2,278) | (1,849) | (1,513) | (1,636) | (2,004) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 938 | 938 | 940 | 781 | 709 | 835 | 944 | 944 | 944 | 944 | 943 | 944 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 580 | 616 | 596 | 700 | 867 | 702 | 513 | 349 | 431 | 414 | 364 | 487 |
| Hydro (70th%)—Other | 217 | 275 | 206 | 251 | 330 | 338 | 276 | 205 | 223 | 220 | 201 | 208 |
| Shoshone Falls Upgrade(70th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 797 | 891 | 802 | 951 | 1,197 | 1,041 | 789 | 554 | 654 | 634 | 565 | 694 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 359 | 347 | 237 | 269 | 219 | 0 | 0 | 61 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,555 | 2,409 | 2,032 | 2,070 | 2,644 | 3,102 | 2,816 | 2,603 | 2,412 | 2,171 | 2,123 | 2,528 |
| **Monthly Surplus/Deficit** | 603 | 656 | 449 | 514 | 828 | 950 | 323 | 325 | 564 | 658 | 487 | 524 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 2 | 8 | 11 | 11 | 9 | 5 | 1 | 0 | 0 |
| Commercial/Industrial | 29 | 29 | 29 | 29 | 30 | 30 | 30 | 30 | 29 | 29 | 29 | 30 |
| Residential | 4 | 4 | 4 | 4 | 4 | 3 | 3 | 3 | 4 | 4 | 4 | 4 |
| **Total New DSM (aMW)** | 33 | 33 | 33 | 35 | 41 | 44 | 45 | 43 | 38 | 34 | 33 | 33 |
| **Monthly Surplus/Deficit** | 636 | 689 | 482 | 550 | 868 | 994 | 368 | 368 | 602 | 692 | 520 | 558 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 636 | 689 | 482 | 550 | 868 | 994 | 368 | 368 | 602 | 692 | 520 | 558 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 34 | 34 | 34 | 35 | 39 | 40 | 40 | 39 | 37 | 34 | 34 | 34 |
| Load Forecast (70th% w/DSM) | (1,974) | (1,768) | (1,599) | (1,572) | (1,835) | (2,175) | (2,520) | (2,303) | (1,869) | (1,529) | (1,654) | (2,029) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 944 | 944 | 881 | 731 | 743 | 922 | 948 | 948 | 948 | 948 | 947 | 948 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 579 | 606 | 588 | 699 | 866 | 694 | 512 | 348 | 430 | 410 | 364 | 480 |
| Hydro (70th%)—Other | 215 | 233 | 206 | 250 | 330 | 337 | 276 | 204 | 222 | 219 | 201 | 207 |
| Shoshone Falls Upgrade(70th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 795 | 839 | 794 | 949 | 1,196 | 1,032 | 788 | 552 | 652 | 630 | 564 | 687 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 385 | 342 | 237 | 267 | 257 | 0 | 0 | 86 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,559 | 2,363 | 1,965 | 2,017 | 2,704 | 3,175 | 2,818 | 2,603 | 2,452 | 2,170 | 2,126 | 2,550 |
| **Monthly Surplus/Deficit** | 585 | 595 | 367 | 445 | 869 | 1,000 | 298 | 299 | 583 | 641 | 472 | 521 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 2 | 9 | 12 | 13 | 11 | 6 | 1 | 0 | 0 |
| Commercial/Industrial | 35 | 35 | 35 | 35 | 35 | 36 | 36 | 36 | 35 | 35 | 35 | 35 |
| Residential | 7 | 7 | 7 | 7 | 7 | 6 | 6 | 6 | 7 | 7 | 7 | 7 |
| **Total New DSM (aMW)** | 42 | 42 | 41 | 44 | 51 | 55 | 55 | 53 | 48 | 42 | 42 | 42 |
| **Monthly Surplus/Deficit** | 627 | 636 | 408 | 489 | 920 | 1,055 | 353 | 352 | 630 | 683 | 513 | 563 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 827 | 836 | 608 | 989 | 1,420 | 1,555 | 853 | 852 | 1,130 | 883 | 713 | 763 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 37 | 37 | 37 | 39 | 44 | 45 | 45 | 44 | 41 | 38 | 37 | 37 |
| Load Forecast (70th% w/DSM) | (1,996) | (1,785) | (1,616) | (1,590) | (1,854) | (2,198) | (2,547) | (2,330) | (1,891) | (1,548) | (1,674) | (2,054) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 948 | 948 | 901 | 833 | 731 | 865 | 954 | 954 | 954 | 954 | 953 | 954 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 578 | 602 | 588 | 695 | 865 | 690 | 511 | 347 | 428 | 399 | 363 | 474 |
| Hydro (70th%)—Other | 215 | 223 | 200 | 243 | 329 | 337 | 275 | 203 | 221 | 219 | 199 | 207 |
| Shoshone Falls Upgrade(70th%) | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 793 | 825 | 788 | 937 | 1,195 | 1,027 | 788 | 549 | 649 | 618 | 564 | 684 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 384 | 342 | 237 | 265 | 270 | 0 | 0 | 111 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,561 | 2,353 | 1,979 | 2,109 | 2,690 | 3,113 | 2,825 | 2,604 | 2,468 | 2,164 | 2,131 | 2,577 |
| **Monthly Surplus/Deficit** | 565 | 568 | 363 | 519 | 836 | 915 | 277 | 274 | 576 | 617 | 457 | 524 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 3 | 10 | 14 | 15 | 12 | 7 | 1 | 0 | 0 |
| Commercial/Industrial | 40 | 39 | 40 | 39 | 40 | 41 | 41 | 41 | 40 | 39 | 40 | 40 |
| Residential | 10 | 10 | 10 | 10 | 10 | 9 | 9 | 9 | 10 | 10 | 10 | 10 |
| **Total New DSM (aMW)** | 49 | 49 | 49 | 52 | 60 | 64 | 65 | 62 | 56 | 50 | 49 | 50 |
| **Monthly Surplus/Deficit** | 614 | 617 | 412 | 571 | 895 | 979 | 342 | 337 | 633 | 667 | 507 | 573 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 814 | 817 | 612 | 1,071 | 1,395 | 1,479 | 842 | 837 | 1,133 | 867 | 707 | 773 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 42 | 42 | 42 | 44 | 49 | 50 | 51 | 49 | 46 | 43 | 42 | 42 |
| Load Forecast (70th% w/DSM) | (2,022) | (1,789) | (1,637) | (1,611) | (1,877) | (2,225) | (2,578) | (2,359) | (1,916) | (1,569) | (1,698) | (2,083) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 948 | 948 | 949 | 762 | 686 | 910 | 954 | 954 | 954 | 954 | 954 | 954 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 577 | 599 | 588 | 691 | 865 | 687 | 510 | 345 | 427 | 395 | 364 | 469 |
| Hydro (70th%)—Other | 214 | 220 | 198 | 236 | 329 | 336 | 274 | 202 | 220 | 218 | 198 | 206 |
| Shoshone Falls Upgrade(70th%) | 6 | 15 | 0 | 1 | 15 | 17 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 798 | 834 | 786 | 929 | 1,208 | 1,039 | 786 | 547 | 647 | 613 | 563 | 677 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 383 | 342 | 237 | 262 | 269 | 0 | 4 | 139 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,566 | 2,361 | 2,025 | 2,029 | 2,657 | 3,170 | 2,822 | 2,599 | 2,464 | 2,160 | 2,136 | 2,598 |
| **Monthly Surplus/Deficit** | 543 | 572 | 388 | 418 | 781 | 945 | 245 | 240 | 549 | 591 | 439 | 515 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 3 | 12 | 16 | 17 | 14 | 8 | 1 | 0 | 0 |
| Commercial/Industrial | 45 | 45 | 45 | 45 | 46 | 47 | 47 | 47 | 45 | 45 | 46 | 45 |
| Residential | 9 | 9 | 9 | 9 | 9 | 8 | 8 | 8 | 9 | 9 | 9 | 9 |
| **Total New DSM (aMW)** | 54 | 54 | 54 | 57 | 66 | 71 | 72 | 69 | 62 | 55 | 55 | 54 |
| **Monthly Surplus/Deficit** | 598 | 626 | 443 | 475 | 847 | 1,017 | 317 | 309 | 610 | 647 | 493 | 570 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 798 | 826 | 643 | 975 | 1,347 | 1,517 | 817 | 809 | 1,110 | 847 | 693 | 770 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 45 | 45 | 45 | 48 | 54 | 55 | 56 | 54 | 51 | 46 | 45 | 45 |
| Load Forecast (70th% w/DSM) | (2,051) | (1,828) | (1,660) | (1,635) | (1,901) | (2,253) | (2,609) | (2,389) | (1,942) | (1,592) | (1,725) | (2,117) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 811 | 624 | 658 | 791 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 576 | 593 | 588 | 687 | 864 | 684 | 508 | 344 | 425 | 395 | 364 | 479 |
| Hydro (70th%)—Other | 213 | 219 | 196 | 238 | 327 | 333 | 273 | 201 | 219 | 217 | 197 | 205 |
| Shoshone Falls Upgrade(70th%) | 6 | 12 | 0 | 1 | 15 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 795 | 824 | 784 | 926 | 1,206 | 1,033 | 784 | 544 | 643 | 612 | 562 | 686 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 87 | 0 | 0 | 0 | 434 | 395 | 290 | 313 | 320 | 0 | 83 | 225 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,596 | 2,267 | 1,884 | 1,888 | 2,678 | 3,099 | 2,819 | 2,593 | 2,458 | 2,104 | 2,159 | 2,639 |
| **Monthly Surplus/Deficit** | 545 | 439 | 224 | 253 | 776 | 845 | 209 | 204 | 516 | 512 | 435 | 522 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 4 | 13 | 19 | 20 | 16 | 9 | 2 | 0 | 0 |
| Commercial/Industrial | 51 | 51 | 50 | 51 | 52 | 53 | 53 | 53 | 51 | 51 | 51 | 51 |
| Residential | 9 | 9 | 9 | 9 | 9 | 8 | 8 | 8 | 9 | 9 | 9 | 9 |
| **Total New DSM (aMW)** | 60 | 60 | 60 | 64 | 74 | 80 | 80 | 77 | 69 | 62 | 60 | 60 |
| **Monthly Surplus/Deficit** | 605 | 499 | 284 | 317 | 851 | 925 | 290 | 281 | 585 | 574 | 495 | 582 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 805 | 699 | 484 | 817 | 1,351 | 1,425 | 790 | 781 | 1,085 | 774 | 695 | 782 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 45 | 45 | 45 | 48 | 54 | 55 | 56 | 54 | 51 | 46 | 45 | 45 |
| Load Forecast (70th% w/DSM) | (2,051) | (1,828) | (1,660) | (1,635) | (1,901) | (2,253) | (2,609) | (2,389) | (1,942) | (1,592) | (1,725) | (2,117) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 811 | 624 | 658 | 791 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 576 | 593 | 588 | 687 | 864 | 684 | 508 | 344 | 425 | 395 | 364 | 479 |
| Hydro (70th%)—Other | 213 | 219 | 196 | 238 | 327 | 333 | 273 | 201 | 219 | 217 | 197 | 205 |
| Shoshone Falls Upgrade(70th%) | 6 | 12 | 0 | 1 | 15 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 795 | 824 | 784 | 926 | 1,206 | 1,033 | 784 | 544 | 643 | 612 | 562 | 686 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 87 | 0 | 0 | 0 | 434 | 395 | 290 | 313 | 320 | 0 | 83 | 225 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,596 | 2,267 | 1,884 | 1,888 | 2,678 | 3,099 | 2,819 | 2,593 | 2,458 | 2,104 | 2,159 | 2,639 |
| **Monthly Surplus/Deficit** | 545 | 439 | 224 | 253 | 776 | 845 | 209 | 204 | 516 | 512 | 435 | 522 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 4 | 13 | 19 | 20 | 16 | 9 | 2 | 0 | 0 |
| Commercial/Industrial | 51 | 51 | 50 | 51 | 52 | 53 | 53 | 53 | 51 | 51 | 51 | 51 |
| Residential | 9 | 9 | 9 | 9 | 9 | 8 | 8 | 8 | 9 | 9 | 9 | 9 |
| **Total New DSM (aMW)** | 60 | 60 | 60 | 64 | 74 | 80 | 80 | 77 | 69 | 62 | 60 | 60 |
| **Monthly Surplus/Deficit** | 605 | 499 | 284 | 317 | 851 | 925 | 290 | 281 | 585 | 574 | 495 | 582 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 805 | 699 | 484 | 817 | 1,351 | 1,425 | 790 | 781 | 1,085 | 774 | 695 | 782 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 49 | 49 | 49 | 51 | 58 | 60 | 60 | 58 | 55 | 50 | 49 | 49 |
| Load Forecast (70th% w/DSM) | (2,075) | (1,846) | (1,680) | (1,654) | (1,921) | (2,276) | (2,635) | (2,414) | (1,964) | (1,612) | (1,747) | (2,147) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 784 | 702 | 730 | 801 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 575 | 592 | 588 | 685 | 863 | 682 | 507 | 342 | 423 | 391 | 364 | 471 |
| Hydro (70th%)—Other | 212 | 218 | 194 | 233 | 326 | 332 | 273 | 200 | 218 | 216 | 196 | 204 |
| Shoshone Falls Upgrade(70th%) | 6 | 9 | 0 | 0 | 14 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 793 | 819 | 782 | 919 | 1,204 | 1,031 | 782 | 542 | 641 | 607 | 561 | 677 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 113 | 0 | 0 | 0 | 433 | 349 | 237 | 308 | 318 | 0 | 103 | 254 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,620 | 2,262 | 1,856 | 1,959 | 2,747 | 3,060 | 2,763 | 2,585 | 2,453 | 2,099 | 2,178 | 2,659 |
| **Monthly Surplus/Deficit** | 544 | 416 | 177 | 305 | 826 | 784 | 128 | 171 | 490 | 488 | 431 | 512 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 4 | 15 | 22 | 22 | 19 | 10 | 2 | 0 | 0 |
| Commercial/Industrial | 59 | 58 | 58 | 58 | 59 | 60 | 60 | 60 | 58 | 58 | 58 | 58 |
| Residential | 9 | 9 | 10 | 10 | 9 | 8 | 8 | 8 | 9 | 9 | 9 | 10 |
| **Total New DSM (aMW)** | 68 | 67 | 67 | 72 | 84 | 90 | 91 | 88 | 78 | 70 | 68 | 67 |
| **Monthly Surplus/Deficit** | 613 | 483 | 244 | 376 | 910 | 875 | 219 | 258 | 567 | 557 | 499 | 580 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 813 | 683 | 444 | 876 | 1,410 | 1,375 | 719 | 758 | 1,067 | 757 | 699 | 780 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 52 | 52 | 52 | 55 | 62 | 64 | 65 | 62 | 58 | 53 | 52 | 52 |
| Load Forecast (70th% w/DSM) | (2,097) | (1,862) | (1,697) | (1,672) | (1,940) | (2,298) | (2,662) | (2,440) | (1,985) | (1,630) | (1,766) | (2,171) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 777 | 662 | 730 | 801 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 574 | 591 | 587 | 682 | 862 | 681 | 505 | 341 | 422 | 387 | 364 | 463 |
| Hydro (70th%)—Other | 211 | 214 | 193 | 223 | 326 | 332 | 272 | 199 | 217 | 216 | 195 | 202 |
| Shoshone Falls Upgrade(70th%) | 6 | 6 | 0 | 0 | 14 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 791 | 812 | 780 | 905 | 1,202 | 1,029 | 779 | 539 | 638 | 602 | 560 | 668 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 136 | 0 | 0 | 0 | 431 | 346 | 237 | 306 | 316 | 0 | 123 | 291 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,641 | 2,254 | 1,848 | 1,905 | 2,743 | 3,055 | 2,761 | 2,581 | 2,449 | 2,094 | 2,198 | 2,687 |
| **Monthly Surplus/Deficit** | 543 | 392 | 151 | 234 | 804 | 757 | 99 | 141 | 464 | 464 | 431 | 516 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 5 | 18 | 25 | 26 | 22 | 11 | 2 | 0 | 0 |
| Commercial/Industrial | 64 | 64 | 64 | 64 | 65 | 67 | 67 | 67 | 64 | 64 | 64 | 65 |
| Residential | 10 | 10 | 10 | 10 | 10 | 9 | 9 | 9 | 10 | 10 | 10 | 10 |
| **Total New DSM (aMW)** | 74 | 74 | 73 | 79 | 92 | 100 | 101 | 97 | 85 | 76 | 74 | 74 |
| **Monthly Surplus/Deficit** | 617 | 466 | 224 | 313 | 896 | 857 | 200 | 237 | 549 | 540 | 505 | 590 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 817 | 666 | 424 | 813 | 1,396 | 1,357 | 700 | 737 | 1,049 | 740 | 705 | 790 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 55 | 54 | 55 | 57 | 65 | 68 | 68 | 66 | 62 | 56 | 55 | 55 |
| Load Forecast (70th% w/DSM) | (2,115) | (1,857) | (1,710) | (1,686) | (1,955) | (2,318) | (2,685) | (2,462) | (2,004) | (1,645) | (1,782) | (2,191) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 777 | 662 | 730 | 801 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 573 | 590 | 587 | 677 | 861 | 680 | 504 | 339 | 421 | 383 | 364 | 458 |
| Hydro (70th%)—Other | 209 | 212 | 191 | 211 | 325 | 331 | 271 | 198 | 216 | 215 | 194 | 201 |
| Shoshone Falls Upgrade(70th%) | 5 | 6 | 0 | 0 | 14 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 787 | 809 | 778 | 889 | 1,201 | 1,027 | 777 | 537 | 637 | 598 | 559 | 662 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 143 | 0 | 0 | 0 | 430 | 342 | 237 | 303 | 315 | 0 | 132 | 312 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,643 | 2,251 | 1,846 | 1,889 | 2,741 | 3,049 | 2,759 | 2,575 | 2,446 | 2,090 | 2,206 | 2,702 |
| **Monthly Surplus/Deficit** | 529 | 394 | 135 | 203 | 785 | 731 | 74 | 113 | 442 | 445 | 424 | 511 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 6 | 20 | 28 | 29 | 25 | 13 | 2 | 0 | 0 |
| Commercial/Industrial | 71 | 71 | 71 | 71 | 71 | 74 | 74 | 74 | 72 | 71 | 71 | 72 |
| Residential | 12 | 12 | 12 | 12 | 12 | 11 | 11 | 11 | 12 | 12 | 12 | 12 |
| **Total New DSM (aMW)** | 84 | 83 | 84 | 89 | 104 | 113 | 114 | 109 | 97 | 86 | 84 | 84 |
| **Monthly Surplus/Deficit** | 612 | 478 | 219 | 292 | 889 | 844 | 188 | 222 | 540 | 531 | 508 | 595 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 812 | 678 | 419 | 792 | 1,389 | 1,344 | 688 | 722 | 1,040 | 731 | 708 | 795 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 57 | 57 | 57 | 60 | 68 | 71 | 72 | 69 | 64 | 58 | 57 | 57 |
| Load Forecast (70th% w/DSM) | (2,130) | (1,885) | (1,723) | (1,699) | (1,969) | (2,334) | (2,705) | (2,481) | (2,020) | (1,659) | (1,796) | (2,215) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 777 | 662 | 730 | 801 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 572 | 589 | 587 | 667 | 861 | 678 | 502 | 338 | 420 | 379 | 365 | 457 |
| Hydro (70th%)—Other | 208 | 212 | 190 | 210 | 325 | 330 | 270 | 197 | 215 | 214 | 193 | 200 |
| Shoshone Falls Upgrade(70th%) | 5 | 6 | 0 | 0 | 14 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 784 | 807 | 777 | 877 | 1,200 | 1,025 | 775 | 535 | 635 | 593 | 559 | 660 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 160 | 0 | 0 | 0 | 428 | 342 | 237 | 300 | 313 | 0 | 135 | 321 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,658 | 2,249 | 1,845 | 1,877 | 2,737 | 3,047 | 2,757 | 2,570 | 2,442 | 2,085 | 2,208 | 2,709 |
| **Monthly Surplus/Deficit** | 528 | 365 | 122 | 178 | 769 | 713 | 52 | 89 | 422 | 426 | 412 | 494 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 6 | 23 | 32 | 33 | 28 | 15 | 3 | 0 | 0 |
| Commercial/Industrial | 77 | 77 | 77 | 77 | 77 | 80 | 80 | 80 | 77 | 77 | 78 | 77 |
| Residential | 16 | 16 | 16 | 16 | 16 | 14 | 14 | 14 | 16 | 16 | 16 | 16 |
| **Total New DSM (aMW)** | 93 | 93 | 93 | 99 | 116 | 126 | 127 | 122 | 108 | 96 | 94 | 93 |
| **Monthly Surplus/Deficit** | 621 | 458 | 216 | 278 | 885 | 839 | 179 | 211 | 530 | 522 | 506 | 587 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 821 | 658 | 416 | 778 | 1,385 | 1,339 | 679 | 711 | 1,030 | 722 | 706 | 787 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 59 | 59 | 59 | 62 | 71 | 74 | 75 | 72 | 67 | 60 | 59 | 59 |
| Load Forecast (70th% w/DSM) | (2,152) | (1,900) | (1,739) | (1,715) | (1,985) | (2,353) | (2,727) | (2,503) | (2,039) | (1,677) | (1,815) | (2,241) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 777 | 662 | 730 | 801 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 570 | 588 | 587 | 666 | 860 | 677 | 501 | 336 | 419 | 375 | 365 | 456 |
| Hydro (70th%)—Other | 205 | 211 | 189 | 209 | 325 | 329 | 269 | 196 | 214 | 213 | 192 | 200 |
| Shoshone Falls Upgrade(70th%) | 4 | 6 | 0 | 0 | 14 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 779 | 805 | 775 | 875 | 1,199 | 1,022 | 773 | 532 | 632 | 588 | 558 | 659 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 183 | 0 | 0 | 0 | 427 | 342 | 237 | 298 | 311 | 0 | 154 | 319 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,676 | 2,247 | 1,843 | 1,876 | 2,735 | 3,045 | 2,754 | 2,565 | 2,438 | 2,081 | 2,226 | 2,706 |
| **Monthly Surplus/Deficit** | 524 | 347 | 104 | 161 | 750 | 692 | 28 | 62 | 399 | 404 | 411 | 465 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 7 | 26 | 36 | 38 | 32 | 17 | 3 | 0 | 0 |
| Commercial/Industrial | 83 | 83 | 83 | 83 | 84 | 86 | 86 | 86 | 83 | 83 | 84 | 83 |
| Residential | 21 | 21 | 21 | 21 | 21 | 18 | 18 | 18 | 21 | 21 | 21 | 21 |
| **Total New DSM (aMW)** | 104 | 104 | 104 | 111 | 131 | 141 | 142 | 136 | 120 | 107 | 105 | 104 |
| **Monthly Surplus/Deficit** | 628 | 451 | 208 | 271 | 881 | 833 | 170 | 198 | 519 | 511 | 516 | 569 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 828 | 651 | 408 | 771 | 1,381 | 1,333 | 670 | 698 | 1,019 | 711 | 716 | 769 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 61 | 61 | 61 | 64 | 74 | 77 | 77 | 74 | 69 | 63 | 61 | 61 |
| Load Forecast (70th% w/DSM) | (2,174) | (1,916) | (1,757) | (1,733) | (2,004) | (2,377) | (2,755) | (2,530) | (2,062) | (1,695) | (1,835) | (2,265) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 777 | 662 | 730 | 801 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 562 | 587 | 586 | 665 | 859 | 676 | 500 | 335 | 417 | 372 | 365 | 455 |
| Hydro (70th%)—Other | 203 | 211 | 187 | 208 | 324 | 328 | 269 | 195 | 213 | 213 | 192 | 199 |
| Shoshone Falls Upgrade(70th%) | 4 | 6 | 0 | 0 | 14 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 769 | 803 | 773 | 874 | 1,197 | 1,020 | 771 | 529 | 630 | 585 | 557 | 657 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 218 | 0 | 0 | 0 | 425 | 342 | 237 | 295 | 308 | 0 | 174 | 317 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,700 | 2,245 | 1,841 | 1,874 | 2,731 | 3,042 | 2,752 | 2,560 | 2,433 | 2,077 | 2,246 | 2,702 |
| **Monthly Surplus/Deficit** | 526 | 329 | 84 | 141 | 727 | 666 | (3) | 29 | 371 | 382 | 411 | 437 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 8 | 29 | 41 | 43 | 36 | 19 | 4 | 0 | 0 |
| Commercial/Industrial | 89 | 88 | 88 | 88 | 90 | 92 | 92 | 92 | 89 | 89 | 89 | 89 |
| Residential | 27 | 27 | 27 | 27 | 26 | 23 | 23 | 23 | 27 | 27 | 27 | 27 |
| **Total New DSM (aMW)** | 116 | 115 | 115 | 123 | 146 | 156 | 158 | 151 | 134 | 119 | 115 | 115 |
| **Monthly Surplus/Deficit** | 642 | 444 | 199 | 264 | 873 | 822 | 155 | 181 | 505 | 501 | 526 | 552 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 842 | 644 | 399 | 764 | 1,373 | 1,322 | 655 | 681 | 1,005 | 701 | 726 | 752 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 63 | 62 | 62 | 66 | 75 | 79 | 79 | 76 | 71 | 64 | 63 | 63 |
| Load Forecast (70th% w/DSM) | (2,191) | (1,910) | (1,769) | (1,747) | (2,020) | (2,397) | (2,780) | (2,553) | (2,081) | (1,710) | (1,850) | (2,288) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 777 | 662 | 730 | 801 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 562 | 587 | 586 | 665 | 859 | 676 | 500 | 335 | 417 | 372 | 365 | 455 |
| Hydro (70th%)—Other | 203 | 211 | 187 | 208 | 324 | 328 | 269 | 195 | 213 | 213 | 192 | 199 |
| Shoshone Falls Upgrade(70th%) | 4 | 6 | 0 | 0 | 14 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 769 | 803 | 773 | 874 | 1,197 | 1,020 | 771 | 529 | 630 | 585 | 557 | 657 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 236 | 0 | 7 | 0 | 423 | 342 | 237 | 293 | 306 | 0 | 182 | 314 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,718 | 2,245 | 1,848 | 1,874 | 2,729 | 3,042 | 2,752 | 2,558 | 2,431 | 2,077 | 2,254 | 2,699 |
| **Monthly Surplus/Deficit** | 527 | 336 | 78 | 127 | 709 | 646 | (27) | 4 | 350 | 367 | 403 | 410 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 9 | 33 | 46 | 48 | 40 | 21 | 4 | 0 | 0 |
| Commercial/Industrial | 96 | 94 | 94 | 95 | 96 | 98 | 98 | 98 | 95 | 95 | 95 | 96 |
| Residential | 33 | 33 | 33 | 33 | 33 | 29 | 29 | 29 | 33 | 33 | 33 | 33 |
| **Total New DSM (aMW)** | 128 | 127 | 127 | 137 | 161 | 174 | 175 | 168 | 149 | 132 | 128 | 128 |
| **Monthly Surplus/Deficit** | 655 | 463 | 206 | 264 | 871 | 819 | 148 | 172 | 499 | 499 | 531 | 538 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 855 | 663 | 406 | 764 | 1,371 | 1,319 | 648 | 672 | 999 | 699 | 731 | 738 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 64 | 64 | 64 | 68 | 77 | 80 | 81 | 78 | 73 | 65 | 64 | 64 |
| Load Forecast (70th% w/DSM) | (2,212) | (1,943) | (1,786) | (1,763) | (2,037) | (2,417) | (2,804) | (2,578) | (2,101) | (1,728) | (1,869) | (2,315) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 777 | 662 | 730 | 801 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 562 | 587 | 586 | 665 | 859 | 676 | 500 | 335 | 417 | 372 | 365 | 455 |
| Hydro (70th%)—Other | 203 | 211 | 187 | 208 | 324 | 328 | 269 | 195 | 213 | 213 | 192 | 199 |
| Shoshone Falls Upgrade(70th%) | 4 | 6 | 0 | 0 | 14 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 769 | 803 | 773 | 874 | 1,197 | 1,020 | 771 | 529 | 630 | 585 | 557 | 657 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 247 | 0 | 24 | 0 | 421 | 342 | 237 | 290 | 304 | 0 | 199 | 312 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,729 | 2,245 | 1,865 | 1,874 | 2,727 | 3,042 | 2,752 | 2,555 | 2,429 | 2,077 | 2,271 | 2,697 |
| **Monthly Surplus/Deficit** | 517 | 303 | 79 | 111 | 690 | 625 | (52) | (23) | 327 | 349 | 402 | 381 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 10 | 37 | 52 | 54 | 45 | 24 | 5 | 0 | 0 |
| Commercial/Industrial | 100 | 100 | 100 | 100 | 101 | 104 | 104 | 104 | 101 | 100 | 100 | 101 |
| Residential | 38 | 38 | 38 | 38 | 37 | 33 | 33 | 33 | 37 | 38 | 38 | 37 |
| **Total New DSM (aMW)** | 138 | 138 | 137 | 148 | 175 | 189 | 191 | 182 | 163 | 142 | 138 | 139 |
| **Monthly Surplus/Deficit** | 655 | 440 | 217 | 259 | 866 | 814 | 138 | 160 | 490 | 491 | 540 | 520 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 855 | 640 | 417 | 759 | 1,366 | 1,314 | 638 | 660 | 990 | 691 | 740 | 720 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 65 | 65 | 65 | 69 | 79 | 82 | 83 | 80 | 74 | 67 | 65 | 66 |
| Load Forecast (70th% w/DSM) | (2,245) | (1,967) | (1,811) | (1,789) | (2,064) | (2,448) | (2,840) | (2,612) | (2,130) | (1,754) | (1,898) | (2,352) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 777 | 662 | 730 | 801 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 562 | 587 | 586 | 665 | 859 | 676 | 500 | 335 | 417 | 372 | 365 | 455 |
| Hydro (70th%)—Other | 203 | 211 | 187 | 208 | 324 | 328 | 269 | 195 | 213 | 213 | 192 | 199 |
| Shoshone Falls Upgrade(70th%) | 4 | 6 | 0 | 0 | 14 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 769 | 803 | 773 | 874 | 1,197 | 1,020 | 771 | 529 | 630 | 585 | 557 | 657 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 281 | 0 | 61 | 0 | 419 | 342 | 237 | 287 | 302 | 0 | 231 | 310 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,763 | 2,245 | 1,902 | 1,874 | 2,725 | 3,042 | 2,752 | 2,552 | 2,427 | 2,077 | 2,303 | 2,695 |
| **Monthly Surplus/Deficit** | 519 | 278 | 90 | 85 | 662 | 594 | (87) | (60) | 296 | 323 | 404 | 343 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 11 | 38 | 54 | 56 | 47 | 25 | 5 | 0 | 0 |
| Commercial/Industrial | 105 | 105 | 105 | 105 | 105 | 109 | 109 | 109 | 106 | 105 | 105 | 106 |
| Residential | 43 | 43 | 43 | 43 | 43 | 38 | 38 | 38 | 43 | 43 | 43 | 43 |
| **Total New DSM (aMW)** | 148 | 148 | 148 | 158 | 186 | 200 | 202 | 194 | 174 | 152 | 148 | 149 |
| **Monthly Surplus/Deficit** | 667 | 426 | 239 | 243 | 848 | 795 | 115 | 134 | 470 | 476 | 553 | 492 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 867 | 626 | 439 | 743 | 1,348 | 1,295 | 615 | 634 | 970 | 676 | 753 | 692 |

# Monthly Average Energy Load and Resource Balance (continued)

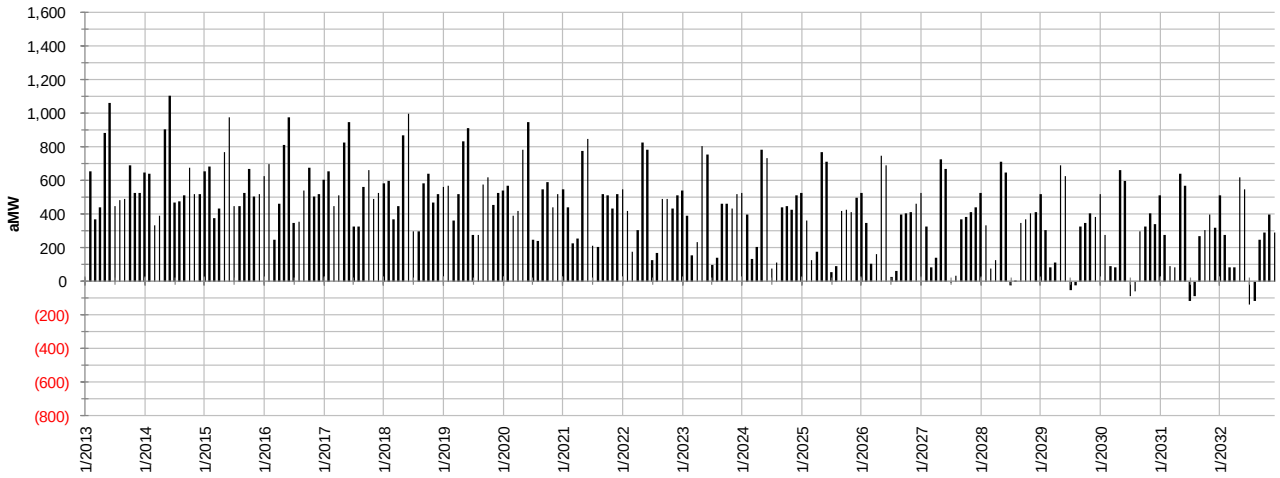
| | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 66 | 66 | 66 | 70 | 80 | 83 | 84 | 81 | 75 | 68 | 66 | 66 |
| Load Forecast (70th% w/DSM) | (2,265) | (1,981) | (1,827) | (1,806) | (2,083) | (2,472) | (2,868) | (2,639) | (2,153) | (1,771) | (1,917) | (2,377) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 777 | 662 | 730 | 801 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 562 | 587 | 586 | 665 | 859 | 676 | 500 | 335 | 417 | 372 | 365 | 455 |
| Hydro (70th%)—Other | 203 | 211 | 187 | 208 | 324 | 328 | 269 | 195 | 213 | 213 | 192 | 199 |
| Shoshone Falls Upgrade(70th%) | 4 | 6 | 0 | 0 | 14 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 769 | 803 | 773 | 874 | 1,197 | 1,020 | 771 | 529 | 630 | 585 | 557 | 657 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 37 | 36 | 34 | 31 | 31 | 35 | 37 | 26 | 31 | 41 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 68 | 67 | 65 | 62 | 62 | 65 | 68 | 57 | 62 | 72 | 78 |
| **Firm Pacific NW Import Capability** | 291 | 12 | 78 | 15 | 418 | 342 | 237 | 285 | 300 | 0 | 245 | 308 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,773 | 2,257 | 1,919 | 1,889 | 2,724 | 3,042 | 2,752 | 2,550 | 2,425 | 2,077 | 2,317 | 2,693 |
| **Monthly Surplus/Deficit** | 508 | 276 | 92 | 83 | 642 | 571 | (116) | (89) | 272 | 306 | 400 | 316 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 11 | 40 | 56 | 58 | 49 | 26 | 5 | 0 | 0 |
| Commercial/Industrial | 110 | 110 | 110 | 109 | 110 | 114 | 114 | 114 | 110 | 109 | 111 | 110 |
| Residential | 48 | 48 | 48 | 48 | 48 | 42 | 42 | 42 | 48 | 48 | 47 | 48 |
| **Total New DSM (aMW)** | 158 | 157 | 158 | 168 | 198 | 212 | 214 | 205 | 184 | 162 | 159 | 158 |
| **Monthly Surplus/Deficit** | 666 | 433 | 249 | 252 | 840 | 783 | 98 | 116 | 455 | 468 | 559 | 474 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 866 | 633 | 449 | 752 | 1,340 | 1,283 | 598 | 616 | 955 | 668 | 759 | 674 |

# Monthly Average Energy Load and Resource Balance (continued)

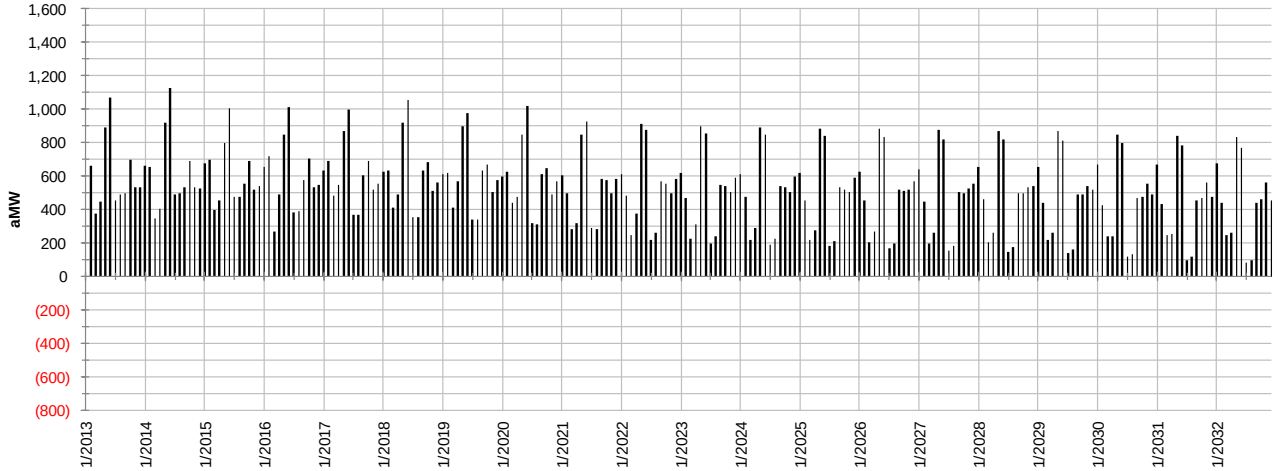
| | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Existing DSM (EE) | 67 | 67 | 67 | 70 | 81 | 84 | 84 | 81 | 75 | 68 | 67 | 67 |
| Load Forecast (70th% w/DSM) | (2,286) | (1,977) | (1,843) | (1,822) | (2,100) | (2,493) | (2,894) | (2,664) | (2,174) | (1,789) | (1,935) | (2,402) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 894 | 863 | 777 | 662 | 730 | 801 | 900 | 900 | 900 | 900 | 900 | 900 |
| **Gas (Langley Gulch)** | 296 | 291 | 0 | 0 | 0 | 278 | 276 | 277 | 279 | 284 | 289 | 296 |
| Hydro (70th%)—HCC | 562 | 587 | 586 | 665 | 859 | 676 | 500 | 335 | 417 | 372 | 365 | 455 |
| Hydro (70th%)—Other | 203 | 211 | 187 | 208 | 324 | 328 | 269 | 195 | 213 | 213 | 192 | 199 |
| Shoshone Falls Upgrade(70th%) | 4 | 6 | 0 | 0 | 14 | 16 | 2 | 0 | 0 | 0 | 1 | 3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 769 | 803 | 773 | 874 | 1,197 | 1,020 | 771 | 529 | 630 | 585 | 557 | 657 |
| **CSPP (PURPA)** | 214 | 221 | 223 | 273 | 317 | 308 | 275 | 253 | 259 | 246 | 254 | 210 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 37 | 34 | 36 | 33 | 31 | 30 | 35 | 37 | 25 | 31 | 40 | 47 |
| Raft River Geothermal | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 57 | 65 | 67 | 64 | 62 | 61 | 65 | 68 | 56 | 62 | 71 | 78 |
| **Firm Pacific NW Import Capability** | 313 | 10 | 85 | 33 | 416 | 342 | 237 | 281 | 299 | 0 | 259 | 306 |
| **Gas Peakers** | 253 | 0 | 0 | 0 | 0 | 231 | 229 | 238 | 0 | 0 | 0 | 244 |
| **Existing Resource Subtotal** | 2,795 | 2,252 | 1,926 | 1,906 | 2,722 | 3,041 | 2,752 | 2,546 | 2,423 | 2,077 | 2,329 | 2,691 |
| **Monthly Surplus/Deficit** | 510 | 275 | 83 | 84 | 622 | 548 | (142) | (118) | 249 | 288 | 394 | 288 |
| **2013 IRP DSM** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 12 | 42 | 59 | 61 | 51 | 27 | 5 | 0 | 0 |
| Commercial/Industrial | 115 | 115 | 114 | 114 | 117 | 119 | 119 | 119 | 115 | 115 | 115 | 115 |
| Residential | 52 | 52 | 52 | 52 | 52 | 46 | 46 | 46 | 52 | 52 | 52 | 52 |
| **Total New DSM (aMW)** | 167 | 167 | 167 | 178 | 210 | 224 | 226 | 216 | 194 | 172 | 167 | 167 |
| **Monthly Surplus/Deficit** | 677 | 442 | 249 | 262 | 832 | 772 | 84 | 98 | 443 | 460 | 561 | 456 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 877 | 642 | 449 | 762 | 1,332 | 1,272 | 584 | 598 | 943 | 660 | 761 | 656 |

# Monthly Average Energy Surplus/Deficit Charts

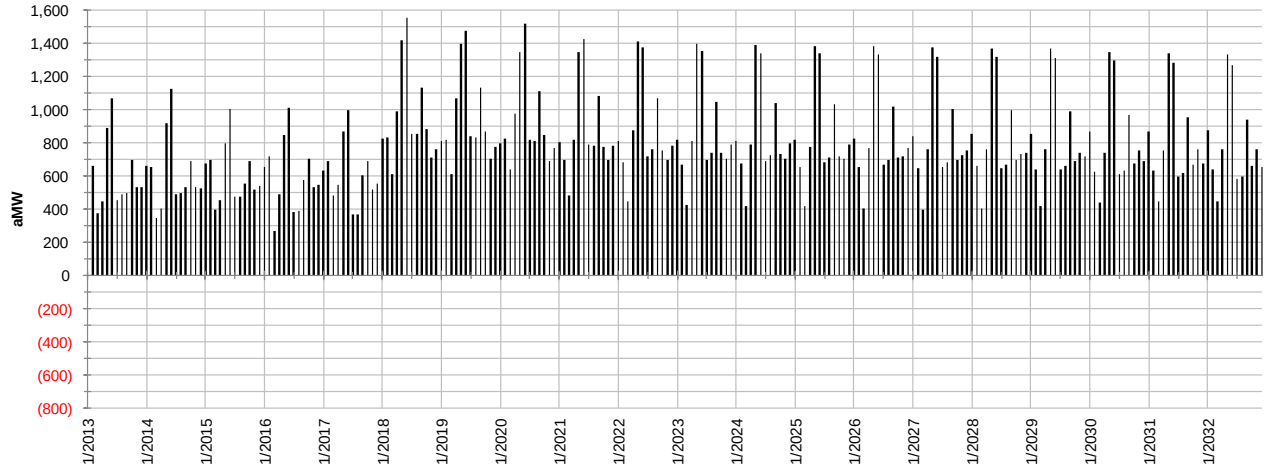
**Average energy monthly surpluses and deficits with existing DSM and existing resources**




**Average energy monthly surpluses and deficits with existing DSM, existing resources, and IRP DSM**




**Average energy monthly surpluses and deficits with existing DSM, existing resources, IRP DSM, and IRP Resources**



# Peak-Hour Load and Resource Balance

| | 1/2013 | 2/2013 | 3/2013 | 4/2013 | 5/2013 | 6/2013 | 7/2013 | 8/2013 | 9/2013 | 10/2013 | 11/2013 | 12/2013 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,513) | (2,392) | (2,099) | (1,978) | (2,813) | (3,272) | (3,390) | (3,035) | (2,785) | (2,033) | (2,274) | (2,690) |
| Existing DSM (EE) | 7 | 7 | 7 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 7 | 7 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,505) | (2,384) | (2,092) | (1,971) | (2,805) | (3,264) | (3,382) | (3,027) | (2,778) | (2,026) | (2,267) | (2,683) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,505) | (2,384) | (2,092) | (1,971) | (2,805) | (3,264) | (3,382) | (3,027) | (2,778) | (2,026) | (2,267) | (2,683) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 1,024 | 1,024 | 1,024 | 1,024 | 966 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 854 | 1,085 | 1,023 | 1,062 | 1,133 | 1,027 | 916 | 878 | 761 | 887 | 673 | 938 |
| Hydro (90th%)—Other | 245 | 246 | 224 | 244 | 347 | 360 | 304 | 270 | 255 | 249 | 240 | 245 |
| Shoshone Falls Upgrade (90th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 48 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,099 | 1,331 | 1,247 | 1,306 | 1,480 | 1,387 | 1,268 | 1,148 | 1,016 | 1,136 | 912 | 1,183 |
| **CSPP (PURPA)** | 73 | 76 | 82 | 117 | 163 | 171 | 177 | 168 | 155 | 117 | 84 | 77 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 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 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 4 | 4 | 4 | 6 | 6 | 7 | 6 | 4 | 3 | 1 | 2 | 3 |
| Clatskanie Exchange– Return | 0 | 0 | (10) | (15) | 0 | 0 | 0 | 0 | 0 | (10) | (15) | 0 |
| **Total PPAs** | 29 | 40 | 30 | 27 | 42 | 43 | 41 | 40 | 39 | 27 | 23 | 39 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 205 | 292 | 194 | 264 | 68 | 0 | 0 | 0 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 2,940 | 3,186 | 3,099 | 3,189 | 3,572 | 3,632 | 3,420 | 3,359 | 3,018 | 3,020 | 2,759 | 3,038 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 1 | 2 | 3 | 3 | 3 | 1 | 0 | 0 | 0 |
| Commercial | 6 | 6 | 6 | 6 | 6 | 7 | 7 | 7 | 6 | 6 | 6 | 6 |
| Residential | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total New DSM Peak Reduction** | 6 | 6 | 6 | 7 | 9 | 10 | 10 | 9 | 8 | 7 | 6 | 7 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 441 | 809 | 1,013 | 1,225 | 776 | 378 | 48 | 342 | 248 | 1,001 | 499 | 362 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2014 | 2/2014 | 3/2014 | 4/2014 | 5/2014 | 6/2014 | 7/2014 | 8/2014 | 9/2014 | 10/2014 | 11/2014 | 12/2014 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,548) | (2,417) | (2,129) | (2,010) | (2,868) | (3,325) | (3,458) | (3,087) | (2,837) | (2,061) | (2,303) | (2,718) |
| Existing DSM (EE) | 14 | 14 | 14 | 15 | 16 | 16 | 16 | 16 | 15 | 14 | 14 | 14 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,534) | (2,403) | (2,115) | (1,996) | (2,852) | (3,310) | (3,442) | (3,071) | (2,822) | (2,047) | (2,289) | (2,704) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,534) | (2,403) | (2,115) | (1,996) | (2,852) | (3,310) | (3,442) | (3,071) | (2,822) | (2,047) | (2,289) | (2,704) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 1,024 | 1,024 | 1,024 | 966 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 852 | 1,078 | 1,017 | 1,061 | 1,132 | 1,024 | 914 | 874 | 758 | 880 | 673 | 935 |
| Hydro (90th%)—Other | 244 | 245 | 224 | 243 | 343 | 356 | 303 | 269 | 255 | 248 | 238 | 244 |
| Shoshone Falls Upgrade (90th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 48 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,097 | 1,323 | 1,241 | 1,304 | 1,475 | 1,380 | 1,265 | 1,143 | 1,012 | 1,129 | 911 | 1,179 |
| **CSPP (PURPA)** | 75 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 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 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 4 | 4 | 4 | 6 | 6 | 7 | 6 | 4 | 3 | 1 | 2 | 3 |
| Clatskanie Exchange– Return | 0 | 0 | (10) | (15) | 0 | 0 | 0 | 0 | 0 | (10) | (15) | 0 |
| **Total PPAs** | 29 | 40 | 30 | 27 | 42 | 43 | 41 | 40 | 39 | 27 | 23 | 39 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 230 | 352 | 237 | 277 | 113 | 0 | 0 | 1 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 2,940 | 3,192 | 3,103 | 3,141 | 3,661 | 3,697 | 3,471 | 3,379 | 3,070 | 3,024 | 2,769 | 3,047 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 1 | 4 | 6 | 6 | 5 | 3 | 0 | 0 | 0 |
| Commercial | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| Residential | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total New DSM Peak Reduction** | 13 | 13 | 13 | 14 | 17 | 19 | 20 | 19 | 16 | 14 | 13 | 13 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 419 | 803 | 1,001 | 1,159 | 825 | 406 | 49 | 326 | 265 | 991 | 493 | 356 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2015 | 2/2015 | 3/2015 | 4/2015 | 5/2015 | 6/2015 | 7/2015 | 8/2015 | 9/2015 | 10/2015 | 11/2015 | 12/2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,552) | (2,435) | (2,129) | (2,002) | (2,922) | (3,369) | (3,520) | (3,129) | (2,879) | (2,087) | (2,310) | (2,739) |
| Existing DSM (EE) | 21 | 21 | 21 | 22 | 24 | 24 | 24 | 23 | 23 | 22 | 21 | 21 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,530) | (2,413) | (2,108) | (1,980) | (2,898) | (3,345) | (3,495) | (3,106) | (2,856) | (2,065) | (2,289) | (2,718) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,530) | (2,413) | (2,108) | (1,980) | (2,898) | (3,345) | (3,495) | (3,106) | (2,856) | (2,065) | (2,289) | (2,718) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 855 | 1,080 | 1,029 | 1,062 | 1,134 | 1,025 | 914 | 873 | 756 | 886 | 672 | 937 |
| Hydro (90th%)—Other | 244 | 246 | 231 | 245 | 352 | 365 | 304 | 272 | 255 | 252 | 241 | 244 |
| Shoshone Falls Upgrade (90th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 48 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,100 | 1,326 | 1,260 | 1,307 | 1,487 | 1,390 | 1,266 | 1,145 | 1,011 | 1,138 | 913 | 1,181 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 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 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 4 | 4 | 4 | 6 | 6 | 7 | 6 | 4 | 3 | 1 | 2 | 3 |
| Clatskanie Exchange– Return | 0 | 0 | (10) | (15) | 0 | 0 | 0 | 0 | 0 | (10) | (15) | 0 |
| **Total PPAs** | 29 | 40 | 30 | 27 | 42 | 43 | 41 | 40 | 39 | 27 | 23 | 39 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 276 | 342 | 237 | 274 | 147 | 0 | 0 | 15 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 2,954 | 3,195 | 3,122 | 3,202 | 3,718 | 3,697 | 3,472 | 3,377 | 3,103 | 3,033 | 2,771 | 3,063 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (24) | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 2 | 6 | 8 | 8 | 7 | 4 | 1 | 0 | 0 |
| Commercial | 19 | 19 | 19 | 19 | 19 | 20 | 20 | 20 | 19 | 19 | 19 | 19 |
| Residential | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| **Total New DSM Peak Reduction** | 20 | 20 | 20 | 21 | 26 | 28 | 29 | 27 | 23 | 20 | 20 | 20 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 443 | 801 | 1,034 | 1,243 | 846 | 381 | 5 | 299 | 270 | 988 | 501 | 364 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2016 | 2/2016 | 3/2016 | 4/2016 | 5/2016 | 6/2016 | 7/2016 | 8/2016 | 9/2016 | 10/2016 | 11/2016 | 12/2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,572) | (2,452) | (2,144) | (2,013) | (2,967) | (3,401) | (3,571) | (3,163) | (2,916) | (2,109) | (2,329) | (2,764) |
| Existing DSM (EE) | 26 | 26 | 26 | 27 | 29 | 30 | 30 | 29 | 28 | 26 | 26 | 26 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,546) | (2,426) | (2,118) | (1,986) | (2,937) | (3,371) | (3,541) | (3,134) | (2,888) | (2,083) | (2,303) | (2,738) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,546) | (2,426) | (2,118) | (1,986) | (2,937) | (3,371) | (3,541) | (3,134) | (2,888) | (2,083) | (2,303) | (2,738) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 1,024 | 1,024 | 1,024 | 1,024 | 966 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 854 | 1,082 | 1,026 | 1,061 | 1,133 | 1,022 | 911 | 797 | 753 | 881 | 672 | 934 |
| Hydro (90th%)—Other | 244 | 248 | 231 | 244 | 353 | 365 | 303 | 233 | 256 | 252 | 241 | 244 |
| Shoshone Falls Upgrade (90th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,098 | 1,329 | 1,257 | 1,305 | 1,485 | 1,388 | 1,215 | 1,030 | 1,009 | 1,133 | 913 | 1,178 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 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 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 314 | 342 | 237 | 272 | 178 | 0 | 0 | 34 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 2,948 | 3,194 | 3,125 | 3,209 | 3,692 | 3,688 | 3,415 | 3,256 | 3,129 | 3,037 | 2,784 | 3,076 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (126) | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 2 | 7 | 9 | 10 | 8 | 4 | 1 | 0 | 0 |
| Commercial | 25 | 24 | 24 | 24 | 25 | 25 | 25 | 25 | 24 | 24 | 24 | 24 |
| Residential | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| **Total New DSM Peak Reduction** | 27 | 26 | 26 | 28 | 33 | 36 | 37 | 35 | 31 | 27 | 26 | 26 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (89) | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 100 | 100 | 100 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 100 | 100 | 100 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 429 | 794 | 1,034 | 1,251 | 788 | 452 | 11 | 258 | 272 | 981 | 508 | 364 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,603) | (2,475) | (2,169) | (2,038) | (3,016) | (3,445) | (3,632) | (3,208) | (2,961) | (2,134) | (2,358) | (2,795) |
| Existing DSM (EE) | 30 | 30 | 30 | 31 | 34 | 35 | 35 | 34 | 33 | 30 | 30 | 30 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,574) | (2,445) | (2,139) | (2,007) | (2,982) | (3,410) | (3,596) | (3,174) | (2,929) | (2,103) | (2,328) | (2,765) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,574) | (2,445) | (2,139) | (2,007) | (2,982) | (3,410) | (3,596) | (3,174) | (2,929) | (2,103) | (2,328) | (2,765) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 852 | 1,080 | 1,023 | 1,060 | 1,132 | 1,020 | 909 | 794 | 750 | 875 | 673 | 932 |
| Hydro (90th%)—Other | 244 | 246 | 231 | 244 | 350 | 363 | 303 | 232 | 256 | 252 | 240 | 244 |
| Shoshone Falls Upgrade (90th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,096 | 1,326 | 1,254 | 1,304 | 1,482 | 1,383 | 1,212 | 1,026 | 1,006 | 1,126 | 914 | 1,176 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 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 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 359 | 347 | 237 | 269 | 219 | 0 | 0 | 61 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 2,946 | 3,191 | 3,123 | 3,208 | 3,791 | 3,688 | 3,413 | 3,250 | 3,167 | 3,030 | 2,785 | 3,101 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (184) | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 2 | 8 | 11 | 11 | 9 | 5 | 1 | 0 | 0 |
| Commercial | 29 | 29 | 29 | 29 | 30 | 30 | 30 | 30 | 29 | 29 | 29 | 30 |
| Residential | 4 | 4 | 4 | 4 | 4 | 3 | 3 | 3 | 4 | 4 | 4 | 4 |
| **Total New DSM Peak Reduction** | 33 | 33 | 33 | 35 | 41 | 44 | 45 | 43 | 38 | 34 | 33 | 33 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (139) | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 150 | 150 | 150 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 150 | 150 | 150 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 405 | 779 | 1,016 | 1,236 | 850 | 471 | 11 | 269 | 276 | 961 | 490 | 368 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,629) | (2,492) | (2,190) | (2,059) | (3,064) | (3,488) | (3,691) | (3,251) | (3,003) | (2,154) | (2,381) | (2,823) |
| Existing DSM (EE) | 34 | 34 | 34 | 35 | 39 | 40 | 40 | 39 | 37 | 34 | 34 | 34 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,595) | (2,459) | (2,156) | (2,023) | (3,025) | (3,448) | (3,651) | (3,212) | (2,966) | (2,120) | (2,347) | (2,789) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,595) | (2,459) | (2,156) | (2,023) | (3,025) | (3,448) | (3,651) | (3,212) | (2,966) | (2,120) | (2,347) | (2,789) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 850 | 1,073 | 1,013 | 1,058 | 1,131 | 1,017 | 907 | 790 | 747 | 870 | 673 | 930 |
| Hydro (90th%)—Other | 243 | 245 | 230 | 244 | 347 | 358 | 302 | 231 | 255 | 250 | 240 | 243 |
| Shoshone Falls Upgrade (90th%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,093 | 1,318 | 1,243 | 1,303 | 1,478 | 1,376 | 1,209 | 1,021 | 1,002 | 1,121 | 912 | 1,173 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 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 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 385 | 342 | 237 | 267 | 257 | 0 | 0 | 86 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 2,943 | 3,183 | 3,111 | 3,206 | 3,812 | 3,676 | 3,409 | 3,243 | 3,201 | 3,025 | 2,784 | 3,123 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (242) | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 2 | 9 | 12 | 13 | 11 | 6 | 1 | 0 | 0 |
| Commercial | 35 | 35 | 35 | 35 | 35 | 36 | 36 | 36 | 35 | 35 | 35 | 35 |
| Residential | 7 | 7 | 7 | 7 | 7 | 6 | 6 | 6 | 7 | 7 | 7 | 7 |
| **Total New DSM Peak Reduction** | 42 | 42 | 41 | 44 | 51 | 55 | 55 | 53 | 48 | 42 | 42 | 42 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (187) | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 589 | 966 | 1,197 | 1,727 | 1,338 | 782 | 313 | 584 | 782 | 1,147 | 678 | 575 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,657) | (2,511) | (2,212) | (2,081) | (3,112) | (3,532) | (3,752) | (3,295) | (3,046) | (2,176) | (2,406) | (2,851) |
| Existing DSM (EE) | 37 | 37 | 37 | 39 | 44 | 45 | 45 | 44 | 41 | 38 | 37 | 37 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,620) | (2,474) | (2,175) | (2,042) | (3,068) | (3,487) | (3,707) | (3,251) | (3,005) | (2,139) | (2,368) | (2,814) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,620) | (2,474) | (2,175) | (2,042) | (3,068) | (3,487) | (3,707) | (3,251) | (3,005) | (2,139) | (2,368) | (2,814) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 1,024 | 1,024 | 1,024 | 1,024 | 966 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 848 | 1,071 | 1,007 | 1,057 | 1,130 | 1,015 | 905 | 787 | 744 | 862 | 674 | 927 |
| Hydro (90th%)—Other | 243 | 245 | 230 | 243 | 344 | 355 | 302 | 231 | 229 | 250 | 238 | 242 |
| Shoshone Falls Upgrade (90th%) | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,091 | 1,316 | 1,237 | 1,300 | 1,473 | 1,371 | 1,208 | 1,018 | 973 | 1,112 | 912 | 1,171 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 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 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 384 | 342 | 237 | 265 | 270 | 0 | 0 | 111 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 2,941 | 3,180 | 3,106 | 3,204 | 3,749 | 3,670 | 3,409 | 3,237 | 3,184 | 3,016 | 2,783 | 3,146 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (298) | (14) | 0 | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 3 | 10 | 14 | 15 | 12 | 7 | 1 | 0 | 0 |
| Commercial | 40 | 39 | 40 | 39 | 40 | 41 | 41 | 41 | 40 | 39 | 40 | 40 |
| Residential | 10 | 10 | 10 | 10 | 10 | 9 | 9 | 9 | 10 | 10 | 10 | 10 |
| **Total New DSM Peak Reduction** | 49 | 49 | 49 | 52 | 60 | 64 | 65 | 62 | 56 | 50 | 49 | 50 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (233) | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 570 | 956 | 1,180 | 1,713 | 1,241 | 747 | 267 | 548 | 736 | 1,128 | 664 | 582 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,690) | (2,535) | (2,239) | (2,107) | (3,166) | (3,580) | (3,817) | (3,342) | (3,092) | (2,204) | (2,436) | (2,885) |
| Existing DSM (EE) | 42 | 42 | 42 | 44 | 49 | 50 | 51 | 49 | 46 | 43 | 42 | 42 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,648) | (2,493) | (2,197) | (2,063) | (3,117) | (3,529) | (3,766) | (3,293) | (3,046) | (2,161) | (2,394) | (2,843) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,648) | (2,493) | (2,197) | (2,063) | (3,117) | (3,529) | (3,766) | (3,293) | (3,046) | (2,161) | (2,394) | (2,843) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 | 1,024 |
| **Gas (Langley Gulch)** | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Hydro (90th%)—HCC | 843 | 1,068 | 1,005 | 1,056 | 1,128 | 1,013 | 902 | 783 | 741 | 853 | 673 | 927 |
| Hydro (90th%)—Other | 243 | 243 | 230 | 243 | 341 | 353 | 301 | 230 | 228 | 250 | 237 | 241 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 9 | 11 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,088 | 1,313 | 1,235 | 1,298 | 1,479 | 1,377 | 1,205 | 1,013 | 968 | 1,103 | 910 | 1,170 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 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 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 0 | 0 | 0 | 0 | 383 | 342 | 237 | 262 | 269 | 0 | 4 | 139 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 2,938 | 3,178 | 3,104 | 3,202 | 3,811 | 3,676 | 3,406 | 3,230 | 3,179 | 3,007 | 2,785 | 3,173 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (360) | (64) | 0 | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 3 | 12 | 16 | 17 | 14 | 8 | 1 | 0 | 0 |
| Commercial | 45 | 45 | 45 | 45 | 46 | 47 | 47 | 47 | 45 | 45 | 46 | 45 |
| Residential | 9 | 9 | 9 | 9 | 9 | 8 | 8 | 8 | 9 | 9 | 9 | 9 |
| **Total New DSM Peak Reduction** | 54 | 54 | 54 | 57 | 66 | 71 | 72 | 69 | 62 | 55 | 55 | 54 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (288) | 0 | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 545 | 939 | 1,161 | 1,696 | 1,261 | 719 | 212 | 506 | 695 | 1,101 | 646 | 584 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,720) | (2,564) | (2,261) | (2,126) | (3,222) | (3,627) | (3,882) | (3,391) | (3,139) | (2,232) | (2,463) | (2,919) |
| Existing DSM (EE) | 45 | 45 | 45 | 48 | 54 | 55 | 56 | 54 | 51 | 46 | 45 | 45 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,674) | (2,519) | (2,216) | (2,079) | (3,168) | (3,572) | (3,827) | (3,337) | (3,088) | (2,186) | (2,418) | (2,874) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,674) | (2,519) | (2,216) | (2,079) | (3,168) | (3,572) | (3,827) | (3,337) | (3,088) | (2,186) | (2,418) | (2,874) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 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 |
| Hydro (90th%)—HCC | 841 | 1,066 | 1,004 | 1,054 | 1,127 | 1,009 | 899 | 779 | 737 | 840 | 674 | 923 |
| Hydro (90th%)—Other | 242 | 243 | 229 | 243 | 341 | 328 | 300 | 229 | 227 | 248 | 235 | 241 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 8 | 10 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,086 | 1,311 | 1,233 | 1,297 | 1,476 | 1,347 | 1,202 | 1,008 | 964 | 1,089 | 909 | 1,166 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 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 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 87 | 0 | 0 | 0 | 434 | 395 | 290 | 313 | 320 | 0 | 83 | 225 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 2,965 | 3,118 | 3,044 | 3,143 | 3,802 | 3,643 | 3,398 | 3,218 | 3,168 | 2,935 | 2,806 | 3,197 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (429) | (119) | 0 | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 4 | 13 | 19 | 20 | 16 | 9 | 2 | 0 | 0 |
| Commercial | 51 | 51 | 50 | 51 | 52 | 53 | 53 | 53 | 51 | 51 | 51 | 51 |
| Residential | 9 | 9 | 9 | 9 | 9 | 8 | 8 | 8 | 9 | 9 | 9 | 9 |
| **Total New DSM Peak Reduction** | 60 | 60 | 60 | 64 | 74 | 80 | 80 | 77 | 69 | 62 | 60 | 60 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (349) | (41) | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 552 | 860 | 1,088 | 1,628 | 1,208 | 650 | 151 | 459 | 648 | 1,011 | 649 | 583 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,745) | (2,585) | (2,281) | (2,144) | (3,272) | (3,668) | (3,941) | (3,432) | (3,180) | (2,257) | (2,487) | (2,950) |
| Existing DSM (EE) | 49 | 49 | 49 | 51 | 58 | 60 | 60 | 58 | 55 | 50 | 49 | 49 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,696) | (2,537) | (2,232) | (2,092) | (3,213) | (3,608) | (3,881) | (3,374) | (3,126) | (2,207) | (2,438) | (2,901) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,696) | (2,537) | (2,232) | (2,092) | (3,213) | (3,608) | (3,881) | (3,374) | (3,126) | (2,207) | (2,438) | (2,901) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 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 |
| Hydro (90th%)—HCC | 839 | 1,063 | 1,000 | 1,052 | 1,126 | 1,006 | 896 | 775 | 733 | 831 | 674 | 920 |
| Hydro (90th%)—Other | 242 | 242 | 229 | 242 | 339 | 326 | 300 | 228 | 226 | 247 | 234 | 240 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 8 | 9 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,083 | 1,307 | 1,229 | 1,294 | 1,473 | 1,342 | 1,198 | 1,003 | 960 | 1,078 | 909 | 1,162 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 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 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 113 | 0 | 0 | 0 | 433 | 349 | 237 | 308 | 318 | 0 | 103 | 254 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 2,988 | 3,115 | 3,040 | 3,140 | 3,798 | 3,591 | 3,341 | 3,208 | 3,162 | 2,924 | 2,826 | 3,222 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (17) | (540) | (166) | 0 | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 4 | 15 | 22 | 22 | 19 | 10 | 2 | 0 | 0 |
| Commercial | 59 | 58 | 58 | 58 | 59 | 60 | 60 | 60 | 58 | 58 | 58 | 58 |
| Residential | 9 | 9 | 10 | 10 | 9 | 8 | 8 | 8 | 9 | 9 | 9 | 10 |
| **Total New DSM Peak Reduction** | 68 | 67 | 67 | 72 | 84 | 90 | 91 | 88 | 78 | 70 | 68 | 67 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (449) | (78) | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 560 | 845 | 1,075 | 1,619 | 1,168 | 574 | 51 | 422 | 614 | 987 | 656 | 588 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,771) | (2,603) | (2,301) | (2,164) | (3,319) | (3,709) | (4,000) | (3,474) | (3,222) | (2,278) | (2,510) | (2,976) |
| Existing DSM (EE) | 52 | 52 | 52 | 55 | 62 | 64 | 65 | 62 | 58 | 53 | 52 | 52 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,719) | (2,551) | (2,249) | (2,109) | (3,257) | (3,645) | (3,935) | (3,412) | (3,164) | (2,225) | (2,458) | (2,924) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,719) | (2,551) | (2,249) | (2,109) | (3,257) | (3,645) | (3,935) | (3,412) | (3,164) | (2,225) | (2,458) | (2,924) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 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 |
| Hydro (90th%)—HCC | 835 | 1,061 | 1,001 | 1,051 | 1,124 | 1,003 | 893 | 770 | 730 | 828 | 674 | 918 |
| Hydro (90th%)—Other | 241 | 242 | 228 | 241 | 336 | 323 | 299 | 227 | 225 | 246 | 234 | 240 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 7 | 9 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,078 | 1,305 | 1,229 | 1,292 | 1,467 | 1,335 | 1,195 | 997 | 955 | 1,074 | 908 | 1,159 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 181 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 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 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 136 | 0 | 0 | 0 | 431 | 346 | 237 | 306 | 316 | 0 | 123 | 291 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,007 | 3,112 | 3,040 | 3,138 | 3,790 | 3,580 | 3,337 | 3,201 | 3,156 | 2,921 | 2,845 | 3,257 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (65) | (598) | (211) | (9) | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 5 | 18 | 25 | 26 | 22 | 11 | 2 | 0 | 0 |
| Commercial | 64 | 64 | 64 | 64 | 65 | 67 | 67 | 67 | 64 | 64 | 64 | 65 |
| Residential | 10 | 10 | 10 | 10 | 10 | 9 | 9 | 9 | 10 | 10 | 10 | 10 |
| **Total New DSM Peak Reduction** | 74 | 74 | 73 | 79 | 92 | 100 | 101 | 97 | 85 | 76 | 74 | 74 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (497) | (114) | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 562 | 834 | 1,064 | 1,608 | 1,125 | 535 | 3 | 386 | 577 | 971 | 661 | 607 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,783) | (2,613) | (2,308) | (2,168) | (3,363) | (3,746) | (4,055) | (3,511) | (3,259) | (2,296) | (2,522) | (2,993) |
| Existing DSM (EE) | 55 | 54 | 55 | 57 | 65 | 68 | 68 | 66 | 62 | 56 | 55 | 55 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,728) | (2,558) | (2,254) | (2,111) | (3,298) | (3,679) | (3,987) | (3,445) | (3,198) | (2,240) | (2,467) | (2,938) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,728) | (2,558) | (2,254) | (2,111) | (3,298) | (3,679) | (3,987) | (3,445) | (3,198) | (2,240) | (2,467) | (2,938) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 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 |
| Hydro (90th%)—HCC | 832 | 1,058 | 999 | 1,049 | 1,112 | 1,000 | 891 | 766 | 727 | 819 | 673 | 917 |
| Hydro (90th%)—Other | 240 | 242 | 228 | 240 | 335 | 321 | 298 | 226 | 225 | 245 | 233 | 239 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 7 | 9 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,075 | 1,301 | 1,228 | 1,289 | 1,453 | 1,330 | 1,191 | 992 | 951 | 1,064 | 906 | 1,158 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 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 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 143 | 0 | 0 | 0 | 430 | 342 | 237 | 303 | 315 | 0 | 132 | 312 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,011 | 3,109 | 3,039 | 3,135 | 3,775 | 3,572 | 3,334 | 3,192 | 3,150 | 2,911 | 2,852 | 3,276 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (106) | (653) | (254) | (47) | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 6 | 20 | 28 | 29 | 25 | 13 | 2 | 0 | 0 |
| Commercial | 71 | 71 | 71 | 71 | 71 | 74 | 74 | 74 | 72 | 71 | 71 | 72 |
| Residential | 12 | 12 | 12 | 12 | 12 | 11 | 11 | 11 | 12 | 12 | 12 | 12 |
| **Total New DSM Peak Reduction** | 84 | 83 | 84 | 89 | 104 | 113 | 114 | 109 | 97 | 86 | 84 | 84 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (539) | (144) | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 50 | 50 | 50 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 550 | 550 | 550 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 567 | 834 | 1,068 | 1,614 | 1,081 | 557 | 11 | 406 | 550 | 956 | 669 | 623 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,786) | (2,624) | (2,308) | (2,163) | (3,406) | (3,776) | (4,105) | (3,542) | (3,291) | (2,312) | (2,527) | (3,009) |
| Existing DSM (EE) | 57 | 57 | 57 | 60 | 68 | 71 | 72 | 69 | 64 | 58 | 57 | 57 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,730) | (2,568) | (2,252) | (2,103) | (3,337) | (3,705) | (4,033) | (3,473) | (3,226) | (2,254) | (2,470) | (2,952) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,730) | (2,568) | (2,252) | (2,103) | (3,337) | (3,705) | (4,033) | (3,473) | (3,226) | (2,254) | (2,470) | (2,952) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 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 |
| Hydro (90th%)—HCC | 830 | 1,055 | 998 | 1,047 | 1,111 | 998 | 888 | 761 | 723 | 812 | 674 | 914 |
| Hydro (90th%)—Other | 240 | 241 | 228 | 240 | 334 | 320 | 298 | 225 | 224 | 245 | 232 | 239 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 6 | 8 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,073 | 1,298 | 1,225 | 1,287 | 1,451 | 1,326 | 1,188 | 987 | 947 | 1,057 | 906 | 1,155 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 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 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 160 | 0 | 0 | 0 | 428 | 342 | 237 | 300 | 313 | 0 | 135 | 321 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,025 | 3,105 | 3,036 | 3,133 | 3,771 | 3,569 | 3,331 | 3,184 | 3,144 | 2,903 | 2,854 | 3,282 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (137) | (703) | (289) | (82) | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 6 | 23 | 32 | 33 | 28 | 15 | 3 | 0 | 0 |
| Commercial | 77 | 77 | 77 | 77 | 77 | 80 | 80 | 80 | 77 | 77 | 78 | 77 |
| Residential | 16 | 16 | 16 | 16 | 16 | 14 | 14 | 14 | 16 | 16 | 16 | 16 |
| **Total New DSM Peak Reduction** | 93 | 93 | 93 | 99 | 116 | 126 | 127 | 122 | 108 | 96 | 94 | 93 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (10) | (575) | (167) | 0 | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 100 | 100 | 100 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 600 | 600 | 600 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 589 | 830 | 1,078 | 1,629 | 1,050 | 590 | 25 | 433 | 526 | 944 | 678 | 623 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,810) | (2,640) | (2,326) | (2,180) | (3,450) | (3,811) | (4,157) | (3,578) | (3,328) | (2,332) | (2,548) | (3,036) |
| Existing DSM (EE) | 59 | 59 | 59 | 62 | 71 | 74 | 75 | 72 | 67 | 60 | 59 | 59 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,751) | (2,581) | (2,267) | (2,117) | (3,379) | (3,737) | (4,083) | (3,506) | (3,262) | (2,272) | (2,489) | (2,977) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,751) | (2,581) | (2,267) | (2,117) | (3,379) | (3,737) | (4,083) | (3,506) | (3,262) | (2,272) | (2,489) | (2,977) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 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 |
| Hydro (90th%)—HCC | 827 | 1,050 | 994 | 1,046 | 1,109 | 995 | 885 | 758 | 720 | 803 | 675 | 910 |
| Hydro (90th%)—Other | 239 | 241 | 227 | 239 | 331 | 318 | 297 | 225 | 223 | 244 | 231 | 238 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 6 | 8 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,068 | 1,292 | 1,222 | 1,285 | 1,447 | 1,322 | 1,184 | 982 | 943 | 1,047 | 906 | 1,150 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 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 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 183 | 0 | 0 | 0 | 427 | 342 | 237 | 298 | 311 | 0 | 154 | 319 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,044 | 3,099 | 3,032 | 3,131 | 3,766 | 3,564 | 3,327 | 3,177 | 3,138 | 2,893 | 2,874 | 3,275 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (173) | (756) | (329) | (124) | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 7 | 26 | 36 | 38 | 32 | 17 | 3 | 0 | 0 |
| Commercial | 83 | 83 | 83 | 83 | 84 | 86 | 86 | 86 | 83 | 83 | 84 | 83 |
| Residential | 21 | 21 | 21 | 21 | 21 | 18 | 18 | 18 | 21 | 21 | 21 | 21 |
| **Total New DSM Peak Reduction** | 104 | 104 | 104 | 111 | 131 | 141 | 142 | 136 | 120 | 107 | 105 | 104 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (32) | (613) | (193) | (3) | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 150 | 150 | 150 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 650 | 650 | 650 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 597 | 822 | 1,069 | 1,625 | 1,018 | 618 | 37 | 457 | 497 | 928 | 690 | 603 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,835) | (2,657) | (2,346) | (2,199) | (3,496) | (3,854) | (4,217) | (3,622) | (3,372) | (2,354) | (2,570) | (3,061) |
| Existing DSM (EE) | 61 | 61 | 61 | 64 | 74 | 77 | 77 | 74 | 69 | 63 | 61 | 61 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,774) | (2,596) | (2,285) | (2,135) | (3,422) | (3,777) | (4,139) | (3,547) | (3,303) | (2,291) | (2,509) | (3,000) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,774) | (2,596) | (2,285) | (2,135) | (3,422) | (3,777) | (4,139) | (3,547) | (3,303) | (2,291) | (2,509) | (3,000) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 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 |
| Hydro (90th%)—HCC | 825.0 | 1,047.9 | 990.6 | 1,044.4 | 1,107.9 | 992.1 | 882.4 | 753.7 | 716.2 | 795.7 | 675.6 | 891.3 |
| Hydro (90th%)—Other | 238.7 | 239.8 | 226.9 | 213.9 | 330.4 | 317.5 | 296.2 | 223.9 | 222.7 | 243.8 | 230.5 | 237.7 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 6 | 8 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,066 | 1,289 | 1,218 | 1,258 | 1,444 | 1,318 | 1,181 | 978 | 939 | 1,040 | 906 | 1,131 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 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 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 218 | 0 | 0 | 0 | 425 | 342 | 237 | 295 | 308 | 0 | 174 | 317 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,077 | 3,097 | 3,028 | 3,104 | 3,761 | 3,560 | 3,324 | 3,170 | 3,131 | 2,886 | 2,894 | 3,254 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (217) | (816) | (378) | (172) | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 8 | 29 | 41 | 43 | 36 | 19 | 4 | 0 | 0 |
| Commercial | 89 | 88 | 88 | 88 | 90 | 92 | 92 | 92 | 89 | 89 | 89 | 89 |
| Residential | 27 | 27 | 27 | 27 | 26 | 23 | 23 | 23 | 27 | 27 | 27 | 27 |
| **Total New DSM Peak Reduction** | 116 | 115 | 115 | 123 | 146 | 156 | 158 | 151 | 134 | 119 | 115 | 115 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (61) | (658) | (226) | (37) | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 200 | 200 | 200 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 700 | 700 | 700 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 619 | 816 | 1,059 | 1,593 | 985 | 639 | 42 | 474 | 463 | 914 | 700 | 570 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,844) | (2,667) | (2,350) | (2,201) | (3,538) | (3,891) | (4,270) | (3,659) | (3,408) | (2,370) | (2,579) | (3,079) |
| Existing DSM (EE) | 63 | 62 | 62 | 66 | 75 | 79 | 79 | 76 | 71 | 64 | 63 | 63 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,781) | (2,605) | (2,288) | (2,135) | (3,463) | (3,812) | (4,191) | (3,582) | (3,337) | (2,306) | (2,517) | (3,016) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,781) | (2,605) | (2,288) | (2,135) | (3,463) | (3,812) | (4,191) | (3,582) | (3,337) | (2,306) | (2,517) | (3,016) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 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 |
| Hydro (90th%)—HCC | 825.0 | 1047.9 | 990.6 | 1044.4 | 1107.9 | 992.1 | 882.4 | 753.7 | 716.2 | 795.7 | 675.6 | 891.3 |
| Hydro (90th%)—Other | 238.7 | 239.8 | 226.9 | 213.9 | 330.4 | 317.5 | 296.2 | 223.9 | 222.7 | 243.8 | 230.5 | 237.7 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 6 | 8 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,066 | 1,289 | 1,218 | 1,258 | 1,444 | 1,318 | 1,181 | 978 | 939 | 1,040 | 906 | 1,131 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 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 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 236 | 0 | 7 | 0 | 423 | 342 | 237 | 293 | 306 | 0 | 182 | 314 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,095 | 3,097 | 3,035 | 3,104 | 3,759 | 3,560 | 3,324 | 3,168 | 3,129 | 2,886 | 2,902 | 3,251 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (252) | (868) | (414) | (208) | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 9 | 33 | 46 | 48 | 40 | 21 | 4 | 0 | 0 |
| Commercial | 96 | 94 | 94 | 95 | 96 | 98 | 98 | 98 | 95 | 95 | 95 | 96 |
| Residential | 33 | 33 | 33 | 33 | 33 | 29 | 29 | 29 | 33 | 33 | 33 | 33 |
| **Total New DSM Peak Reduction** | 128 | 127 | 127 | 137 | 161 | 174 | 175 | 168 | 149 | 132 | 128 | 128 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (78) | (693) | (247) | (59) | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 200 | 200 | 200 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 700 | 700 | 700 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 642 | 819 | 1,075 | 1,607 | 958 | 622 | 7 | 453 | 441 | 912 | 713 | 563 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,864) | (2,680) | (2,365) | (2,214) | (3,582) | (3,927) | (4,325) | (3,697) | (3,447) | (2,389) | (2,598) | (3,104) |
| Existing DSM (EE) | 64 | 64 | 64 | 68 | 77 | 80 | 81 | 78 | 73 | 65 | 64 | 64 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,800) | (2,616) | (2,301) | (2,147) | (3,505) | (3,847) | (4,244) | (3,619) | (3,375) | (2,324) | (2,534) | (3,040) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,800) | (2,616) | (2,301) | (2,147) | (3,505) | (3,847) | (4,244) | (3,619) | (3,375) | (2,324) | (2,534) | (3,040) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 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 |
| Hydro (90th%)—HCC | 825.0 | 1,047.9 | 990.6 | 1,044.4 | 1,107.9 | 992.1 | 882.4 | 753.7 | 716.2 | 795.7 | 675.6 | 891.3 |
| Hydro (90th%)—Other | 238.7 | 239.8 | 226.9 | 213.9 | 330.4 | 317.5 | 296.2 | 223.9 | 222.7 | 243.8 | 230.5 | 237.7 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 6 | 8 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,066 | 1,289 | 1,218 | 1,258 | 1,444 | 1,318 | 1,181 | 978 | 939 | 1,040 | 906 | 1,131 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 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 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 247 | 0 | 24 | 0 | 421 | 342 | 237 | 290 | 304 | 0 | 199 | 312 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,106 | 3,097 | 3,052 | 3,104 | 3,757 | 3,560 | 3,324 | 3,165 | 3,127 | 2,886 | 2,919 | 3,249 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (287) | (920) | (454) | (248) | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 10 | 37 | 52 | 54 | 45 | 24 | 5 | 0 | 0 |
| Commercial | 100 | 100 | 100 | 100 | 101 | 104 | 104 | 104 | 101 | 100 | 100 | 101 |
| Residential | 38 | 38 | 38 | 38 | 37 | 33 | 33 | 33 | 37 | 38 | 38 | 37 |
| **Total New DSM Peak Reduction** | 138 | 138 | 137 | 148 | 175 | 189 | 191 | 182 | 163 | 142 | 138 | 139 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (98) | (729) | (271) | (85) | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 250 | 250 | 250 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 750 | 750 | 750 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 644 | 818 | 1,089 | 1,606 | 928 | 652 | 21 | 479 | 415 | 904 | 723 | 547 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,902) | (2,708) | (2,395) | (2,242) | (3,635) | (3,978) | (4,391) | (3,748) | (3,498) | (2,418) | (2,631) | (3,142) |
| Existing DSM (EE) | 65 | 65 | 65 | 69 | 79 | 82 | 83 | 80 | 74 | 67 | 65 | 66 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,836) | (2,642) | (2,329) | (2,174) | (3,556) | (3,895) | (4,308) | (3,668) | (3,424) | (2,351) | (2,566) | (3,077) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,836) | (2,642) | (2,329) | (2,174) | (3,556) | (3,895) | (4,308) | (3,668) | (3,424) | (2,351) | (2,566) | (3,077) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 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 |
| Hydro (90th%)—HCC | 825 | 1,048 | 991 | 1,044 | 1,108 | 992 | 882 | 754 | 716 | 796 | 676 | 891 |
| Hydro (90th%)—Other | 239 | 240 | 227 | 214 | 330 | 317 | 296 | 224 | 223 | 244 | 230 | 238 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 6 | 8 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,066 | 1,289 | 1,218 | 1,258 | 1,444 | 1,318 | 1,181 | 978 | 939 | 1,040 | 906 | 1,131 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 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 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 281 | 0 | 61 | 0 | 419 | 342 | 237 | 287 | 302 | 0 | 231 | 310 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,140 | 3,097 | 3,089 | 3,104 | 3,755 | 3,560 | 3,324 | 3,162 | 3,125 | 2,886 | 2,951 | 3,247 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (336) | (984) | (507) | (299) | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 11 | 38 | 54 | 56 | 47 | 25 | 5 | 0 | 0 |
| Commercial | 105 | 105 | 105 | 105 | 105 | 109 | 109 | 109 | 106 | 105 | 105 | 106 |
| Residential | 43 | 43 | 43 | 43 | 43 | 38 | 38 | 38 | 43 | 43 | 43 | 43 |
| **Total New DSM Peak Reduction** | 148 | 148 | 148 | 158 | 186 | 200 | 202 | 194 | 174 | 152 | 148 | 149 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (135) | (782) | (313) | (125) | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 300 | 300 | 300 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 800 | 800 | 800 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 652 | 802 | 1,108 | 1,589 | 886 | 665 | 18 | 487 | 375 | 887 | 733 | 519 |

# Peak-Hour Load and Resource Balance (continued)

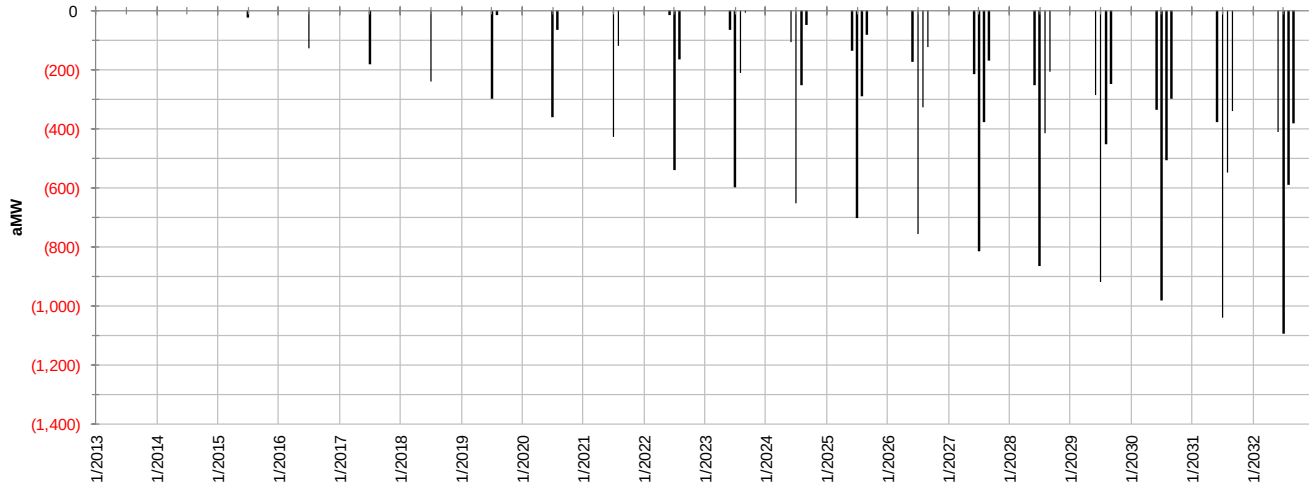
| | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,918) | (2,720) | (2,405) | (2,251) | (3,679) | (4,019) | (4,448) | (3,790) | (3,540) | (2,437) | (2,646) | (3,163) |
| Existing DSM (EE) | 66 | 66 | 66 | 70 | 80 | 83 | 84 | 81 | 75 | 68 | 66 | 66 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,851) | (2,654) | (2,339) | (2,181) | (3,599) | (3,936) | (4,365) | (3,710) | (3,465) | (2,369) | (2,580) | (3,097) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,851) | (2,654) | (2,339) | (2,181) | (3,599) | (3,936) | (4,365) | (3,710) | (3,465) | (2,369) | (2,580) | (3,097) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 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 |
| Hydro (90th%)—HCC | 825 | 1,048 | 991 | 1,044 | 1,108 | 992 | 882 | 754 | 716 | 796 | 676 | 891 |
| Hydro (90th%)—Other | 239 | 240 | 227 | 214 | 330 | 317 | 296 | 224 | 223 | 244 | 230 | 238 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 6 | 8 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,066 | 1,289 | 1,218 | 1,258 | 1,444 | 1,318 | 1,181 | 978 | 939 | 1,040 | 906 | 1,131 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 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 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 291 | 12 | 78 | 15 | 418 | 342 | 237 | 285 | 300 | 0 | 245 | 308 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,150 | 3,109 | 3,106 | 3,119 | 3,754 | 3,560 | 3,324 | 3,160 | 3,123 | 2,886 | 2,965 | 3,245 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (376) | (1,041) | (550) | (342) | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 11 | 40 | 56 | 58 | 49 | 26 | 5 | 0 | 0 |
| Commercial | 110 | 110 | 110 | 109 | 110 | 114 | 114 | 114 | 110 | 109 | 111 | 110 |
| Residential | 48 | 48 | 48 | 48 | 48 | 42 | 42 | 42 | 48 | 48 | 47 | 48 |
| **Total New DSM Peak Reduction** | 158 | 157 | 158 | 168 | 198 | 212 | 214 | 205 | 184 | 162 | 159 | 158 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (164) | (827) | (345) | (158) | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 350 | 350 | 350 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 850 | 850 | 850 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 656 | 812 | 1,125 | 1,606 | 853 | 686 | 23 | 505 | 342 | 879 | 743 | 505 |

# Peak-Hour Load and Resource Balance (continued)

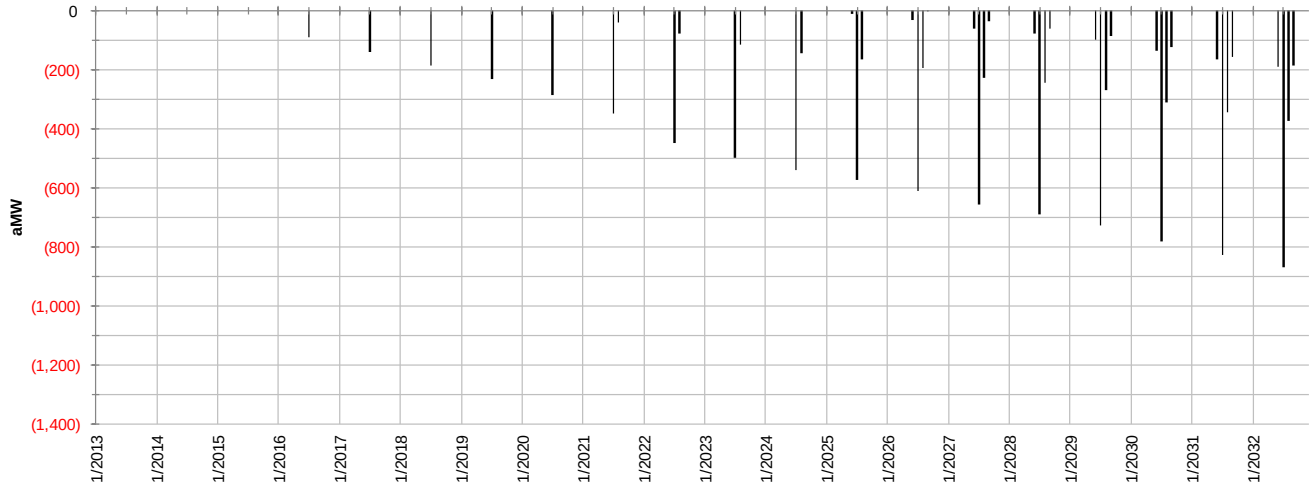
| | 1/2032 | 2/2032 | 3/2032 | 4/2032 | 5/2032 | 6/2032 | 7/2032 | 8/2032 | 9/2032 | 10/2032 | 11/2032 | 12/2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,933) | (2,719) | (2,416) | (2,260) | (3,722) | (4,057) | (4,503) | (3,829) | (3,579) | (2,455) | (2,661) | (3,185) |
| Existing DSM (EE) | 67 | 67 | 67 | 70 | 81 | 84 | 84 | 81 | 75 | 68 | 67 | 67 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,867) | (2,652) | (2,349) | (2,189) | (3,642) | (3,973) | (4,418) | (3,748) | (3,504) | (2,387) | (2,594) | (3,118) |
| Existing DSM (DR) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (DR)** | (2,867) | (2,652) | (2,349) | (2,189) | (3,642) | (3,973) | (4,418) | (3,748) | (3,504) | (2,387) | (2,594) | (3,118) |
| Existing Resources | | | | | | | | | | | | |
| **Coal** | 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 |
| Hydro (90th%)—HCC | 825 | 1,048 | 991 | 1,044 | 1,108 | 992 | 882 | 754 | 716 | 796 | 676 | 891 |
| Hydro (90th%)—Other | 239 | 240 | 227 | 214 | 330 | 317 | 296 | 224 | 223 | 244 | 230 | 238 |
| Shoshone Falls Upgrade (90th%) | 3 | 2 | 0 | 0 | 6 | 8 | 2 | 0 | 0 | 0 | 0 | 2 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,066 | 1,289 | 1,218 | 1,258 | 1,444 | 1,318 | 1,181 | 978 | 939 | 1,040 | 906 | 1,131 |
| **CSPP (PURPA)** | 86 | 89 | 93 | 128 | 174 | 182 | 189 | 179 | 167 | 128 | 96 | 88 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 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 |
| Neal Hot Springs Geothermal | 11 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 22 | 22 | 22 | 22 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 25 | 36 | 36 | 36 | 36 | 36 | 35 | 36 | 36 | 36 | 36 | 36 |
| **Firm Pacific NW Import Capability** | 313 | 10 | 85 | 33 | 416 | 342 | 237 | 281 | 299 | 0 | 259 | 306 |
| **Gas Peakers** | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Existing Resource Subtotal** | 3,172 | 3,107 | 3,113 | 3,137 | 3,752 | 3,560 | 3,324 | 3,156 | 3,122 | 2,886 | 2,979 | 3,243 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (413) | (1,095) | (592) | (382) | 0 | 0 | 0 |
| **2013 IRP DSM (EE)** | | | | | | | | | | | | |
| Irrigation | 0 | 0 | 0 | 12 | 42 | 59 | 61 | 51 | 27 | 5 | 0 | 0 |
| Commercial | 115 | 115 | 114 | 114 | 117 | 119 | 119 | 119 | 115 | 115 | 115 | 115 |
| Residential | 52 | 52 | 52 | 52 | 52 | 46 | 46 | 46 | 52 | 52 | 52 | 52 |
| **Total New DSM Peak Reduction** | 167 | 167 | 167 | 178 | 210 | 224 | 226 | 216 | 194 | 172 | 167 | 167 |
| **Remaining Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (190) | (869) | (375) | (187) | 0 | 0 | 0 |
| **2013 IRP Resources** | | | | | | | | | | | | |
| 2018 Boardman to Hemingway | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| Demand Response | 0 | 0 | 0 | 0 | 0 | 370 | 370 | 370 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 870 | 870 | 870 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 672 | 821 | 1,131 | 1,627 | 821 | 680 | 1 | 495 | 313 | 871 | 752 | 492 |

# Peak-Hour Surplus/Deficit Charts

**Peak-hour monthly deficits with existing DSM and existing resources**




**Peak-hour monthly deficits with existing DSM, existing resources, and IRP DSM**




**Peak-hour monthly deficits with existing DSM, existing resources, IRP DSM, and IRP resources**



# DEMAND-SIDE RESOURCE DATA

## Cost Effectiveness

Idaho Power considers cost-effectiveness to be the primary screening tool prior to demand-side management (DSM) program implementation. Idaho Power uses the total resource cost (TRC) test and the utility cost (UC) test to develop benefit cost (B/C) ratios to determine the cost-effectiveness of DSM programs for inclusion in resource planning. The two tests insure that the program benefits will exceed costs from both the perspective of Idaho Power (UC) and its customers (TRC). For ongoing programs, tests are also run to look at cost-effectiveness from the point of view of the program participant. Each energy efficiency and demand response program and individual program measures are reviewed annually as part of preparation of an annual report that is submitted to both the Idaho and Oregon public utility commissions. More information on Idaho Power's programs and cost-effectiveness are included in the *Demand-Side Management 2012 Annual Report* and its *Supplement 1: Cost-Effectiveness*, (http://www.idahopower.com/EnergyEfficiency/reports.cfm).

Incorporated into the cost-effectiveness analysis are inputs from various sources that represent the most current and reliable information available. Measure savings, measure life, and participant cost assumptions for prescriptive programs are usually sourced from the Regional Technical Forum (RTF), which is the regional advisory group and technical arm of the Northwest Power and Conservation Council (NPCC). For custom and non-prescriptive programs, annual energy savings can be derived from program evaluations, engineering estimates, or regionally deemed values. Participant costs for non-prescriptive programs are often actual costs from customer-submitted information. Other inputs used in the cost-effectiveness models are obtained from the IRP process, including the financial assumptions along with the forecasted value of DSM alternative costs.

Idaho Power determines cost-effectiveness on both a program basis and also on a measure-by-measure basis. In all cases, when cost-effectiveness is calculated for one measure or for an entire program, to be considered cost-effective, the B/C ratios must be greater than one for both the TRC and UC tests.

The cost-effective analysis methods used at Idaho Power are consistent with published methods and standard practices. Idaho Power relies on the *Electric Power Research Institute End Use Technical Assessment Guide* (TAG) and the *California Standard Practice Manual* for the cost-effectiveness methodology. As defined in the TAG and *California Standard Practice Manual*, the TRC and UC tests are most similar to supply-side cost analysis and provide a useful basis to compare demand-side and supply-side resources.

When developing energy efficiency programs, Idaho Power uses actual data and experiences from other companies in the region, or throughout the country, where applicable, to help identify specific program parameters. The regional program review is typically accomplished through discussions with other utilities' program managers and research staff. Other program development resources include; E Source, Edison Electrical Institute (EEI), Consortium for Energy Efficiency (CEE), American Council for an Energy Efficient Economy (ACEEE), Advanced Load Control Alliance (ALCA). For other assumptions, including estimated cost, savings, Idaho Power relies on sources, such as the NPCC, the RTF, NEEA, the Database for Energy Efficiency Resources (DEER), third-party consultants, and other regional utilities.

Idaho Power may choose to launch a pilot or limited-scale program to evaluate estimates or assumptions in the cost-effectiveness model. Pilot programs are designed to measure actual program experiences, including program expenses, savings, and participation. Following implementation of a program,

the cost-effectiveness models are reviewed as data from actual program activity becomes available. The program design may be re-examined after program implementation.

All programs are included in an ongoing evaluation schedule where a third-party consultant will verify the claimed savings from the program. Programs are also evaluated to review the program processes to review the effectiveness of the program delivery. If an evaluation determines that savings are less than claimed or that there is potential for improvement in delivery of the program then changes can be made based on the recommendations.

The financial assumptions used in the analysis for the 2013 IRP are consistent with the financial assumptions made for supply-side resources, including the discount rate and cost escalation rates. The IRP is also the source of the DSM alternative costs, which is the basis for estimating the value of energy savings and demand reduction resulting from the DSM programs. The DSM alternative costs vary by season and time-of-day. The DSM alternative energy costs are based on either projected fuel costs of a natural gas peaking unit for peak summer hours or forward marginal prices as determined by the AURORAxmp® Electric Market Model. The avoided capacity resource for peak summer hours and for demand response programs is based on a 170 MW natural gas-fired, simple-cycle combustion turbine (SCCT).

## Alternate Costs

The prices of avoided energy throughout the 20-year planning period were simulated using the Preferred Portfolio module within the AURORA model. The preferred portfolio module considers the energy capacity and resource costs of the current preferred mix of IRP resources along with regional transmission resources in the Western Electricity Coordinating Council (WECC) region to project forward marginal electricity prices. The forward prices are placed into five homogenous pricing categories that follow the pattern of heavy- and light-load pricing throughout each year of the planning period. The resulting categories are:

- Summer On-Peak (SONP)—Average of Idaho Power variable energy and operating costs of a 170 MW SCCT, which is the marginal resource for peak hour load deficits during summertime heavy load hours
- Summer Mid-Peak (SMP)—Average of heavy load prices from June to August (excluding the SONP hours)
- Summer Off-Peak (SOFP)—Average of light load prices from June to August
- Non-Summer Mid-Peak (NSMP)—Average of heavy load prices in January through May and September through December
- Non-Summer Off-Peak (NSOFP)—Average of light load prices in January through May and September through December

The SONP is treated differently than the other four pricing periods. The estimated levelized capacity cost of a new SCCT is approximately $102 per kW over a 30-year period. When multiplied by the Effective Load Carry Capacity (ELCC) of 93 percent, the annual avoided capacity cost is $95/kW. For demand response or direct load control DSM programs $95 per kW becomes the cost threshold for program cost-effectiveness. The avoided capacity value is spread across the annual SONP hours to estimate the value of energy efficiency savings occurring during the hours. The total SONP hours vary between 512 to 528 depending on the calendar year.

Table DSM-1 lists the financial assumptions used for the cost-effectiveness analysis and new program screening.

Table DSM-2 shows the results of averaging forward marginal energy prices over the 20-year planning period that were determined as a result of the IRP planning process and selection of the preferred portfolio. The alternate cost prices for energy efficiency measures that have a life longer than the 20-year planning horizon, which is typical for weatherization and building shell measures, are escalated at 3 percent annually beyond the planning period.

Tables DSM-3 and DSM-4 show the distribution of the three summer and two non-summer pricing periods across the hours and days of the week and for holidays.

Tables DSM-5 and DSM-6 show the 20-year cumulative forecasted impact of energy efficiency by customer class, and the associated annual TRC.

Table DSM-7 outlines the 20-year flow of avoided generation and the benefits attributed to energy efficiency programs.

Table DSM-8 summarizes the cost-effectiveness analysis for energy efficiency programs through the 20-year IRP planning period.

Table DSM-9 summarizes the 20 year cumulative forecasted new potential for energy efficiency.

**Table DSM-1. IRP financial assumptions**

| DSM Analysis Assumptions | |
|---|---|
| **Avoided 30-Year Levelized Capacity Costs** | |
| SCCT | $102/kW |
| **Financial Assumptions** | |
| Weighted average cost of capital (2008 year ending after tax) | 6.77% |
| Financial escalation factor | 3.00% |
| **Transmission Losses** | |
| Non-summer secondary losses | 10.90% |
| Summer peak loss | 13.00% |

**Table DSM-2. DSM alternate costs by pricing period**

| Year | Summer On-Peak* (SONP) | Summer Mid-Peak (SMP) | Summer Off-Peak (SOFP) | Non-Summer Mid-Peak (NSMP) | Non-Summer Off-Peak (NSOFP) |
|---|---|---|---|---|---|
| 2013 | $76.49 | $34.48 | $25.31 | $34.93 | $30.02 |
| 2014 | $80.75 | $37.08 | $27.11 | $37.34 | $31.76 |
| 2015 | $84.72 | $39.35 | $29.10 | $40.13 | $33.67 |
| 2016 | $86.92 | $40.96 | $30.40 | $41.62 | $34.89 |
| 2017 | $89.91 | $43.92 | $31.84 | $43.66 | $36.65 |
| 2018 | $105.15 | $56.81 | $41.02 | $56.36 | $48.35 |
| 2019 | $110.73 | $59.75 | $43.63 | $58.59 | $50.43 |
| 2020 | $116.20 | $63.46 | $46.03 | $60.93 | $52.05 |
| 2021 | $123.89 | $68.11 | $49.29 | $65.65 | $55.83 |
| 2022 | $133.18 | $73.43 | $53.52 | $71.81 | $60.51 |
| 2023 | $141.12 | $76.86 | $57.74 | $76.07 | $64.49 |
| 2024 | $148.17 | $83.42 | $60.91 | $80.83 | $68.21 |
| 2025 | $156.30 | $87.00 | $65.11 | $86.57 | $72.62 |
| 2026 | $163.99 | $91.41 | $68.20 | $92.53 | $77.24 |
| 2027 | $172.62 | $96.14 | $72.06 | $97.31 | $80.92 |
| 2028 | $180.43 | $102.13 | $75.83 | $103.04 | $85.24 |
| 2029 | $188.75 | $107.61 | $78.85 | $106.65 | $89.01 |
| 2030 | $197.88 | $116.12 | $82.84 | $112.22 | $94.27 |
| 2031 | $207.57 | $121.61 | $86.58 | $118.59 | $98.88 |
| 2032 | $218.39 | $133.14 | $91.20 | $125.54 | $104.29 |

* Estimated variable operations and management costs of a 170 MW capacity SCCT.

**Table DSM-3. DSM alternate cost summer pricing periods (June 1–August 31)**

| Hour | Sunday | Monday | Tuesday | Wednesday | Thursday | Friday | Saturday | Holiday |
|---|---|---|---|---|---|---|---|---|
| 1 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 2 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 3 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 4 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 5 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 6 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 7 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 8 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 9 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 10 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 11 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 12 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 13 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 14 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 15 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 16 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 17 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 18 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 19 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 20 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 21 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 22 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 23 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 24 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |

**Table DSM-4. DSM alternate cost non-summer pricing periods (September 1–May 31)**

| Hour | Sunday | Monday | Tuesday | Wednesday | Thursday | Friday | Saturday | Holiday |
|---|---|---|---|---|---|---|---|---|
| 1 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 2 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 3 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 4 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 5 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 6 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 7 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 8 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 9 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 10 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 11 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 12 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 13 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 14 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 15 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 16 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 17 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 18 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 19 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 20 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 21 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 22 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 23 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 24 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |

**Table DSM-5. Cumulative existing energy efficiency portfolio forecast 2013–2032**
*(aMW w/transmission losses)*

| Year | Commercial/Industrial | Irrigation | Residential | Total |
|---|---|---|---|---|
| 2013 | 11 | 3 | 1 | 15 |
| 2014 | 20 | 7 | 3 | 30 |
| 2015 | 29 | 11 | 4 | 44 |
| 2016 | 37 | 14 | 5 | 56 |
| 2017 | 45 | 18 | 6 | 69 |
| 2018 | 53 | 22 | 7 | 82 |
| 2019 | 60 | 26 | 8 | 94 |
| 2020 | 68 | 27 | 10 | 105 |
| 2021 | 76 | 29 | 11 | 116 |
| 2022 | 86 | 30 | 13 | 129 |
| 2023 | 94 | 31 | 14 | 139 |
| 2024 | 103 | 35 | 16 | 154 |
| 2025 | 111 | 39 | 18 | 168 |
| 2026 | 118 | 44 | 19 | 181 |
| 2027 | 125 | 50 | 21 | 196 |
| 2028 | 133 | 57 | 23 | 213 |
| 2029 | 139 | 61 | 26 | 226 |
| 2030 | 145 | 67 | 27 | 239 |
| 2031 | 151 | 72 | 27 | 250 |
| 2032 | 157 | 76 | 28 | 261 |

**Table DSM-6. Existing energy efficiency portfolio TRC 2013–2032**

| Year | Commercial/Industrial | Irrigation | Residential | Total All Sectors |
|---|---|---|---|---|
| 2013 | $17,684,888 | $4,444,305 | $5,086,693 | $18,384,322 |
| 2014 | $15,023,476 | $4,457,135 | $5,234,296 | $19,369,878 |
| 2015 | $14,489,836 | $5,436,652 | $4,658,449 | $21,075,362 |
| 2016 | $15,795,923 | $5,422,132 | $3,079,095 | $24,297,150 |
| 2017 | $12,804,433 | $6,222,769 | $3,485,460 | $22,512,662 |
| 2018 | $18,933,992 | $8,491,051 | $3,832,902 | $31,257,946 |
| 2019 | $14,504,997 | $8,473,738 | $4,116,430 | $27,095,166 |
| 2020 | $16,784,968 | $11,988,119 | $4,458,449 | $33,231,536 |
| 2021 | $16,569,043 | $15,941,955 | $4,777,871 | $37,288,869 |
| 2022 | $24,300,214 | $12,054,486 | $5,258,756 | $41,613,456 |
| 2023 | $21,616,897 | $11,248,712 | $5,519,440 | $38,385,049 |
| 2024 | $24,308,004 | $22,807,017 | $5,908,096 | $53,023,117 |
| 2025 | $19,146,569 | $27,109,620 | $6,319,791 | $52,575,980 |
| 2026 | $17,637,971 | $18,967,276 | $6,673,290 | $43,278,537 |
| 2027 | $16,436,862 | $18,996,353 | $7,018,133 | $42,451,348 |
| 2028 | $20,547,973 | $19,800,123 | $7,405,932 | $47,754,028 |
| 2029 | $18,360,242 | $17,039,341 | $7,748,039 | $43,147,622 |
| 2030 | $16,662,697 | $19,003,939 | $3,224,961 | $38,891,596 |
| 2031 | $15,856,083 | $17,560,593 | $3,375,416 | $36,792,091 |
| 2032 | $20,858,372 | $12,799,825 | $3,245,360 | $36,903,556 |
| **20-Year NPV** | **$188,245,928** | **$123,502,451** | **$52,623,496** | **$364,755,770** |

**Table DSM-7. Existing energy efficiency portfolio avoided energy costs 2013–2032**

| Year | Commercial/Industrial | Irrigation | Residential | Total All Sectors |
|---|---|---|---|---|
| 2013 | $1,995,192 | $785,140 | $82,481 | $2,862,813 |
| 2014 | $4,447,169 | $1,877,276 | $306,505 | $6,630,950 |
| 2015 | $7,448,806 | $3,562,786 | $608,946 | $11,620,538 |
| 2016 | $10,536,474 | $4,823,818 | $936,699 | $16,296,990 |
| 2017 | $13,603,373 | $6,184,262 | $1,326,187 | $21,113,822 |
| 2018 | $21,636,893 | $10,091,290 | $2,252,452 | $33,980,635 |
| 2019 | $26,150,714 | $12,719,356 | $2,941,227 | $41,811,296 |
| 2020 | $31,747,645 | $13,994,828 | $3,744,939 | $49,487,412 |
| 2021 | $37,762,710 | $15,493,623 | $4,672,567 | $57,928,901 |
| 2022 | $45,798,427 | $17,142,980 | $5,825,460 | $68,766,868 |
| 2023 | $52,827,025 | $18,655,035 | $7,029,285 | $78,511,345 |
| 2024 | $60,135,516 | $21,307,128 | $8,281,800 | $89,724,444 |
| 2025 | $67,330,305 | $24,745,002 | $9,733,405 | $101,808,713 |
| 2026 | $75,445,701 | $29,484,780 | $11,436,383 | $116,366,864 |
| 2027 | $83,498,887 | $34,951,122 | $13,269,044 | $131,719,053 |
| 2028 | $93,058,554 | $41,361,986 | $15,432,666 | $149,853,206 |
| 2029 | $101,824,572 | $46,837,103 | $17,697,063 | $166,358,738 |
| 2030 | $112,112,296 | $53,607,202 | $19,343,108 | $185,062,606 |
| 2031 | $120,032,498 | $59,203,492 | $20,675,610 | $199,911,600 |
| 2032 | $128,401,187 | $64,820,001 | $22,038,852 | $215,260,039 |
| **20-Year NPV** | **$437,466,195** | **$189,233,708** | **$63,693,931** | **$690,393,833** |

**Table DSM-8. Existing energy efficiency portfolio cost-effectiveness summary**

| | Impact | 20-Year NPV | | TRC | |
|---|---|---|---|---|---|
| | 2032 Load (aMW) | Resource Costs | Alternate Energy Benefits | B/C Ratio | 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** |

**Table DSM-9. Cumulative new energy efficiency portfolio forecast 2013–2032**
*(aMW w/transmission losses)*

| Year | Commercial/ Industrial | Residential | Irrigation | Total |
|---|---|---|---|---|
| 2013 | 6 | 0 | 1 | 8 |
| 2014 | 13 | 0 | 2 | 15 |
| 2015 | 19 | 1 | 3 | 23 |
| 2016 | 25 | 2 | 3 | 30 |
| 2017 | 30 | 4 | 4 | 37 |
| 2018 | 35 | 6 | 5 | 46 |
| 2019 | 40 | 10 | 5 | 55 |
| 2020 | 46 | 9 | 6 | 60 |
| 2021 | 51 | 9 | 7 | 67 |
| 2022 | 59 | 9 | 8 | 76 |
| 2023 | 65 | 9 | 9 | 83 |
| 2024 | 72 | 12 | 10 | 94 |
| 2025 | 78 | 16 | 12 | 105 |
| 2026 | 84 | 20 | 13 | 117 |
| 2027 | 90 | 26 | 15 | 130 |
| 2028 | 96 | 32 | 17 | 145 |
| 2029 | 101 | 36 | 19 | 157 |
| 2030 | 106 | 41 | 20 | 167 |
| 2031 | 111 | 46 | 21 | 178 |
| 2032 | 116 | 51 | 21 | 188 |

# SUPPLY-SIDE RESOURCE DATA

## Key Financial and Forecast Assumptions

| Financing Cap Structure and Cost | |
|---|---|
| **Composition** | |
| Debt | 50.04% |
| Preferred | 0.00% |
| Common | 49.96% |
| **Total** | **100.00%** |
| **Cost** | |
| Debt | 5.73% |
| Preferred | 0.00% |
| Common | 10.00% |
| Average Weighted Cost | 7.86% |

| Financial Assumptions and Factors | |
|---|---|
| Plant operating (book) life | 30 Years |
| Discount rate (weighted average cost of capital[1]) | 6.70% |
| Composite tax rate | 39.10% |
| Deferred rate | 35.00% |
| General O&M escalation rate | 3.00% |
| Emissions adder escalation rate | 3.00% |
| Annual property tax rate (% of investment) | 0.29% |
| Property tax escalation rate | 3.00% |
| Annual insurance premiums (% of investment) | 0.31% |
| Insurance escalation rate | 2.00% |
| AFUDC rate (annual) | 7.78% |

[1] Incorporates tax effects.

| Emission Intensity Rate (lbs per MWh by technology, adder brought into the analysis beginning in 2018) | |
|---|---|
| | **$CO_2$** |
| Small aeroderivative SCCT | 1,115 |
| Large aeroderivative SCCT | 1,047 |
| Large frame SCCT | 1,413 |
| CCCT 1x1 | 809 |
| CCCT 2x1 | 809 |
| Combined heat and power (CHP) | 1,115 |
| Distributed generation–gas fired | 1,115 |
| Pulverized coal | 1,901 |
| IGCC | 2,279 |
| IGCC w/carbon sequestration | 421 |

| Emissions Adder Rates | |
|---|---|
| $CO_2$ | $14.64 per ton (2018 $) |

**Fuel Forecast Base Case (Nominal, $ per MMBtu)**

| Year | Natural Gas[1] | Regional Coal | Uranium[2] |
|---|---|---|---|
| 2013 | $5.55 | $2.32 | $0.70 |
| 2014 | $5.88 | $2.44 | $0.70 |
| 2015 | $6.19 | $2.42 | $0.71 |
| 2016 | $6.35 | $2.45 | $0.71 |
| 2017 | $6.57 | $2.56 | $0.72 |
| 2018 | $6.83 | $2.68 | $0.72 |
| 2019 | $7.22 | $2.64 | $0.73 |
| 2020 | $7.59 | $2.70 | $0.73 |
| 2021 | $8.15 | $2.79 | $0.73 |
| 2022 | $8.84 | $2.89 | $0.74 |
| 2023 | $9.42 | $2.98 | $0.74 |
| 2024 | $9.91 | $3.07 | $0.75 |
| 2025 | $10.49 | $3.17 | $0.75 |
| 2026 | $11.03 | $3.27 | $0.76 |
| 2027 | $11.65 | $3.38 | $0.76 |
| 2028 | $12.19 | $3.48 | $0.77 |
| 2029 | $12.76 | $3.59 | $0.77 |
| 2030 | $13.40 | $3.71 | $0.77 |
| 2031 | $14.09 | $3.87 | $0.78 |
| 2032 | $14.86 | $4.00 | $0.78 |
| 2033 | $14.95 | $4.02 | $0.79 |
| 2034 | $15.04 | $4.04 | $0.79 |
| 2035 | $15.13 | $4.07 | $0.80 |
| 2036 | $15.22 | $4.09 | $0.80 |
| 2037 | $15.31 | $4.12 | $0.81 |
| 2038 | $15.40 | $4.14 | $0.81 |
| 2039 | $15.49 | $4.17 | $0.82 |
| 2040 | $15.59 | $4.19 | $0.82 |
| 2041 | $15.68 | $4.22 | $0.83 |
| 2042 | $15.78 | $4.24 | $0.83 |

[1] Henry Hub + Sumas basis + transportation cost = Idaho city gate price

[2] Nuclear fuel

# Cost Inputs and Operating Assumptions

(All costs in 2013 dollars)

| Supply-Side Resources | Plant Capacity (MW) | Plant Capital ($/kW)[1,3] | Transmission Capital $/kW | Total Capital $/kW | Total Investment $/kW[2] | Fixed O&M $/kW[3] | Variable O&M $/kW | Emissions $/MWh | Heat Rate Btu/kWh |
|---|---|---|---|---|---|---|---|---|---|
| Advanced Nuclear | 250 | $6,866 | $625 | $7,491 | $11,381 | $143 | $1 | $0 | 10,488 |
| Biomass Digesters | 50 | $4,311 | $285 | $4,596 | $4,921 | $107 | $16 | $0 | NA |
| CCCT—(1x1) F Class | 270 | $1,120 | $140 | $1,260 | $1,477 | $8 | $2 | $7 | 6,800 |
| CCCT—(2x1) F Class | 580 | $1,039 | $109 | $1,148 | $1,346 | $6 | $2 | $7 | 6,738 |
| CHP/Co-Generation | 100 | $1,975 | $25 | $2,000 | $2,142 | $8 | $5 | $0 | 9,200 |
| Conventional Scrubbed Coal | 600 | $3,253 | $730 | $3,983 | $4,754 | $26 | $4 | $26 | 9,200 |
| Distributed Generation (Option # 1) Load shed | 10 | $0 | $0 | $0 | $0 | $63 | $0 | $0 | 9,050 |
| Distributed Generation (Option # 2) Grid synchronized | 15 | $0 | $160 | $160 | $166 | $63 | $0 | $0 | 9,050 |
| Geothermal—Idaho | 26 | $6,630 | $979 | $7,609 | $8,442 | $144 | $5 | $0 | NA |
| Geothermal—Nevada | 26 | $6,630 | $552 | $7,182 | $7,968 | $144 | $5 | $0 | NA |
| Geothermal—Oregon | 26 | $6,630 | $787 | $7,417 | $8,229 | $144 | $5 | $0 | NA |
| IGCC | 550 | $4,513 | $730 | $5,243 | $6,547 | $35 | $7 | $25 | 8,765 |
| Low Drop/Small Hydro New | 10 | $4,000 | $80 | $4,080 | $4,784 | $15 | $4 | $0 | NA |
| Pulverized Coal w/ carbon capture and sequestration | 455 | $7,755 | $730 | $8,485 | $10,595 | $143 | $7 | $5 | 12,600 |
| Pumped Storage Fueled by LL Wind | 500 | $2,510 | $646 | $3,156 | $3,700 | $5 | $0 | $0 | NA |
| SCCT—Industrial Frame | 170 | $733 | $88 | $821 | $875 | $4 | $3 | $13 | 11,870 |
| SCCT—Large Aeroderivative | 100 | $1,250 | $149 | $1,399 | $1,491 | $15 | $3 | $10 | 8,800 |
| SCCT—Small Aeroderivative | 47 | $1,113 | $31 | $1,144 | $1,219 | $14 | $5 | $8 | 9,370 |
| Solar—1-Axis Tracking Flat Plate PV (Utility) | 1 | $4,029 | $0 | $4,029 | $4,108 | $27 | $0 | $0 | NA |
| Solar—1-Axis Tracking Flat Plate PV (Utility 10 MW) | 10 | $3,268 | $80 | $3,348 | $3,414 | $27 | $0 | $0 | NA |
| Solar—Concentrating Solar Power | 100 | $5,398 | $212 | $5,610 | $6,578 | $56 | $0 | $0 | NA |
| Solar—Concentrating Solar Power with Energy Storage | 100 | $7,771 | $212 | $7,983 | $9,360 | $56 | $0 | $0 | NA |
| Solar—Flat Plate PV (Distributed)[4] | 10 | $5,610 | $0 | $5,610 | $5,720 | $55 | $0 | $0 | NA |
| Solar—Flat Plate PV (Utility) | 1 | $3,714 | $0 | $3,714 | $3,787 | $27 | $0 | $0 | NA |
| Solar—Flat Plate PV (Utility 10MW) | 10 | $2,996 | $80 | $3,076 | $3,136 | $27 | $0 | $0 | NA |
| Transmission—Boardman to Hemingway[5] | 350 | $0 | $602 | $602 | $602 | $1 | $0 | $0 | NA |
| Wind—Eastern Oregon | 100 | $2,229 | $1,210 | $3,439 | $3,675 | $37 | $1 | $0 | NA |
| Wind—Magic Valley | 100 | $2,229 | $369 | $2,598 | $2,776 | $37 | $1 | $0 | NA |
| Wind—Southeast Idaho | 100 | $2,229 | $382 | $2,611 | $2,790 | $37 | $1 | $0 | NA |

[1] Plant costs include engineering development costs, generating and ancillary equipment purchase, and installation costs, as well as balance of plant construction.

[2] Total Investment includes capital costs and AFUDC.

[3] Fixed O&M excludes property taxes and insurance (separately calculated within the levelized resource cost analysis)

[4] Approximately 2,500 4-kW PV systems.

[5] 350-MW average, 500-MW summer, and 200-MW winter.

# Transmission Cost Assumptions

## *Cost Assumptions by Supply-Side Resource Type*

| Capacity (MW Rating) | Overnight Transmission Capital Cost/kW[1] | Cost Assumptions Notes | Local Interconnection Assumptions | Backbone Transmission Assumptions |
|---|---|---|---|---|
| Advanced Nuclear | | | | |
| 250 | $625 | Pro-rated the 250 MW based on Idaho Power's present 21.2% share of estimated $900 million Boardman to Hemingway project cost plus BPA wheeling rates to get to Boardman Station | 230 kV upgrades from Hemingway to Bowmont and Hubbard stations | Assume transmission in place by 2025 for access to Boardman area from Central Washington. Use BPA tariff rate to Boardman and pro-rata share of Boardman to Hemingway to Treasure Valley. |
| Biomass Digesters | | | | |
| 50 | $285 | Assume multiple feeder locations. Assume $250 thousand of feeder upgrades per 10 MW plus 138-kV integration costs. Assume Jerome area integration requiring 138-kV transformer, breaker and miscellaneous line work and station reconfigurations. | Assume multiple feeder locations. Assume $250 thousand of feeder upgrades per 10 MW plus 138-kV integration costs. Assume Jerome area integration requiring 138-kV transformer, breaker, and miscellaneous line work and station reconfigurations. | Assume pro-rata share of Midpoint West path upgrades. |
| CCCT—(1x1) F Class | | | | |
| 270 | $140 | Build new facility between Mountain Home and Boise with associated 230-kV plan of service consisting of 230-kV switching station with a 22-mile, 230-kV line to Boise Bench substation and double circuit in/out of existing 230-kV line. | New supporting transmission will be required. Entire project assumed as backbone upgrade. | Build new facility between Mountain Home and Boise with associated 230-kV plan of service consisting of 230-kV switching station with a 22-mile, 230-kV line to Boise Bench substation and double circuit in/out of existing 230-kV line. |
| CCCT—(2x1) F Class | | | | |
| 580 | $109 | Build new facility between Mountain Home and Boise with associated 230-kV plan of service consisting of 230-kV switching station a 22-mile, 230-kV line to Boise Bench substation and a new 28-mile, 230-kV line to Hubbard substation. | New supporting transmission will be required. Entire project assumed as backbone upgrade. | Build new facility between Mountain Home and Boise with associated 230-kV plan of service consisting of 230-kV switching station a 22-mile, 230-kV line to Boise Bench substation and a new 28-mile, 230-kV line to Hubbard substation. |
| CHP/Co-Generation | | | | |
| 100 | $25 | Assume Amalgamated Sugar location. Interconnection requires a tap of existing 138-kV line. Interconnection will require approximately 0.5 mile, 138-kV line and tap substation. | Approximately 0.5 mile, 138-kV line and 138-kV source substation with transformer. | Assume no additional transmission required. |
| Conventional Scrubbed Coal | | | | |
| 600 | $730 | Assume Wyoming location requiring pro-rata share of 3000 MW Gateway West project. | Assume transmission in place to access Aeolus from resource location. Use tariff rate for capacity to Aeolus and then pro-rata share of Gateway West to Treasure Valley. | Pro-rata share of Gateway. |
| Distributed Generation—(Option # 1) Load Shed | | | | |
| 10 | $0 | No upgrades required for load shed. | No upgrades required for load shed. | No backbone upgrades required. |
| Distributed Generation—(Option # 2) Grid synchronized | | | | |
| 15 | $160 | Assume feeder interconnection with minor amount of distribution rebuild. | Assume a small amount of distribution rebuild. | No backbone upgrades required. |
| Geothermal—Idaho | | | | |
| 26 | $979 | Assume Raft River area geothermal with 45 mile, 138-kV line to Minidoka area substation with new 138-line bay. Assume 26 MW fits on existing backbone. | Assume Raft River area geothermal with 45 mile, 138-kV line to Minidoka area substation with new 138-line bay. | No backbone upgrades required. |

| Capacity (MW Rating) | Overnight Transmission Capital Cost/kW[1] | Cost Assumptions Notes | Local Interconnection Assumptions | Backbone Transmission Assumptions |
|---|---|---|---|---|
| Geothermal—Nevada | | | | |
| 26 | $552 | Assume a location 20 miles from existing 138-kV line. Assume 26 MW fits on existing 138-kV line. | Assume 20 miles of 138-kV local transmission to point of interconnection at 138-kV substation. | No backbone upgrades required. |
| Geothermal—Oregon | | | | |
| 26 | $787 | Assume a project similar to Neal Hot Springs Interconnect (1 breaker station, line switches, 10-mile interconnect). Assume 26 MW fits on existing backbone. | Assume 10 miles of 138-kV local transmission to point of interconnection at 138-kV substation. | No backbone upgrades required. |
| IGCC | | | | |
| 550 | $730 | Assume Wyoming location requiring pro-rata share of 3000 MW Gateway West project. | Assume transmission in place to access Aeolus from resource location. Use tariff rate for capacity to Aeolus and then pro-rata share of Gateway West to Treasure Valley. | Pro-rata share of Gateway. |
| Low Drop/Small Hydro New | | | | |
| 10 | $80 | Assume 46-kV sub-transmission or local feeder interconnection. Assume 4 miles of distribution rebuild required. | Assume 4 miles of distribution rebuild required. | No backbone upgrades required. |
| Pumped Storage Fueled by LL Wind | | | | |
| 500 | $646 | Assume multiple locations. Assume 20-mile, 138- or 230-kV interconnection per location. | Assume multiple locations. Assume 20-mile, 138- or 230-kV interconnection per location. | No backbone upgrades assumed in the upgrade costs; however, this assumption will vary drastically based on size of resource and number of locations |
| Pulverized Coal with Carbon Capture and Sequestration | | | | |
| 455 | $730 | Assume Wyoming location requiring pro-rata share of 3000 MW Gateway West project. | Assume transmission in place to access Aeolus from resource location. Use tariff rate for capacity to Aeolus and then pro-rata share of Gateway West to Treasure Valley. | Pro-rata share of Gateway. |
| SCCT—Industrial Frame | | | | |
| 170 | $88 | See requirements in previous estimate and also rebuild 16 miles of existing 230-kV construction to bundled conductor. | Langley Substation expansion, new transformer terminal. | 9 miles of new urban 230-kV transmission plus three-terminal expansion of existing Caldwell-area substation, 16 mile, 230-kV bundled conductor rebuild of Caldwell–Langley line. |
| SCCT—Large Aeroderivative | | | | |
| 100 | $149 | 9 miles of new urban 230-kV transmission plus three-terminal expansion of existing Caldwell-area substation plus Langley site expansion for second generating unit (new transformer terminal in substation). | Langley substation expansion, new transformer terminal. | 9 miles of new urban 230-kV transmission plus three-terminal expansion of existing Caldwell-area substation |
| SCCT—Small Aeroderivative | | | | |
| 47 | $31 | Assume an addition to existing generation site in Mountain Home area. New 230-kV terminal and associated station modifications. | New 230-kV terminal and associated station modifications. | No backbone upgrades required. |
| Solar—1-Axis Tracking Flat Plate PV (Utility 10 MW) | | | | |
| 10 | $80 | Assume 34.5 kV feeder interconnection. Assume 4 miles of distribution rebuild required. | Assume 4 miles of distribution rebuild required. | No backbone upgrades required. |
| Solar—1-Axis Tracking Flat Plate PV (Utility) | | | | |
| 1 | $0 | 12.5-kV feeder interconnection. No upgrades required. | 12.5-kV feeder interconnection. No upgrades required. | No backbone upgrades required. |
| Solar—Flat Plate PV (Distributed)[2] | | | | |
| 10 | $0 | 12.5-kV feeder interconnection. No upgrades required. | 12.5-kV feeder interconnection. No upgrades required. | No backbone upgrades required. |

| Capacity (MW Rating) | Overnight Transmission Capital Cost/kW[1] | Cost Assumptions Notes | Local Interconnection Assumptions | Backbone Transmission Assumptions |
|---|---|---|---|---|
| Solar—Flat Plate PV (Utility 10 MW) | | | | |
| 10 | $80 | Assume 34.5-kV feeder interconnection. Assume 4 miles of distribution rebuild required. | Assume 4 miles of distribution rebuild required. | No backbone upgrades required. |
| Solar—Flat Plate PV (Utility) | | | | |
| 1 | $0 | 12.5-kV feeder interconnection. No upgrades required. | 12.5-kV feeder interconnection. No upgrades required. | No backbone upgrades required. |
| Solar—Concentrating Solar Power | | | | |
| 100 | $212 | Assume Mountain Home desert area with 15 mile, 138-kV line (or multiple 34.5-kV feeders) to new substation intersecting existing 230-kV line. | Assume Mountain Home desert area with 15 mile, 138-kV line (or multiple 34.5-kV feeders) to new substation intersecting existing 230-kV line. Assume multi-transformer station. | New three-terminal 230-kV switching station connecting existing 230-kV line. |
| Solar—Concentrating Solar Power with Energy Storage | | | | |
| 100 | $212 | Assume Mountain Home desert area with 15 mile, 138-kV line (or multiple 34.5-kV feeders) to new substation intersecting existing 230-kV line. | Assume Mountain Home desert area with 15 mile, 138-kV line (or multiple 34.5-kV feeders) to new substation intersecting existing 230-kV line. Assume multi-transformer station. | New three-terminal 230-kV switching station connecting existing 230-kV line. |
| Transmission—Boardman to Hemingway | | | | |
| 350–Average<br>500–Summer<br>200–Winter | $602 | Per the Boardman to Hemingway Funding Agreement, Idaho Power's share of the project is 21.2% of an estimated $900 million project cost. Project also requires 230-kV local interconnection upgrades from Hemingway into the Treasure Valley. | 230-kV upgrades from Hemingway to Bowmont and Hubbard | Pro-rata share of Boardman to Hemingway. |
| Wind—Eastern Oregon | | | | |
| 100 | $1,210 | Assume location near Quartz Substation. A new 110 mile, 230-kV line will need to be constructed into Treasure Valley. | Assume 10 miles of 138-kV local transmission to point of interconnection at 138-kV substation. | 110 mile, 230-kV line to Treasure Valley. |
| Wind—Magic Valley | | | | |
| 100 | $369 | Assume 10 mile interconnection to existing 230/138-kV substation plus 230-kV substation upgrades plus 1/16$^{th}$ share of Gateway West segment between Cedar Hill and Hemingway | Assume 10 miles of 138-kV local transmission to point of interconnection at 138-kV substation. | Upgrades at 230/138 kV integration substation + 100 MW pro-rata share of 1600-MW Cedar Hill–Hemingway 500-kV line |
| Wind—Southeast Idaho | | | | |
| 100 | $382 | Assume 10 mile interconnection to local 138-kV substation plus Borah West path RAS upgrades plus 1/16$^{th}$ share of Gateway West segment between Cedar Hill and Hemingway | Assume 138-kV step-up station with transformer with 10 miles of 138-kV local transmission to 138-kV point of interconnection. | New terminal at 138-kV point of interconnection plus Borah West RAS upgrades plus 100 MW pro-rata share of 1600-MW Cedar Hill–Hemingway 500-kV line |

[1] 2013 dollars, no AFUDC

[2] Approximately 2,500 4-kW PV systems.

# Levelized Cost of Production

**30-Year Levelized Cost of Production (at stated capacity factors)**

| Supply-Side Resources | Cost of Capital | Non-Fuel O&M[1] | Fuel | Wholesale Energy | Emission Adders | Total Cost per MWh[1] | Annual Capacity Factor |
|---|---|---|---|---|---|---|---|
| Advanced Nuclear (250 MW) | $156 | $41 | $8 | $0 | $0 | $205 | 85% |
| Biomass Digesters (50 MW) | $64 | $47 | $0 | $0 | $0 | $111 | 90% |
| CCCT—1x1 (270 MW) | $27 | $6 | $67 | $0 | $7 | $106 | 65% |
| CCCT—2x1 (580 MW) | $24 | $7 | $66 | $0 | $7 | $104 | 65% |
| Combined Heat and Power (100 MW) | $27 | $11 | $74 | $0 | $0 | $111 | 93% |
| Distributed Generation—Grid Sync (15 MW) | $1,941 | $10,305 | $0 | $0 | $0 | $12,246 | 0% |
| Distributed Generation—Load Shed (10 MW) | $0 | $10,305 | $0 | $0 | $0 | $10,305 | 0% |
| Geothermal—Idaho (26 MW) | $107 | $41 | $0 | $0 | $0 | $148 | 92% |
| Geothermal—Nevada (26 MW) | $101 | $41 | $0 | $0 | $0 | $142 | 92% |
| Geothermal—Oregon (26 MW) | $104 | $41 | $0 | $0 | $0 | $145 | 92% |
| IGCC (550 MW) | $90 | $24 | $27 | $0 | $25 | $166 | 85% |
| Low Drop/Small Hydro New (10 MW) | $124 | $20 | $0 | $0 | $0 | $144 | 45% |
| Pulverized Coal (600 MW) | $63 | $16 | $29 | $0 | $26 | $133 | 88% |
| Pulverized Coal w/Carbon Capture and Sequestration (455 MW) | $145 | $48 | $40 | $0 | $5 | $238 | 85% |
| Pumped Storage Fueled by LL Wind | $173 | $18 | $0 | $49 | $0 | $239 | 25% |
| SCCT—Industrial Frame (170 MW) | $170 | $29 | $116 | $0 | $13 | $328 | 6% |
| SCCT—Large Aero (100 MW) | $174 | $42 | $86 | $0 | $10 | $312 | 10% |
| SCCT—Small Aero (47 MW) | $178 | $50 | $92 | $0 | $8 | $327 | 8% |
| Solar—Concentrating Energy (100 MW) | $206 | $84 | $0 | $0 | $0 | $290 | 18% |
| Solar—Concentrating Energy Storage (100 MW) | $202 | $63 | $0 | $0 | $0 | $265 | 28% |
| Solar—Flat Plate PV Distributed (10 MW) [2] | $227 | $84 | $0 | $0 | $0 | $311 | 17% |
| Solar—Flat Plate PV Utility (10 MW) | $117 | $38 | $0 | $0 | $0 | $154 | 19% |
| Solar—Flat Plate PV Utility (1 MW) | $179 | $41 | $0 | $0 | $0 | $220 | 19% |
| Solar—Flat Plate Tracking PV Utility (1 MW) | $153 | $34 | $0 | $0 | $0 | $187 | 24% |
| Solar—Flat Plate Tracking PV Utility (10 MW) | $102 | $31 | $0 | $0 | $0 | $133 | 24% |
| Transmission—Boardman to Hemingway (350 MW)[3] | $20 | $2 | $0 | $68 | $0 | $89 | 34% |
| Wind—Eastern Oregon (100 MW) | $165 | $47 | $0 | $0 | $0 | $212 | 26% |
| Wind—Magic Valley (100 MW) | $125 | $44 | $0 | $0 | $0 | $169 | 26% |
| Wind—Southeast Idaho(100 MW) | $125 | $44 | $0 | $0 | $0 | $169 | 26% |

[1] Includes fixed and variable costs and property taxes.

[2] Approximately 2,500 4-kW PV systems.

[3] 350-MW average, 500-MW summer, and 200-MW winter.

| 30-Year Levelized Capacity (fixed) Cost per kW/Month | | | | | |
|---|---|---|---|---|---|
| **Supply-Side Resources** | **Cost of Capital** | **Non-Fuel O&M[1]** | **Fuel** | **Emission Adders** | **Total Cost per kW** |
| Advanced Nuclear (250 MW) | $97 | $25 | $0 | $0 | $122 |
| Biomass Digesters (50 MW) | $42 | $16 | $0 | $0 | $58 |
| CCCT—1x1 (270 MW) | $13 | $2 | $0 | $0 | $14 |
| CCCT—2x1 (580 MW) | $11 | $2 | $0 | $0 | $13 |
| Combined Heat and Power (100 MW) | $18 | $2 | $0 | $0 | $21 |
| Distributed Generation—Grid Sync (15 MW) | $1 | $8 | $0 | $0 | $9 |
| Distributed Generation—Load Shed (10 MW) | $0 | $8 | $0 | $0 | $8 |
| Geothermal—Idaho (26 MW) | $72 | $23 | $0 | $0 | $95 |
| Geothermal—Nevada (26 MW) | $68 | $22 | $0 | $0 | $90 |
| Geothermal—Oregon (26 MW) | $70 | $23 | $0 | $0 | $93 |
| IGCC (550 MW) | $56 | $9 | $0 | $0 | $64 |
| Low Drop/Small Hydro New (10 MW) | $41 | $5 | $0 | $0 | $46 |
| Pulverized Coal (600 MW) | $40 | $6 | $0 | $0 | $47 |
| Pulverized Coal w/Carbon Capture and Sequestration (455 MW) | $90 | $24 | $0 | $0 | $114 |
| Pumped Storage Fueled by LL Wind | $32 | $3 | $0 | $0 | $35 |
| SCCT—Industrial Frame (170 MW) | $7 | $1 | $0 | $0 | $9 |
| SCCT—Large Aero (100 MW) | $13 | $3 | $0 | $0 | $15 |
| SCCT—Small Aero (47 MW) | $10 | $2 | $0 | $0 | $13 |
| Solar—Concentrating Energy (100 MW) | $56 | $11 | $0 | $0 | $67 |
| Solar—Concentrating Energy Storage (100 MW) | $80 | $13 | $0 | $0 | $93 |
| Solar—Flat Plate PV Distributed (10 MW)[1] | $49 | $10 | $0 | $0 | $59 |
| Solar—Flat Plate PV Utility (1 MW) | $32 | $6 | $0 | $0 | $38 |
| Solar—Flat Plate PV Utility (10 MW) | $27 | $5 | $0 | $0 | $32 |
| Solar—Flat Plate Tracking PV Utility (1 MW) | $35 | $6 | $0 | $0 | $41 |
| Solar—Flat Plate Tracking PV Utility (10 MW) | $29 | $5 | $0 | $0 | $35 |
| Transmission—Boardman to Hemingway (350 MW)[2] | $5 | $0 | $0 | $0 | $5 |
| Wind—Eastern Oregon (100 MW) | $31 | $7 | $0 | $0 | $38 |
| Wind—Magic Valley (100 MW) | $24 | $6 | $0 | $0 | $30 |
| Wind—Southeast Idaho(100 MW) | $24 | $6 | $0 | $0 | $30 |

[1] Approximately 2,500 4-kW PV systems.

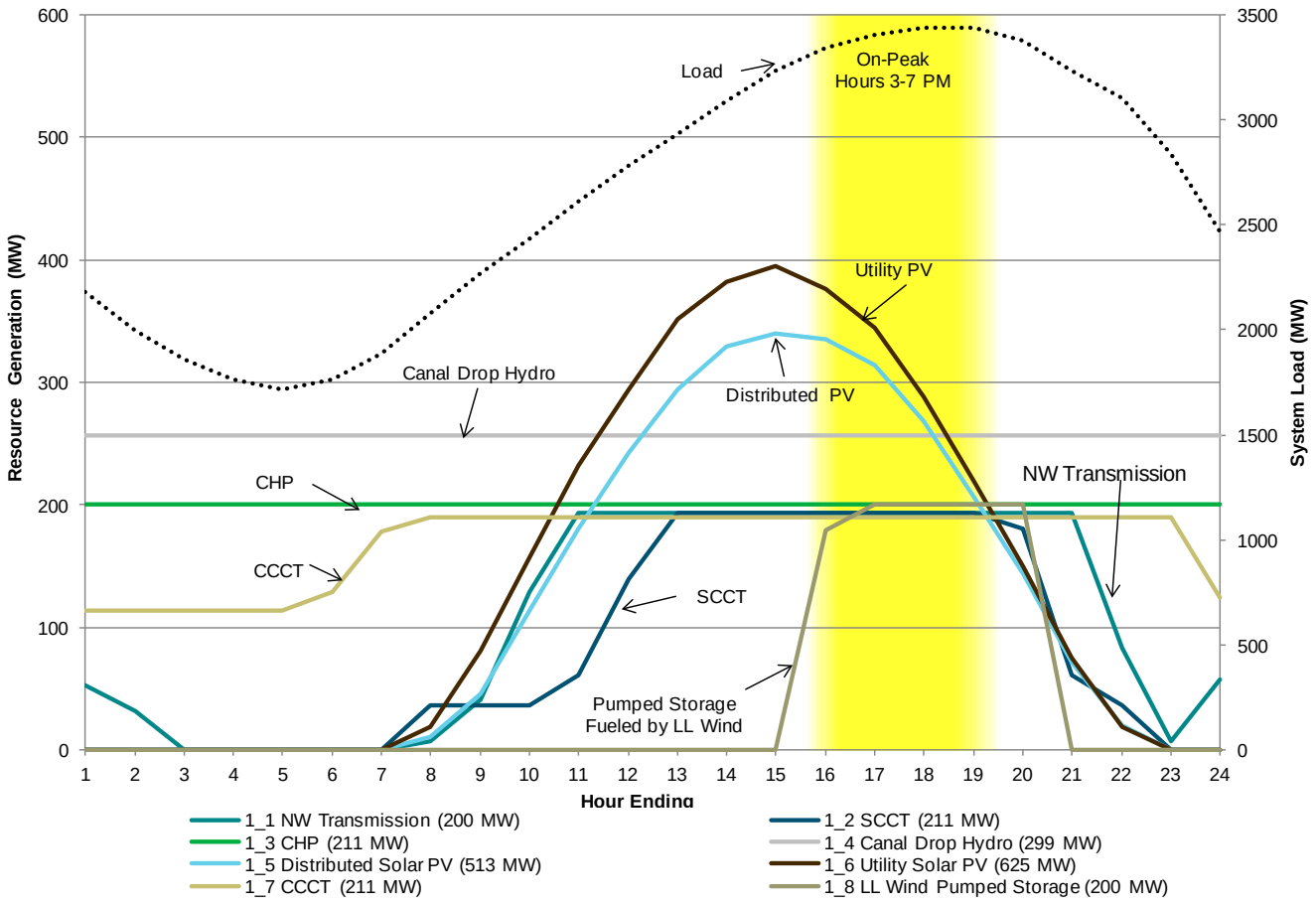
[2] 350-MW average, 500-MW summer, and 200-MW winter.

# Resource Advantages and Disadvantages

| Resource Type | Advantages | Disadvantages |
|---|---|---|
| **Biomass** | • Renewable resource<br>• No harmful emissions<br>• Minimum fuel risk<br>• Low, variable operating costs<br>• Baseload generation (90%+ capacity factor) | • Limited number of sites<br>• Uncertainty surrounding future tax incentives<br>• Fuel supply risk |
| **Coal** | | |
| Pulverized | • Abundant, low-cost fuel<br>• Less price volatility than natural gas<br>• Proven and reliable technology<br>• Dispatchable resource<br>• Well suited for baseload operations | • Potential lack of public acceptance<br>• Significant particulate and gas emissions, particularly $CO_2$<br>• Significant capital investment<br>• Long construction lead times<br>• Lengthy environmental permitting and siting processes |
| Advanced Technology | • Abundant, low cost fuel<br>• Potentially lower greenhouse gas emissions if $CO_2$ is sequestered<br>• Potential for financial incentives<br>• Dispatchable resource | • New, unproven technologies<br>• Higher capital costs than pulverized coal<br>• Long construction lead times |
| **Distributed Generation** | • Utilize existing backup generators at customer sites<br>• Dispatchable resource<br>• Provides operating reserves | • More expensive than other resource options<br>• Limited number of sites<br>• Fuel price risk and volatility<br>• Existing air quality permits may need to be modified<br>• Small size, many sites would be required |
| **Geothermal** | • Renewable resource<br>• No harmful emissions<br>• Minimum fuel risk (once developed)<br>• Low, variable operating costs<br>• Baseload generation (90%+ capacity factor) | • Limited number of sites<br>• High exploration costs due to drilling risks<br>• Uncertainty surrounding future tax incentives |
| **Hydro** | • Renewable resource<br>• No fuel cost<br>• No harmful emissions<br>• Low, variable operating costs | • Limited number of sites<br>• Future development is limited to small sites or at existing dams without power generation<br>• Fish and other environmental issues |
| **In-stream Generation** | • Renewable resource<br>• No harmful emissions<br>• No fuel cost | • Small size, many sites would be required<br>• Environmental impact and permitting<br>• High maintenance cost |

| Resource Type | Advantages | Disadvantages |
|---|---|---|
| **Natural Gas** | | |
| CCCT | • Proven and reliable technology<br>• Dispatchable resource<br>• Provides operating reserves necessary for integration of renewable generation<br>• More efficient than a SCCT<br>• Greater than 50% reduction in $CO_2$ emissions per MWh of output compared to conventional pulverized coal technology | • Fuel price risk and volatility<br>• Potential fuel supply and transportation issues |
| SCCT | • Dispatchable resource<br>• Proven, reliable resource<br>• Low capital cost<br>• Short construction lead times<br>• Ideal for peaking service | • High variable operating cost<br>• Fuel price risk and volatility<br>• Less efficient than a CCCT |
| **Nuclear** | • Forecasted low fuel costs<br>• Forecasted adequate fuel availability<br>• Lack of greenhouse gas emissions<br>• Potential low cost of production<br>• Proven technology (existing reactor types) | • Lack of public acceptance<br>• Safety concerns<br>• Waste disposal<br>• Construction cost uncertainties and the potential for construction cost overruns<br>• Security concerns |
| **Solar** (General) | • Renewable resource<br>• No fuel cost<br>• No harmful emissions<br>• Low, variable operating costs<br>• Generation would match well with summer peak loads. | • More expensive than other resource options<br>• Poor generation during winter months<br>• Intermittent and non-dispatchable resource<br>• Inefficient use of limited firm transmission capacity<br>• Limited utility scale projects exist |
| Parabolic Trough | • Can be built with thermal storage | • Utility scale production is limited |
| Power Tower | • By using molten salt, thermal storage can be built integrally into the system | • Utility scale production is unproven<br>• Requires land slope of 1% or less |
| Parabolic Dish | • Off-grid electricity production in remote areas | • Not suitable for storage options<br>• Unproven technology |
| Photovoltaic | • Proven & reliable technology<br>• Suitable for distributed generation | • Cloud cover creates a rapid power drop-off<br>• Utility scale projects are only practical up to 10 MW |
| **Transmission** | • Provides peak-hour capacity<br>• Can help integrate renewable generation<br>• Lower capital cost compared to other resources<br>• Expanded capacity for off-system sales<br>• Stability associated with possible long-term firm contracts (sales and purchases) | • Siting is difficult with impact to many land owners<br>• Exposure to potential market volatility<br>• Considerable lead times required |
| **Wind** | • Renewable resource<br>• No fuel cost<br>• No harmful emissions<br>• Low, variable operating costs | • Limited number of good sites in southern Idaho<br>• Intermittent and non-dispatchable resource<br>• Inefficient use of limited firm transmission capacity<br>• Avian and aesthetic impacts<br>• Uncertainty surrounding future tax incentives |

# Resource Peak Hour Shape




# Capacity Factors for Solar PV

The following tables show capacity factors for solar photovoltaic (PV) panels located in Boise, Idaho. The data is from a tool, PVWatts™, developed by the Nation Renewable Energy Laboratory (NREL). NREL describes PVWatts in the following manner:

> NREL's PVWatts™ calculator determines the energy production and cost savings of grid-connected photovoltaic (PV) energy systems throughout the world. It allows homeowners, installers, manufacturers, and researchers to easily develop estimates of the performance of hypothetical PV installations.
>
> The PVWatts calculator works by creating hour-by-hour performance simulations that provide estimated monthly and annual energy production in kilowatts and energy value. Users can select a location and choose to use default values or their own system parameters for size, electric cost, array type, tilt angle, and azimuth angle. In addition, the PVWatts calculator can provide hourly performance data for the selected location.

Using typical meteorological year weather data for the selected location, the PVWatts calculator determines the solar radiation incident of the PV array and the PV cell temperature for each hour of the year. The DC energy for each hour is calculated from the PV system DC rating and the incident solar radiation and then corrected for the PV cell temperature. The AC energy for each hour is calculated by multiplying the DC energy by the overall DC-to-AC derate factor and adjusting for inverter efficiency as a function of load. Hourly values of AC energy are then summed to calculate monthly and annual AC energy production.

The following NREL PVWatts data are for a solar PV array in the Boise area. The PV oriented to the southwest is equivalent to a north-based azimuth of 225 degrees. The PV oriented to the south is equivalent to a north-based azimuth of 180 degrees. The following link displays the PVWatts data in Boise: http://rredc.nrel.gov/solar/calculators/PVWATTS/version1/US/Idaho/Boise.html.

## *Capacity Factors for Southerly Oriented PV in Boise*

| Time | Hour | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 12 am–1 am | 1 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 1 am–2 am | 2 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2 am–3 am | 3 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 3 am–4 am | 4 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 4 am–5 am | 5 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 5 am–6 am | 6 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 6 am–7 am | 7 | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.3% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 7 am–8 am | 8 | 0.0% | 0.0% | 0.7% | 6.4% | 9.6% | 10.9% | 8.1% | 6.6% | 6.2% | 3.5% | 0.2% | 0.0% |
| 8 am–9 am | 9 | 1.3% | 7.4% | 15.9% | 23.1% | 25.7% | 26.4% | 24.2% | 24.8% | 24.3% | 20.6% | 9.8% | 1.9% |
| 9 am–10 am | 10 | 15.5% | 25.4% | 31.1% | 38.4% | 38.8% | 41.6% | 39.2% | 41.8% | 41.5% | 36.5% | 23.1% | 15.3% |
| 10 am–11 am | 11 | 26.1% | 39.5% | 41.8% | 48.0% | 49.3% | 49.8% | 52.6% | 51.7% | 50.1% | 48.0% | 36.2% | 28.0% |
| 11 am–12 pm | 12 | 33.4% | 47.6% | 51.3% | 55.2% | 54.5% | 56.2% | 59.1% | 61.0% | 56.2% | 54.5% | 41.0% | 35.9% |
| 12 pm–1 pm | 13 | 36.7% | 51.2% | 54.6% | 54.9% | 58.3% | 60.6% | 62.0% | 63.0% | 60.7% | 59.3% | 42.9% | 38.9% |
| 1 pm–2 pm | 14 | 39.7% | 47.7% | 50.9% | 56.2% | 58.8% | 57.9% | 62.6% | 62.6% | 61.8% | 52.7% | 43.1% | 37.6% |
| 2 pm–3 pm | 15 | 32.5% | 44.3% | 50.2% | 54.3% | 52.4% | 53.1% | 58.0% | 58.9% | 55.5% | 49.7% | 34.8% | 32.3% |
| 3 pm–4 pm | 16 | 25.3% | 32.3% | 39.8% | 42.3% | 41.3% | 43.9% | 49.0% | 49.8% | 47.1% | 38.0% | 21.8% | 22.1% |
| 4 pm–5 pm | 17 | 11.4% | 20.1% | 25.6% | 28.7% | 31.6% | 31.3% | 34.5% | 35.2% | 30.7% | 21.0% | 8.2% | 7.4% |
| 5 pm–6 pm | 18 | 0.6% | 5.3% | 11.4% | 14.6% | 15.5% | 17.0% | 18.5% | 17.5% | 12.6% | 4.0% | 0.1% | 0.0% |
| 6 pm–7 pm | 19 | 0.0% | 0.0% | 0.1% | 0.2% | 1.0% | 1.8% | 1.5% | 0.4% | 0.0% | 0.0% | 0.0% | 0.0% |
| 7 pm–8 pm | 20 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 8 pm–9 pm | 21 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 9 pm–10 pm | 22 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 10 pm–11 pm | 23 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 11 pm–12 am | 24 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| **Average** | | **9.3%** | **13.4%** | **15.6%** | **17.6%** | **18.2%** | **18.8%** | **19.6%** | **19.7%** | **18.6%** | **16.2%** | **10.9%** | **9.1%** |
| **Annual Average** | | **15.6%** | | | | | | | | | | | |

All values are in Mountain Standard Time (MST) and have not been adjusted for Daylight Savings Time (DST). DST begins on the second Saturday in March and ends the first Sunday in November.

## Capacity Factors for Southwesterly Oriented PV in Boise

| Time | Hour | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 12 am–1 am | 1 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 1 am–2 am | 2 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 2 am–3 am | 3 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 3 am–4 am | 4 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 4 am–5 am | 5 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 5 am–6 am | 6 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 6 am–7 am | 7 | 0.0% | 0.0% | 0.0% | 0.0% | 0.1% | 0.3% | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 7 am–8 am | 8 | 0.0% | 0.0% | 0.0% | 1.1% | 2.2% | 2.8% | 1.8% | 0.5% | 0.1% | 0.0% | 0.0% | 0.0% |
| 8 am–9 am | 9 | 0.0% | 0.1% | 1.1% | 4.4% | 5.2% | 6.1% | 2.8% | 1.9% | 1.3% | 0.4% | 0.1% | 0.0% |
| 9 am–10 am | 10 | 1.8% | 3.3% | 11.4% | 16.6% | 18.7% | 18.9% | 15.4% | 15.2% | 14.7% | 13.5% | 6.9% | 1.7% |
| 10 am–11 am | 11 | 14.3% | 19.7% | 25.2% | 31.6% | 33.6% | 33.5% | 33.0% | 32.0% | 31.1% | 29.6% | 21.6% | 14.9% |
| 11 am–12 pm | 12 | 24.2% | 33.2% | 38.9% | 43.9% | 44.7% | 45.9% | 46.8% | 47.7% | 43.9% | 42.1% | 30.8% | 25.8% |
| 12 pm–1 pm | 13 | 30.7% | 42.3% | 47.2% | 49.4% | 53.6% | 55.6% | 55.9% | 56.1% | 53.8% | 52.0% | 37.0% | 32.5% |
| 1 pm–2 pm | 14 | 36.6% | 44.0% | 48.9% | 55.6% | 59.6% | 58.8% | 62.8% | 62.0% | 60.8% | 51.4% | 41.3% | 35.0% |
| 2 pm–3 pm | 15 | 32.9% | 45.2% | 53.1% | 59.2% | 58.8% | 59.7% | 64.7% | 64.7% | 60.7% | 54.1% | 37.1% | 33.3% |
| 3 pm–4 pm | 16 | 28.7% | 36.8% | 46.9% | 51.5% | 51.8% | 55.4% | 61.8% | 62.0% | 58.6% | 47.4% | 26.6% | 26.3% |
| 4 pm–5 pm | 17 | 16.3% | 27.3% | 35.8% | 41.3% | 48.8% | 47.6% | 52.9% | 53.4% | 47.1% | 33.5% | 13.8% | 11.7% |
| 5 pm–6 pm | 18 | 1.8% | 12.2% | 24.6% | 30.1% | 34.1% | 38.5% | 41.4% | 40.3% | 32.1% | 15.1% | 1.0% | 0.0% |
| 6 pm–7 pm | 19 | 0.0% | 0.0% | 8.1% | 15.3% | 17.5% | 23.1% | 25.7% | 21.7% | 10.3% | 0.0% | 0.0% | 0.0% |
| 7 pm–8 pm | 20 | 0.0% | 0.0% | 0.0% | 0.1% | 2.9% | 6.6% | 8.5% | 2.7% | 0.0% | 0.0% | 0.0% | 0.0% |
| 8 pm–9 pm | 21 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 9 pm–10 pm | 22 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 10 pm–11 pm | 23 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| 11 pm–12 am | 24 | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| **Average** | | **9.3%** | **7.8%** | **11.0%** | **14.2%** | **16.7%** | **18.0%** | **18.9%** | **19.7%** | **19.2%** | **17.3%** | **14.1%** | **9.0%** |
| **Annual Average** | | **14.5%** | | | | | | | | | | | |

All values are in MST and have not been adjusted for DST. DST begins on the second Saturday in March and ends the first Sunday in November.

The tables show a PV oriented to the southwest produces more energy in the months of June and July. The PV oriented to the south generates more energy in all other months, and the south orientation generates more energy annually. Annual average capacity factors for a southern PV orientation in Boise is 15.6 percent, and for a southwestern orientation is 14.5 percent.

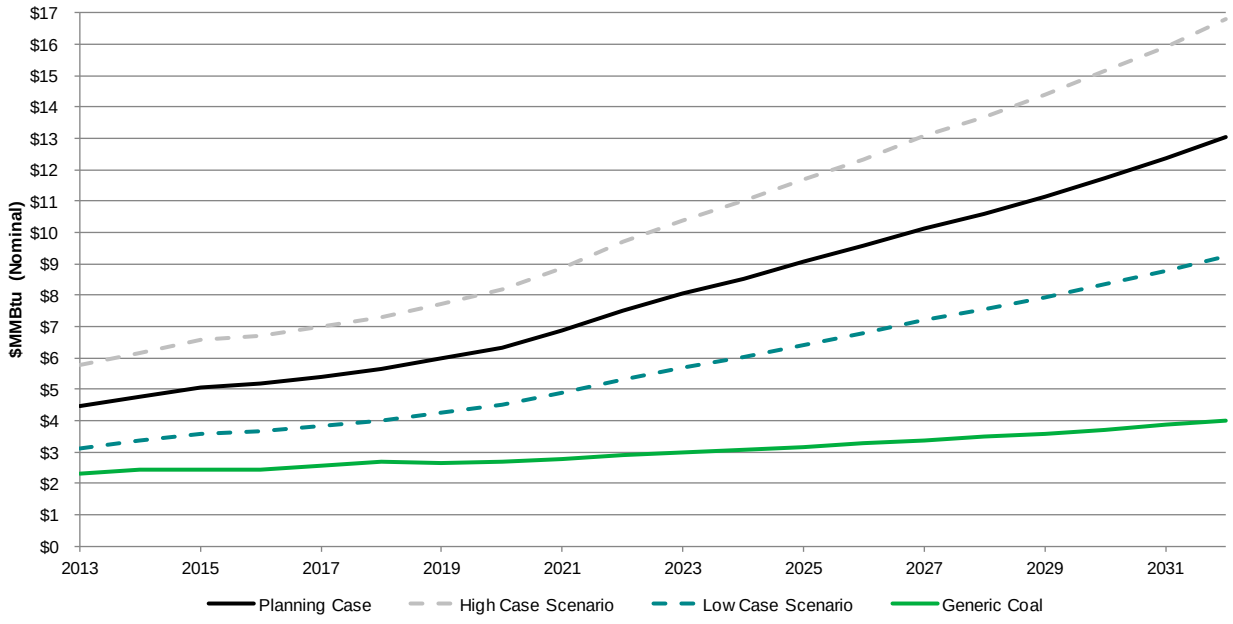
The tables indicate the southwest orientation in Boise has a 25.7 percent capacity factor from 6:00 to 7:00 pm in July and the south orientation has a 1.5 percent capacity factor during the same hour in July. Even though the southwestern exposure has a considerably greater capacity factor in late afternoon in July, the southwestern exposure capacity factor is still only 26 percent during the 6:00 to 7:00 pm hour in July. To meet a 100 MW capacity deficit during the 6:00 to 7:00 pm hour in July would require almost 400 MW of installed nameplate solar PV according to the NREL data. It is likely that the $90^{th}$ percentile exceedance criteria used by Idaho Power for capacity resource planning would further increase the quantity of solar generation needed to address a capacity deficit.

# FUEL DATA

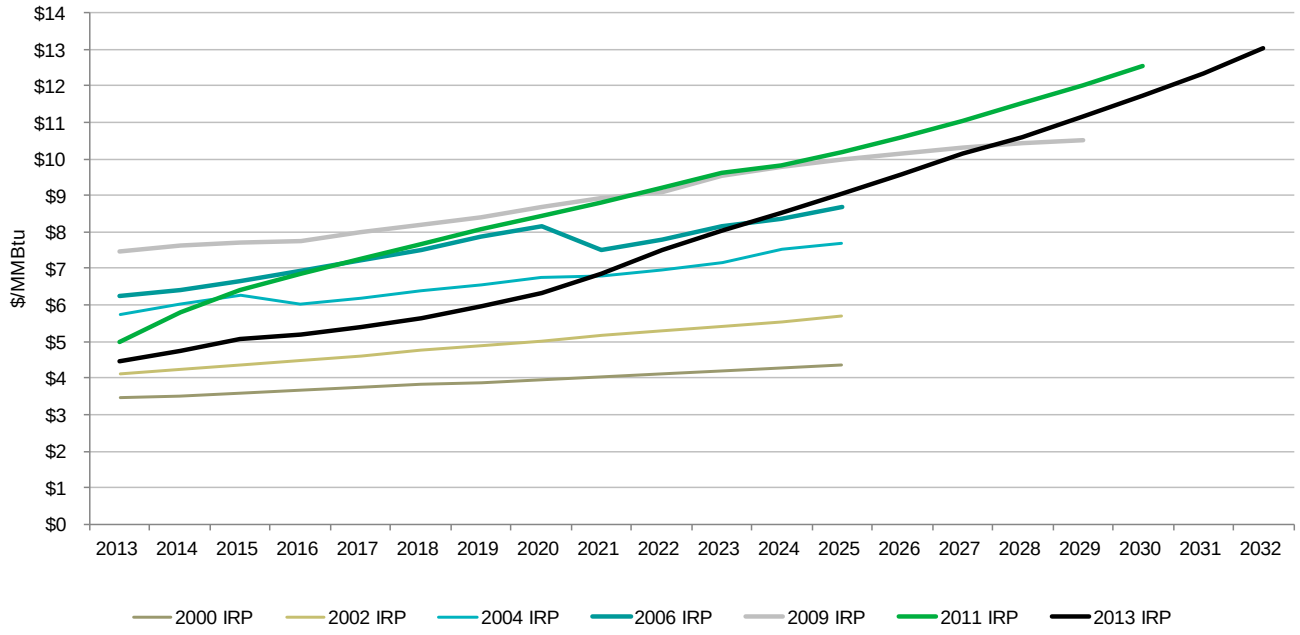
## Natural Gas and Coal Price Forecast

| Year | Sumas (Expected) | Sumas (High) | Sumas (Low) | Regional Coal |
|---|---|---|---|---|
| 2013 | $4.46 | $5.79 | $3.13 | $2.32 |
| 2014 | $4.76 | $6.17 | $3.36 | $2.44 |
| 2015 | $5.06 | $6.56 | $3.57 | $2.42 |
| 2016 | $5.19 | $6.71 | $3.66 | $2.45 |
| 2017 | $5.40 | $6.98 | $3.81 | $2.56 |
| 2018 | $5.64 | $7.29 | $3.99 | $2.68 |
| 2019 | $5.98 | $7.73 | $4.23 | $2.64 |
| 2020 | $6.34 | $8.18 | $4.49 | $2.70 |
| 2021 | $6.87 | $8.87 | $4.87 | $2.79 |
| 2022 | $7.51 | $9.69 | $5.32 | $2.89 |
| 2023 | $8.05 | $10.40 | $5.71 | $2.98 |
| 2024 | $8.52 | $11.00 | $6.04 | $3.07 |
| 2025 | $9.05 | $11.68 | $6.42 | $3.17 |
| 2026 | $9.56 | $12.34 | $6.78 | $3.27 |
| 2027 | $10.14 | $13.08 | $7.19 | $3.38 |
| 2028 | $10.61 | $13.69 | $7.53 | $3.48 |
| 2029 | $11.14 | $14.38 | $7.91 | $3.59 |
| 2030 | $11.74 | $15.15 | $8.33 | $3.71 |
| 2031 | $12.34 | $15.93 | $8.76 | $3.87 |
| 2032 | $13.03 | $16.81 | $9.25 | $4.00 |

**Sumas Natural Gas and Coal Price Forecast**



**Sumas Natural Gas Price Forecast Comparison (planning case)**



# EXISTING RESOURCE DATA

## Hydroelectric and Thermal Plant Data

| Hydroelectric Power Plants | Nameplate kVA | Nameplate kW | Normal Rating kW[4] | Emergency Rating kW[5] |
|---|---|---|---|---|
| American Falls | 102,600 | 92,340 | 92,340 | 106,190 |
| Bliss | 86,250 | 75,000 | 75,000 | 84,860 |
| Brownlee | 650,444 | 585,400 | 585,400 | 678,040 |
| Cascade | 13,800 | 12,420 | 12,420 | 14,280 |
| C.J. Strike | 90,000 | 82,800 | 82,800 | 95,420 |
| Clear Lake | 3,125 | 2,500[1] | 2,420 | 2,430 |
| Hells Canyon | 435,000 | 391,500 | 391,500 | 449,580 |
| Lower Salmon | 70,000 | 60,000 | 60,000 | 69,140 |
| Malad–Lower | 15,500 | 13,500 | 13,500 | 13,500 |
| Malad–Upper | 9,650 | 8,270 | 8,270 | 8,400 |
| Milner | 62,890 | 59,448 | 59,448 | 61,880 |
| Oxbow | 211,112 | 190,000 | 190,000 | 218,520 |
| Shoshone Falls | 14,900 | 12,500[1] | 12,500 | 12,500 |
| Swan Falls | 28,600 | 27,170 | 24,170[3] | 24,170 |
| Thousand Springs | 11,000 | 8,800 | 6,380[2] | 6,380 |
| Twin Falls | 56,175 | 52,897 | 52,561 | 54,170 |
| Upper Salmon “A” | 18,000 | 18,000 | 18,000 | 18,000 |
| Upper Salmon “B” | 18,000 | 16,500 | 16,500 | 16,560 |
| **Total Hydro** | **1,897,046** | **1,709,045** | | |

| Thermal, Natural Gas, and Diesel Power Plants | Generator Nameplate Rating Gross kVA | Generator Nameplate Rating Gross kW | Net Dependable Capability (NDC)[6,7] kW | Net Dependable Capability (NDC)[6,7] Summer kW | Net Dependable Capability (NDC)[6,7] Winter kW |
|---|---|---|---|---|---|
| Bridger (Idaho Power share) | 811,053 | 770,501 | | 703,667 | 703,667 |
| Boardman (Idaho Power share) | 67,600 | 64,200 | | 57,800 | 58,300 |
| Valmy (Idaho Power share) | 315,000 | 283,500 | | 261,000 | 261,000 |
| **Total Thermal** | **1,193,653** | **1,118,201** | | | |
| Bennett Mountain | 192,000 | 172,800 | 164,159 | | |
| Evander Andrews Unit #1 | 199,000 | 179,100 | 170,955 | | |
| Evander Andrews Unit #2 | 51,000 | 45,900 | 45,405 | | |
| Evander Andrews Unit #3 | 51,000 | 45,900 | 45,066 | | |
| Langley Gulch CT | 220,000 | 187,000 | 176,880 | | |
| Langley Gulch ST | 154,650 | 131,452 | 122,765 | | |
| **Total Natural Gas** | **867,650** | **762,152** | | | |
| Salmon Diesel | 6,880 | 5,000 | 5,500 | | |
| **Total IPC Generation** | **3,965,229** | **3,594,398** | | | |

1 A power factor rating of 0.8 is assumed on four units (Clear Lake, Shoshone Falls unit 2, and Thousand Springs units 1 and 2) with a total kVA rating of 6,127 kVA where there is no nameplate kW rating.

2 The two smaller units, 1 and 2, have nameplate ratings of 1.25 MVA and 1 MW and are not in service due to reduced flows from the springs and penstock integrity.

3 The Swan Falls units have been limited to 24,170 kW as a result of vibration issues.

4 Normal Rating is the normal kW output of the facility with all units on-line. This rating includes all equipment limitations and may be lower than the nameplate rating. To operate at the Normal Rating, appropriate water conditions must exist and the FERC license requirements permit.

5 Emergency Rating is the maximum kW output of the facility with all units on-line. The Emergency Rating is based on manufacturer guidelines, ANSI standards, and limited by auxiliary equipment ratings. To operate at the Emergency Rating, appropriate water conditions must exist and the FERC license requirements permit.

6 Ratings for coal-fired generators are provided by Idaho Power's thermal partners who operate these plants.

7 NDC is defined in the NERC Generating Availability Data System (GADS) as Gross Dependable Capacity (GDC) less the unit capacity utilized for that unit's station service or auxiliaries. GDC is the Gross Maximum Capacity (GMC) modified for seasonal limitations over a specified period of time. The GDC and Maximum Dependable Capacity (MDC) used in previous GADS reports are the same in intent and purpose. GMC is the maximum capacity a unit can sustain over a specified period of time when not restricted by seasonal or other de-ratings.

# Qualifying Facility Data (PURPA)

**Cogeneration and Small Power Production Projects**

**Status as of June 17, 2013.**

| Project | MW | Contract On-line Date | Contract End Date | Project | MW | Contract On-line Date | Contract End Date |
|---|---|---|---|---|---|---|---|
| **Hydro Projects** | | | | | | | |
| Arena Drop | 0.45 | Sep-2010 | Sep-2030 | Lowline Canal | 2.50 | May-1985 | Apr-2005 |
| Barber Dam | 3.70 | Apr-1989 | Apr-2024 | Lowline Midway Hydro | 7.97 | Aug-2007 | Aug-2027 |
| Birch Creek | 0.05 | Nov-1984 | Oct-2019 | Lowline #2 | 2.79 | Apr-1988 | Apr-2023 |
| Black Canyon #3 | 0.14 | Apr-1984 | Apr-2019 | Magic Reservoir | 9.07 | Jun-1989 | May-2024 |
| Blind Canyon | 1.50 | Dec-1994 | Dec-2014 | Malad River | 0.62 | May-1984 | Apr-2019 |
| Box Canyon | 0.36 | Feb-1984 | Feb-2019 | Marco Ranches | 1.20 | Aug-1985 | Jul-2020 |
| Briggs Creek | 0.60 | Oct-1985 | Oct-2020 | Mile 28 | 1.50 | Jun-1994 | May-2029 |
| Bypass | 9.96 | Jun-1988 | Jun-2023 | Mill Creek | 0.80 | Nov-2011 | Jun-2017 |
| Canyon Springs | 0.13 | Oct-1984 | Non firm | Mitchell Butte | 2.09 | May-1989 | May-2024 |
| Cedar Draw | 1.55 | Jun-1984 | May-2019 | Mora Drop | 1.90 | Oct-2006 | Sep-2026 |
| Clark Canyon | 4.70 | Dec-2013 | Estimated | Mud Creek S&S | 0.52 | Feb-1982 | Feb-2017 |
| Clear Springs Trout | 0.52 | Nov-1983 | Oct-2018 | Mud Creek White | 0.21 | Jan-1986 | Jan-2021 |
| Crystal Springs | 2.44 | Apr-1986 | Mar-2021 | Owyhee Dam CSPP | 5.00 | Aug-1985 | Aug-2015 |
| Curry Cattle Company | 0.22 | Jun-1983 | Jun-2018 | Pigeon Cove | 1.89 | Oct-1984 | Oct-2019 |
| Dietrich Drop | 4.50 | Aug-1988 | Aug-2023 | Pristine Springs | 0.13 | May-2005 | Apr-2015 |
| Elk Creek | 2.00 | May-1986 | May-2021 | Pristine Springs #3 | 0.20 | May-2005 | Apr-2015 |
| Falls River | 9.10 | Aug-1993 | Aug-2028 | Reynolds Irrigation | 0.26 | May-1986 | May-2021 |
| Fargo Drop | 1.27 | Apr-2013 | Apr-2033 | Rock Creek #1 | 2.05 | Sep-1983 | Sep-2018 |
| Faulkner Ranch | 0.87 | Aug-1987 | Aug-2022 | Rock Creek #2 | 1.90 | Apr-1989 | Mar-2024 |
| Fisheries Development Co | 0.26 | Jul-1990 | Non firm | Sagebrush | 0.43 | Sep-1985 | Aug-2020 |
| Geo Bon #2 | 0.93 | Nov-1986 | Nov-2021 | Sahko Hydro | 0.50 | Jun-2006 | Feb-2021 |
| Hailey CSPP | 0.06 | Jun-1985 | Jun-2020 | Schaffner | 0.53 | Aug-1986 | Jul-2021 |
| Hazelton A | 8.10 | Jun-1990 | Mar-2026 | Shingle Creek | 0.22 | Aug-1983 | Jul-2018 |
| Hazelton B | 7.60 | May-1993 | Apr-2028 | Shoshone #2 | 0.58 | May-1996 | Apr-2031 |
| Horseshoe Bend Hydroelectric | 9.50 | Sep-1995 | Sep-2030 | Shoshone CSPP | 0.37 | Jun-1982 | Jun-2017 |
| Jim Knight | 0.34 | Jun-1985 | Jun-2020 | Snake River Pottery | 0.07 | Nov-1984 | Nov-2019 |
| Kasel and Witherspoon | 0.90 | Mar-1984 | Feb-2019 | Snedigar | 0.54 | Jan-1985 | Dec-2019 |
| Koyle Small Hydro | 1.25 | Apr-1984 | Mar-2019 | Tiber Dam | 7.50 | Jun-2004 | May-2024 |
| Lateral # 10 | 2.06 | May-1985 | Apr-2020 | Trout—Co | 0.24 | Dec-1986 | Nov-2021 |
| Lemoyne | 0.08 | Jun-1985 | Jun-2020 | Tunnel #1 | 7.00 | Jun-1993 | May-2028 |
| Little Wood Rvr Res | 2.85 | Feb-1985 | Feb-2020 | White Water Ranch | 0.16 | Aug-1985 | Jul-2020 |
| Littlewood–Arkoosh | 0.87 | Aug-1986 | Jul-2021 | Wilson Lake Hydro | 8.40 | May-1993 | May-2028 |
| **Total Hydro Nameplate Rating 147.92 MW** | | | | | | | |
| **Thermal Projects** | | | | | | | |
| Magic Valley Natural Gas | 10.00 | Nov-1996 | Nov-2016 | TASCO—Nampa Natural Gas | 2.00 | Sep-2003 | Non firm |
| Magic West Natural Gas | 10.00 | Dec-1996 | Nov-2016 | TASCO—Twin Falls Natural Gas | 3.00 | Aug-2001 | Non firm |
| Simplot Pocatello Cogen | 15.90 | Mar-2013 | Feb-2016 | | | | |
| **Total Thermal Nameplate Rating 40.90 MW** | | | | | | | |

| Project | MW | Contract On-line Date | Contract End Date | Project | MW | Contract On-line Date | Contract End Date |
|---|---|---|---|---|---|---|---|
| **Biomass Projects** | | | | | | | |
| B6 Anaerobic Digester | 2.28 | Aug-2009 | Aug-2019 | Hidden Hollow Landfill Gas | 3.20 | Oct-2006 | Jan-2027 |
| Bettencourt Dry Creek | 2.25 | Aug-2008 | Aug-2018 | Pocatello Waste | 0.46 | Dec-1985 | Dec-2020 |
| Big Sky West Dairy Digester | 1.50 | Jan-2009 | Jan-2029 | Rock Creek Dairy | 4.00 | May-2012 | Aug-2027 |
| Double A Digester Project | 4.50 | Jan-2012 | Jan-2032 | Tamarack CSPP | 5.00 | Jun-1983 | May-2018 |
| **Total Biomass Nameplate Rating 23.19 MW** | | | | | | | |
| **Wind Projects** | | | | | | | |
| Bennett Creek Wind Farm | 21.00 | Dec-2008 | Dec-2028 | Milner Dam Wind | 19.92 | Feb-2011 | Feb-2031 |
| Burley Butte Wind | 21.30 | Feb-2011 | Feb-2031 | Oregon Trail Wind | 13.50 | Jan-2011 | Jan-2031 |
| Camp Reed Wind Park | 22.50 | Dec-2010 | Dec-2030 | Payne's Ferry Wind Park | 21.00 | Dec-2010 | Dec-2030 |
| Cassia Wind Farm | 10.50 | Mar-2009 | Mar-2029 | Pilgrim Stage Station Wind | 10.50 | Jan-2011 | Jan-2031 |
| Cold Springs Windfarm | 23.00 | Dec-2012 | Dec-2032 | Rockland Wind Project | 80.00 | Dec-2011 | Dec-2031 |
| Desert Meadow Windfarm | 23.00 | Dec-2012 | Dec-2032 | Ryegrass Windfarm | 23.00 | Dec-2012 | Dec-2032 |
| Fossil Gulch Wind | 10.50 | Sep-2005 | Sep-2025 | Salmon Falls Wind | 22.00 | Apr-2011 | Apr-2031 |
| Golden Valley Wind | 12.00 | Feb-2011 | Feb-2031 | Sawtooth Wind Project | 22.00 | Nov-2011 | Nov-2031 |
| Hammett Hill Windfarm | 23.00 | Dec-2012 | Dec-2032 | Thousand Springs Wind | 12.00 | Jan-2011 | Jan-2031 |
| High Mesa | 40.00 | Dec-2012 | Dec-2032 | Tuana Gulch Wind | 10.50 | Jan-2011 | Jan-2031 |
| Horseshoe Bend Wind Park | 9.00 | Feb-2006 | Feb-2026 | Tuana Springs Expansion | 35.70 | May-2010 | Jun-2030 |
| Hot Springs Wind Farm | 21.00 | Dec-2008 | Dec-2028 | Two Ponds Windfarm | 23.00 | Dec-2012 | Dec-2012 |
| Lime Wind Energy | 3.00 | Dec-2011 | Dec-2031 | Yahoo Creek Wind Park | 21.00 | Dec-2010 | Dec-2030 |
| Mainline Windfarm | 23.00 | Dec-2012 | Dec-2032 | | | | |
| **Total Wind Nameplate Rating 576.92 MW** | | | | | | | |
| **Total Nameplate Rating 788.93 MW** | | | | | | | |

The above is a summary of the nameplate rating for the CSPP projects under contract with Idaho Power as of June 17, 2013. In the case of CSPP projects, nameplate rating of the actual generation units is not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource-specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy these projects will produce.

# Power Purchase Agreement Data

**Idaho Power Company Power Purchase Agreements Status as of April 1, 2013**

| Project | MW | Contract On-Line Date | Contract End Date |
|---|---|---|---|
| **Wind projects** | | | |
| Elkhorn Wind Project | 101 | December 2007 | December 2027 |
| **Total wind nameplate MW rating** | 101 | | |
| **Geothermal Projects** | | | |
| Raft River Unit 1 | 13 | April 2008 | April 2033 |
| Neal Hot Springs | 22 | September 2012 | September 2037 |
| **Total geothermal nameplate MW rating** | 35 | | |
| **Total nameplate MW rating** | 136 | | |

Above is a summary of the nameplate ratings for the Power Purchase Agreements under contract with Idaho Power. Nameplate ratings of the actual generation units are not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource-specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy the projects will produce.

# Hydro Modeling Results (PDR580)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2013** | **2/2013** | **3/2013** | **4/2013** | **5/2013** | **6/2013** | **7/2013** | **8/2013** | **9/2013** | **10/2013** | **11/2013** | **12/2013** | **aMW** |
| Brownlee | HCC* | 343.1 | 293.0 | 343.5 | 435.3 | 421.2 | 424.5 | 242.8 | 170.4 | 215.4 | 193.2 | 152.6 | 253.0 | 290.7 |
| Oxbow | HCC | 143.5 | 127.9 | 150.4 | 181.0 | 168.9 | 171.1 | 103.2 | 78.0 | 98.7 | 88.8 | 69.4 | 106.5 | 123.9 |
| Hells Canyon | HCC | 282.0 | 255.2 | 304.1 | 371.7 | 348.1 | 345.5 | 204.8 | 153.1 | 193.8 | 175.2 | 138.2 | 211.3 | 248.6 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 23.6 | 24.4 | 24.3 | 51.0 | 80.6 | 88.2 | 81.8 | 67.7 | 41.1 | 15.3 | 0.0 | 13.5 | 42.6 |
| Bliss | ROR | 49.5 | 49.5 | 42.8 | 49.8 | 46.8 | 42.9 | 35.5 | 32.1 | 37.8 | 40.4 | 38.3 | 42.6 | 42.3 |
| C .J. Strike | ROR | 64.4 | 64.9 | 57.1 | 64.4 | 62.0 | 53.6 | 38.3 | 34.8 | 45.3 | 51.5 | 50.5 | 55.4 | 53.5 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 34.9 | 35.0 | 28.5 | 34.6 | 33.1 | 29.2 | 23.1 | 19.4 | 24.2 | 26.3 | 24.7 | 29.5 | 28.5 |
| Milner | ROR | 40.1 | 40.2 | 20.7 | 36.3 | 31.4 | 18.2 | 5.9 | 6.7 | 0.0 | 0.0 | 4.6 | 24.3 | 19.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.7 | 10.5 | 12.0 | 12.0 | 11.4 |
| Swan Falls | ROR | 20.8 | 21.1 | 18.6 | 20.9 | 20.0 | 17.5 | 13.3 | 12.1 | 15.2 | 17.0 | 16.7 | 18.1 | 17.6 |
| Twin Falls | ROR | 39.6 | 39.9 | 22.4 | 35.9 | 32.1 | 21.7 | 10.2 | 11.5 | 0.0 | 6.6 | 9.2 | 25.9 | 21.3 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 18.9 | 14.1 | 11.5 | 14.9 | 16.4 | 15.1 | 19.0 | 16.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 17.4 | 13.3 | 11.0 | 13.9 | 15.2 | 14.1 | 17.5 | 15.7 |
| **HCC Total** | | **768.6** | **676.1** | **798.0** | **988.0** | **938.1** | **941.1** | **550.8** | **401.5** | **507.9** | **457.2** | **360.2** | **570.8** | **663.2** |
| **ROR Total** | | **348.3** | **349.8** | **285.5** | **370.9** | **388.0** | **357.5** | **283.2** | **258.3** | **236.1** | **228.4** | **209.3** | **284.5** | **300.0** |
| **Total** | | **1116.9** | **1025.9** | **1083.5** | **1358.9** | **1326.0** | **1298.6** | **834.0** | **659.8** | **744.0** | **685.6** | **569.5** | **855.3** | **963.2** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2014** | **2/2014** | **3/2014** | **4/2014** | **5/2014** | **6/2014** | **7/2014** | **8/2014** | **9/2014** | **10/2014** | **11/2014** | **12/2014** | **aMW** |
| Brownlee | HCC* | 342.2 | 292.5 | 342.6 | 435.0 | 420.5 | 423.9 | 242.2 | 169.8 | 213.6 | 194.0 | 152.9 | 247.9 | 289.8 |
| Oxbow | HCC | 143.1 | 127.7 | 150.0 | 180.9 | 168.6 | 170.9 | 103.0 | 77.7 | 97.7 | 88.9 | 69.3 | 104.3 | 123.5 |
| Hells Canyon | HCC | 281.3 | 254.9 | 303.3 | 371.4 | 347.5 | 345.1 | 204.3 | 152.6 | 191.7 | 175.4 | 138.1 | 207.0 | 247.7 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 22.3 | 24.2 | 23.6 | 50.7 | 79.6 | 88.1 | 81.8 | 67.6 | 41.0 | 15.2 | 0.0 | 11.0 | 42.1 |
| Bliss | ROR | 49.0 | 49.3 | 42.3 | 49.6 | 46.8 | 42.8 | 35.3 | 31.9 | 37.6 | 40.2 | 38.1 | 42.4 | 42.1 |
| C .J. Strike | ROR | 64.1 | 64.6 | 56.8 | 64.1 | 61.8 | 53.3 | 38.1 | 34.6 | 45.0 | 51.3 | 50.3 | 53.2 | 53.1 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 34.5 | 34.9 | 27.8 | 34.4 | 32.5 | 29.1 | 23.0 | 19.3 | 24.0 | 26.2 | 24.5 | 28.9 | 28.3 |
| Milner | ROR | 38.2 | 39.9 | 18.7 | 36.0 | 30.5 | 18.2 | 5.9 | 6.7 | 0.0 | 0.0 | 4.6 | 20.1 | 18.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.7 | 10.5 | 12.0 | 12.0 | 11.4 |
| Swan Falls | ROR | 20.5 | 21.0 | 18.5 | 20.8 | 19.9 | 17.4 | 13.3 | 12.1 | 15.1 | 16.9 | 16.5 | 17.5 | 17.5 |
| Twin Falls | ROR | 37.9 | 39.7 | 21.8 | 35.7 | 31.2 | 21.7 | 10.2 | 11.5 | 0.0 | 6.6 | 9.2 | 22.1 | 20.6 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.2 | 18.8 | 14.1 | 11.4 | 14.8 | 16.3 | 15.0 | 18.5 | 16.6 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 17.3 | 13.2 | 10.9 | 13.8 | 15.1 | 14.0 | 17.0 | 15.6 |
| **HCC Total** | | **766.6** | **675.1** | **795.9** | **987.3** | **936.5** | **939.9** | **549.5** | **400.1** | **502.9** | **458.3** | **360.3** | **559.2** | **661.0** |
| **ROR Total** | | **341.9** | **348.4** | **280.6** | **369.3** | **384.4** | **356.6** | **282.6** | **257.5** | **235.0** | **227.5** | **208.3** | **269.4** | **296.8** |
| **Total** | | **1108.5** | **1023.5** | **1076.5** | **1356.6** | **1320.8** | **1296.5** | **832.1** | **657.6** | **737.9** | **685.8** | **568.6** | **828.6** | **957.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2015** | **2/2015** | **3/2015** | **4/2015** | **5/2015** | **6/2015** | **7/2015** | **8/2015** | **9/2015** | **10/2015** | **11/2015** | **12/2015** | **aMW** |
| Brownlee | HCC* | 350.5 | 292.8 | 342.1 | 440.5 | 435.0 | 438.7 | 242.3 | 169.7 | 222.1 | 192.9 | 152.6 | 255.1 | 294.5 |
| Oxbow | HCC | 146.5 | 127.9 | 149.8 | 183.1 | 174.2 | 176.7 | 103.0 | 77.7 | 100.3 | 89.0 | 69.4 | 107.4 | 125.4 |
| Hells Canyon | HCC | 287.9 | 255.1 | 302.9 | 375.8 | 358.7 | 356.4 | 204.3 | 152.5 | 195.9 | 175.5 | 138.3 | 213.1 | 251.4 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 24.5 | 24.6 | 25.2 | 59.0 | 86.2 | 91.8 | 82.4 | 68.5 | 41.5 | 17.2 | 0.0 | 16.7 | 44.8 |
| Bliss | ROR | 49.8 | 49.4 | 42.2 | 53.0 | 51.0 | 44.8 | 35.3 | 31.9 | 37.6 | 40.4 | 38.7 | 46.2 | 43.4 |
| C .J. Strike | ROR | 65.3 | 65.1 | 56.9 | 68.0 | 66.4 | 55.2 | 38.0 | 34.5 | 44.9 | 51.6 | 50.8 | 58.6 | 54.6 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 35.2 | 34.9 | 27.8 | 37.4 | 36.7 | 30.2 | 23.0 | 19.2 | 23.9 | 26.4 | 24.7 | 32.1 | 29.3 |
| Milner | ROR | 41.5 | 40.4 | 20.5 | 44.3 | 40.9 | 22.9 | 5.9 | 6.7 | 0.0 | 0.0 | 5.5 | 29.7 | 21.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.7 | 10.5 | 12.0 | 12.0 | 11.4 |
| Swan Falls | ROR | 21.0 | 21.2 | 18.6 | 21.9 | 21.4 | 18.0 | 13.3 | 12.1 | 15.1 | 17.0 | 16.8 | 19.0 | 18.0 |
| Twin Falls | ROR | 41.5 | 40.2 | 22.1 | 43.6 | 40.4 | 25.5 | 10.2 | 11.5 | 0.0 | 6.6 | 9.5 | 30.6 | 23.5 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 19.2 | 14.0 | 11.3 | 14.7 | 16.4 | 15.2 | 19.2 | 16.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 16.5 | 16.8 | 17.4 | 17.7 | 13.2 | 10.9 | 13.8 | 15.2 | 14.2 | 17.7 | 15.7 |
| **HCC Total** | | **784.9** | **675.8** | **794.8** | **999.4** | **967.9** | **971.8** | **549.6** | **399.9** | **518.2** | **457.4** | **360.3** | **575.6** | **671.3** |
| **ROR Total** | | **354.2** | **350.6** | **284.4** | **405.2** | **424.9** | **375.2** | **283.0** | **258.1** | **235.3** | **230.5** | **211.5** | **308.5** | **310.1** |
| **Total** | | **1139.1** | **1026.4** | **1079.2** | **1404.6** | **1392.8** | **1347.0** | **832.6** | **658.0** | **753.5** | **687.9** | **571.8** | **884.1** | **981.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2016** | **2/2016** | **3/2016** | **4/2016** | **5/2016** | **6/2016** | **7/2016** | **8/2016** | **9/2016** | **10/2016** | **11/2016** | **12/2016** | **aMW** |
| Brownlee | HCC* | 349.6 | 295.1 | 341.2 | 440.2 | 434.2 | 438.2 | 241.7 | 156.9 | 216.9 | 193.3 | 152.6 | 254.6 | 292.9 |
| Oxbow | HCC | 146.1 | 128.8 | 149.4 | 183.0 | 173.9 | 176.4 | 102.7 | 71.6 | 99.7 | 89.1 | 69.4 | 107.2 | 124.8 |
| Hells Canyon | HCC | 287.2 | 257.0 | 302.1 | 375.6 | 358.1 | 356.0 | 203.8 | 141.1 | 195.7 | 175.8 | 138.3 | 212.6 | 250.3 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 24.3 | 24.4 | 25.0 | 58.8 | 86.0 | 91.8 | 82.3 | 64.3 | 42.2 | 17.4 | 0.0 | 20.6 | 44.8 |
| Bliss | ROR | 49.5 | 49.2 | 42.0 | 52.9 | 50.8 | 44.7 | 35.2 | 28.1 | 37.4 | 40.4 | 38.7 | 48.5 | 43.1 |
| C .J. Strike | ROR | 65.0 | 64.9 | 57.2 | 67.7 | 66.1 | 55.0 | 37.8 | 29.7 | 44.7 | 51.6 | 51.1 | 61.8 | 54.4 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 35.0 | 34.7 | 27.6 | 37.6 | 36.5 | 30.1 | 22.9 | 16.0 | 23.8 | 26.3 | 24.7 | 34.1 | 29.1 |
| Milner | ROR | 41.2 | 40.2 | 20.1 | 43.9 | 40.6 | 22.5 | 5.9 | 0.0 | 0.0 | 0.0 | 5.5 | 36.0 | 21.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 21.0 | 21.1 | 18.6 | 21.8 | 21.3 | 17.9 | 13.2 | 10.4 | 15.0 | 17.0 | 16.9 | 19.9 | 17.8 |
| Twin Falls | ROR | 41.3 | 39.9 | 21.7 | 43.3 | 40.2 | 25.3 | 10.2 | 0.0 | 0.0 | 6.6 | 10.0 | 36.1 | 22.9 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 19.2 | 13.9 | 8.8 | 14.6 | 16.4 | 15.1 | 19.1 | 16.4 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 16.4 | 16.8 | 17.4 | 17.7 | 13.1 | 8.8 | 13.7 | 15.2 | 14.1 | 17.7 | 15.5 |
| **HCC Total** | | **782.9** | **680.9** | **792.7** | **998.8** | **966.2** | **970.6** | **548.2** | **369.6** | **512.2** | **458.2** | **360.3** | **574.4** | **667.9** |
| **ROR Total** | | **352.7** | **349.2** | **283.2** | **404.0** | **423.4** | **374.1** | **282.2** | **212.5** | **235.1** | **230.6** | **212.2** | **332.5** | **307.6** |
| **Total** | | **1135.6** | **1030.1** | **1075.9** | **1402.8** | **1389.6** | **1344.7** | **830.4** | **582.1** | **747.3** | **688.8** | **572.5** | **906.9** | **975.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2017** | **2/2017** | **3/2017** | **4/2017** | **5/2017** | **6/2017** | **7/2017** | **8/2017** | **9/2017** | **10/2017** | **11/2017** | **12/2017** | **aMW** |
| Brownlee | HCC* | 349.0 | 292.0 | 338.8 | 440.0 | 433.1 | 437.7 | 241.2 | 156.4 | 215.0 | 193.5 | 152.4 | 254.5 | 292.0 |
| Oxbow | HCC | 145.9 | 127.5 | 148.4 | 182.9 | 173.5 | 176.3 | 102.5 | 71.4 | 98.7 | 89.0 | 69.3 | 107.2 | 124.4 |
| Hells Canyon | HCC | 286.7 | 254.5 | 300.2 | 375.4 | 357.2 | 355.6 | 203.4 | 140.6 | 193.6 | 175.6 | 138.0 | 212.5 | 249.4 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 24.1 | 24.2 | 24.8 | 58.2 | 85.5 | 91.4 | 82.2 | 64.2 | 42.5 | 17.3 | 0.0 | 20.6 | 44.6 |
| Bliss | ROR | 49.4 | 49.1 | 41.8 | 51.6 | 50.4 | 44.6 | 35.0 | 28.0 | 37.3 | 40.2 | 38.7 | 48.2 | 42.9 |
| C .J. Strike | ROR | 64.8 | 64.7 | 56.5 | 66.6 | 65.6 | 54.8 | 37.7 | 29.5 | 44.5 | 51.4 | 50.9 | 61.5 | 54.0 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 34.8 | 34.5 | 27.0 | 36.7 | 36.1 | 30.1 | 22.8 | 15.8 | 23.6 | 26.2 | 24.5 | 33.9 | 28.8 |
| Milner | ROR | 41.0 | 40.0 | 18.2 | 42.1 | 40.0 | 22.3 | 5.9 | 0.0 | 0.0 | 0.0 | 5.5 | 36.0 | 20.9 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.9 | 21.1 | 18.4 | 21.5 | 21.2 | 17.9 | 13.1 | 10.4 | 15.0 | 16.9 | 16.8 | 19.8 | 17.8 |
| Twin Falls | ROR | 41.1 | 39.6 | 20.4 | 41.7 | 39.6 | 25.0 | 10.2 | 0.0 | 0.0 | 6.6 | 10.0 | 36.2 | 22.5 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 19.2 | 13.8 | 8.7 | 14.5 | 16.3 | 15.0 | 19.1 | 16.4 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 16.1 | 16.8 | 17.4 | 17.7 | 13.0 | 8.7 | 13.6 | 15.1 | 14.0 | 17.7 | 15.5 |
| **HCC Total** | | **781.6** | **674.0** | **787.4** | **998.3** | **963.8** | **969.6** | **547.1** | **368.4** | **507.2** | **458.1** | **359.7** | **574.2** | **665.8** |
| **ROR Total** | | **351.5** | **348.0** | **277.8** | **396.4** | **420.3** | **372.9** | **281.4** | **211.7** | **234.8** | **229.7** | **211.5** | **331.7** | **305.6** |
| **Total** | | **1133.1** | **1022.0** | **1065.2** | **1394.7** | **1384.1** | **1342.5** | **828.5** | **580.1** | **741.9** | **687.8** | **571.2** | **905.9** | **971.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2018** | **2/2018** | **3/2018** | **4/2018** | **5/2018** | **6/2018** | **7/2018** | **8/2018** | **9/2018** | **10/2018** | **11/2018** | **12/2018** | **aMW** |
| Brownlee | HCC* | 348.6 | 291.7 | 338.2 | 439.6 | 432.8 | 437.1 | 240.7 | 155.8 | 213.4 | 193.6 | 152.5 | 253.9 | 291.5 |
| Oxbow | HCC | 145.7 | 127.4 | 148.2 | 182.8 | 173.4 | 176.0 | 102.3 | 71.1 | 97.8 | 89.0 | 69.3 | 106.9 | 124.2 |
| Hells Canyon | HCC | 286.4 | 254.2 | 299.7 | 375.1 | 357.0 | 355.2 | 203.0 | 140.1 | 192.0 | 175.5 | 138.1 | 212.1 | 249.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 24.1 | 24.2 | 24.6 | 58.0 | 85.4 | 91.1 | 82.1 | 64.2 | 42.5 | 17.3 | 0.0 | 17.3 | 44.2 |
| Bliss | ROR | 49.3 | 49.0 | 41.2 | 51.4 | 49.9 | 44.5 | 34.9 | 27.8 | 37.2 | 40.0 | 38.4 | 45.7 | 42.4 |
| C .J. Strike | ROR | 64.7 | 64.5 | 56.3 | 66.4 | 64.8 | 54.4 | 37.5 | 29.3 | 44.2 | 51.0 | 50.5 | 58.5 | 53.5 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 34.8 | 34.4 | 26.6 | 35.4 | 35.7 | 30.0 | 22.6 | 15.7 | 23.5 | 26.0 | 24.4 | 31.8 | 28.4 |
| Milner | ROR | 41.0 | 40.0 | 15.5 | 40.1 | 38.8 | 22.3 | 5.9 | 0.0 | 0.0 | 0.0 | 5.5 | 30.6 | 20.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.9 | 20.9 | 18.4 | 21.4 | 21.0 | 17.7 | 13.1 | 10.3 | 14.9 | 16.9 | 16.7 | 19.0 | 17.6 |
| Twin Falls | ROR | 41.2 | 39.6 | 19.2 | 39.3 | 38.6 | 24.6 | 10.2 | 0.0 | 0.0 | 6.6 | 9.6 | 31.5 | 21.7 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 19.2 | 13.8 | 8.6 | 14.3 | 16.1 | 14.9 | 19.2 | 16.3 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.8 | 16.8 | 17.4 | 17.7 | 13.0 | 8.6 | 13.5 | 15.0 | 14.0 | 17.7 | 15.4 |
| **HCC Total** | | **780.7** | **673.3** | **786.1** | **997.5** | **963.1** | **968.3** | **546.0** | **367.0** | **503.2** | **458.1** | **359.9** | **572.9** | **664.7** |
| **ROR Total** | | **351.4** | **347.4** | **272.2** | **390.0** | **416.1** | **371.4** | **280.8** | **210.9** | **233.9** | **228.6** | **210.1** | **310.0** | **301.9** |
| **Total** | | **1132.1** | **1020.7** | **1058.3** | **1387.5** | **1379.2** | **1339.7** | **826.8** | **577.9** | **737.1** | **686.7** | **570.0** | **882.9** | **966.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2019** | **2/2019** | **3/2019** | **4/2019** | **5/2019** | **6/2019** | **7/2019** | **8/2019** | **9/2019** | **10/2019** | **11/2019** | **12/2019** | **aMW** |
| Brownlee | HCC* | 347.7 | 291.4 | 336.7 | 438.8 | 432.5 | 436.6 | 240.1 | 155.3 | 211.9 | 193.8 | 152.6 | 253.5 | 290.9 |
| Oxbow | HCC | 145.4 | 127.2 | 147.5 | 182.5 | 173.3 | 175.8 | 102.1 | 70.8 | 97.0 | 88.9 | 69.3 | 106.7 | 123.9 |
| Hells Canyon | HCC | 285.7 | 253.9 | 298.4 | 374.5 | 356.7 | 354.8 | 202.5 | 139.6 | 190.4 | 175.4 | 138.1 | 211.7 | 248.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 23.9 | 24.0 | 24.3 | 57.8 | 85.2 | 90.7 | 82.1 | 64.1 | 42.4 | 17.7 | 0.0 | 15.7 | 44.0 |
| Bliss | ROR | 49.1 | 48.8 | 40.8 | 51.0 | 49.7 | 44.4 | 34.7 | 27.7 | 37.0 | 39.9 | 38.2 | 44.6 | 42.2 |
| C .J. Strike | ROR | 64.4 | 64.3 | 55.7 | 66.1 | 64.5 | 54.1 | 37.2 | 29.1 | 44.0 | 50.9 | 49.9 | 57.0 | 53.1 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 34.6 | 34.2 | 26.2 | 34.5 | 35.5 | 29.8 | 22.5 | 15.5 | 23.3 | 25.9 | 24.1 | 30.7 | 28.1 |
| Milner | ROR | 40.7 | 39.6 | 14.7 | 36.2 | 38.6 | 21.7 | 5.9 | 0.0 | 0.0 | 0.0 | 5.5 | 28.0 | 19.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.8 | 20.8 | 18.2 | 21.4 | 20.9 | 17.7 | 13.0 | 10.2 | 14.8 | 16.8 | 16.4 | 18.6 | 17.5 |
| Twin Falls | ROR | 40.9 | 39.3 | 18.4 | 36.2 | 38.4 | 24.2 | 10.2 | 0.0 | 0.0 | 6.6 | 9.5 | 29.1 | 21.1 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 19.2 | 13.7 | 8.5 | 14.2 | 16.0 | 14.7 | 19.2 | 16.3 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.5 | 16.8 | 17.4 | 17.7 | 12.9 | 8.5 | 13.4 | 14.9 | 13.8 | 17.7 | 15.3 |
| **HCC Total** | | **778.8** | **672.5** | **782.6** | **995.8** | **962.5** | **967.2** | **544.7** | **365.7** | **499.2** | **458.1** | **360.0** | **571.9** | **663.2** |
| **ROR Total** | | **349.8** | **345.8** | **268.4** | **381.2** | **414.7** | **369.4** | **279.9** | **210.0** | **232.9** | **228.4** | **208.2** | **299.3** | **299.0** |
| **Total** | | **1128.6** | **1018.3** | **1051.0** | **1377.0** | **1377.2** | **1336.6** | **824.6** | **575.7** | **732.1** | **686.5** | **568.2** | **871.2** | **962.2** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2020** | **2/2020** | **3/2020** | **4/2020** | **5/2020** | **6/2020** | **7/2020** | **8/2020** | **9/2020** | **10/2020** | **11/2020** | **12/2020** | **aMW** |
| Brownlee | HCC* | 346.8 | 290.9 | 336.4 | 437.2 | 432.2 | 436.0 | 239.5 | 154.6 | 210.5 | 193.9 | 152.7 | 252.9 | 290.3 |
| Oxbow | HCC | 145.0 | 127.1 | 147.4 | 181.8 | 173.2 | 175.6 | 101.8 | 70.6 | 96.3 | 88.9 | 69.3 | 106.5 | 123.6 |
| Hells Canyon | HCC | 284.9 | 253.6 | 298.2 | 373.1 | 356.5 | 354.3 | 202.0 | 139.1 | 189.0 | 175.4 | 138.1 | 211.2 | 247.9 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 23.7 | 23.7 | 23.7 | 56.4 | 84.9 | 90.4 | 82.1 | 64.0 | 42.4 | 17.3 | 0.0 | 14.5 | 43.6 |
| Bliss | ROR | 48.8 | 48.6 | 40.8 | 50.6 | 49.5 | 44.2 | 34.6 | 27.5 | 36.8 | 39.8 | 38.1 | 43.7 | 41.9 |
| C .J. Strike | ROR | 64.0 | 64.0 | 55.6 | 65.6 | 64.3 | 53.8 | 37.0 | 28.9 | 43.7 | 50.6 | 49.7 | 55.7 | 52.7 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 34.4 | 34.0 | 26.2 | 34.2 | 35.3 | 29.6 | 22.4 | 15.4 | 23.1 | 25.7 | 24.0 | 29.9 | 27.9 |
| Milner | ROR | 40.4 | 39.3 | 14.8 | 35.4 | 38.3 | 21.1 | 5.9 | 0.0 | 0.0 | 0.0 | 5.5 | 26.0 | 18.9 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.4 | 20.5 | 18.2 | 21.2 | 20.9 | 17.6 | 12.9 | 10.2 | 14.8 | 16.8 | 16.3 | 18.2 | 17.3 |
| Twin Falls | ROR | 40.6 | 39.0 | 18.4 | 35.2 | 38.1 | 24.0 | 10.2 | 0.0 | 0.0 | 6.6 | 9.5 | 27.3 | 20.7 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 19.2 | 13.6 | 8.4 | 14.1 | 15.9 | 14.6 | 19.2 | 16.2 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.5 | 16.8 | 17.4 | 17.6 | 12.8 | 8.4 | 13.2 | 14.8 | 13.7 | 17.7 | 15.3 |
| **HCC Total** | | **776.7** | **671.6** | **782.0** | **992.1** | **961.8** | **965.9** | **543.3** | **364.3** | **495.7** | **458.2** | **360.1** | **570.6** | **661.9** |
| **ROR Total** | | **347.7** | **343.9** | **267.8** | **376.6** | **413.3** | **367.4** | **279.2** | **209.2** | **231.8** | **227.2** | **207.5** | **290.9** | **296.9** |
| **Total** | | **1124.4** | **1015.5** | **1049.8** | **1368.7** | **1375.0** | **1333.3** | **822.5** | **573.5** | **727.5** | **685.4** | **567.6** | **861.5** | **958.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2021** | **2/2021** | **3/2021** | **4/2021** | **5/2021** | **6/2021** | **7/2021** | **8/2021** | **9/2021** | **10/2021** | **11/2021** | **12/2021** | **aMW** |
| Brownlee | HCC* | 345.7 | 290.4 | 335.4 | 433.8 | 431.9 | 435.4 | 238.8 | 154.0 | 207.9 | 194.5 | 152.6 | 252.5 | 289.4 |
| Oxbow | HCC | 144.5 | 126.8 | 147.0 | 180.4 | 173.0 | 175.4 | 101.5 | 70.2 | 94.9 | 88.9 | 69.2 | 106.3 | 123.2 |
| Hells Canyon | HCC | 284.1 | 253.1 | 297.4 | 370.5 | 356.2 | 353.8 | 201.5 | 138.5 | 186.2 | 175.4 | 137.9 | 210.9 | 247.1 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 23.5 | 23.5 | 22.3 | 56.1 | 84.5 | 89.8 | 82.1 | 63.9 | 42.2 | 16.5 | 0.0 | 13.2 | 43.1 |
| Bliss | ROR | 48.6 | 48.3 | 40.4 | 50.4 | 49.3 | 44.1 | 34.4 | 27.3 | 36.6 | 39.6 | 37.7 | 43.2 | 41.7 |
| C .J. Strike | ROR | 63.7 | 63.6 | 55.3 | 64.4 | 63.9 | 53.4 | 36.8 | 28.6 | 43.5 | 50.4 | 49.5 | 54.3 | 52.3 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 34.1 | 33.8 | 25.9 | 33.8 | 35.1 | 29.5 | 22.2 | 15.2 | 23.0 | 25.6 | 23.7 | 29.4 | 27.6 |
| Milner | ROR | 40.2 | 38.9 | 14.1 | 35.0 | 37.9 | 20.8 | 5.9 | 0.0 | 0.0 | 0.0 | 5.1 | 23.8 | 18.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.3 | 20.4 | 18.1 | 20.9 | 20.8 | 17.5 | 12.9 | 10.1 | 14.7 | 16.7 | 16.2 | 17.8 | 17.2 |
| Twin Falls | ROR | 40.3 | 38.6 | 17.2 | 34.8 | 37.8 | 23.6 | 10.2 | 0.0 | 0.0 | 6.6 | 9.3 | 25.6 | 20.3 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 19.1 | 13.4 | 8.2 | 14.0 | 15.8 | 14.4 | 18.9 | 16.1 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.3 | 16.8 | 17.4 | 17.6 | 12.7 | 8.3 | 13.1 | 14.7 | 13.5 | 17.4 | 15.2 |
| **HCC Total** | | **774.3** | **670.3** | **779.8** | **984.7** | **961.1** | **964.6** | **541.8** | **362.7** | **489.0** | **458.8** | **359.7** | **569.7** | **659.7** |
| **ROR Total** | | **346.1** | **341.9** | **263.2** | **373.4** | **411.3** | **365.3** | **278.3** | **208.0** | **230.9** | **225.6** | **205.5** | **282.3** | **294.3** |
| **Total** | | **1120.4** | **1012.2** | **1043.0** | **1358.1** | **1372.3** | **1329.9** | **820.1** | **570.7** | **719.8** | **684.4** | **565.2** | **852.0** | **954.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2022** | **2/2022** | **3/2022** | **4/2022** | **5/2022** | **6/2022** | **7/2022** | **8/2022** | **9/2022** | **10/2022** | **11/2022** | **12/2022** | **aMW** |
| Brownlee | HCC* | 344.6 | 289.9 | 334.8 | 433.4 | 431.5 | 434.8 | 238.2 | 153.3 | 205.7 | 194.8 | 153.0 | 249.8 | 288.6 |
| Oxbow | HCC | 144.1 | 126.6 | 146.7 | 180.3 | 172.9 | 175.1 | 101.3 | 69.9 | 93.7 | 88.9 | 69.3 | 105.2 | 122.8 |
| Hells Canyon | HCC | 283.2 | 252.7 | 296.9 | 370.2 | 355.9 | 353.4 | 201.0 | 137.9 | 184.0 | 175.3 | 138.1 | 208.6 | 246.4 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 23.3 | 23.2 | 22.0 | 52.2 | 84.3 | 89.5 | 82.1 | 63.8 | 42.1 | 17.3 | 0.0 | 11.9 | 42.6 |
| Bliss | ROR | 48.3 | 48.0 | 40.1 | 50.1 | 49.1 | 43.9 | 34.3 | 27.1 | 36.4 | 39.4 | 37.6 | 42.2 | 41.4 |
| C .J. Strike | ROR | 63.3 | 63.3 | 54.9 | 64.1 | 63.6 | 53.2 | 36.6 | 28.4 | 43.2 | 50.2 | 49.2 | 52.8 | 51.9 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 33.9 | 33.6 | 25.7 | 33.4 | 34.9 | 29.4 | 22.1 | 15.1 | 22.8 | 25.5 | 23.6 | 28.4 | 27.4 |
| Milner | ROR | 39.9 | 38.5 | 13.5 | 34.1 | 37.6 | 20.4 | 5.9 | 0.0 | 0.0 | 0.0 | 5.1 | 21.5 | 18.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.2 | 20.3 | 18.0 | 20.8 | 20.8 | 17.4 | 12.8 | 10.0 | 14.6 | 16.5 | 16.2 | 17.4 | 17.1 |
| Twin Falls | ROR | 40.0 | 38.3 | 17.2 | 34.0 | 37.5 | 23.3 | 10.2 | 0.0 | 0.0 | 6.6 | 9.3 | 23.4 | 20.0 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 19.0 | 13.3 | 8.1 | 13.8 | 15.7 | 14.3 | 18.1 | 16.0 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.2 | 16.8 | 17.4 | 17.5 | 12.6 | 8.2 | 13.0 | 14.6 | 13.4 | 16.7 | 15.1 |
| **HCC Total** | | **771.9** | **669.2** | **778.4** | **983.9** | **960.2** | **963.3** | **540.5** | **361.1** | **483.3** | **459.0** | **360.4** | **563.6** | **657.9** |
| **ROR Total** | | **344.3** | **340.0** | **261.2** | **366.7** | **409.8** | **363.5** | **277.6** | **207.1** | **229.7** | **225.5** | **204.8** | **271.1** | **291.8** |
| **Total** | | **1116.2** | **1009.2** | **1039.6** | **1350.6** | **1370.0** | **1326.8** | **818.1** | **568.2** | **713.0** | **684.5** | **565.2** | **834.7** | **949.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2023** | **2/2023** | **3/2023** | **4/2023** | **5/2023** | **6/2023** | **7/2023** | **8/2023** | **9/2023** | **10/2023** | **11/2023** | **12/2023** | **aMW** |
| Brownlee | HCC* | 343.4 | 286.8 | 334.6 | 433.1 | 431.05 | 434.2 | 237.6 | 152.6 | 203.55 | 195.2 | 153 | 246.4 | 287.6 |
| Oxbow | HCC | 143.6 | 125.3 | 146.6 | 180.1 | 172.7 | 174.9 | 101 | 69.6 | 92.5 | 88.9 | 69.2 | 103.7 | 122.3 |
| Hells Canyon | HCC | 282.3 | 250.1 | 296.7 | 369.9 | 355.6 | 352.9 | 200.4 | 137.3 | 181.7 | 175.3 | 137.9 | 205.7 | 245.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 22.7 | 22.9 | 21.7 | 51.9 | 83.75 | 89.3 | 82.1 | 63.8 | 41.95 | 17.1 | 0 | 10.4 | 42.3 |
| Bliss | ROR | 48.1 | 47.8 | 39.8 | 49.7 | 48.8 | 43.6 | 34.1 | 26.9 | 36.2 | 39.3 | 37.3 | 41.1 | 41.1 |
| C .J. Strike | ROR | 62.9 | 62.9 | 54.5 | 63.7 | 63.3 | 53 | 36.4 | 28.1 | 43 | 50 | 48.9 | 52.8 | 51.6 |
| Cascade | ROR | 1.5 | 1.5 | 3 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 33.3 | 33.3 | 25.1 | 33.0 | 34.7 | 29.3 | 21.9 | 14.9 | 22.7 | 25.3 | 23.4 | 27.5 | 27.0 |
| Milner | ROR | 38.8 | 38.1 | 13.0 | 33.2 | 36.8 | 20.0 | 5.9 | 0.0 | 0.0 | 0.0 | 5.1 | 18.8 | 17.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.1 | 20.2 | 17.9 | 20.4 | 20.5 | 17.4 | 12.8 | 9.9 | 14.5 | 16.4 | 16.1 | 17.4 | 17.0 |
| Twin Falls | ROR | 38.5 | 37.9 | 16.9 | 33.2 | 36.8 | 23.0 | 10.2 | 0.0 | 0.0 | 6.6 | 9.3 | 21.3 | 19.5 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.1 | 19.1 | 18.9 | 13.2 | 8.0 | 13.7 | 15.6 | 14.1 | 17.4 | 15.9 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.8 | 16.8 | 17.4 | 17.4 | 12.5 | 8.1 | 12.9 | 14.5 | 13.3 | 16.1 | 14.9 |
| **HCC Total** | | **769.3** | **662.2** | **777.9** | **983.1** | **959.4** | **962.0** | **539.0** | **359.5** | **477.8** | **459.4** | **360.1** | **555.8** | **655.5** |
| **ROR Total** | | **339.8** | **337.9** | **258.3** | **363.1** | **406.6** | **361.8** | **276.8** | **206.1** | **228.7** | **224.5** | **203.6** | **261.5** | **289.1** |
| **Total** | | **1109.1** | **1000.1** | **1036.2** | **1346.2** | **1366.0** | **1323.8** | **815.8** | **565.6** | **706.5** | **683.9** | **563.7** | **817.3** | **944.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2024** | **2/2024** | **3/2024** | **4/2024** | **5/2024** | **6/2024** | **7/2024** | **8/2024** | **9/2024** | **10/2024** | **11/2024** | **12/2024** | **aMW** |
| Brownlee | HCC* | 342.4 | 286.4 | 336.0 | 432.6 | 430.7 | 433.6 | 237.0 | 152.0 | 200.9 | 195.6 | 153.6 | 242.5 | 286.9 |
| Oxbow | HCC | 143.2 | 125.1 | 147.2 | 180.0 | 172.6 | 174.7 | 100.7 | 69.3 | 91.1 | 88.8 | 69.4 | 102.0 | 122.0 |
| Hells Canyon | HCC | 281.4 | 249.8 | 297.9 | 369.5 | 355.3 | 352.5 | 199.9 | 136.7 | 178.9 | 175.2 | 138.3 | 202.5 | 244.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 22.5 | 22.6 | 21.3 | 51.7 | 83.5 | 89.1 | 82.0 | 63.6 | 41.9 | 16.4 | 0.0 | 8.9 | 42.0 |
| Bliss | ROR | 47.5 | 47.5 | 39.6 | 49.3 | 48.6 | 43.4 | 34.0 | 26.7 | 36.0 | 39.1 | 36.9 | 40.0 | 40.7 |
| C .J. Strike | ROR | 62.6 | 62.5 | 53.4 | 63.3 | 63.0 | 52.8 | 36.2 | 27.8 | 42.7 | 49.8 | 48.6 | 52.0 | 51.2 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 33.1 | 33.1 | 25.0 | 32.7 | 34.4 | 29.1 | 21.8 | 14.7 | 22.5 | 25.2 | 23.2 | 26.5 | 26.8 |
| Milner | ROR | 38.4 | 37.7 | 12.6 | 32.4 | 36.0 | 19.3 | 5.9 | 0.0 | 0.0 | 0.0 | 5.0 | 16.1 | 17.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.0 | 20.1 | 17.6 | 20.3 | 20.4 | 17.3 | 12.7 | 9.8 | 14.4 | 16.3 | 16.0 | 17.2 | 16.8 |
| Twin Falls | ROR | 38.2 | 37.6 | 16.5 | 32.5 | 36.1 | 22.7 | 10.2 | 0.0 | 0.0 | 6.6 | 9.3 | 19.0 | 19.1 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.1 | 18.8 | 13.8 | 19.2 | 19.1 | 18.8 | 13.1 | 7.9 | 13.6 | 15.5 | 14.0 | 16.6 | 15.8 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.7 | 16.8 | 17.4 | 17.3 | 12.4 | 8.0 | 12.8 | 14.5 | 13.2 | 15.4 | 14.8 |
| **HCC Total** | | **767.0** | **661.3** | **781.1** | **982.1** | **958.5** | **960.8** | **537.6** | **358.0** | **470.9** | **459.6** | **361.3** | **547.0** | **653.8** |
| **ROR Total** | | **337.7** | **335.9** | **255.3** | **360.3** | **403.9** | **359.7** | **276.0** | **204.9** | **227.6** | **223.1** | **202.3** | **250.4** | **286.4** |
| **Total** | | **1104.7** | **997.2** | **1036.4** | **1342.4** | **1362.4** | **1320.5** | **813.6** | **562.9** | **698.5** | **682.7** | **563.6** | **797.4** | **940.2** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2025** | **2/2025** | **3/2025** | **4/2025** | **5/2025** | **6/2025** | **7/2025** | **8/2025** | **9/2025** | **10/2025** | **11/2025** | **12/2025** | **aMW** |
| Brownlee | HCC* | 340.6 | 285.9 | 335.1 | 432.2 | 430.4 | 433.0 | 236.3 | 151.2 | 198.7 | 196.0 | 153.5 | 239.8 | 286.1 |
| Oxbow | HCC | 142.4 | 124.9 | 146.9 | 179.8 | 172.5 | 174.4 | 100.5 | 68.9 | 90.0 | 88.8 | 69.3 | 100.8 | 121.6 |
| Hells Canyon | HCC | 280.0 | 249.4 | 297.1 | 369.2 | 355.1 | 352.0 | 199.4 | 136.0 | 176.7 | 175.2 | 138.0 | 200.2 | 244.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 22.3 | 22.4 | 21.1 | 51.4 | 83.2 | 89.0 | 82.0 | 63.5 | 41.8 | 16.1 | 0.0 | 7.8 | 41.7 |
| Bliss | ROR | 47.3 | 47.3 | 39.3 | 48.9 | 48.4 | 43.1 | 33.8 | 26.5 | 35.8 | 38.9 | 37.0 | 39.1 | 40.5 |
| C .J. Strike | ROR | 62.1 | 62.2 | 53.1 | 63.0 | 62.8 | 52.6 | 36.0 | 27.6 | 42.4 | 49.6 | 48.4 | 50.8 | 50.9 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 32.9 | 32.9 | 25.0 | 32.5 | 34.2 | 29.0 | 21.7 | 14.6 | 22.3 | 25.0 | 23.0 | 25.7 | 26.6 |
| Milner | ROR | 38.1 | 37.4 | 12.2 | 32.1 | 35.7 | 18.9 | 5.9 | 0.0 | 0.0 | 0.0 | 5.0 | 14.1 | 16.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 19.9 | 20.0 | 17.5 | 20.3 | 20.3 | 17.3 | 12.7 | 9.8 | 14.4 | 16.3 | 16.0 | 16.8 | 16.8 |
| Twin Falls | ROR | 37.9 | 37.3 | 16.1 | 32.2 | 35.8 | 22.6 | 10.2 | 0.0 | 0.0 | 6.6 | 9.3 | 17.1 | 18.8 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.2 | 18.8 | 13.8 | 19.2 | 19.1 | 18.7 | 13.0 | 7.8 | 13.4 | 15.4 | 13.9 | 16.0 | 15.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.7 | 16.8 | 17.4 | 17.2 | 12.3 | 7.9 | 12.7 | 14.4 | 13.1 | 14.9 | 14.7 |
| **HCC Total** | | **763.0** | **660.2** | **779.1** | **981.2** | **957.9** | **959.4** | **536.2** | **356.1** | **465.3** | **460.0** | **360.8** | **540.8** | **651.7** |
| **ROR Total** | | **336.0** | **334.3** | **253.6** | **358.5** | **402.3** | **358.3** | **275.3** | **204.1** | **226.6** | **222.0** | **201.8** | **241.0** | **284.5** |
| **Total** | | **1099.0** | **994.5** | **1032.7** | **1339.7** | **1360.2** | **1317.7** | **811.5** | **560.2** | **691.8** | **682.0** | **562.6** | **781.8** | **936.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2026** | **2/2026** | **3/2026** | **4/2026** | **5/2026** | **6/2026** | **7/2026** | **8/2026** | **9/2026** | **10/2026** | **11/2026** | **12/2026** | **aMW** |
| Brownlee | HCC* | 338.7 | 285.6 | 334.1 | 431.3 | 430.1 | 428.0 | 235.7 | 150.4 | 196.5 | 196.5 | 153.9 | 236.7 | 284.8 |
| Oxbow | HCC | 141.7 | 124.8 | 146.4 | 179.4 | 172.3 | 172.5 | 100.2 | 68.6 | 88.8 | 88.8 | 69.4 | 99.5 | 121.0 |
| Hells Canyon | HCC | 278.5 | 249.1 | 296.3 | 368.5 | 354.8 | 348.2 | 198.9 | 135.3 | 174.4 | 175.2 | 138.2 | 197.6 | 242.9 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 22.1 | 22.2 | 20.8 | 51.1 | 82.8 | 88.8 | 82.0 | 63.4 | 41.7 | 17.0 | 0.0 | 6.8 | 41.6 |
| Bliss | ROR | 47.0 | 47.1 | 39.1 | 48.5 | 48.2 | 42.6 | 33.6 | 26.3 | 35.7 | 38.8 | 36.3 | 38.2 | 40.1 |
| C .J. Strike | ROR | 61.3 | 61.9 | 52.8 | 62.6 | 62.7 | 52.4 | 35.8 | 27.4 | 42.2 | 49.4 | 48.0 | 50.0 | 50.5 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 32.7 | 32.7 | 24.8 | 32.3 | 34.0 | 28.1 | 21.5 | 14.4 | 22.1 | 24.9 | 22.9 | 24.9 | 26.3 |
| Milner | ROR | 37.8 | 37.1 | 12.2 | 31.7 | 35.4 | 18.7 | 5.9 | 0.0 | 0.0 | 0.0 | 4.6 | 12.4 | 16.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 19.7 | 19.9 | 17.4 | 20.2 | 20.2 | 17.2 | 12.6 | 9.7 | 14.3 | 16.2 | 15.9 | 16.5 | 16.7 |
| Twin Falls | ROR | 37.7 | 37.0 | 15.7 | 31.9 | 35.6 | 22.5 | 10.2 | 0.0 | 0.0 | 6.6 | 9.2 | 15.5 | 18.5 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.2 | 18.8 | 13.8 | 19.2 | 19.1 | 18.0 | 12.9 | 7.6 | 13.3 | 15.3 | 13.7 | 15.4 | 15.5 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.6 | 16.8 | 17.4 | 16.6 | 12.2 | 7.8 | 12.6 | 14.3 | 12.9 | 14.4 | 14.6 |
| **HCC Total** | | **758.9** | **659.5** | **776.8** | **979.2** | **957.2** | **948.7** | **534.8** | **354.3** | **459.6** | **460.5** | **361.5** | **533.8** | **648.7** |
| **ROR Total** | | **333.8** | **332.7** | **252.0** | **356.4** | **400.9** | **354.8** | **274.4** | **203.0** | **225.7** | **222.2** | **199.6** | **232.8** | **282.4** |
| **Total** | | **1092.7** | **992.2** | **1028.8** | **1335.6** | **1358.0** | **1303.5** | **809.2** | **557.3** | **685.3** | **682.7** | **561.1** | **766.6** | **931.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2027** | **2/2027** | **3/2027** | **4/2027** | **5/2027** | **6/2027** | **7/2027** | **8/2027** | **9/2027** | **10/2027** | **11/2027** | **12/2027** | **aMW** |
| Brownlee | HCC* | 333.8 | 285.1 | 333.1 | 430.4 | 421.8 | 423.2 | 235.1 | 149.9 | 194.3 | 196.8 | 154.0 | 234.0 | 282.6 |
| Oxbow | HCC | 139.7 | 124.6 | 146.0 | 187.2 | 169.1 | 170.6 | 100.0 | 68.3 | 87.6 | 88.8 | 69.3 | 98.3 | 120.8 |
| Hells Canyon | HCC | 274.6 | 248.8 | 295.5 | 378.4 | 348.5 | 344.5 | 198.4 | 134.8 | 172.1 | 175.2 | 138.1 | 195.3 | 242.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 20.7 | 21.9 | 20.6 | 50.0 | 82.6 | 88.7 | 81.7 | 63.3 | 41.6 | 16.1 | 0.0 | 5.6 | 41.1 |
| Bliss | ROR | 46.8 | 46.8 | 38.8 | 48.2 | 48.0 | 42.5 | 33.5 | 26.2 | 35.5 | 38.6 | 36.2 | 37.3 | 39.9 |
| C .J. Strike | ROR | 61.0 | 61.6 | 52.4 | 62.1 | 62.6 | 52.1 | 35.6 | 27.1 | 41.9 | 49.2 | 47.9 | 49.5 | 50.3 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 32.2 | 32.5 | 24.6 | 32.0 | 33.8 | 27.9 | 21.4 | 14.3 | 22.0 | 24.8 | 22.7 | 24.1 | 26.0 |
| Milner | ROR | 35.7 | 36.6 | 11.7 | 31.3 | 35.1 | 18.2 | 5.9 | 0.0 | 0.0 | 0.0 | 4.6 | 10.5 | 15.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 19.6 | 19.8 | 17.3 | 20.0 | 20.2 | 17.1 | 12.5 | 9.6 | 14.2 | 16.2 | 15.8 | 16.3 | 16.6 |
| Twin Falls | ROR | 35.7 | 36.6 | 15.3 | 31.6 | 35.3 | 21.8 | 10.2 | 0.0 | 0.0 | 6.6 | 9.2 | 13.7 | 18.0 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.2 | 18.8 | 13.8 | 19.2 | 19.1 | 17.8 | 12.8 | 7.5 | 13.2 | 15.2 | 13.6 | 14.8 | 15.4 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.4 | 16.8 | 17.4 | 16.5 | 12.1 | 7.7 | 12.5 | 14.2 | 12.8 | 13.8 | 14.5 |
| **HCC Total** | | **748.1** | **658.5** | **774.6** | **996.0** | **939.3** | **938.3** | **533.5** | **353.0** | **453.9** | **460.8** | **361.4** | **527.6** | **645.4** |
| **ROR Total** | | **327.2** | **330.6** | **249.7** | **353.3** | **399.5** | **352.5** | **273.4** | **202.1** | **224.7** | **220.6** | **198.9** | **224.3** | **279.7** |
| **Total** | | **1075.3** | **989.1** | **1024.3** | **1349.3** | **1338.8** | **1290.8** | **806.9** | **555.1** | **678.6** | **681.4** | **560.3** | **751.9** | **925.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2028** | **2/2028** | **3/2028** | **4/2028** | **5/2028** | **6/2028** | **7/2028** | **8/2028** | **9/2028** | **10/2028** | **11/2028** | **12/2028** | **aMW** |
| Brownlee | HCC* | 333.8 | 285.1 | 333.1 | 430.4 | 421.8 | 423.2 | 235.1 | 149.9 | 194.3 | 196.8 | 154.0 | 234.0 | 282.6 |
| Oxbow | HCC | 139.7 | 124.6 | 146.0 | 187.2 | 169.1 | 170.6 | 100.0 | 68.3 | 87.6 | 88.8 | 69.3 | 98.3 | 120.8 |
| Hells Canyon | HCC | 274.6 | 248.8 | 295.5 | 378.4 | 348.5 | 344.5 | 198.4 | 134.8 | 172.1 | 175.2 | 138.1 | 195.3 | 242.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 20.6 | 21.9 | 20.6 | 50.0 | 82.6 | 88.7 | 81.7 | 63.3 | 41.6 | 16.1 | 0.0 | 5.6 | 41.1 |
| Bliss | ROR | 46.8 | 46.8 | 38.8 | 48.2 | 48.0 | 42.5 | 33.5 | 26.2 | 35.5 | 38.6 | 36.2 | 37.3 | 39.9 |
| C .J. Strike | ROR | 61.0 | 61.6 | 52.4 | 62.1 | 62.6 | 52.1 | 35.6 | 27.1 | 41.9 | 49.2 | 47.9 | 49.5 | 50.3 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 32.2 | 32.5 | 24.6 | 32.0 | 33.8 | 27.9 | 21.4 | 14.3 | 22.0 | 24.8 | 22.7 | 24.1 | 26.0 |
| Milner | ROR | 35.7 | 36.6 | 11.7 | 31.3 | 35.1 | 18.2 | 5.9 | 0.0 | 0.0 | 0.0 | 4.6 | 10.5 | 15.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 19.6 | 19.8 | 17.3 | 20.0 | 20.2 | 17.1 | 12.5 | 9.6 | 14.2 | 16.2 | 15.8 | 16.3 | 16.6 |
| Twin Falls | ROR | 35.7 | 36.6 | 15.3 | 31.6 | 35.3 | 21.8 | 10.2 | 0.0 | 0.0 | 6.6 | 9.2 | 13.7 | 18.0 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.2 | 18.8 | 13.8 | 19.2 | 19.1 | 17.8 | 12.8 | 7.5 | 13.2 | 15.2 | 13.6 | 14.8 | 15.4 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.4 | 16.8 | 17.4 | 16.5 | 12.1 | 7.7 | 12.5 | 14.2 | 12.8 | 13.8 | 14.5 |
| **HCC Total** | | **748.1** | **658.5** | **774.6** | **996.0** | **939.3** | **938.3** | **533.5** | **353.0** | **453.9** | **460.8** | **361.4** | **527.6** | **645.4** |
| **ROR Total** | | **327.1** | **330.6** | **249.7** | **353.3** | **399.5** | **352.5** | **273.4** | **202.1** | **224.7** | **220.6** | **198.9** | **224.3** | **279.7** |
| **Total** | | **1075.2** | **989.1** | **1024.3** | **1349.3** | **1338.8** | **1290.8** | **806.9** | **555.1** | **678.6** | **681.4** | **560.3** | **751.9** | **925.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2029** | **2/2029** | **3/2029** | **4/2029** | **5/2029** | **6/2029** | **7/2029** | **8/2029** | **9/2029** | **10/2029** | **11/2029** | **12/2029** | **aMW** |
| Brownlee | HCC* | 333.8 | 285.1 | 333.1 | 430.4 | 421.8 | 423.2 | 235.1 | 149.9 | 194.3 | 196.8 | 154.0 | 234.0 | 282.6 |
| Oxbow | HCC | 139.7 | 124.6 | 146.0 | 187.2 | 169.1 | 170.6 | 100.0 | 68.3 | 87.6 | 88.8 | 69.3 | 98.3 | 120.8 |
| Hells Canyon | HCC | 274.6 | 248.8 | 295.5 | 378.4 | 348.5 | 344.5 | 198.4 | 134.8 | 172.1 | 175.2 | 138.1 | 195.3 | 242.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 20.6 | 21.9 | 20.6 | 50.0 | 82.6 | 88.7 | 81.7 | 63.3 | 41.6 | 16.1 | 0.0 | 5.6 | 41.1 |
| Bliss | ROR | 46.8 | 46.8 | 38.8 | 48.2 | 48.0 | 42.5 | 33.5 | 26.2 | 35.5 | 38.6 | 36.2 | 37.3 | 39.9 |
| C .J. Strike | ROR | 61.0 | 61.6 | 52.4 | 62.1 | 62.6 | 52.1 | 35.6 | 27.1 | 41.9 | 49.2 | 47.9 | 49.5 | 50.3 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 32.2 | 32.5 | 24.6 | 32.0 | 33.8 | 27.9 | 21.4 | 14.3 | 22.0 | 24.8 | 22.7 | 24.1 | 26.0 |
| Milner | ROR | 35.7 | 36.6 | 11.7 | 31.3 | 35.1 | 18.2 | 5.9 | 0.0 | 0.0 | 0.0 | 4.6 | 10.5 | 15.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 19.6 | 19.8 | 17.3 | 20.0 | 20.2 | 17.1 | 12.5 | 9.6 | 14.2 | 16.2 | 15.8 | 16.3 | 16.6 |
| Twin Falls | ROR | 35.7 | 36.6 | 15.3 | 31.6 | 35.3 | 21.8 | 10.2 | 0.0 | 0.0 | 6.6 | 9.2 | 13.7 | 18.0 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.2 | 18.8 | 13.8 | 19.2 | 19.1 | 17.8 | 12.8 | 7.5 | 13.2 | 15.2 | 13.6 | 14.8 | 15.4 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.4 | 16.8 | 17.4 | 16.5 | 12.1 | 7.7 | 12.5 | 14.2 | 12.8 | 13.8 | 14.5 |
| **HCC Total** | | **748.1** | **658.5** | **774.6** | **996.0** | **939.3** | **938.3** | **533.5** | **353.0** | **453.9** | **460.8** | **361.4** | **527.6** | **645.4** |
| **ROR Total** | | **327.1** | **330.6** | **249.7** | **353.3** | **399.5** | **352.5** | **273.4** | **202.1** | **224.7** | **220.6** | **198.9** | **224.3** | **279.7** |
| **Total** | | **1075.2** | **989.1** | **1024.3** | **1349.3** | **1338.8** | **1290.8** | **806.9** | **555.1** | **678.6** | **681.4** | **560.3** | **751.9** | **925.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2030** | **2/2030** | **3/2030** | **4/2030** | **5/2030** | **6/2030** | **7/2030** | **8/2030** | **9/2030** | **10/2030** | **11/2030** | **12/2030** | **aMW** |
| Brownlee | HCC* | 333.8 | 285.1 | 333.1 | 430.4 | 421.8 | 423.2 | 235.1 | 149.9 | 194.3 | 196.8 | 154.0 | 234.0 | 282.6 |
| Oxbow | HCC | 139.7 | 124.6 | 146.0 | 187.2 | 169.1 | 170.6 | 100.0 | 68.3 | 87.6 | 88.8 | 69.3 | 98.3 | 120.8 |
| Hells Canyon | HCC | 274.6 | 248.8 | 295.5 | 378.4 | 348.5 | 344.5 | 198.4 | 134.8 | 172.1 | 175.2 | 138.1 | 195.3 | 242.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 20.6 | 21.9 | 20.6 | 50.0 | 82.6 | 88.7 | 81.7 | 63.3 | 41.6 | 16.1 | 0.0 | 5.6 | 41.1 |
| Bliss | ROR | 46.8 | 46.8 | 38.8 | 48.2 | 48.0 | 42.5 | 33.5 | 26.2 | 35.5 | 38.6 | 36.2 | 37.3 | 39.9 |
| C .J. Strike | ROR | 61.0 | 61.6 | 52.4 | 62.1 | 62.6 | 52.1 | 35.6 | 27.1 | 41.9 | 49.2 | 47.9 | 49.5 | 50.3 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 32.2 | 32.5 | 24.6 | 32.0 | 33.8 | 27.9 | 21.4 | 14.3 | 22.0 | 24.8 | 22.7 | 24.1 | 26.0 |
| Milner | ROR | 35.7 | 36.6 | 11.7 | 31.3 | 35.1 | 18.2 | 5.9 | 0.0 | 0.0 | 0.0 | 4.6 | 10.5 | 15.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 19.6 | 19.8 | 17.3 | 20.0 | 20.2 | 17.1 | 12.5 | 9.6 | 14.2 | 16.2 | 15.8 | 16.3 | 16.6 |
| Twin Falls | ROR | 35.7 | 36.6 | 15.3 | 31.6 | 35.3 | 21.8 | 10.2 | 0.0 | 0.0 | 6.6 | 9.2 | 13.7 | 18.0 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.2 | 18.8 | 13.8 | 19.2 | 19.1 | 17.8 | 12.8 | 7.5 | 13.2 | 15.2 | 13.6 | 14.8 | 15.4 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.4 | 16.8 | 17.4 | 16.5 | 12.1 | 7.7 | 12.5 | 14.2 | 12.8 | 13.8 | 14.5 |
| **HCC Total** | | **748.1** | **658.5** | **774.6** | **996.0** | **939.3** | **938.3** | **533.5** | **353.0** | **453.9** | **460.8** | **361.4** | **527.6** | **645.4** |
| **ROR Total** | | **327.1** | **330.6** | **249.7** | **353.3** | **399.5** | **352.5** | **273.4** | **202.1** | **224.7** | **220.6** | **198.9** | **224.3** | **279.7** |
| **Total** | | **1075.2** | **989.1** | **1024.3** | **1349.3** | **1338.8** | **1290.8** | **806.9** | **555.1** | **678.6** | **681.4** | **560.3** | **751.9** | **925.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2031** | **2/2031** | **3/2031** | **4/2031** | **5/2031** | **6/2031** | **7/2031** | **8/2031** | **9/2031** | **10/2031** | **11/2031** | **12/2031** | **aMW** |
| Brownlee | HCC* | 333.8 | 285.1 | 333.1 | 430.4 | 421.8 | 423.2 | 235.1 | 149.9 | 194.3 | 196.8 | 154.0 | 234.0 | 282.6 |
| Oxbow | HCC | 139.7 | 124.6 | 146.0 | 187.2 | 169.1 | 170.6 | 100.0 | 68.3 | 87.6 | 88.8 | 69.3 | 98.3 | 120.8 |
| Hells Canyon | HCC | 274.6 | 248.8 | 295.5 | 378.4 | 348.5 | 344.5 | 198.4 | 134.8 | 172.1 | 175.2 | 138.1 | 195.3 | 242.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 20.6 | 21.9 | 20.6 | 50.0 | 82.6 | 88.7 | 81.7 | 63.3 | 41.6 | 16.1 | 0.0 | 5.6 | 41.1 |
| Bliss | ROR | 46.8 | 46.8 | 38.8 | 48.2 | 48.0 | 42.5 | 33.5 | 26.2 | 35.5 | 38.6 | 36.2 | 37.3 | 39.9 |
| C .J. Strike | ROR | 61.0 | 61.6 | 52.4 | 62.1 | 62.6 | 52.1 | 35.6 | 27.1 | 41.9 | 49.2 | 47.9 | 49.5 | 50.3 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 32.2 | 32.5 | 24.6 | 32.0 | 33.8 | 27.9 | 21.4 | 14.3 | 22.0 | 24.8 | 22.7 | 24.1 | 26.0 |
| Milner | ROR | 35.7 | 36.6 | 11.7 | 31.3 | 35.1 | 18.2 | 5.9 | 0.0 | 0.0 | 0.0 | 4.6 | 10.5 | 15.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 19.6 | 19.8 | 17.3 | 20.0 | 20.2 | 17.1 | 12.5 | 9.6 | 14.2 | 16.2 | 15.8 | 16.3 | 16.6 |
| Twin Falls | ROR | 35.7 | 36.6 | 15.3 | 31.6 | 35.3 | 21.8 | 10.2 | 0.0 | 0.0 | 6.6 | 9.2 | 13.7 | 18.0 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.2 | 18.8 | 13.8 | 19.2 | 19.1 | 17.8 | 12.8 | 7.5 | 13.2 | 15.2 | 13.6 | 14.8 | 15.4 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.4 | 16.8 | 17.4 | 16.5 | 12.1 | 7.7 | 12.5 | 14.2 | 12.8 | 13.8 | 14.5 |
| **HCC Total** | | **748.1** | **658.5** | **774.6** | **996.0** | **939.3** | **938.3** | **533.5** | **353.0** | **453.9** | **460.8** | **361.4** | **527.6** | **645.4** |
| **ROR Total** | | **327.1** | **330.6** | **249.7** | **353.3** | **399.5** | **352.5** | **273.4** | **202.1** | **224.7** | **220.6** | **198.9** | **224.3** | **279.7** |
| **Total** | | **1075.2** | **989.1** | **1024.3** | **1349.3** | **1338.8** | **1290.8** | **806.9** | **555.1** | **678.6** | **681.4** | **560.3** | **751.9** | **925.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2032** | **2/2032** | **3/2032** | **4/2032** | **5/2032** | **6/2032** | **7/2032** | **8/2032** | **9/2032** | **10/2032** | **11/2032** | **12/2032** | **aMW** |
| Brownlee | HCC* | 333.8 | 285.1 | 333.1 | 430.4 | 421.8 | 423.2 | 235.1 | 149.9 | 194.3 | 196.8 | 154.0 | 234.0 | 282.6 |
| Oxbow | HCC | 139.7 | 124.6 | 146.0 | 187.2 | 169.1 | 170.6 | 100.0 | 68.3 | 87.6 | 88.8 | 69.3 | 98.3 | 120.8 |
| Hells Canyon | HCC | 274.6 | 248.8 | 295.5 | 378.4 | 348.5 | 344.5 | 198.4 | 134.8 | 172.1 | 175.2 | 138.1 | 195.3 | 242.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 20.6 | 21.9 | 20.6 | 50.0 | 82.6 | 88.7 | 81.7 | 63.3 | 41.6 | 16.1 | 0.0 | 5.6 | 41.1 |
| Bliss | ROR | 46.8 | 46.8 | 38.8 | 48.2 | 48.0 | 42.5 | 33.5 | 26.2 | 35.5 | 38.6 | 36.2 | 37.3 | 39.9 |
| C .J. Strike | ROR | 61.0 | 61.6 | 52.4 | 62.1 | 62.6 | 52.1 | 35.6 | 27.1 | 41.9 | 49.2 | 47.9 | 49.5 | 50.3 |
| Cascade | ROR | 1.5 | 1.5 | 3.0 | 5.8 | 5.5 | 11.1 | 10.2 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 32.2 | 32.5 | 24.6 | 32.0 | 33.8 | 27.9 | 21.4 | 14.3 | 22.0 | 24.8 | 22.7 | 24.1 | 26.0 |
| Milner | ROR | 35.7 | 36.6 | 11.7 | 31.3 | 35.1 | 18.2 | 5.9 | 0.0 | 0.0 | 0.0 | 4.6 | 10.5 | 15.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 19.6 | 19.8 | 17.3 | 20.0 | 20.2 | 17.1 | 12.5 | 9.6 | 14.2 | 16.2 | 15.8 | 16.3 | 16.6 |
| Twin Falls | ROR | 35.7 | 36.6 | 15.3 | 31.6 | 35.3 | 21.8 | 10.2 | 0.0 | 0.0 | 6.6 | 9.2 | 13.7 | 18.0 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 19.2 | 18.8 | 13.8 | 19.2 | 19.1 | 17.8 | 12.8 | 7.5 | 13.2 | 15.2 | 13.6 | 14.8 | 15.4 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.4 | 16.8 | 17.4 | 16.5 | 12.1 | 7.7 | 12.5 | 14.2 | 12.8 | 13.8 | 14.5 |
| **HCC Total** | | **748.1** | **658.5** | **774.6** | **996.0** | **939.3** | **938.3** | **533.5** | **353.0** | **453.9** | **460.8** | **361.4** | **527.6** | **645.4** |
| **ROR Total** | | **327.1** | **330.6** | **249.7** | **353.3** | **399.5** | **352.5** | **273.4** | **202.1** | **224.7** | **220.6** | **198.9** | **224.3** | **279.7** |
| **Total** | | **1075.2** | **989.1** | **1024.3** | **1349.3** | **1338.8** | **1290.8** | **806.9** | **555.1** | **678.6** | **681.4** | **560.3** | **751.9** | **925.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2013** | **2/2013** | **3/2013** | **4/2013** | **5/2013** | **6/2013** | **7/2013** | **8/2013** | **9/2013** | **10/2013** | **11/2013** | **12/2013** | **aMW** |
| Brownlee | HCC* | 256.5 | 264.8 | 259.1 | 301.5 | 390.1 | 316.6 | 228.7 | 162.7 | 184.9 | 177.2 | 156.2 | 208.7 | 242.2 |
| Oxbow | HCC | 108.2 | 113.0 | 110.6 | 123.5 | 157.5 | 127.8 | 96.9 | 74.3 | 84.9 | 79.2 | 69.5 | 87.3 | 102.7 |
| Hells Canyon | HCC | 214.2 | 225.5 | 225.7 | 251.2 | 320.0 | 258.2 | 191.3 | 145.8 | 166.4 | 156.2 | 138.1 | 173.1 | 205.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 5.7 | 11.1 | 33.8 | 72.6 | 88.6 | 83.0 | 64.1 | 34.1 | 11.6 | 0.0 | 0.0 | 33.7 |
| Bliss | ROR | 38.3 | 39.7 | 37.4 | 37.2 | 42.1 | 40.8 | 34.8 | 31.5 | 37.1 | 39.3 | 37.4 | 37.4 | 37.8 |
| C .J. Strike | ROR | 49.9 | 52.8 | 49.0 | 49.9 | 52.7 | 47.0 | 36.8 | 33.9 | 44.3 | 50.1 | 48.5 | 48.5 | 47.0 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 23.9 | 25.0 | 22.2 | 23.0 | 28.5 | 28.3 | 22.7 | 19.1 | 23.6 | 25.5 | 24.0 | 23.8 | 24.1 |
| Milner | ROR | 8.9 | 10.6 | 5.2 | 3.7 | 17.0 | 17.0 | 5.9 | 6.7 | 0.0 | 0.0 | 3.6 | 6.2 | 7.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 11.3 | 12.0 | 12.0 | 12.0 | 12.0 | 6.7 | 10.5 | 12.0 | 12.0 | 11.4 |
| Swan Falls | ROR | 16.3 | 17.4 | 16.2 | 16.3 | 17.4 | 15.5 | 12.9 | 11.9 | 14.9 | 16.4 | 16.0 | 16.0 | 15.6 |
| Twin Falls | ROR | 11.5 | 13.7 | 8.6 | 7.3 | 19.9 | 20.6 | 10.2 | 11.5 | 0.0 | 6.6 | 8.3 | 9.5 | 10.6 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 14.7 | 15.7 | 13.6 | 14.2 | 18.5 | 18.2 | 13.8 | 11.2 | 14.4 | 15.8 | 14.6 | 14.5 | 14.9 |
| Upper Salmon 3&4 | ROR | 13.7 | 14.6 | 12.8 | 13.4 | 17.1 | 16.8 | 13 | 10.8 | 13.5 | 14.7 | 13.7 | 13.6 | 14.0 |
| **HCC Total** | | **578.9** | **603.3** | **595.4** | **676.2** | **867.6** | **702.6** | **516.9** | **382.8** | **436.1** | **412.6** | **363.8** | **469.1** | **550.4** |
| **ROR Total** | | **215.8** | **233.5** | **215.2** | **235.6** | **327.8** | **336.9** | **278.2** | **251.1** | **224.1** | **219.3** | **202.1** | **208.2** | **245.7** |
| **Total** | | **794.7** | **836.8** | **810.6** | **911.8** | **1195.4** | **1039.5** | **795.1** | **633.9** | **660.2** | **631.9** | **565.9** | **677.3** | **796.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2014** | **2/2014** | **3/2014** | **4/2014** | **5/2014** | **6/2014** | **7/2014** | **8/2014** | **9/2014** | **10/2014** | **11/2014** | **12/2014** | **aMW** |
| Brownlee | HCC* | 254.6 | 264.1 | 258.4 | 300.2 | 389.8 | 315.8 | 228.2 | 162.1 | 184.3 | 176.1 | 156.3 | 207.3 | 241.4 |
| Oxbow | HCC | 107.4 | 112.7 | 110.2 | 123.0 | 157.3 | 127.5 | 96.7 | 74.0 | 84.6 | 78.6 | 69.6 | 86.7 | 102.4 |
| Hells Canyon | HCC | 212.7 | 224.9 | 225.1 | 250.2 | 319.7 | 257.5 | 190.8 | 145.3 | 165.8 | 155.2 | 138.1 | 171.9 | 204.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0 | 0 | 10.4 | 32.8 | 72.6 | 88.5 | 83.1 | 64 | 34.05 | 11.6 | 0 | 0 | 33.1 |
| Bliss | ROR | 38.2 | 39.4 | 36.8 | 36.1 | 42 | 40.6 | 34.7 | 31.4 | 36.9 | 39.2 | 37.2 | 37.1 | 37.5 |
| C .J. Strike | ROR | 49.8 | 51.8 | 48.7 | 48.9 | 52.6 | 46.8 | 36.6 | 33.7 | 44.1 | 49.8 | 48.3 | 48 | 46.6 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.05 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 23.8 | 24.2 | 22.2 | 22.6 | 28.4 | 28.2 | 22.5 | 18.9 | 23.4 | 25.4 | 23.9 | 23.6 | 23.9 |
| Milner | ROR | 8.9 | 8.8 | 4.8 | 2.3 | 17 | 17 | 5.9 | 6.7 | 0 | 0 | 3.6 | 6.2 | 6.8 |
| Shoshone Falls | ROR | 12 | 12 | 12 | 10 | 12 | 12 | 12 | 12 | 6.7 | 10.5 | 12 | 12 | 11.3 |
| Swan Falls | ROR | 16.2 | 17.1 | 16.1 | 16.2 | 17.3 | 15.5 | 12.8 | 11.8 | 14.8 | 16.4 | 15.9 | 15.9 | 15.5 |
| Twin Falls | ROR | 11.5 | 12.1 | 8.3 | 6.2 | 19.9 | 20.6 | 10.2 | 11.5 | 0 | 6.6 | 8.3 | 9.5 | 10.4 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 14.6 | 15.0 | 13.6 | 14.0 | 18.5 | 18.1 | 13.7 | 11.1 | 14.3 | 15.7 | 14.5 | 14.4 | 14.8 |
| Upper Salmon 3&4 | ROR | 13.7 | 14.1 | 12.8 | 13.1 | 17.0 | 16.7 | 12.9 | 10.7 | 13.4 | 14.6 | 13.6 | 13.5 | 13.8 |
| **HCC Total** | | **574.7** | **601.7** | **593.7** | **673.4** | **866.8** | **700.8** | **515.7** | **381.4** | **434.6** | **409.9** | **364.0** | **465.9** | **548.5** |
| **ROR Total** | | **215.3** | **220.8** | **212.8** | **227.7** | **327.3** | **336.1** | **277.5** | **250.2** | **223.2** | **218.6** | **201.3** | **206.9** | **243.1** |
| **Total** | | **790.0** | **822.5** | **806.5** | **901.1** | **1194.1** | **1036.9** | **793.2** | **631.6** | **657.8** | **628.5** | **565.3** | **672.8** | **791.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2015** | **2/2015** | **3/2015** | **4/2015** | **5/2015** | **6/2015** | **7/2015** | **8/2015** | **9/2015** | **10/2015** | **11/2015** | **12/2015** | **aMW** |
| Brownlee | HCC* | 257.8 | 271.6 | 260.5 | 319.5 | 390.6 | 317.6 | 228.2 | 162.0 | 184.0 | 179.2 | 155.8 | 213.0 | 245.0 |
| Oxbow | HCC | 108.8 | 115.9 | 111.1 | 130.7 | 157.6 | 128.2 | 96.7 | 74.0 | 84.4 | 80.2 | 69.5 | 89.1 | 103.9 |
| Hells Canyon | HCC | 215.3 | 231.1 | 226.8 | 265.1 | 320.3 | 259.0 | 190.9 | 145.2 | 165.6 | 158.1 | 137.9 | 176.7 | 207.7 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 9.9 | 13.5 | 37.1 | 72.7 | 89.4 | 83.2 | 65.2 | 34.9 | 13.4 | 0.0 | 0.0 | 34.9 |
| Bliss | ROR | 38.4 | 40.8 | 37.3 | 38.8 | 42.5 | 40.7 | 34.6 | 31.3 | 36.8 | 39.4 | 37.6 | 37.4 | 38.0 |
| C .J. Strike | ROR | 50.1 | 54.5 | 48.3 | 52.7 | 52.8 | 47.1 | 36.6 | 33.6 | 44.0 | 50.1 | 48.5 | 49.1 | 47.3 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 24.4 | 27.0 | 22.1 | 24.9 | 28.6 | 28.4 | 22.5 | 18.8 | 23.3 | 25.6 | 24.1 | 23.8 | 24.5 |
| Milner | ROR | 8.9 | 17.1 | 4.0 | 8.5 | 18.2 | 18.2 | 5.9 | 6.7 | 0.0 | 0.0 | 3.6 | 6.2 | 8.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 11.9 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.7 | 10.5 | 12.0 | 12.0 | 11.4 |
| Swan Falls | ROR | 16.4 | 17.7 | 16.0 | 17.3 | 17.4 | 15.7 | 12.8 | 11.8 | 14.8 | 16.4 | 15.9 | 16.1 | 15.7 |
| Twin Falls | ROR | 11.7 | 19.5 | 7.8 | 11.3 | 20.6 | 21.7 | 10.2 | 11.5 | 0.0 | 6.6 | 8.3 | 9.5 | 11.6 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 15.0 | 17.2 | 13.5 | 15.8 | 18.6 | 18.2 | 13.7 | 11.0 | 14.2 | 15.8 | 14.7 | 14.5 | 15.2 |
| Upper Salmon 3&4 | ROR | 14.0 | 16.0 | 12.8 | 14.7 | 17.1 | 16.8 | 12.9 | 10.6 | 13.4 | 14.7 | 13.8 | 13.6 | 14.2 |
| **HCC Total** | | **581.9** | **618.6** | **598.4** | **715.3** | **868.5** | **704.8** | **515.8** | **381.2** | **433.9** | **417.5** | **363.2** | **478.8** | **556.5** |
| **ROR Total** | | **217.5** | **258.0** | **214.3** | **258.6** | **330.5** | **340.3** | **277.5** | **250.9** | **223.7** | **221.3** | **202.5** | **208.9** | **250.3** |
| **Total** | | **799.4** | **876.6** | **812.7** | **973.9** | **1199.0** | **1045.1** | **793.3** | **632.1** | **657.6** | **638.8** | **565.7** | **687.7** | **806.8** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2016** | **2/2016** | **3/2016** | **4/2016** | **5/2016** | **6/2016** | **7/2016** | **8/2016** | **9/2016** | **10/2016** | **11/2016** | **12/2016** | **aMW** |
| Brownlee | HCC* | 257.4 | 270.8 | 260.8 | 318.1 | 392.0 | 317.1 | 227.6 | 149.1 | 183.3 | 178.6 | 155.9 | 216.8 | 244.0 |
| Oxbow | HCC | 108.6 | 115.6 | 111.3 | 130.1 | 158.2 | 128.0 | 96.5 | 67.9 | 84.1 | 79.9 | 69.6 | 90.8 | 103.4 |
| Hells Canyon | HCC | 214.9 | 230.5 | 227.1 | 264.0 | 321.5 | 258.5 | 190.4 | 133.7 | 164.9 | 157.6 | 138.1 | 179.9 | 206.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 14.0 | 13.3 | 38.8 | 72.7 | 89.4 | 83.1 | 61.2 | 36.0 | 13.6 | 0.0 | 0.0 | 35.2 |
| Bliss | ROR | 38.5 | 42.4 | 36.4 | 38.9 | 42.4 | 40.6 | 34.5 | 27.6 | 36.6 | 39.2 | 37.6 | 37.3 | 37.7 |
| C .J. Strike | ROR | 49.9 | 54.8 | 47.7 | 52.4 | 52.7 | 47.0 | 36.4 | 28.8 | 43.7 | 49.9 | 48.4 | 48.9 | 46.7 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 24.3 | 29.1 | 22.2 | 25.1 | 28.5 | 28.2 | 22.4 | 15.6 | 23.2 | 25.5 | 23.9 | 23.8 | 24.3 |
| Milner | ROR | 9.0 | 24.2 | 4.6 | 8.7 | 18.2 | 18.2 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 8.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 16.3 | 17.9 | 15.8 | 17.3 | 17.4 | 15.6 | 12.8 | 10.1 | 14.7 | 16.4 | 15.9 | 16.0 | 15.5 |
| Twin Falls | ROR | 12.0 | 25.6 | 8.2 | 11.4 | 20.6 | 21.7 | 10.2 | 0.0 | 0.0 | 6.6 | 8.3 | 9.5 | 11.2 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 14.9 | 18.9 | 13.6 | 15.9 | 18.5 | 18.1 | 13.5 | 8.5 | 14.1 | 15.7 | 14.6 | 14.5 | 15.1 |
| Upper Salmon 3&4 | ROR | 14.0 | 17.4 | 12.8 | 14.8 | 17.1 | 16.7 | 12.8 | 8.5 | 13.3 | 14.6 | 13.7 | 13.6 | 14.1 |
| **HCC Total** | | **580.9** | **616.9** | **599.2** | **712.2** | **871.7** | **703.6** | **514.5** | **350.7** | **432.3** | **416.1** | **363.6** | **487.5** | **554.1** |
| **ROR Total** | | **217.5** | **282.6** | **213.7** | **260.8** | **330.1** | **339.6** | **276.7** | **205.6** | **223.9** | **220.8** | **202.0** | **208.5** | **248.5** |
| **Total** | | **798.4** | **899.5** | **812.9** | **973.0** | **1201.8** | **1043.2** | **791.2** | **556.3** | **656.1** | **636.9** | **565.6** | **696.0** | **802.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2017** | **2/2017** | **3/2017** | **4/2017** | **5/2017** | **6/2017** | **7/2017** | **8/2017** | **9/2017** | **10/2017** | **11/2017** | **12/2017** | **aMW** |
| Brownlee | HCC* | 257.0 | 270.2 | 259.3 | 312.5 | 389.8 | 316.5 | 227.1 | 148.6 | 182.7 | 177.6 | 156.1 | 216.4 | 242.8 |
| Oxbow | HCC | 108.4 | 115.3 | 110.6 | 127.9 | 157.4 | 127.8 | 96.3 | 67.6 | 83.9 | 79.4 | 69.6 | 90.6 | 102.9 |
| Hells Canyon | HCC | 214.6 | 230.0 | 225.8 | 259.7 | 319.8 | 258.1 | 190.0 | 133.2 | 164.5 | 156.7 | 138.2 | 179.5 | 205.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 12.8 | 13.2 | 37.3 | 72.7 | 89.3 | 83.0 | 61.2 | 36.0 | 13.6 | 0.0 | 0.0 | 34.9 |
| Bliss | ROR | 38.5 | 41.7 | 36.0 | 37.8 | 42.4 | 40.4 | 34.4 | 27.4 | 36.4 | 39.1 | 37.4 | 37.2 | 37.4 |
| C .J. Strike | ROR | 49.8 | 54.7 | 47.4 | 52.0 | 52.6 | 46.8 | 36.2 | 28.6 | 43.5 | 49.8 | 48.1 | 48.8 | 46.5 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 24.2 | 28.5 | 21.9 | 24.1 | 28.5 | 28.1 | 22.3 | 15.5 | 23 | 25.4 | 23.8 | 23.7 | 24.1 |
| Milner | ROR | 8.9 | 22.2 | 2.4 | 6.2 | 18.2 | 18.2 | 5.9 | 0 | 0 | 0 | 3.6 | 6.2 | 7.7 |
| Shoshone Falls | ROR | 12 | 12 | 10.2 | 12 | 12 | 12 | 12 | 6.9 | 6.7 | 10.5 | 12 | 12 | 10.9 |
| Swan Falls | ROR | 16.3 | 17.9 | 15.7 | 17.1 | 17.3 | 15.5 | 12.7 | 10.1 | 14.6 | 16.3 | 15.9 | 16 | 15.5 |
| Twin Falls | ROR | 11.7 | 23.8 | 6.4 | 9.5 | 20.6 | 21.4 | 10.2 | 0 | 0 | 6.6 | 8.4 | 9.5 | 10.7 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 14.9 | 18.4 | 13.4 | 15.1 | 18.5 | 18.0 | 13.5 | 8.4 | 14.0 | 15.6 | 14.5 | 14.4 | 14.9 |
| Upper Salmon 3&4 | ROR | 13.9 | 16.9 | 12.6 | 14.1 | 17.0 | 16.6 | 12.7 | 8.4 | 13.2 | 14.6 | 13.6 | 13.5 | 13.9 |
| **HCC Total** | | **580.0** | **615.5** | **595.7** | **700.1** | **867.0** | **702.4** | **513.4** | **349.4** | **431.0** | **413.7** | **363.9** | **486.5** | **551.6** |
| **ROR Total** | | **216.8** | **275.2** | **206.3** | **250.7** | **329.8** | **338.4** | **276.0** | **204.9** | **222.9** | **220.3** | **201.3** | **208.0** | **245.9** |
| **Total** | | **796.8** | **890.7** | **802.0** | **950.8** | **1196.8** | **1040.8** | **789.4** | **554.3** | **653.9** | **634.0** | **565.2** | **694.5** | **797.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2018** | **2/2018** | **3/2018** | **4/2018** | **5/2018** | **6/2018** | **7/2018** | **8/2018** | **9/2018** | **10/2018** | **11/2018** | **12/2018** | **aMW** |
| Brownlee | HCC* | 256.6 | 265.8 | 255.9 | 311.9 | 389.4 | 312.7 | 226.6 | 148.0 | 182.2 | 176.2 | 156.1 | 213.6 | 241.2 |
| Oxbow | HCC | 108.3 | 113.4 | 109.2 | 127.7 | 157.2 | 126.3 | 96.0 | 67.4 | 83.6 | 78.7 | 69.6 | 89.4 | 102.2 |
| Hells Canyon | HCC | 214.3 | 226.3 | 223.0 | 259.2 | 319.5 | 255.2 | 189.5 | 132.7 | 163.9 | 155.4 | 138.1 | 177.2 | 204.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0 | 6 | 13 | 37.3 | 73.35 | 89.3 | 83.1 | 61.1 | 35.8 | 13.4 | 0 | 0 | 34.4 |
| Bliss | ROR | 38 | 39.7 | 35.9 | 37.6 | 42.1 | 40.3 | 34.3 | 27.2 | 36.2 | 39 | 37.3 | 37 | 37.1 |
| C .J. Strike | ROR | 49.7 | 52.5 | 47.3 | 51.9 | 52.5 | 46.6 | 36.1 | 28.4 | 43.3 | 49.5 | 47.9 | 48.6 | 46.2 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.05 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 23.9 | 24.6 | 21.9 | 23.9 | 28.4 | 28 | 22.1 | 15.3 | 22.9 | 25.2 | 23.7 | 23.5 | 23.6 |
| Milner | ROR | 8.9 | 11 | 2.4 | 6.4 | 18.2 | 18.2 | 5.9 | 0 | 0 | 0 | 3.6 | 6.2 | 6.7 |
| Shoshone Falls | ROR | 12 | 12 | 10.2 | 12 | 12 | 12 | 12 | 6.9 | 6.7 | 10.5 | 12 | 12 | 10.9 |
| Swan Falls | ROR | 16.3 | 17.3 | 15.8 | 17 | 17.3 | 15.4 | 12.7 | 10 | 14.6 | 16.3 | 15.8 | 15.9 | 15.4 |
| Twin Falls | ROR | 11.5 | 14.1 | 6.4 | 9.2 | 20.6 | 21 | 10.2 | 0 | 0 | 6.6 | 8.4 | 9.5 | 9.8 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 14.7 | 15.4 | 13.3 | 15.0 | 18.4 | 17.9 | 13.4 | 8.3 | 13.9 | 15.5 | 14.4 | 14.3 | 14.5 |
| Upper Salmon 3&4 | ROR | 13.8 | 14.4 | 12.6 | 14.0 | 17.0 | 16.5 | 12.6 | 8.3 | 13.1 | 14.5 | 13.5 | 13.4 | 13.6 |
| **HCC Total** | | **579.2** | **605.5** | **588.1** | **698.8** | **866.1** | **694.2** | **512.1** | **348.1** | **429.6** | **410.3** | **363.8** | **480.2** | **548.0** |
| **ROR Total** | | **215.4** | **233.3** | **205.9** | **249.8** | **329.9** | **337.3** | **275.5** | **203.9** | **222.1** | **219.3** | **200.6** | **207.1** | **241.7** |
| **Total** | | **794.6** | **838.8** | **794.0** | **948.6** | **1196.0** | **1031.5** | **787.6** | **552.0** | **651.7** | **629.6** | **564.4** | **687.3** | **789.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2019** | **2/2019** | **3/2019** | **4/2019** | **5/2019** | **6/2019** | **7/2019** | **8/2019** | **9/2019** | **10/2019** | **11/2019** | **12/2019** | **aMW** |
| Brownlee | HCC* | 256.2 | 264.3 | 255.9 | 310.0 | 389.1 | 310.8 | 226.1 | 147.4 | 181.6 | 167.5 | 156.0 | 211.0 | 239.7 |
| Oxbow | HCC | 108.1 | 112.8 | 109.2 | 126.9 | 157.1 | 125.5 | 95.8 | 67.1 | 83.3 | 78.0 | 69.4 | 88.3 | 101.8 |
| Hells Canyon | HCC | 214.0 | 225.0 | 223.0 | 257.8 | 319.2 | 253.7 | 189.1 | 132.2 | 163.4 | 153.5 | 137.9 | 175.0 | 203.7 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0 | 0 | 12.5 | 36.6 | 73.3 | 89.2 | 83.1 | 60.6 | 35.2 | 13.7 | 0 | 0 | 33.7 |
| Bliss | ROR | 37.9 | 39.3 | 35.8 | 37.2 | 42 | 40.2 | 34.2 | 27.1 | 36.1 | 38.8 | 37 | 36.9 | 36.9 |
| C .J. Strike | ROR | 49.6 | 51.5 | 47.2 | 51.5 | 52.4 | 46.4 | 35.9 | 28.1 | 43 | 49.3 | 47.7 | 48.5 | 45.9 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.05 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 23.8 | 24.3 | 21.6 | 22.7 | 28.3 | 27.9 | 22.0 | 15.2 | 22.8 | 25.1 | 23.5 | 23.5 | 23.4 |
| Milner | ROR | 8.9 | 10.1 | 0.0 | 4.7 | 18.2 | 18.2 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 6.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 9.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.8 |
| Swan Falls | ROR | 16.2 | 17.0 | 15.6 | 16.8 | 17.3 | 15.4 | 12.7 | 9.9 | 14.5 | 16.2 | 15.7 | 15.9 | 15.3 |
| Twin Falls | ROR | 11.5 | 13.3 | 5.4 | 8.5 | 20.6 | 21.0 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 9.6 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 14.6 | 15.1 | 13.1 | 14.0 | 18.3 | 17.8 | 13.3 | 8.2 | 13.8 | 15.4 | 14.2 | 14.3 | 14.3 |
| Upper Salmon 3&4 | ROR | 13.7 | 14.1 | 12.4 | 13.2 | 16.9 | 16.5 | 12.6 | 8.2 | 13.0 | 14.4 | 13.4 | 13.4 | 13.5 |
| **HCC Total** | | **578.3** | **602.1** | **588.1** | **694.7** | **865.4** | **690.0** | **511.0** | **346.7** | **428.2** | **399.0** | **363.3** | **474.3** | **545.1** |
| **ROR Total** | | **214.8** | **223.0** | **199.7** | **242.7** | **329.3** | **336.7** | **275.0** | **202.6** | **220.7** | **218.8** | **199.5** | **206.9** | **239.1** |
| **Total** | | **793.1** | **825.1** | **787.8** | **937.4** | **1194.7** | **1026.7** | **786.0** | **549.3** | **648.9** | **617.8** | **562.8** | **681.2** | **784.2** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2020** | **2/2020** | **3/2020** | **4/2020** | **5/2020** | **6/2020** | **7/2020** | **8/2020** | **9/2020** | **10/2020** | **11/2020** | **12/2020** | **aMW** |
| Brownlee | HCC* | 255.7 | 262.7 | 255.8 | 308.3 | 388.7 | 309.5 | 225.5 | 146.8 | 180.9 | 166.0 | 156.4 | 208.4 | 238.7 |
| Oxbow | HCC | 107.9 | 112.1 | 109.1 | 126.2 | 156.9 | 125.0 | 95.6 | 66.8 | 83.0 | 77.2 | 69.6 | 87.2 | 101.4 |
| Hells Canyon | HCC | 213.6 | 223.7 | 222.9 | 256.5 | 319.0 | 252.8 | 188.6 | 131.7 | 162.8 | 152.0 | 138.1 | 172.9 | 202.9 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 11.6 | 36.9 | 73.3 | 89.1 | 83.1 | 60.5 | 35.2 | 13.7 | 0.0 | 0.0 | 33.6 |
| Bliss | ROR | 37.7 | 39.0 | 35.3 | 36.1 | 41.9 | 40.0 | 34.0 | 26.9 | 35.9 | 38.6 | 36.6 | 36.7 | 36.6 |
| C .J. Strike | ROR | 49.4 | 51.3 | 46.8 | 50.1 | 52.3 | 46.2 | 35.7 | 27.9 | 42.8 | 49.1 | 47.4 | 48.2 | 45.6 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 23.7 | 23.9 | 21.5 | 22.1 | 28.2 | 27.8 | 21.9 | 15.0 | 22.7 | 25.0 | 23.4 | 23.3 | 23.2 |
| Milner | ROR | 8.9 | 9.1 | 0.0 | 3.6 | 18.2 | 17.9 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 6.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 9.1 | 11.7 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.7 |
| Swan Falls | ROR | 16.2 | 17.0 | 15.5 | 16.5 | 17.3 | 15.3 | 12.6 | 9.9 | 14.5 | 16.2 | 15.7 | 15.8 | 15.2 |
| Twin Falls | ROR | 11.5 | 12.6 | 5.4 | 7.7 | 20.4 | 21.0 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 9.4 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 14.5 | 14.8 | 13.1 | 13.5 | 18.3 | 17.7 | 13.2 | 8.1 | 13.7 | 15.3 | 14.1 | 14.2 | 14.2 |
| Upper Salmon 3&4 | ROR | 13.6 | 13.9 | 12.4 | 12.8 | 16.9 | 16.4 | 12.5 | 8.1 | 12.9 | 14.3 | 13.3 | 13.3 | 13.4 |
| **HCC Total** | | **577.2** | **598.5** | **587.8** | **691.0** | **864.6** | **687.3** | **509.7** | **345.3** | **426.6** | **395.2** | **364.1** | **468.5** | **543.0** |
| **ROR Total** | | **214.1** | **219.9** | **197.8** | **236.5** | **328.8** | **335.5** | **274.2** | **201.7** | **219.9** | **218.1** | **198.5** | **205.9** | **237.6** |
| **Total** | | **791.3** | **818.4** | **785.6** | **927.5** | **1193.4** | **1022.8** | **783.9** | **547.0** | **646.5** | **613.3** | **562.6** | **674.4** | **780.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2021** | **2/2021** | **3/2021** | **4/2021** | **5/2021** | **6/2021** | **7/2021** | **8/2021** | **9/2021** | **10/2021** | **11/2021** | **12/2021** | **aMW** |
| Brownlee | HCC* | 255.2 | 260.1 | 255.7 | 306.4 | 388.4 | 307.9 | 224.8 | 146.1 | 180.1 | 165.9 | 156.1 | 212.9 | 238.3 |
| Oxbow | HCC | 107.7 | 111.0 | 109.1 | 125.5 | 156.8 | 124.4 | 95.3 | 66.5 | 82.6 | 77.1 | 69.5 | 89.1 | 101.2 |
| Hells Canyon | HCC | 213.1 | 221.6 | 222.9 | 255.0 | 318.7 | 251.5 | 188.1 | 131.1 | 162.1 | 151.9 | 138.0 | 176.6 | 202.6 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 10.3 | 35.6 | 73.3 | 88.9 | 83.0 | 60.4 | 35.0 | 13.7 | 0.0 | 0.0 | 33.3 |
| Bliss | ROR | 37.6 | 38.9 | 35.1 | 36.8 | 41.8 | 39.9 | 33.9 | 26.7 | 35.7 | 38.5 | 36.4 | 36.5 | 36.5 |
| C .J. Strike | ROR | 49.2 | 51.2 | 46.7 | 49.9 | 52.2 | 45.7 | 35.5 | 27.6 | 42.5 | 48.9 | 47.2 | 47.8 | 45.4 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 23.3 | 23.7 | 21.4 | 22.5 | 28.1 | 27.7 | 21.7 | 14.8 | 22.5 | 24.8 | 23.1 | 23.2 | 23.1 |
| Milner | ROR | 8.9 | 9.1 | 0.0 | 4.6 | 17.4 | 17.1 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 6.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 9.1 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.8 |
| Swan Falls | ROR | 16.0 | 16.9 | 15.5 | 16.4 | 17.2 | 15.2 | 12.6 | 9.8 | 14.4 | 16.1 | 15.6 | 15.7 | 15.1 |
| Twin Falls | ROR | 11.5 | 12.6 | 5.4 | 8.1 | 20.1 | 20.6 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 9.4 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 14.2 | 14.7 | 13.0 | 13.9 | 18.2 | 17.6 | 13.1 | 8.0 | 13.6 | 15.2 | 13.9 | 14.1 | 14.1 |
| Upper Salmon 3&4 | ROR | 13.4 | 13.8 | 12.3 | 13.1 | 16.8 | 16.3 | 12.4 | 8.0 | 12.8 | 14.2 | 13.1 | 13.2 | 13.3 |
| **HCC Total** | | **576.0** | **592.7** | **587.7** | **686.9** | **863.9** | **683.8** | **508.2** | **343.7** | **424.8** | **394.9** | **363.6** | **478.6** | **542.1** |
| **ROR Total** | | **212.7** | **219.2** | **195.9** | **238.4** | **327.1** | **333.1** | **273.4** | **200.6** | **218.7** | **217.3** | **197.3** | **204.9** | **236.6** |
| **Total** | | **788.7** | **811.9** | **783.6** | **925.3** | **1191.0** | **1016.9** | **781.6** | **544.3** | **643.5** | **612.2** | **560.9** | **683.5** | **778.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2022** | **2/2022** | **3/2022** | **4/2022** | **5/2022** | **6/2022** | **7/2022** | **8/2022** | **9/2022** | **10/2022** | **11/2022** | **12/2022** | **aMW** |
| Brownlee | HCC* | 254.7 | 259.7 | 255.7 | 305.5 | 388.0 | 307.1 | 224.2 | 145.5 | 179.5 | 164.3 | 156.2 | 209.3 | 237.5 |
| Oxbow | HCC | 107.4 | 110.8 | 109.1 | 125.1 | 156.7 | 124.1 | 95.0 | 66.2 | 82.3 | 76.3 | 69.4 | 87.6 | 100.8 |
| Hells Canyon | HCC | 212.7 | 221.2 | 222.8 | 254.3 | 318.4 | 250.9 | 187.5 | 130.5 | 161.5 | 150.4 | 137.9 | 173.6 | 201.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0 | 0 | 10.1 | 35.6 | 73.3 | 88.9 | 83.1 | 60.3 | 34.85 | 13.6 | 0 | 0 | 33.3 |
| Bliss | ROR | 37.5 | 38.6 | 35 | 36.6 | 41.7 | 39.7 | 33.7 | 26.5 | 35.5 | 38.3 | 36.2 | 36.4 | 36.3 |
| C .J. Strike | ROR | 49.1 | 50.7 | 46.6 | 49.6 | 52 | 45.5 | 35.2 | 27.4 | 42.3 | 48.7 | 46.9 | 47.6 | 45.1 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.05 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 23.1 | 23.6 | 21.3 | 22.3 | 28.1 | 27.5 | 21.6 | 14.7 | 22.3 | 24.6 | 22.9 | 23.1 | 22.9 |
| Milner | ROR | 8.9 | 9.1 | 0.0 | 2.7 | 17.0 | 17.0 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 5.9 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.6 | 11.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.6 |
| Swan Falls | ROR | 16.0 | 16.8 | 15.5 | 16.3 | 17.2 | 15.4 | 12.5 | 9.7 | 14.3 | 16.0 | 15.5 | 15.7 | 15.1 |
| Twin Falls | ROR | 11.5 | 12.6 | 4.8 | 7.1 | 20.1 | 20.6 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 9.3 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 14.1 | 14.6 | 12.9 | 13.7 | 18.2 | 17.5 | 12.9 | 7.8 | 13.4 | 15.1 | 13.8 | 14.0 | 14.0 |
| Upper Salmon 3&4 | ROR | 13.2 | 13.7 | 12.2 | 12.9 | 16.8 | 16.2 | 12.3 | 7.9 | 12.7 | 14.1 | 13.0 | 13.1 | 13.2 |
| **HCC Total** | | **574.8** | **591.7** | **587.6** | **684.9** | **863.1** | **682.1** | **506.7** | **342.2** | **423.2** | **391.0** | **363.5** | **470.5** | **540.1** |
| **ROR Total** | | **212.0** | **218.0** | **194.1** | **233.3** | **326.4** | **332.4** | **272.5** | **199.6** | **217.6** | **216.3** | **196.3** | **204.3** | **235.2** |
| **Total** | | **786.8** | **809.7** | **781.7** | **918.2** | **1189.5** | **1014.5** | **779.2** | **541.8** | **640.8** | **607.3** | **559.8** | **674.8** | **775.3** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2023** | **2/2023** | **3/2023** | **4/2023** | **5/2023** | **6/2023** | **7/2023** | **8/2023** | **9/2023** | **10/2023** | **11/2023** | **12/2023** | **aMW** |
| Brownlee | HCC* | 254.2 | 259.4 | 255.6 | 304.3 | 387.6 | 306.6 | 223.5 | 144.8 | 178.9 | 162.6 | 156.6 | 205.8 | 236.7 |
| Oxbow | HCC | 107.2 | 110.7 | 109.0 | 124.6 | 156.5 | 123.9 | 94.7 | 65.9 | 82.1 | 75.4 | 69.5 | 86.1 | 100.5 |
| Hells Canyon | HCC | 212.3 | 221.0 | 222.7 | 253.3 | 318.1 | 250.5 | 187.0 | 129.9 | 161.0 | 148.7 | 138.1 | 170.7 | 201.1 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 9.1 | 36.0 | 73.3 | 88.9 | 83.1 | 60.3 | 34.8 | 13.6 | 0.0 | 0.0 | 33.3 |
| Bliss | ROR | 37.3 | 37.6 | 34.9 | 35.8 | 41.6 | 39.6 | 33.5 | 26.3 | 35.3 | 38.1 | 36.0 | 36.2 | 36.0 |
| C .J. Strike | ROR | 48.6 | 49.7 | 46.5 | 49.3 | 51.9 | 45.3 | 35.0 | 27.1 | 42.0 | 48.5 | 46.6 | 46.8 | 44.8 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 23.0 | 23.5 | 21.3 | 21.8 | 28.0 | 27.3 | 21.4 | 14.5 | 22.1 | 24.5 | 22.7 | 22.8 | 22.7 |
| Milner | ROR | 8.9 | 8.7 | 0.0 | 0.0 | 17.0 | 17.0 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 5.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.6 | 8.1 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.4 |
| Swan Falls | ROR | 15.9 | 16.3 | 15.3 | 16.3 | 17.2 | 15.3 | 12.4 | 9.7 | 14.2 | 16.0 | 15.4 | 15.5 | 15.0 |
| Twin Falls | ROR | 11.5 | 11.8 | 4.8 | 4.4 | 20.1 | 20.6 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 9.0 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 14.0 | 14.5 | 12.9 | 13.3 | 18.1 | 17.4 | 12.8 | 7.7 | 13.3 | 14.9 | 13.6 | 13.8 | 13.9 |
| Upper Salmon 3&4 | ROR | 13.2 | 13.6 | 12.2 | 12.6 | 16.7 | 16.1 | 12.2 | 7.8 | 12.6 | 14.0 | 12.8 | 13.0 | 13.1 |
| **HCC Total** | | **573.7** | **591.1** | **587.3** | **682.2** | **862.2** | **681.0** | **505.2** | **340.6** | **421.9** | **386.7** | **364.2** | **462.6** | **538.2** |
| **ROR Total** | | **211.0** | **214.0** | **192.7** | **223.1** | **325.9** | **331.6** | **271.6** | **198.7** | **216.6** | **215.5** | **195.1** | **202.5** | **233.2** |
| **Total** | | **784.7** | **805.1** | **780.0** | **905.3** | **1188.1** | **1012.6** | **776.8** | **539.3** | **638.4** | **602.2** | **559.3** | **665.1** | **771.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2024** | **2/2024** | **3/2024** | **4/2024** | **5/2024** | **6/2024** | **7/2024** | **8/2024** | **9/2024** | **10/2024** | **11/2024** | **12/2024** | **aMW** |
| Brownlee | HCC* | 253.7 | 259.0 | 255.5 | 302.0 | 387.2 | 305.9 | 222.9 | 144.2 | 178.6 | 161.3 | 156.7 | 203.7 | 235.9 |
| Oxbow | HCC | 107.0 | 110.5 | 109.0 | 123.7 | 156.3 | 123.6 | 94.5 | 65.6 | 81.9 | 74.7 | 69.5 | 85.2 | 100.1 |
| Hells Canyon | HCC | 211.9 | 220.6 | 222.7 | 251.6 | 317.8 | 250.0 | 186.5 | 129.3 | 160.7 | 147.4 | 138.0 | 168.9 | 200.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 8.0 | 35.6 | 73.3 | 88.9 | 83.1 | 60.2 | 34.8 | 13.5 | 0.0 | 0.0 | 33.1 |
| Bliss | ROR | 37.2 | 37.5 | 34.8 | 35.5 | 41.5 | 39.4 | 33.4 | 26.1 | 35.1 | 38.0 | 35.8 | 35.9 | 35.9 |
| C .J. Strike | ROR | 47.8 | 49.4 | 46.5 | 48.2 | 51.8 | 45.2 | 34.8 | 26.9 | 41.7 | 48.3 | 46.4 | 46.6 | 44.5 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.8 | 23.4 | 21.0 | 20.9 | 27.9 | 27.2 | 21.3 | 14.3 | 22.0 | 24.4 | 22.5 | 22.6 | 22.5 |
| Milner | ROR | 8.2 | 8.3 | 0.0 | 0.0 | 17.0 | 17.0 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 5.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.5 | 4.8 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.1 |
| Swan Falls | ROR | 15.7 | 16.2 | 15.3 | 16.0 | 17.1 | 15.3 | 12.4 | 9.6 | 14.1 | 15.9 | 15.4 | 15.5 | 14.9 |
| Twin Falls | ROR | 11.5 | 11.2 | 4.8 | 0.0 | 19.9 | 20.6 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 8.6 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.8 | 14.4 | 12.7 | 12.7 | 18.0 | 17.2 | 12.7 | 7.6 | 13.2 | 14.9 | 13.5 | 13.6 | 13.7 |
| Upper Salmon 3&4 | ROR | 13.0 | 13.5 | 12.0 | 12.0 | 16.7 | 16.0 | 12.1 | 7.7 | 12.5 | 13.9 | 12.7 | 12.8 | 12.9 |
| **HCC Total** | | **572.6** | **590.1** | **587.2** | **677.3** | **861.3** | **679.5** | **503.9** | **339.1** | **421.1** | **383.4** | **364.2** | **457.8** | **536.5** |
| **ROR Total** | | **208.6** | **212.2** | **190.7** | **211.2** | **325.2** | **330.9** | **271.0** | **197.7** | **215.6** | **214.8** | **194.3** | **201.4** | **231.1** |
| **Total** | | **781.2** | **802.3** | **777.9** | **888.5** | **1186.5** | **1010.4** | **774.9** | **536.8** | **636.7** | **598.2** | **558.5** | **659.2** | **767.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2025** | **2/2025** | **3/2025** | **4/2025** | **5/2025** | **6/2025** | **7/2025** | **8/2025** | **9/2025** | **10/2025** | **11/2025** | **12/2025** | **aMW** |
| Brownlee | HCC* | 253.2 | 258.4 | 255.4 | 297.3 | 386.9 | 305.3 | 222.2 | 143.5 | 178.1 | 159.6 | 156.9 | 203.1 | 235.0 |
| Oxbow | HCC | 106.8 | 110.3 | 109.0 | 121.9 | 156.2 | 123.4 | 94.2 | 65.3 | 81.7 | 73.8 | 69.6 | 84.9 | 99.8 |
| Hells Canyon | HCC | 211.5 | 220.2 | 222.6 | 247.9 | 317.5 | 249.6 | 185.9 | 128.8 | 160.2 | 145.7 | 138.1 | 168.5 | 199.7 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 8.0 | 35.5 | 73.3 | 88.8 | 83.0 | 60.2 | 34.8 | 13.5 | 0.0 | 0.0 | 33.1 |
| Bliss | ROR | 36.7 | 37.4 | 34.7 | 34.8 | 41.4 | 39.3 | 33.2 | 25.9 | 34.9 | 37.8 | 35.6 | 35.8 | 35.6 |
| C .J. Strike | ROR | 47.6 | 49.3 | 46.2 | 48.0 | 51.7 | 45.0 | 34.6 | 26.7 | 41.4 | 48.0 | 46.1 | 46.2 | 44.2 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.7 | 23.3 | 21 | 20.7 | 27.8 | 27 | 21.2 | 14.2 | 21.8 | 24.3 | 22.4 | 22.5 | 22.4 |
| Milner | ROR | 8.2 | 8.3 | 0 | 0 | 17 | 17 | 5.9 | 0 | 0 | 0 | 3.6 | 6.2 | 5.5 |
| Shoshone Falls | ROR | 12 | 12 | 8.5 | 4.8 | 12 | 12 | 12 | 6.9 | 6.7 | 10.5 | 12 | 12 | 10.1 |
| Swan Falls | ROR | 15.6 | 16.2 | 15.3 | 15.9 | 17.1 | 15.2 | 12.3 | 9.5 | 14.1 | 15.9 | 15.3 | 15.4 | 14.8 |
| Twin Falls | ROR | 11.5 | 11.2 | 4.8 | 0 | 19.9 | 20.6 | 10.2 | 0 | 0 | 6.6 | 8.4 | 9.5 | 8.6 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.8 | 14.3 | 12.6 | 12.5 | 18.0 | 17.2 | 12.6 | 7.5 | 13.0 | 14.8 | 13.4 | 13.5 | 13.6 |
| Upper Salmon 3&4 | ROR | 13.0 | 13.5 | 12.0 | 11.9 | 16.6 | 15.9 | 12.0 | 7.6 | 12.4 | 13.9 | 12.6 | 12.7 | 12.8 |
| **HCC Total** | | **571.5** | **588.9** | **587.0** | **667.1** | **860.6** | **678.3** | **502.3** | **337.6** | **419.9** | **379.1** | **364.6** | **456.5** | **534.5** |
| **ROR Total** | | **207.7** | **211.8** | **190.2** | **209.6** | **324.8** | **330.1** | **270.1** | **196.9** | **214.6** | **214.1** | **193.4** | **200.5** | **230.3** |
| **Total** | | **779.2** | **800.7** | **777.2** | **876.7** | **1185.4** | **1008.4** | **772.4** | **534.5** | **634.5** | **593.2** | **558.0** | **657.0** | **764.8** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2026** | **2/2026** | **3/2026** | **4/2026** | **5/2026** | **6/2026** | **7/2026** | **8/2026** | **9/2026** | **10/2026** | **11/2026** | **12/2026** | **aMW** |
| Brownlee | HCC* | 252.3 | 257.9 | 255.2 | 297.0 | 386.5 | 304.7 | 221.6 | 142.9 | 177.5 | 157.9 | 157.0 | 203.0 | 234.5 |
| Oxbow | HCC | 106.4 | 110.1 | 108.9 | 121.7 | 156.1 | 123.1 | 93.9 | 65.0 | 81.4 | 73.0 | 69.5 | 84.9 | 99.5 |
| Hells Canyon | HCC | 210.8 | 219.8 | 222.4 | 247.7 | 317.3 | 249.1 | 185.4 | 128.2 | 159.7 | 144.1 | 138.1 | 168.4 | 199.3 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 7.0 | 35.5 | 73.3 | 88.8 | 83.0 | 60.1 | 34.8 | 13.5 | 0.0 | 0.0 | 33.0 |
| Bliss | ROR | 36.5 | 37.3 | 34.6 | 34.7 | 41.3 | 39.2 | 33.0 | 25.7 | 34.7 | 37.7 | 35.4 | 35.6 | 35.5 |
| C .J. Strike | ROR | 47.4 | 49.1 | 45.9 | 47.9 | 51.6 | 44.8 | 34.4 | 26.4 | 41.2 | 47.8 | 45.9 | 46.1 | 44.0 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.5 | 23.2 | 20.9 | 20.7 | 27.8 | 26.9 | 21.0 | 14.0 | 21.6 | 24.2 | 22.2 | 22.3 | 22.3 |
| Milner | ROR | 7.6 | 8.3 | 0.0 | 0.0 | 17.0 | 17.0 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 5.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.5 | 4.7 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.1 |
| Swan Falls | ROR | 15.6 | 16.1 | 15.2 | 15.8 | 17.1 | 15.2 | 12.2 | 9.4 | 14.1 | 15.8 | 15.2 | 15.3 | 14.8 |
| Twin Falls | ROR | 10.6 | 11.2 | 4.8 | 0.0 | 19.9 | 20.6 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 8.5 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.6 | 14.3 | 12.6 | 12.4 | 17.9 | 17.0 | 12.5 | 7.3 | 12.9 | 14.7 | 13.2 | 13.4 | 13.5 |
| Upper Salmon 3&4 | ROR | 12.8 | 13.4 | 12.0 | 11.8 | 16.6 | 15.8 | 11.9 | 7.5 | 12.2 | 13.8 | 12.5 | 12.7 | 12.8 |
| **HCC Total** | | **569.5** | **587.8** | **586.5** | **666.4** | **859.9** | **676.9** | **500.9** | **336.1** | **418.6** | **375.0** | **364.6** | **456.3** | **533.2** |
| **ROR Total** | | **205.2** | **211.2** | **188.6** | **209.0** | **324.5** | **329.4** | **269.2** | **195.7** | **213.7** | **213.4** | **192.4** | **199.8** | **229.3** |
| **Total** | | **774.7** | **799.0** | **775.1** | **875.4** | **1184.4** | **1006.3** | **770.1** | **531.8** | **632.3** | **588.4** | **557.0** | **656.1** | **762.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2027** | **2/2027** | **3/2027** | **4/2027** | **5/2027** | **6/2027** | **7/2027** | **8/2027** | **9/2027** | **10/2027** | **11/2027** | **12/2027** | **aMW** |
| Brownlee | HCC* | 248.9 | 257.4 | 255.0 | 296.6 | 386.1 | 304.1 | 221.0 | 142.3 | 176.9 | 156.8 | 157.1 | 202.4 | 233.7 |
| Oxbow | HCC | 105.0 | 109.8 | 108.8 | 121.5 | 155.9 | 122.9 | 93.7 | 64.7 | 81.1 | 72.4 | 69.5 | 84.6 | 99.2 |
| Hells Canyon | HCC | 208.0 | 219.3 | 222.3 | 247.3 | 316.9 | 248.6 | 184.9 | 127.6 | 159.2 | 143.1 | 138.1 | 167.9 | 198.6 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 7.0 | 35.5 | 73.3 | 88.7 | 82.9 | 60.0 | 34.7 | 13.5 | 0.0 | 0.0 | 33.0 |
| Bliss | ROR | 36.3 | 37.0 | 34.5 | 34.6 | 41.0 | 38.7 | 32.9 | 25.5 | 34.6 | 37.5 | 35.2 | 35.5 | 35.3 |
| C .J. Strike | ROR | 47.1 | 49.0 | 45.6 | 47.5 | 51.5 | 44.5 | 34.2 | 26.2 | 41.0 | 47.6 | 45.6 | 45.9 | 43.8 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.4 | 23.1 | 20.8 | 20.6 | 27.7 | 26.8 | 20.9 | 13.9 | 21.5 | 24.0 | 22.1 | 22.2 | 22.2 |
| Milner | ROR | 6.9 | 8.3 | 0.0 | 0.0 | 17.0 | 17.0 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 5.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.0 | 4.7 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.1 |
| Swan Falls | ROR | 15.5 | 16.1 | 15.4 | 15.8 | 17.0 | 15.1 | 12.2 | 9.3 | 14.0 | 15.7 | 15.4 | 15.3 | 14.7 |
| Twin Falls | ROR | 10.0 | 11.2 | 4.4 | 0.0 | 19.9 | 20.6 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 8.4 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.5 | 14.2 | 12.5 | 12.4 | 17.9 | 17.0 | 12.4 | 7.2 | 12.8 | 14.6 | 13.1 | 13.3 | 13.4 |
| Upper Salmon 3&4 | ROR | 12.7 | 13.3 | 11.9 | 11.8 | 16.5 | 15.7 | 11.8 | 7.4 | 12.1 | 13.7 | 12.4 | 12.6 | 12.7 |
| **HCC Total** | | **561.9** | **586.5** | **586.1** | **665.4** | **858.9** | **675.6** | **499.6** | **334.6** | **417.1** | **372.3** | **364.7** | **454.9** | **531.5** |
| **ROR Total** | | **203.0** | **210.5** | **187.2** | **208.4** | **323.8** | **328.2** | **268.5** | **194.8** | **213.0** | **212.5** | **191.8** | **199.2** | **228.4** |
| **Total** | | **764.9** | **797.0** | **773.3** | **873.8** | **1182.7** | **1003.8** | **768.1** | **529.4** | **630.1** | **584.8** | **556.5** | **654.1** | **759.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2028** | **2/2028** | **3/2028** | **4/2028** | **5/2028** | **6/2028** | **7/2028** | **8/2028** | **9/2028** | **10/2028** | **11/2028** | **12/2028** | **aMW** |
| Brownlee | HCC* | 248.9 | 257.4 | 255.0 | 296.6 | 386.1 | 304.1 | 221.0 | 142.3 | 176.9 | 156.8 | 157.1 | 202.4 | 233.7 |
| Oxbow | HCC | 105.0 | 109.8 | 108.8 | 121.5 | 155.9 | 122.9 | 93.7 | 64.7 | 81.1 | 72.4 | 69.5 | 84.6 | 99.2 |
| Hells Canyon | HCC | 208.0 | 219.3 | 222.3 | 247.3 | 316.9 | 248.6 | 184.9 | 127.6 | 159.2 | 143.1 | 138.1 | 167.9 | 198.6 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 7.0 | 35.5 | 73.3 | 88.7 | 82.9 | 60.0 | 34.7 | 13.5 | 0.0 | 0.0 | 33.0 |
| Bliss | ROR | 36.3 | 37.0 | 34.5 | 34.6 | 41.0 | 38.7 | 32.9 | 25.5 | 34.6 | 37.5 | 35.2 | 35.5 | 35.3 |
| C .J. Strike | ROR | 47.1 | 49.0 | 45.6 | 47.5 | 51.5 | 44.5 | 34.2 | 26.2 | 41.0 | 47.6 | 45.6 | 45.9 | 43.8 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.4 | 23.1 | 20.8 | 20.6 | 27.7 | 26.8 | 20.9 | 13.9 | 21.5 | 24.0 | 22.1 | 22.2 | 22.2 |
| Milner | ROR | 6.9 | 8.3 | 0.0 | 0.0 | 17.0 | 17.0 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 5.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.0 | 4.7 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.1 |
| Swan Falls | ROR | 15.5 | 16.1 | 15.4 | 15.8 | 17.0 | 15.1 | 12.2 | 9.3 | 14.0 | 15.7 | 15.4 | 15.3 | 14.7 |
| Twin Falls | ROR | 10.0 | 11.2 | 4.4 | 0.0 | 19.9 | 20.6 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 8.4 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.5 | 14.2 | 12.5 | 12.4 | 17.9 | 17 | 12.4 | 7.2 | 12.8 | 14.6 | 13.1 | 13.3 | 13.4 |
| Upper Salmon 3&4 | ROR | 12.7 | 13.3 | 11.9 | 11.8 | 16.5 | 15.7 | 11.8 | 7.4 | 12.1 | 13.7 | 12.4 | 12.6 | 12.7 |
| **HCC Total** | | **561.9** | **586.5** | **586.1** | **665.4** | **858.9** | **675.6** | **499.6** | **334.6** | **417.1** | **372.3** | **364.7** | **454.9** | **531.5** |
| **ROR Total** | | **203.0** | **210.5** | **187.2** | **208.4** | **323.8** | **328.2** | **268.5** | **194.8** | **213.0** | **212.5** | **191.8** | **199.2** | **228.4** |
| **Total** | | **764.9** | **797.0** | **773.3** | **873.8** | **1182.7** | **1003.8** | **768.1** | **529.4** | **630.1** | **584.8** | **556.5** | **654.1** | **759.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2029** | **2/2029** | **3/2029** | **4/2029** | **5/2029** | **6/2029** | **7/2029** | **8/2029** | **9/2029** | **10/2029** | **11/2029** | **12/2029** | **aMW** |
| Brownlee | HCC* | 248.9 | 257.4 | 255.0 | 296.6 | 386.1 | 304.1 | 221.0 | 142.3 | 176.9 | 156.8 | 157.1 | 202.4 | 233.7 |
| Oxbow | HCC | 105.0 | 109.8 | 108.8 | 121.5 | 155.9 | 122.9 | 93.7 | 64.7 | 81.1 | 72.4 | 69.5 | 84.6 | 99.2 |
| Hells Canyon | HCC | 208.0 | 219.3 | 222.3 | 247.3 | 316.9 | 248.6 | 184.9 | 127.6 | 159.2 | 143.1 | 138.1 | 167.9 | 198.6 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 7.0 | 35.5 | 73.3 | 88.7 | 82.9 | 60.0 | 34.7 | 13.5 | 0.0 | 0.0 | 33.0 |
| Bliss | ROR | 36.3 | 37.0 | 34.5 | 34.6 | 41.0 | 38.7 | 32.9 | 25.5 | 34.6 | 37.5 | 35.2 | 35.5 | 35.3 |
| C .J. Strike | ROR | 47.1 | 49.0 | 45.6 | 47.5 | 51.5 | 44.5 | 34.2 | 26.2 | 41.0 | 47.6 | 45.6 | 45.9 | 43.8 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.4 | 23.1 | 20.8 | 20.6 | 27.7 | 26.8 | 20.9 | 13.9 | 21.5 | 24.0 | 22.1 | 22.2 | 22.2 |
| Milner | ROR | 6.9 | 8.3 | 0.0 | 0.0 | 17.0 | 17.0 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 5.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.0 | 4.7 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.1 |
| Swan Falls | ROR | 15.5 | 16.1 | 15.4 | 15.8 | 17.0 | 15.1 | 12.2 | 9.3 | 14.0 | 15.7 | 15.4 | 15.3 | 14.7 |
| Twin Falls | ROR | 10.0 | 11.2 | 4.4 | 0.0 | 19.9 | 20.6 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 8.4 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.5 | 14.2 | 12.5 | 12.4 | 17.9 | 17.0 | 12.4 | 7.2 | 12.8 | 14.6 | 13.1 | 13.3 | 13.4 |
| Upper Salmon 3&4 | ROR | 12.7 | 13.3 | 11.9 | 11.8 | 16.5 | 15.7 | 11.8 | 7.4 | 12.1 | 13.7 | 12.4 | 12.6 | 12.7 |
| **HCC Total** | | **561.9** | **586.5** | **586.1** | **665.4** | **858.9** | **675.6** | **499.6** | **334.6** | **417.1** | **372.3** | **364.7** | **454.9** | **531.5** |
| **ROR Total** | | **203.0** | **210.5** | **187.2** | **208.4** | **323.8** | **328.2** | **268.5** | **194.8** | **213.0** | **212.5** | **191.8** | **199.2** | **228.4** |
| **Total** | | **764.9** | **797.0** | **773.3** | **873.8** | **1182.7** | **1003.8** | **768.1** | **529.4** | **630.1** | **584.8** | **556.5** | **654.1** | **759.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2030** | **2/2030** | **3/2030** | **4/2030** | **5/2030** | **6/2030** | **7/2030** | **8/2030** | **9/2030** | **10/2030** | **11/2030** | **12/2030** | **aMW** |
| Brownlee | HCC* | 248.9 | 257.4 | 255.0 | 296.6 | 386.1 | 304.1 | 221.0 | 142.3 | 176.9 | 156.8 | 157.1 | 202.4 | 233.7 |
| Oxbow | HCC | 105.0 | 109.8 | 108.8 | 121.5 | 155.9 | 122.9 | 93.7 | 64.7 | 81.1 | 72.4 | 69.5 | 84.6 | 99.2 |
| Hells Canyon | HCC | 208.0 | 219.3 | 222.3 | 247.3 | 316.9 | 248.6 | 184.9 | 127.6 | 159.2 | 143.1 | 138.1 | 167.9 | 198.6 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 7.0 | 35.5 | 73.3 | 88.7 | 82.9 | 60.0 | 34.7 | 13.5 | 0.0 | 0.0 | 33.0 |
| Bliss | ROR | 36.3 | 37.0 | 34.5 | 34.6 | 41.0 | 38.7 | 32.9 | 25.5 | 34.6 | 37.5 | 35.2 | 35.5 | 35.3 |
| C .J. Strike | ROR | 47.1 | 49.0 | 45.6 | 47.5 | 51.5 | 44.5 | 34.2 | 26.2 | 41.0 | 47.6 | 45.6 | 45.9 | 43.8 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.4 | 23.1 | 20.8 | 20.6 | 27.7 | 26.8 | 20.9 | 13.9 | 21.5 | 24.0 | 22.1 | 22.2 | 22.2 |
| Milner | ROR | 6.9 | 8.3 | 0.0 | 0.0 | 17.0 | 17.0 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 5.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.0 | 4.7 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.1 |
| Swan Falls | ROR | 15.5 | 16.1 | 15.4 | 15.8 | 17.0 | 15.1 | 12.2 | 9.3 | 14.0 | 15.7 | 15.4 | 15.3 | 14.7 |
| Twin Falls | ROR | 10.0 | 11.2 | 4.4 | 0.0 | 19.9 | 20.6 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 8.4 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.5 | 14.2 | 12.5 | 12.4 | 17.9 | 17.0 | 12.4 | 7.2 | 12.8 | 14.6 | 13.1 | 13.3 | 13.4 |
| Upper Salmon 3&4 | ROR | 12.7 | 13.3 | 11.9 | 11.8 | 16.5 | 15.7 | 11.8 | 7.4 | 12.1 | 13.7 | 12.4 | 12.6 | 12.7 |
| **HCC Total** | | **561.9** | **586.5** | **586.1** | **665.4** | **858.9** | **675.6** | **499.6** | **334.6** | **417.1** | **372.3** | **364.7** | **454.9** | **531.5** |
| **ROR Total** | | **203.0** | **210.5** | **187.2** | **208.4** | **323.8** | **328.2** | **268.5** | **194.8** | **213.0** | **212.5** | **191.8** | **199.2** | **228.4** |
| **Total** | | **764.9** | **797.0** | **773.3** | **873.8** | **1182.7** | **1003.8** | **768.1** | **529.4** | **630.1** | **584.8** | **556.5** | **654.1** | **759.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2031** | **2/2031** | **3/2031** | **4/2031** | **5/2031** | **6/2031** | **7/2031** | **8/2031** | **9/2031** | **10/2031** | **11/2031** | **12/2031** | **aMW** |
| Brownlee | HCC* | 248.9 | 257.4 | 255.0 | 296.6 | 386.1 | 304.1 | 221.0 | 142.3 | 176.9 | 156.8 | 157.1 | 202.4 | 233.7 |
| Oxbow | HCC | 105.0 | 109.8 | 108.8 | 121.5 | 155.9 | 122.9 | 93.7 | 64.7 | 81.1 | 72.4 | 69.5 | 84.6 | 99.2 |
| Hells Canyon | HCC | 208.0 | 219.3 | 222.3 | 247.3 | 316.9 | 248.6 | 184.9 | 127.6 | 159.2 | 143.1 | 138.1 | 167.9 | 198.6 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 7.0 | 35.5 | 73.3 | 88.7 | 82.9 | 60.0 | 34.7 | 13.5 | 0.0 | 0.0 | 33.0 |
| Bliss | ROR | 36.3 | 37.0 | 34.5 | 34.6 | 41.0 | 38.7 | 32.9 | 25.5 | 34.6 | 37.5 | 35.2 | 35.5 | 35.3 |
| C .J. Strike | ROR | 47.1 | 49.0 | 45.6 | 47.5 | 51.5 | 44.5 | 34.2 | 26.2 | 41.0 | 47.6 | 45.6 | 45.9 | 43.8 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.4 | 23.1 | 20.8 | 20.6 | 27.7 | 26.8 | 20.9 | 13.9 | 21.5 | 24.0 | 22.1 | 22.2 | 22.2 |
| Milner | ROR | 6.9 | 8.3 | 0.0 | 0.0 | 17.0 | 17.0 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 5.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.0 | 4.7 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.1 |
| Swan Falls | ROR | 15.5 | 16.1 | 15.4 | 15.8 | 17.0 | 15.1 | 12.2 | 9.3 | 14.0 | 15.7 | 15.4 | 15.3 | 14.7 |
| Twin Falls | ROR | 10.0 | 11.2 | 4.4 | 0.0 | 19.9 | 20.6 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 8.4 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.5 | 14.2 | 12.5 | 12.4 | 17.9 | 17.0 | 12.4 | 7.2 | 12.8 | 14.6 | 13.1 | 13.3 | 13.4 |
| Upper Salmon 3&4 | ROR | 12.7 | 13.3 | 11.9 | 11.8 | 16.5 | 15.7 | 11.8 | 7.4 | 12.1 | 13.7 | 12.4 | 12.6 | 12.7 |
| **HCC Total** | | **561.9** | **586.5** | **586.1** | **665.4** | **858.9** | **675.6** | **499.6** | **334.6** | **417.1** | **372.3** | **364.7** | **454.9** | **531.5** |
| **ROR Total** | | **203.0** | **210.5** | **187.2** | **208.4** | **323.8** | **328.2** | **268.5** | **194.8** | **213.0** | **212.5** | **191.8** | **199.2** | **228.4** |
| **Total** | | **764.9** | **797.0** | **773.3** | **873.8** | **1182.7** | **1003.8** | **768.1** | **529.4** | **630.1** | **584.8** | **556.5** | **654.1** | **759.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2032** | **2/2032** | **3/2032** | **4/2032** | **5/2032** | **6/2032** | **7/2032** | **8/2032** | **9/2032** | **10/2032** | **11/2032** | **12/2032** | **aMW** |
| Brownlee | HCC* | 248.9 | 257.4 | 255.0 | 296.6 | 386.1 | 304.1 | 221.0 | 142.3 | 176.9 | 156.8 | 157.1 | 202.4 | 233.7 |
| Oxbow | HCC | 105.0 | 109.8 | 108.8 | 121.5 | 155.9 | 122.9 | 93.7 | 64.7 | 81.1 | 72.4 | 69.5 | 84.6 | 99.2 |
| Hells Canyon | HCC | 208.0 | 219.3 | 222.3 | 247.3 | 316.9 | 248.6 | 184.9 | 127.6 | 159.2 | 143.1 | 138.1 | 167.9 | 198.6 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 7.0 | 35.5 | 73.3 | 88.7 | 82.9 | 60.0 | 34.7 | 13.5 | 0.0 | 0.0 | 33.0 |
| Bliss | ROR | 36.3 | 37.0 | 34.5 | 34.6 | 41.0 | 38.7 | 32.9 | 25.5 | 34.6 | 37.5 | 35.2 | 35.5 | 35.3 |
| C .J. Strike | ROR | 47.1 | 49.0 | 45.6 | 47.5 | 51.5 | 44.5 | 34.2 | 26.2 | 41.0 | 47.6 | 45.6 | 45.9 | 43.8 |
| Cascade | ROR | 1.5 | 1.5 | 1.3 | 1.2 | 2.1 | 5.3 | 7.6 | 12.2 | 7.3 | 1.5 | 1.3 | 1.4 | 3.7 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.4 | 23.1 | 20.8 | 20.6 | 27.7 | 26.8 | 20.9 | 13.9 | 21.5 | 24.0 | 22.1 | 22.2 | 22.2 |
| Milner | ROR | 6.9 | 8.3 | 0.0 | 0.0 | 17.0 | 17.0 | 5.9 | 0.0 | 0.0 | 0.0 | 3.6 | 6.2 | 5.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.0 | 4.7 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 10.1 |
| Swan Falls | ROR | 15.5 | 16.1 | 15.4 | 15.8 | 17.0 | 15.1 | 12.2 | 9.3 | 14.0 | 15.7 | 15.4 | 15.3 | 14.7 |
| Twin Falls | ROR | 10.0 | 11.2 | 4.4 | 0.0 | 19.9 | 20.6 | 10.2 | 0.0 | 0.0 | 6.6 | 8.4 | 9.5 | 8.4 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.5 | 14.2 | 12.5 | 12.4 | 17.9 | 17.0 | 12.4 | 7.2 | 12.8 | 14.6 | 13.1 | 13.3 | 13.4 |
| Upper Salmon 3&4 | ROR | 12.7 | 13.3 | 11.9 | 11.8 | 16.5 | 15.7 | 11.8 | 7.4 | 12.1 | 13.7 | 12.4 | 12.6 | 12.7 |
| **HCC Total** | | **561.9** | **586.5** | **586.1** | **665.4** | **858.9** | **675.6** | **499.6** | **334.6** | **417.1** | **372.3** | **364.7** | **454.9** | **531.5** |
| **ROR Total** | | **203.0** | **210.5** | **187.2** | **208.4** | **323.8** | **328.2** | **268.5** | **194.8** | **213.0** | **212.5** | **191.8** | **199.2** | **228.4** |
| **Total** | | **764.9** | **797.0** | **773.3** | **873.8** | **1182.7** | **1003.8** | **768.1** | **529.4** | **630.1** | **584.8** | **556.5** | **654.1** | **759.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2013** | **2/2013** | **3/2013** | **4/2013** | **5/2013** | **6/2013** | **7/2013** | **8/2013** | **9/2013** | **10/2013** | **11/2013** | **12/2013** | **aMW** |
| Brownlee | HCC* | 200.7 | 199.7 | 244.5 | 251.3 | 294.0 | 213.0 | 214.2 | 150.3 | 152.4 | 156.4 | 158.7 | 194.2 | 202.5 |
| Oxbow | HCC | 83.5 | 82.9 | 101.7 | 104.6 | 119.0 | 88.3 | 90.4 | 68.4 | 70.1 | 71.0 | 69.7 | 80.9 | 85.9 |
| Hells Canyon | HCC | 165.2 | 165.0 | 205.8 | 212.3 | 241.6 | 177.7 | 177.7 | 134.2 | 137.5 | 140.0 | 138.1 | 159.9 | 171.3 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 29.7 | 71.0 | 86.4 | 83.8 | 56.4 | 25.7 | 9.1 | 0.0 | 0.0 | 30.2 |
| Bliss | ROR | 35.3 | 35.3 | 33.9 | 32.7 | 38.8 | 37.6 | 33.7 | 30.4 | 35.3 | 37.8 | 36.1 | 35.8 | 35.2 |
| C .J. Strike | ROR | 44.7 | 44.3 | 43.8 | 42.1 | 45.1 | 41.1 | 33.0 | 32.4 | 40.6 | 45.8 | 45.5 | 44.4 | 41.9 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.6 | 22.8 | 20.8 | 20.3 | 26.1 | 25.5 | 22.0 | 18.4 | 22.5 | 24.4 | 23.3 | 23.0 | 22.6 |
| Milner | ROR | 6.3 | 6.2 | 0.0 | 0.0 | 14.2 | 14.2 | 5.9 | 6.7 | 0.0 | 0.0 | 1.7 | 5.0 | 5.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 12.0 | 6.5 | 8.8 | 11.0 | 12.0 | 10.1 |
| Swan Falls | ROR | 15.1 | 15.0 | 14.9 | 14.4 | 15.4 | 14.3 | 11.9 | 11.4 | 13.7 | 15.4 | 15.4 | 15.2 | 14.3 |
| Twin Falls | ROR | 9.4 | 9.0 | 3.8 | 0.0 | 17.0 | 17.8 | 10.0 | 11.0 | 0.0 | 5.2 | 7.1 | 8.8 | 8.3 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.6 | 13.9 | 12.5 | 12.2 | 16.7 | 16.0 | 13.2 | 10.7 | 13.6 | 14.9 | 14.0 | 13.9 | 13.8 |
| Upper Salmon 3&4 | ROR | 12.9 | 13.1 | 11.9 | 11.6 | 15.5 | 14.9 | 12.5 | 10.3 | 12.8 | 14.0 | 13.2 | 13.1 | 13.0 |
| **HCC Total** | | **449.4** | **447.6** | **552.0** | **568.2** | **654.6** | **479.0** | **482.3** | **352.9** | **360.0** | **367.4** | **366.5** | **435.0** | **459.6** |
| **ROR Total** | | **198.4** | **197.8** | **176.0** | **192.5** | **301.3** | **310.8** | **270.5** | **236.2** | **205.4** | **204.1** | **191.3** | **197.8** | **223.5** |
| **Total** | | **647.8** | **645.4** | **728.0** | **760.7** | **955.9** | **789.8** | **752.8** | **589.1** | **565.4** | **571.5** | **557.8** | **632.8** | **683.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2014** | **2/2014** | **3/2014** | **4/2014** | **5/2014** | **6/2014** | **7/2014** | **8/2014** | **9/2014** | **10/2014** | **11/2014** | **12/2014** | **aMW** |
| Brownlee | HCC* | 200.2 | 198.4 | 243.1 | 251.0 | 293.7 | 212.4 | 213.6 | 149.6 | 151.7 | 155.3 | 158.9 | 193.6 | 201.8 |
| Oxbow | HCC | 83.3 | 82.4 | 101.1 | 104.5 | 118.9 | 88.0 | 90.2 | 68.0 | 69.8 | 70.4 | 69.7 | 80.6 | 85.6 |
| Hells Canyon | HCC | 164.8 | 163.9 | 204.6 | 212.0 | 241.4 | 177.2 | 177.2 | 133.6 | 136.9 | 138.9 | 138.1 | 159.4 | 170.7 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 29.9 | 71.0 | 86.0 | 83.8 | 56.4 | 25.6 | 9.0 | 0.0 | 0.0 | 30.1 |
| Bliss | ROR | 35.2 | 35.2 | 33.7 | 32.5 | 38.3 | 37.1 | 33.6 | 30.3 | 35.2 | 37.6 | 35.9 | 35.7 | 35.0 |
| C .J. Strike | ROR | 44.6 | 44.1 | 43.4 | 41.9 | 45.1 | 40.7 | 32.8 | 32.2 | 40.5 | 45.6 | 45.3 | 44.3 | 41.7 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.5 | 22.5 | 20.7 | 20.1 | 25.7 | 25.4 | 21.8 | 18.2 | 22.3 | 24.3 | 23.1 | 22.9 | 22.5 |
| Milner | ROR | 6.3 | 6.2 | 0.0 | 0.0 | 12.6 | 12.6 | 5.9 | 6.7 | 0.0 | 0.0 | 1.7 | 4.9 | 4.7 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 12.0 | 6.5 | 8.8 | 10.7 | 12.0 | 10.1 |
| Swan Falls | ROR | 15.0 | 15.0 | 14.8 | 14.3 | 15.3 | 14.1 | 11.9 | 11.2 | 13.7 | 15.3 | 15.3 | 15.1 | 14.3 |
| Twin Falls | ROR | 9.4 | 9.0 | 3.8 | 0.0 | 16.2 | 16.6 | 10.0 | 11.0 | 0.0 | 5.2 | 6.8 | 8.7 | 8.1 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.6 | 13.7 | 12.4 | 12 | 16.3 | 15.9 | 13.1 | 10.5 | 13.4 | 14.8 | 13.9 | 13.8 | 13.6 |
| Upper Salmon 3&4 | ROR | 12.8 | 12.9 | 11.8 | 11.5 | 15.2 | 14.8 | 12.4 | 10.2 | 12.7 | 13.8 | 13.1 | 13 | 12.9 |
| **HCC Total** | | **448.3** | **444.7** | **548.8** | **567.5** | **654.0** | **477.6** | **481.0** | **351.2** | **358.4** | **364.6** | **366.7** | **433.6** | **458.0** |
| **ROR Total** | | **197.9** | **196.8** | **175.0** | **191.7** | **297.1** | **306.2** | **269.8** | **235.2** | **204.6** | **203.1** | **189.8** | **197.0** | **222.0** |
| **Total** | | **646.2** | **641.5** | **723.8** | **759.2** | **951.1** | **783.8** | **750.8** | **586.4** | **563.0** | **567.7** | **556.5** | **630.6** | **680.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2015** | **2/2015** | **3/2015** | **4/2015** | **5/2015** | **6/2015** | **7/2015** | **8/2015** | **9/2015** | **10/2015** | **11/2015** | **12/2015** | **aMW** |
| Brownlee | HCC* | 200.9 | 198.7 | 245.8 | 251.4 | 294.2 | 212.6 | 213.6 | 149.4 | 151.5 | 156.3 | 158.5 | 193.9 | 202.2 |
| Oxbow | HCC | 83.5 | 82.5 | 102.2 | 104.6 | 119.1 | 88.1 | 90.2 | 68.0 | 69.7 | 70.9 | 69.6 | 80.8 | 85.8 |
| Hells Canyon | HCC | 165.3 | 164.2 | 206.8 | 212.4 | 241.8 | 177.4 | 177.2 | 133.5 | 136.7 | 139.8 | 137.9 | 159.7 | 171.1 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.9 | 30.7 | 71.2 | 87.6 | 84.4 | 58.9 | 25.9 | 10.1 | 0.0 | 0.0 | 31.3 |
| Bliss | ROR | 35.2 | 35.4 | 33.9 | 32.8 | 39.6 | 38.3 | 33.5 | 30.2 | 35.2 | 37.7 | 35.9 | 35.6 | 35.3 |
| C .J. Strike | ROR | 44.5 | 44.1 | 43.9 | 41.9 | 46.6 | 42.3 | 32.8 | 32.1 | 40.5 | 46.0 | 45.2 | 44.6 | 42.0 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.5 | 22.7 | 20.8 | 20.3 | 26.8 | 25.8 | 21.8 | 18.1 | 22.3 | 24.5 | 23.3 | 22.9 | 22.7 |
| Milner | ROR | 6.3 | 6.3 | 0.0 | 0.0 | 15.5 | 15.5 | 5.9 | 6.7 | 0.0 | 0.0 | 2.4 | 5.0 | 5.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 4.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.5 | 9.7 | 11.4 | 12.0 | 10.2 |
| Swan Falls | ROR | 15.1 | 14.9 | 14.9 | 14.3 | 15.8 | 14.5 | 11.9 | 11.2 | 13.7 | 15.4 | 15.3 | 15.2 | 14.4 |
| Twin Falls | ROR | 9.4 | 9.2 | 3.8 | 0.0 | 18.3 | 19.1 | 10.0 | 11.0 | 0.0 | 6.0 | 7.5 | 8.9 | 8.6 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.6 | 13.9 | 12.5 | 12.2 | 17.1 | 16.2 | 13.1 | 10.5 | 13.5 | 15.0 | 14.1 | 13.8 | 13.8 |
| Upper Salmon 3&4 | ROR | 12.8 | 13.1 | 11.9 | 11.6 | 15.9 | 15.1 | 12.4 | 10.2 | 12.7 | 14.0 | 13.2 | 13.0 | 13.0 |
| **HCC Total** | | **449.7** | **445.4** | **554.8** | **568.4** | **655.1** | **478.1** | **481.0** | **350.9** | **357.9** | **367.0** | **366.0** | **434.4** | **459.1** |
| **ROR Total** | | **197.9** | **197.8** | **183.0** | **193.4** | **308.3** | **317.4** | **270.3** | **237.4** | **205.0** | **207.1** | **192.3** | **197.6** | **225.6** |
| **Total** | | **647.6** | **643.2** | **737.8** | **761.8** | **963.4** | **795.5** | **751.3** | **588.3** | **562.9** | **574.1** | **558.3** | **632.0** | **684.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2016** | **2/2016** | **3/2016** | **4/2016** | **5/2016** | **6/2016** | **7/2016** | **8/2016** | **9/2016** | **10/2016** | **11/2016** | **12/2016** | **aMW** |
| Brownlee | HCC* | 200.5 | 199.1 | 245.2 | 251.1 | 293.9 | 212.1 | 213.1 | 136.5 | 150.8 | 155.4 | 158.7 | 193.4 | 200.8 |
| Oxbow | HCC | 83.4 | 82.7 | 102.0 | 104.5 | 118.9 | 87.9 | 89.9 | 61.9 | 69.4 | 70.4 | 69.7 | 80.5 | 85.1 |
| Hells Canyon | HCC | 165.0 | 164.5 | 206.3 | 212.1 | 241.6 | 177.0 | 176.7 | 122.0 | 136.0 | 139.0 | 138.0 | 159.3 | 169.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.9 | 30.5 | 71.3 | 87.6 | 84.3 | 55.9 | 27.5 | 10.2 | 0.0 | 0.0 | 31.2 |
| Bliss | ROR | 35.1 | 35.4 | 33.8 | 32.7 | 39.6 | 38.3 | 33.5 | 26.5 | 35.2 | 37.6 | 35.8 | 35.5 | 34.9 |
| C .J. Strike | ROR | 44.4 | 44.0 | 43.9 | 41.4 | 46.5 | 42.2 | 32.7 | 27.3 | 40.4 | 45.8 | 45.1 | 44.5 | 41.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.4 | 22.8 | 20.7 | 20.3 | 26.8 | 25.7 | 21.7 | 14.9 | 22.3 | 24.4 | 23.2 | 22.8 | 22.3 |
| Milner | ROR | 6.3 | 7.3 | 0.0 | 0.0 | 15.5 | 15.5 | 5.9 | 0.0 | 0.0 | 0.0 | 2.5 | 5.1 | 4.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 4.0 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 9.8 | 11.5 | 12.0 | 9.8 |
| Swan Falls | ROR | 15.0 | 14.9 | 15.0 | 14.1 | 15.8 | 14.5 | 11.8 | 9.7 | 13.6 | 15.4 | 15.3 | 15.2 | 14.2 |
| Twin Falls | ROR | 9.4 | 9.7 | 3.8 | 0.0 | 18.3 | 19.2 | 10.0 | 0.0 | 0.0 | 6.1 | 7.5 | 9.0 | 7.8 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.5 | 13.9 | 12.4 | 12.2 | 17.2 | 16.1 | 13.0 | 8.0 | 13.4 | 14.9 | 14.0 | 13.7 | 13.5 |
| Upper Salmon 3&4 | ROR | 12.7 | 13.1 | 11.8 | 11.6 | 15.9 | 15.0 | 12.3 | 8.1 | 12.7 | 13.9 | 13.1 | 13.0 | 12.8 |
| **HCC Total** | | **448.9** | **446.3** | **553.5** | **567.7** | **654.4** | **477.0** | **479.7** | **320.4** | **356.2** | **364.8** | **366.4** | **433.2** | **455.7** |
| **ROR Total** | | **197.3** | **199.3** | **182.7** | **192.4** | **308.4** | **317.1** | **269.7** | **193.5** | **206.3** | **206.8** | **192.0** | **197.4** | **221.9** |
| **Total** | | **646.2** | **645.6** | **736.2** | **760.1** | **962.8** | **794.1** | **749.4** | **513.9** | **562.5** | **571.6** | **558.4** | **630.6** | **677.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2017** | **2/2017** | **3/2017** | **4/2017** | **5/2017** | **6/2017** | **7/2017** | **8/2017** | **9/2017** | **10/2017** | **11/2017** | **12/2017** | **aMW** |
| Brownlee | HCC* | 200.1 | 198.8 | 244.6 | 250.8 | 293.6 | 211.6 | 212.6 | 136.0 | 150.2 | 154.4 | 159.0 | 192.9 | 200.4 |
| Oxbow | HCC | 83.2 | 82.6 | 101.7 | 104.4 | 118.8 | 87.7 | 89.7 | 61.7 | 69.1 | 69.9 | 69.8 | 80.4 | 84.9 |
| Hells Canyon | HCC | 164.7 | 164.2 | 205.8 | 211.9 | 241.4 | 176.6 | 176.3 | 121.5 | 135.5 | 138.0 | 138.2 | 158.9 | 169.4 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 7.0 | 30.5 | 71.1 | 87.1 | 84.3 | 55.9 | 27.7 | 10.1 | 0.0 | 0.0 | 31.1 |
| Bliss | ROR | 35.0 | 35.2 | 33.8 | 32.7 | 39.3 | 38.0 | 33.3 | 26.3 | 35.1 | 37.5 | 35.7 | 35.4 | 34.8 |
| C .J. Strike | ROR | 44.3 | 43.9 | 43.7 | 41.1 | 46.4 | 42.1 | 32.5 | 27.1 | 40.3 | 45.8 | 44.9 | 44.4 | 41.4 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.3 | 22.7 | 20.7 | 20.2 | 26.5 | 25.6 | 21.6 | 14.8 | 22.1 | 24.3 | 23.0 | 22.7 | 22.2 |
| Milner | ROR | 6.3 | 6.3 | 0.0 | 0.0 | 15.0 | 15.0 | 5.9 | 0.0 | 0.0 | 0.0 | 2.5 | 5.2 | 4.7 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 9.8 | 11.5 | 12.0 | 9.8 |
| Swan Falls | ROR | 15.0 | 14.9 | 14.9 | 14.2 | 15.7 | 14.4 | 11.8 | 9.6 | 13.5 | 15.4 | 15.2 | 15.1 | 14.1 |
| Twin Falls | ROR | 9.5 | 9.2 | 3.8 | 0.0 | 17.9 | 18.3 | 10.0 | 0.0 | 0.0 | 6.1 | 7.5 | 9.0 | 7.6 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.4 | 13.9 | 12.4 | 12.1 | 17.0 | 16.0 | 12.9 | 7.9 | 13.3 | 14.8 | 13.9 | 13.7 | 13.4 |
| Upper Salmon 3&4 | ROR | 12.7 | 13.1 | 11.8 | 11.6 | 15.7 | 14.9 | 12.3 | 8.0 | 12.6 | 13.9 | 13.1 | 12.9 | 12.7 |
| **HCC Total** | | **448.0** | **445.6** | **552.1** | **567.1** | **653.8** | **475.9** | **478.6** | **319.2** | **354.8** | **362.3** | **367.0** | **432.2** | **454.7** |
| **ROR Total** | | **197.0** | **197.4** | **182.5** | **191.9** | **306.1** | **314.4** | **269.1** | **192.7** | **205.8** | **206.4** | **191.3** | **197.0** | **221.0** |
| **Total** | | **645.0** | **643.0** | **734.6** | **759.0** | **959.9** | **790.3** | **747.7** | **511.9** | **560.6** | **568.7** | **558.3** | **629.2** | **675.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2018** | **2/2018** | **3/2018** | **4/2018** | **5/2018** | **6/2018** | **7/2018** | **8/2018** | **9/2018** | **10/2018** | **11/2018** | **12/2018** | **aMW** |
| Brownlee | HCC* | 199.5 | 197.4 | 242.0 | 250.4 | 293.4 | 211.1 | 212.0 | 135.3 | 149.5 | 153.6 | 158.9 | 192.5 | 199.6 |
| Oxbow | HCC | 83.0 | 82.0 | 100.6 | 104.2 | 118.7 | 87.5 | 89.5 | 61.3 | 68.8 | 69.6 | 69.7 | 80.2 | 84.6 |
| Hells Canyon | HCC | 164.2 | 163.1 | 203.7 | 211.6 | 241.2 | 176.2 | 175.9 | 120.9 | 134.9 | 137.3 | 138.0 | 158.6 | 168.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.9 | 31.4 | 70.9 | 86.2 | 84.3 | 55.8 | 27.6 | 10.1 | 0.0 | 0.0 | 31.1 |
| Bliss | ROR | 34.9 | 35.2 | 33.7 | 32.6 | 38.8 | 37.3 | 33.1 | 26.1 | 34.8 | 37.3 | 35.4 | 35.2 | 34.5 |
| C .J. Strike | ROR | 44.1 | 43.7 | 43.6 | 41.1 | 45.8 | 41.3 | 32.3 | 26.9 | 40.2 | 45.7 | 44.6 | 44.3 | 41.1 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.2 | 22.5 | 20.6 | 20.1 | 26.3 | 25.4 | 21.4 | 14.6 | 21.9 | 24.2 | 22.9 | 22.5 | 22.1 |
| Milner | ROR | 6.3 | 6.3 | 0.0 | 0.0 | 13.9 | 13.9 | 5.9 | 0.0 | 0.0 | 0.0 | 2.6 | 5.0 | 4.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 9.5 | 11.6 | 12.0 | 9.8 |
| Swan Falls | ROR | 15.0 | 14.8 | 14.8 | 14.1 | 15.4 | 14.1 | 11.7 | 9.5 | 13.4 | 15.3 | 15.1 | 15.1 | 14.0 |
| Twin Falls | ROR | 9.5 | 9.2 | 3.8 | 0.0 | 16.8 | 17.4 | 10.0 | 0.0 | 0.0 | 5.7 | 7.6 | 8.9 | 7.4 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.4 | 13.7 | 12.3 | 12.0 | 16.8 | 15.9 | 12.8 | 7.8 | 13.1 | 14.7 | 13.7 | 13.6 | 13.3 |
| Upper Salmon 3&4 | ROR | 12.6 | 12.9 | 11.8 | 11.5 | 15.6 | 14.8 | 12.2 | 7.9 | 12.4 | 13.8 | 12.9 | 12.8 | 12.6 |
| **HCC Total** | | **446.7** | **442.5** | **546.3** | **566.2** | **653.3** | **474.8** | **477.4** | **317.5** | **353.2** | **360.5** | **366.6** | **431.3** | **453.0** |
| **ROR Total** | | **196.5** | **196.5** | **181.9** | **192.3** | **301.8** | **309.3** | **268.2** | **191.7** | **204.6** | **205.0** | **190.4** | **196.0** | **219.5** |
| **Total** | | **643.2** | **639.0** | **728.2** | **758.5** | **955.1** | **784.1** | **745.6** | **509.2** | **557.8** | **565.5** | **557.0** | **627.3** | **672.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2019** | **2/2019** | **3/2019** | **4/2019** | **5/2019** | **6/2019** | **7/2019** | **8/2019** | **9/2019** | **10/2019** | **11/2019** | **12/2019** | **aMW** |
| Brownlee | HCC* | 199.1 | 197.1 | 240.6 | 250.1 | 293.0 | 210.6 | 211.5 | 134.7 | 148.9 | 152.2 | 159.2 | 192.0 | 199.1 |
| Oxbow | HCC | 82.8 | 81.8 | 100.0 | 104.1 | 118.6 | 87.3 | 89.3 | 61.1 | 68.5 | 68.9 | 69.8 | 79.9 | 84.3 |
| Hells Canyon | HCC | 163.9 | 162.8 | 202.6 | 211.4 | 240.9 | 175.8 | 175.4 | 120.4 | 134.4 | 136.0 | 138.2 | 158.1 | 168.3 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 7.2 | 30.2 | 70.5 | 85.9 | 84.2 | 55.8 | 27.4 | 10.3 | 0.0 | 0.0 | 31.0 |
| Bliss | ROR | 34.8 | 35.1 | 33.6 | 32.5 | 38.6 | 37.1 | 32.9 | 25.9 | 34.7 | 37.2 | 35.3 | 35.1 | 34.4 |
| C .J. Strike | ROR | 43.9 | 43.6 | 43.5 | 40.9 | 44.9 | 40.8 | 32.1 | 26.7 | 40.0 | 45.5 | 44.4 | 43.8 | 40.8 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.1 | 22.4 | 20.6 | 20.0 | 26.1 | 25.3 | 21.3 | 14.5 | 21.7 | 24.1 | 22.6 | 22.4 | 21.9 |
| Milner | ROR | 6.3 | 6.3 | 0.0 | 0.0 | 12.7 | 12.7 | 5.9 | 0.0 | 0.0 | 0.0 | 2.0 | 5.0 | 4.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 9.5 | 11.3 | 12.0 | 9.8 |
| Swan Falls | ROR | 15.0 | 14.8 | 14.8 | 14.1 | 15.4 | 13.9 | 11.6 | 9.5 | 13.4 | 15.3 | 15.0 | 14.9 | 14.0 |
| Twin Falls | ROR | 9.5 | 9.2 | 3.8 | 0.0 | 15.9 | 16.5 | 10.0 | 0.0 | 0.0 | 5.7 | 7.4 | 8.9 | 7.2 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.3 | 13.6 | 12.3 | 12.0 | 16.7 | 15.8 | 12.7 | 7.7 | 13.0 | 14.6 | 13.5 | 13.4 | 13.2 |
| Upper Salmon 3&4 | ROR | 12.6 | 12.9 | 11.7 | 11.4 | 15.5 | 14.7 | 12.1 | 7.8 | 12.3 | 13.7 | 12.8 | 12.7 | 12.5 |
| **HCC Total** | | **445.8** | **441.7** | **543.2** | **565.6** | **652.5** | **473.7** | **476.2** | **316.2** | **351.8** | **357.1** | **367.2** | **430.0** | **451.8** |
| **ROR Total** | | **196.0** | **196.1** | **181.9** | **190.6** | **297.8** | **305.7** | **267.3** | **191.0** | **203.7** | **204.6** | **188.3** | **194.8** | **218.1** |
| **Total** | | **641.8** | **637.8** | **725.1** | **756.2** | **950.3** | **779.4** | **743.5** | **507.2** | **555.5** | **561.7** | **555.5** | **624.8** | **669.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2020** | **2/2020** | **3/2020** | **4/2020** | **5/2020** | **6/2020** | **7/2020** | **8/2020** | **9/2020** | **10/2020** | **11/2020** | **12/2020** | **aMW** |
| Brownlee | HCC* | 198.0 | 196.6 | 240.2 | 249.8 | 292.7 | 210.0 | 210.9 | 134.1 | 148.3 | 150.7 | 159.1 | 191.9 | 198.5 |
| Oxbow | HCC | 82.4 | 81.6 | 99.9 | 104.0 | 118.5 | 87.0 | 89.0 | 60.8 | 68.2 | 68.1 | 69.7 | 79.9 | 84.1 |
| Hells Canyon | HCC | 163.0 | 162.4 | 202.3 | 211.1 | 240.6 | 175.3 | 174.9 | 119.8 | 133.8 | 134.6 | 138.0 | 158.0 | 167.8 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.9 | 30.2 | 70.3 | 85.8 | 84.2 | 55.8 | 27.1 | 10.3 | 0.0 | 0.0 | 30.9 |
| Bliss | ROR | 34.7 | 34.8 | 33.5 | 32.4 | 38.4 | 36.8 | 32.8 | 25.8 | 34.5 | 37.2 | 35.1 | 34.9 | 34.2 |
| C .J. Strike | ROR | 43.8 | 43.4 | 43.4 | 40.8 | 44.7 | 40.4 | 31.9 | 26.4 | 39.9 | 45.4 | 44.2 | 43.6 | 40.7 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 22.0 | 22.2 | 20.5 | 20.0 | 25.8 | 25.1 | 21.1 | 14.3 | 21.5 | 23.9 | 22.4 | 22.2 | 21.8 |
| Milner | ROR | 6.3 | 5.8 | 0.0 | 0.0 | 12.3 | 12.3 | 5.9 | 0.0 | 0.0 | 0.0 | 1.8 | 5.0 | 4.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 9.5 | 11.3 | 12.0 | 9.8 |
| Swan Falls | ROR | 14.8 | 14.7 | 14.8 | 14.0 | 15.3 | 13.8 | 11.6 | 9.4 | 13.3 | 15.2 | 15.0 | 14.9 | 13.9 |
| Twin Falls | ROR | 9.5 | 8.9 | 3.8 | 0.0 | 15.1 | 15.8 | 10.0 | 0.0 | 0.0 | 5.7 | 7.4 | 8.8 | 7.1 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.2 | 13.5 | 12.3 | 11.9 | 16.4 | 15.7 | 12.6 | 7.5 | 12.8 | 14.5 | 13.4 | 13.3 | 13.1 |
| Upper Salmon 3&4 | ROR | 12.5 | 12.8 | 11.7 | 11.4 | 15.2 | 14.6 | 12.0 | 7.7 | 12.2 | 13.6 | 12.6 | 12.6 | 12.4 |
| **HCC Total** | | **443.4** | **440.6** | **542.4** | **564.9** | **651.8** | **472.3** | **474.8** | **314.7** | **350.3** | **353.4** | **366.8** | **429.8** | **450.4** |
| **ROR Total** | | **195.3** | **194.3** | **181.3** | **190.2** | **295.0** | **303.3** | **266.6** | **190.0** | **202.5** | **204.0** | **187.2** | **193.9** | **217.0** |
| **Total** | | **638.7** | **634.9** | **723.7** | **755.1** | **946.8** | **775.6** | **741.4** | **504.7** | **552.8** | **557.4** | **554.0** | **623.7** | **667.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load

| Resource | Type | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 197.5 | 196.1 | 239.9 | 249.4 | 292.3 | 209.3 | 210.2 | 133.5 | 147.5 | 148.5 | 159.3 | 191.2 | 197.9 |
| Oxbow | HCC | 82.2 | 81.4 | 99.7 | 103.8 | 118.3 | 86.7 | 88.7 | 60.5 | 67.8 | 67.0 | 69.7 | 79.6 | 83.8 |
| Hells Canyon | HCC | 162.6 | 162.1 | 202.0 | 210.7 | 240.4 | 174.7 | 174.4 | 119.3 | 133.1 | 132.5 | 138.1 | 157.4 | 167.3 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.8 | 30.8 | 70.3 | 85.6 | 84.1 | 55.3 | 26.9 | 9.9 | 0.0 | 0.0 | 30.8 |
| Bliss | ROR | 34.5 | 34.8 | 33.4 | 32.4 | 38.1 | 36.6 | 32.6 | 25.6 | 34.2 | 37.1 | 34.8 | 34.8 | 34.1 |
| C .J. Strike | ROR | 43.6 | 43.3 | 43.3 | 40.8 | 44.5 | 40.0 | 31.7 | 26.2 | 39.7 | 45.1 | 43.8 | 43.4 | 40.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.9 | 22.1 | 20.4 | 19.9 | 25.6 | 25.0 | 21.0 | 14.1 | 21.3 | 23.7 | 22.2 | 22.1 | 21.6 |
| Milner | ROR | 6.3 | 6.2 | 0.0 | 0.0 | 12.3 | 12.3 | 5.9 | 0.0 | 0.0 | 0.0 | 1.8 | 4.9 | 4.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 9.4 | 11.1 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.8 | 14.7 | 14.7 | 14.1 | 15.2 | 13.7 | 11.5 | 9.3 | 13.3 | 15.2 | 14.9 | 14.8 | 13.9 |
| Twin Falls | ROR | 9.5 | 9.0 | 3.8 | 0.0 | 15.5 | 16.6 | 10.0 | 0.0 | 0.0 | 5.7 | 7.2 | 8.8 | 7.2 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.1 | 13.4 | 12.2 | 11.8 | 16.3 | 15.6 | 12.5 | 7.4 | 12.7 | 14.3 | 13.2 | 13.2 | 13.0 |
| Upper Salmon 3&4 | ROR | 12.4 | 12.7 | 11.6 | 11.3 | 15.1 | 14.5 | 11.9 | 7.6 | 12.0 | 13.5 | 12.5 | 12.5 | 12.3 |
| **HCC Total** | | **442.3** | **439.6** | **541.6** | **563.9** | **651.0** | **470.7** | **473.3** | **313.3** | **348.4** | **348.0** | **367.1** | **428.2** | **449.0** |
| **ROR Total** | | **194.6** | **194.4** | **180.6** | **190.6** | **294.3** | **302.9** | **265.7** | **188.6** | **201.3** | **202.6** | **185.5** | **193.1** | **216.2** |
| **Total** | | **636.9** | **634.0** | **722.2** | **754.5** | **945.3** | **773.6** | **739.0** | **501.9** | **549.7** | **550.6** | **552.6** | **621.3** | **665.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load

| Resource | Type | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 196.9 | 195.6 | 238.9 | 248.9 | 292.0 | 208.7 | 209.5 | 132.7 | 146.8 | 146.8 | 159.5 | 190.5 | 197.2 |
| Oxbow | HCC | 81.9 | 81.2 | 99.3 | 103.6 | 118.2 | 86.5 | 88.4 | 60.1 | 67.5 | 66.2 | 69.8 | 79.3 | 83.5 |
| Hells Canyon | HCC | 162.1 | 161.7 | 201.2 | 210.4 | 240.1 | 174.2 | 173.8 | 118.6 | 132.5 | 131.0 | 138.2 | 156.9 | 166.7 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.6 | 30.6 | 70.0 | 85.5 | 84.2 | 55.3 | 26.9 | 9.9 | 0.0 | 0.0 | 30.7 |
| Bliss | ROR | 34.4 | 34.6 | 33.3 | 32.1 | 38.1 | 36.2 | 32.3 | 25.4 | 34.0 | 37.0 | 34.7 | 34.7 | 33.9 |
| C .J. Strike | ROR | 43.4 | 43.1 | 43.0 | 40.7 | 44.4 | 39.5 | 31.4 | 25.9 | 39.5 | 44.9 | 43.5 | 43.2 | 40.2 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.8 | 22.0 | 20.3 | 19.5 | 25.4 | 24.7 | 20.8 | 14.0 | 21.1 | 23.5 | 22.0 | 22.0 | 21.4 |
| Milner | ROR | 6.3 | 5.8 | 0.0 | 0.0 | 12.2 | 12.2 | 5.9 | 0.0 | 0.0 | 0.0 | 1.7 | 4.9 | 4.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 8.8 | 10.9 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.7 | 14.7 | 14.7 | 14.0 | 15.2 | 13.6 | 11.4 | 9.2 | 13.2 | 15.1 | 14.8 | 14.8 | 13.8 |
| Twin Falls | ROR | 9.5 | 8.9 | 3.8 | 0.0 | 15.0 | 16.0 | 10.0 | 0.0 | 0.0 | 5.2 | 7.0 | 8.8 | 7.0 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 13.0 | 13.3 | 12.1 | 11.5 | 16.1 | 15.4 | 12.3 | 7.3 | 12.5 | 14.2 | 13.1 | 13.1 | 12.8 |
| Upper Salmon 3&4 | ROR | 12.3 | 12.6 | 11.6 | 11.1 | 15.0 | 14.3 | 11.7 | 7.5 | 11.9 | 13.4 | 12.4 | 12.4 | 12.2 |
| **HCC Total** | | **440.9** | **438.5** | **539.4** | **562.9** | **650.3** | **469.4** | **471.7** | **311.4** | **346.8** | **344.0** | **367.5** | **426.7** | **447.5** |
| **ROR Total** | | **193.9** | **193.2** | **179.8** | **189.0** | **292.9** | **300.4** | **264.5** | **187.7** | **200.3** | **200.7** | **184.1** | **192.5** | **214.9** |
| **Total** | | **634.8** | **631.7** | **719.2** | **751.9** | **943.2** | **769.8** | **736.2** | **499.1** | **547.1** | **544.7** | **551.6** | **619.2** | **662.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2023** | **2/2023** | **3/2023** | **4/2023** | **5/2023** | **6/2023** | **7/2023** | **8/2023** | **9/2023** | **10/2023** | **11/2023** | **12/2023** | **aMW** |
| Brownlee | HCC* | 196.1 | 195.2 | 239.1 | 248.6 | 291.6 | 208.1 | 208.9 | 131.9 | 146.2 | 146.3 | 159.4 | 190.1 | 196.8 |
| Oxbow | HCC | 81.5 | 81.1 | 99.4 | 103.5 | 118.0 | 86.2 | 88.2 | 59.8 | 67.2 | 66.0 | 69.7 | 79.1 | 83.3 |
| Hells Canyon | HCC | 161.4 | 161.3 | 201.4 | 210.1 | 239.8 | 173.8 | 173.3 | 117.9 | 131.9 | 130.5 | 138.1 | 156.5 | 166.3 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.6 | 30.5 | 69.8 | 85.2 | 84.3 | 55.1 | 26.9 | 10.1 | 0.0 | 0.0 | 30.7 |
| Bliss | ROR | 34.3 | 34.5 | 33.2 | 32.0 | 38.0 | 35.9 | 32.1 | 25.2 | 33.8 | 36.9 | 34.5 | 34.5 | 33.7 |
| C .J. Strike | ROR | 43.1 | 43.0 | 43.0 | 40.7 | 44.2 | 38.8 | 31.2 | 25.7 | 39.2 | 44.6 | 43.3 | 43.0 | 40.0 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.7 | 21.9 | 20.2 | 19.4 | 25.2 | 24.4 | 20.6 | 13.8 | 20.9 | 23.3 | 21.9 | 21.9 | 21.3 |
| Milner | ROR | 6.2 | 5.8 | 0.0 | 0.0 | 11.3 | 11.3 | 5.9 | 0.0 | 0.0 | 0.0 | 1.7 | 4.9 | 3.9 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 8.8 | 11.1 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.7 | 14.7 | 14.6 | 13.9 | 15.0 | 13.3 | 11.4 | 9.1 | 13.2 | 15.0 | 14.7 | 14.7 | 13.7 |
| Twin Falls | ROR | 9.4 | 8.9 | 3.8 | 0.0 | 14.0 | 15.1 | 10.0 | 0.0 | 0.0 | 5.2 | 7.2 | 8.8 | 6.9 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 12.9 | 13.3 | 12.1 | 11.5 | 15.9 | 15.1 | 12.2 | 7.2 | 12.3 | 14.1 | 13.0 | 13.0 | 12.7 |
| Upper Salmon 3&4 | ROR | 12.3 | 12.6 | 11.5 | 11.0 | 14.8 | 14.1 | 11.6 | 7.4 | 11.8 | 13.2 | 12.3 | 12.3 | 12.1 |
| **HCC Total** | | **439.0** | **437.6** | **539.9** | **562.2** | **649.4** | **468.1** | **470.4** | **309.6** | **345.3** | **342.8** | **367.2** | **425.7** | **446.4** |
| **ROR Total** | | **193.1** | **192.9** | **179.4** | **188.5** | **289.6** | **296.2** | **263.8** | **186.6** | **199.3** | **199.9** | **183.7** | **191.7** | **213.7** |
| **Total** | | **632.1** | **630.5** | **719.3** | **750.7** | **939.0** | **764.3** | **734.2** | **496.2** | **544.6** | **542.7** | **550.9** | **617.4** | **660.2** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2024** | **2/2024** | **3/2024** | **4/2024** | **5/2024** | **6/2024** | **7/2024** | **8/2024** | **9/2024** | **10/2024** | **11/2024** | **12/2024** | **aMW** |
| Brownlee | HCC* | 195.5 | 194.7 | 238.8 | 248.2 | 283.1 | 207.5 | 208.3 | 131.2 | 145.5 | 144.8 | 159.3 | 189.9 | 195.6 |
| Oxbow | HCC | 81.3 | 80.8 | 99.3 | 103.3 | 117.9 | 86.0 | 87.9 | 59.4 | 66.9 | 65.2 | 69.6 | 79.0 | 83.1 |
| Hells Canyon | HCC | 160.9 | 160.9 | 201.1 | 209.8 | 241.3 | 173.3 | 172.8 | 117.2 | 131.3 | 129.1 | 137.9 | 156.4 | 166.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0 | 0 | 6.6 | 30.2 | 69.35 | 85.1 | 84.3 | 54.5 | 26.8 | 9.9 | 0 | 0 | 30.6 |
| Bliss | ROR | 34.2 | 34.4 | 33.1 | 31.9 | 38 | 35.8 | 32 | 25 | 33.6 | 36.7 | 34.3 | 34.3 | 33.6 |
| C .J. Strike | ROR | 43 | 42.8 | 42.9 | 40.4 | 44 | 38.5 | 31 | 25.4 | 39 | 44.4 | 43 | 42.8 | 39.8 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7 | 10.3 | 6.45 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.6 | 21.8 | 20.2 | 19.3 | 25.1 | 24.2 | 20.4 | 13.6 | 20.7 | 23.2 | 21.7 | 21.7 | 21.1 |
| Milner | ROR | 6.0 | 5.8 | 0.0 | 0.0 | 10.9 | 10.9 | 5.9 | 0.0 | 0.0 | 0.0 | 1.7 | 4.9 | 3.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 8.8 | 10.9 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.6 | 14.6 | 14.6 | 13.9 | 14.9 | 13.2 | 11.2 | 9.0 | 13.2 | 15.0 | 14.6 | 14.6 | 13.6 |
| Twin Falls | ROR | 9.4 | 8.9 | 3.8 | 0.0 | 13.7 | 14.7 | 10.0 | 0.0 | 0.0 | 5.2 | 7.0 | 8.8 | 6.8 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 12.9 | 13.2 | 12.0 | 11.4 | 15.9 | 15.0 | 12.0 | 7.0 | 12.2 | 13.9 | 12.8 | 12.9 | 12.6 |
| Upper Salmon 3&4 | ROR | 12.2 | 12.5 | 11.5 | 10.9 | 14.8 | 14.0 | 11.5 | 7.3 | 11.6 | 13.1 | 12.2 | 12.2 | 12.0 |
| **HCC Total** | | **437.7** | **436.4** | **539.2** | **561.3** | **642.3** | **466.8** | **469.0** | **307.8** | **343.7** | **339.1** | **366.8** | **425.3** | **444.6** |
| **ROR Total** | | **192.4** | **192.2** | **179.1** | **187.5** | **288.1** | **294.4** | **262.8** | **184.9** | **198.3** | **198.9** | **182.2** | **190.8** | **212.6** |
| **Total** | | **630.1** | **628.6** | **718.3** | **748.8** | **930.4** | **761.2** | **731.8** | **492.7** | **542.0** | **538.0** | **549.0** | **616.1** | **657.3** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2025** | **2/2025** | **3/2025** | **4/2025** | **5/2025** | **6/2025** | **7/2025** | **8/2025** | **9/2025** | **10/2025** | **11/2025** | **12/2025** | **aMW** |
| Brownlee | HCC* | 195.0 | 194.1 | 238.3 | 247.7 | 282.7 | 206.9 | 207.6 | 130.4 | 144.8 | 143.6 | 159.4 | 189.4 | 195.0 |
| Oxbow | HCC | 81.1 | 80.6 | 99.1 | 103.1 | 117.7 | 85.7 | 87.6 | 59.1 | 66.5 | 64.6 | 69.7 | 78.8 | 82.8 |
| Hells Canyon | HCC | 160.5 | 160.4 | 200.8 | 209.4 | 241.1 | 172.8 | 172.2 | 116.5 | 130.7 | 127.9 | 138.0 | 155.9 | 165.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.6 | 30.0 | 69.2 | 85.0 | 84.4 | 54.4 | 26.8 | 9.8 | 0.0 | 0.0 | 30.5 |
| Bliss | ROR | 34.0 | 34.2 | 33.0 | 31.8 | 37.8 | 35.7 | 31.7 | 24.8 | 33.4 | 36.5 | 34.1 | 34.2 | 33.4 |
| C .J. Strike | ROR | 43.0 | 42.7 | 42.8 | 40.3 | 43.1 | 37.8 | 30.8 | 25.2 | 38.7 | 44.3 | 42.8 | 42.6 | 39.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.5 | 21.7 | 20.1 | 19.2 | 25 | 24.1 | 20.3 | 13.5 | 20.5 | 23.1 | 21.5 | 21.6 | 21.0 |
| Milner | ROR | 6 | 5.8 | 0 | 0 | 10.7 | 10.7 | 5.9 | 0 | 0 | 0 | 1.7 | 4.9 | 3.8 |
| Shoshone Falls | ROR | 12 | 12 | 7.3 | 3.9 | 12 | 12 | 12 | 6.6 | 6.5 | 8.8 | 10.8 | 12 | 9.7 |
| Swan Falls | ROR | 14.6 | 14.6 | 14.6 | 13.8 | 14.7 | 13 | 11.2 | 8.9 | 13.1 | 14.9 | 14.5 | 14.6 | 13.5 |
| Twin Falls | ROR | 9.4 | 8.9 | 3.8 | 0 | 13.5 | 14.5 | 10 | 0 | 0 | 5.2 | 6.9 | 8.8 | 6.8 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 12.8 | 13.1 | 12.0 | 11.3 | 15.8 | 14.9 | 11.9 | 6.9 | 12.0 | 13.9 | 12.7 | 12.8 | 12.5 |
| Upper Salmon 3&4 | ROR | 12.1 | 12.4 | 11.4 | 10.9 | 14.7 | 13.9 | 11.4 | 7.2 | 11.5 | 13.1 | 12.0 | 12.1 | 11.9 |
| **HCC Total** | | **436.6** | **435.1** | **538.2** | **560.2** | **641.5** | **465.4** | **467.4** | **306.0** | **342.0** | **336.1** | **367.1** | **424.1** | **443.3** |
| **ROR Total** | | **191.9** | **191.6** | **178.7** | **186.8** | **285.9** | **292.6** | **262.1** | **184.0** | **197.2** | **198.3** | **181.0** | **190.2** | **211.7** |
| **Total** | | **628.5** | **626.7** | **716.9** | **747.0** | **927.4** | **758.0** | **729.5** | **490.0** | **539.2** | **534.4** | **548.1** | **614.3** | **655.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2026** | **2/2026** | **3/2026** | **4/2026** | **5/2026** | **6/2026** | **7/2026** | **8/2026** | **9/2026** | **10/2026** | **11/2026** | **12/2026** | **aMW** |
| Brownlee | HCC* | 194.2 | 193.2 | 237.5 | 247.4 | 282.4 | 206.3 | 207.0 | 129.8 | 144.1 | 142.0 | 159.9 | 188.5 | 194.4 |
| Oxbow | HCC | 80.7 | 80.2 | 98.7 | 103.0 | 117.6 | 85.5 | 87.3 | 58.8 | 66.2 | 63.9 | 69.8 | 78.4 | 82.5 |
| Hells Canyon | HCC | 159.9 | 159.7 | 200.1 | 209.2 | 240.8 | 172.3 | 171.7 | 116.0 | 130.0 | 126.5 | 138.3 | 155.2 | 165.0 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.6 | 29.9 | 68.8 | 84.6 | 84.4 | 54.4 | 26.7 | 9.6 | 0.0 | 0.0 | 30.4 |
| Bliss | ROR | 33.7 | 34.2 | 32.9 | 31.7 | 37.3 | 35.4 | 31.5 | 24.6 | 33.2 | 36.4 | 33.9 | 34.1 | 33.2 |
| C .J. Strike | ROR | 42.9 | 42.5 | 42.7 | 40.2 | 42.1 | 37.6 | 30.6 | 24.9 | 38.5 | 44.1 | 42.5 | 42.4 | 39.3 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.3 | 21.5 | 20.0 | 19.1 | 24.4 | 23.7 | 20.2 | 13.3 | 20.3 | 23.0 | 21.4 | 21.4 | 20.8 |
| Milner | ROR | 6.0 | 5.8 | 0.0 | 0.0 | 10.7 | 10.7 | 5.9 | 0.0 | 0.0 | 0.0 | 1.7 | 4.9 | 3.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 8.8 | 10.7 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.8 | 14.6 | 12.9 | 11.1 | 8.9 | 13.1 | 14.8 | 14.4 | 14.5 | 13.5 |
| Twin Falls | ROR | 9.4 | 8.8 | 3.8 | 0.0 | 13.5 | 14.5 | 10.0 | 0.0 | 0.0 | 5.2 | 6.8 | 8.8 | 6.7 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 12.7 | 12.9 | 11.9 | 11.3 | 15.3 | 14.6 | 11.8 | 6.8 | 11.9 | 13.8 | 12.6 | 12.7 | 12.4 |
| Upper Salmon 3&4 | ROR | 12 | 12.3 | 11.4 | 10.8 | 14.3 | 13.7 | 11.3 | 7.1 | 11.4 | 13 | 12 | 12.1 | 11.8 |
| **HCC Total** | | **434.8** | **433.1** | **536.3** | **559.6** | **640.8** | **464.1** | **466.0** | **304.6** | **340.3** | **332.4** | **368.0** | **422.1** | **441.8** |
| **ROR Total** | | **191.0** | **190.7** | **178.2** | **186.3** | **282.4** | **290.7** | **261.3** | **183.1** | **196.3** | **197.4** | **180.0** | **189.5** | **210.6** |
| **Total** | | **625.8** | **623.8** | **714.5** | **745.9** | **923.2** | **754.8** | **727.3** | **487.7** | **536.6** | **529.8** | **548.0** | **611.6** | **652.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2027** | **2/2027** | **3/2027** | **4/2027** | **5/2027** | **6/2027** | **7/2027** | **8/2027** | **9/2027** | **10/2027** | **11/2027** | **12/2027** | **aMW** |
| Brownlee | HCC* | 193.8 | 192.8 | 236.6 | 247.0 | 282.1 | 205.7 | 206.3 | 129.1 | 143.4 | 140.9 | 160.0 | 180.8 | 193.2 |
| Oxbow | HCC | 80.6 | 80.1 | 98.4 | 102.8 | 117.4 | 85.3 | 87.1 | 58.5 | 65.9 | 63.3 | 69.9 | 78.2 | 82.3 |
| Hells Canyon | HCC | 159.5 | 159.4 | 199.4 | 208.9 | 240.5 | 171.9 | 171.2 | 115.4 | 129.4 | 125.4 | 138.3 | 154.4 | 164.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.5 | 29.8 | 68.8 | 84.4 | 84.1 | 54.3 | 26.7 | 9.7 | 0.0 | 0.0 | 30.4 |
| Bliss | ROR | 33.6 | 34.0 | 32.8 | 31.6 | 36.9 | 35.2 | 31.4 | 24.4 | 33.0 | 36.2 | 33.7 | 33.9 | 33.1 |
| C .J. Strike | ROR | 42.8 | 42.4 | 42.5 | 40.0 | 41.9 | 37.4 | 30.4 | 24.6 | 38.2 | 43.9 | 42.3 | 42.2 | 39.1 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.2 | 21.4 | 19.9 | 19.1 | 24.3 | 23.5 | 20.0 | 13.2 | 20.2 | 22.8 | 21.2 | 21.3 | 20.7 |
| Milner | ROR | 6.0 | 5.5 | 0.0 | 0.0 | 10.7 | 10.7 | 5.9 | 0.0 | 0.0 | 0.0 | 1.7 | 4.9 | 3.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 8.8 | 10.7 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.7 | 14.5 | 12.9 | 11.0 | 8.8 | 13.1 | 14.8 | 14.4 | 14.5 | 13.4 |
| Twin Falls | ROR | 9.4 | 8.8 | 3.8 | 0.0 | 13.5 | 14.5 | 10.0 | 0.0 | 0.0 | 5.2 | 6.8 | 8.8 | 6.7 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 12.6 | 12.9 | 11.8 | 11.2 | 15.3 | 14.4 | 11.7 | 6.7 | 11.8 | 13.7 | 12.4 | 12.6 | 12.3 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.2 | 11.3 | 10.8 | 14.2 | 13.5 | 11.2 | 7.0 | 11.3 | 12.9 | 11.8 | 12.0 | 11.7 |
| **HCC Total** | | **433.9** | **432.3** | **534.4** | **558.7** | **640.0** | **462.9** | **464.6** | **303.0** | **338.7** | **329.6** | **368.2** | **413.4** | **440.0** |
| **ROR Total** | | **190.5** | **189.9** | **177.5** | **185.7** | **281.5** | **289.5** | **260.2** | **182.1** | **195.5** | **196.7** | **179.0** | **188.8** | **209.7** |
| **Total** | | **624.4** | **622.2** | **711.9** | **744.4** | **921.5** | **752.4** | **724.8** | **485.1** | **534.2** | **526.3** | **547.2** | **602.2** | **649.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2028** | **2/2028** | **3/2028** | **4/2028** | **5/2028** | **6/2028** | **7/2028** | **8/2028** | **9/2028** | **10/2028** | **11/2028** | **12/2028** | **aMW** |
| Brownlee | HCC* | 193.8 | 192.8 | 236.6 | 247.0 | 282.1 | 205.7 | 206.3 | 129.1 | 143.4 | 140.9 | 160.0 | 180.8 | 193.2 |
| Oxbow | HCC | 80.6 | 80.1 | 98.4 | 102.8 | 117.4 | 85.3 | 87.1 | 58.5 | 65.9 | 63.3 | 69.9 | 78.2 | 82.3 |
| Hells Canyon | HCC | 159.5 | 159.4 | 199.4 | 208.9 | 240.5 | 171.9 | 171.2 | 115.4 | 129.4 | 125.4 | 138.3 | 154.4 | 164.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.5 | 29.8 | 68.8 | 84.4 | 84.1 | 54.3 | 26.7 | 9.7 | 0.0 | 0.0 | 30.4 |
| Bliss | ROR | 33.6 | 34.0 | 32.8 | 31.6 | 36.9 | 35.2 | 31.4 | 24.4 | 33.0 | 36.2 | 33.7 | 33.9 | 33.1 |
| C .J. Strike | ROR | 42.8 | 42.4 | 42.5 | 40.0 | 41.9 | 37.4 | 30.4 | 24.6 | 38.2 | 43.9 | 42.3 | 42.2 | 39.1 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.2 | 21.4 | 19.9 | 19.1 | 24.3 | 23.5 | 20.0 | 13.2 | 20.2 | 22.8 | 21.2 | 21.3 | 20.7 |
| Milner | ROR | 6.0 | 5.5 | 0.0 | 0.0 | 10.7 | 10.7 | 5.9 | 0.0 | 0.0 | 0.0 | 1.7 | 4.9 | 3.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 8.8 | 10.7 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.7 | 14.5 | 12.9 | 11.0 | 8.8 | 13.1 | 14.8 | 14.4 | 14.5 | 13.4 |
| Twin Falls | ROR | 9.4 | 8.8 | 3.8 | 0.0 | 13.5 | 14.5 | 10.0 | 0.0 | 0.0 | 5.2 | 6.8 | 8.8 | 6.7 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 12.6 | 12.9 | 11.8 | 11.2 | 15.3 | 14.4 | 11.7 | 6.7 | 11.8 | 13.7 | 12.4 | 12.6 | 12.3 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.2 | 11.3 | 10.8 | 14.2 | 13.5 | 11.2 | 7.0 | 11.3 | 12.9 | 11.8 | 12.0 | 11.7 |
| **HCC Total** | | **433.9** | **432.3** | **534.4** | **558.7** | **640.0** | **462.9** | **464.6** | **303.0** | **338.7** | **329.6** | **368.2** | **413.4** | **440.0** |
| **ROR Total** | | **190.5** | **189.9** | **177.5** | **185.7** | **281.5** | **289.5** | **260.2** | **182.1** | **195.5** | **196.7** | **179.0** | **188.8** | **209.7** |
| **Total** | | **624.4** | **622.2** | **711.9** | **744.4** | **921.5** | **752.4** | **724.8** | **485.1** | **534.2** | **526.3** | **547.2** | **602.2** | **649.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2029** | **2/2029** | **3/2029** | **4/2029** | **5/2029** | **6/2029** | **7/2029** | **8/2029** | **9/2029** | **10/2029** | **11/2029** | **12/2029** | **aMW** |
| Brownlee | HCC* | 193.8 | 192.8 | 236.6 | 247.0 | 282.1 | 205.7 | 206.3 | 129.1 | 143.4 | 140.9 | 160.0 | 180.8 | 193.2 |
| Oxbow | HCC | 80.6 | 80.1 | 98.4 | 102.8 | 117.4 | 85.3 | 87.1 | 58.5 | 65.9 | 63.3 | 69.9 | 78.2 | 82.3 |
| Hells Canyon | HCC | 159.5 | 159.4 | 199.4 | 208.9 | 240.5 | 171.9 | 171.2 | 115.4 | 129.4 | 125.4 | 138.3 | 154.4 | 164.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.5 | 29.8 | 68.8 | 84.4 | 84.1 | 54.3 | 26.7 | 9.7 | 0.0 | 0.0 | 30.4 |
| Bliss | ROR | 33.6 | 34.0 | 32.8 | 31.6 | 36.9 | 35.2 | 31.4 | 24.4 | 33.0 | 36.2 | 33.7 | 33.9 | 33.1 |
| C .J. Strike | ROR | 42.8 | 42.4 | 42.5 | 40.0 | 41.9 | 37.4 | 30.4 | 24.6 | 38.2 | 43.9 | 42.3 | 42.2 | 39.1 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.2 | 21.4 | 19.9 | 19.1 | 24.3 | 23.5 | 20.0 | 13.2 | 20.2 | 22.8 | 21.2 | 21.3 | 20.7 |
| Milner | ROR | 6.0 | 5.5 | 0.0 | 0.0 | 10.7 | 10.7 | 5.9 | 0.0 | 0.0 | 0.0 | 1.7 | 4.9 | 3.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 8.8 | 10.7 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.7 | 14.5 | 12.9 | 11.0 | 8.8 | 13.1 | 14.8 | 14.4 | 14.5 | 13.4 |
| Twin Falls | ROR | 9.4 | 8.8 | 3.8 | 0.0 | 13.5 | 14.5 | 10.0 | 0.0 | 0.0 | 5.2 | 6.8 | 8.8 | 6.7 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 12.6 | 12.9 | 11.8 | 11.2 | 15.3 | 14.4 | 11.7 | 6.7 | 11.8 | 13.7 | 12.4 | 12.6 | 12.3 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.2 | 11.3 | 10.8 | 14.2 | 13.5 | 11.2 | 7.0 | 11.3 | 12.9 | 11.8 | 12.0 | 11.7 |
| **HCC Total** | | **433.9** | **432.3** | **534.4** | **558.7** | **640.0** | **462.9** | **464.6** | **303.0** | **338.7** | **329.6** | **368.2** | **413.4** | **440.0** |
| **ROR Total** | | **190.5** | **189.9** | **177.5** | **185.7** | **281.5** | **289.5** | **260.2** | **182.1** | **195.5** | **196.7** | **179.0** | **188.8** | **209.7** |
| **Total** | | **624.4** | **622.2** | **711.9** | **744.4** | **921.5** | **752.4** | **724.8** | **485.1** | **534.2** | **526.3** | **547.2** | **602.2** | **649.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2030** | **2/2030** | **3/2030** | **4/2030** | **5/2030** | **6/2030** | **7/2030** | **8/2030** | **9/2030** | **10/2030** | **11/2030** | **12/2030** | **aMW** |
| Brownlee | HCC* | 193.8 | 192.8 | 236.6 | 247.0 | 282.1 | 205.7 | 206.3 | 129.1 | 143.4 | 140.9 | 160.0 | 180.8 | 193.2 |
| Oxbow | HCC | 80.6 | 80.1 | 98.4 | 102.8 | 117.4 | 85.3 | 87.1 | 58.5 | 65.9 | 63.3 | 69.9 | 78.2 | 82.3 |
| Hells Canyon | HCC | 159.5 | 159.4 | 199.4 | 208.9 | 240.5 | 171.9 | 171.2 | 115.4 | 129.4 | 125.4 | 138.3 | 154.4 | 164.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.5 | 29.8 | 68.8 | 84.4 | 84.1 | 54.3 | 26.7 | 9.7 | 0.0 | 0.0 | 30.4 |
| Bliss | ROR | 33.6 | 34.0 | 32.8 | 31.6 | 36.9 | 35.2 | 31.4 | 24.4 | 33.0 | 36.2 | 33.7 | 33.9 | 33.1 |
| C .J. Strike | ROR | 42.8 | 42.4 | 42.5 | 40.0 | 41.9 | 37.4 | 30.4 | 24.6 | 38.2 | 43.9 | 42.3 | 42.2 | 39.1 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.2 | 21.4 | 19.9 | 19.1 | 24.3 | 23.5 | 20.0 | 13.2 | 20.2 | 22.8 | 21.2 | 21.3 | 20.7 |
| Milner | ROR | 6.0 | 5.5 | 0.0 | 0.0 | 10.7 | 10.7 | 5.9 | 0.0 | 0.0 | 0.0 | 1.7 | 4.9 | 3.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 8.8 | 10.7 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.7 | 14.5 | 12.9 | 11.0 | 8.8 | 13.1 | 14.8 | 14.4 | 14.5 | 13.4 |
| Twin Falls | ROR | 9.4 | 8.8 | 3.8 | 0.0 | 13.5 | 14.5 | 10.0 | 0.0 | 0.0 | 5.2 | 6.8 | 8.8 | 6.7 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 12.6 | 12.9 | 11.8 | 11.2 | 15.3 | 14.4 | 11.7 | 6.7 | 11.8 | 13.7 | 12.4 | 12.6 | 12.3 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.2 | 11.3 | 10.8 | 14.2 | 13.5 | 11.2 | 7.0 | 11.3 | 12.9 | 11.8 | 12.0 | 11.7 |
| **HCC Total** | | **433.9** | **432.3** | **534.4** | **558.7** | **640.0** | **462.9** | **464.6** | **303.0** | **338.7** | **329.6** | **368.2** | **413.4** | **440.0** |
| **ROR Total** | | **190.5** | **189.9** | **177.5** | **185.7** | **281.5** | **289.5** | **260.2** | **182.1** | **195.5** | **196.7** | **179.0** | **188.8** | **209.7** |
| **Total** | | **624.4** | **622.2** | **711.9** | **744.4** | **921.5** | **752.4** | **724.8** | **485.1** | **534.2** | **526.3** | **547.2** | **602.2** | **649.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2031** | **2/2031** | **3/2031** | **4/2031** | **5/2031** | **6/2031** | **7/2031** | **8/2031** | **9/2031** | **10/2031** | **11/2031** | **12/2031** | **aMW** |
| Brownlee | HCC* | 193.8 | 192.8 | 236.6 | 247.0 | 282.1 | 205.7 | 206.3 | 129.1 | 143.4 | 140.9 | 160.0 | 180.8 | 193.2 |
| Oxbow | HCC | 80.6 | 80.1 | 98.4 | 102.8 | 117.4 | 85.3 | 87.1 | 58.5 | 65.9 | 63.3 | 69.9 | 78.2 | 82.3 |
| Hells Canyon | HCC | 159.5 | 159.4 | 199.4 | 208.9 | 240.5 | 171.9 | 171.2 | 115.4 | 129.4 | 125.4 | 138.3 | 154.4 | 164.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.5 | 29.8 | 68.8 | 84.4 | 84.1 | 54.3 | 26.7 | 9.7 | 0.0 | 0.0 | 30.4 |
| Bliss | ROR | 33.6 | 34.0 | 32.8 | 31.6 | 36.9 | 35.2 | 31.4 | 24.4 | 33.0 | 36.2 | 33.7 | 33.9 | 33.1 |
| C .J. Strike | ROR | 42.8 | 42.4 | 42.5 | 40.0 | 41.9 | 37.4 | 30.4 | 24.6 | 38.2 | 43.9 | 42.3 | 42.2 | 39.1 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.2 | 21.4 | 19.9 | 19.1 | 24.3 | 23.5 | 20.0 | 13.2 | 20.2 | 22.8 | 21.2 | 21.3 | 20.7 |
| Milner | ROR | 6.0 | 5.5 | 0.0 | 0.0 | 10.7 | 10.7 | 5.9 | 0.0 | 0.0 | 0.0 | 1.7 | 4.9 | 3.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 8.8 | 10.7 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.7 | 14.5 | 12.9 | 11.0 | 8.8 | 13.1 | 14.8 | 14.4 | 14.5 | 13.4 |
| Twin Falls | ROR | 9.4 | 8.8 | 3.8 | 0.0 | 13.5 | 14.5 | 10.0 | 0.0 | 0.0 | 5.2 | 6.8 | 8.8 | 6.7 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 12.6 | 12.9 | 11.8 | 11.2 | 15.3 | 14.4 | 11.7 | 6.7 | 11.8 | 13.7 | 12.4 | 12.6 | 12.3 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.2 | 11.3 | 10.8 | 14.2 | 13.5 | 11.2 | 7.0 | 11.3 | 12.9 | 11.8 | 12.0 | 11.7 |
| **HCC Total** | | **433.9** | **432.3** | **534.4** | **558.7** | **640.0** | **462.9** | **464.6** | **303.0** | **338.7** | **329.6** | **368.2** | **413.4** | **440.0** |
| **ROR Total** | | **190.5** | **189.9** | **177.5** | **185.7** | **281.5** | **289.5** | **260.2** | **182.1** | **195.5** | **196.7** | **179.0** | **188.8** | **209.7** |
| **Total** | | **624.4** | **622.2** | **711.9** | **744.4** | **921.5** | **752.4** | **724.8** | **485.1** | **534.2** | **526.3** | **547.2** | **602.2** | **649.7** |

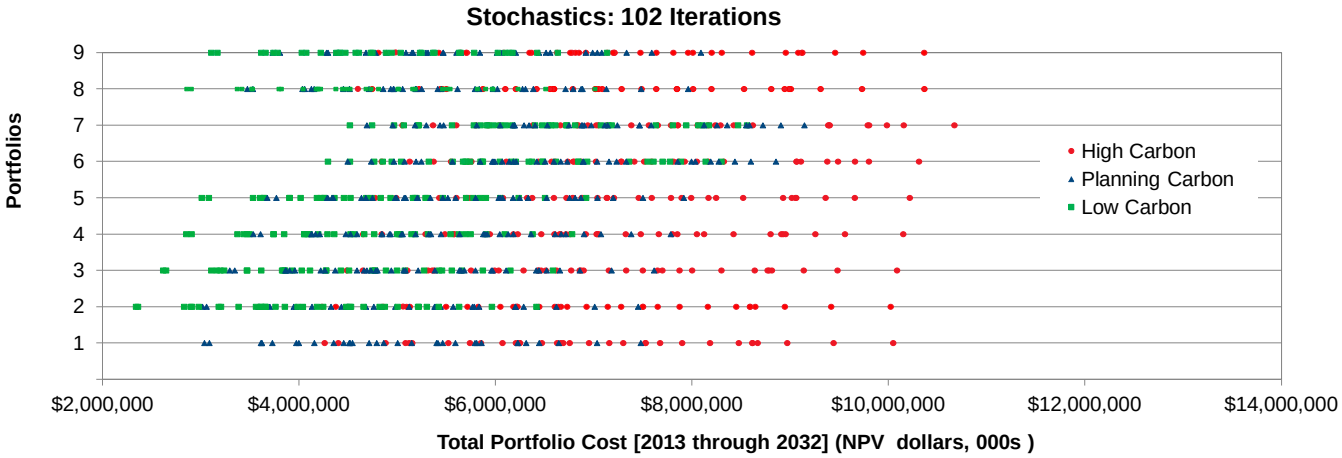
*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2032** | **2/2032** | **3/2032** | **4/2032** | **5/2032** | **6/2032** | **7/2032** | **8/2032** | **9/2032** | **10/2032** | **11/2032** | **12/2032** | **aMW** |
| Brownlee | HCC* | 193.8 | 192.8 | 236.6 | 247.0 | 282.1 | 205.7 | 206.3 | 129.1 | 143.4 | 140.9 | 160.0 | 180.8 | 193.2 |
| Oxbow | HCC | 80.6 | 80.1 | 98.4 | 102.8 | 117.4 | 85.3 | 87.1 | 58.5 | 65.9 | 63.3 | 69.9 | 78.2 | 82.3 |
| Hells Canyon | HCC | 159.5 | 159.4 | 199.4 | 208.9 | 240.5 | 171.9 | 171.2 | 115.4 | 129.4 | 125.4 | 138.3 | 154.4 | 164.5 |
| 1000 Springs | ROR** | 6.0 | 5.8 | 5.7 | 5.3 | 5.6 | 6.0 | 5.8 | 6.0 | 6.4 | 6.4 | 5.4 | 6.1 | 5.9 |
| American Falls | ROR | 0.0 | 0.0 | 6.5 | 29.8 | 68.8 | 84.4 | 84.1 | 54.3 | 26.7 | 9.7 | 0.0 | 0.0 | 30.4 |
| Bliss | ROR | 33.6 | 34.0 | 32.8 | 31.6 | 36.9 | 35.2 | 31.4 | 24.4 | 33.0 | 36.2 | 33.7 | 33.9 | 33.1 |
| C .J. Strike | ROR | 42.8 | 42.4 | 42.5 | 40.0 | 41.9 | 37.4 | 30.4 | 24.6 | 38.2 | 43.9 | 42.3 | 42.2 | 39.1 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.5 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.7 | 1.6 | 1.6 | 1.4 | 1.6 | 1.4 | 1.4 | 1.5 | 1.6 | 1.7 | 1.5 | 1.7 | 1.6 |
| Lower Malad | ROR | 11.1 | 11.2 | 11.9 | 11.3 | 13.0 | 12.0 | 11.7 | 12.0 | 13.0 | 12.8 | 10.1 | 11.2 | 11.8 |
| Lowe Salmon | ROR | 21.2 | 21.4 | 19.9 | 19.1 | 24.3 | 23.5 | 20.0 | 13.2 | 20.2 | 22.8 | 21.2 | 21.3 | 20.7 |
| Milner | ROR | 6.0 | 5.5 | 0.0 | 0.0 | 10.7 | 10.7 | 5.9 | 0.0 | 0.0 | 0.0 | 1.7 | 4.9 | 3.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.6 | 6.5 | 8.8 | 10.7 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.5 | 14.5 | 14.5 | 13.7 | 14.5 | 12.9 | 11.0 | 8.8 | 13.1 | 14.8 | 14.4 | 14.5 | 13.4 |
| Twin Falls | ROR | 9.4 | 8.8 | 3.8 | 0.0 | 13.5 | 14.5 | 10.0 | 0.0 | 0.0 | 5.2 | 6.8 | 8.8 | 6.7 |
| Upper Malad | ROR | 6.3 | 6.2 | 6.6 | 6.3 | 7.7 | 7.3 | 6.7 | 6.7 | 7.2 | 6.5 | 5.6 | 6.3 | 6.6 |
| Upper Salmon 1&2 | ROR | 12.6 | 12.9 | 11.8 | 11.2 | 15.3 | 14.4 | 11.7 | 6.7 | 11.8 | 13.7 | 12.4 | 12.6 | 12.3 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.2 | 11.3 | 10.8 | 14.2 | 13.5 | 11.2 | 7.0 | 11.3 | 12.9 | 11.8 | 12.0 | 11.7 |
| **HCC Total** | | **433.9** | **432.3** | **534.4** | **558.7** | **640.0** | **462.9** | **464.6** | **303.0** | **338.7** | **329.6** | **368.2** | **413.4** | **440.0** |
| **ROR Total** | | **190.5** | **189.9** | **177.5** | **185.7** | **281.5** | **289.5** | **260.2** | **182.1** | **195.5** | **196.7** | **179.0** | **188.8** | **209.7** |
| **Total** | | **624.4** | **622.2** | **711.9** | **744.4** | **921.5** | **752.4** | **724.8** | **485.1** | **534.2** | **526.3** | **547.2** | **602.2** | **649.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

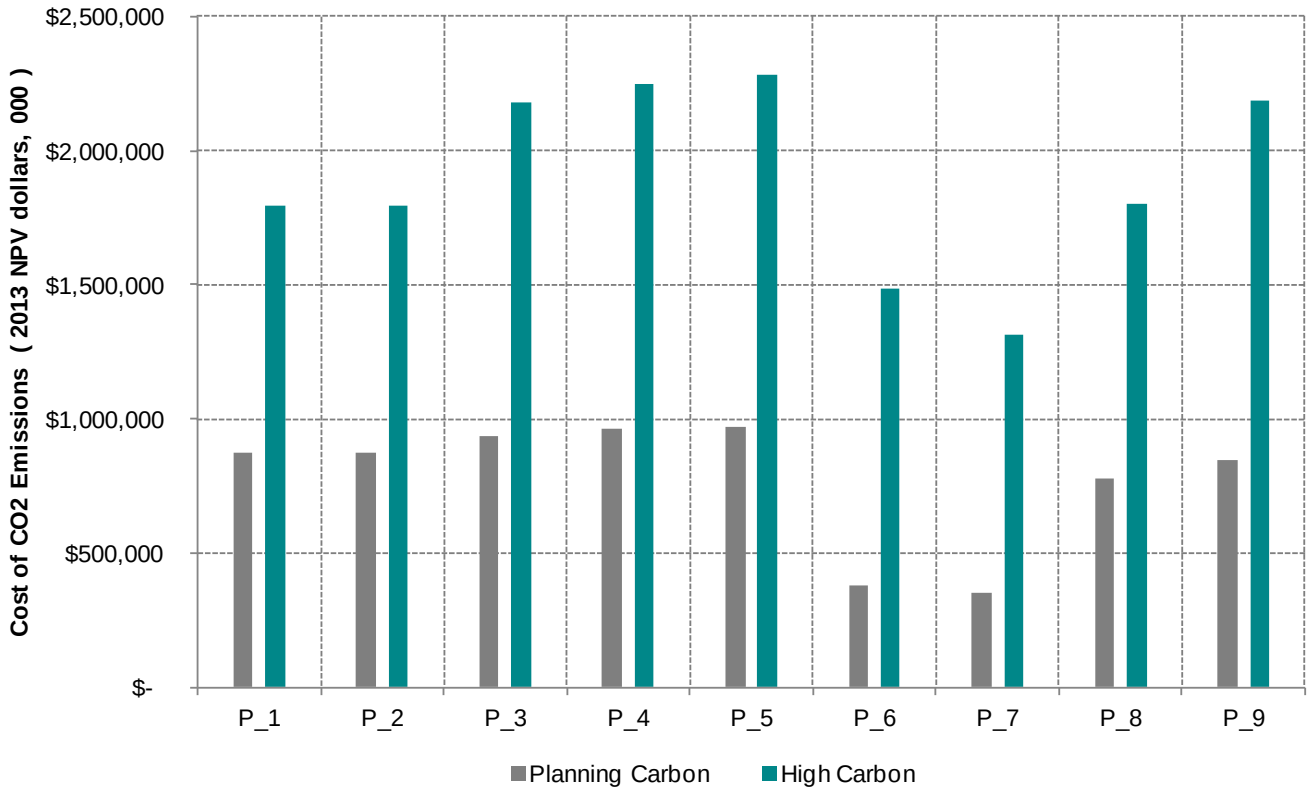
# PORTFOLIO ANALYSIS, RESULTS, AND SUPPORTING DOCUMENTATION

## Stochastic Dispersion Plot




## Regulatory Environmental Compliance Costs

### *Portfolio Analysis Cost of $CO_2$ Emissions*




**Note**: Instead of assuming NOx, 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 these emission types.

# Loss of Load Expectation Analysis

**Loss of Load Expectation Summary Data*–Portfolio 1**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2014 | 0.79 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.78 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2015 | 0.63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.61 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.32 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2017 | 0.58 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.53 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2018 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 0.07 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.19 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.19 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2027 | 0.15 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.13 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2028 | 0.29 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.26 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2029 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data*–Portfolio 2**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2014 | 0.79 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.78 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2015 | 0.63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.61 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.32 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2017 | 0.58 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.53 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2018 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.17 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.16 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.17 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.16 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2027 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2028 | 0.21 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.18 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2029 | 0.08 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.08 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 0.25 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.24 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 0.91 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.90 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 0.36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.34 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data*–Portfolio 3**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | 0.74 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.69 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2014 | 1.24 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.21 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2015 | 0.63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.61 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.32 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2017 | 0.58 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.53 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2018 | 0.97 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.44 | 0.30 | 0.18 | 0.02 | 0.00 | 0.00 | 0.01 |
| 2019 | 1.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.36 | 0.57 | 0.37 | 0.08 | 0.00 | 0.00 | 0.01 |
| 2020 | 3.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.10 | 0.26 | 1.19 | 1.68 | 0.04 | 0.00 | 0.00 | 0.02 |
| 2021 | 2.61 | 0.01 | 0.00 | 0.00 | 0.00 | 0.05 | 0.25 | 1.59 | 0.52 | 0.11 | 0.00 | 0.00 | 0.07 |
| 2022 | 0.28 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.06 | 0.14 | 0.05 | 0.01 | 0.00 | 0.00 | 0.01 |
| 2023 | 0.46 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.28 | 0.06 | 0.01 | 0.00 | 0.00 | 0.01 |
| 2024 | 0.94 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.07 | 0.69 | 0.08 | 0.09 | 0.00 | 0.00 | 0.01 |
| 2025 | 2.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 1.86 | 0.06 | 0.05 | 0.00 | 0.00 | 0.01 |
| 2026 | 2.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.04 | 1.83 | 0.10 | 0.02 | 0.00 | 0.00 | 0.01 |
| 2027 | 1.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 1.22 | 0.05 | 0.01 | 0.00 | 0.00 | 0.02 |
| 2028 | 2.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.14 | 2.06 | 0.05 | 0.02 | 0.00 | 0.00 | 0.02 |
| 2029 | 1.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 0.98 | 0.01 | 0.01 | 0.00 | 0.00 | 0.01 |
| 2030 | 2.55 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.06 | 2.45 | 0.02 | 0.01 | 0.00 | 0.00 | 0.01 |
| 2031 | 6.75 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 6.67 | 0.03 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2032 | 3.28 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.08 | 3.15 | 0.02 | 0.00 | 0.00 | 0.00 | 0.02 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data*–Portfolio 4**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2014 | 0.79 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.78 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2015 | 0.63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.61 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.32 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2017 | 0.58 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.53 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2018 | 0.14 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 0.07 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.12 | 0.04 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.03 | 0.24 | 0.19 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.29 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.19 | 0.05 | 0.01 | 0.00 | 0.00 | 0.01 |
| 2022 | 0.29 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.06 | 0.16 | 0.05 | 0.01 | 0.00 | 0.00 | 0.01 |
| 2023 | 0.49 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.32 | 0.06 | 0.01 | 0.00 | 0.00 | 0.01 |
| 2024 | 1.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.07 | 0.76 | 0.08 | 0.09 | 0.00 | 0.00 | 0.01 |
| 2025 | 2.18 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 2.03 | 0.06 | 0.05 | 0.00 | 0.00 | 0.01 |
| 2026 | 0.27 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.25 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.18 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.17 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.32 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.30 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.55 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.51 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 1.33 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 1.28 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 3.63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 3.59 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 1.75 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 1.69 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data*–Portfolio 5**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2014 | 0.79 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.78 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2015 | 0.63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.61 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.32 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2017 | 0.58 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.53 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2018 | 0.14 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 0.07 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.12 | 0.04 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.03 | 0.24 | 0.19 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.04 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.08 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.18 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.49 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.47 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.27 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.25 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.18 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.17 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.32 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.30 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.55 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.51 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 1.33 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 1.28 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 3.63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 3.59 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 1.75 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 1.69 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data*–Portfolio 6**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2014 | 0.79 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.78 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2015 | 0.63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.61 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.45 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.41 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2017 | 2.59 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.16 | 2.29 | 0.04 | 0.01 | 0.00 | 0.00 | 0.07 |
| 2018 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.03 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.15 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.07 | 0.06 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2021 | 0.07 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.01 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2022 | 0.07 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.03 | 0.01 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2023 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.06 | 0.01 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2024 | 0.22 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.15 | 0.01 | 0.02 | 0.00 | 0.00 | 0.02 |
| 2025 | 0.44 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.39 | 0.01 | 0.01 | 0.00 | 0.00 | 0.02 |
| 2026 | 0.44 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.38 | 0.02 | 0.00 | 0.00 | 0.00 | 0.03 |
| 2027 | 0.34 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.27 | 0.01 | 0.00 | 0.00 | 0.00 | 0.05 |
| 2028 | 0.55 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.44 | 0.01 | 0.00 | 0.00 | 0.00 | 0.06 |
| 2029 | 0.90 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.76 | 0.01 | 0.01 | 0.00 | 0.00 | 0.07 |
| 2030 | 2.18 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 2.03 | 0.02 | 0.01 | 0.00 | 0.00 | 0.07 |
| 2031 | 3.97 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 3.85 | 0.01 | 0.00 | 0.00 | 0.00 | 0.06 |
| 2032 | 2.03 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 1.85 | 0.01 | 0.00 | 0.00 | 0.00 | 0.11 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data*–Portfolio 7**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2014 | 0.79 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.78 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2015 | 0.78 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.75 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2016 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.28 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2018 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2022 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.02 | 0.01 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2023 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.05 | 0.01 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2024 | 0.18 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.12 | 0.01 | 0.01 | 0.00 | 0.00 | 0.02 |
| 2025 | 0.36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.32 | 0.01 | 0.01 | 0.00 | 0.00 | 0.02 |
| 2026 | 0.36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.31 | 0.02 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2027 | 0.28 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.21 | 0.01 | 0.00 | 0.00 | 0.00 | 0.04 |
| 2028 | 0.44 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.36 | 0.01 | 0.00 | 0.00 | 0.00 | 0.05 |
| 2029 | 0.73 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.61 | 0.01 | 0.00 | 0.00 | 0.00 | 0.06 |
| 2030 | 1.68 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 1.55 | 0.01 | 0.01 | 0.00 | 0.00 | 0.05 |
| 2031 | 3.95 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 3.81 | 0.02 | 0.00 | 0.00 | 0.00 | 0.08 |
| 2032 | 2.20 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 1.97 | 0.02 | 0.00 | 0.00 | 0.00 | 0.14 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data*–Portfolio 8**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2014 | 0.79 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.78 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2015 | 0.63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.61 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.32 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2017 | 0.58 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.53 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2018 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.02 | 0.01 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2023 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.05 | 0.01 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2024 | 0.19 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.14 | 0.01 | 0.01 | 0.00 | 0.00 | 0.02 |
| 2025 | 0.51 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.47 | 0.01 | 0.01 | 0.00 | 0.00 | 0.02 |
| 2026 | 1.70 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 1.49 | 0.06 | 0.01 | 0.00 | 0.00 | 0.09 |
| 2027 | 0.14 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2028 | 0.21 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.18 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2029 | 0.39 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.34 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2030 | 0.98 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.94 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 |
| 2031 | 3.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 2.96 | 0.01 | 0.00 | 0.00 | 0.00 | 0.03 |
| 2032 | 1.34 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 1.24 | 0.01 | 0.00 | 0.00 | 0.00 | 0.06 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data*–Portfolio 9**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2014 | 0.79 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.78 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2015 | 0.63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.61 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.32 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2017 | 0.58 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.53 | 0.01 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2018 | 0.97 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.44 | 0.30 | 0.18 | 0.02 | 0.00 | 0.00 | 0.01 |
| 2019 | 1.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.36 | 0.57 | 0.37 | 0.08 | 0.00 | 0.00 | 0.01 |
| 2020 | 3.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.10 | 0.26 | 1.19 | 1.68 | 0.04 | 0.00 | 0.00 | 0.02 |
| 2021 | 2.61 | 0.01 | 0.00 | 0.00 | 0.00 | 0.05 | 0.25 | 1.59 | 0.52 | 0.11 | 0.00 | 0.00 | 0.07 |
| 2022 | 1.14 | 0.05 | 0.01 | 0.00 | 0.00 | 0.28 | 0.17 | 0.42 | 0.15 | 0.03 | 0.00 | 0.00 | 0.03 |
| 2023 | 1.33 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.25 | 0.81 | 0.17 | 0.05 | 0.00 | 0.00 | 0.03 |
| 2024 | 2.56 | 0.01 | 0.00 | 0.00 | 0.00 | 0.03 | 0.20 | 1.82 | 0.22 | 0.25 | 0.00 | 0.00 | 0.02 |
| 2025 | 0.68 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.62 | 0.02 | 0.02 | 0.00 | 0.00 | 0.00 |
| 2026 | 1.90 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.04 | 1.70 | 0.11 | 0.02 | 0.00 | 0.00 | 0.01 |
| 2027 | 1.37 | 0.03 | 0.00 | 0.00 | 0.00 | 0.05 | 0.05 | 1.14 | 0.05 | 0.02 | 0.00 | 0.00 | 0.02 |
| 2028 | 2.14 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.12 | 1.90 | 0.06 | 0.02 | 0.00 | 0.00 | 0.03 |
| 2029 | 3.46 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.21 | 3.12 | 0.05 | 0.03 | 0.00 | 0.00 | 0.03 |
| 2030 | 2.37 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.06 | 2.26 | 0.02 | 0.01 | 0.00 | 0.00 | 0.01 |
| 2031 | 6.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.05 | 5.97 | 0.03 | 0.00 | 0.00 | 0.00 | 0.01 |
| 2032 | 3.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.09 | 2.87 | 0.03 | 0.00 | 0.00 | 0.00 | 0.02 |

* With CBM@330 MW

# STATE OF OREGON IRP GUIDELINES

ORDER NO. 07-047

ENTERED 02/09/07

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

UM 1056

| | | |
|---|---|---|
| In the Matter of<br><br>PUBLIC UTILITY COMMISSION OF OREGON<br><br>Investigation Into Integrated Resource Planning. | )<br>)<br>)<br>)<br>)<br>)<br>) | ERRATA ORDER |

DISPOSITION: APPENDIX TO ORDER NO. 07-002 CORRECTED

In Order No. 07-002, we adopted guidelines to govern the Integrated Resource Planning (IRP) process. In setting forth those guidelines in an appendix, we inadvertently omitted Guideline 1(d), which we discussed and adopted in the body of the order on pages 7 and 8. Accordingly, Appendix A to Order No. 07-002 is replaced with the attached appendix to this order, which includes all the adopted guidelines. The remainder of the order is unchanged.

IT IS SO ORDERED.

Made, entered, and effective FEB 09 2007.

**Lee Beyer**
Chairman

**John Savage**
Commissioner

**Ray Baum**
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

**Adopted IRP Guidelines**

**Guideline 1: Substantive Requirements**

*a. All resources must be evaluated on a consistent and comparable basis.*

- *All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.*
- *Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.*
- *Consistent assumptions and methods should be used for evaluation of all resources.*
- *The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.*

*b. Risk and uncertainty must be considered.*

- *At a minimum, utilities should address the following sources of risk and uncertainty:*
  1. *Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.*
  2. *Natural gas utilities: demand (peak, swing and base-load), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.*
- *Utilities should identify in their plans any additional sources of risk and uncertainty.*

*c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and*

*associated risks and uncertainties for the utility and its customers.*[1]

- *The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.*

- *Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.*

- *To address risk, the plan should include, at a minimum:*

  1. *Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.*

  2. *Discussion of the proposed use and impact on costs and risks of physical and financial hedging.*

- *The utility should explain in its plan how its resource choices appropriately balance cost and risk.*

d. *The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.*

**Guideline 2: Procedural Requirements.**

a. *The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.*

[1] We sometimes refer to this portfolio as the "best cost/risk portfolio."

*b. While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.*

*c. The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.*

**Guideline 3: Plan Filing, Review, and Updates.**

*a. A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.*

*b. The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.*

*c. Commission staff and parties should complete their comments and recommendations within six months of IRP filing.*

*d. The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.*

*e. The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.*

*f. Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.*

g. *Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:*

- *Describes what actions the utility has taken to implement the plan;*
- *Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and*
- *Justifies any deviations from the acknowledged action plan.*

**Guideline 4: Plan Components.**

*At a minimum, the plan must include the following elements:*

a. *An explanation of how the utility met each of the substantive and procedural requirements;*

b. *Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;*

c. *For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;*

d. *For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;*

e. *Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;*

*f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;*

*g. Identification of key assumptions about the future( e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;*

*h. Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;*

*i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;*

*j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;*

*k. Analysis of the uncertainties associated with each portfolio evaluated;*

*l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;*

*m. Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and*

*n. An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.*

**Guideline 5: Transmission.**

*Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote*

*locations, acquiring alternative fuel supplies, and improving reliability.*

**Guideline 6: Conservation.**

a. *Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.*

b. *To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.*

c. *To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:*

   - *Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and*

   - *Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.*

**Guideline 7: Demand Response.**

*Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).*

**Guideline 8: Environmental Costs.**

*Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide ($CO_2$), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential $CO_2$ regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.*

**Guideline 9: Direct Access Loads.**

*An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.*

**Guideline 10: Multi-state Utilities.**

*Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.*

**Guideline 11: Reliability.**

*Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.*

**Guideline 12: Distributed Generation.**

*Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.*

**Guideline 13: Resource Acquisition.**

a. *An electric utility should, in its IRP:*

   - *Identify its proposed acquisition strategy for each resource in its action plan.*
   - *Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.*
   - *Identify any Benchmark Resources it plans to consider in competitive bidding.*

b. *Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.*

# Compliance with State of Oregon IRP Guidelines

| Oregon Order 07-047 Action Items | 2013 IRP |
|---|---|
| **Guideline 1: Substantive Requirements** | |
| a. All resources must be evaluated on a consistent and comparable basis.<br>• All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand side options which focus on conservation and demand response.<br>• Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.<br>• Consistent assumptions and methods should be used for evaluation of all resources.<br>• The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs. | a-1) Supply-side and purchased resources for meeting the utility's load are discussed in Chapter 3. Idaho Power Today, section *Existing Supply-Side Resources*, pages 25–36. Demand-side options for meeting the utility's load are discussed in Chapter 4. Demand-Side Resources, pages 37–45.<br>a-2) Different resource alternatives results are compared in Chapter 7. Resource Alternatives Analysis, Table 7.1 on page 84. Different resource portfolios results are compared in Chapter 9. Modeling Analysis and Results, section *Portfolio Costs*, Table 9.2 on page 98.<br>a-3) The consistent modeling method for evaluating all resource alternatives is explained in Chapter 7. Resource Alternatives Analysis, pages 83-85. The consistent modeling method for evaluating all resource portfolios are explained in Chapter 9. Modeling Analysis and Results, pages 97–99.<br>a-4) The WACC rate used to discount all future resource costs is stated in Chapter 9. Modeling Analysis and Results, in Table 9.1 Financial Assumptions, on page 97. |
| b. Risk and uncertainty must be considered.<br>• At a minimum, utilities should address the following sources of risk and uncertainty:<br>1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.<br>2. Natural gas utilities: demand (peak, swing and baseload), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.<br>• Utilities should identify in their plans any additional sources of risk and uncertainty. | b-1) Electric utility risk and uncertainty factors (carbon, NG and water conditions) for resource alternatives are considered in Chapter 7. Resource Alternatives Analysis, section *Risk Analysis and Results,* pages 86–87.<br>Electric utility risk and uncertainty factors (load, carbon, NG and water conditions) for resource alternatives are considered in Chapter 9. Modeling Analysis and Results, section *Stochastic Analysis*, pages 103–105 (For electricity prices, AURORA forecasts electric market prices; therefore AURORA variables are changed to create different electric market price scenarios). An additional analysis for $CO_2$ emissions costs can be found in the *2013 IRP Technical Appendix*, section *Regulatory Environmental Compliance Costs,* page 131.<br>Note: Plant forced outages for resource alternatives and resource portfolios are not discussed in the IRP document or *2013 IRP Technical Appendix*. Plant forced outages are modeled in AURORA on a unit basis.<br>b-1-other) Additional sources of risk and uncertainty are identified in Chapter 2. Political, Regulatory, and Operational Issues the following sections: *FERC Relicensing*, page 12; *Idaho Water Issues*, page 13; *Northwest Power Pool Energy Imbalance Market*, page 17; and *Federal Energy Legislation*, page 19. Also, the uncertainty in transmission planning process is described in Chapter 6. Transmission Planning, pages 72–73.<br>A tipping-point analyses for carbon adder and dispatch cost is analyzed in Chapter 5. Planning Period Forecasts, section *Carbon Adder Generation Dispatch Analysis,* pages 69–70. |
| c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.<br>• The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.<br>• Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all longlived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.<br>• To address risk, the plan should include, at a minimum:<br>1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.<br>2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.<br>• The utility should explain in its plan how its resource choices appropriately balance cost and risk. | c-1) The IRP methodology and its' subsequent planning horizon of 20 years are discussed in Chapter 1. Summary, section *IRP Methodology,* fourth paragraph on page 4.<br>c-2) Idaho Power uses the company's internal P-Worth model to calculate the PVRR for the capital component of the various portfolios. AURORA is used to model the variable (operating) component of the various portfolios. All costs are then discounted using the company's WACC. The summary of the expected NPV for resource alternative costs are found in Chapter 7. Resource Alternative Analysis, Table 7.1 on page 84. The summary of the expected NPV for total portfolio costs are found in Chapter 9. Modeling Analysis and Results, section *Portfolio Costs*, Table 9.2 on page 98. |
| d. The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies. | |

| Oregon Order 07-047 Action Items | 2013 IRP |
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| | c-1.) Measures of the variability of costs and the severity of bad outcomes are considered in Chapter 9. Modeling Analysis and Results, section *Stochastic Analysis,* pages 103–105. A plot of stochastic dispersion is shown in the *2013 IRP Technical Appendix*, S*tochastic Dispersion Plot* on page 131.<br>c-2.) The risks of physical and financial hedging are referenced to Idaho Power's *Energy Risk Management Policy* discussed in Chapter 1. Summary, in the last paragraph of section Introduction, on page 2. Idaho Power explains how its resource choices appropriately balance cost and risk in a twofold process:<br>Identifying resources alternatives: discussed in Chapter 7. Resource Alternatives Analysis, pages 83–87.<br>For designing portfolios: discussed in Chapter 8. Planning Criteria and Portfolio Selection, pages 89–96.<br>d-1) The plan is consistent with long-run public interests and is discussed in Chapter 2. Political, Regulatory, and Operational Issues, beginning pages 11–19 as well as in Chapter 1. Summary, section *Public Advisory Process*, pages 2–3. |
| **Guideline 2: Procedural Requirements.**<br>a. The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.<br>b. While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.<br>c. The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission. | As set forth in Guideline 2, part a., Idaho Power solicits public involvement in the planning process. The company convenes a public forum as part of the resource planning process. For the 2004, 2006, 2009, 2011 and 2013 plans, Idaho Power assembled an IRP Advisory Council composed of customer representatives, representatives from both the Idaho and Oregon public utility commission staffs, and representatives from special interest groups. A roster of the IRP Advisory Council members is provided in the technical appendices of the 2004, 2006, 2009, 2011 and 2013 IRPs. The IRP Advisory Council meetings are open to the public, on a limited basis due to space constraints. IRP Advisory Council meetings are attended by members of the public and Idaho Power has involved the public participants in the IRP Advisory Council's discussions. These meetings allow parties to make relevant inquiries of Idaho Power formulating the plan.<br>As set forth in Guideline 2, part b., Idaho Power makes public extensive information relevant to its resource evaluation and action plan in its plan. This information is found throughout the 2013 IRP, the 2013 Load and Sales Forecast and in the 2013 Technical Appendix.<br>As set forth in Guideline 2, part c., Idaho Power provided a draft 2013 IRP for public review on Friday, June 6, 2013, via a hard copy to members of IRP Advisory Committee and public attendees of the 2013 IRP Advisory Committee meetings. June 17, 2013 was the deadline for getting IRP Advisory Committee and public comments back on the draft plan. |

| Oregon Order 07-047 Action Items | 2013 IRP |
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| **Guideline 3: Plan Filing, Review, and Updates.**<br>a. A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.<br>b. The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.<br>c. Commission staff and parties should complete their comments and recommendations within six months of IRP filing.<br>d. The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.<br>e. The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.<br>f. Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.<br>g. Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:<br>• Describes what actions the utility has taken to implement the plan;<br>• Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and<br>• Justifies any deviations from the acknowledged action plan. | a. The OPUC acknowledged Idaho Power's 2011 IRP on May 21, 2012 in Order 12-177. Idaho Power plans to file the 2013 IRP on June 28, 2013.<br>b. Idaho Power will schedule a public meeting at the OPUC after the 2013 IRP has been filed.<br>c. No action needed.<br>d. No action needed unless the OPUC provides Idaho Power an opportunity to revise the plan.<br>e. In ORDER NO. 12-013, the OPUC provided direction on IRP flexible resource guidelines for EV. In ORDER NO. 12-177, the OPUC noted 12 action items regarding Idaho Power's 2011 IRP. Idaho Power has addressed these action items in the 2013 IRP.<br>f. Idaho Power submitted an update to the 2011 IRP in February 2013.<br>g. No action needed. |

| Oregon Order 07-047 Action Items | 2013 IRP |
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| **Guideline 4: Plan Components.**<br>At a minimum, the plan must include the following elements:<br>a. An explanation of how the utility met each of the substantive and procedural requirements;<br>b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;<br>c. For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;<br>d. For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;<br>e. Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;<br>f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;<br>g. Identification of key assumptions about the future( e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;<br>h. Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;<br>i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;<br>j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;<br>k. Analysis of the uncertainties associated with each portfolio evaluated;<br>l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;<br>m. Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and<br>n. An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing. | a. Idaho Power anticipates delivering this table in an informal letter to the OPUC staff.<br>b. Idaho Power revises the sales and load forecast each year and Idaho Power included the most recent sales and load forecast assumptions in Chapter 5. Planning Period Forecasts, section *Load Forecast,* beginning on page 47. High- and low-growth scenarios in addition to stochastic load risk analysis are discussed in Chapter 9. Modeling Analysis and Results, section *Stochastic Analysis,* pages 103–105.<br>c. Peaking capacity and energy capability for each year of the plan are discussed in Chapter 5. Planning Period Forecasts, sections *Average Monthly Energy Planning* and *Peak-Hour Planning,* pages 60–61. Idaho Power uses AURORA in the modeling of all existing transmission. Future transmission additions associated with the resource portfolios tested are discussed in Chapter 6. Transmission Planning, section *Transmission Assumptions in the IRP Portfolios,* beginning on page 80.<br>d. Not applicable.<br>e. Supply-side resources and their levelized costs and technologies are covered in Chapter 5. Planning Period Forecasts on figures 5.7 and 5.8, pages 66 and 67 respectively. Demand-side resources and their levelized costs and technologies are covered in Chapter 4. Demand-Side Resources, in Table 4.2 on page 43.<br>f. Resource reliability is covered in Chapter 9. Modeling Analysis and Results, section *Loss of Load Expectation,* on pages 110111.<br>g. Fuel price forecasts are discussed in Chapter 5. Planning Period Forecasts, section *Coal Resources* (coal price forecast and environmental compliance cost analysis), pages 5859, section *Natural Gas Price Forecast,* on page 62. Environmental compliance costs are also discussed in section *Emissions Adders for Fossil Fuel-Based Resources,* pages 63–64. Alternative scenarios are considered in Chapter 9. Modeling Analysis and Results, section *Stochastic Analysis,* pages 103–105.<br>h. Construction of resource portfolios are made in a twofold process:<br>1) Identifying resources alternatives: discussed in Chapter 7. Resource Alternatives Analysis, pages 83–87. 2) For designing portfolios: discussed in Chapter 8. Planning Criteria and Portfolio Selection, pages 89–96.<br>i. The resource portfolios are evaluated against various risks in Chapter 9. Modeling Analysis and Results, section *Stochastic Analysis,* pages 103–105.<br>j. The portfolios are evaluated and ranked in Chapter 9. Modeling Analysis and Results, Table 9.2 on page 98.<br>k. The uncertainties associated with each portfolio are evaluated in Chapter 9. Modeling Analysis and Results, section *Stochastic Analysis,* pages 103–105.<br>l. The selection reasoning for the preferred resource portfolio is identified in Chapter 9. Modeling Analysis and Results, Table 9.2 on page 98 and Figure 9.6 on page *104*.<br>m. No inconsistencies were identified.<br>n. An annual near-term action plan is described in Chapter 1. Summary, section *Near-Term Action Plan*, starting on page 9. |

| Oregon Order 07-047 Action Items | 2013 IRP |
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| **Guideline 5: Transmission.**<br>Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability. | The transmission required for each resource being considered is described in the *2013 IRP Technical Appendix*, section *Transmission Cost Assumptions* on page 86. The transmission required for each resource portfolio being considered is also described in Chapter 6. Transmission Planning, section *Transmission Assumptions in the IRP Portfolios*, pages 80–81. AURORA accounts for the cost of wheeling when selling and purchasing power from the market. Transmission facilities were analyzed as a resource option in Chapter 7. Resource Alternatives Analysis, pages 83–84. All the resource portfolios contained the Boardman to Hemingway Transmission Line as a resource option as discussed in Chapter 8. Planning Criteria and Portfolio Selection, pages 89–96. |
| **Guideline 6: Conservation.**<br>a. Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.<br>b. To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.<br>c. To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:<br>• Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and<br>• Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition. | a. Idaho Power periodically studies conservation potential and a summary of the company's conservation (DSM) philosophy is described in Chapter 4. Demand-Side Resources, pages 37–38.<br>b. Cost-effectiveness of energy efficiency programs are detailed in Chapter 4. Demand-Side Resources, section *Demand Response Performances,* pages 38–44.<br>c. As described in Chapter 4. Demand-Side Resources, third paragraph of page 37, due to the indirect nature of savings from regional market transformation activities, Idaho Power's outside party administrator Northwest Energy Efficiency Alliance (NEEA) impacts are not accounted for in the 2013 IRP. |
| **Guideline 7: Demand Response.**<br>Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities). | Demand response resources are detailed in Chapter 4. Demand-Side Resources, section *Demand Response Resources* on page 44. |
| **Guideline 8: Environmental Costs.**<br>Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide ($CO_2$), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential $CO^2$ regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable. | Idaho Power discusses the regulatory compliance costs they expect for carbon dioxide ($CO_2$), nitrogen oxides, sulfur oxides, and mercury emissions in Chapter 5. Planning Period Forecasts, section *Emission Adder for Fossil Fuel-Based Resources,* pages 63–64. The costs are shown in the *2013 IRP Technical Appendix*, section *Environmental Compliance Costs* beginning on page 131.<br>Idaho Power performed a base case, upper case, and zero-cost case and for the compliance cost of $CO_2$ and is discussed in Chapter 5. Planning Period Forecasts, section *Carbon Adder,* pages 68–69.<br>Idaho Power discusses the sensitivity analysis on a range of reasonably possible cost adders (low and high case) for nitrogen oxides, sulfur oxides, and mercury emissions in Chapter 5. Planning Period Forecasts, section *Emission Adder for Fossil Fuel-Based Resources* on page 64. The costs are shown in *2013 IRP Technical Appendix*, section *Environmental Compliance Costs* beginning on page 131. |
| **Guideline 9: Direct Access Loads.**<br>An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier. | At present, Idaho Power does not have any customers served by alternative electricity suppliers and Idaho Power has no direct access loads. Guideline 9 is not expected to apply to Idaho Power during the 2013 IRP 20-year planning period. |
| **Guideline 10: Multi-state Utilities.**<br>Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers. | Idaho Power intends to file the 2013 IRP in both the Idaho and Oregon jurisdictions. |

| Oregon Order 07-047 Action Items | 2013 IRP |
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| **Guideline 11: Reliability.**<br>Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demandside resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives. | Idaho Power discussed the capacity planning margin in Chapter 9. Modeling Analysis and Results, section *Capacity Planning Margin*, pages 106–108, and the loss of load probability in Chapter 9. Modeling Analysis and Results, section *Loss of Load Expectation,* pages 110–111. |
| **Guideline 12: Distributed Generation.**<br>Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation. | Idaho Power evaluated distributed generation technologies in the following sections:<br>Load shed, grid sync, and distributed PV: in Chapter 5. Planning Period Forecasts, Figure 5.7 and 5.8, pages 66 and 67, respectively.<br>Distributed PV: in Chapter 7. Resource Alternatives, pages 83–87. |
| **Guideline 13: Resource Acquisition.**<br>a. An electric utility should, in its IRP:<br>• Identify its proposed acquisition strategy for each resource in its action plan.<br>• Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.<br>• Identify any Benchmark Resources it plans to consider in competitive bidding.<br>b. Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment. | Idaho Power continues to evaluate resource ownership along with other supply options. Idaho Power conducts its resource acquisition and competitive bidding processes consistent with the guidelines established by Oregon in Order 06-446 issued on August 10, 2006.<br>Idaho Power discussed asset ownership in Chapter 10 Action Plan, section *Acton Plan (2013–2032)*, last paragraph on page 114.<br>In the next 10 years, the Boardman to Hemingway Transmission Line is the only new IRP resource identified. Idaho Power is currently permitting this project and plans to contract the construction work. |

# STATE OF OREGON IRP ELECTRIC VEHICLES (EV) GUIDELINES

ORDER NO. 12 013

ENTERED JAN 19 2012

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

UM 1461

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| In the Matter of<br><br>PUBLIC UTILITY COMMISSION OF OREGON<br><br>Investigation of matters related to Electric Vehicle Charging. | ORDER |

DISPOSITION: GUIDELINES ADOPTED; UTILITIES ORDERED TO MAKE REVISED TARIFF FILINGS

## I. PROCEDURAL HISTORY

At our December 8, 2009, Public Meeting, we opened this docket at our Staff's request to investigate matters related to the charging infrastructure for plug-in hybrid vehicles and electric vehicles (collectively referred to as EVs).[1] Specifically, we intended this docket to address general matters related to the emergence and development of the EV charging market and industry, including the role of electric utilities with regard to owning and operating EV service equipment (EVSE) and acting as EV service providers (EVSP). The Citizens' Utility Board of Oregon (CUB) noticed its intervention in the investigation, and the following parties were authorized over the course of the docket to intervene as parties: the Oregon Department of Energy (ODOE); ECOtality, Inc.; Smart Grid of Oregon (SGO); Grid Mobility LLC; Mitsubishi Motors R&D of America; the Oregon Department of Environmental Quality (DEQ); Nissan North America, Inc.; CleanFuture; the Northwest Energy Coalition (NWEC); Portland General Electric Company (PGE); PacifiCorp, dba Pacific Power (Pacific Power); and Idaho Power Company (Idaho Power).

On June 22, 2010, Staff and interested parties participated in a public workshop to discuss the scope of the investigation. Staff subsequently prepared a "straw proposal," published on July 22, 2010, that was intended to facilitate and focus further discussion in the docket. On August 6, 2010, a second public workshop was held. Staff and parties submitted opening comments on August 27, 2010.

[1] *See* Staff Report for December 8, 2009 Public Meeting, Item No. 4.

*2. Resolution*

We agree with Staff and all of the other parties in this docket that there is no discernible reason, at least at this time, to treat EV charging load differently than any other load with regard to distribution system upgrades. Moreover, we acknowledge that EV charging load may not necessitate system upgrades at any time should the load be effectively managed. Consequently, we adopt Staff's recommendation that utilities' existing line extension policies continue to apply, without modification, to all loads, including plug-in EV load.

**D. Integrated Resource Planning Flexible Resources Guidelines**

The current Integrated Resource Planning (IRP) guidelines are silent regarding flexible capacity. In opening comments, Staff proposed an IRP guideline to fill this need.

*1. Parties' Positions*

Staff's proposed IRP guideline has three parts, as follows:

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; and

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.

Staff asserts that the proposed IRP guideline is consistent with the language and content of the existing IRP guidelines, and addresses an issue that is relevant for resource and planning both now and in the future. Staff states, "[f]lexibility is an increasingly important consideration in the integration of higher percentages of variable renewable generation resources."[31] Staff further comments that "EVs, as the first 'smart appliance', represent an opportunity to capture the power of demand response flexibility as a compliment to other flexibility strategies coming from generation and storage technologies."[32] Although Staff realizes that EVs will not be ready to provide flexible

[31] Staff Response to Bench Request, p. 25.
[32] *Id.*

capacity any time soon due to measured market penetration and technical challenges, Staff argues that it appropriate to begin planning for the future and that a 20-year planning horizon is consistent with current IRP practice.

ECOtality, Inc., agrees, observing that as IRPs involve long-range planning, they should include developing technologies, or events may eclipse planning. ODOE recommends supports Staff's proposed IRP guideline. Neither NWEC nor CUB object to Staff's proposed IRP guideline, although CUB notes a possible practical limitation to EVs functioning as a flexible capacity resource should the manufacturers of EVs or EV batteries be reluctant to allow third parties access to EV battery storage capacity, thereby limiting flexible capacity availability from EVs.

All three utilities oppose adoption of Staff's proposed IRP guideline, arguing that the guideline is prematurely too prescriptive about planning for a resource that is still unknown and uncertain. Pacific Power complains about the administrative burden on a utility versus the analytical value of studies that would be undertaken pursuant to Staff's proposed guideline. Similarly, Idaho Power argues that given the significant uncertainties about whether and when EVs might provide flexible capacity, the Commission should direct utilities to consider, but not model such resources. PGE takes the position that adoption of Staff's proposed guideline is premature, and would impose long range speculative assumptions and create significant administrative burden.

All three utilities recommend further discussion and study in some other forum before adopting an IRP guideline related to flexible resource planning. Pacific Power urges the Commission to further study flexible capacity resources in a manner that accounts for each utility's planning and modeling framework, whether as part of an evolving investigation or through the public IRP processes. Pacific Power also notes that to the extent that these new guidelines are intended to inform the development of demand response programs more generally, the Commission should open an investigation to reevaluate all IRP guidelines related to demand response programs, rather than adopting certain new guidelines in an EV-specific proceeding. As already discussed, PGE suggests the Commission develop a pilot program to collect information to be used to late guide policy. PGE observes, however, that the company is increasing non-controllable variable generation in the form of wind and losing access to controllable flexible generation in the form of hydro. PGE acknowledges, therefore, that this situation makes the assessment of flexible generation an important component of PGE's IRP planning on a going forward basis. Consequently, PGE indicates that the first two parts of Staff's proposed guideline may have value. PGE argues, however, that it is unreasonable to link flexible capacity to EVs at this time, since EVs may be at least a decade away from commercial viability.

### *2. Resolution*

At the outset, we conclude there is no need for further discussion on this issue. All three utilities submitted several rounds of comments regarding Staff's proposed guideline, including responses to our bench request. Although all three

ORDER NO. 12 013

2. We direct each electric utility to fully address the new Integrated Resource Planning guideline adopted herein in the utility's next Integrated Resource Planning proceeding.

Made, entered, and effective JAN 19 2012.

**John Savage**
Commissioner

**Susan K. Ackerman**
Commissioner

**Stephen M. Bloom**
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

# Compliance with EV Guidelines

| Oregon Order 12-013 Guideline | 2013 IRP |
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| **Guideline 1: Forecast the Demand for Flexible Capacity.**<br>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; | Forecasting the balancing reserves needed at different time intervals to respond to variation in load and intermittent renewable generation is discussed in Chapter 9. Modeling Analysis, section *Flexible Resource Needs Assessment*, pages 109–110. |
| **Guideline 2: Forecast the Supply for Flexible Capacity.**<br>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; | Forecasting the balancing reserves available at different time intervals from existing generating resources is discussed in Chapter 9. Modeling Analysis, section *Flexible Resource Needs Assessment*, pages 109–110. |
| **Guideline 3: Evaluate Flexible Resources on a Consistent and Comparable Basis**<br>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. | Evaluating all resource options, including the use of EVs, is discussed in Chapter 9. Modeling Analysis, section *Flexible Resource Needs Assessment*, pages 109–110. |

# STATE OF OREGON ACTION ITEMS REGARDING IDAHO POWER'S 2011 IRP

ORDER NO. 12 177

ENTERED MAY 21 2012

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

LC 53

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| In the Matter of<br>IDAHO POWER COMPANY<br>2011 Integrated Resource Plan. | ORDER |

DISPOSITION: INTEGRATED RESOURCE PLAN ACKNOWLEDGED WITH CONDITIONS AND EXCEPTIONS

## I. INTRODUCTION

Idaho Power Company (Idaho Power) seeks acknowledgment of its 2011 Integrated Resource Plan (IRP). The Company submitted the IRP to meet the requirement that all regulated energy utilities operating in Oregon engage in integrated resource planning.[1] We acknowledge the company's 2011 IRP with conditions and exceptions.

## II. BACKGROUND

We require each regulated energy utility to prepare and file an IRP within two years after acknowledgment of a utility's last IRP. Substantively, we require that energy utilities: (1) evaluate resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) make the primary goal of the process selecting a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers; and (4) create an action plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.[2]

We acknowledge a utility's IRP to the extent the plan satisfies our procedural and substantive requirements, and the plan is deemed reasonable at the time of acknowledgement. Acknowledgment does not constitute a determination of the prudency of any resource acquisitions or other expenditures made by the utility pursuant to the plan. As a legal matter, we must reserve judgment on all rate-making issues.[3] Nonetheless, we consider the integrated resource planning process to complement the rate-making process. In rate-making proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions which are consistent with acknowledged IRP action plans. Utilities will also be

[1] *See* Order Nos. 89-507, 07-002, and 07-047.
[2] *See* Order No. 07-002.
[3] *See* Order No. 07-002 at 24.

expected to explain actions they take which may be inconsistent with Commission-acknowledged plans.

## III. PROCEDURAL HISTORY

Idaho Power filed its 2011 IRP on June 30, 2011. A prehearing conference was held July 29, 2011, and the schedule adopted. Petitions to intervene were granted on behalf of Renewable Northwest Project (RNP), Portland General Electric Company (PGE), the Oregon Department of Energy (ODOE), Move Idaho Power, and Stop Idaho Power. The Citizens' Utility Board of Oregon (CUB) intervened by right.

On September 20, 2011, Idaho Power presented its IRP to the Commission at a public meeting. A technical workshop was held for parties on September 20, 2011. Staff and intervenor initial comments were filed October 18, 2011. Company reply comments were filed November 8, 2011. Staff's final comments and a proposed order were filed December 6, 2011. Company and intervenor comments in reply to Staff's final comments were filed January 3, 2012. Staff's report and its final proposed order were filed on January 24, 2012. This matter was taken up for Commission action at a public meeting on February 14, 2012.

## IV. DISCUSSION

### A. 2011 IRP Overview

Its 2011 IRP is Idaho Power's tenth resource plan filed to meet the requirements and guidelines established by this Commission and the Idaho Public Utilities Commission. In its filing Idaho Power assumed that, during the planning period (2011 through 2030), it will continue to be responsible for acquiring resources sufficient to serve all of its retail customers in its Oregon and Idaho service areas as a vertically integrated company. In developing its plan, Idaho Power worked with its IRP Advisory Council, which is comprised of major stakeholders representing the environmental community, major industrial customers, irrigation customers, state legislators, public utility commission representatives, and others. Following the filing of its final plan, Idaho Power presented the IRP at public meetings in various cities within its service area.

Idaho Power expects the number of customers in its service area to increase from about 492,000 in 2010 to over 650,000 by 2030. The IRP expected-case load forecast projects peak-hour load will grow 69 megawatts (MW) annually (1.8 percent), and average-system load will increase annually 29 average megawatts (aMW) (1.4 percent) over the 20-year term. In 2011, Idaho Power's demand response programs are expected to reduce peak-hour load by 330 MW. Two resources identified in the 2009 IRP are considered committed resources in the 2011 IRP: (1) the 300 MW Langley Gulch combined cycle combustion turbine that is expected to be available in the summer of 2012; and (2) a 49 MW upgrade of the Shoshone Falls Hydroelectric Project in 2015.

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Idaho Power divided its 20-year planning period into two 10-year segments. In the first 10-year period, the company examined nine resource portfolios. Each portfolio was designed to substantially meet the energy and capacity deficits identified in the resource balance. For the second 10-year period, Idaho Power analyzed the preferred resource portfolio from the initial 10-year period coupled with each of the 10 portfolios considered for the second period.

In addition to those committed resources (Langley Gulch and the Shoshone Falls upgrade), the preferred resource portfolio includes 450 MW of market purchases beginning in 2016, with the completion of the Boardman to Hemingway transmission line. The total west-to-east transfer capacity reserved on Boardman to Hemingway by Idaho Power is expected to be 450 MW. For the second 10-year period the preferred portfolio adds a mixture of renewable resources along with natural gas-fired baseload and peaking resources.

**B. Objections to Idaho Power's 2011 IRP**

Staff and other parties raised numerous issues and provided considerable commentary on certain aspects and elements of the original action items in Idaho Power's IRP Action Plan. We also expressed concerns with aspects of the plan at the public meeting held on February 14, 2011. Those issues, and our resolution of them, are as follows:

***1. Evaluation of Environmental Compliance Costs for Existing Coal-Fired Plants (Action Item 11)***

Idaho Power does not wholly own or operate any coal plants, but does have a significant ownership interest in three large plants (Boardman, North Valmy, and Jim Bridger). As reported by CUB, these plants provide 41 percent of Idaho Power's total generation. CUB points out that the owners of these three plants likely will face increasing costs to comply with clean air regulations in the coming years.

CUB and RNP are not satisfied with Idaho Power's analysis of the possible environmental compliance costs associated with ownership and operation of these plants. CUB suggests that Idaho Power be required to conduct a unit-by-unit evaluation of its clean air investment costs (similar to that conducted by PGE for its Boardman plant) before the IRP provisions relating to coal plant investment are considered for acknowledgement. CUB recommends that the Commission withhold acknowledgment of the IRP until Idaho Power completes a study of its coal investment compliance costs and the parties have had the opportunity to review and comment on the study. RNP also recommends that the Commission require Idaho Power to analyze the costs and risks of maintaining its coal plants (including carbon costs and environmental regulations) before the company commits to significant investments.

Idaho Power responds that because the amount of any environmental compliance costs is "highly speculative" at this time, any analysis of the costs would be highly speculative as

well. The company argues that the Commission should acknowledge its 2011 IRP, and require that Idaho Power conduct the environmental costs analysis in future IRP filings.

Staff shares CUB's and RNP's concerns about future environmental compliance costs, but agrees with Idaho Power that the company should provide the requested analysis in its 2011 IRP Update. Staff proposes an additional Action Item 11 to address this future requirement.

*Resolution*

As discussed at the public meeting, we share the concerns raised by CUB and RNP regarding Idaho Power's failure to perform a comprehensive study of the possible costs and consequences of environmental regulations associated with the company's partial ownership of three coal plants. Accordingly, we acknowledge Staff's proposed Action Item 11, but not any other IRP provision relating to new investments in coal plants until Idaho Power completes a study of its coal investment compliance costs and other parties have had the opportunity to comment on the study.

### *2. Boardman to Hemingway Transmission (Action Item 7)*

RNP supports acknowledgment of the Boardman to Hemingway (B2H) transmission project as the primary resource in Idaho Power's near-term portfolio. Staff recommends we acknowledge Action Item 7 requiring Idaho Power to continue to make progress on the B2H transmission project between now and the completion of the company's 2013 IRP. CUB notes, however, that closure of one or more coal plants would open up capacity on existing transmission lines and could cause changes to the design and location of new lines.

*Resolution*

We share CUB's concern that coal cost study results will have implications for Idaho Power's transmission line use and plans, but acknowledge Action Item 7 requiring the company to continue to make progress on the B2H transmission project as an uncommitted resource.

### *3. Conservation Voltage Reduction (Action Item 4)*

Staff notes the "promising beginnings" for conservation voltage reduction (CVR) measures reported by Idaho Power. Staff points out, however, that the Company shows no further CVR measures in either its IRP or its Appendix B on Demand-Side Management.

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*Resolution*

We are convinced that there is an untapped CVR resource and that this resource is cost effective. We direct the addition of a CVR action item as follows:

> Action Item 4 – Conservation Voltage Reduction – The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The company will propose an action plan in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's load-resource balance forecasts.

***4. Demand Response (Action Item 3)***

In this IRP cycle Idaho Power switched from an "all cost-effective DSM" approach to "need-based" approach. Based on its analysis comparing the costs of energy saved from demand response to the cost of owning and operating a simple cycle combustion turbine (SCCT), Idaho Power derived an optimal amount of demand response for its system. Staff believes that the Company should pursue all cost-effective demand response through existing programs and consider new programs as applicable. Staff believes Idaho Power should pursue the maximum amount of demand response that (1) is less costly on a kW basis than a supply-side resource, and (2) up to the company's system capacity deficit amount.

*Resolution*

Staff proposed no change to this IRP action item. We accept Staff's proposal that during the preparation of its 2013 IRP, Idaho Power will convene a meeting of its IRP Advisory Council to address demand response, where Staff intends to work with the parties to develop a demand response approach in the best interest of ratepayers.

***5. Energy Efficiency (Action Items 1 and 2)***

Staff recommends acknowledgment of Idaho Power's Action Items 1 and 2, and recommends the Company continue to pursue all cost-effective demand side management as the lowest cost resource for customers.

*Resolution*

We agree with Staff that Idaho Power should continue to pursue all cost-effective demand side management. No revision to these action items is required.

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### 6. *Alternative Portfolio (Action Items 8 and 9)*

RNP urges the Commission to consider alternatives to acknowledging Idaho Power's alternative resource portfolio (which is comprised solely of SCCT plants). RNP recommends the Commission give demand side management and solar photovoltaic resources time to ripen. Staff recommends the Commission not acknowledge the alternative portfolio, because there are existing mechanisms in the IRP process to deal with unforeseen circumstances.

*Resolution*

We agree with Staff that there are existing mechanisms in the IRP process to address unforeseen circumstances and do not find a need to acknowledge an alternative resource portfolio. We clarify, however, that the non-acknowledgment of the Alternative Portfolio Action Items 8 and 9 is not due to a flaw or failure in the IRP.

### 7. *Long Term Action Items (Action Item 12)*

In its Action Plan, Idaho Power included action items for the 2021 through 2030 time period. Because the IRP Guidelines focus on actions over the next two to four years, Staff recommends that these long-term action items not be acknowledged as part of this IRP.

*Resolution*

We agree with Staff that the desired focus in the IRP is on actions over the next two to four years. We decline to acknowledge the long-term action items contained in Action Item 12.

### 8. *Load Forecast*

Staff is concerned that Idaho Power's assumptions of average energy growth and peak-hour load growth are too high. Staff's concerns are based on the lingering economic conditions, plus shifts occurring in the demand/supply balance, conservation, and environmental regulation.

*Resolution*

We agree with Staff that the 2011 IRP Update and the 2013 IRP need to be based on an updated load forecast that reflects current conditions. We concur that it is appropriate to include an allowance for new large loads in the load forecast only if there is a signed energy service agreement, and the load forecast is based on specific supporting documentation.

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***9 Risk Analysis***

Staff is troubled by aspects of Idaho Power's stochastic risk analyses, as contrasted with the more conventional approaches used by other Oregon utilities. With the approach used by Idaho Power, an adverse combination of two or more unfavorable risk factors will never be "sampled," because only one risk factor is allowed to depart from its base value for any one "draw." Staff also recommends the company include hydro generation variability as a risk factor for its next IRP cycle, in light of Idaho Power's significant reliance on hydroelectric generation.

*Resolution*

We adopt Staff's recommendation that the 2013 IRP risk analysis should include hydroelectric generation variability. We agree with Staff's goal of working toward collaborative improvement of Idaho Power's stochastic risk analysis. At least one of the 2013 IRP meetings of the IRP Advisory Committee should focus on this subject.

***10. Wind Integration Study***

RNP noted that Idaho Power is conducting a wind integration study internally. It encouraged the company to look for ways to lower its costs of wind integration, to seek independent technical review of its study, and to provide stakeholders the chance to provide meaningful feedback.

*Resolution*

We agree that Idaho Power should seek independent technical review of its wind integration study and allow stakeholders the opportunity to provide feedback before the study results are incorporated into the company's next IRP. Accordingly, we direct Idaho Power to form a wind integration study technical review committee that is fully engaged in the process. We also direct Idaho Power to establish a schedule for workshops, providing full opportunity for stakeholder involvement.

***11. Solar Photovoltaic Analysis***

RNP encourages Idaho Power to evaluate the performance of solar photovoltaic projects as a class, not simply as single projects. The geographic distribution of the projects could have a significant effect of smoothing the short-term variability of single projects.

*Resolution*

We agree with RNP that Idaho Power should evaluate the performance of the solar photovoltaic projects as a class, as consistent with the goals of the pilot program.

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### *12. Adherence of Plan to Integrated Resource Planning Guidelines*

Intervenors and Staff agree that Idaho Power's 2011 IRP filing did not comply with IRP Guidelines 1(c) and 4(g),[4] because the company failed to provide a comprehensive evaluation of the compliance of its existing coal fired generation resources with new, draft, and anticipated environmental regulations. Without that evaluation, it was not possible to determine whether any of the candidate resource portfolios met the specified standard.

In response to that deficiency, in its September 20, 2011 IRP presentation to the Commission, Idaho Power presented a "very high-level" evaluation of a range of costs that could potentially result if certain environmental regulations were implemented. According to the company, the existing coal-fired resources would still be less expensive than replacement natural gas generation resources, even if the company were required to spend the estimated amounts to comply with the potential federal environmental regulations.

Staff also noted that Idaho Power did not comply with IRP Guidelines 4(a) and 4(n), because the company did not explain how the utility met each substantive and procedural requirement, nor provide a concise listing of action items for all resources and resource related activities.

*Resolution*

We note Idaho Power's high-level presentation about environmental compliance costs, and expect more detailed information to be provided in the company's coal study. We agree with Staff that future Idaho Power IRPs should include: (1) an explanation of how the utility met each substantive and procedural requirement, and (2) a concise listing of action items for all resources and resource related activities, with each action item numbered.

[4] IRP Guideline 1(c) prescribes the primary goal of the IRP to be the selection of a portfolio of resources with the best combination of cost and risk for the utility and its customers. IRP Guideline 4(g) requires the utility to identify key assumptions about the future, including future enviromnental compliance costs.

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## IV. ORDER

IT IS ORDERED that the 2011 Integrated Resource Plan filed by Idaho Power Company is acknowledged with conditions and exceptions contained in this order, with the action items and recommendations summarized in Appendix A .

This order memorializes the decision of the Public Utility Commission of Oregon made and effective at a public meeting held on February 14, 2012.

Dated this 21 day of May, 2012, at Salem, Oregon.

**John Savage**
Commissioner

**Susan K. Ackerman**
Commissioner

**Stephen M. Bloom**
Commissioner



# Compliance with State of Oregon Action Items Regarding Idaho Power's 2011 IRP

| Oregon Order 12-177 Action Items | 2013 IRP |
|---|---|
| **Action Item 1: Evaluation of Environmental Compliance Costs for Existing Coal-Fired Plants (Action Item 11)**<br>Idaho Power does not wholly own or operate any coal plants, but does have a significant ownership interest in three large plants (Boardman, North Valmy, and Jim Bridger). As reported by CUB, these plants provide 41 percent of Idaho Power's total generation.<br>CUB points out that the owners of these three plants likely will face increasing costs to comply with clean air regulations in the coming years. CUB and RNP are not satisfied with Idaho Power's analysis of the possible environmental compliance costs associated with ownership and operation of these plants. CUB suggests that Idaho Power be required to conduct a unit-by-unit evaluation of its clean air investment costs (similar to that conducted by PGE for its Boardman plant) before the IRP provisions relating to coal plant investment are considered for acknowledgement. CUB recommends that the Commission withhold acknowledgment of the IRP until Idaho Power completes a study of its coal investment compliance costs and the parties have had the opportunity to review and comment on the study. RNP also recommends that the Commission require Idaho Power to analyze the costs and risks of maintaining its coal plants (including carbon costs and environmental regulations) before the company commits to significant investments.<br>Idaho Power responds that because the amount of any environmental compliance costs is "highly speculative" at this time, any analysis of the costs would be highly speculative as well. The company argues that the Commission should acknowledge its 2011 IRP, and require that Idaho Power conduct the environmental costs analysis in future IRP filings.<br>Staff shares CUB's and RNP 's concerns about future environmental compliance costs, but agrees with Idaho Power that the company should provide the requested analysis in its 2011 IRP Update. Staff proposes an additional Action Item 11 to address this future requirement. | Idaho Power performed an evaluation of environmental compliance costs for existing coal-fired plants in the *Coal Unit Environmental Investment Analysis for the Jim Bridger and North Valmy Coal-Fired Power Plants* (the coal study excludes the Boardman Plant in Oregon that is scheduled to cease coal-fired operations at the end of 2020). Idaho Power filed the report with the IPUC and OPUC in February 2013 as part of the *2011 Integrated Resource Plan Update*.<br>In the 2013 IRP, Idaho Power analyzed two portfolios where the company exited from both Jim Bridger and North Valmy coal-fired generating facilities. Idaho Power also analyzed two portfolios where the company exited from North Valmy coal-fired generating facility on the schedule announced by NV Energy. The results of the analysis can be found in Chapter 9. Modeling Analysis and Results, Table 9.2 on page 98. |
| **Action Item 2: Boardman to Hemingway Transmission (Action Item 7)**<br>RNP supports acknowledgment of the Boardman to Hemingway (B2H) transmission project as the primary resource in Idaho Power's near-term portfolio. Staff recommends we acknowledge Action Item 7 requiring Idaho Power to continue to make progress on the B2H transmission project between now and the completion of the company's 2013IRP. CUB notes, however, that closure of one or more coal plants would open up capacity on existing transmission lines and could cause changes to the design and location of new lines. | Idaho Power analyzed Boardman to Hemingway as uncommitted resource in two ways:<br>1) Resource Alternatives: eight resources were analyzed side-by-side to achieve a 200-MW capacity of peak-hour contribution. The Resource Alternatives analysis can be found in Chapter 7. Resource Alternative Analysis, pages 83–87.<br>2) Resource Portfolios: Boardman to Hemingway was in all nine portfolios. The results of the Resource Portfolio analysis can be found in Chapter 9. Modeling Analysis and Results, Table 9.2 on page 98.<br>Progress on Boardman to Hemingway was discussed in the *Boardman to Hemingway* section of Chapter 6. Transmission Planning, pages 77–78. |
| **Action Item 3: Conservation Voltage Reduction (Action Item 4)**<br>Staff notes the "promising beginnings" for conservation voltage reduction (CVR) measures reported by Idaho Power. Staff points out, however, that the Company shows no further CVR measures in either its IRP or its Appendix B on Demand-Side Management. We are convinced that there is an untapped CVR resource and that this resource is cost effective. We direct the addition of a CVR action item as follows:<br>Action Item 4 - Conservation Voltage Reduction- The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The company will propose an action plan in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's load-resource balance forecasts. | Idaho Power included an assessment of the available cost-effective CVR resource potential in its service area. This can be found in the *Conservation Voltage Reduction* section of Chapter 4 Demand-Side Resources on page 45. |

| Oregon Order 12-177 Action Items | 2013 IRP |
|---|---|
| **Action Item 4: Demand Response (Action Item 3)**<br>In this IRP cycle Idaho Power switched from an "all cost-effective DSM" approach to "need-based" approach. Based on its analysis comparing the costs of energy saved from demand response to the cost of owning and operating a simple cycle combustion turbine (SCCT), Idaho Power derived an optimal amount of demand response for its system. Staff believes that the Company should pursue all cost-effective demand response through existing programs and consider new programs as applicable. Staff believes Idaho Power should pursue the maximum amount of demand response that (1) is less costly on a kW basis than a supply-side resource, and (2) up to the company's system capacity deficit amount. | Chapter 4. Demand-Side Resources, pages 37–45. provides a detailed discussion and analysis of the company's DSM programs. All nine resource portfolios include Demand Response. Resource portfolios are described in the *Portfolio Design and Selection* section of Chapter 8. Planning Criteria And Portfolio Selection, pages 90–96. |
| **Action Item 5: Energy Efficiency (Action Items 1 and 2)**<br>Staff recommends acknowledgment of Idaho Power's Action Items 1 and 2, and recommends the Company continue to pursue all cost-effective demand side management as the lowest cost resource for customers. | Energy efficiency performance is discussed in Chapter 4 Demand-Side Resources, section Energy Efficiency Performance, pages 38-39. New energy efficiency programs are discussed in Chapter 4 Demand-Side Resources, section New Energy Efficiency Resources, pages 41-44. |
| **Action Item 6: Alternative Portfolio (Action Items 8 and 9)**<br>RNP urges the Commission to consider alternatives to acknowledging Idaho Power's alternative resource portfolio (which is comprised solely of SCCT plants). RNP recommends the Commission give demand side management and solar photovoltaic resources time to ripen. Staff recommends the Commission not acknowledge the alternative portfolio, because there are existing mechanisms in the IRP process to deal with unforeseen circumstances. | Eight resources, including four renewable resources, were analyzed side-by-side to achieve 200 MW of peak-hour contribution. The analysis can be found in Chapter 7. Resource Alternative Analysis, pages 83–87.<br>Four resource portfolios were constructed where Idaho Power ceased operations at some or all of the Idaho Power coal-fired generation facilities. One of the portfolios was jointly designed by the Idaho Conservation League and Boise State University. Portfolio design is discussed in the *Portfolio Design and Selection* section of Chapter 8. Planning, pages 90–96. |
| **Action Item 7: Long Term Action Items (Action Item 12)**<br>In its Action Plan, Idaho Power included action items for the 2021 through 2030 time period. Because the IRP Guidelines focus on actions over the next two to four years, Staff recommends that these long-term action items not be acknowledged as part of this IRP. | Idaho Power provides its action plan in Chapter 10. Action Plan, pages 113–115. |
| **Action Item 8: Load Forecast**<br>Staff is concerned that Idaho Power's assumptions of average energy growth and peak-hour load growth are too high. Staffs concerns are based on the lingering economic conditions, plus shifts occurring in the demand/supply balance, conservation, and environmental regulation. | Idaho Power's load forecast is discussed in detail in Chapter 5. Planning Period Forecasts, section *Load Forecast*, pages 47–55. Lingering economic conditions are discussed in detail, pages 48–50. |
| **Action Item 9: Risk Analysis**<br>Staff is troubled by aspects of Idaho Power's stochastic risk analyses, as contrasted with the more conventional approaches used by other Oregon utilities. With the approach used by Idaho Power, an adverse combination of two or more unfavorable risk factors will never be "sampled," because only one risk factor is allowed to depart from its base value for any one "draw." Staff also recommends the company include hydro generation variability as a risk factor for its next IRP cycle, in light of Idaho Power's significant reliance on hydroelectric generation. | Idaho Power incorporated hydro generation variability as a risk factor. Idaho Power also used the AURORA model to perform stochastic risk analyses. Stochastic analysis is discussed in the *Stochastic Analysis* section of Chapter 9. Modeling Analysis and Results, pages 103–105. |
| **Action Item 10: Wind Integration Study**<br>RNP noted that Idaho Power is conducting a wind integration study internally. It encouraged the company to look for ways to lower its costs of wind integration, to seek independent technical review of its study, and to provide stakeholders the chance to provide meaningful feedback. | Idaho Power filed a wind integration study in February 2013. The wind integration study included an independent technical review. The wind integration study can be found on the Idaho Power website: www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2013/windIntegrationStudy.pdf |
| **Action Item 11: Solar Photovoltaic Analysis**<br>RNP encourages Idaho Power to evaluate the performance of solar photovoltaic projects as a class, not simply as single projects. The geographic distribution of the projects could have a significant effect of smoothing the short-term variability of single projects. | Idaho Power evaluated the performance of solar PV generation as a class. The PV analysis can be found in Chapter 7. Resource Alternative Analysis, pages 83–87. |

| Oregon Order 12-177 Action Items | 2013 IRP |
|---|---|
| **Action Item 12: Adherence of Plan to Integrated Resource Planning Guidelines**<br>Intervenors and Staff agree that Idaho Power's 2011 IRP filing did not comply with IRP Guidelines 1 (c) and 4(g), 4 because the company failed to provide a comprehensive evaluation of the compliance of its existing coal fired generation resources with new, draft, and anticipated environmental regulations. Without that evaluation, it was not possible to determine whether any of the candidate resource portfolios met the specified standard.<br>In response to that deficiency, in its September 20, 2011 IRP presentation to the Commission, Idaho Power presented a "very high-level" evaluation of a range of costs that could potentially result if certain environmental regulations were implemented.<br>According to the company, the existing coal-fired resources would still be less expensive than replacement natural gas generation resources, even if the company were required to spend the estimated amounts to comply with the potential federal environmental regulations.<br>Staff also noted that Idaho Power did not comply with IRP Guidelines 4(a) and 4(n), because the company did not explain how the utility met each substantive and procedural requirement, nor provide a concise listing of action items for all resources and resource related activities. | Idaho Power performed an evaluation of environmental compliance costs for existing coal-fired plants in the *Coal Unit Environmental Investment Analysis for the Jim Bridger and North Valmy Coal-Fired Power Plants* (the coal study excludes the Boardman plant in Oregon which is scheduled to cease coal-fired operations at the end of 2020). Idaho Power filed the report with the IPUC and OPUC in February 2013 as part of the *2011 Integrated Resource Plan Update*.<br>In the 2013 IRP, Idaho Power analyzed two portfolios where the company exited from both Jim Bridger and North Valmy coal-fired generating facilities. Idaho Power also analyzed two portfolios where the company exited from North Valmy coal-fired generating facility on the schedule announced by NV Energy. The results of the analysis can be found in Chapter 9. Modeling Analysis and Results, Table 9.2 on page 98.The OPUC is currently reviewing the Idaho Power coal study as part of Oregon Docket No. LC 57.<br>1. Idaho Power provides a concise listing of action items in Chapter 10. Action Plan, pages 113–114. |

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# ATTACHMENT N-4
# IDAHO POWER COMPANY'S 2015 INTEGRATED RESOURCE PLAN (DOCKET LC 63)

IDAHO POWER®
An IDACORP Company

June 2015

# Integrated Resource Plan 2015







## SAFE HARBOR STATEMENT

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

IDAHO POWER®
An IDACORP Company

June 2015

# Integrated Resource Plan 2015

## ACKNOWLEDGMENT

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 *2015 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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# GLOSSARY OF ACRONYMS

AC—Alternating Current

A/C—Air Conditioning

AEG—Applied Energy Group

AFUDC—Allowance for Funds Used During Construction

AgI—Silver Iodide

akW—Average Kilowatt

AMI—Advanced Metering Infrastructure

aMW—Average Megawatt

ANSI—American National Standards Institute

ATC—Available Transmission Capacity

B2H—Boardman to Hemingway

BLM—Bureau of Land Management

BPA—Bonneville Power Administration

CAA—*Clean Air Act of 1970*

CAMP—Comprehensive Aquifer Management Plan

CBM—Capacity Benefit Margin

CCCT—Combined-Cycle Combustion Turbine

CERCLA—*Comprehensive Environmental Response, Compensation and Liability Act of 1980*

cfs—Cubic Feet per Second

CHP—Combined Heat and Power

CHQ—Corporate headquarters

Clatskanie PUD—Clatskanie People's Utility District

$CO_2$—Carbon Dioxide

CREP—Conservation Reserve Enhancement Program

CSPP—Cogeneration and Small-Power Producers

CVR—Conservation Voltage Reduction

CWA— *Clean Water Act of 1972*

DC—Direct Current

DOE—Department of Energy

DSM—Demand-Side Management

EEAG—Energy Efficiency Advisory Group

EIA—Energy Information Administration

EIM—Energy Imbalance Market

EIS—Environmental Impact Statement

EPA—Environmental Protection Agency

ESA—*Endangered Species Act of 1973*

ESPA—Eastern Snake River Plain Aquifer

ESPAM—Enhanced Snake River Plain Aquifer Model

F—Fahrenheit

FCRPS—Federal Columbia River Power System

FERC—Federal Energy Regulatory Commission

FLA—Final License Agreement

FPA—*Federal Power Act of 1920*

FWS—US Fish and Wildlife Service

GWh—Gigawatt-Hour

HCC—Hells Canyon Complex

Hg—Mercury

HRSG—Heat Recovery Steam Generator

IGCC—Integrated Gasification Combined Cycle

INL—Idaho National Laboratory

IPUC—Idaho Public Utilities Commission

IRP—Integrated Resource Plan

IRPAC—IRP Advisory Council

IWRB—Idaho Water Resource Board

kV—Kilovolt

kW—Kilowatt

kWh—Kilowatt-Hour

LED—Light-Emitting Diode

LOLE—Loss of Load Expectation

LTP—Local Transmission Plan

LOLP—Loss of Load Probability

$m^2$—Square Meters

MOU—Memorandum of Understanding

MSA—Metropolitan Statistical Area

MW—Megawatt

MWh—Megawatt-Hour

NEEA—Northwest Energy Efficiency Alliance

NEPA—*National Environmental Policy Act of 1969*

NERC—North American Electric Reliability Corporation

$NO_x$—Nitrogen Oxide

NTTG—Northern Tier Transmission Group

NPV—Net Present Value

NWPCC—Northwest Power and Conservation Council

NWPP—Northwest Power Pool

NREL—National Renewable Energy Laboratory

O&M—Operation and Maintenance

OATT—Open Access Transmission Tariff

ODEQ—Oregon Department of Environmental Quality

ODOE—Oregon Department of Energy

OER—Idaho Governor's Office of Energy Resources

OPUC—Public Utility Commission of Oregon

ORS—Oregon Revised Statue

pASC—Preliminary Application for Site Certificate

PCA—Power Cost Adjustment

PM&E—Protection, Mitigation, and Enhancement

PGE—Portland General Electric

PPA—Power Purchase Agreement

PURPA—*Public Utility Regulatory Policies Act of 1978*

PV—Photovoltaic

Q/A—Quality Assurance

QF—Qualifying Facility

RAAC—Resource Adequacy Advisory Committee

RCRA—*Resource Conservation and Recovery Act of 1976*

REC—Renewable Energy Certificate

RES—Renewable Electricity Standard

RFP—Request for Proposal

RH BART—Regional Haze Best Available Retrofit Technology

ROI—Return on Investment

ROR—Run-of-River

RPS—Renewable Portfolio Standard

SCCT—Simple-Cycle Combustion Turbine

SCED—Security-Constrained Economic Dispatch

SCR—Selective Catalytic Reduction

SNCR—Selective Non-Catalytic Reduction

$SO_2$—Sulfur Dioxide

SPE—Special-Purpose Entity

SRBA—Snake River Basin Adjudication

SRPM—Snake River Planning Model

TEPPC—Transmission Expansion Planning Policy Committee

TES—Thermal Energy Storage

TRC—Total Resource Cost

TSCA—*Toxic Substances Control Act of 1976*

USACE—United States Army Corps of Engineers

UAMPS—Utah Associated Municipal Power Systems

US—United States

USBR—Bureau of Reclamation

USFS—United States Forest Service

VRB—Vanadium Redox-Flow Battery

WECC—Western Electricity Coordinating Council

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# 1. SUMMARY

## Introduction

The *2015 Integrated Resource Plan* (IRP) is Idaho Power's 12th resource plan prepared to fulfill the regulatory requirements and guidelines established by the Idaho Public Utilities Commission (IPUC) and the Public Utility Commission of Oregon (OPUC). Idaho Power's resource planning process has four primary goals:

1. Identify sufficient resources to reliably serve the growing demand for energy within Idaho Power's service area throughout the 20-year planning period.

2. Ensure the selected resource portfolio balances cost, risk, and environmental concerns.

3. Give equal and balanced treatment to supply-side resources, demand-side measures, and transmission resources.

4. Involve the public in the planning process in a meaningful way.

The 2015 IRP evaluates the 20-year planning period from 2015 through 2034. During this period, load is forecasted to grow by 1.2 percent per year for average energy demand and 1.5 percent per year for peak-hour demand. Total customers are expected to increase to 711,000 by 2034 from 515,000 in 2014. Additional company-owned resources will be needed to meet these increased demands.

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

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

The Idaho Power resource planning process also evaluates additional transmission capacity as a resource alternative to serve retail customers. Transmission projects are often regional resources, and their planning is conducted by regional industry groups, such as the Western Electricity Coordinating Council (WECC) and the Northern Tier Transmission Group (NTTG). Idaho Power coordinates local transmission planning with 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] Timing of new transmission projects is subject to complex permitting, siting, and regulatory and partner coordination.

IRPs address Idaho Power's long-term resource needs. Idaho Power plans for near-term energy and capacity needs in accordance with the *Energy Risk Management Policy and 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 (IRPAC). The IRPAC 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 also participate even though they are not members of the IRPAC. Some individuals have participated in Idaho Power's resource planning process for over 20 years. A list of the 2015 IRPAC members can be found in *Appendix C—Technical Appendix*.

For the 2015 IRP, Idaho Power conducted 12 IRPAC meetings, including a resource portfolio design workshop. Public working group meetings to address the specific topics of energy efficiency, solar resources, and the study of coal resources were also held.



The IRPAC visits Swan Falls Dam.

In addition, Idaho Power hosted a field trip to the Swan Falls Hydroelectric Project (Swan Falls Project) for participants of the IRP process. Idaho Power personnel leading the field trip shared information on many topics,

[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.

including high-voltage transmission, recreation, avian biology, archaeology, and Snake River water supply. Field trip participants were led on a tour of the Swan Falls power plant and the Swan Falls museum.

Idaho Power believes working with members of the IRPAC and the public improves the IRP. Idaho Power and the members of the IRPAC recognize that final decisions on the resource plan are made by Idaho Power. However, Idaho Power encourages IRPAC members and members of the public to submit comments expressing their views regarding the 2015 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 communities around the company's 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 2015 IRP began with the forecast of future customer demand. Existing generation resources, demand-side resources, and transmission import capacity were combined with customer demand to create a load and resource balance for energy and capacity. Idaho Power then evaluated new energy efficiency programs and the expansion of existing programs to revise 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), transmission upgrades, and anticipated environmental controls and emission costs. The financial benefits include economic resource operations, projected market sales, and the market value of renewable energy certificates (REC).

Idaho Power is part of the larger northwestern 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 regional market prices. Likewise, there are times when the generation connected to the Idaho Power system exceeds customer demand and the transmission export capacity, and the company must curtail generation on its system.

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 (B2H) Transmission Line Project. Idaho Power again evaluated the B2H transmission line in the 2015 resource plan to ensure the transmission addition remains a prudent resource acquisition.

Similar to the 2013 IRP, Idaho Power analyzed various resource portfolios over the entire 20-year planning period in the 2015 IRP. The analyzed portfolios in the 2015 IRP add resources

under certain scenarios as early as 2020; consequently, Idaho Power determined it is practical to again consider the 20-year planning period in total.

## 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 megawatt-hour [MWh] generation). According to a May 2014 collaborative report using publicly reported 2012 generation and emissions data, Idaho Power and Ida-West Energy (a non-regulated subsidiary of IDACORP, Inc.) together ranked as the 38th lowest emitter of $CO_2$ per MWh produced and the 36th lowest emitter of $CO_2$ by tons of emissions among the nation's 100 largest electricity producers (figures 1.1 and 1.2).[3] According to the report, out of the 100 companies named, Idaho Power and Ida-West Energy together ranked as the 52nd largest power producer based on fossil fuel, nuclear, and renewable energy facility total electricity generation.

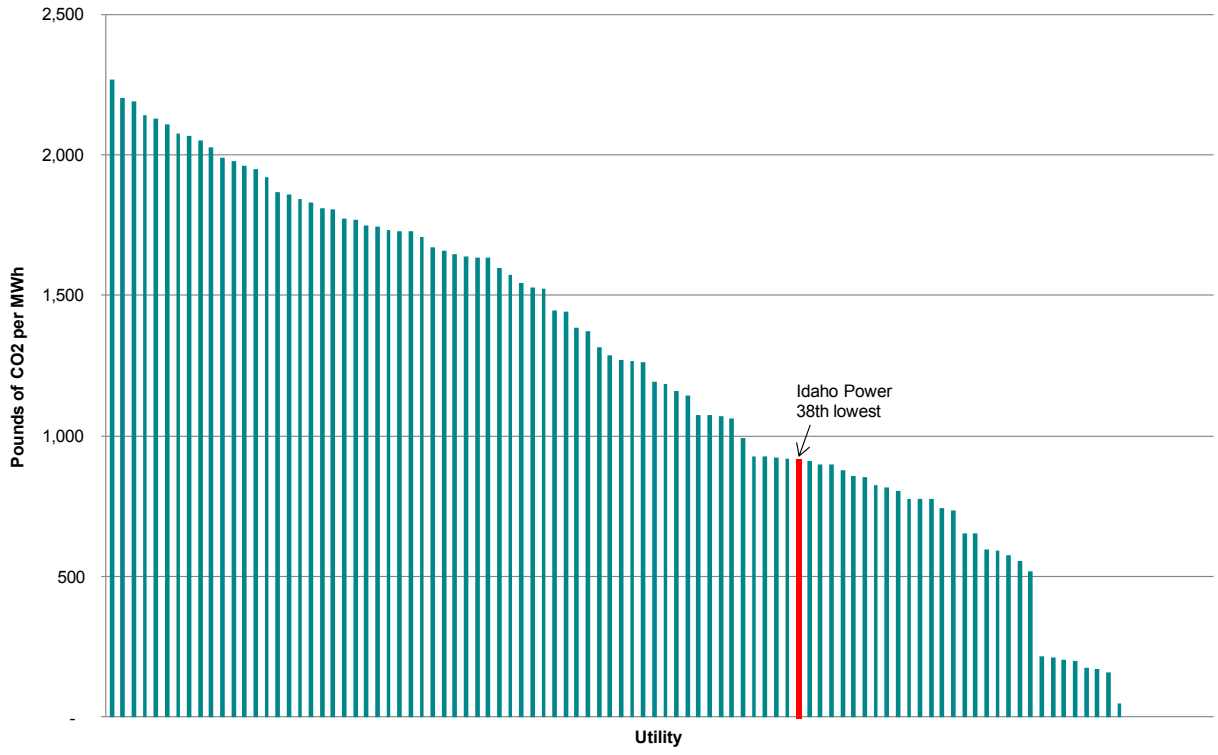



**Figure 1.1 $CO_2$ emissions intensity of the largest 100 utilities**

[3] M. J. Bradley & Associates. 2014. Benchmarking air emissions of the 100 largest electric power producers in the United States.

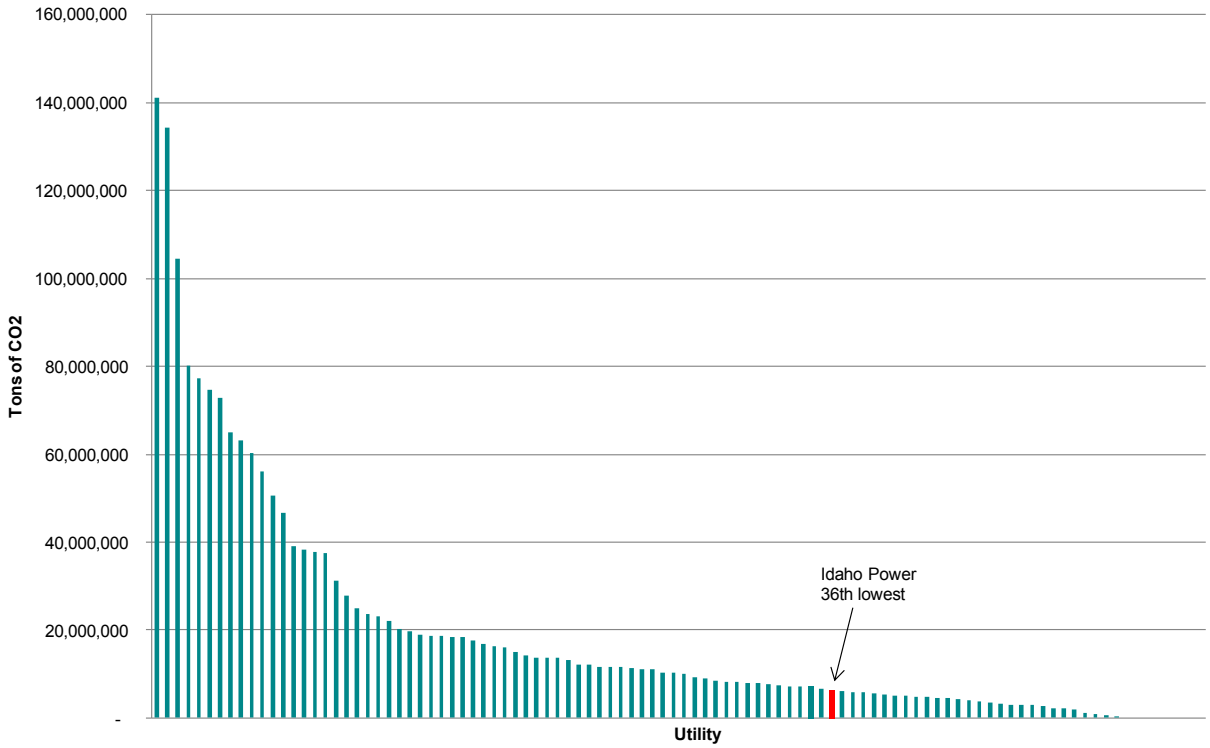



**Figure 1.2 $CO_2$ emissions of the largest 100 utilities**

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 at 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 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 as restated in 2012 is to achieve $CO_2$ emission intensity 10 to 15 percent below the 2005 $CO_2$ emission intensity from 2010 to 2015. A second extension of the goal approved by the Board of Directors in May 2015 sets a target $CO_2$ emission intensity of 15 to 20 percent below the 2005 $CO_2$ emission intensity for 2016 to 2017.

For the first time in several cycles, the 2015 IRP does not use a carbon adder to estimate the future cost of carbon emissions. The 2015 IRP incorporates the cost and long-term effects of carbon regulation by modeling several scenarios based on the Environmental Protection Agency's (EPA) proposed *Clean Air Act* (CAA) Section 111(d) regulations and the impact it

would have on the company's operations. A more complete discussion of climate change and the regulation of greenhouse gas emissions is available starting on page 64 of the IDACORP, Inc., 2014 Form 10-K at idacorpinc.com/pdfs/10K/10k2014a.pdf.

# Proposed Pilot Projects

## *Solar Photovoltaic to Address Distribution Feeder Voltage Loss*

A small-scale proof-of-concept photovoltaic (PV) and battery system pilot project is being considered for feeders with low voltage near the end of the feeder. The purpose of the pilot project is to evaluate its operational performance and its cost-effectiveness. The system will be designed to maintain the feeder voltage within +/- 5 percent of nominal voltage (American National Standards Institute [ANSI] C84.1) and be cost competitive with other options. During 2015 and 2016 the physical and economic feasibility will be examined. If feasible, a pilot system will be constructed and monitored. The results of the work will be reported in the 2017 IRP.

## *Ice-Based Thermal Energy Storage*

Idaho Power proposes a pilot project to investigate the benefits of using ice-based thermal energy storage (TES) to shift peak-hour air conditioning (A/C) load to off-peak periods. The initial phase of the pilot project would involve identifying a customer, designing the system, and putting together a detailed cost estimate. The second phase would be purchasing and installing the equipment, followed by data collection to determine the effectiveness of the concept. The ice-based TES technology is discussed further in Chapter 5.

# Community Solar

In the 2009 IRP, Idaho Power proposed a solar PV pilot project. At the time, a downward trend in the cost of solar PV was identified, and that trend has continued over the past few years. In addition, the energy shape of solar generation has been seen as a much better fit with Idaho Power's customer needs when compared to other variable and intermittent renewable resources. For these reasons, the company was interested in gaining experience and data related to solar generation, and a small pilot project was proposed.

In August 2010, the IPUC commented in Order No. 32042 (Case No. IPC-E-09-33) on the proposed solar pilot project, stating:

> Solar power has been identified as a resource that should be pursued by the Company. The recently announced Boise City solar project, we find, will provide Idaho Power that opportunity to assess the merits of such a resource.

Since the issuance of Order No. 32042, a number of unique circumstances have arisen that caused Idaho Power to reassess the appropriate timing and nature of its involvement in solar research and related projects. First, the solar project referenced in the IPUC order did not ultimately provide the assessment opportunity envisioned by the IPUC, as the developers chose not to pursue completion of the project. Further, three months after Order No. 32042 was issued, in November 2010 Idaho Power had 80 megawatts (MW) of *Public Utility Regulatory Policies Act of 1978* (PURPA) wind contracts pending approval at the IPUC, and the company had received another 570 MW of requests for new contracts. It was at that time the company

filed a joint petition to address PURPA policy and pricing issues at the state level, and Case No. GNR-E-10-04 was opened. A short time later, Idaho Power filed an application to modify its net metering service offering, and the IPUC opened Case No. IPC-E-12-27. In this case, the commission considered policy issues related to net metering, specifically in the areas of pricing and equitable cost assignment. Because of the broad scope of policy issues involving renewable generation under consideration by the IPUC in each of these cases, Idaho Power felt it was appropriate to postpone the development of any solar research project or customer-focused program pending the outcome of those cases.

Customer interest in central station and distributed solar generation was the subject of many 2015 IRP discussions, both among IRPAC members and Idaho Power leadership. Late in the 2015 IRP public process, Idaho Power was approached by several interested parties and asked to consider sponsoring a community solar project. The US Department of Energy (DOE) defines "community shared solar" as a solar-electric system that provides power and/or financial benefit to multiple community members.[4] The DOE further states the primary goal of community solar is to increase access to solar energy and to reduce up-front costs for participants. Secondary goals include: 1) improved economies of scale, 2) optimal project siting, 3) increased public understanding of solar energy, and 4) local job generation.

Several models have been used to facilitate community-shared solar projects, including utility-sponsored, special-purpose entity (SPE), and non-profit. Table 1.1 from the DOE compares various community solar models.[5]

**Table 1.1 Community solar model comparison**

| | Utility | SPE | Non-Profit |
|---|---|---|---|
| ***Owned By*** | Utility or third party | SPE members | Non-profit |
| ***Financed By*** | Utility, grants, customer subscriptions | Member investments, grants, incentives | Memberships, donor contributions, grants |
| ***Hosted By*** | Utility or third party | Third party | Non-profit |
| ***Subscriber Profile*** | Electric customers of the utility | Community investors | Donors, members |
| ***Subscriber Motive*** | Offset personal electricity use | Return on investment (ROI); offset personal electricity use | ROI; philanthropy |
| ***Long-term Strategy of Sponsor*** | Offer solar options; add solar generation (possibly for a renewable portfolio standard [RPS]) | Sell system to host; retain for electricity production | Retain for electricity production for life of the system |
| ***Examples*** | • Sacramento Municipal Utility District—SolarShares Program<br>• Tucson Electric Power—Bright Tucson Program | • University Park Community Solar, LLC<br>• Clean Energy Collective, LLC<br>• Island Community Solar, LLC | • Winthrop Community Solar Project<br>• Solar for Sakai |

[4] US Department of Energy. 2012. A guide to community shared solar: Utility, private, and nonprofit project development. http://www.nrel.gov/docs/fy12osti/54570.pdf.

[5] Ibid.

Several possibilities exist for the structure of a solar pilot project. One option Idaho Power is interested in pursuing would be to develop a PV project at a substation near existing load. This concept would not require the addition of new transmission resources and would have economy-of-scale advantages over distributed rooftop installations. The cost of the project could be subsidized by allowing participating customers to voluntarily buy the output from the project to invest in renewable energy.

The interested parties have asked Idaho Power to sponsor a community-based solar project to satisfy the solar pilot project proposed by the company in the 2009 IRP. For an example of this concept, there are several utility-sponsored projects whereby utility customers volunteer by contributing either an up-front or ongoing payment to support a solar project. In exchange, customers receive a payment or credit on their electric bills that is proportional to 1) their contribution and 2) how much electricity the solar project produces. Usually, the utility or an identified third-party owns the solar system itself. The participating customer has no ownership stake in the solar system. Rather, the customer buys rights to the benefits of the energy produced by the system.

It is important to note that Idaho Power's load and resource balance indicates an investment in any new generation, including solar generation, is neither needed nor economic to pursue at this time or during the four-year action plan horizon. However, as regulations governing carbon emissions mature, additional renewable generation may be warranted, and community-shared solar could be a viable option to help satisfy some future carbon intensity targets.

Given the quickly changing regulatory, technological, and economic landscape, the company will explore the risks and opportunities of, and potential designs for, a community-based solar project by continuing to work with interested parties. Because there is no identified resource need in the near-term, a project of this nature would be pursued outside the traditional needs-based regulatory framework and would focus on meeting changing customer preferences with regard to where and how the energy they use is produced.

## Portfolio Analysis Summary

A fundamental goal of the IRP process is to identify a selected, or preferred, resource portfolio. The preferred portfolio identifies resource options and timing to allow Idaho Power to continue to reliably serve customer demand, balancing cost, risk, and environmental factors over the 2015 to 2034 planning period. Several key factors create uncertainty regarding the selection of a preferred portfolio in the 2015 IRP. These factors include consideration of North Valmy and Jim Bridger coal unit early retirement, the EPA's proposed CAA Section 111(d) regulation, large contracted amounts of unbuilt PURPA solar projects, and the timing of the B2H transmission line.

### *North Valmy and Jim Bridger Coal Unit Early Retirement and CAA Section 111(d) Regulation*

The 2015 IRP examines the EPA's proposed CAA Section 111(d) regulation and the future of Idaho Power's ownership share of the Jim Bridger and North Valmy coal-fired power plants. With the exception of the Status Quo portfolio, all other portfolios analyzed evaluate alternatives to continued investment in the coal units and/or the impact of reducing generation from

fossil-fueled power plants to comply with uncertain environmental regulations. The optimization of coal unit shutdown alternatives using computer modeling tools will not be possible until the proposed CAA Section 111(d) regulation is finalized sometime in the second half of 2015. It is possible to identify trends in the modeling results that indicate a portfolio with an earlier North Valmy unit shutdown coupled with the completion of the B2H project performs well on a 20-year net-present-value (NPV) basis.

The early retirement of an asset requires accelerating the recovery of the remaining investment in that asset. This increases the cost in the early years in exchange for longer-term savings. This is conceptually similar to repaying a home mortgage early. Over the shortened life of a loan, the total payments will be less, but in the near term the monthly payment will be higher. The same is true when contemplating early retirement of North Valmy or Jim Bridger units. For example, a North Valmy 2019 early shutdown will cost approximately $95 million more between 2015 and 2019 but save approximately $181 million in fixed O&M, capital investment, and finance costs compared to a 2031 to 2034 retirement (in nominal dollars). Unlike the home mortgage example, a coal unit will have little value at the decommissioning date, and it is likely another resource investment will be required.

## Uncertainty Related to PURPA Solar

Power supply planning is complicated by the inability of a utility to control the timing, type, and quantity of PURPA resources being added to the Idaho Power generation portfolio. Under PURPA, a utility is obligated to sign energy sales agreements with all qualifying facilities (QF) that request to sell energy to Idaho Power. Changes in PURPA regulations, resource incentives, and technology can and do continuously change the quantity and MWs of projects being proposed or contracted for under PURPA. In addition, even after a PURPA QF agreement is executed with a proposed project, there is still uncertainty whether the project will be built. The result is increased planning uncertainty to the timing and type of company-owned resources needed. Current PURPA regulations also do not consider Idaho Power energy needs or impacts on system reliability, which creates challenging integration issues and is contrary to the company's desire to develop a reliable system as efficiently and cost-effectively as possible.

The IRP load and resource balance includes 461 MW of solar PV from PURPA projects scheduled to be on-line by year-end 2016. The energy and peak-hour capacity of these projects was included in the PURPA forecast at the time the forecast was prepared. The risk of relying on these signed contracts is exemplified by the fact that 141 MW of the 461 MW were recently terminated due to inaction by the PURPA developers. The removal of the 141 MW of solar capacity increases peak-hour capacity deficits by approximately 75 MW. Because the schedule for completing the IRP would not allow the PURPA generation forecast to be updated, the removal of the 141 MW of solar PV generation is addressed in a qualitative manner in the risk analysis section of Chapter 9.

## Boardman to Hemingway Transmission

Portfolio analysis for the 2015 IRP indicates portfolios with the B2H transmission line consistently outperform those in which the transmission line is excluded. This result is consistent with analyses of past IRPs, which have shown the B2H project is a valuable supply-side resource that will allow Idaho Power to meet future system needs. Regional growth in renewable energy

resources, such as wind and solar, makes B2H increasingly valuable as it provides increased system flexibility critical to the reliability of interconnected systems with high penetration levels of variable and intermittent resources.

### Selection of the Preferred Portfolio

As previously noted, portfolios with early North Valmy unit retirements performed well in the 2015 IRP analysis; analyses show favorable economics for portfolios with the retirement of North Valmy Unit 1 as early as 2019. However, these portfolios carry considerable risk associated with the following factors:

- Uncertainty related to the proposed CAA Section 111(d) regulation, particularly the effect of the final rule on operations at existing coal and natural gas-fired power plants in the proposed interim compliance period beginning in 2020
- Uncertainty related to retirement planning for a jointly owned power plant, specifically the challenges associated with arriving at a retirement date that is feasible to both owners of the plant
- Uncertainty related to PURPA solar and the effect of further project cancellations on capacity additions in the early 2020s
- Uncertainty related to the completion date of the B2H project due to permitting issues and the needs of project partners
- Uncertainty of regulatory acceptance of early coal unit retirement and rate impacts associated with accelerated cost recovery

Given these risks, the preferred portfolio selected is portfolio P6(b), which includes the retirement of the North Valmy plant at year-end 2025 and the completion of the B2H project in 2025. The close linking of these resource actions suggests an earlier completion date of the B2H project could accelerate the decommissioning of the North Valmy plant. Portfolio P6(b) also includes the addition of 60 MW of demand response and 20 MW of ice-based TES in 2030. In 2031, portfolio P6(b) also adds a 300 MW combined-cycle combustion turbine (CCCT). These resource additions late in the planning period address projected needs for resources providing peaking capability and system flexibility. With the expected long-term expansion of variable energy resources, the need for dispatchable resources that provide system flexibility will also increase.

## Action Plan

### Action plan (2015–2018)

Table 1.2 provides the schedule of action items Idaho Power anticipates over the next four years. Additional details regarding actions related to the Shoshone Falls Hydroelectric Project (Shoshone Falls Project) are presented in chapters 5 and 9 of the IRP.

**Table 1.2 Action plan (2015–2018)**

| Year(s) | Resource | Action | Action Number |
|---|---|---|---|
| 2015–2018 | B2H | Ongoing permitting, planning studies, and regulatory filings | 1 |
| 2015–2018 | Gateway West | Ongoing permitting, planning studies, and regulatory filings | 2 |
| 2015–2019 | Energy efficiency | Continue the pursuit of cost-effective energy efficiency. The forecast reduction for 2015–2019 programs is 84 average megawatts (aMW) for energy demand and 126 MW for peak demand. | 3 |
| 2015–2016 | N/A | Coordinate with government agencies on implementation planning for CAA Section 111(d). | 4 |
| 2015 | Shoshone Falls | File to amend FERC license regarding 50-MW expansion | 5 |
| 2015 | Jim Bridger Unit 3 | Complete installation of selective catalytic reduction (SCR) emission-control technology | 6 |
| 2015–2016 | Shoshone Falls | Study options for a smaller upgrade ranging in size up to approximately 4 MW | 7 |
| 2016 | Jim Bridger Unit 4 | Complete installation of SCR emission-control technology | 8 |
| 2016 | North Valmy units 1 and 2 | Continue to work with NV Energy to synchronize depreciation dates and determine if a date can be established to cease coal-fired operations | 9 |
| 2017 | Shoshone Falls | Commence construction of smaller upgrade | 10 |
| 2017 | Jim Bridger units 1 and 2 | Evaluate the installation of SCR technology for units 1 and 2 at Jim Bridger in the 2017 IRP | 11 |
| 2019 | Shoshone Falls | On-line date for smaller upgrade during first quarter | 12 |

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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 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 Governor's Office of Energy Resources (OER) and the Idaho Strategic Energy Alliance assisted the Interim Committee in updating 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.

Because the OER was charged with coordinating and cooperating with federal and state agencies on issues concerning the State's energy requirement, Governor C. L. "Butch" Otter asked the OER to coordinate the State of Idaho's response to the EPA Clean Power Plan on behalf of all relevant state agencies.

## Idaho Strategic Energy Alliance

Under the umbrella of the OER, the Idaho Strategic Energy Alliance allows various stakeholders to have representation and participate in developing energy plans and strategies for Idaho's

energy future. The Idaho Strategic Energy Alliance is Idaho's primary mechanism for advancing energy production, energy efficiency, and energy business in the State of Idaho.

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

Idaho Power representatives serve on both the Idaho Strategic Energy Alliance board of directors and a number of the volunteer task forces that work 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

## 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 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 in 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 1973* (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 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 2015 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-right proceedings. Idaho Power's ongoing participation in water-right issues is intended to guarantee sufficient water is available for use at the company's hydroelectric projects on the Snake River.



Snake River below Bliss.

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

In 1984, the Swan Falls Agreement resolved a struggle between the State of Idaho and Idaho Power over the company's water rights at the Swan Falls Project. The agreement stated Idaho Power's water rights at its hydroelectric facilities between Milner Dam and Swan Falls entitled the company to a minimum flow at Swan Falls of 3,900 cubic feet per second (cfs) during the irrigation season and 5,600 cfs during the non-irrigation season.

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

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

A settlement signed in 2009 reaffirmed the Swan Falls Agreement and resolved the litigation by clarifying the water rights held in trust by the state 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 are working with water users and other stakeholders in the development of water-management measures through the implementation of the Eastern Snake River Plain Aquifer (ESPA) *Comprehensive Aquifer Management Plan* (CAMP) as approved by the Idaho Water Resource Board (IWRB) and the 2009 Swan Falls Reaffirmation Agreement.

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 continues to emphasis implementation of the ESPA CAMP to improve aquifer levels and tributary spring flows to the Snake River. While some of the Phase I recommendations outlined in Table 2.1 were slow to develop due to limited initial funding, House Bill 547 signed into law by Governor Otter in 2014 provides $5 million annually to the IWRB for aquifer stabilization projects, with the ESPA having first priority.

While there have been two practices—recharge and weather modification—that have received funding and have met or exceeded targets, declining aquifer levels and spring discharge persist.

During the winter of 2014 to 2015, weather and canal maintenance conditions allowed for an extended wintertime recharge season from October 27, 2014, to March 24, 2015, resulting in a volume recharged of 72,325 acre-feet. This volume significantly exceeded the combined recharge of the two previous seasons and exceeded the average annual recharge of the previous five seasons by 4,500 acre-feet.

Idaho Power initiated and pursued a successful weather modification program in the Snake River Basin. The company partnered with an existing program in the upper Snake River Basin and, through the cooperative effort, has greatly expanded the existing weather modification operational program, along with forecasting and meteorological data support. The company has an established, long-term plan to continue the expansion of this program. In 2014, Idaho Power expanded its cloud-seeding program to the Boise and Wood River basins, in collaboration with basin water users and the IWRB. Wood River cloud seeding, along with the upper Snake activities, will benefit the ESPA CAMP implementation through additional water supply.

**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 | 30,300 |
| Managed aquifer recharge | 100,000 | 78,000* |
| 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 | 34,000 |
| Weather modification | 50,000 | 250,000 |

*Average annual recharge from 2009 to 2014.

For the 2015 IRP, Idaho Power forecasted flows similar to those in the 2013 IRP, with declines in reach gains extending through the end of the IRP planning period. Based on modeling under the 90-percent exceedance forecast, declining flows at Swan Falls drop to 4,030 cfs, which is slightly higher than the Swan Falls minimum of 3,900 cfs. Figure 2.1 provides the yearly April through July inflow to Brownlee Reservoir as forecasted for the 2015 IRP.

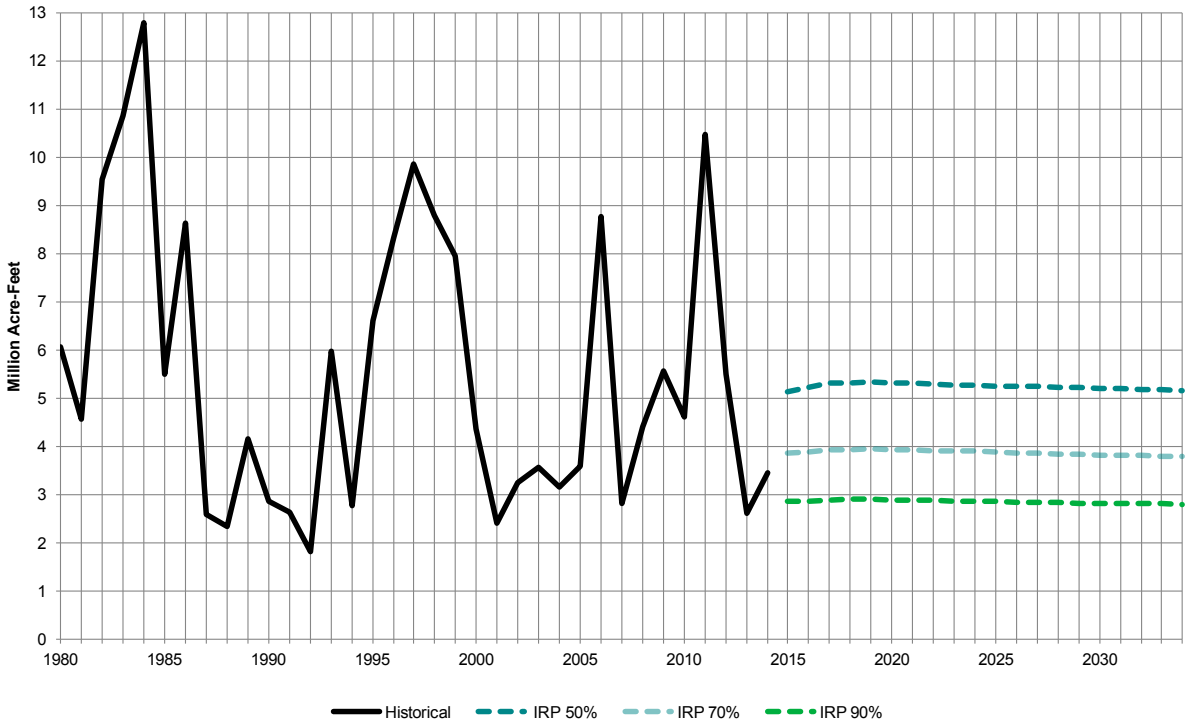



**Figure 2.1 Brownlee historical and 2015 to 2034 forecasted April to July inflow**

## Renewable Integration Study

Idaho Power has completed two wind integration studies and one solar integration study since the mid-2000s. These studies increased the company's understanding of the impacts and costs associated with integrating variable and intermittent resources without compromising reliability. The variable and uncertain production from wind and solar resources requires Idaho Power to provide additional balancing reserves from existing dispatchable generating resources, which results in lost opportunity costs and corresponding increases in power supply expenses.

Idaho Power completed the most recent wind integration study in 2013, which was the basis for a tariff schedule of wind integration costs proposed to the IPUC by Idaho Power. The IPUC approved the proposal as Schedule 87 in Order No. 33150 in October 2014.

The first Idaho Power solar integration study was completed in 2014, and the subsequent revision to Schedule 87 was approved by the IPUC in Order No. 33227 in February 2015 as part of a settlement stipulation between Idaho Power and intervening parties. The solar integration

settlement stipulation includes provisions requiring Idaho Power to initiate a second solar integration study by January 2015 and to complete the second study within 12 months. Idaho Power has formed a Technical Review Committee of renewable energy experts for the second solar integration study, which is in progress but will not be finished prior to the completion of the 2015 IRP.

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

For the IRP, integration costs for existing wind and solar resources are common to all the portfolios analyzed and are not included in the portfolio cost accounting. However, portfolios with new wind or solar resources do include costs consistent with Schedule 87 for the new resources. A copy of Schedule 87 is provided in *Appendix C—Technical Appendix*.

## Northwest Power Pool Energy Imbalance Market

Since 2012, the Northwest Power Pool (NWPP) has evaluated energy imbalance markets (EIM), sometimes referred to as a security-constrained economic dispatch (SCED). A second phase of the effort was focused on refining the design elements of a SCED to suit the unique issues present in the NWPP. A third phase just completed developed a number of operational tools to facilitate a more robust and reliable system operation. The NWPP is now moving into a fourth phase to continue to refine design elements of an SCED to develop additional low-cost/high-value tools to enhance system operation. Many institutional issues remain before an SCED 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 green tags, represent the green or renewable attributes of energy produced by certified renewable resources. A REC represents the renewable attributes associated with the production of 1 MWh of electricity generated by a qualified renewable energy resource, such as a wind turbine, geothermal plant, or solar facility. The purchase of a REC buys the renewable attributes, or "greenness," of that energy.

A renewable or green energy provider (e.g., a wind farm) is credited with one REC for every 1,000 kilowatt-hours (kWh), or 1 MWh, of electricity produced. RECs and the electricity produced by a certified renewable resource can either be sold together (bundled), sold separately (unbundled), or be retired to comply with a state- or federal-level RPS. An RPS is a policy requiring that a minimum amount (usually a percentage) of the electricity each utility delivers to customers comes from renewable energy.

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

REC prices depend on many factors, including the following:

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

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

Idaho Power customers who choose to purchase renewable energy can do so under Idaho Power's Green Power Program. Under this program, every dollar contributed by a customer brings about the delivery of 118 kWh of renewable energy to the region's power grid, providing the contributing customer associated claims for the renewable energy. The entire amount designated is used to purchase green power from renewable projects in the Northwest and to support Solar 4R Schools. On behalf of program participants, Idaho Power obtains and retires RECs. For the 2014 Green Power Program, Idaho Power purchased and subsequently retired 19,318 RECs on behalf of Green Power participants.

# Renewable Portfolio Standard

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 5- or 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.

## *REC 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 to customers their 95-percent share of the proceeds as defined under the PCA mechanism. In June 2010, the IPUC accepted Idaho Power's REC management plan in Order No. 32002 (Case No. IPC-E-08-24).

# Federal Energy Legislation CAA Section 111(d)

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 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.

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.

On June 2, 2014, the EPA, under President Obama's Climate Action Plan, released its long-anticipated proposal to regulate $CO_2$ emissions from existing power plants under CAA Section 111(d). EPA's proposed Clean Power Plan includes ambitious, mandatory $CO_2$ reduction targets for each state designed to achieve nationwide 30-percent $CO_2$ emission reductions over 2005 levels by 2030. The EPA has proposed a novel approach, extending regulations beyond the stationary source itself, which is where the EPA has traditionally confined its authority. Each state's rate-based goal, namely pounds of $CO_2$ per MWh was calculated using four building blocks:

1. Building Block 1—Improve efficiency in existing coal-fired power plants.

2. Building Block 2—Re-dispatch generation from existing coal-fired power plants to natural gas combined-cycle plants.

3. Building Block 3—Increase generation from non-$CO_2$-emitting resources.

4. Building Block 4—Increase end-use energy efficiency programs.

A combination of the four building blocks was used to calculate an interim goal (average of years 2020–2029) and a final 2030 goal. Each state would then implement the goals through a state plan, which will need to be approved by the EPA. Each rate-based goal would be legally binding on each state.

With new comprehensive federal energy legislation, a utility's resource portfolio will continue to evolve in response to its obligation to serve, market conditions, perceived risks, and regulatory policy changes. Because the EPA's proposed regulation will not be finalized until sometime after the completion of the 2015 IRP, the IRP analysis examines several compliance sensitivities that represent possible outcomes of the final regulation. Additional information on these sensitivities is presented in Chapter 9 and in *Appendix C—Technical Appendix*.

# 3. IDAHO POWER TODAY

## Customer Load and Growth

In 1990, Idaho Power served approximately 290,000 general business customers. Today, Idaho Power serves more than 515,000 general business customers in Idaho and Oregon. Firm peak-hour load has increased from 2,052 MW in 1990 to over 3,400 MW. On July 2, 2013, the peak-hour load reached 3,407 MW—the system peak-hour record.



Construction in downtown Boise.

Average firm load increased from 1,200 aMW in 1990 to 1,739 aMW in 2014 (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 3,594 MW. The 959-MW increase in capacity represents enough generation to serve nearly 175,000 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. This 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 kilowatts (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.

Since 1990, Idaho Power has added about 225,000 new customers. The simple peak-hour and average-energy calculations mentioned earlier suggest the additional 225,000 customers require 1,237 MW of additional peak-hour capacity and about 560 aMW of energy.

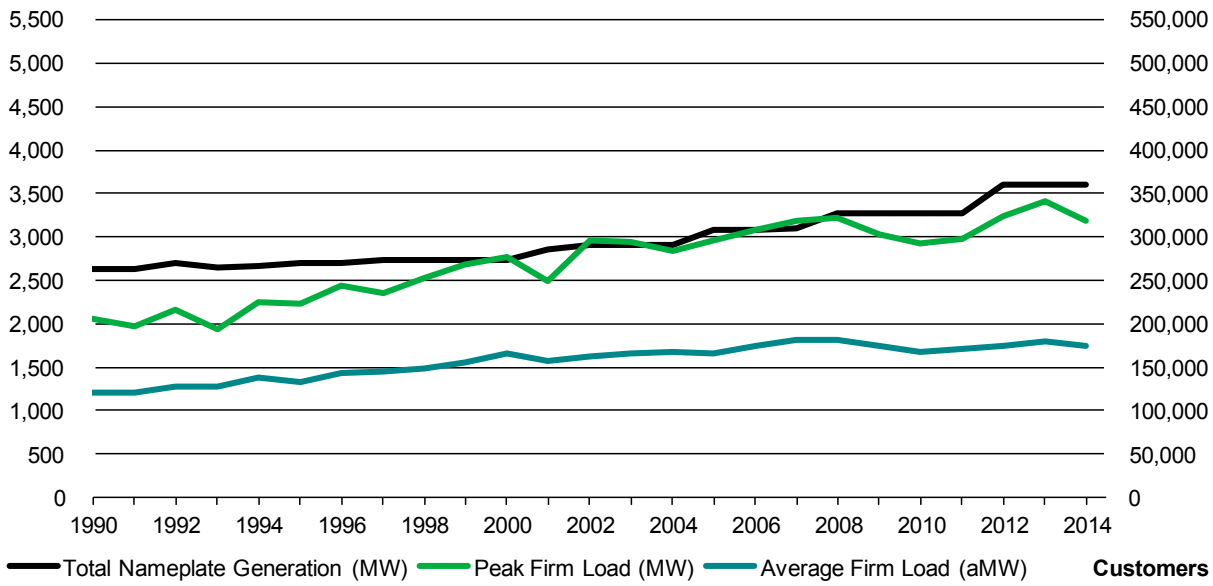



**Figure 3.1 Historical capacity, load, and customer data**

**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 | 3,594 | 3,245 | 1,745 | 500,731 |
| 2013 | 3,594 | 3,407 | 1,801 | 508,051 |
| 2014 | 3,594 | 3,184 | 1,739 | 515,262 |

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

Idaho Power anticipates adding approximately 9,800 customers each year throughout the 20-year planning period. The expected-case load forecast predicts summer peak-hour load requirements will grow at about 62 MW per year, and the average-energy requirement is forecast to grow at 24 aMW per year. More detailed customer and load forecast information is presented in Chapter 7 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 five 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 7 provide some perspective on customer growth. 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 $1,145 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 $800 per kW for a natural gas-fired simple-cycle combustion turbine (SCCT), such as the Danskin and Bennett Mountain projects. These capital-cost estimates are in 2015 dollars and do not include fuel or any other O&M expenses.

Based on the capital-cost estimates, each new residential customer requires over $1,700 of capital investment for 1.5 kW of baseload generation, plus an additional $4,400 for 5 to 6 kW of peak-hour capacity, leading to a total generation capital cost of over $6,100. Other capital expenditures for transmission, distribution, customer systems, and other administrative costs are not included in the $6,100 capital generation requirement. A residential customer growth rate of 9,800 new customers per year translates into almost $60 million of new generation plant capital each year to serve the baseload and peak energy requirements of new residential customers.

## 2014 Energy Sources

Idaho Power's system receives energy from a variety of fuel types and integrates energy from more than 100 PURPA projects and three power purchase agreements (PPA) in addition to company-owned generation. Figure 3.2 shows the nameplate capacity of resources delivering to Idaho Power's system from company-owned resources, PURPA contracts, and long-term PPAs.

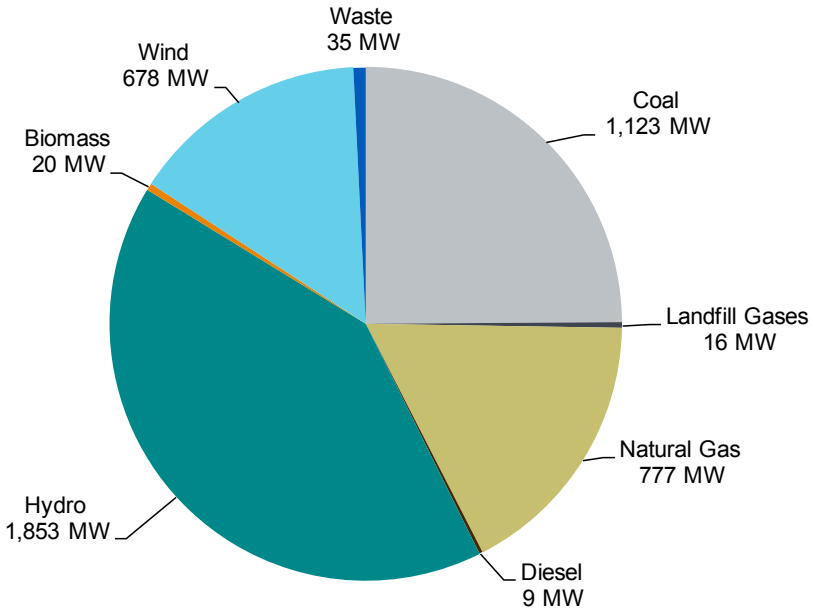



**Figure 3.2 2014 Idaho Power system nameplate by fuel type (MW) (owned resources plus purchased power)**

Idaho Power's electricity sources for 2014 are shown in Figure 3.3. Idaho Power generated 77 percent of the total energy requirement. In above-average water years, Idaho Power's low-cost hydroelectric plants are typically the company's largest source of electricity. Purchased power provides the remaining 23 percent of the energy requirement and includes power purchased from PURPA projects, market purchases, and PPAs, the need for which has been identified in past IRPs.

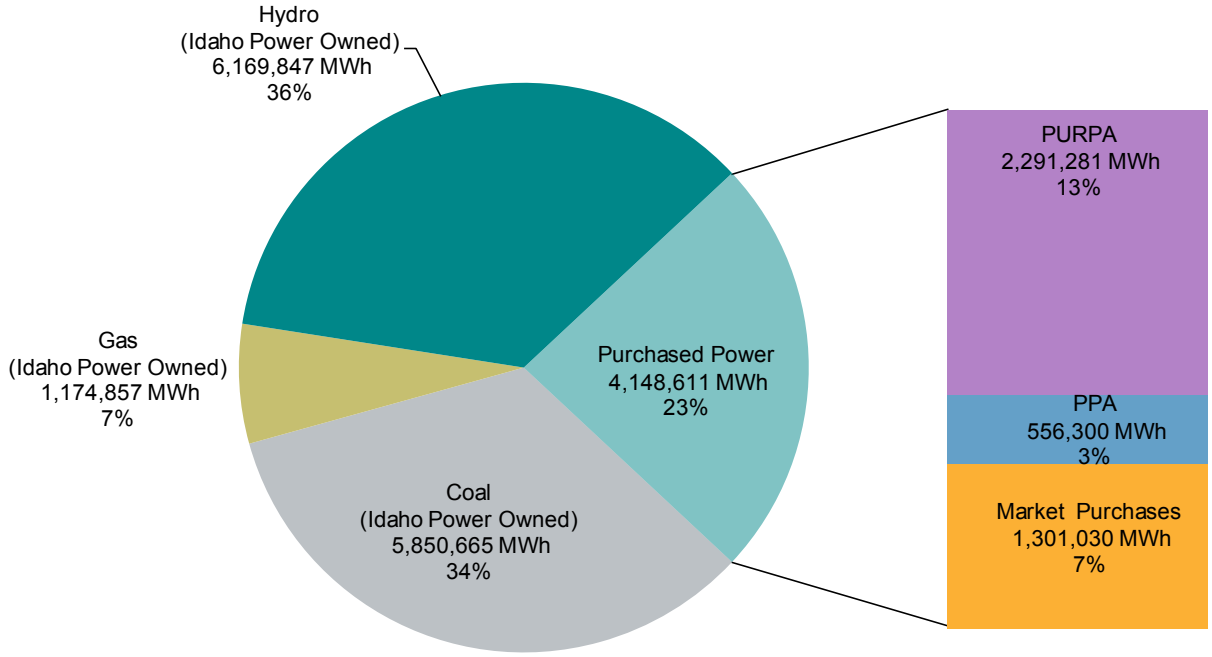



**Figure 3.3 2014 energy by source**

In 2014, Idaho Power purchased 4,148,611 MWh of electricity through PURPA contracts, market purchases, and long-term PPAs. Figure 3.4 provides a percentage breakdown by fuel type for the PPA and PURPA purchases. Market purchases are shown in total but not identified by fuel type since the original resource is not known. Idaho Power receives RECs from the Elkhorn Valley Wind Project, the Raft River Geothermal Project, and the Neal Hot Springs Geothermal Project. However, as noted in Chapter 2, Idaho Power is required to sell these RECs, and none of the renewable generation is represented as being delivered to Idaho Power retail customers in 2014.

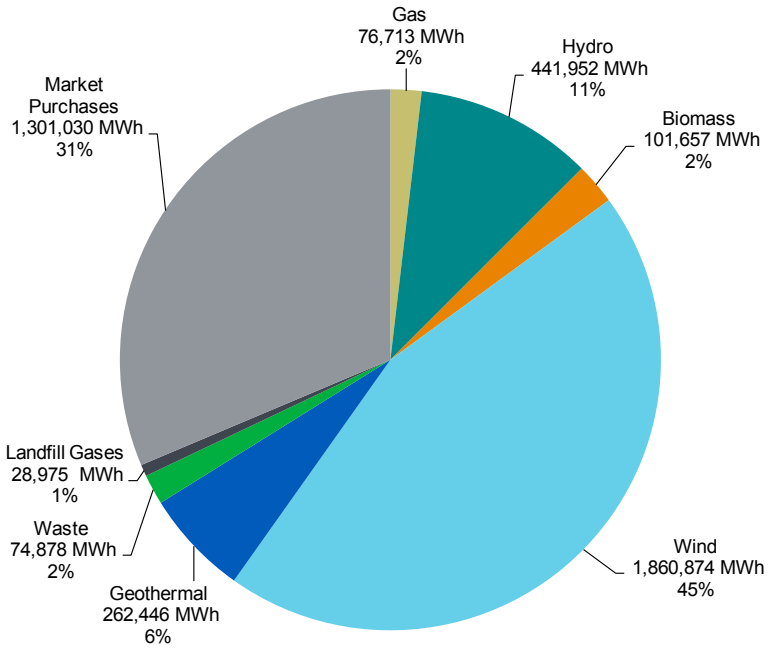



**Figure 3.4 2014 power purchases by fuel type**

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

**Table 3.2 Existing resources**

| Resource | Type | Generator Nameplate Capacity (MW) | Location |
|---|---|---|---|
| American Falls | Hydroelectric | 92.3 | Upper Snake |
| Bliss | Hydroelectric | 75.0 | Mid-Snake |
| Brownlee | Hydroelectric | 585.4 | Hells Canyon |
| C. J. Strike | Hydroelectric | 82.8 | Mid-Snake |
| Cascade | Hydroelectric | 12.4 | North Fork Payette |
| Clear Lake | Hydroelectric | 2.5 | South Central Idaho |
| Hells Canyon | Hydroelectric | 391.5 | Hells Canyon |
| Lower Malad | Hydroelectric | 13.5 | South Central Idaho |
| Lower Salmon | Hydroelectric | 60.0 | Mid-Snake |
| Milner | Hydroelectric | 59.4 | Upper Snake |
| Oxbow | Hydroelectric | 190.0 | Hells Canyon |
| Shoshone Falls | Hydroelectric | 12.5 | Upper Snake |
| Swan Falls | Hydroelectric | 27.2 | Mid-Snake |
| Thousand Springs | Hydroelectric | 8.8 | South Central Idaho |
| Twin Falls | Hydroelectric | 52.9 | Mid-Snake |
| Upper Malad | Hydroelectric | 8.3 | South Central Idaho |
| Upper Salmon A | Hydroelectric | 18.0 | Mid-Snake |
| Upper Salmon B | Hydroelectric | 16.5 | Mid-Snake |
| Boardman | Coal | 64.2 | North Central Oregon |
| Jim Bridger | Coal | 770.5 | Southwest Wyoming |
| North Valmy | Coal | 283.5 | North Central Nevada |
| Langley Gulch | Natural Gas—CCCT | 318.5 | Southwest Idaho |
| Bennett Mountain | Natural Gas—SCCT | 172.8 | Southwest Idaho |
| Danskin | Natural Gas—SCCT | 270.9 | Southwest Idaho |
| Salmon Diesel | Diesel | 5.0 | Eastern Idaho |
| **Total existing nameplate capacity** | | **3,594.4** | |

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

## Hydroelectric Facilities

Idaho Power operates 17 hydroelectric projects on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,709 MW and an annual generation equal to approximately 970 aMW, or 8.5 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 annual FERC license as well as voluntary arrangements to accommodate other interests, such as recreational use and environmental resources. Among the arrangements are the Fall Chinook Program, voluntarily adopted by Idaho Power in 1991 to protect the spawning and incubation of fall Chinook salmon (*Oncorhynchus tshawytscha*) below Hells Canyon Dam. The fall Chinook salmon is currently listed as threatened under the ESA.

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

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

Brownlee Dam is one of several Pacific Northwest dams coordinated to provide springtime flood control on the lower Columbia River. Idaho Power operates the reservoir in accordance with flood-control directions received from the US Army Corps of Engineers (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 basin above Brownlee Reservoir to augment flows in the lower Snake River to help anadromous fish migrate past the Federal Columbia River Power System (FCRPS) projects. The releases are part of the flow augmentation implemented by the 2008 FCRPS biological opinion. Much of the flow augmentation water travels through Idaho Power's middle Snake River (mid-Snake) projects, with all 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 Program 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

operations, Idaho Power attempts to refill Brownlee Reservoir by the first week of December to meet wintertime peak-hour loads. The fall Chinook plan spawning flows establish the minimum flow below Hells Canyon Dam throughout the winter until the fall Chinook fry emerge in the spring.

### Upper Snake and Mid-Snake Projects

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

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

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

### Water Lease Agreements

Idaho Power views the rental of water for delivery through its hydroelectric system as a potentially cost-effective power-supply alternative. Water leases that allow the company to request delivery when the water is needed are especially beneficial. Acquiring water through the water bank also helps the company improve water-quality and temperature conditions in the Snake River as part of ongoing relicensing efforts associated with the HCC.

The company signed a rental agreement in 2014 with Water District 63 in the Boise River basin to rent 8,000 acre-feet of storage water released in January 2015. 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. In 2011, the company extended the Shoshone–Bannock rental agreement for two additional years, 2014 and 2015.

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 mainstem Snake River

hydroelectric projects. The company typically scheduled delivery of the water between July and October 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. The company is reviewing the potential to renegotiate the Shoshone–Bannock agreement for future years. 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 Basin above Milner Dam. Idaho Power has continued to work with the stakeholders in the upper Snake River to expand the program and has recently collaborated with irrigators in the Boise and Wood River Basins to expand the target to include those watersheds.

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



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 both 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 nuclei 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 (weathermodification.org/images/AGI_toxicity.pdf). Analyses conducted by Idaho Power since 2003 indicate the annual snowpack in the Payette River Basin increased between 1 and 28 percent annually with an annual average of 14 percent. Idaho Power estimates cloud seeding currently provides an additional 250,000 acre-feet from the upper Snake River and 269,000 acre-feet from the Payette River. At program build-out, Idaho Power estimates that additional runoff from the Payette, Boise, Wood, and Upper Snake projects will total approximately 1,000,000 acre-feet. Studies conducted by the Desert Research Institute from 2003 to 2005 support the effectiveness of Idaho Power's program.

For the 2014 to 2015 winter season, the program included 23 remote-controlled, ground-based generators and 2 aircraft for operations in the west central mountains (Payette, Boise, and Wood River basins. The Upper Snake River Basin program included 21 remote-controlled, ground-based generators operated by Idaho Power and 25 manual, ground-based generators operated by the coalition of stakeholders in the Upper Snake. Idaho Power provides meteorological data and weather forecasting to guide the coalition's operations.

## Coal Facilities

### Jim Bridger

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

### North Valmy

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

### Boardman

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

The 2015 IRP assumes Idaho Power's share of the Boardman plant will not be available after December 31, 2020. The 2020 date is the result of an agreement reached between the Oregon Department of Environmental Quality (ODEQ), PGE, and the EPA related to compliance with Regional Haze Best Available Retrofit Technology (RH BART) rules on particulate matter, sulfur dioxide ($SO_2$), and nitrogen oxide ($NO_x$) emissions. At the end of 2014, the net-book value of Idaho Power's share of the Boardman facility was approximately $20.9 million.

## Natural Gas Facilities

### Langley Gulch

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

### Danskin

Idaho Power owns and operates the 271-MW Danskin natural gas-fired SCCT facility. The facility consists of one 179-MW Siemens 501F and two 46-MW Siemens–Westinghouse

W251B12A combustion turbines. The Danskin facility is located northwest of Mountain Home, Idaho. The two smaller turbines were installed in 2001, and the larger turbine was installed in 2008. The Danskin units are dispatched when needed to support system load.

### Bennett Mountain

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

### Salmon Diesel

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

## *Solar Facilities*

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

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

### Net Metering Service

Idaho Power's net metering service allows customers to generate power on their property and connect to Idaho Power's system. For net metering customers, the energy generated is first consumed on the property itself, while excess energy flows out to the company's grid. The majority of net metering customers use solar PV systems. As of May 1, 2015, there were 479 solar PV systems interconnected through the company's net metering service with a total capacity of 3.316 MW. At that time, the company had received completed applications for an additional 48 net metered solar PV systems representing an incremental capacity of 0.498 MW. For further details regarding customer-owned generation resources interconnected through the company's net metering service, see Table 3.3.

**Table 3.3 Net metering service customer count and generation capacity as of May 1, 2015**

| | Number of Customers | | | Generation Capacity (MW) | | |
|---|---|---|---|---|---|---|
| **Resource Type** | **Active** | **Pending** | **Total** | **Active** | **Pending** | **Total** |
| Solar PV | 479 | 48 | 527 | 3.316 | 0.498 | 3.8140 |
| Wind | 70 | 2 | 72 | 0.557 | 0.010 | 0.5670 |
| Other/hydroelectric | 10 | – | 10 | 0.147 | 0.000 | 0.0147 |
| **Total** | 559 | 50 | 609 | – | 0.508 | 4.5280 |

### Oregon Solar Photovoltaic Pilot Program and Oregon Solar Photovoltaic Capacity Standard

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

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

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

Under the Oregon Solar PV Capacity Standard as stated in ORS 757.370, 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. Idaho Power does not plan to build or acquire the generation from a 500-MW solar facility in Oregon prior to 2016, as the company already has sufficient RECs to meet the Oregon RPS requirement and no near-term needs for additional generation. The company will further evaluate this requirement in the 2017 IRP and determine the best method of meeting the 2020 compliance deadline.

## *Power Purchase Agreements*

### Elkhorn Valley Wind Project

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



Elkhorn Valley Wind Project, Union County, Oregon

### Raft River Geothermal Project

In January 2008, the IPUC approved a PPA for 13 MW of nameplate generation from the Raft River Geothermal Power Plant (Unit 1) located in southern Idaho. The Raft River project began commercial operations in October 2007 under a PURPA contract with Idaho Power that

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

### Neal Hot Springs Geothermal Project

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

### Clatskanie Energy Exchange

In September 2009, Idaho Power and the Clatskanie People's Utility District (Clatskanie PUD) in Oregon entered into an energy exchange agreement. Under the agreement, Idaho Power receives the energy as it is generated from the 18-MW power plant at Arrowrock Dam on the Boise River; in exchange, Idaho Power provides the Clatskanie PUD energy of an equivalent value delivered seasonally—primarily during months when Idaho Power expects to have surplus energy. An energy bank account is maintained to ensure a balanced exchange between the parties where the energy value will be determined using the Mid-Columbia market price index. The Arrowrock project began generating in January 2010, 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 the price 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 Idaho and the OPUC rules and regulations for all PURPA facilities located in 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 2015 IRP was completed in October 2014.

As of March 31, 2015, Idaho Power had 133 PURPA contracts with independent developers for approximately 1,302 MW of nameplate capacity. These PURPA contracts are for low-head hydroelectric projects on various irrigation canals, cogeneration projects at industrial facilities, wind projects, solar projects, anaerobic digesters, landfill gas, wood-burning facilities,

and various other small, renewable-power generation facilities. Of the 133 contracts, 105 were on-line as of March 31, 2015, with a cumulative nameplate rating of approximately 781 MW. Figure 3.5 shows the percentage of the total PURPA capacity of each resource type under contract.

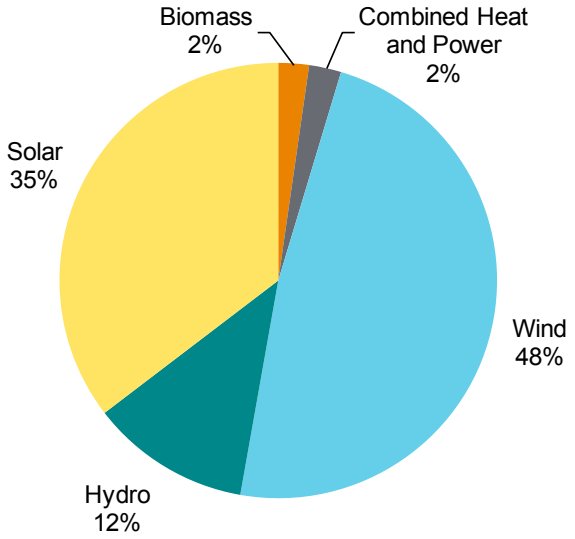



**Figure 3.5 PURPA contracts by resource type**

## 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. Some of the general guidelines are outlined below.

### *Published Avoided Cost Eligibility*

- *Idaho*—Wind and solar projects with a nameplate rating of less than 100 kW and all other projects with less than 10 aMW calculated on a monthly basis

- *Oregon*—All projects with a nameplate rating of less than 10 MW

For all projects not eligible for the published avoided cost rate, a unique negotiated avoided cost is calculated for each project. The basis for this negotiated avoided cost rate is the commission approved incremental cost IRP avoided cost methodology. In Idaho and Oregon, the published avoided cost is different based on the resource type (i.e. wind, solar, hydro, base load).

### *REC Ownership*

- *Idaho*—Projects that contract with Idaho Power using the published avoided cost rate will retain all RECs associated with the project. If the PURPA contract contains negotiated rates, IPUC Order No. 32697, issued December 18, 2012, stipulates the RECs will be equally shared between Idaho Power and the project owner.

- *Oregon*—The project owner retains all rights to the RECs associated with the project.

On January 30, 2015, Idaho Power filed a petition with the IPUC requesting the required contract term within new Idaho PURPA contracts be revised from 20 to 2 years. The IPUC opened case IPC-E-15-01 to address this matter, and a hearing is scheduled for June 29, 2015. IPUC Order No. 33222, issued February 6, 2015, temporarily revised the contract term from 20 to 5 years during the processing of the case.

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 Oregon. Parties have been filing testimony and comments in the case. The initial hearing was held in Salem, Oregon, on May 23, 2013. This case is moving into its second and third phases, continuing to review and address numerous PURPA-related issues.

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 remains at 10 aMW.
- Idaho Power's proposed incremental cost IRP methodology was approved to calculate the avoided cost pricing for projects ineligible for published avoided costs.
- A unique published avoided cost was established for wind, solar, hydroelectric, canal drop hydroelectric, and other projects.
- The QF project owner retains the RECs associated with the project for QF contracts containing published avoided cost rates.
- Idaho Power shall be entitled to 50 percent of the RECs for QF contracts that contain negotiated rates.

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 regard to PURPA contracts with Idaho Power.

## Wholesale Contracts

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

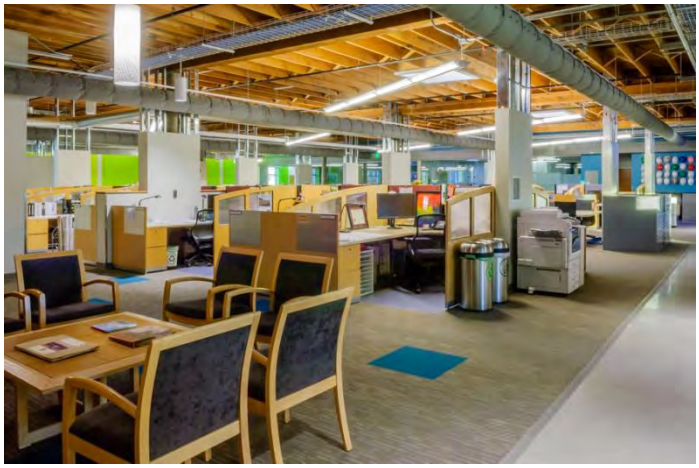
## Market Purchases and Sales

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 through the import of low-cost energy. Customers also benefit from sales revenues associated with surplus energy from economically dispatched resources.

# 4. DEMAND-SIDE RESOURCES

## Introduction

Demand-side resources have been the first resource choice in every IRP since 2004. No supply-side generation resource is considered as part of Idaho Power's plan until all future cost-effective achievable potential energy efficiency and forecasted demand response is accounted for and credited against future loads. In the 2015 IRP, demand response will provide 390 MW of peak summer reduction, while energy efficiency will reduce average annual loads by 301 aMW and 473 MW of peak reduction by the year 2034.



CSHQA's new offices received the City of Boise Building Excellence awards for Best Sustainable Commercial Project and Best Overall Project for 2014. CSHQA participated in Idaho Power's Building Efficiency program.

## Demand-Side Management Program Overview

DSM programs are an essential part of Idaho Power's resource strategy, and its portfolio of programs consists of demand response, energy efficiency, and market transformation programs. The three program categories provide different system benefits. Demand response programs reduce peak loads through 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 base load resources. Market transformation 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. Energy efficiency, demand response, and market transformation programs are offered to all four major customer classes: residential, irrigation, commercial, and industrial. Education programs and services are also offered to customers to support, promote, and encourage efficiency efforts.

Cost-effectiveness analyses, which indicate whether the benefits of these programs exceed the costs to administer them along with the costs incurred by participants, are published annually. The most recent analysis can be found in the *Demand-Side Management 2014 Annual Report Supplement 1: Cost-Effectiveness*. Each program and its component measures in the existing portfolio of demand-side resources are reviewed for their load impact over the 20-year IRP planning horizon as part of the IRP process. Additionally, in 2014 Idaho Power contracted with Applied Energy Group (AEG) to conduct an energy efficiency potential study that resulted in a forecast of energy savings over the 20-year IRP planning period. The resulting AEG forecast and program history were analyzed against the load forecast to ensure the energy efficiency

forecasted by AEG was credited with offsetting future loads. Details on the integration of the energy efficiency forecast are found in *Appendix A—Sales and Load Forecast*, *Appendix B—Demand-Side Management 2014 Annual Report*, and *Appendix C—Technical Appendix*.

## DSM Planning Changes from the 2013 IRP

Demand response and market transformation were considered differently in the 2015 IRP than the previous 2013 plan. Since market transformation was included in the 2014 AEG study, market transformation savings are considered a demand-side resource in the 2015 IRP, whereas in the past market transformation savings have been excluded from resource planning. In the 2015 IRP, demand response was treated as both a committed resource based on cost-effectiveness and as a potential new future resource addition beyond the committed resource level in select portfolios.

The 2013 IRP load and resource balance analysis demonstrated no capacity deficits in the near term. As a consequence, Idaho Power temporarily suspended two of its three demand response programs for summer 2013 under IPUC Case No. IPC-E-12-29 and Tariff Advice No. 13-04 with the OPUC. Through IPUC Case No. IPC-E-13-14 (Order No. 32923) and OPUC Case No. UM 1653 (Order No. 13-482), Idaho Power and interested parties reached a settlement agreement to continue the company's demand response programs for 2014 and beyond.

In the 2015 IRP, 390 MW of demand response capacity are included in every portfolio, and up to an additional 60 MW are in some portfolios as needed. In 2014, these programs cost $10.6 million; had the programs been used for the maximum number of hours, the cost would have been approximately $13.8 million. These costs represent approximately $6 million dollars in savings compared to 2012 ($21.2 million) and are significantly less than the annual value of $16.7 million agreed on in the settlement agreement. Another result of the settlement was guidance on how to operate the programs in years where they may not be short-term peak capacity deficits. To maintain the engagement of participants in demand response programs, Idaho Power will conduct a minimum of three events, even when extreme loads, low water, and extreme temperatures that demand response programs were designed to meet do not occur. In addition to helping retain participants, these three events will allow Idaho Power to evaluate and improve operations of the programs. Since demand response is considered a committed resource to the company, the potential load reduction of 390 MW from demand response was applied to future peak summer loads prior to the selection of additional resources to meet future peak deficits.

Market transformation achieves energy efficiency savings through engaging and influencing large national and regional companies and organizations. These organizations influence the design of energy efficiency into products, services, and practices that improve their energy efficiency. Idaho Power achieves market transformation savings primarily through its participation in NEEA. Idaho Power has been a funding member of NEEA since its inception in 1997.

Historically, Idaho Power has treated the savings reported by NEEA separately from savings from company run and administered efficiency programs. While the company has been supporting market transformation since the regional collaborative started, the value in the

programs for Idaho Power was to promote new potential energy-savings technologies and to look for new opportunities to be adopted into Idaho Power's program offerings. Examples of this include residential energy-efficient lighting that started out as a NEEA initiative to promote compact fluorescent technologies and transitioned to utility programs across the Northwest, including Idaho Power. Another reason affecting how market transformation savings were used in resource planning was related to how savings were attributed to utilities. Until 2010, NEEA primarily apportioned savings by how much each regional funder utility contributed to their various initiatives and put very little effort into assigning savings to geographic locations. This made it difficult to count on NEEA savings that may or may not be actually reducing Idaho Power loads while reducing regional system loads.

Since 2010, NEEA has been working on and continuously improving its ability to verify savings at the service-area level of its funders through evaluation and increased data collection. This allows Idaho Power to include market transformation savings as part of the company's efforts to meet IRP energy-savings targets. Another consideration to fully integrate market transformation into the IRP is that the AEG potential study that determines the energy efficiency forecast is agnostic to where the savings for any potential measure or technology come from or who provides them. The forecasted future savings can come from market transformation efforts done on a regional basis or from a traditional utility-administered program.

## Program Screening

All DSM programs and measures included in Idaho Power's current portfolio of programs and the forecast have been screened for cost-effectiveness. Cost-effectiveness analyses of DSM forecasts for the 2015 IRP are presented in more detail in *Appendix C—Technical Appendix*. *Appendix B—Demand-Side Management 2014 Annual Report* contains a detailed description of Idaho Power's 2014 energy efficiency program portfolio along with historical program performance. A complete review of Idaho Power's DSM programs, evaluations, and cost-effectiveness can be found in the 2014 annual report filing, *Demand-Side Management 2014 Annual Report*, *Supplement 1: Cost-Effectiveness*, and *Supplement 2: Evaluation*, which are available on Idaho Power's website at idahopower.com/EnergyEfficiency/reports.cfm.

## DSM Program Performance

While the IRP planning process primarily looks forward, it is also important to review historical DSM performance to understand the effects on system load. Accumulated annual savings from energy efficiency investments grow over time based on measure lives of the efficient equipment and measures adopted and installed by customers each year. Additionally, past performance of demand response programs has changed over time as the design and use of the programs have evolved.

### *Energy Efficiency Performance*

Energy efficiency investments since 2002 have resulted in a cumulative average annual load reduction of 167 aMW or over 1.4 million MWh of reduced supply-side energy production to customers through 2014. Figure 4.1 shows the cumulative annual growth in energy efficiency effects over the 13-year period from 2002 through 2014, along with the associated IRP targets developed as part of the IRP process since 2004.

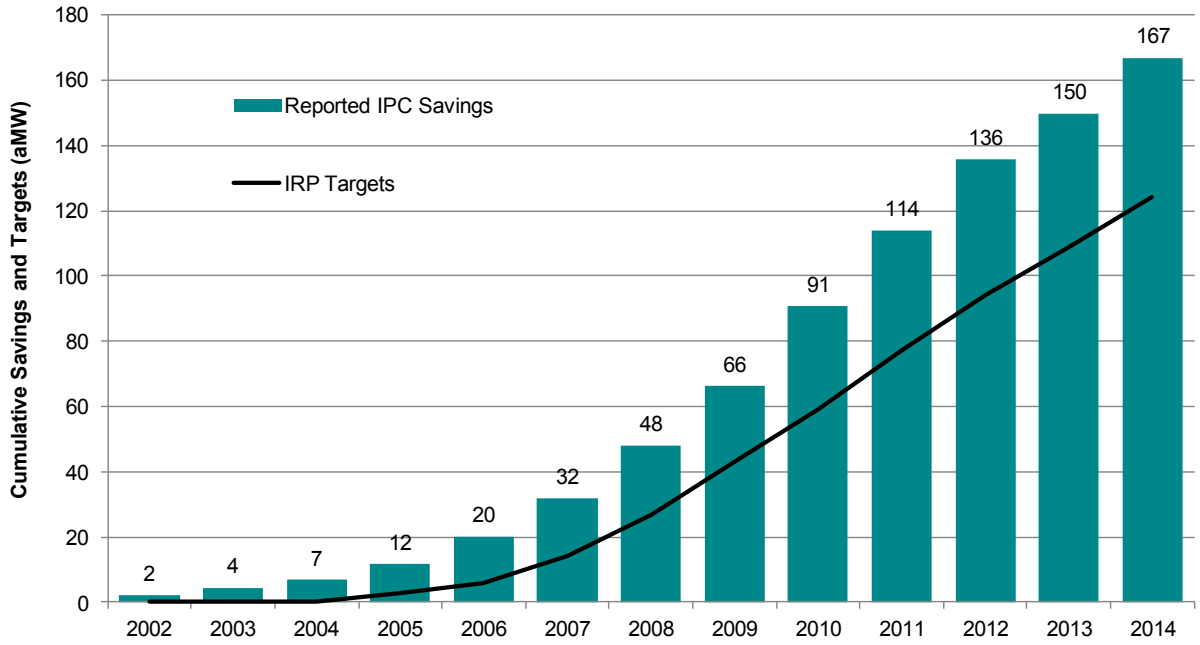



**Figure 4.1 Cumulative energy efficiency savings, 2002–2014 (aMW)**

## *Demand Response Performance*

Demand response resources have been part of the demand-side portfolio since the 2004 IRP. The current demand response portfolio is comprised of three distinct programs that work together as one resource. Each program targets a different customer class. Table 4.1 lists the three programs that make up the current demand response portfolio, along with the different program characteristics. The Irrigation Peak Rewards program represents the largest percent of potential demand reduction. During the 2014 summer season, participating irrigation program customers contributed 78 percent of the total potential demand reduction, or 295 MW. More details on Idaho Power's demand response programs can be found in *Appendix B—Demand-Side Management 2014 Annual Report.*

**Table 4.1 Current demand response programs 2014 performance**

| Program | Customer Class | Reduction Technology | 2014 Peak Performance (MW) | Percent of Total 2014 Peak Performance |
|---|---|---|---|---|
| A/C Cool Credit | Residential | Central A/C | 44 | 12% |
| Irrigation Peak Rewards | Irrigation | Pumps | 295 | 78% |
| FlexPeak Management | Commercial, industrial | Various | 40 | 11% |
| | | **Total** | **378** | |

Figure 4.2 shows the historical annual demand response program capacity between 2004 and 2014 along with associated IRP targets between 2004 and 2012. There were no targets for 2013 to 2014 in the 2013 IRP. The large jump in demand response capacity from 61 MW in 2008 to 218 MW in 2009 was a result of transitioning the majority of the Irrigation Peak Rewards

program to a dispatchable program. The demand response capacity in 2011 and 2012 included 320 and 340 MW of capacity, respectively, from the Irrigation Peak Rewards program, which was not used based on the lack of need and the variable cost to dispatch the program. The reported capacity value was lower in 2013 because of the one-year suspension of the irrigation and residential programs.

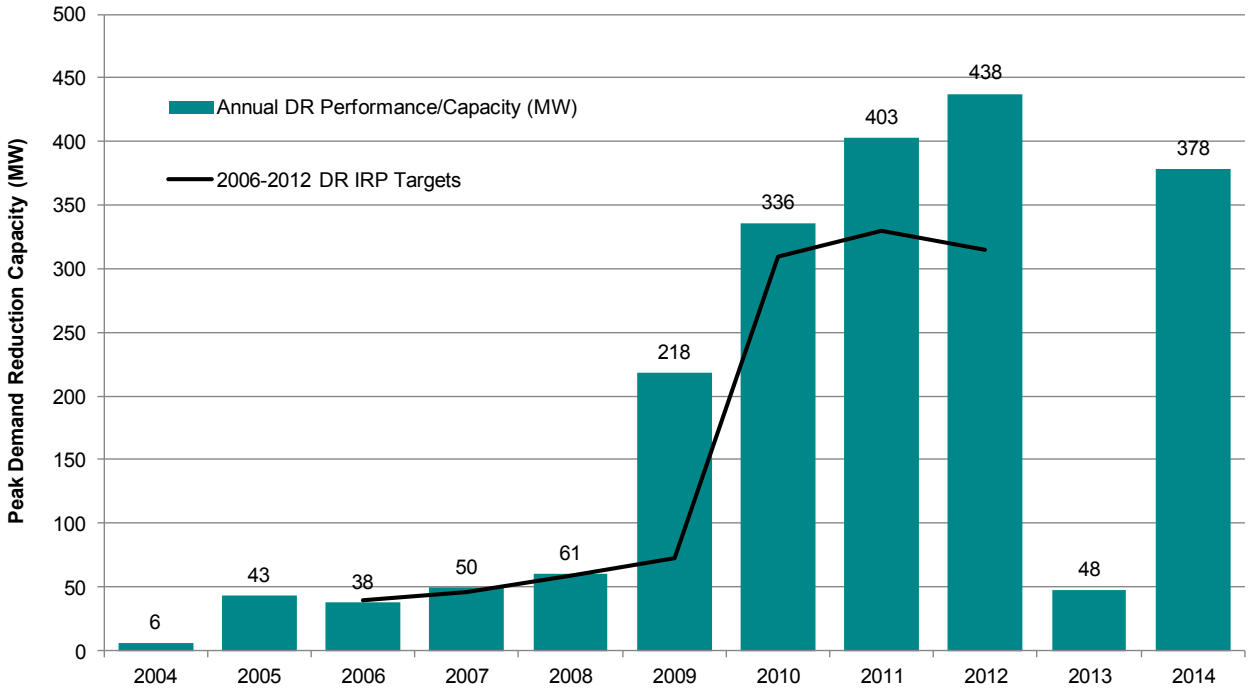



**Figure 4.2 Demand response peak reduction capacity and IRP targets, 2004–2014 (MW)**

## Committed Energy Efficiency Forecast

For the 2015 IRP, AEG was retained to update the previous study from 2012 and provide an updated 20-year comprehensive view of Idaho Power's energy efficiency potential. The objectives of the 2014 potential study were as follows:

- Incorporate the rapid changes in residential lighting potential based on the impacts from light-emitting diode (LED) lighting.
- Provide credible and transparent estimation of the technical, economic, and achievable energy efficiency potential by year over 20 years (2015–2034) within the Idaho Power service area.
- Assess potential energy savings and peak demand associated with each potential area by energy efficiency measure or bundled measure and sector.
- Provide a dynamic model that will support the potential assessment and allow testing of the sensitivity of all model inputs and assumptions.
- Develop a final report, including summary data tables and graphs reporting incremental and cumulative potential by year from 2015 through 2034.

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

In the AEG study, the energy efficiency potential estimates represent gross savings developed into three types of potential: technical potential, economic potential, and achievable potential. Technical and economic potential are both theoretical limits to efficiency savings. Achievable potential embodies a set of assumptions about the decisions consumers make regarding the efficiency of the equipment they purchase, the maintenance activities they undertake, the controls they use for energy-consuming equipment, and the elements of building construction. These levels are described below.

- *Technical*—Technical potential is defined as the theoretical upper limit of energy efficiency potential. Technical potential assumes customers adopt all feasible measures regardless of cost. At the time of equipment replacement, customers are assumed to select the most efficient equipment available. In new construction, customers and developers are also assumed to choose the most efficient equipment available. Technical potential also assumes the adoption of every other applicable measure available. The retrofit measures are phased in over 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 total resource cost (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 standard 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 phase included 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 provided to Idaho Power in gigawatt-hours (GWh), where it is converted to hourly, then monthly, demand reduction (aMW) to compare with supply-side resources for the IRP analysis, the savings are shaped by end-use load shapes that spread the forecasted savings across all hours of the year. The load shapes used to allocate savings by end-use were provided by AEG as part of the study deliverables. All reported energy efficiency and demand response forecasts are expressed at generation level and therefore include line losses of 9.6 percent for energy and 9.7 percent for peak demand to account for energy that would have been lost as a result of transmitting energy from a supply-side generation resource to the meter level.

Table 4.2 shows the forecasted potential effect of the current portfolio of energy efficiency programs for 2015 to 2034 in five-year blocks in terms of cumulative average annual energy reduction (aMW) by customer class. In 2019, the forecast reduction for 2015 to 2019 programs is forecast to be 84.3 aMW; by 2024 (halfway through the planning period), the cumulative reduction across all customer classes increases to 169.4 aMW. By the end of the IRP planning horizon in 2034, 300.8 aMW of reduction are forecast to come from the energy efficiency portfolio, with 55 percent of forecasted reduction coming from programs serving commercial and industrial customers. Detailed annual forecast values can be found in *Appendix C—Technical Appendix*.

**Table 4.2 Total energy efficiency portfolio forecasted effects (2015–2034) (aMW)**

| | 2015 | 2019 | 2024 | 2029 | 2034 |
|---|---|---|---|---|---|
| Industrial/commercial/special contracts | 8 | 46 | 93 | 138 | 167 |
| Residential | 3 | 28 | 55 | 85 | 111 |
| Irrigation | 1 | 11 | 22 | 23 | 23 |
| **Total*** | **12** | **84** | **169** | **246** | **301** |

*Totals may not add exactly due to rounding.

Table 4.3 shows the cost-effectiveness summary from the potential study. The table shows the NPV analysis of the 20-year forecast of the TRCs and DSM preliminary alternative costs or program benefits. 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 marginal resources.

**Table 4.3 Total energy efficiency portfolio cost-effectiveness summary**

| | 2034 Load Reduction (aMW) | 2034 Peak Load Reduction (MW) | Resource Costs ($000s) (20-Year NPV) | Total Benefits ($000s) (20-Year NPV) | TRC: Benefit/ Cost Ratio | TRC Levelized Costs (cents/kWh) |
|---|---|---|---|---|---|---|
| Residential | 111 | 175 | $425,360 | $691,151 | 1.6 | 9.8 |
| Industrial/commercial/ special contract | 167 | 226 | $253,982 | $618,633 | 2.4 | 3.3 |
| Irrigation | 23 | 72 | $139,206 | $222,009 | 1.6 | 10.3 |
| **Total** | **301** | **473** | **$818,548** | **$1,531,793** | **1.9** | **6.1** |

The value of avoided energy over the 20-year investment in the energy efficiency measures was almost twice the TRC when comparing benefits and costs resulting in an overall benefit/cost ratio of two. The levelized cost to reduce energy demand by 301 aMW and peak demand by 473 MW is 6.1 cents per kWh from a TRC perspective.

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 changes to codes and standards, 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 a more prospective approach. The amount of energy efficiency not captured by the load forecast trends is accounted for in the load and resource balance analysis.

## Committed Demand Response Resources

Under the current program design and participation levels, demand response from all programs is forecast to provide 390 MW of peak reduction during July throughout the IRP planning period with additional program potential available during June and August. The committed demand response included in the IRP has a capacity cost of $33 per annual kW per year.



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

## Non-Cost-Effective DSM Resource Options

AEG provided an additional potential study analysis to model additional achievable potential that would occur if the cost-effectiveness benefit/cost ratio requirements of a TRC test were changed from the standard requirement of one or greater down to a value of 0.8. The revised assumptions in the model produced a non-cost-effective energy-savings potential of 16 aMW and 24 MW of peak reduction over the 20-year IRP planning horizon. The 20-year present value cost of the additional efficiency was determined to have a levelized cost of 9.1 cents per kWh, which is 3.0 cents higher than the 20-year levelized cost of the achievable potential within the normal parameters of the TRC test. The additional DSM amount was made available as a resource in three of the analyzed portfolios.

## Additional Demand Response

An additional 60 MW of demand response were made available for peak summer reduction in some portfolios. If Idaho Power were to pay increased incentive amounts to customers, there would be added available capacity to expand the Irrigation Peak Rewards program in future years. While the current demand response portfolio cost is $33 per kW per year, this additional demand response capacity would cost approximately $51 per kW per year. This additional demand response capacity is included in some portfolios beginning in the year 2021 and is included in the preferred portfolio in 2030.

## Energy Efficiency Working Group

On November 4, 2014, the IPUC issued Order No. 33161 (Case No. IPC-E-14-04) finding that Idaho Power's 2013 DSM expenses were prudently incurred. On November 7, 2014, the IPUC issued Errata to Order No. 33161, stating in relation to issues raised in the case:

> The Commission agrees that the issues raised by Staff and other parties are significant and warrant a more in-depth review. We direct the parties to do so in the context of the Company's next Integrated Resource Plan filing.

In response to the Errata, Idaho Power organized an Energy Efficiency Working Group inviting members of the IRPAC, public participants in the IRP process, and the Energy Efficiency Advisory Group (EEAG). The Energy Efficiency Working Group held two public meetings in December 2014.

The first Energy Efficiency Working Group meeting included a discussion of a broad range of energy efficiency and resource planning issues that can be classified into two general categories: 1) strategies related to energy-efficiency program delivery and 2) the treatment of energy efficiency in the resource planning process. The second Energy Efficiency Working Group meeting focused on how energy efficiency as a resource should be treated in the IRP. Topics discussed at the second working group meeting included the following:

- A comparison presented by AEG of potential studies from other regional utilities
- A comparison presented by IPUC staff of Idaho Power's inclusion of energy efficiency in the IRP to the inclusion of energy efficiency by other regional utilities
- An Idaho Power-led discussion of the inclusion of transmission and distribution investment deferral into the benefits in the DSM cost-effectiveness analysis.

Through correspondence with working group participants, Idaho Power expressed the view that its current treatment of energy efficiency in the resource planning process appropriately balances the need for responsible and effective resource planning and the desire to pursue all cost-effective and achievable energy efficiency. Idaho Power also recognizes that achieving those balanced objectives on an ongoing basis requires continued review and evaluation of the planning process, as well as an awareness of related industry best practices.

Idaho Power has committed to continuing to investigate the extent to which transmission and/or distribution benefits result from energy efficiency measures and programs, as well as the approximate value of such benefits. Idaho Power presented a status update of this investigation at the May 7, 2015, IRPAC meeting. In the May 7, 2015, IRPAC meeting, Idaho Power indicated the study of transmission and distribution investment deferment is ongoing. Actions to be taken as part of the ongoing study include a review of transmission and distribution investments related to growth, an evaluation of the effectiveness of energy efficiency measures and programs in deferring transmission and distribution investment, and an estimate of the deferral value for those cases with the potential for transmission and/or distribution investment deferment.

Idaho Power is also committed to continuing to discuss the program delivery issues identified by working group participants, by IPUC staff, and by some intervenors in comments filed in Case No. IPC-E-14-04. The company plans to use EEAG as the forum to provide customers, regulatory staff, and other interested stakeholders an opportunity to provide advice and recommendations to Idaho Power on formulating, implementing, and evaluating energy efficiency and demand response programs and activities.

## Conservation Voltage Reduction

The goal of conservation voltage reduction (CVR) is to reduce electrical demand and energy by minimizing the distribution feeder voltage while providing service voltage within the standard operation range. Idaho Power participated in a northwest CVR pilot and implemented CVR on a few distribution feeders. In the 2013 IRP, Idaho Power proposed to validate the energy savings and reduced peak demand of CVR using new technologies and methods of measurement. Idaho Power included the validation plan (*Conservation Voltage Reduction Enhancements Project*) in its *2014 Smart Grid Report*. The project scope includes the following:

- Validate the energy and demand savings associated with CVR at the customer level
- Quantify the costs and benefits associated with implementing CVR
- Determine methods for expanding the CVR program to additional feeders
- Pilot methods for making Idaho Power's CVR program more dynamic
- Determine methods for the ongoing measurement and validation of the CVR program's effectiveness

The CVR measurement and verification process has been identified. Idaho Power has installed the infrastructure to evaluate CVR energy savings and demand reduction at seven substations in six different weather zones. In addition, new technology has been deployed on test feeders to evaluate its effectiveness in making CVR more dynamic. Hourly customer usage data will be collected from the Advanced Metering Infrastructure (AMI) system throughout 2015. This usage data will be analyzed to determine how CVR impacts the customer classes in weather zones across Idaho Power's service area. Idaho Power expects to complete the CVR analysis in 2016. Extending CVR measures to other Idaho Power facilities will then be evaluated.

# 5. SUPPLY-SIDE GENERATION AND STORAGE RESOURCES

Supply-side resources are traditional generation resources. Early IRP utility commission orders directed Idaho Power and other utilities to give equal treatment to both supply-side and demand-side resources. As discussed in Chapter 4, demand-side programs are an essential component of Idaho Power's resource strategy. The following sections describe the supply-side resources and storage technologies considered when Idaho Power developed the resource portfolios for the 2015 IRP. Not all supply-side resources described in this section were included in the preliminary resource portfolios, but every resource described was considered.

The primary source of cost information for the 2015 IRP is a report titled *Lazard's Levelized Cost of Energy Analysis*.[6] Lazard, a leading independent financial advisory and asset management firm, issued the levelized cost report in September 2014. Other information sources were relied on or considered on a case-by-case basis depending on the credibility of the source and the age of the information. For a full list of all the resources considered and cost information, see figures 7.5 and 7.6 in Chapter 7. All cost information presented is in 2015 dollars.

## Renewable Resources

Renewable resources are the foundation of Idaho Power, and the company has a long history of renewable resource development and operation. In the 2015 IRP, renewable resources were included in many of the portfolios analyzed as part of meeting the EPA's proposed CAA Section 111(d) regulation. Renewable resources are discussed in general terms in the following sections.

### *Solar*

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

Insolation is a measure of solar radiation reaching the earth's surface and is used to evaluate the solar potential of an area. Typically, insolation is measured in kWh per square meter ($m^2$) per day (daily insolation average over a year). The higher the insolation number, the better the solar power potential for an area. National Renewable Energy Laboratory (NREL) insolation charts show the desert southwest has the highest solar potential in the US.

In designing initial portfolios that included solar resources, Idaho Power chose the utility-scale PV technology because of its compliance to EPA's proposed CAA Section 111(d) regulation,

[6] Lazard. 2014. Lazard's levelized cost of energy analysis. http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf.

its flexibility, and its lower overall cost. Solar PV technology has existed for a number of years but has historically been cost prohibitive. Recent improvements in technology and manufacturing, combined with increased demand due to state RPSs, have made PV resources more cost competitive with other renewable and conventional generating technologies.

The capital-cost estimate used in the 2015 IRP for utility-scale PV resources is based on the 2014 Lazard report, which estimates a cost of $1,500 per kW for fixed panels and $1,750 per kW for PV with a single-axis tracking system. The 20-year levelized cost of production for fixed panels is $118 per MWh based on a 21.5-percent annual capacity factor and $109 per MWh for PV with a single-axis tracking system and a 26.8-percent annual capacity factor. In attempting to capture the decreasing cost of solar, Idaho Power used the 2017 forecast provided by Lazard of $1,250 per kW for PV with a single-axis tracking system.

To account for the decreasing cost trend seen in PV resources over the past few years, the 2015 IRP assumes solar PV costs remain fixed over the 20-year planning period. In comparison, other resource costs are escalated at 2.2 percent over the same 20 years. Therefore, in real-dollar terms, solar PV costs decline over the 20-year planning period. Idaho Power will continue to closely follow the decreasing price trend of solar PV as this technology continues to become more cost competitive with more traditional resource alternatives.

### Solar Capacity Credit

Idaho Power reviewed the solar capacity credit calculations due to comments received during the 2013 IRPAC meetings as well as comments received after filing the 2013 IRP. Idaho Power, interested members of the IRPAC, and interested members of the public formed a study group separate from the IRPAC to evaluate solar peak-hour capacity factors. The group formally met in September and October, and Idaho Power had additional informal meetings and conversations with members of the study group. Idaho Power updated the solar PV peak-hour capacity factors based on guidance from the members of the solar work group.

Idaho Power simulated solar generation for water years 2011 through 2013 as part of the solar integration study (data for the period October 1, 2010, through September 30, 2013). Idaho Power used the simulated solar generation combined with actual load data from the same time period to estimate the solar peak-hour capacity factors. In essence, the estimation used the system load data to identify the highest 150 load hours, used the simulated solar generation data to estimate the time-coincident simulated solar generation, and calculated a weighted average of the solar peak-hour capacity factor where the frequency of the hour was used as the weight in the weighted average calculation. The steps of the process are as follows:

1. Identify the 150 highest load hours from 2011 through 2013 (all are summer hours).

2. Determine the simulated solar generation during each of the 150 highest load hours. Solar generation simulation is from the Idaho Power solar integration study and is simulated at five-minute intervals at a set of utility-scale solar generation sites across Idaho Power's service area. The five-minute data was compiled into an average for the hour.

3. Group the solar generation by clock hour for the 150 highest load hours (e.g., a list of all the solar generation values for the clock hour from 2:00 p.m. to 3:00 p.m. during the 150 highest load hours).

4. Estimate the 90$^{th}$ percentile exceedance for each clock hour represented in the 150 highest load hours (among the highest 150 load hours, during the clock hour starting at xx:00, 9 times out of 10, the solar generation was simulated to be at least xx percent of the maximum possible delivered solar generation).

5. Calculate a weighted average of the solar generation for the series of clock hours; the clock hours are weighted by the proportion the clock hour is represented in the top 150 load hours.

Idaho Power used the same process for estimating fixed-panel generation systems and solar tracking generation.

The solar capacity credit is expressed as a percentage of installed AC nameplate capacity. The solar capacity credit is used to determine the amount of peak-hour capacity delivered to the Idaho Power system from a solar PV plant considered as a new IRP resource option. The solar capacity credit values used in the 2015 resource plan are reported in Table 5.1.

**Table 5.1 Solar capacity credit values**

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

## Geothermal

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

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

condensed and recycled through a heat exchanger. The secondary fluid is in a closed system and is reused continuously in a binary-cycle plant. The primary fluid (the geothermal water) is returned to the geothermal reservoir through injection wells.

Cost estimates and operating parameters used for binary-cycle geothermal generation in the 2015 IRP are based on data from independent geothermal developers and cost information from a PPA Idaho Power has with U.S. Geothermal, Inc., for the generation from the Raft River Geothermal Project located in southern Idaho. The capital-cost estimate used in the 2015 IRP for geothermal resources is $4,021 per kW, and the 25-year levelized cost of production is $101 per MWh based on a 90-percent annual capacity factor.

## *Hydroelectric*

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

### Small Hydroelectric

Because small hydroelectric projects, such as ROR and projects requiring small or no impoundments, do not have the same level of environmental and permitting issues as large hydroelectric projects, the IRPAC expressed an interest in evaluating small hydroelectric in the 2015 IRP. The potential for new, small hydroelectric projects was studied by the Idaho Strategic Energy Alliance's Hydropower Task Force, and the results released in May 2009 indicate between 150 MW to 800 MW of new hydroelectric resources could be developed in Idaho. These figures are based on potential upgrades to existing facilities, undeveloped existing impoundments and water delivery systems, and in-stream flow opportunities. The capital-cost estimate used in the IRP for small hydroelectric resources is $3,600 per kW, and the 75-year levelized cost of production is $159 per MWh.

### Shoshone Falls Expansion Project

In August 2006, Idaho Power filed a license amendment application with FERC to expand the Shoshone Falls Project 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 expansion project involves replacing the two smaller units with a single 50-MW unit that will result in a net expansion of 49 MW.

In July 2010, FERC issued a license amendment for the project allowing two years to begin construction and five years to complete the project. Idaho Power has received two extensions from FERC since the issuance of the license amendment. The latest extension, granted by FERC in May 2014, allows Idaho Power until July 2022 to complete the project. Construction associated with renovations at the intake structure, the new scenic flow structure, and the replacement of the gated spillway at Shoshone Falls commenced in 2014 and is scheduled to be completed in December 2015. Idaho Power continues to analyze the costs and benefits of the generator/turbine expansion segment of the project.

For the 2015 IRP, Idaho Power is considering the Shoshone Falls generator/turbine expansion a resource option. The expansion is expected to produce on average about 200 GWh annually of incremental energy above the existing power plant configuration, with nearly 75 percent of the incremental energy occurring during the January through June period. The incremental energy is assumed to be REC eligible. A cost-benefit analysis of the generator/turbine expansion is provided in Chapter 9.

### Wind

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

When compared to other renewable options, wind resources are well suited for the Pacific Northwest and Intermountain regions, as evidenced by the number of existing projects. Wind resources present a problem for utilities due to the variable and intermittent nature of wind generation. Therefore, planning new wind resources requires estimates of the expected annual energy and peak-hour capacity. For the 2015 IRP, Idaho Power used an annual average capacity factor of 28 percent and a capacity factor of 5 percent for peak-hour planning. The capital-cost estimate used in the IRP for wind resources is $1,800 per kW, and the 25-year levelized cost of energy is $135 per MWh, which includes a wind integration cost of $15.39 per MWh.

### Biomass

Biomass resource types considered in the 2015 IRP include wood-burning resources and anaerobic digesters. Wood burning resources typically rely on a steady supply of woody residue collected from forested areas. Therefore, fuel supply can be an issue for these types of plants as the radius of the area used to collect fuel is expanded. Several anaerobic digesters have been built in southern Idaho due to the size of the dairy industry and the quantity of fuel available. However, these digesters are limited in size and would be difficult to develop on a utility scale.

The capital-cost estimate used in the IRP for a 35-MW wood-burning biomass project is $2,622 per kW, and $4,761 per kW for a 3-MW anaerobic digester project. The wood-burning unit is expected to have an annual capacity factor of 85 percent, while the anaerobic digester is expected to operate at 75 percent. Based on the annual capacity factors, the 30-year levelized cost of production is $102 per MWh for the wood-burning unit and $119 per MWh for the anaerobic digester.

## Conventional Resources

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

## Natural Gas-Fired Resources

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

CCCT and SCCT resources are typically sited near existing gas pipelines, which is the case for Idaho Power's existing gas resources. However, the capacity of the existing gas pipeline system is almost fully allocated. Therefore, the 2015 IRP assumes new natural gas resources would require building additional pipeline capacity. This additional cost is accounted for in portfolios containing new gas resources and not in the resource stack cost estimate for CCCTs or SCCTs.

### Combined-Cycle Combustion Turbines

CCCT plants have been the preferred choice for new commercial power generation in the region. CCCT technology carries a low initial capital cost compared to other baseload resources, has high thermal efficiencies, is highly reliable, offers significant operating flexibility, and emits fewer emissions when compared to coal, therefore requiring fewer pollution controls.

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

Several CCCT plants, similar to Idaho Power's Langley Gulch project, are planned in the region due to recently declining natural gas prices, the need for baseload energy, and additional operating reserves needed to integrate wind resources. While there is no current shortage of natural gas, fuel supply is a critical component of the long-term operation of a CCCT. The capital-cost estimate used in the IRP for a CCCT resource is $1,145 per kW, and the 30-year levelized cost of production at a 70-percent annual capacity factor is $79 per MWh.

### Simple-Cycle Combustion Turbines

Simple-cycle, natural gas-turbine technology involves pressurizing air that is then heated by burning gas in fuel combustors. The hot, pressurized air expands through the blades of the turbine that connects by a shaft to the electric generator. Designs range from larger, industrial machines at 80 to 200 MW to smaller machines derived from aircraft technology. SCCTs have a lower thermal efficiency than CCCT resources and are not typically economical to operate other than to meet peak-hour load requirements.

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

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

The 2015 IRP evaluated two SCCT technologies: 1) a 47-MW small, aeroderivative unit and 2) a 170-MW industrial-frame unit. The capital-cost estimate used in the IRP for the small, aeroderivative unit is $1,000 per kW, and an industrial-frame unit is $800 per kW. Both the aeroderivative unit and the industrial-frame unit are expected to have an annual capacity factor of 10 percent.

Based on the annual capacity factor, the 35-year levelized cost of production is $250 per MWh for the small, aeroderivative unit and $219 per MWh for the industrial-frame unit. These levelized costs are close to the same as the higher efficiency of the small aeroderivative unit offsets the slightly higher capital cost. If needed, Idaho Power would evaluate these two technologies in greater detail prior to issuing a request for proposal (RFP) to determine which technology would provide the greatest benefit.

### Reciprocating Engines

Reciprocating engine generation sets are typically natural gas-fired engines connected to a generator through a flywheel and coupling. Because they are mounted on a common baseframe, the entire unit can be assembled, tuned, and tested in the factory before being delivered to the power plant location, which minimizes capital costs. Operationally, reciprocating engines are typically installed in configurations with multiple, identical units, which allows each unit to run at its best efficiency point once started. As more generation is needed, additional units are started. This configuration also allows for relatively inexpensive future expansion of the plant capacity.

For the IRP, Idaho Power modeled a reciprocating engine similar to the 34SG model manufactured by Wärtsilä with a nameplate rating of 18.8 MW. The capital-cost estimate used for a reciprocating engine resource is $500 per kW, and the 40-year levelized cost of production at a 10-percent annual capacity factor is $136 per MWh.

### Combined Heat and Power

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

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

for the steam host provide a competitive advantage that would ultimately help the local economy.

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

Recognizing the actual cost of a CHP resource may vary depending on the specific facility being considered, the capital-cost estimate used in the IRP for CHP is $2,123 per kW, and the 40-year levelized cost of production evaluated at an annual capacity factor of 80 percent is $81 per MWh.

## Nuclear Resources

The nuclear power industry has been working to develop and improve reactor technology for some time, and Idaho Power has continued to evaluate various technologies in the IRP. Due to the Idaho National Laboratory (INL) site in eastern Idaho, the IRP has typically assumed that an advanced-design or small modular reactor could be built on the site. For the 2015 IRP, high capital costs coupled with a great amount of uncertainty in waste disposal issues prevented a nuclear resource from being included in the portfolio analysis. In addition, the recent earthquake and tsunami in Japan, and the impact on the Fukushima nuclear plant, created a global concern over the safety of nuclear power generation. While there have been new design and safety measures implemented, it is difficult to know the full impact this disaster will have on the future of nuclear power generation.

For the 2015 IRP, a 1,100-MW advanced nuclear resource and a 600-MW small modular plant were analyzed; however, for both types of plants, it was assumed that Idaho Power would only be a part owner in either type of facility by taking 250 MW of the total plant capacity. The capital-cost estimate used in the IRP for an advanced nuclear resource is $4,350 per kW, and the 40-year levelized cost of production, evaluated at an annual capacity factor of 90 percent, is $119 per MWh. For the small modular reactor technology, the capital-cost estimate is $5,000 per kW, and the 40-year levelized cost of production, evaluated at an annual capacity factor of 95 percent, is $343 per MWh.

## Coal Resources

Conventional coal resources have been a part of Idaho Power's generation portfolio since the early 1970s. Growing concerns over global warming and climate change have made it impractical to consider building any new conventional coal resources; however, integrated gasification combined cycle (IGCC) and IGCC coupled with carbon sequestration are two technologies that were still evaluated in the IRP.

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

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

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

Carbon sequestration involves taking captured $CO_2$ and storing it away from the atmosphere by compressing and pumping it into underground geologic formations. If compression and pumping costs are charged to the plant, the overall efficiency of the plant is reduced by an additional 15 to 20 percent. Sequestration methods are currently being developed and tested; however, commercialization of the technology is not expected to happen for some time. The capital-cost estimate used in the IRP for IGCC is $3,257 per kW, and the 35-year levelized cost of production, evaluated at an annual capacity factor of 85 percent, is $116 per MWh. The capital-cost estimate used for IGCC with carbon sequestration is $6,390 per kW, and the 35-year levelized cost of production, evaluated at an annual capacity factor of 75 percent, is $184 per MWh.

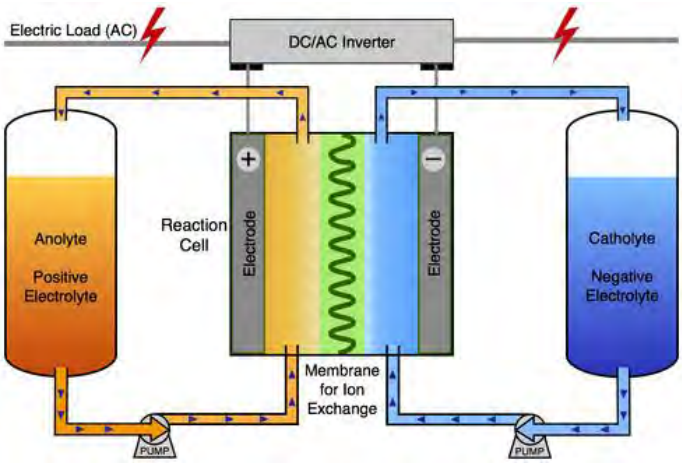
## Storage Technologies

RPSs have spurred the development of renewable resources in the Pacific Northwest to the point where there is an oversupply of energy. Recently, Mid-Columbia wholesale market prices for electricity are typically one-third to one-half lower than just a few years ago. At the same time, retail rates for electricity continue to grow as utilities have to pass the cost of building these resources on to customers. The oversupply issue has grown to the point where at certain times of the year, such as in the spring, low customer demand coupled with large amounts of hydro and wind generation cause real-time and day-ahead wholesale market prices to go negative.

As more intermittent renewable resources like wind and solar continue to be built within the region, the need for energy storage is amplified. While there are many storage technologies at various stages of development, such as hydrogen storage, compressed air, and flywheels, the 2015 IRP considered and evaluated three specific storage technologies: 1) battery storage, 2) ice-based TES, and 3) pumped storage.

## Battery Storage

Just as there are many types of storage technologies being researched and developed, there are numerous types of battery storage technologies at various stages of development. The 2015 IRP focused on one specific type of battery technology; the vanadium redox-flow battery (VRB).




Basic illustration of a flow battery.[7]

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

VRB technology also has an advantage in maintenance and replacement costs, as only certain components need replaced about every 10 years, whereas other battery technologies require a complete replacement of the battery and more frequently depending on how they are used. For the IRP, the capital-cost estimate for the VRB is $3,000 per kW, and the 10-year levelized cost of production, evaluated at an annual capacity factor of 25 percent, is $240 per MWh.

## Ice-Based Thermal Energy Storage

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

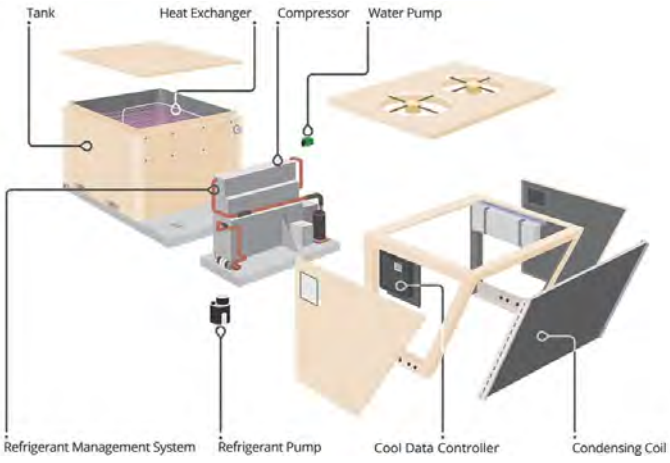



Illustration of an ice-based TES system.[8]

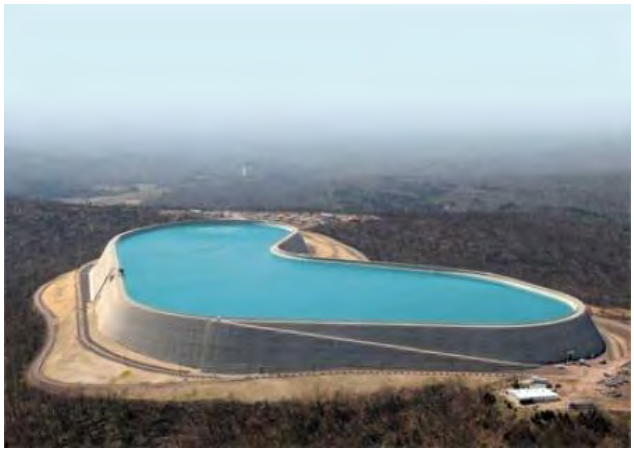
[7] Source: http://strategy.sauder.ubc.ca/antweiler/blog.php?item=2014-09-28.

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

One company currently commercializing the ice-based TES technology is Ice Energy with their *Ice Bear Energy Storage System*. Requirements in California to develop energy storage have allowed several utilities to begin installing and testing this technology, with several installations of 5 MW to 15 MW in size. For the IRP, the capital-cost estimate used for this technology is $1,500 per kW, and the 20-year levelized cost of production, evaluated at an annual capacity factor of 10.4 percent, is $224 per MWh.

## Pumped Storage

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



Pumped-storage facility.[9]

For pumped storage to be economical, there must be a significant differential in the price of electricity between peak and off-peak times to overcome the costs incurred due to efficiency and other losses that make pumped storage a net consumer of energy overall. Historically, the differential between peak and off-peak energy prices in the Pacific Northwest has not been sufficient to make pumped storage an economically viable resource; however, with the recent increase in the number of wind projects, the amount of intermittent generation provided, and the ancillary services required, this may change. The capital-cost estimate used in the IRP for pumped storage is $5,000 per kW, and the 50-year levelized cost of production is $346 per MWh.

[9] Source: http://www.renewableenergyworld.com/rea/news/article/2010/10/worldwide-pumped-storage-activity.

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# 6. TRANSMISSION PLANNING

## Past and Present Transmission



Idaho Power's double-circuit 230-kilovolt (kV) transmission line traversing Hells Canyon.

High-voltage transmission lines are vital to the development of energy resources to serve Idaho Power customers. Transmission lines have facilitated the development of southern Idaho's network of hydroelectric projects that serve the electric customers of southern Idaho and eastern Oregon. Regional transmission lines that stretch from the Pacific Northwest to the HCC and to the Treasure Valley were central to the development of the HCC projects in the 1950s and 1960s. In the 1970s and 1980s, transmission lines 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 and intermittent 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.
- System reliability is increased.
- Capacity is added to help integrate intermittent resources, such as wind and solar.
- Flexibility is provided to respond to the proposed CAA Section 111(d) requirements.
- The ability to more efficiently implement advanced market tools, such as EIMs or SCED.

# Transmission Planning Process

In recent years, FERC 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. The plans account for land-use limits and other resources of the local area. The plans identify the approximate year a project will be placed in service. Local-area plans have been created for the following five load centers in southern Idaho:

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

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 third-party transmission customer requirements. By identifying potential resources,

potential resource locations, and load-center growth, the required transmission system capacity expansions are identified to safely and reliably provide service to customers. The LTP is shared with the regional transmission planning process.

### *Regional Transmission Planning*

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

### *Interconnection-Wide Transmission Planning*

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

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

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

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

## Existing Transmission System

Idaho Power's transmission system extends from eastern Oregon through southern Idaho to western Wyoming and is composed of 115-, 138-, 161-, 230-, 345-, and 500-kV transmission facilities. The sets of lines that transmit power from one geographic area to another are known as transmission paths. There are defined transmission paths to other states and between the southern Idaho load centers mentioned previously in this chapter. Idaho Power's transmission system and paths are shown in Figure 6.1.

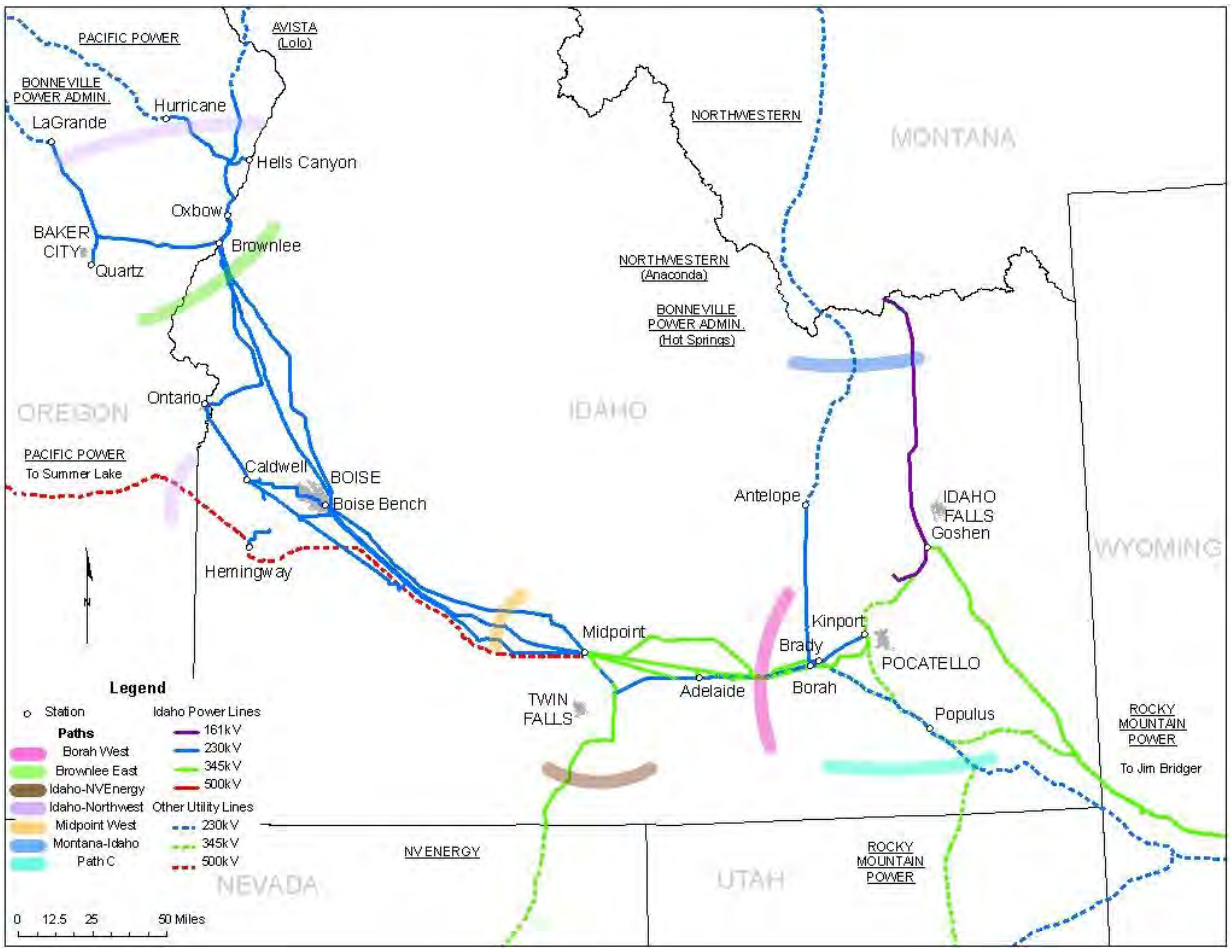



**Figure 6.1 Idaho Power transmission system map**

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 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. To access new resources, including market purchases, located west of the path, additional transmission capacity will be required to deliver the energy to Idaho Power's service area.

## Brownlee East Path

The Brownlee East transmission path is on the east side of the Idaho–Northwest Interconnection shown in Figure 6.1. Brownlee East is comprised of the 230-kV and 138-kV lines east of the HCC and Quartz Substation near Baker City, Oregon. When the Hemingway–Summer Lake 500-kV line is included with the Brownlee East path, the path is typically referred to as the

Brownlee East Total path. The 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 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 774 MW of the 2,400-MW east-to-west capacity. PacifiCorp owns the remaining capacity. The Bridger West path effectively feeds into the Borah West path when power is moving east to west from Jim Bridger; consequently, the import capability of the Bridger West path is limited by Borah West path capacity constraints.

### Idaho–Utah Path

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

**Table 6.1 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 | 383 | 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 available transmission capacity (ATC) as of April 1, 2015.

** 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

In the 2006 IRP process, Idaho Power identified the need for a transmission line to the Pacific Northwest electric market. At that time, a line interconnecting at the McNary Substation to the greater Boise area was included in IRP portfolios. Since its initial identification, the project has been refined and developed, including different terminus locations and sizing the project to economically meet projected demand. The project identified in 2006 has evolved into what is currently the B2H project. The project currently involves permitting, constructing, operating, and maintaining a new, single-circuit 500-kV transmission line approximately 300 miles long

between the proposed Longhorn Station in the Boardman, Oregon, area and the Hemingway Substation in 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 demands on the system continue to grow
- Assurance of Idaho Power's ability to meet customers' existing and future energy needs in Idaho and Oregon
- Flexibility to integrate renewable resources, respond to pending carbon legislation and more efficiently implement advanced market tools
- Flexibility to respond to the proposed CAA Section 111(d) requirements

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

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

**Table 6.2 B2H capacity and permitting cost allocation**

| | Idaho Power | BPA | PacifiCorp |
|---|---|---|---|
| Capacity (MW) west to east ..... | 350<br>200 winter/500 summer | 400<br>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 B2H options—to meet its load-service obligations in southeast Idaho. On October 2, 2012, BPA publically announced the preferred solution to be the B2H project.

The permitting phase of the B2H project is subject to review and approval by, among other government entities, the Bureau of Land Management (BLM), the US Forest Service (USFS), and the Oregon Department of Energy (ODOE). The federal permitting process is dictated primarily by the *Federal Land Policy Management Act* and *National Forest Management Act* and is subject to NEPA review. The BLM is the lead agency in administering the NEPA process for the B2H project. On December 19, 2014, BLM published the Draft Environmental Impact Statement (Draft EIS). Figure 6.2 shows the proposed transmission line routes included in the Draft EIS with the agency preferred route. Idaho Power expects the BLM to issue a Final EIS in 2016.

In late February 2013, Idaho Power submitted the preliminary Application for Site Certificate (pASC) to the ODOE as part of the state siting process. Idaho Power intends to submit an amended pASC in late 2015 or 2016.

In light of the permitting delays and siting impediments that have occurred and may occur, Idaho Power is unable to accurately determine an approximate in-service date for the line but expects the in-service date would be in 2021 or beyond. Additional project information is available at boardmantohemingway.com.

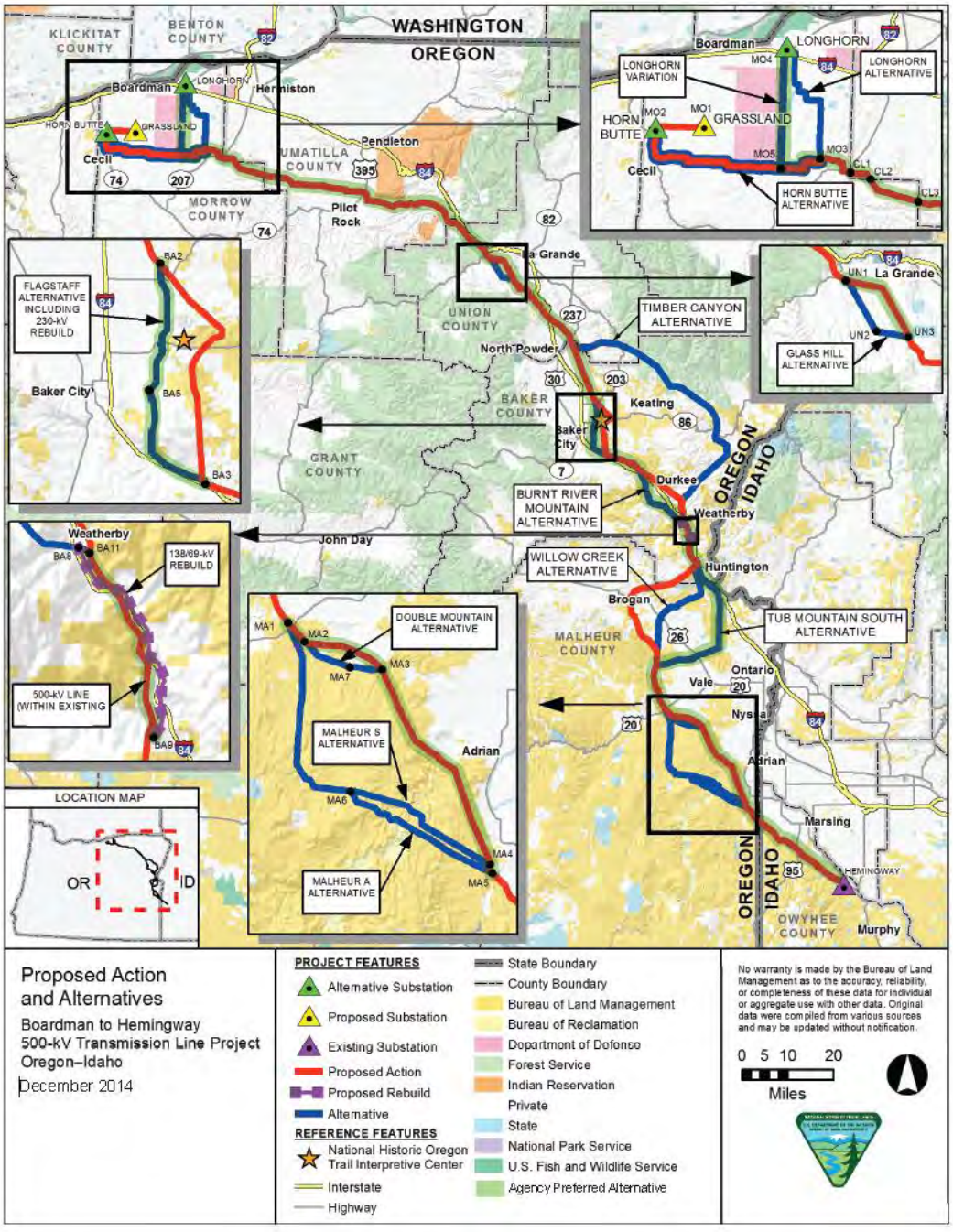



**Figure 6.2 B2H routes with the agency-preferred alternative**

# 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 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 (segment 6), which is an existing transmission line operated at 345-kV but constructed at 500-kV.




**Figure 6.3 Gateway West Map**

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

1. Relieve Idaho Power's constrained transmission system between the Magic Valley area (Midpoint) and the Treasure Valley area (Hemingway). Transmission connecting the Magic Valley and Treasure Valley is part of Idaho Power's "core" transmission system, connecting two major Idaho Power load pockets.

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

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

4. Transmission capability is needed to meet the transmission needs of the future, including transmission needs associated with intermittent resources.

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

The two transmission projects, B2H 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.

Under the federal permitting process established by NEPA, the BLM has completed the EIS for all segments of the Gateway West project except segment 8 (Midpoint to Hemingway) and segment 9 (Cedar Hill to Hemingway). The BLM is conducting a supplemental environmental analysis on these two segments. A final record of decision for these two segments is expected by late 2016, subject to permitting completion.

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

## Gateway West Need Analysis

Idaho Power has two internal transmission paths between the Magic Valley and Treasure Valley:

- Boise East
- Midpoint West

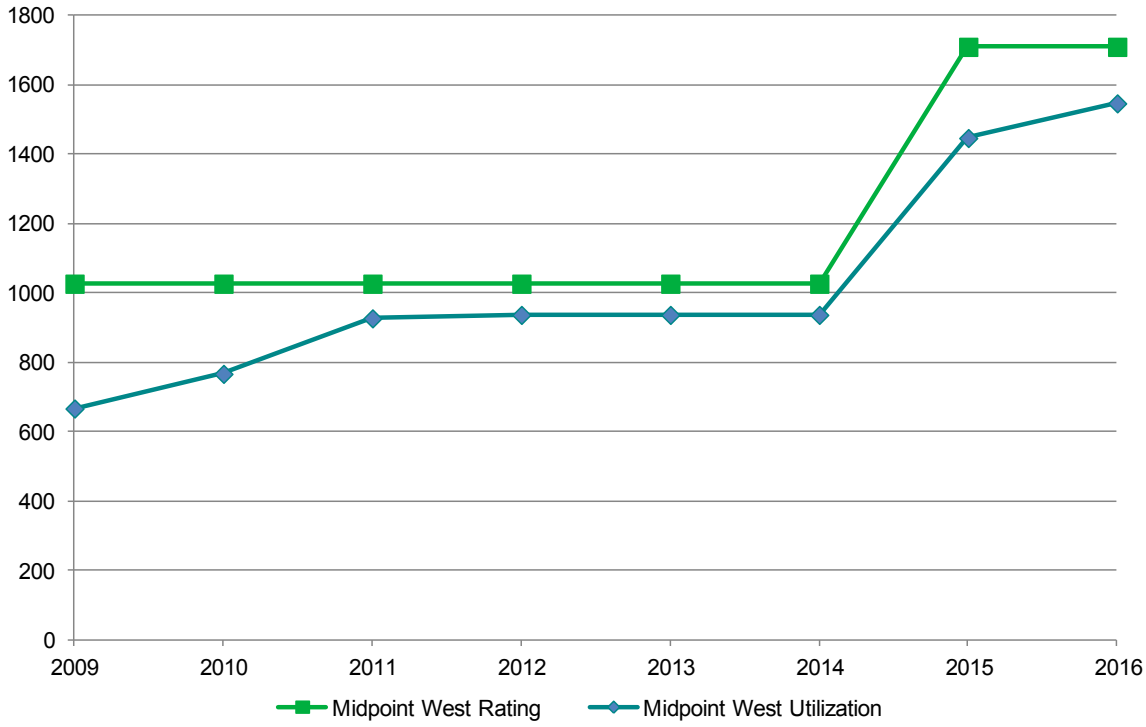
The Boise East transmission path consists of 230-kV, 138-kV and 69-kV transmission lines connecting the Mountain Home area to the Boise/Nampa/Caldwell area. This transmission path is currently being studied due to large amounts of solar generation proposed to be sited in and around the Mountain Home area. Gateway West will increase the capability of the Boise East path.

The Midpoint West transmission path consists of 230-kV and 138-kV transmission lines connecting the Magic Valley area to the Mountain Home area. The Midpoint West transmission path has a rating of 1,027 MW which will increase to 1,710 MW following two initiatives currently underway:

1. Idaho Power will expand the Midpoint West rating from 1,027 MW to 1,300 MW through incremental upgrades to existing transmission assets (230 kV and below). These upgrades are expected to be in service by the end of 2015.

2. Idaho Power has made arrangements to acquire an ownership share of the PacifiCorp-owned Midpoint–Hemingway 500-kV line, pending regulatory approval. Idaho Power's ownership share will equate to 410 MW of the 1,500-MW line rating. This is expected to be finalized by the end of 2015.

Over the past several years, Idaho Power's use of the Midpoint West transmission path has steadily increased. Figure 6.4 illustrates this increasing use.




**Note**: Large increases to the use of Midpoint West occurred in 2010 (PURPA Wind), 2011 (PURPA Wind), and 2015 (third-party transmission service). Use is also projected to increase in 2016 with the interconnection of 100 MW of solar in eastern Idaho.

**Figure 6.4 Midpoint West Historical Utilization**

The Midpoint West path will continue to be constrained following the upgrades described above. As the Boise East and Midpoint West paths become further used, Idaho Power will continue to invest in new transmission facilities to reinforce the transmission system. Gateway West is the planned upgrade that will increase the capability of the Midpoint West path.

## Transmission Assumptions in the IRP Portfolios

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



The 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 (incremental amounts) | Additional Transmission Requirements |
|---|---|---|---|
| B2H line | Hemingway Substation | 500 MW (summer)/ 200 MW (winter) | New 230-kV line from Hemingway to the Treasure Valley. |
| Gas turbine (SCCT) | Elmore County | 170 MW | New 230-kV substation and new 230-kV line to the Treasure Valley. |
| Gas turbine (CCCT) | Elmore County | 300 MW | New 230-kV substation and new 230-kV line to the Treasure Valley. |
| CHP | Canyon County | 45 MW | New 138-kV substation and new 138-kV line to existing 138-kV system. |
| Geothermal | Cassia County | 30 MW | New 138-kV line from resource to existing 138-kV substation. |
| Reciprocating engines | Distributed | 18 MW | No new transmission. New distribution upgrades assumed for each engine location. |
| PV | Elmore/Owyhee County | 10 MW | New 138-kV substation and new 138-kV line to existing 138-kV system. |
| Pumped storage hydro | Above Brownlee Reservoir | 300 MW | New 230-kV line from Oxbow to Treasure Valley, new 138-kV tap from site to existing 138-kV system. |

The assumptions about the geographic area where particular supply-side resources are developed determine the transmission upgrades required.

# 7. Planning Period Forecasts

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

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



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 2015 IRP.

## Load Forecast

Historically, Idaho Power has been a summer peaking utility with peak loads driven by irrigation pumps and A/C in 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 2015 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 retail 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 70$^{th}$-percentile and 90$^{th}$-percentile load forecasts were developed to assist Idaho Power in reviewing the resource requirements that would result from higher loads due to adverse weather conditions.

Idaho Power prepares a sales and load forecast each year as part of the company's annual financial forecast. The sales forecast is heavily influenced by the most recent economic forecast of national and regional economic activity developed by Moody's Analytics, Inc., a national econometric consulting firm. Moody's Analytics, Inc., July 2014 macroeconomic forecast strongly influenced the 2015 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, Inc., are also used in developing the 2015 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 were analyzed to address load variability due to weather—70$^{th}$-percentile and 90$^{th}$-percentile load forecasts. Seventieth percentile weather means that in 7 out of 10 years, load is expected to be less than forecast, and in 3 out of 10 years, load is expected to exceed the forecast. Ninetieth percentile load has a similar definition with a 1-in-10 likelihood the load will be greater than the forecast.

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

## Economic Effects

The national recession that began in 2008 affected the local economy and energy use in Idaho Power's service area. The severity of the recession resulted in a decline in new customer growth. 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 over 6,500.

Likewise, overall system sales declined by 3.8 percent in 2009, followed by a 0.9-percent decline 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 2000 to 2001. In 2012, 2013, and 2014, system electricity sales increased by 1.7 percent, 0.5 percent, and 1.0 percent, respectively. The sales increases were 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 residential customers in Idaho Power's service area is expected to increase 1.6 percent annually from 428,000 at the end of 2014 to nearly 591,000 by the end of the planning period in 2034. Growth in the number of customers within Idaho Power's service area, combined with an expected declining consumption per customer, results in a 1.3-percent average residential load-growth rate.

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 1.2 percent (over the period

2015 through 2034) is comprised of a residential load growth of 1.3 percent, a commercial load growth of 1.0 percent, an irrigation load growth of 0.5 percent, an industrial load growth of 2.0 percent, and an additional firm load growth of 0.6 percent.

The 2015 IRP average annual system load forecast reflects the continued improvement in the service-area economy. While economic conditions during the development of the 2013 IRP were positive, they were less optimistic than the actual performance experienced in the interim period leading up to the 2015 IRP. The improved economic and demographic variables driving the 2015 forecast are reflected by a more positive sales outlook throughout the planning period. The stalled recovery in the national and, to a lesser extent, service area economy caused load growth to stall through 2011. However, in 2012, the recovery was evident, with strength exhibited in most all economic time series. Retail electricity price projections for the 2015 IRP are lower relative to the 2013 IRP, serving to increase the forecast of average loads, especially in the second 10 years of the forecast period.

Significant factors and considerations that influenced the outcome of the 2015 IRP load forecast include the following:

- The load forecast used for the 2015 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, since 2011, residential and commercial customer growth along with housing and industrial activity, have shown signs of a meaningful and sustainable recovery. By 2017, 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 2015 IRP reflects the additional plant investment and variable costs of integrating the resources identified in the 2013 IRP preferred portfolio, including the expected costs of carbon emissions assumed for the 2013 IRP. When compared to the electricity price forecast used to prepare the 2013 IRP sales and load forecast, the 2015 IRP price forecast yields lower future prices. The retail prices are most evident in the second 10 years of the planning period and impact the sales forecast positively, a consequence of the inverse relationship between electricity prices and electricity demand.

- There continues to be significant uncertainty associated with the industrial and special-contract sales forecasts due to the number of parties that contact Idaho Power expressing interest in locating operations within Idaho Power's service area, typically with an unknown magnitude of the energy and peak-demand requirements. The 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 2015 irrigation sales forecast is higher than the 2013 IRP forecast throughout the entire forecast period due to the significant growth in the dairy industry, higher commodity prices, and changing crop-planting patterns. Following the dairy industry growth, there has been a trend toward more water-intensive crops, primarily alfalfa and corn. Farmers have also taken advantage of the commodities market by planting increasing levels of acreage. Additionally, the conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to farmers trying to reduce labor costs, explains most of the increased energy consumption in recent years.

- Updated loss factors were determined by Idaho Power's Customer Operations Planning department. The annual average energy loss coefficients are multiplied by the calendar-month load, yielding the system load, including losses. A system loss study of 2012 was completed in May 2014. The results of the study concluded that, on average, the loss coefficients are lower than those used in the 2013 IRP. This resulted in a permanent reduction of nearly 20 aMW to the load forecast annually.

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

Idaho Power's system peak-hour load record—3,407 MW—was recorded on July 2, 2013, at 4:00 p.m. The previous summer peak demand record was 3,245 MW on July 12, 2012, at 4:00 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 2015 IRP load forecast projects peak-hour load to grow by approximately 63 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 7.1 and Table 7.1 summarize three forecast outcomes of Idaho Power's estimated annual system peak load—median, 90$^{th}$ percentile, and 95$^{th}$ percentile. The 95$^{th}$-percentile forecast uses the 95$^{th}$-percentile peak-day average temperature to determine monthly peak-hour demand and serves as the planning criteria for determining the need for peak-hour capacity. The alternative scenarios are based on their respective peak-day average temperature probabilities to determine forecast outcomes.

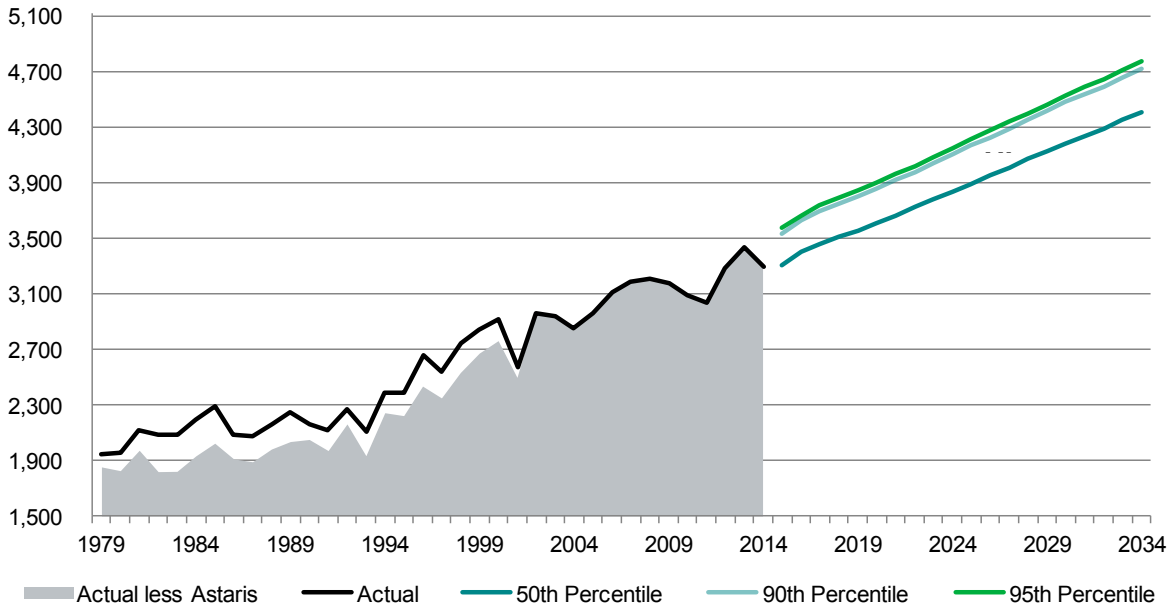



**Figure 7.1 Peak-hour load-growth forecast (MW)**

**Table 7.1 Load forecast—peak hour (MW)**

| Year | Median | 90th Percentile | 95th Percentile |
|---|---|---|---|
| 2014 (Actual) | 3,184 | 3,184 | 3,184 |
| 2015 | 3,313 | 3,537 | 3,576 |
| 2016 | 3,401 | 3,630 | 3,669 |
| 2017 | 3,463 | 3,696 | 3,736 |
| 2018 | 3,514 | 3,752 | 3,793 |
| 2019 | 3,562 | 3,805 | 3,847 |
| 2020 | 3,615 | 3,862 | 3,905 |
| 2021 | 3,670 | 3,922 | 3,965 |
| 2022 | 3,725 | 3,981 | 4,026 |
| 2023 | 3,780 | 4,041 | 4,086 |
| 2024 | 3,839 | 4,105 | 4,151 |
| 2025 | 3,897 | 4,168 | 4,215 |
| 2026 | 3,956 | 4,231 | 4,278 |
| 2027 | 4,013 | 4,293 | 4,341 |
| 2028 | 4,071 | 4,355 | 4,404 |
| 2029 | 4,130 | 4,419 | 4,469 |
| 2030 | 4,187 | 4,481 | 4,531 |
| 2031 | 4,242 | 4,540 | 4,592 |
| 2032 | 4,296 | 4,599 | 4,651 |
| 2033 | 4,352 | 4,659 | 4,713 |
| 2034 | 4,407 | 4,719 | 4,773 |
| **Growth rate (2015–2034)** | **1.5%** | **1.5%** | **1.5%** |

The median or expected case peak-hour load forecast predicts that peak-hour load will grow from 3,313 MW in 2015 to 4,407 MW in 2034—an average annual compound growth rate of 1.5 percent. The projected average annual compound growth rate of the 95th-percentile peak forecast is also 1.5 percent. In the 95th-percentile forecast, summer peak-hour load is expected to increase from 3,576 MW in 2015 to 4,773 MW in 2034. Historical peak-hour loads, as well as the three forecast scenarios, are shown in Figure 7.1.

Idaho Power's winter peak-hour load record is 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 three load forecasts that reflect load uncertainty resulting from different weather-related assumptions. Figure 7.2 and Table 7.2 show the results of the three forecasts used in the 2015 IRP as annual system load growth over the planning period. There is an approximately 50-percent probability Idaho Power's load will exceed the expected-case forecast, a 30-percent probability of load exceeding the 70th-percentile forecast, and a 10-percent probability of exceeding the 90th-percentile forecast. The projected 20-year average compound annual growth rate in each of the forecasts is 1.2 percent.

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

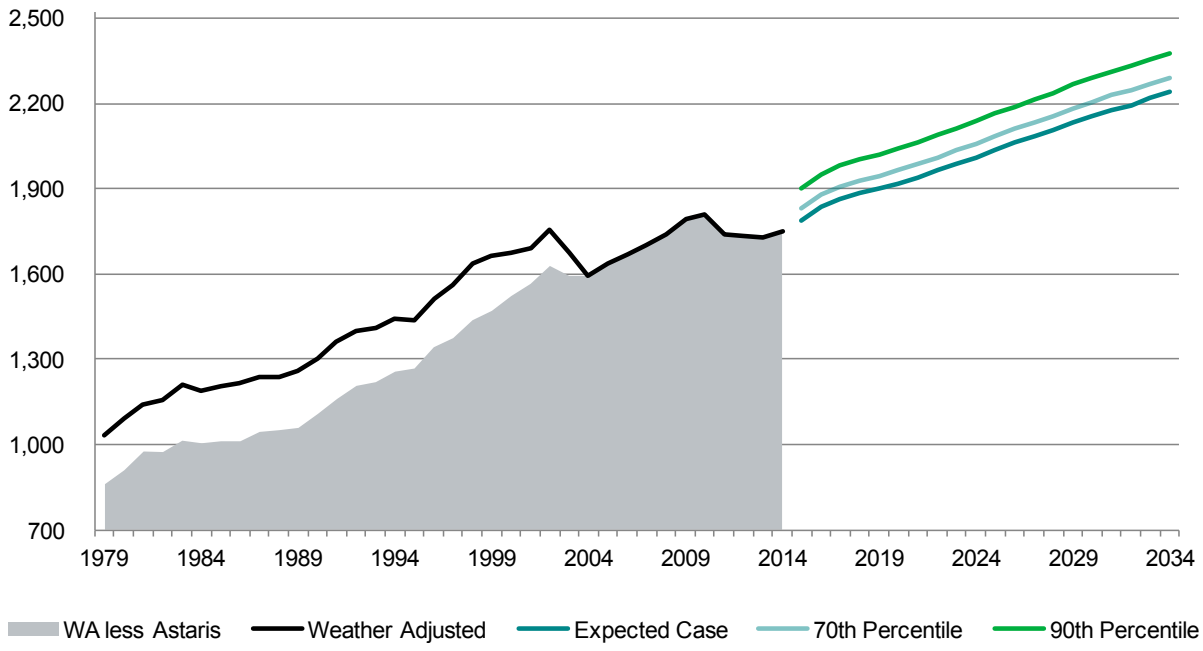



**Figure 7.2 Average monthly load-growth forecast (aMW)**

**Table 7.2 Load forecast—average monthly energy (aMW)**

| Year | Median | 70th Percentile | 90th Percentile |
|---|---|---|---|
| 2015 | 1,786 | 1,829 | 1,900 |
| 2016 | 1,835 | 1,878 | 1,950 |
| 2017 | 1,864 | 1,908 | 1,981 |
| 2018 | 1,883 | 1,928 | 2,002 |
| 2019 | 1,900 | 1,946 | 2,021 |
| 2020 | 1,918 | 1,964 | 2,040 |
| 2021 | 1,941 | 1,987 | 2,064 |
| 2022 | 1,964 | 2,011 | 2,088 |
| 2023 | 1,988 | 2,035 | 2,113 |
| 2024 | 2,012 | 2,059 | 2,139 |
| 2025 | 2,037 | 2,085 | 2,165 |
| 2026 | 2,061 | 2,110 | 2,190 |
| 2027 | 2,085 | 2,134 | 2,215 |
| 2028 | 2,107 | 2,156 | 2,238 |
| 2029 | 2,133 | 2,183 | 2,266 |
| 2030 | 2,156 | 2,206 | 2,290 |
| 2031 | 2,177 | 2,228 | 2,312 |
| 2032 | 2,195 | 2,246 | 2,331 |
| 2033 | 2,219 | 2,271 | 2,356 |
| 2034 | 2,240 | 2,292 | 2,378 |
| **Growth rate (2015–2034)** | **1.2%** | **1.2%** | **1.2%** |

## *Additional Firm Load*

The additional firm-load category consists of Idaho Power's largest customers. Idaho Power's tariff requires the company to serve requests for electric service greater than 20 MW under a special-contract schedule negotiated between Idaho Power and each large-power customer. The contract and tariff schedule are approved by the appropriate commission. A special contract allows a customer-specific cost-of-service analysis and unique operating characteristics to be accounted for in the agreement. A special contract also allows Idaho Power to provide requested service consistent with system capability and reliability. Idaho Power currently has three special-contract customers recognized as firm-load customers: Micron Technology, Simplot Fertilizer, and the INL. 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 through 2016, then stay flat throughout the remainder of the planning period.

### Idaho National Laboratory

The DOE provided an energy-consumption and peak-demand forecast through 2034 for the INL. The forecast calls for loads to slowly rise through 2021, rise dramatically through 2024, and stay near that higher level throughout the remainder of the forecast period.

## Generation Forecast for 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 provide a description of Idaho Power's hydroelectric, thermal, and transmission resources and how they are accounted for in the load and resource balance.



Swan Falls Dam.

### *Hydroelectric Resources*

For the 2015 IRP, Idaho Power continues using 70$^{th}$-percentile forecast streamflow conditions for the Snake River Basin as the basis for the projections of monthly average hydroelectric generation. The 70$^{th}$ 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 90$^{th}$-percentile streamflow conditions to project peak-hour hydroelectric generation. The 90$^{th}$ 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 2015 IRP is included in *Appendix C—Technical Appendix*.

A review of Snake River Basin streamflow trends suggests that persistent decline documented in the ESPA is mirrored by downward trends in total surface-water outflow from the river basin. The ESPA CAMP includes demand-reduction and weather-modification measures that will add new water to the basin water budget. Idaho Power believes the positive effect of the new water associated with the CAMP measures is likely to be temporary. The current water-use practices driving the steady decline over recent years are expected to continue, resulting in declining basin outflows assumed to persist well into the 2030s. The declining basin outflows for this IRP are assumed to continue through the planning period.



Oxbow Dam, part of the Hells Canyon Complex.

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 the 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 occur 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 2015 IRP. Augmentation water delivered from the Payette River Basin is assumed to remain in July and August.

The 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 from historical operation data.

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

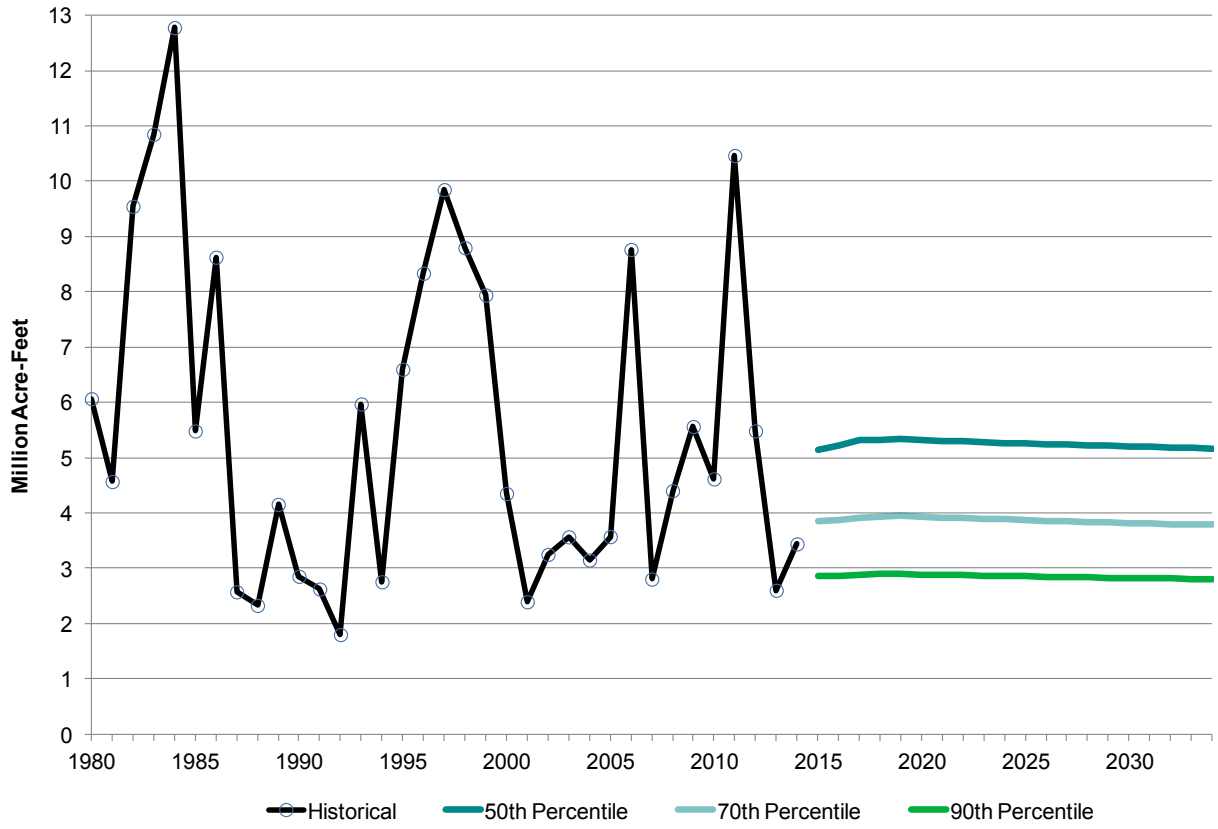



**Figure 7.3 Brownlee historical and forecast inflows**

Idaho Power recognizes the need to remain apprised of scientific advancements concerning climate change on a 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 2015 IRP. A more complete discussion of climate change and expectations of possible effects on Snake River water supply is available starting on page 64 of the IDACORP, Inc., 2014 Form 10-K.

## Coal Resources

Idaho Power's coal-fired generating facilities have typically operated as baseload resources. Monthly average-energy forecasts in the load and resource balance for the coal-fired projects are based on typical baseload output levels. 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*.

Major plant modifications or changes in plant operations required to maintain compliance with air-quality standards are projected for the Jim Bridger units in 2015, 2016, 2021, and 2022 due to the Regional Haze final rulemaking.

The 2015 IRP assumes Idaho Power's share of the Boardman plant will not be available for coal-fired operations after December 31, 2020. This date is the result of an agreement reached between the ODEQ and PGE related to compliance with Regional Haze rules on particulate matter, $SO_2$, and $NO_x$ emissions.

## Coal Analysis

Idaho Power prepared an initial coal study as part of the *2011 IRP Update*, and the report was filed with the IPUC and OPUC in February 2013. The 2011 study evaluated several investment alternatives, including converting coal units to burn natural gas, installing SCR or selective non-catalytic reduction (SNCR), and scrubber additions. The study recommended installing SCR on Jim Bridger units 3 and 4 in 2015 and 2016, respectively. Since the completion of that initial coal study, the company has continued to monitor the costs and benefits associated with the SCR investments for Jim Bridger units 3 and 4 to ensure those investments remain cost-effective. An update to the economic analysis of the Bridger 3 and 4 SCR investments that supports the continued installation of the SCRs for those units is presented in *Appendix C—Technical Appendix* of the 2015 IRP.

There are no further environmental investment action items required by state or federal regulators prior to preparing and filing the 2017 IRP. In addition, there have been no material changes in the underlying forecast assumptions from the 2011 study. The company will evaluate investment alternatives for SCRs at Jim Bridger units 1 and 2 no later than the 2017 IRP.

Idaho Power seeks to balance the impacts of carbon regulation with the economic impact to customers, as well as customer needs for reliable service. For the 2015 IRP, the company applied a more dynamic economic analysis of the existing coal units compared to prior IRPs. The 2015 IRP evaluated numerous portfolios that included coal unit shutdowns on various dates. The company believes the termination of operations at its coal-fired plants in the very near future would lead to an increased risk of higher costs for customers in the near-term without a commensurate long-term economic benefit. The company is mindful that an early retirement of an asset requires accelerating the recovery of the remaining investment in that asset. This increases the cost in the early years to achieve longer-term savings.

Idaho Power has been in discussions with the joint owner of the North Valmy plant regarding the future of that plant. State public utility commissions and Idaho Power's customers expect future costs to be mitigated and balanced with future risks. Cost and risk will continue to be important factors in the utilities' discussions and decision processes.

Idaho Power currently benefits from the diversity of its generation resources, and that diversity helps mitigate the power supply cost risk borne by customers as the company transitions to the new energy landscape.

### Natural Gas Resources

Idaho Power owns and operates four natural gas-fired SCCTs and one natural gas-fired CCCT. The SCCT units are typically operated during peak load events in 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.

## Natural Gas Price Forecast

Future natural gas price assumptions significantly influence the financial results of the operational modeling used to evaluate and rank resource portfolios. For the 2015 IRP, Idaho Power is using the US Energy Information Administration (EIA) natural gas price forecast. Idaho Power also used the EIA as the source for the natural gas price forecast for the 2013 IRP and continues to use the EIA forecast for Idaho-jurisdiction avoided cost-calculation purposes. The natural gas price forecast was discussed during the first three monthly IRPAC meetings held in August through October 2014. During these discussions, Idaho Power provided comparisons of the EIA natural gas price forecast to an alternative forecast, as well as comparisons to observed settlement prices for futures trading in the natural gas market.

The *Annual Energy Outlook 2014*, published by the EIA in April 2014, is the source for the natural gas price forecast for the 2015 IRP. For the 2015 IRP, Idaho Power uses nominal prices, as published by the EIA, as inputs to the analysis performed. Figure 7.4 shows forecast Henry Hub natural gas prices. The low- and high-case natural gas price forecasts used for the 2015 IRP and shown on the chart correspond respectively to the high resource (high availability) and low resource (low availability) cases reported by the EIA in the *Annual Energy Outlook 2014*. Idaho Power applies a Sumas basis and transportation cost to the Henry Hub price to derive an Idaho Citygate price. The Idaho Citygate price is representative of the gas price delivered to Idaho Power's natural gas plants. The Idaho Citygate price forecast is provided in *Appendix C—Technical Appendix*.

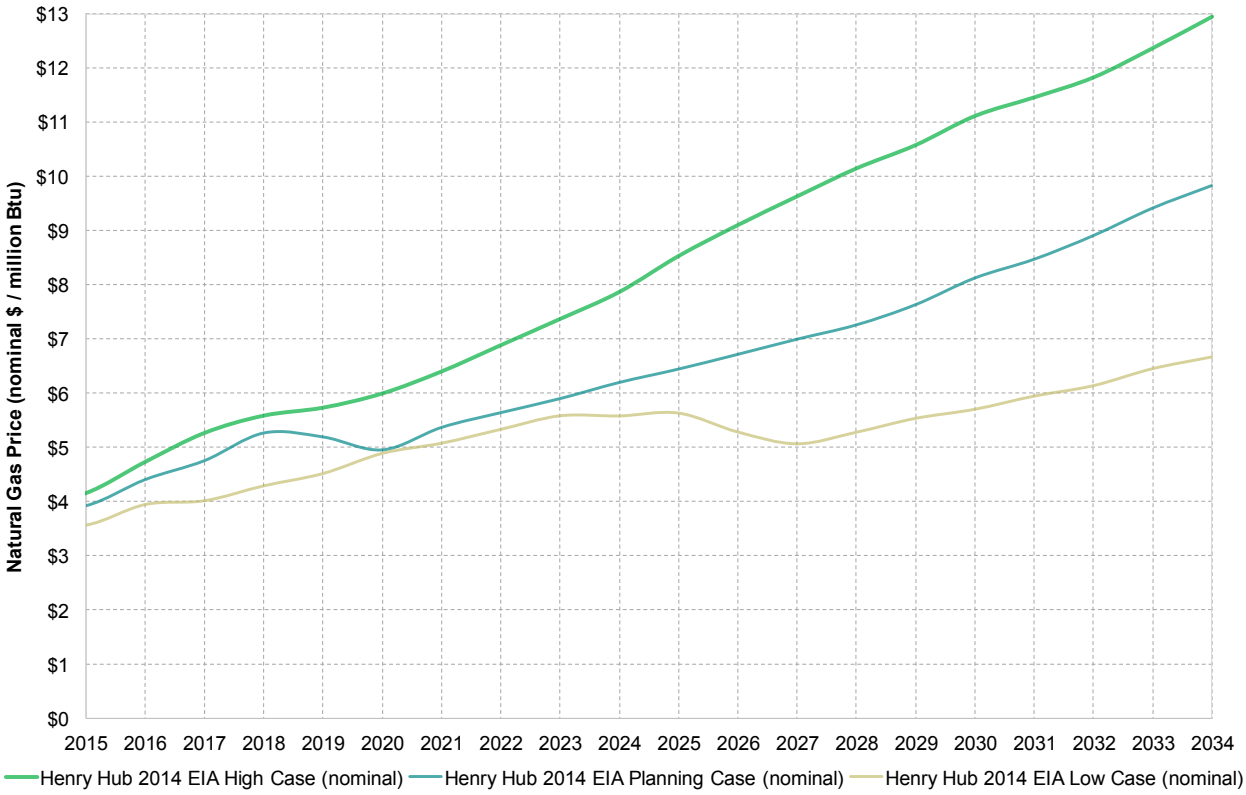



**Figure 7.4 Henry Hub price forecast—EIA *Annual Energy Outlook 2014* (nominal dollars)**

## Resource Cost Analysis

A comparative cost analysis of a variety of supply-side and demand-side resources was conducted as part of resource screening for the 2015 IRP. As described previously, cost inputs and operating data used to develop the resource cost analysis were derived from the September 2014 Lazard report, Idaho Power engineering studies and operating experience, and consultation with specific resource developers. Resource costs are presented as follows:

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

- *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 capital cost of solar PV resources has been the subject of considerable IRPAC discussions over recent IRPs. As widely reported, solar PV costs have declined markedly over recent years, presenting unique challenges in determining appropriate costs for solar resources. For the 2015 IRP, Idaho Power used the Lazard report's projected 2017 capital cost of $1,250 per kW for utility-scale, single-axis tracking solar PV resources. To further capture reported trends in solar PV capital costs, the 2015 IRP capital cost of $1,250 per kW was not escalated according to the IRP's assumed level of inflation, as the capital costs for other considered resources were.

For the 2015 IRP, Idaho Power is including in resource cost calculations the assumption that potential IRP resources have varying economic life. Financial analyses for the IRP assume the annual depreciation expense of capital costs is based on an apportioning of the capital costs over the entire economic life of a given resource.

The levelized costs for the various supply-side alternatives include capital costs, O&M costs, fuel costs, and other applicable adders and credits. The initial capital investment and associated capital costs 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 transmission interconnection to Idaho Power's network system. The capital costs also include an allowance for funds used during construction (AFUDC) (capitalized interest). The O&M portion of each resource's levelized cost includes general estimates for property taxes and property insurance premiums. The value of RECs is not included in the levelized cost estimates but is accounted for when analyzing the total cost of each resource portfolio.

The 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*.

# 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 the assumed economic life and are presented in terms of dollars per kW of plant nameplate capacity per month. Included in these levelized fixed costs are the initial resource investment and associated capital cost and fixed O&M estimates. As noted earlier, resources are considered to have varying economic life, and the financial analysis to determine the annual depreciation of capital costs is based on an apportioning of the capital costs over the entire economic life. Figure 7.5 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 natural gas peaking resources and demand response are the lowest capacity-cost alternatives. The natural gas peaking resources have high operating costs, but operating costs are less important for resources intended for use only during a limited number of hours per year to meet peak-hour demand.

## *Levelized Cost of Production*

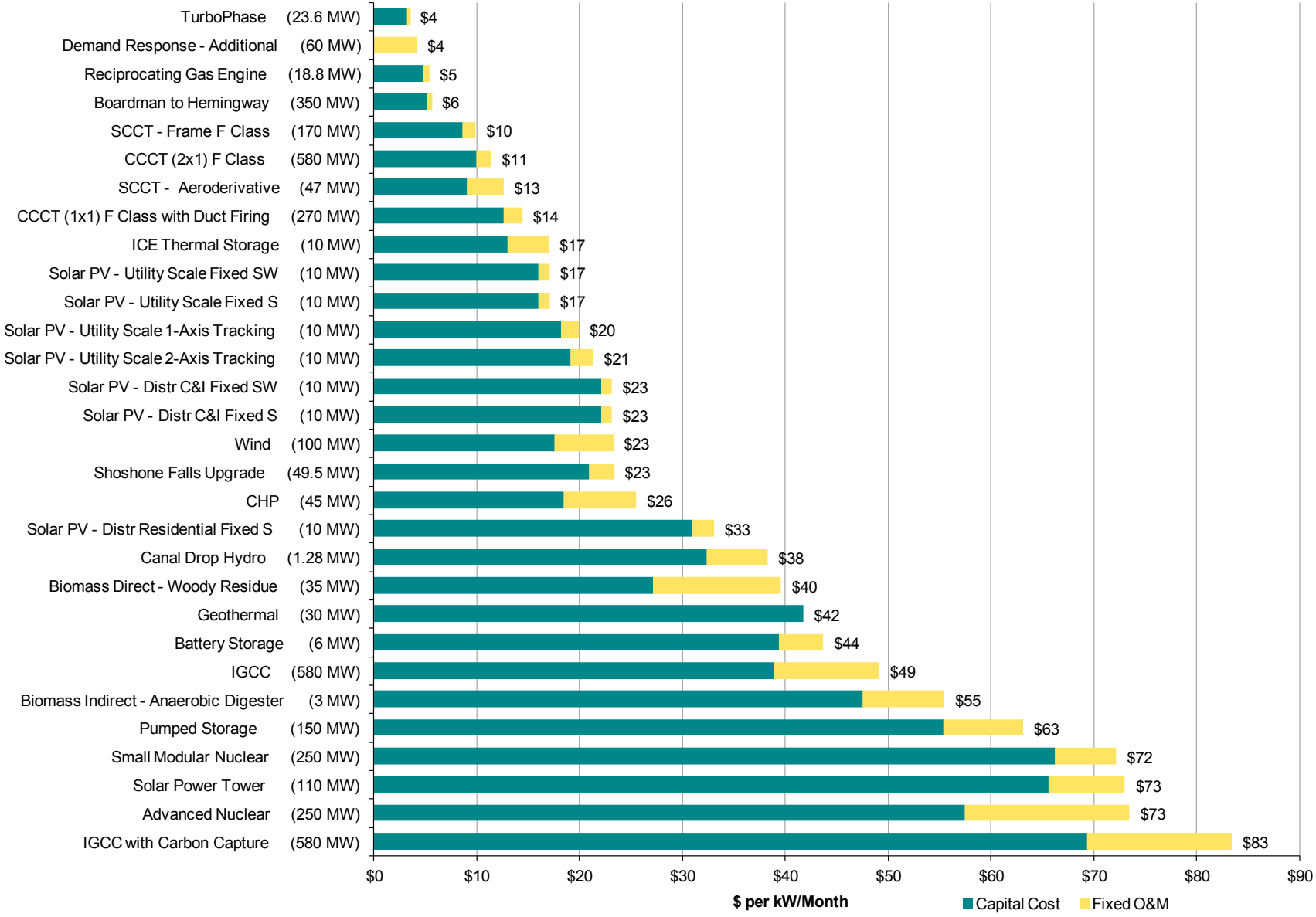
Certain resource alternatives carry low fixed costs and high variable operating costs, while other alternatives require significantly higher capital investment and fixed operating costs but have low variable operating costs. The levelized cost-of-production measurement represents the estimated annual cost (revenue requirements) per MWh in nominal dollars for a resource based on an expected level of energy output (capacity factor) over the economic life of the resource.

The nominal, levelized cost of production assuming the expected capacity factors for each resource type is shown in Figure 7.6. Included in these costs are the capital cost, non-fuel O&M, fuel, and emissions adders; however, no value for RECs was assumed in this analysis. The B2H transmission line is among the lowest-cost resources 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.

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


TurboPhase (23.6 MW) $4
Demand Response - Additional (60 MW) $4
Reciprocating Gas Engine (18.8 MW) $5
Boardman to Hemingway (350 MW) $6
SCCT - Frame F Class (170 MW) $10
CCCT (2x1) F Class (580 MW) $11
SCCT - Aeroderivative (47 MW) $13
CCCT (1x1) F Class with Duct Firing (270 MW) $14
ICE Thermal Storage (10 MW) $17
Solar PV - Utility Scale Fixed SW (10 MW) $17
Solar PV - Utility Scale Fixed S (10 MW) $17
Solar PV - Utility Scale 1-Axis Tracking (10 MW) $20
Solar PV - Utility Scale 2-Axis Tracking (10 MW) $21
Solar PV - Distr C&I Fixed SW (10 MW) $23
Solar PV - Distr C&I Fixed S (10 MW) $23
Wind (100 MW) $23
Shoshone Falls Upgrade (49.5 MW) $23
CHP (45 MW) $26
Solar PV - Distr Residential Fixed S (10 MW) $33
Canal Drop Hydro (1.28 MW) $38
Biomass Direct - Woody Residue (35 MW) $40
Geothermal (30 MW) $42
Battery Storage (6 MW) $44
IGCC (580 MW) $49
Biomass Indirect - Anaerobic Digester (3 MW) $55
Pumped Storage (150 MW) $63
Small Modular Nuclear (250 MW) $72
Solar Power Tower (110 MW) $73
Advanced Nuclear (250 MW) $73
IGCC with Carbon Capture (580 MW) $83
$0 $10 $20 $30 $40 $50 $60 $70 $80 $90
$ per kW/Month
Capital Cost
Fixed O&M

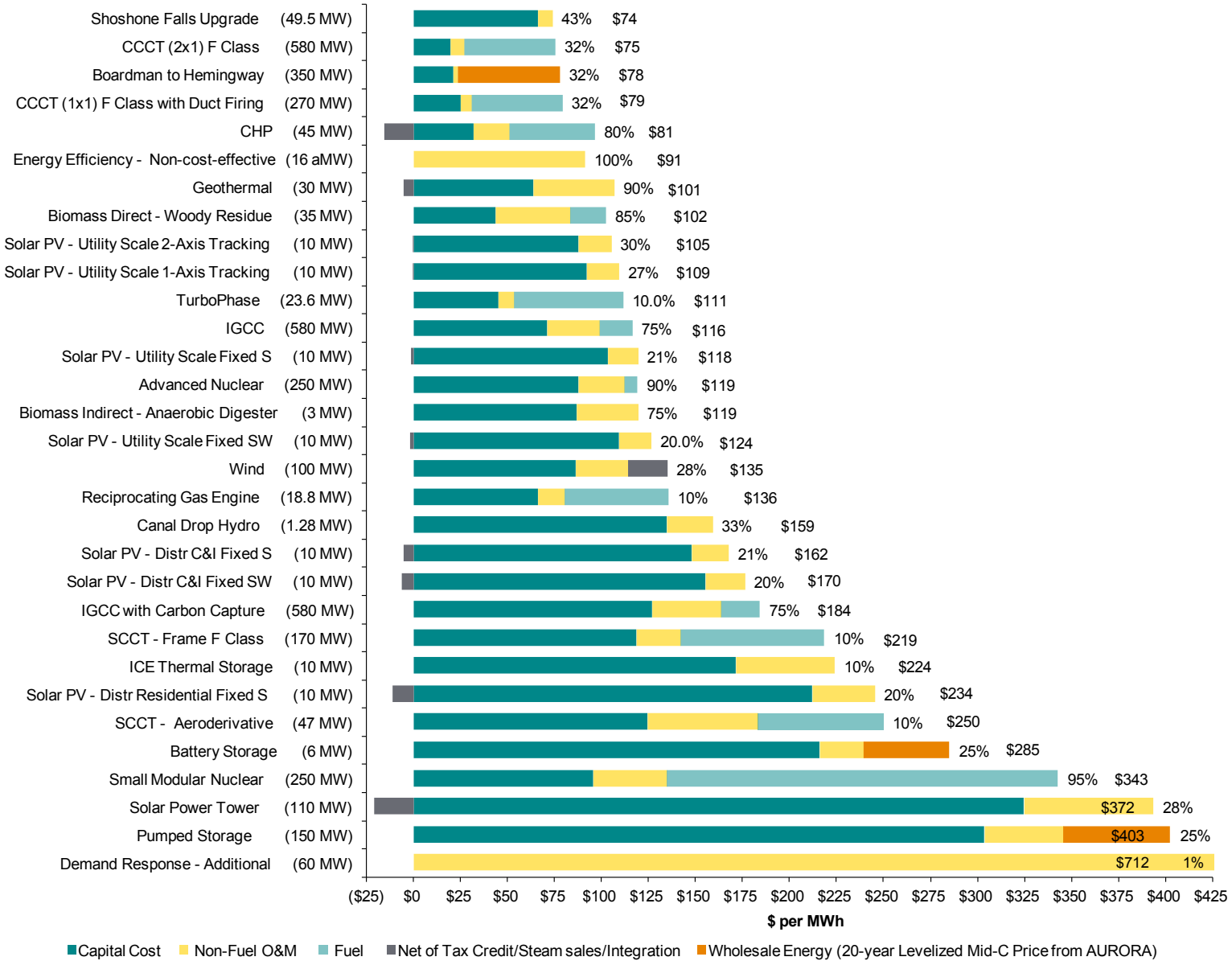



**Figure 7.6 30-year levelized cost of production (at stated capacity factors)**

## Supply-Side Resource Costs

Idaho Power prefers to use independent estimates of the supply-side resource costs when the estimates are available. For the 2015 IRP, Idaho Power used the 2014 Lazard report as the primary source for supply-side resource costs. Idaho Power engineering studies and plant operating experience were also used. Costs for select resources not provided by the Lazard report and for which Idaho Power has limited engineering and operating experience were determined through consultation with specific resource developers.

The 2015 IRP forecasts load growth in Idaho Power's service area and identifies supply-side resources and demand-side measures necessary to meet the future energy needs of customers. The 2015 IRP has identified periods of future system deficiencies. New resource costs are levelized estimates (based on expected annual generation) that include capital, fuel, and non-fuel O&M. Figure 7.7 shows the capital costs in nominal dollars per kW for a new resource with a 2020 online date plotted against peak-hour capacity for various supply-side resources considered in the 2015 IRP. The on-line date of 2020 is used because, depending on the coal-retirement scenario, the earliest date for new resources in the 2015 IRP is 2020. The use of the 2020 on-line date also allows projected 2015 to 2016 capital-cost declines in utility-scale PV solar to be captured in the plotted data.

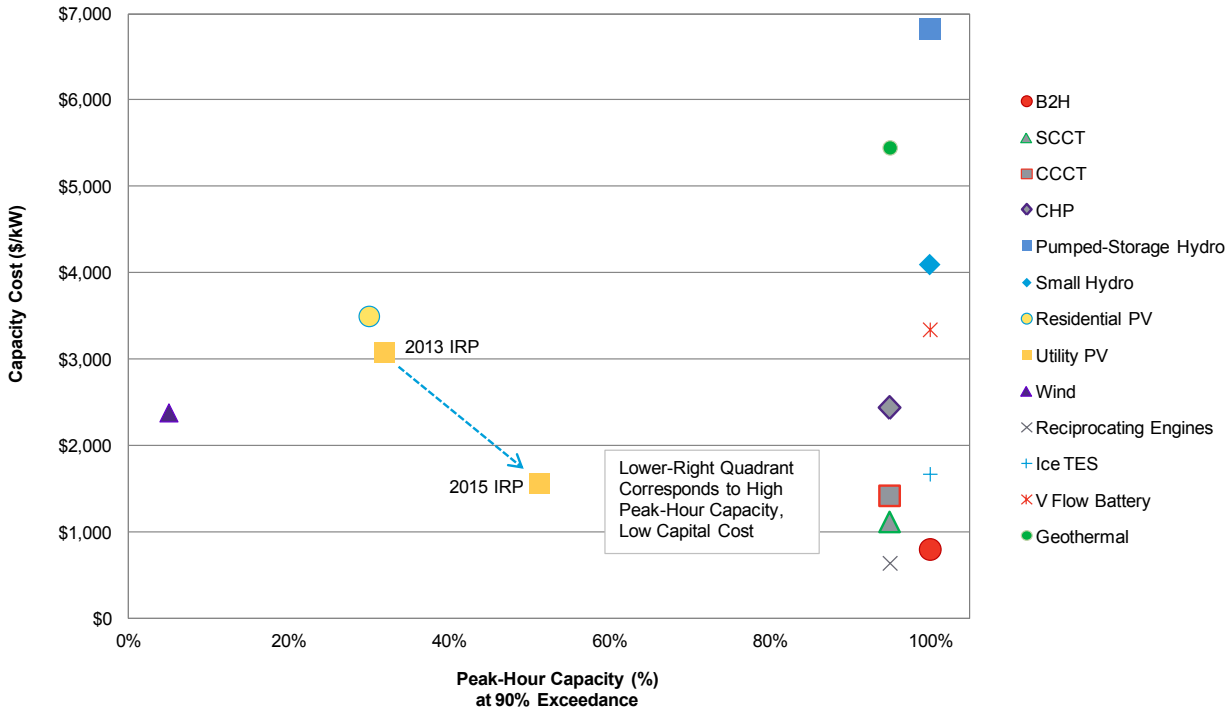



**Figure 7.7 Capacity cost of new supply-side resources, online 2020**

Resources in the lower-right portion of Figure 7.7 are considered to provide peak-hour capacity at a relatively low capital cost. Among the resources in the lower-right portion, the B2H transmission line and various natural-gas fired generating resources provide the highest peak-hour capacity at the lowest cost. Ice-based TES also appears in the lower-right portion as a relatively low-cost capacity resource. The dashed arrow on the figure represents the notable shift in assumptions since the 2013 IRP for utility-scale PV solar. The marked decline in PV solar

capital costs has been extensively reported over recent years. The shift in peak-hour capacity is based on an analysis performed for the 2015 IRP indicating peak-hour capacity slightly in excess of 50 percent of nameplate capacity for single-axis PV solar power plants. This analysis is described in Chapter 5.

While it is important to evaluate the costs presented in Figure 7.7, these costs represent only part of the 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; supply-side resources have different operating characteristics, making some better suited for meeting capacity needs, while others are better for providing energy.

Figure 7.8 shows the levelized cost of energy in dollars per MWh for various new supply-side resources considered in the 2015 IRP, where costs considered include those related to building and operating the resource for a 20-year period. The data used to create Figure 7.8 allows for resource alternatives to be compared based on the capacity cost and the total levelized cost of production.

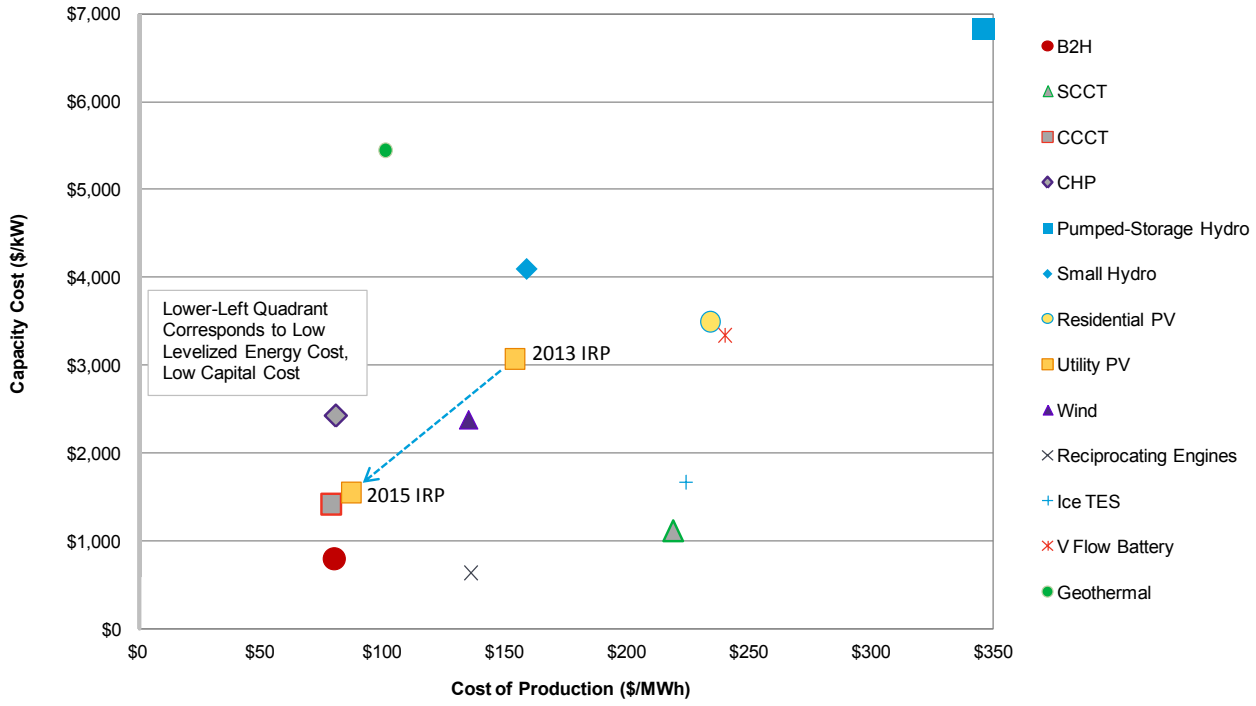



**Figure 7.8 Energy cost of new supply-side resources**

Resources in the lower-left portion of Figure 7.8 produce (or deliver) energy at a low levelized cost and have a relatively low capital cost. The B2H transmission line is among those resources having low levelized costs and low capital costs. Figures 7.7 and 7.8 respectively demonstrate that the B2H transmission line is attractive as a capacity resource (i.e., one needed relatively infrequently) and energy resource (i.e., one needed for frequent energy delivery). In contrast, a SCCT has competitive costs with respect to the relatively infrequent delivery of capacity (Figure 7.7) but is much less competitive when required to deliver energy (Figure 7.8). The dashed line represents the capital-cost decrease observed in utility-scale PV solar since 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. Due to the uncertainty of the CAA Section 111(d) regulation, many different assumptions can be made for the future of Idaho Power's coal resources. To address these different coal futures, Idaho Power analyzed nine load and resource balance scenarios:

- **Status Quo:** The first scenario assumes Idaho Power makes no changes in the operations of its coal fleet. This scenario is very similar to the load and resource balance provided in the 2013 IRP and is designed to provide a basis for comparison.

- **Maintain Coal Capacity**: The second scenario assumes Idaho Power will maintain its coal fleet but reduce emissions output in compliance with the proposed CAA Section 111(d) regulation by limiting or capping the amount generators can run.

- **Retire North Valmy Coal Plant:** A third set of scenarios assumes varying timing dates for the retirement of units 1 and 2 of the North Valmy coal plant. There are four scenarios that reflect possible retirement dates for units 1 and 2 of North Valmy:

    - Retire units 1 and 2 by the end of 2019

    - Retire units 1 and 2 by the end of 2025

    - Retire Unit 1 by the end of 2019 and Unit 2 by the end of 2025

    - Retire Unit 1 by the end of 2021 and Unit 2 by the end of 2025

- **Retire units 1 and 2 of Jim Bridger Coal Plant:** Two sets of scenarios assume different retirement dates for units 1 and 2 of the Jim Bridger coal plant. There are a total of four units at Jim Bridger, and units 3 and 4 are not being considered for retirement.

    - Retire Unit 1 by the end of 2023 and Unit 2 by the end of 2028

    - Retire Unit 1 by the end of 2023 and Unit 2 by the end of 2032

- **Retire North Valmy Coal Plant and units 1 and 2 of Jim Bridger Coal Plant:** A final scenario assumes the retirement of units 1 and 2 of North Valmy coal plant by the end of 2025, retirement of Unit 1 of Jim Bridger coal plant by the end of 2023, and retirement of Unit 2 of Jim Bridger by the end of 2032.

Each scenario will include a load and resource balance using average monthly energy planning assumptions and peak-hour planning assumptions.

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

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

All load and resource balances, irrespective of the coal future under consideration, include the following:

- Existing demand reduction due to the demand response programs and the forecast effect of existing energy efficiency programs.

- Existing PPAs with Elkhorn Valley Wind, Raft River Geothermal, and Neal Hot Springs. Idaho Power's agreement with Elkhorn Valley Wind expires at the end of 2027. The other agreements do not expire within the planning period.

- Firm Pacific Northwest import capability. This does not include the import capacity from the B2H transmission line or the Gateway West transmission line.

- Expected generation from all Idaho Power-owned resources. The Boardman coal plant has a planned retirement date of 2020.

- Existing PURPA projects and contracts completed by October 31, 2014, including 461 MW of solar projects under contract but not yet operational. (Contracts for four solar projects totaling 141 MW of installed capacity were terminated on April 6, 2015. The relatively late termination date precludes the removal of these projects from the load and resource balance analysis for the 2015 IRP.) Idaho Power assumes all PURPA contracts, with the exception of wind projects, will continue to deliver energy throughout the planning period, and the renewal of contracts will be consistent with PURPA rules and regulations existing at the time the new contracts are negotiated. Wind projects are not expected to be renewed. There is a total of 627 MW of wind under contract. Wind contracts begin to expire in October 2025, and the total wind under contract drops to 130 MW at the end of the planning period.

At times of peak summer load, Idaho Power is using all ATC from the Pacific Northwest. If Idaho Power encountered a significant outage at one of its main generation facilities or a transmission interruption on one of the main import paths, the company would fail to meet reserve requirement standards. If Idaho Power was unable to meet reserve requirements, the company would be required to shed load by initiating rolling blackouts. Although infrequent, Idaho Power has initiated rolling blackouts in the past during emergencies. Idaho Power has

committed to a build program, including demand-side programs, generation, and transmission resources, to reliably meet customer demand and minimize the likelihood of events that would require the implementation of rolling blackouts.

Idaho Power's customers reach a maximum energy demand in the summer. From a resource adequacy perspective, July has historically been the month during which Idaho Power's system is most constrained. Based on projections for the 2015 IRP, July is likely to remain the most resource-constrained month. A secondary maximum energy demand occurs during the winter in the month of December. Tables 7.3 and 7.4 provide for July and December the monthly average-energy deficits for each of the coal futures considered in the 2015 IRP. Darker shading in the tables corresponds with larger deficits. Surplus positions are not specified in the tables. Because no deficits exist prior to 2020, the tables include data for only the period 2020 to 2034.

**Table 7.3 July monthly average energy deficits (average MW) by coal future with existing and committed supply- and demand-side resources (70th-percentile water and 70th-percentile load)**

| Energy Deficits (aMW) | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Status Quo | – | – | – | – | – | – | – | – | – | – | – | (1) | (52) | (121) | (145) |
| Maintain Coal Capacity | – | – | – | – | – | – | – | – | – | (3) | (69) | (135) | (186) | (255) | (279) |
| Valmy Retire Units 1 and 2 Year–End 2019 | – | – | – | – | – | – | (34) | (59) | (112) | (149) | (186) | (251) | (303) | (371) | (396) |
| Valmy Retire Units 1 and 2 Year–End 2025 | – | – | – | – | – | – | (34) | (59) | (112) | (149) | (186) | (251) | (303) | (371) | (396) |
| Valmy Retire Unit 1 Year–End 2019 and Unit 2 Year–End 2025 | – | – | – | – | – | – | (34) | (59) | (112) | (149) | (186) | (251) | (303) | (371) | (396) |
| Valmy Retire Unit 1 Year–End 2021 and Unit 2 Year–End 2025 | – | – | – | – | – | – | (34) | (59) | (112) | (149) | (186) | (251) | (303) | (371) | (396) |
| Bridger Retire Unit 1 Year–End 2023 and Unit 2 Year–End 2028 | – | – | – | – | – | (3) | (51) | (76) | (129) | (329) | (395) | (460) | (511) | (580) | (605) |
| Bridger Retire Unit 1 Year–End 2023 and Unit 2 Year–End 2032 | – | – | – | – | – | (3) | (51) | (76) | (129) | (166) | (232) | (298) | (349) | (580) | (605) |
| Bridger Retire Unit 1 Year–End 2023 and Unit 2 Year–End 2032, Valmy Retire Units 1 and 2 Year–End 2025 | – | – | – | – | – | (3) | (197) | (222) | (275) | (312) | (349) | (414) | (465) | (697) | (721) |

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

| Energy Deficits (aMW) | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Status Quo | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – |
| Maintain Coal Capacity | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – |
| Valmy Retire Units 1 and 2 Year-End 2019 | – | – | – | – | – | – | – | – | – | – | – | – | – | (16) | (35) |
| Valmy Retire Units 1 and 2 Year-End 2025 | – | – | – | – | – | – | – | – | – | – | – | – | – | (16) | (35) |
| Valmy Retire Unit 1 Year-End 2019 and Unit 2 Year-End 2025 | – | – | – | – | – | – | – | – | – | – | – | – | – | (16) | (35) |
| Valmy Retire Unit 1 Year-End 2021 and Unit 2 Year-End 2025 | – | – | – | – | – | – | – | – | – | – | – | – | – | (16) | (35) |
| Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2028 | – | – | – | – | – | – | – | – | – | (32) | (64) | (149) | (180) | (239) | (259) |
| Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2032 | – | – | – | – | – | – | – | – | – | – | – | – | (17) | (239) | (259) |
| Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2032, Valmy Retire Units 1 and 2 Year-End 2025 | – | – | – | – | – | – | – | – | – | – | (3) | (88) | (119) | (341) | (361) |

Tables 7.5 and 7.6 provide the peak-hour capacity deficits for July and December for the coal futures considered. Darker shading in the tables corresponds to larger deficits. Surplus positions are not specified in the tables. Because no deficits exist prior to 2020, the tables include data only for 2020 to 2034.

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

| Energy Deficits (aMW) | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Status Quo | – | – | – | – | – | (14) | (61) | (136) | (175) | (224) | (316) | (352) | (426) | (491) | (523) |
| Maintain Coal Capacity | – | – | – | – | – | (14) | (61) | (136) | (175) | (224) | (316) | (352) | (426) | (491) | (523) |
| Valmy Retire Units 1 and 2 Year-End 2019 | (24) | (141) | (143) | (176) | (236) | (277) | (324) | (399) | (438) | (487) | (579) | (615) | (689) | (754) | (786) |
| Valmy Retire Units 1 and 2 Year-End 2025 | – | – | – | – | – | (14) | (324) | (399) | (438) | (487) | (579) | (615) | (689) | (754) | (786) |
| Valmy Retire Unit 1 Year-End 2019 and Unit 2 Year-End 2025 | – | (9) | (11) | (44) | (105) | (145) | (324) | (399) | (438) | (487) | (579) | (615) | (689) | (754) | (786) |
| Valmy Retire Unit 1 Year-End 2021 and Unit 2 Year-End 2025 | – | – | (11) | (44) | (105) | (145) | (324) | (399) | (438) | (487) | (579) | (615) | (689) | (754) | (786) |
| Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2028 | – | – | – | – | (149) | (190) | (236) | (312) | (350) | (576) | (667) | (703) | (777) | (842) | (874) |
| Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2032 | – | – | – | – | (149) | (190) | (236) | (312) | (350) | (400) | (491) | (527) | (601) | (842) | (874) |
| Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2032, Valmy Retire Units 1 and 2 Year-End 2025 | – | – | – | – | (149) | (190) | (499) | (575) | (613) | (663) | (754) | (790) | (864) | (1,105) | (1,137) |

**Table 7.6 December monthly peak-hour capacity deficits (MW) by coal future with existing and committed supply- and demand-side resources (90th-percentile water and 95th-percentile load)**

| Energy Deficits (aMW) | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Status Quo | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – |
| Maintain Coal Capacity | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – |
| Valmy Retire Units 1 and 2 Year-End 2019 | – | – | – | – | – | – | (12) | (32) | (59) | (58) | (99) | (129) | (158) | (187) | (165) |
| Valmy Retire Units 1 and 2 Year-End 2025 | – | – | – | – | – | – | (12) | (32) | (59) | (58) | (99) | (129) | (158) | (187) | (165) |
| Valmy Retire Unit 1 Year-End 2019 and Unit 2 Year-End 2025 | – | – | – | – | – | – | (12) | (32) | (59) | (58) | (99) | (129) | (158) | (187) | (165) |
| Valmy Retire Unit 1 Year-End 2021 and Unit 2 Year-End 2025 | – | – | – | – | – | – | (12) | (32) | (59) | (58) | (99) | (129) | (158) | (187) | (165) |
| Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2028 | – | – | – | – | – | – | – | – | – | (147) | (188) | (218) | (247) | (276) | (254) |
| Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2032 | – | – | – | – | – | – | – | – | – | – | (12) | (42) | (71) | (276) | (254) |
| Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2032, Valmy Retire Units 1 and 2 Year-End 2025 | – | – | – | – | – | – | (187) | (207) | (235) | (234) | (275) | (305) | (334) | (539) | (517) |

# 8. PORTFOLIO SELECTION

## Portfolio Design

In the 2015 IRP, Idaho Power continued the 2013 IRP's practice of analyzing a range of coal-retirement portfolios. The consideration of additional early coal retirement, or early shutdown portfolios is consistent with expectations expressed by the IPUC in its Acceptance of Filing order for the 2013 IRP (Case No. IPC-E-13-15, Order No. 32980). The 23 portfolios analyzed for the 2015 IRP can be grouped into the following 10 categories. All portfolios are assumed to have SCR installation for Jim Bridger units 3 and 4 completed by 2016.

1. **Status quo portfolio**—A single resource portfolio with no additional retirement of coal-fired generating units other than Boardman in 2020 and without output constraints related to the proposed CAA Section 111(d) regulation. The status quo portfolio relies on the B2H transmission line and reciprocating gas engines to meet future resource needs.

   All other portfolios considered in the 2015 IRP assume compliance with CAA Section 111(d) based on various assumptions regarding what the final regulation will contain.

2. **Maintain coal capacity portfolios**—A set of three portfolios with no retirement of coal capacity during the IRP planning period with the exception of the planned 2020 year-end Boardman shutdown.

3. **North Valmy retirement year-end 2019 portfolios**—A set of five portfolios with the retirement of both North Valmy units at year-end 2019.

4. **North Valmy retirement year-end 2025 portfolios**—A set of three portfolios with the retirement of both North Valmy units at year-end 2025.

5. **North Valmy staggered retirement year-end 2019 (Unit 1) and year-end 2025 (Unit 2) portfolios**—A set of two portfolios with retirement of North Valmy Unit 1 at year-end 2019 and Unit 2 at year-end 2025.

6. **North Valmy staggered retirement year-end 2021 (Unit 1) and year-end 2025 (Unit 2) portfolio**—A single portfolio with the retirement of North Valmy Unit 1 at year-end 2021 and Unit 2 at year-end 2025.

7. **Jim Bridger staggered retirement year-end 2023 (Unit 1) and year-end 2032 (Unit 2) portfolios**—A set of two portfolios with the retirement of Jim Bridger Unit 1 at year-end 2023 and Unit 2 at year-end 2032. The early retirement of these portfolios is assumed to allow avoiding installation of SCRs for Unit 1 in 2022 and Unit 2 in 2021.

8. **Jim Bridger staggered retirement year-end 2023 (Unit 1) and year-end 2028 (Unit 2) portfolio**—A single portfolio with the retirement of Jim Bridger Unit 1 at year-end 2023 and Unit 2 at year-end 2028. The early retirement of this portfolio is assumed to allow avoiding installation of SCRs for Unit 1 in 2022 and Unit 2 in 2021.

9. **Jim Bridger staggered retirement year-end 2023 (Unit 1) and year-end 2032 (Unit 2), North Valmy retirement year-end 2025 portfolio**—A single portfolio with the retirement of Jim Bridger Unit 1 at year-end 2023 and Unit 2 at year-end 2028, and the retirement of both North Valmy units at year-end 2025. The early Jim Bridger retirement in this portfolio is assumed to allow avoiding installation of SCRs for Unit 1 in 2022 and Unit 2 in 2021.

10. **Alternative to B2H portfolios**—A set of four portfolios in which the B2H transmission line is replaced by alternative resources. Except for this set of portfolios, all other 2015 IRP portfolios have the B2H transmission line.

The coal-retirement portfolios include the additional cost of recovering the remaining investment in the coal units prior to retirement. In addition, resource retirement includes the accelerated decommissioning costs when estimating the resource portfolio costs.

The coal-retirement portfolios also include the cost savings associated with early investment recovery and shutdown. These savings include avoided future capital investments, fixed operating costs, and avoided ROI. Treatment of the fixed-cost accounting is summarized in Table 8.1.

**Table 8.1 Fixed-cost impacts of coal retirement**

| Fixed-Cost Description | Cost Impact |
|---|---|
| Accelerated recovery of depreciation expense on remaining investments | Cost |
| Utility rate of return applied over a shorter life | Savings |
| Accelerated recovery of decommissioning and demolition costs (net of salvage) | Cost |
| Avoidance of future incremental capital (including avoidance of environmental retrofit investments) | Savings |
| Avoidance of future fixed operating expenses | Savings |

## Portfolio Design and Selection

Idaho Power analyzed 23 resource portfolios for the 2015 IRP. All portfolios are designed to balance forecast load with available or additional resources to eliminate energy and capacity deficits according to the IRP planning criteria described in Chapter 7. The energy and capacity deficits for the considered coal-retirement futures are also provided in Chapter 7. The portfolios were designed in collaboration with the IRPAC and public participants in the IRP process.

### *Status Quo Portfolio*

The resource additions in the status quo portfolio are driven by the need to eliminate peak-hour capacity deficits beginning in July 2025 and reaching 523 MW by July 2034. The status quo portfolio is designated as resource portfolio P1.

### P1

**Table 8.2 Resource portfolio P1**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2034 | Reciprocating engines | 36 MW | 36 MW |
| | | Total retired capacity | (0 MW) |
| | | Total added capacity | 536 MW |
| | | Net peak-hour capacity | 536 MW |

## *Maintain Coal Capacity Portfolios*

Resource additions of the set of portfolios with coal capacity maintained, excepting the planned Boardman shutdown, are driven by capacity deficits beginning in July 2025 and reaching 523 MW by July 2034. These portfolios differ from P1 only in the assumed on-line date for B2H, ranging from 2021 to 2025. The portfolios are designated as resource portfolios P2(a), P2(b), and P2(c).

### P2(a)

**Table 8.3 Resource portfolio P2(a)**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2034 | Reciprocating engines | 36 MW | 36 MW |
| | | Total retired capacity | (0 MW) |
| | | Total added capacity | 536 MW |
| | | Net peak-hour capacity | 536 MW |

### P2(b)

**Table 8.4 Resource portfolio P2(b)**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2023 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2034 | Reciprocating engines | 36 MW | 36 MW |
| | | Total retired capacity | (0 MW) |
| | | Total added capacity | 536 MW |
| | | Net peak-hour capacity | 536 MW |

### P2(c)

**Table 8.5 Resource portfolio P2(c)**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2021 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2034 | Reciprocating engines | 36 MW | 36 MW |
| | | Total retired capacity | (0 MW) |
| | | Total added capacity | 536 MW |
| | | Net peak-hour capacity | 536 MW |

## *North Valmy Retirement Year-End 2019 Portfolios*

Resource additions for portfolios with North Valmy retirement in 2019 are driven by capacity deficits beginning in July 2020 and reaching 786 MW by July 2034. These resource portfolios are designated as P3, P4(a), P4(b), P4(c), and P5. The P4 portfolios differ primarily in the assumed on-line date for B2H, ranging from 2021 to 2025.

### P3

The resource portfolio P3 adds 60 MW of ice-based TES and 330 MW of utility-scale, single-axis PV solar in the early 2020s and the B2H transmission line in 2025. In 2033, 75 MW of additional utility-scale, single-axis PV solar is added. P3 also adds energy efficiency beyond the amount identified as cost-effective in the DSM potential study included in all portfolios. The extra energy efficiency ramps gradually during the IRP planning period, reaching 16 MW of average energy and 24 MW of peak-hour capacity by 2034.

**Table 8.6 Resource portfolio P3**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2019 | Retire North Valmy (both units) | (262 MW) | (262 MW) |
| 2020 | Ice-based TES | 25 MW | 25 MW |
| 2021 | Ice-based TES | 35 MW | 35 MW |
| 2021 | Utility-scale solar PV 1-axis | 150 MW | 77 MW |
| 2023 | Utility-scale solar PV 1-axis | 180 MW | 92 MW |
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2033 | Utility-scale solar PV 1-axis | 75 MW | 38 MW |
| 2034 | Reciprocating engines | 36 MW | 36 MW |
| 2020–34 | Energy efficiency* | N/A | 24 MW |
| | | Total retired capacity | (262 MW) |
| | | Total added capacity | 827 MW |
| | | Net peak-hour capacity | 550 MW |

*Note: Extra energy efficiency is beyond the cost-effective amount determined by the DSM potential study.

## P4(a)

The resource portfolio P4(a) adds 60 MW of Vanadium redox flow battery storage and 198 MW of reciprocating engines in the early 2020s prior to the B2H transmission line in 2025. The 60 MW of battery storage are replaced in 2030 to 2031 with new battery storage, followed by the addition of 54 MW of reciprocating engines in 2033.

**Table 8.7 Resource portfolio P4(a)**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2019 | Retire North Valmy (both units) | (262 MW) | (262 MW) |
| 2020 | Vanadium redox flow battery storage | 25 MW | 25 MW |
| 2021 | Vanadium redox flow battery storage | 35 MW | 35 MW |
| 2021 | Reciprocating engines | 90 MW | 90 MW |
| 2023 | Reciprocating engines | 108 MW | 108 MW |
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2030 | 2020 battery storage end of life | (25 MW) | (25 MW) |
| 2030 | Vanadium redox flow battery storage (replace) | 25 MW | 25 MW |
| 2030 | 2021 battery storage end of life | (35 MW) | (35 MW) |
| 2031 | Vanadium redox flow battery storage (replace) | 35 MW | 35 MW |
| 2033 | Reciprocating engines | 54 MW | 54 MW |
| | | Total retired capacity | (322 MW) |
| | | Total added capacity | 872 MW |
| | | Net peak-hour capacity | 550 MW |

## P4(b)

The resource portfolio P4(a) adds 60 MW of Vanadium redox flow battery storage, 90 MW of reciprocating engines in 2020 to 2021, and the B2H transmission line in 2023. The 60 MW of battery storage is replaced in 2030 to 2031 with additional battery storage, followed by the addition of 162 MW of reciprocating engines in 2032 to 2034.

**Table 8.8 Resource portfolio P4(b)**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2019 | Retire North Valmy (both units) | (262 MW) | (262 MW) |
| 2020 | Vanadium redox flow battery storage | 25 MW | 25 MW |
| 2021 | Vanadium redox flow battery storage | 35 MW | 35 MW |
| 2021 | Reciprocating engines | 90 MW | 90 MW |
| 2023 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2030 | 2020 battery storage end of life | (25 MW) | (25 MW) |
| 2030 | Vanadium redox flow battery storage (replace) | 25 MW | 25 MW |
| 2030 | 2021 battery storage end of life | (35 MW) | (35 MW) |
| 2031 | Vanadium redox flow battery storage (replace) | 35 MW | 35 MW |

**Table 8.8 Resource portfolio P4(b) (continued)**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2032 | Reciprocating engines | 54 MW | 54 MW |
| 2033 | Reciprocating engines | 72 MW | 72 MW |
| 2034 | Reciprocating engines | 36 MW | 36 MW |
| | | Total retired capacity | (322 MW) |
| | | Total added capacity | 872 MW |
| | | Net peak-hour capacity | 550 MW |

## P4(c)

Portfolio P4(c) adds 25 MW of Vanadium redox flow battery storage in 2020 and the B2H transmission line in 2021. The portfolio also includes 35 MW of Vanadium redox flow battery storage added in 2029, with 25 MW of battery storage replacement in 2030. Reciprocating engines totaling 252 MW are added in the early 2030s.

**Table 8.9 Resource portfolio P4(c)**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2019 | Retire North Valmy (both units) | (262 MW) | (262 MW) |
| 2020 | Vanadium redox flow battery storage | 25 MW | 25 MW |
| 2021 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2029 | Vanadium redox flow battery storage | 35 MW | 35 MW |
| 2030 | Reciprocating engines | 36 MW | 36 MW |
| 2030 | 2020 battery storage end of life | (25 MW) | (25 MW) |
| 2030 | Vanadium redox flow battery storage (replace) | 25 MW | 25 MW |
| 2031 | Reciprocating engines | 108 MW | 108 MW |
| 2033 | Reciprocating engines | 108 MW | 108 MW |
| | | Total retired capacity | (287 MW) |
| | | Total added capacity | 837 MW |
| | | Net peak-hour capacity | 550 MW |

## P5

Resource portfolio P5 adds a 300-MW CCCT in 2020 and the B2H transmission line in 2025.

**Table 8.10 Resource portfolio P5**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2019 | Retire North Valmy (both units) | (262 MW) | (262 MW) |
| 2020 | CCCT | 300 MW | 300 MW |
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| | | Total retired capacity | (262 MW) |
| | | Total added capacity | 800 MW |
| | | Net peak-hour capacity | 538 MW |

## North Valmy Retirement Year-End 2025 Portfolios

Portfolios with North Valmy retirement in 2025 experience capacity deficits beginning in July 2025 and reaching 786 MW by July 2034. These resource portfolios are designated as P6, P6(b), and P7.

### P6

Resource portfolio P6 adds the B2H transmission line in 2025 prior to retiring North Valmy at year-end 2025. A 300-MW CCCT is added in 2030.

**Table 8.11 Resource portfolio P6**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2025 | Retire North Valmy (both units) | (262 MW) | (262 MW) |
| 2030 | CCCT | 300 MW | 300 MW |
| | | Total retired capacity | (262 MW) |
| | | Total added capacity | 800 MW |
| | | Net peak-hour capacity | 538 MW |

### P6(b)

Resource portfolio P6(b) is a variation of P6 that includes in 2030 60 MW of demand response and 20 MW of ice-based TES, allowing the 300-MW CCCT to be deferred by one year to 2031. The 60 MW of demand response is above and beyond the 390 MW of summer demand response included as an existing resource in all portfolios.

**Table 8.12 Resource portfolio P6(b)**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2025 | Retire North Valmy (both units) | (262 MW) | (262 MW) |
| 2030 | Demand response | 60 MW | 60 MW |
| 2030 | Ice-based TES | 20 MW | 20 MW |
| 2031 | CCCT | 300 MW | 300 MW |
| | | Total retired capacity | (262 MW) |
| | | Total added capacity | 880 MW |
| | | Net peak-hour capacity | 618 MW |

### P7

Resource portfolio P7 adds the B2H transmission line in 2025 prior to retiring North Valmy at year-end 2025. A 300 MW pumped-storage hydro project is added in 2030.

**Table 8.13 Resource portfolio P7**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2025 | Retire North Valmy (both units) | (262 MW) | (262 MW) |
| 2030 | Pumped-storage hydro | 300 MW | 300 MW |
| | | Total retired capacity | (262 MW) |
| | | Total added capacity | 800 MW |
| | | Net peak-hour capacity | 538 MW |

## *North Valmy Staggered Retirement Year-End 2019 (Unit 1) and Year-End 2025 (Unit 2) Portfolios*

Resource additions of portfolios with North Valmy retirement in 2019 (Unit 1) and 2025 (Unit 2) are driven by capacity deficits beginning in July 2021 and reaching 786 MW by July 2034. The portfolios of this set are designated P8 and P9.

### P8

Resource portfolio P8 adds 60 MW of ice-based TES and 70 MW of utility-scale, single-axis PV solar in 2021 to 2024 and the B2H transmission line in 2025. P8 adds 45 MW of canal hydro in 2031 and 126 MW of reciprocating engines in 2032 to 2033. Equivalent to resource portfolio P3, portfolio P8 also adds energy efficiency beyond the amount identified as cost-effective in the DSM potential study. The extra energy efficiency ramps gradually during the IRP planning period, reaching 16 MW of average energy and 24 MW of peak-hour capacity by 2034.

**Table 8.14 Resource portfolio P8**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2019 | Retire North Valmy (Unit 1) | (126 MW) | (126 MW) |
| 2021 | Ice-based TES | 15 MW | 15 MW |
| 2023 | Ice-based TES | 30 MW | 30 MW |
| 2024 | Utility-scale solar PV 1-axis | 70 MW | 36 MW |
| 2024 | Ice-based TES | 15 MW | 15 MW |
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2025 | Retire North Valmy (Unit 2) | (136 MW) | (136 MW) |
| 2031 | Canal hydro | 45 MW | 45 MW |
| 2032 | Reciprocating engines | 72 MW | 72 MW |
| 2033 | Reciprocating engines | 54 MW | 54 MW |
| 2020-34 | Energy efficiency* | N/A | 24 MW |
| | | Total retired capacity | (262 MW) |
| | | Total added capacity | 791 MW |
| | | Net peak-hour capacity | 529 MW |

*Note: Extra energy efficiency beyond cost-effective amount determined by DSM potential study.

### P9

The resource portfolio P9 adds 60 MW of demand response in 2021-24. The 60 MW of demand response is above and beyond the 390 MW of summer demand response included as an existing resource in all portfolios. P9 also adds 54 MW of reciprocating engines in 2024. The B2H transmission line is added in 2025, followed by 18 MW of reciprocating engines in 2031 and a 170-MW SCCT in 2032.

**Table 8.15 Resource portfolio P9**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2019 | Retire North Valmy (Unit 1) | (126 MW) | (126 MW) |
| 2021 | Demand response | 15 MW | 15 MW |
| 2023 | Demand response | 30 MW | 30 MW |
| 2024 | Reciprocating engines | 54 MW | 54 MW |
| 2024 | Demand response | 15 MW | 15 MW |
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2025 | Retire North Valmy (Unit 2) | (136 MW) | (136 MW) |
| 2031 | Reciprocating engines | 18 MW | 18 MW |
| 2032 | SCCT | 170 MW | 170 MW |
| | | Total retired capacity | (262 MW) |
| | | Total added capacity | 802 MW |
| | | Net peak-hour capacity | 540 MW |

## *Jim Bridger Staggered Retirement Year-End 2023 (Unit 1) and Year-End 2032 (Unit 2) Portfolios*

The resource additions to portfolios with Jim Bridger retirement in 2023 (Unit 1) and 2032 (Unit 2) are driven by peak-hour capacity deficits beginning in July 2024 and reaching 874 MW by July 2034. These resource portfolios are designated as P10 and P11.

### P10

The resource portfolio P10 adds a 170-MW SCCT in 2024 and the B2H transmission line in 2025. P10 adds a 300-MW CCCT in 2033.

**Table 8.16 Resource portfolio P10**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2023 | Retire Jim Bridger (Unit 1) | (177 MW) | (177 MW) |
| 2024 | SCCT | 170 MW | 170 MW |
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2032 | Retire Jim Bridger (Unit 2) | (176 MW) | (176 MW) |
| 2033 | CCCT | 300 MW | 300 MW |
| | | Total retired capacity | (353 MW) |
| | | Total added capacity | 970 MW |
| | | Net peak-hour capacity | 617 MW |

### P11

Resource portfolio P11 adds 60 MW of ice-based TES, 155 MW of utility-scale, single-axis PV solar in 2024, and the B2H transmission line in 2025. P11 also adds 180 MW of reciprocating engines and a 45-MW CHP facility in 2033. Like portfolios P3 and P8, P11 also adds energy efficiency beyond the amount identified as cost-effective in the DSM potential study. The extra energy efficiency ramps gradually during the IRP planning period, reaching 16 MW of average energy and 24 MW of peak-hour capacity by 2034.

**Table 8.17 Resource portfolio P11**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2023 | Retire Jim Bridger (Unit 1) | (177 MW) | (177 MW) |
| 2024 | Ice-based TES | 60 MW | 60 MW |
| 2024 | Utility-scale solar PV 1-axis | 155 MW | 80 MW |
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2032 | Reciprocating engines | 108 MW | 108 MW |
| 2032 | Retire Jim Bridger (Unit 2) | (176 MW) | (176 MW) |
| 2033 | CHP | 45 MW | 45 MW |
| 2033 | Reciprocating engines | 36 MW | 36 MW |
| 2034 | Reciprocating engines | 36 MW | 36 MW |
| 2020-34 | Energy efficiency* | N/A | 24 MW |
| | | Total retired capacity | (353 MW) |
| | | Total added capacity | 889 MW |
| | | Net peak-hour capacity | 536 MW |

*Note: Extra energy efficiency is beyond the cost-effective amount determined by the DSM potential study.

## *Jim Bridger Staggered Retirement Year-End 2023 (Unit 1) and Year-End 2028 (Unit 2) Portfolio*

The resource additions to portfolios with Jim Bridger retirement in 2023 (Unit 1) and 2028 (Unit 2) are driven by capacity deficits beginning in July 2024 and reaching 874 MW by July 2034. This resource portfolio is designated as P12.

### P12

The resource portfolio P12 adds a 170-MW SCCT in 2024 and the B2H transmission line in 2025. P12 also adds a 300-MW CCCT in 2029.

**Table 8.18 Resource portfolio P12**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2023 | Retire Jim Bridger (Unit 1) | (177 MW) | (177 MW) |
| 2024 | SCCT | 170 MW | 170 MW |
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2028 | Retire Jim Bridger (Unit 2) | (176 MW) | (176 MW) |
| 2029 | CCCT | 300 MW | 300 MW |
| | | Total retired capacity | (353 MW) |
| | | Total added capacity | 970 MW |
| | | Net peak-hour capacity | 617 MW |

## *Jim Bridger Staggered Retirement Year-End 2023 (Unit 1) and Year-End 2032 (Unit 2), North Valmy Retirement Year-End 2025 Portfolio*

The resource additions to the portfolio with Jim Bridger retirement in 2023 (Unit 1) and 2032 (Unit 2), and North Valmy retirement in 2025, are driven by capacity deficits beginning in July 2024 and reaching 1,137 MW by July 2034. This resource portfolio is designated as P13.

### P13

Resource portfolio P13 adds a 170-MW SCCT in 2024 and the B2H transmission line in 2025. P13 also adds a 300-MW CCCT in 2029 and a second CCCT in 2033.

**Table 8.19 Resource portfolio P13**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2023 | Retire Jim Bridger (Unit 1) | (177 MW) | (177 MW) |
| 2024 | SCCT | 170 MW | 170 MW |
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2025 | Retire North Valmy (both units) | (262 MW) | (262 MW) |
| 2029 | CCCT | 300 MW | 300 MW |
| 2032 | Retire Jim Bridger (Unit 2) | (176 MW) | (176 MW) |
| 2033 | CCCT | 300 MW | 300 MW |
| | | Total retired capacity | (615 MW) |
| | | Total added capacity | 1,270 MW |
| | | Net peak-hour capacity | 655 MW |

## *Alternative to B2H Portfolios*

This set of four portfolios replaces the B2H transmission line with alternatives. Each B2H alternative portfolio assumes a different coal-retirement future. Resource portfolio P14 assumes coal capacity is maintained. Resource portfolio P15 assumes North Valmy retirement in 2019. Resource portfolio P16 assumes the staggered retirement of North Valmy units 1 and 2 in 2019 and 2025, respectively. Resource portfolio P17 assumes the staggered retirement of Jim Bridger units 1 and 2 in 2023 and 2032, respectively.

## P14

Resource portfolio P14 adds 60 MW of ice-based TES in 2025 to 2026, 18 MW of reciprocating engines in 2026, a 300-MW CCCT in 2027, and a 170-MW SCCT in 2032.

**Table 8.20 Resource portfolio P14**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2025 | Ice-based TES | 15 MW | 15 MW |
| 2026 | Ice-based TES | 45 MW | 45 MW |
| 2026 | Reciprocating engines | 18 MW | 18 MW |
| 2027 | CCCT | 300 MW | 300 MW |
| 2032 | SCCT | 170 MW | 170 MW |
| | | Total retired capacity | (0 MW) |
| | | Total added capacity | 548 MW |
| | | Net peak-hour capacity | 548 MW |

## P15

Resource portfolio P15 adds 60 MW of Vanadium redox flow battery storage in 2020 to 2021 and 252 MW of reciprocating engines in 2020 to 2025. P15 also adds a 170-MW SCCT and a 300-MW CCCT in the second half of the 2020s, 60 MW of battery storage replacement, and 36 MW of reciprocating engines in 2034.

**Table 8.21 Resource portfolio P15**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2019 | Retire North Valmy (both units) | (262 MW) | (262 MW) |
| 2020 | Vanadium redox flow battery storage | 25 MW | 25 MW |
| 2021 | Vanadium redox flow battery storage | 35 MW | 35 MW |
| 2021 | Reciprocating engines | 90 MW | 90 MW |
| 2023 | Reciprocating engines | 108 MW | 108 MW |
| 2025 | Reciprocating engines | 54 MW | 54 MW |
| 2026 | SCCT | 170 MW | 170 MW |
| 2029 | CCCT | 300 MW | 300 MW |
| 2030 | 2020 battery storage end of life | (25 MW) | (25 MW) |
| 2030 | Vanadium redox flow battery storage (replace) | 25 MW | 25 MW |
| 2031 | 2021 battery storage end of life | (35 MW) | (35 MW) |
| 2031 | Vanadium redox flow battery storage (replace) | 35 MW | 35 MW |
| 2034 | Reciprocating engines | 36 MW | 36 MW |
| | | Total retired capacity | (322 MW) |
| | | Total added capacity | 878 MW |
| | | Net peak-hour capacity | 556 MW |

## P16

Resource portfolio P16 adds 60 MW of demand response and 90 MW of reciprocating engines in 2021 to 2025. The 60 MW of demand response is beyond the 390 MW of summer demand

response included as an existing resource in all portfolios. P16 also adds a 300-MW CCCT and a 170-MW SCCT in the second half of the 2020s. In the early 2030s, 18 MW of reciprocating engines and a 170-MW SCCT are added.

**Table 8.22 Resource portfolio P16**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2019 | Retire North Valmy (Unit 1) | (126 MW) | (126 MW) |
| 2021 | Demand response | 15 MW | 15 MW |
| 2023 | Demand response | 30 MW | 30 MW |
| 2024 | Demand response | 15 MW | 15 MW |
| 2024 | Reciprocating engines | 54 MW | 54 MW |
| 2025 | Reciprocating engines | 36 MW | 36 MW |
| 2025 | Retire North Valmy (Unit 2) | (136 MW) | (136 MW) |
| 2026 | CCCT | 300 MW | 300 MW |
| 2029 | SCCT | 170 MW | 170 MW |
| 2031 | Reciprocating engines | 18 MW | 18 MW |
| 2032 | SCCT | 170 MW | 170 MW |
| | | Total retired capacity | (262 MW) |
| | | Total added capacity | 808 MW |
| | | Net peak-hour capacity | 546 MW |

## P17

Resource portfolio P17 adds a variety of resources, including 250 MW of utility-scale, single-axis solar PV; 162 MW of reciprocating engines; 45 MW of CHP; 30 MW of geothermal; and 60 MW of ice-based TES in 2024 to 2029. In the 2030s, P18 adds a 300-MW CCCT and a 170-MW SCCT.

**Table 8.23 Resource portfolio P17**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2023 | Retire Jim Bridger (Unit 1) | (177 MW) | (177 MW) |
| 2024 | Ice-based TES | 60 MW | 60 MW |
| 2024 | Utility-scale solar PV 1-axis | 175 MW | 90 MW |
| 2025 | CHP | 45 MW | 45 MW |
| 2026 | Reciprocating engines | 54 MW | 54 MW |
| 2027 | Geothermal | 30 MW | 30 MW |
| 2027 | Utility-scale solar PV 1-axis | 75 MW | 38 MW |
| 2028 | Reciprocating engines | 54 MW | 54 MW |
| 2029 | Reciprocating engines | 54 MW | 54 MW |
| 2030 | CCCT | 300 MW | 300 MW |
| 2032 | Retire Jim Bridger (Unit 2) | (176 MW) | (176 MW) |
| 2033 | SCCT | 170 MW | 170 MW |
| | | Total retired capacity | (353 MW) |
| | | Total added capacity | 895 MW |
| | | Net peak-hour capacity | 542 MW |

## North Valmy Staggered Retirement Year-End 2021 (Unit 1) and Year-End 2025 (Unit 2) Portfolio

After the April 2015 IRPAC meeting, Idaho Power received a submittal requesting the analysis of a portfolio with the retirement of North Valmy Unit 1 in 2021 from IRPAC member David Hawk (Oil and Gas Industry Advisor) in partnership with IRPAC member Ben Otto (Idaho Conservation League). New resources specified by the submittal included B2H, demand response, CHP, small hydro, geothermal, and residential PV solar. Idaho Power developed a resource portfolio using these specifications, adding the retirement of North Valmy Unit 2 in 2025. With the retirement of North Valmy Unit 1 in 2021 and Unit 2 in 2025, capacity deficits begin in July 2022 and reach 786 MW by July 2034. The resulting resource portfolio, designed to meet these deficits and the submitted request for specific resource actions, is designated as resource portfolio P18.

### P18

Resource portfolio P18 adds 20 MW of residential PV solar, 60 MW of demand response, a 45-MW CHP facility in 2022 to 2024, and the B2H transmission line in 2025. The 60 MW of demand response is above and beyond the 390 MW of summer demand response included as an existing resource in all portfolios. P18 also adds 3 MW of residential PV solar per year in 2031 to 2034, 40 MW of geothermal in 2031, 45 MW of CHP in 2032, 60 MW of small hydro in 2033, and 18 MW of reciprocating engines in 2034.

**Table 8.24 Resource portfolio P18**

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2021 | Retire North Valmy (Unit 1) | (126 MW) | (126 MW) |
| 2022 | Residential PV solar | 5 MW | 2 MW |
| 2022 | Demand response | 10 MW | 10 MW |
| 2023 | Residential PV solar | 5 MW | 2 MW |
| 2023 | Demand response | 30 MW | 30 MW |
| 2024 | Residential PV solar | 10 MW | 3 MW |
| 2024 | Demand response | 20 MW | 20 MW |
| 2024 | CHP | 45 MW | 45 MW |
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2025 | Retire North Valmy (Unit 2) | (136 MW) | (136 MW) |
| 2031 | Residential PV solar | 10 MW | 3 MW |
| 2031 | Geothermal | 40 MW | 40 MW |
| 2032 | Residential PV solar | 10 MW | 3 MW |
| 2032 | CHP | 45 MW | 45 MW |
| 2033 | Residential PV solar | 10 MW | 3 MW |
| 2033 | Small hydro | 60 MW | 60 MW |
| 2034 | Residential PV solar | 10 MW | 3 MW |
| 2034 | Reciprocating engines | 18 MW | 18 MW |
| | | Total retired capacity | (262 MW) |
| | | Total added capacity | 766 MW |
| | | Net peak-hour capacity | 504 MW |

## Portfolio Design Summary

The 23 portfolios analyzed for the 2015 IRP consider a range of alternatives with regard to early coal retirement and the B2H transmission line. The following table provides a summary of the 2015 IRP portfolio scenarios on the basis of early coal retirement and the B2H transmission line.

**Table 8.25 Resource portfolio scenario summary**

| Coal | B2H | Alternative to B2H |
|---|---|---|
| No coal capacity retirement | 4 | 1 |
| Early retirement—North Valmy | 11 | 2 |
| Early retirement—Jim Bridger | 3 | 1 |
| Early retirement—North Valmy and Jim Bridger | 1 | – |

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# 9. MODELING ANALYSIS AND RESULTS

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 serve customer load using all resources in the portfolio. Portfolio costs are expressed in terms of NPV in the IRP's cost-comparison analysis of portfolios.

The IRP portfolio costs consist of fixed and variable components. The fixed component includes annualized capital costs for new portfolio resources, including transmission interconnection costs for new generating facilities, and fixed O&M costs and ROI. Capital costs for new resources are annualized over the resource's estimated economic life. Annualized capital costs beyond the IRP planning window (2015–2034) are not included in portfolio costs.

Coal-retirement portfolios include costs for the accelerated recovery of remaining depreciation expenses and accelerated recovery of decommissioning and demolition costs (net of salvage). The costs of coal-retirement portfolios are countered by savings from avoiding future coal plant capital upgrades, including environmental retrofit upgrades, and from avoiding future fixed operating expenses and ROI for the retired coal unit(s).

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

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

Multiple electricity markets, zones, and hubs can be modeled using AURORA. Idaho Power models the entire WECC system when evaluating the various resource portfolios for the IRP. A database of WECC data is maintained and regularly updated by the software vendor EPIS, Inc. Prior to starting the IRP analysis, Idaho Power updates the AURORA database based on available information on generation resources within the WECC and calibrates the model to ensure it provides realistic results. Updates to the database generally add additional hourly operational details and move away from flat generation output, de-rates, and fixed-capacity factors. The updates also incorporate detailed generating resource scheduling, which results in a model that is more deterministic in character and provides a more specific operational view of the WECC.

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

**Table 9.1 Financial assumptions**

| Plant Operating (Book) Life | 30 Years |
|---|---|
| Discount rate (weighted average capital cost) | 6.74% |
| Composite tax rate | 39.10% |
| Deferred rate | 35.00% |
| General O&M escalation rate | 2.20% |
| 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) | 7.75% |

# CAA Section 111(d) Sensitivity Analysis

Idaho Power developed multiple sensitivities for the EPA's proposed regulation for regulating $CO_2$ emissions from existing generating sources under CAA Section 111(d). The multiple sensitivities are a reflection of the considerable uncertainty related to the stipulations of the finalized regulation scheduled to be issued in summer 2015. Each sensitivity, with the exception of a null sensitivity in which no restrictions are assumed, is based on a set of assumptions on compliance stipulations for the final regulation. Analyzing multiple sensitivities allows the estimation of a range of possible cost impacts from CAA Section 111(d). The cost sensitivity analysis could provide information to state-level agencies tasked with the development of state plans for CAA Section 111(d) implementation.

The analyzed CAA Section 111(d) sensitivities are described by four categories:

1. Null sensitivity (no CAA Section 111(d))
2. State-by-state mass-based compliance
3. System-wide mass-based compliance
4. Emissions-intensity compliance using the EPA's compliance building blocks

## *Null Sensitivity (no CAA Section 111(d))*

Idaho Power analyzes a null sensitivity to provide a comparison with portfolios complying with regulations on $CO_2$ emissions for existing power plants. The only portfolio analyzed under the null sensitivity is the status quo portfolio (P1), which maintains coal capacity and meets planning-period deficits with B2H in 2025 and 36 MW of reciprocating engines in 2034.

## *State-by-State Mass-Based Compliance*

Under state-by-state mass-based compliance, CAA Section 111(d) proposed state-specific target reductions are the basis for compliance. The proposed regulation's treatment of Langley Gulch is

uncertain, as it was brought on-line midway through EPA's 2012 baseline year. Consequently, Langley Gulch is assumed to be constrained at one of three possible annual capacity factors: 30 percent (837,018 MWh), 55 percent (1,534,533 MWh), or 70 percent (1,953,042 MWh). The proposed target reductions are defined in Table 9.2.

**Table 9.2 Proposed target reductions for state-by-state mass-based compliance (IPC share)**

| Affected Source | 2020–2029 Target MWh | 2030 and Beyond Target MWh |
|---|---|---|
| Jim Bridger | 3,914,502 MWh<br>(13.8% below 2012 MWh) | 3,675,608 MWh<br>(19.1% below 2012 MWh) |
| North Valmy | 574,382 MWh<br>(29.5% below 2012 MWh) | 533,343 MWh<br>(34.5% below 2012 MWh) |
| Boardman | 149,967 MWh<br>(43.2% below 2012 MWh) | 137,029 MWh<br>(48.1% below 2012 MWh) |
| Langley Gulch | Target 30%, 55%, or 70% annual capacity factor 2020–2034 | |

## System-Wide Mass-Based Compliance

Under system-wide mass-based compliance, CAA Section 111(d) compliance is based on adherence to $CO_2$ limits imposed at an individual-utility system level. The assumed Idaho Power system-level limits were derived to be consistent with EPA's proposed state-specific target reductions. Under this approach, system-wide emissions, which include emissions from Langley Gulch and Idaho Power's share of Jim Bridger and North Valmy, are constrained to 6,332,020 tons of $CO_2$ for 2020 to 2029 and to 5,925,874 tons of $CO_2$ for 2030 and beyond. Compared to 2012 system-wide emissions, these constraint levels are lower by 20 percent (2020 to 2029 constraint) and 25 percent (2030 and beyond constraint).

## Emissions-Intensity Compliance Using the EPA's Compliance Building Blocks

In its proposed regulation, the EPA describes building blocks to assist in developing a plan for achieving compliance. Keys to the building-block approach for achieving compliance are the reduction of $CO_2$ emissions through the re-dispatch of affected sources and the development of renewable energy and energy efficiency resources leading to a reduction in emissions intensity. Idaho Power makes the following assumptions in using the EPA's building blocks as the basis for CAA Section 111(d) compliance:

- Boardman coal plant is reduced to a zero production level and retired by year-end 2020.
- North Valmy coal plant is reduced to a zero production level and retired as early as year-end 2019 or as late as year-end 2025; until retirement, Idaho Power's share of North Valmy is assumed to have an annual production constraint equal to its 2012 production level (IPC share = 814,264 MWh).
- Jim Bridger coal plant is reduced to a production level 53,320 MWh less than its 2012 production level of 4,541,712 MWh (IPC share); the re-dispatch of Jim Bridger is to a new 95-MW CCCT under construction in Wyoming.

- The Langley Gulch natural gas-fired plant is limited to one of three levels based on annual capacity factors of 30 percent (837,018 MWh), 55 percent (1,534,533 MWh), or 70 percent (1,953,042 MWh).

- Renewable energy and energy efficiency resources are developed in Idaho to the EPA's proposed target levels.

## *Baseline CAA Section 111(d)*

Among the sensitivities developed for the 2015 IRP, Idaho Power selected a baseline sensitivity for the initial portfolio cost analysis. The baseline CAA Section 111(d) portfolio cost analysis assumes state-by-state mass-based compliance with Langley Gulch constrained at a 30 percent annual capacity factor. The selection of these assumptions for the baseline analysis is not a reflection of Idaho Power's preference for CAA Section 111(d), nor is it an indication of the company's view of the most probable CAA Section 111(d) outcome. Rather, it is selected to provide information in comparing costs between portfolios. The baseline costs identify portfolios for further analysis under other CAA Section 111(d) sensitivities and for the stochastic risk analysis. The results of the baseline CAA Section 111(d) sensitivity analyses are provided in Table 9.3.

**Table 9.3 2015 IRP portfolios, NPV years 2015–2034 ($ thousands) (portfolios in green were studied in the stochastic risk analysis)**

| Portfolio[1] | | | | Variable Costs | Fixed Costs[3] | Summary | | |
|---|---|---|---|---|---|---|---|---|
| Portfolio Index (1) | Portfolio Description (2) | B2H (3) | Coal Capacity Retirement (4) | Operating[2] (AURORA) (5) | Total Fixed Costs (6) | Total Fixed + Variable Costs (7) (7) = (5) + (6) | Lowest Cost Rank (8) | Lowest Cost Relative Difference (9) |
| P1 | Status quo w/ B2H_25, recips, (no coal capacity retirement & no CAA Section 111(d) restrictions) | ✓ | | $4,306,018 | $110,689 | $4,416,707 | 1 | $0 |
| P9* | Valmy19_25 w/ DR, recips, B2H_25, SCCT | ✓ | ✓ | $4,489,655 | $30,933 | $4,520,588 | 2 | $103,880 |
| P11* | Bridger23_32 w/ ice TES, PV, B2H_25, CHP, recips, EE accrue by 2034 to 16 aMW & 24 MW | ✓ | ✓ | $4,418,783 | $130,594 | $4,549,377 | 3 | $132,670 |
| P2(a)* | B2H_25, recips, (no coal capacity retirement) | ✓ | | $4,461,356 | $110,689 | $4,572,046 | 4 | $155,338 |
| P8* | Valmy19_25 w/ ice TES, PV, B2H_25, hydro, recips, EE accrue by 2034 to 16 aMW & 24 MW | ✓ | ✓ | $4,445,028 | $129,423 | $4,574,450 | 5 | $157,743 |
| P10* | Bridger23_32 w/ SCCT, B2H_25, CCCT | ✓ | ✓ | $4,505,955 | $75,219 | $4,581,175 | 6 | $164,467 |
| P2(b) | B2H_23, recips, (no coal capacity retirement) | ✓ | | $4,456,215 | $136,570 | $4,592,785 | 7 | $176,078 |
| P6(b)* | Valmy25_25 w/B2H_25, DR, ice TES, CCCT | ✓ | ✓ | $4,492,228 | $102,944 | $4,595,171 | 8 | $178,464 |
| P6 | Valmy25_25 w/ B2H_25, CCCT | ✓ | ✓ | $4,492,934 | $111,303 | $4,604,237 | 9 | $187,529 |
| P13* | Bridger23_32 & Valmy25_25 w/ SCCT, B2H_25, CCCT | ✓ | ✓ | $4,507,342 | $100,935 | $4,608,277 | 10 | $191,570 |
| P2(c) | B2H_21, recips, (no coal capacity retirement) | ✓ | | $4,452,737 | $164,124 | $4,616,861 | 11 | $200,154 |
| P3* | Valmy19_19 w/ ice TES, PV, B2H_25, EE accrue by 2034 to 16 aMW & 24 MW | ✓ | ✓ | $4,311,661 | $309,467 | $4,621,128 | 12 | $204,421 |
| P12 | Bridger23_28 w/ SCCT, B2H_25, CCCT | ✓ | ✓ | $4,541,071 | $100,730 | $4,641,800 | 13 | $225,093 |
| P18* | Valmy 21_25 w/ res PV, B2H_25, CHP, geotherm, hydro, recips | ✓ | ✓ | $4,464,898 | $179,429 | $4,644,327 | 14 | $227,619 |
| P4(c) | Valmy19_19 w/ battery, recips, B2H_21 | ✓ | ✓ | $4,539,309 | $105,904 | $4,645,213 | 15 | $228,506 |
| P4(b) | Valmy19_19 w/ battery, recips, B2H_23 | ✓ | ✓ | $4,528,608 | $180,442 | $4,709,050 | 16 | $292,343 |
| P4(a) | Valmy19_19 w/ battery, recips, B2H_25 | ✓ | ✓ | $4,521,759 | $188,424 | $4,710,183 | 17 | $293,475 |
| P17* | Bridger23_32 w/ ice TES, PV, CHP, recips, geothermal, CCCT, SCCT | | ✓ | $4,380,138 | $332,652 | $4,712,790 | 18 | $296,083 |
| P16* | Valmy19_25 w/ DR, recips, CCCT, SCCT | | ✓ | $4,518,985 | $197,652 | $4,716,637 | 19 | $299,930 |
| P14 | Ice TES, recips, CCCT, SCCT, (no coal capacity retirement) | | | $4,477,547 | $263,236 | $4,740,783 | 20 | $324,075 |
| P5 | Valmy19_19 w/ CCCT, B2H_25 | ✓ | ✓ | $4,482,891 | $281,412 | $4,764,303 | 21 | $347,595 |
| P15 | Valmy19_19 w/ battery, recips, SCCT, CCCT | | ✓ | $4,493,671 | $311,829 | $4,805,500 | 22 | $388,793 |
| P7 | Valmy25_25 w/ B2H_25, pumped storage | ✓ | ✓ | $4,509,228 | $487,899 | $4,997,127 | 23 | $580,419 |

Notes:

[1] All portfolios assume CAA Section 111(d) implementation except for P1.

[2] AURORA simulates the variable fuel and O&M costs and REC sales (when applicable). This includes the existing system, the effects of coal plant shutdowns (when applicable), plus the new portfolio resources and compliance with CAA Section 111(d) (when applicable). The reservation charge for new and existing natural gas plants is calculated in AURORA.

[3] Fixed costs of existing resources are excluded except as needed in accounting for coal-retirement portfolios.

* Denotes portfolios that were studied in the stochastic risk analysis

The selection of portfolios for further analysis indicated in Table 9.3 is based on the results of the baseline CAA Section 111(d) analyses as well as discussions held at IRPAC meetings in which participants voiced a desire to further analyze a relatively broad spectrum of portfolio types (e.g., portfolios with and without B2H).

## *CAA Section 111(d) Sensitivity Analysis Results*

The analysis of portfolio costs under the different CAA Section 111(d) sensitivities indicates that portfolio relative performance does not change significantly across the sensitivities; low-cost portfolios under the baseline CAA Section 111(d) sensitivity tend to have low costs under the other sensitivities. Cost impacts of CAA Section 111(d) are greatest when individual coal-plant dispatch decisions are mandated under a state-by-state approach. Likewise, the more severely Langley Gulch generation is reduced, the higher the cost of compliance. Cost impacts are least when the EPA's building blocks are the basis for CAA Section 111(d) compliance and Langley Gulch is assumed to be permitted to run up to a capacity factor of 70 percent (approximately 1.95 million MWh annually). Under the building block approach, Idaho Power assumes North Valmy can be operated at 2012 production levels (annually) until retirement and Jim Bridger can be operated at annual production levels 53,320 MWh less than 2012 production levels. For reference, P1 costs under the null sensitivity are $4,417 million. Table 9.4 provides the results of the CAA Section 111(d) sensitivity analysis.

**Table 9.4 Portfolio costs by CAA Section 111(d) sensitivity ($ millions)**

| | | State-by-State Mass-Based Compliance | | | System-Wide Mass-Based Compliance | Emissions-Intensity Compliance with Building Blocks | | |
|---|---|---|---|---|---|---|---|---|
| Portfolio | Portfolio Description | Langley Gulch at 30% Annual CF* | Langley Gulch at 55% Annual CF | Langley Gulch at 70% Annual CF | | Langley Gulch at 30% Annual CF | Langley Gulch at 55% Annual CF | Langley Gulch at 70% Annual CF |
| P1 | Status quo w/ B2H_25, recips, (no coal capacity retirement & no CAA Section 111(d) restrictions) | Status Quo—No CAA Section 111(d) | Status Quo—No CAA Section 111(d) | Status Quo—No CAA Section 111(d) | Status Quo—No CAA Section 111(d) | Status Quo—No CAA Section 111(d) | Status Quo—No CAA Section 111(d) | Status Quo—No CAA Section 111(d) |
| P2(a) | B2H_25, recips, (no coal capacity retirement) | $4,572 | $4,541 | $4,536 | $4,518 | N/A | N/A | N/A |
| P2(b) | B2H_23, recips, (no coal capacity retirement) | $4,593 | $4,563 | $4,557 | $4,539 | N/A | N/A | N/A |
| P2(c) | B2H_21, recips, (no coal capacity retirement) | $4,617 | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | N/A | N/A | N/A |
| P3 | Valmy19_19 w/ ice TES, PV, B2H_25, EE accrue by 2034 to 16 aMW & 24 MW | $4,621 | $4,563 | $4,558 | $4,512 | $4,518 | $4,490 | $4,488 |
| P4(a) | Valmy19_19 w/ battery, recips, B2H_25 | $4,710 | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High |
| P4(b) | Valmy19_19 w/ battery, recips, B2H_23 | $4,709 | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High |
| P4(c) | Valmy19_19 w/ battery, recips, B2H_21 | $4,645 | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High |
| P5 | Valmy19_19 w/ CCCT, B2H_25 | $4,764 | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High |
| P6 | Valmy25_25 w/ B2H_25, CCCT | $4,604 | $4,571 | $4,568 | $4,536 | $4,517 | $4,485 | $4,480 |
| P6(b) | Valmy25_25 w/B2H_25, DR, ice TES, CCCT | $4,595 | $4,564 | $4,561 | $4,527 | $4,509 | $4,478 | $4,473 |
| P7 | Valmy25_25 w/ B2H_25, pumped storage | $4,997 | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High |
| P8 | Valmy19_25 w/ ice TES, PV, B2H_25, hydro, recips, EE accrue by 2034 to 16 aMW & 24 MW | $4,574 | $4,541 | $4,538 | $4,503 | $4,485 | $4,458 | $4,455 |
| P9 | Valmy19_25 w/ DR, recips, B2H_25, SCCT | $4,521 | $4,494 | $4,490 | $4,455 | $4,438 | $4,408 | $4,410 |
| P10 | Bridger23_32 w/ SCCT, B2H_25, CCCT | $4,581 | $4,551 | $4,545 | $4,545 | N/A | N/A | N/A |

**Table 9.4 Portfolio costs by CAA Section 111(d) sensitivity ($ millions) (continued)**

| Portfolio | Portfolio Description | State-by-State Mass-Based Compliance | | | System-Wide Mass-Based Compliance | Emissions-Intensity Compliance with Building Blocks | | |
|---|---|---|---|---|---|---|---|---|
| | | Langley Gulch at 30% Annual CF* | Langley Gulch at 55% Annual CF | Langley Gulch at 70% Annual CF | | Langley Gulch at 30% Annual CF | Langley Gulch at 55% Annual CF | Langley Gulch at 70% Annual CF |
| P11 | Bridger23_32 w/ ice TES, PV, B2H_25, CHP, recips, EE accrue by 2034 to 16 aMW & 24 MW | $4,549 | $4,511 | $4,506 | $4,510 | N/A | N/A | N/A |
| P12 | Bridger23_28 w/ SCCT, B2H_25, CCCT | $4,642 | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | N/A | N/A | N/A |
| P13 | Bridger23_32 & Valmy25_25 w/ SCCT, B2H_25, CCCT | $4,608 | $4,577 | $4,572 | $4,570 | $4,535 | $4,505 | $4,498 |
| P14 | Ice TES, recips, CCCT, SCCT, (no coal capacity retirement) | $4,741 | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | N/A | N/A | N/A |
| P15 | Valmy19_19 w/ battery, recips, SCCT, CCCT | $4,806 | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High | Baseline Costs too High |
| P16 | Valmy19_25 w/ DR, recips, CCCT, SCCT | $4,717 | $4,682 | $4,672 | $4,530 | $4,639 | $4,606 | $4,600 |
| P17 | Bridger23_32 w/ ice TES, PV, CHP, recips, geotherm, CCCT, SCCT | $4,713 | $4,657 | $4,649 | $4,665 | N/A | N/A | N/A |
| P18 | Valmy 21_25 w/ res PV, B2H_25, CHP, geotherm, hydro, recips | $4,644 | $4,615 | $4,610 | $4,578 | $4,560 | $4,533 | $4,528 |

Note: Gray shaded cells not analyzed because no Valmy retirement is assumed (N/A) and/or baseline costs are too high.

* Baseline CAA Section 111(d) sensitivity.

## Stochastic Risk Analysis

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

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

1. *Natural gas price*—Natural gas prices follow a log-normal distribution centered on the planning case forecast. Natural gas prices are serial correlated, and the serial correlation is based on the historic year-to-year correlation from 1990 through 2014. The serial correlation factor is 0.65.

2. *Customer load*—Customer load follows a normal distribution and is correlated with Pacific Northwest regional load. Idaho Power worked with the Northwest Power and Conservation Council (NWPCC) as part of research conducted for the 2013 IRP to estimate the correlation between Idaho Power customer load and regional customer load. The correlation factor is 0.50.

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

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

The stochastic analysis was performed under the system-wide mass-based limits on $CO_2$ emissions. This assumption was selected because all eleven portfolios can comply with CAA Section 111(d) under this compliance approach. Moreover, the objective of the stochastic analysis is to determine the cost impact when portfolios are stochastically shocked. The purpose of the analysis is to understand the range of portfolio costs across the full extent of stochastic shocks (i.e., across the full set of stochastic iterations), and how the ranges for portfolios differ.

Idaho Power created a set of 100 iterations based on the three stochastic variables. Idaho Power then calculated the portfolio cost for eleven portfolios, where the eleven portfolios were selected based on results of the initial cost analysis under the baseline CAA Section 111(d) sensitivity or to provide a wide range of resource types (e.g., with and without B2H). Each stochastic iteration was reduced to one numerical value—the NPV of the total cost to serve customer load over the 20-year planning period. Figure 9.1 shows the stochastic analysis results.

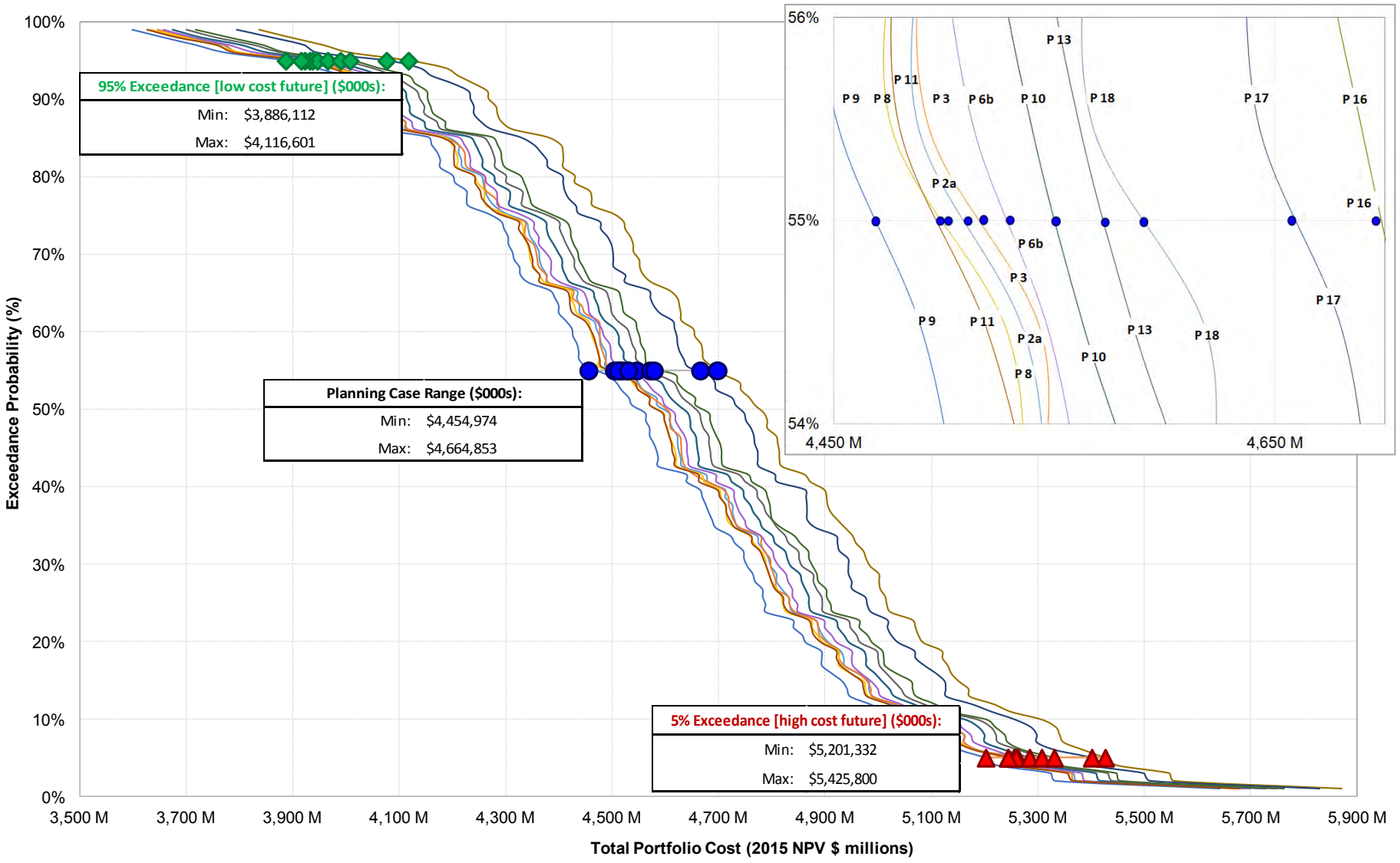



**Figure 9.1 Portfolio stochastic analysis**

In Figure 9.1, the horizontal axis is the portfolio cost (NPV) and the vertical axis is the exceedance probability. Each line on the figure corresponds to one of the eleven portfolios stochastically analyzed, and the line is the connection of ranked NPV observations for the 100 stochastic iterations. The figure illustrates portfolio costs at the 5-percent and 95-percent exceedance probabilities, as well as portfolio costs with planning case inputs for the three stochastic variables (natural gas, customer load, hydro condition). Reassuringly, the planning case results approximate well the 50-percent exceedance level.

Figure 9.1 illustrates portfolio P9, a North Valmy early retirement portfolio with B2H, is the least-cost portfolio for the full set of 100 iterations. Portfolios are relatively clustered across the top nine least-cost portfolios, with B2H alternative portfolios P16 and P17 somewhat set apart with higher costs.

While not easily discerned, there is some crossing of the portfolio-specific lines in Figure 9.1. Significant crossing of lines in the exceedance graph is an indication of substantial portfolio disparity; portfolio cost performance in this case is markedly different across the set of stochastic iterations. As an example, a portfolio consisting of exclusively natural gas-fired generation would be expected to conspicuously cross lines on Figure 9.1 as portfolio costs range greatly from low to high natural gas-price futures. Finally, the lack of significant crossing of lines is a testament to the resource diversity of Idaho Power's existing portfolio and the portfolios of new resources considered in the IRP; under no set of stochastic futures is a portfolio a clear and runaway cost winner, only to be countered by a different set of futures for which it is just as clearly a losing portfolio susceptible to significantly higher costs than other portfolios.

## *Portfolio Cost-Assessment of Year-to-Year Variability*

At the request of participants in the IRPAC process, Idaho Power expanded the stochastic analysis for the 2015 IRP to include an assessment of year-to-year portfolio cost variability. This assessment of year-to-year variability allows portfolios to be compared on the basis of their susceptibility to large year-to-year price swings. Idaho Power assesses the year-to-year variability by use of the standard deviation metric. For each stochastic iteration, the standard deviation of the 20-year stream of AURORA-determined variable costs (converted to base 2015 dollars) is calculated. Therefore, each of the eleven portfolios for which stochastic analysis is performed has 100 standard deviation measures corresponding to the 100 different stochastic iterations. Portfolios susceptible to large year-to-year price swings tend to have larger standard deviations.

An exceedance graph of the standard deviations for each of the eleven portfolios is shown as Figure 9.2. The exceedance graph indicates that P3, which adds just over 400 MW of utility-scale PV solar, is the least susceptible to large year-to-year swings. Portfolio P16, which adds more than 700 MW of natural gas-fired generating capacity, is the most susceptible to large year-to-year swings.

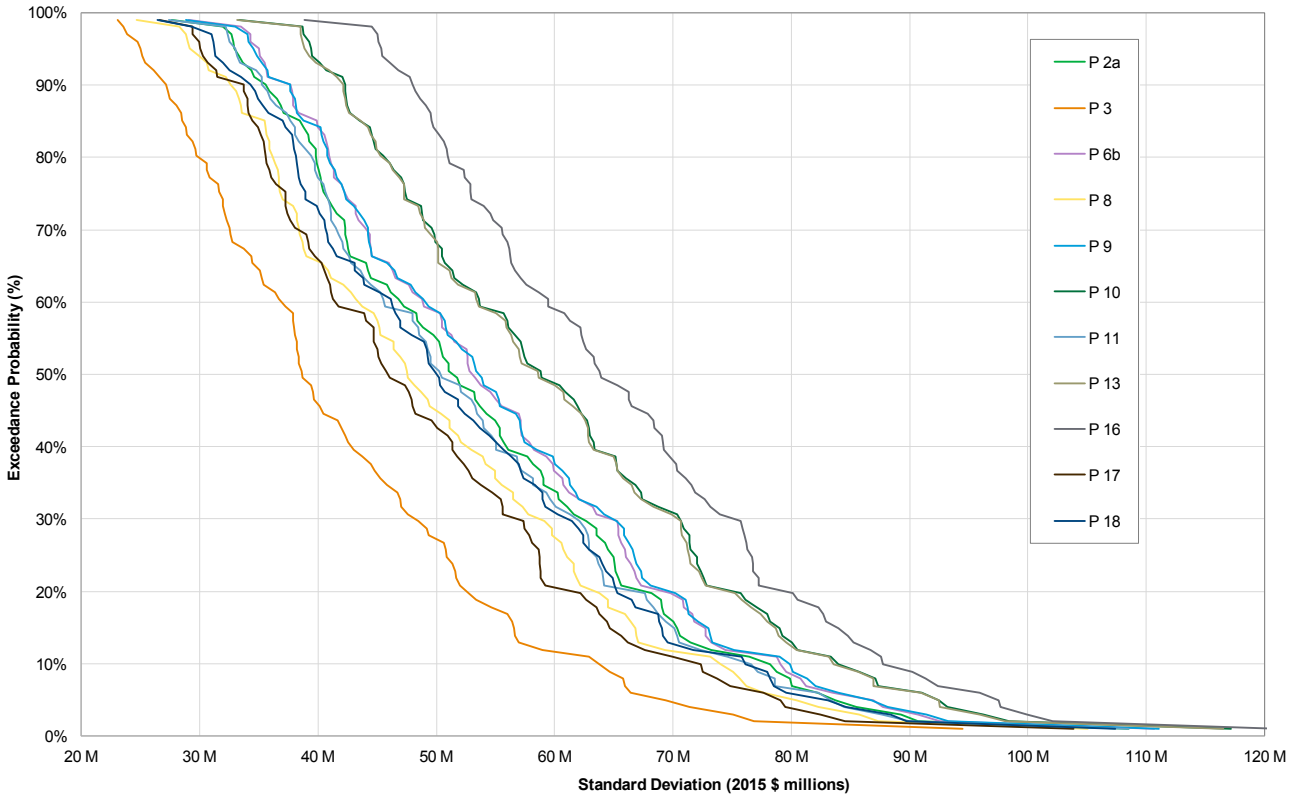



**Figure 9.2 Exceedance graph of standard deviations**

## Tipping-Point Analysis

To test the sensitivity of total portfolio cost to capital-cost estimates, Idaho Power conducted a tipping-point analysis for P3, which has a high penetration of utility-scale, single-axis PV solar, and P7, which has 300 MW of pumped-storage hydro. In the tipping-point analysis, the change in the total portfolio cost is determined as a function of change in the capital cost. The capital cost of the solar resource is varied for P3, and the capital cost of pumped-storage hydro is varied for P7. The percent change in the capital cost is relative to planning-case capital-cost estimates, where the solar resource under the planning case is estimated at $1,250 per kW (for capacity constructed in 2017 or later) and pumped-storage hydro is estimated at $5,000 per kW. A graph of the tipping-point analysis results is provided in Figure 9.3. As an example, the graph illustrates that a change in utility-scale, single-axis PV solar of -30 percent results in an estimated decrease in total portfolio costs for P3 of $50 million (NPV).

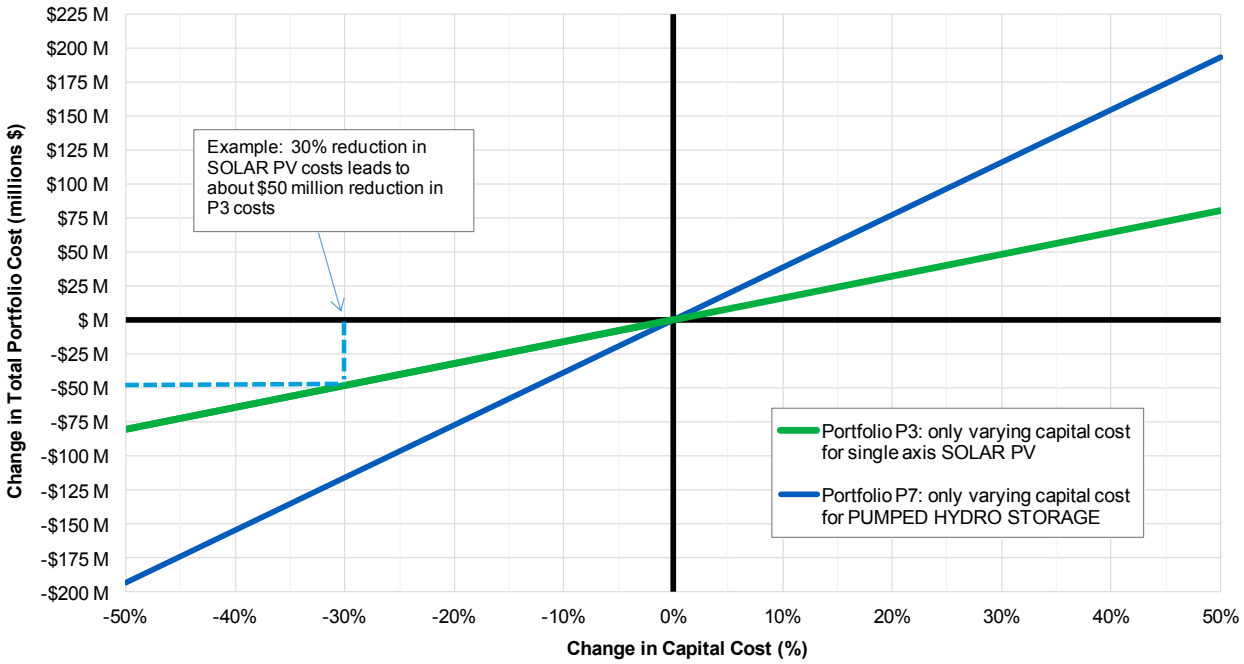



**Figure 9.3 Tipping-point analysis results**

## Portfolio Emissions

For the 2015 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. The total emissions for each portfolio include emissions from new resources in addition to emissions from Idaho Power's existing resources. With the exception of portfolios retiring Jim Bridger units 1 and 2 without installation of $NO_x$-controlling environmental retrofits, all portfolios comply with environmental regulations. Illustrations of the four emission types for the eleven portfolios on which CAA Section 111(d) sensitivity and stochastic analyses were performed are provided in *Appendix C—Technical Appendix.*

## Qualitative Risk Analysis

The qualitative risks associated with the portfolios are more difficult to assess. The goal is to select a portfolio likely to withstand unforeseen events. The portfolios contain a diverse range of resource futures. Each future includes existing and new generating resources with different implementation, fuel, and technology risks. The following section highlights specific risks within

the portfolios, describes Idaho Power's interpretation of the risk profiles associated with each resource, and acknowledges that the portfolios may contain unique and differing risks.

## Existing Generation

### Hydro—Water-Supply Risk

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

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

The assumptions used in developing the 20-year streamflow forecast are carefully planned and based on the current knowledge of Idaho Power staff in consultation with other stakeholders. Those assumptions are also subject to the limitations of the current models used in developing the twenty-year streamflow forecast for the 2015 IRP.

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

- Changes in the timing and demand for irrigation water due to climate variability
- Changes to the sources of flow augmentation water and the potential for overestimation of flow augmentation availability in low-water years
- Long-term changes in the timing of flood control releases at Brownlee Reservoir in response to earlier snowmelt
- The potential for underestimation of the decline in reach gains within the Snake River Basin
- Changes to funding or the ability to achieve forecasted levels of aquifer management on the ESPA.

### Relicensing Risk

Working within the constraints of the original FERC licenses, the HCC has historically provided operational flexibility that has benefited Idaho Power's customers. The operational flexibility of the HCC is increasingly critical to the successful integration of variable energy resources. As a result of the FERC relicensing process, operational requirements, such as minimum

reservoir elevations, minimum flows, and limitations on ramping rates, may become more stringent. The loss of operational flexibility will limit Idaho Power's ability to optimally manage the HCC, making the integration of variable energy resources more challenging and ultimately increasing power supply costs.

### Fossil Fuel-Fired Power Generation and Proposed CAA Section 111(d) Regulation Risks

In 2014, the EPA released, under CAA Section 111(d), a proposed regulation for addressing greenhouse gas emissions from existing fossil fuel-fired electric generating units. The EPA's proposal requires states meet their goal by 2030, with interim goals from 2020 to 2029. The EPA stated it expects to finalize the rulemaking by summer 2015. State implementation plans would be due by June 20, 2016, subject to extensions for portions of the plan to June 30, 2017, for state plans or June 20, 2018, for multi-state plans, under certain circumstances. Since this is a proposed regulation, it is subject to interpretation and change. There is considerable uncertainty on the stipulations of the final regulation, and the resulting impact on fossil fuel-fired generation on Idaho Power's system and throughout the region.

### Regulatory risk

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

### $NO_x$ Compliance Alternatives Risk

Portfolios with the early retirement of Jim Bridger units 1 and 2 assume these units are permitted to operate until retirement without installation of SCR retrofits necessary for compliance with EPA regional haze regulations. All other portfolios assume the SCR retrofits are installed on schedule in 2021 for Unit 2 and 2022 for Unit 1. The permitting associated with the Jim Bridger early retirement compliance alternatives is highly speculative at this point. An inability to successfully achieve permitting consistent with the assumptions of these compliance alternatives would likely have a significant effect on the costs and feasibility of portfolios with the early retirement of Jim Bridger units 1 and 2.

## *New Generation*

### Resource Commitment Risk

Idaho Power faces risk in the timing of, and commitment to, new resources. There are a number of factors that influence the actual timing of resource planning, including the pace of PURPA resource development, siting issues, partnership influences, and the performance of existing resources.

## PURPA Development

In the IRP's assessment of resource adequacy, Idaho Power assumes PURPA projects having signed contracts are part of system resources. The forecast of PURPA development is a unique challenge in the IRP's assessment of resource adequacy; PURPA development occurs independent of the IRP process and can abruptly alter resource adequacy. Idaho Power's practice is to include PURPA projects that are operational or under signed contract.

Since the 2015 IRP process began in late summer 2014, Idaho Power signed contracts for 461 MW of solar PURPA projects and has received inquiries for an additional 885 MW. Since including the 461 MW of solar contracts as part of committed system resources in the 2015 IRP, contracts for four solar PURPA projects totaling 141 MW have been terminated, leaving 320 MW still under contract. Table 9.5 illustrates the effect of removing the 141 MW of solar PURPA projects with terminated contracts on the 2015 IRP first deficit year.

**Table 9.5 First peak-hour capacity deficit effects of removing 141 MW of solar PURPA**

| Scenario | First deficit 2015 IRP | First deficit without 141 MW solar PURPA |
|---|---|---|
| Status quo | July 2025 | July 2024 |
| Maintain coal capacity | July 2025 | July 2024 |
| North Valmy retire units 1 and 2 year-end 2019 | July 2020 | July 2020 |
| North Valmy retire units 1 and 2 year-end 2025 | July 2025 | July 2024 |
| North Valmy retire Unit 1 year-end 2019 and Unit 2 year-end 2025 | July 2021 | July 2021 |
| North Valmy retire Unit 1 year-end 2021 and Unit 2 year-end 2025 | July 2022 | July 2022 |
| Jim Bridger retire Unit 1 year-end 2023 and Unit 2 year-end 2028 | July 2024 | July 2024 |
| Jim Bridger retire Unit 1 year-end 2023 and Unit 2 year-end 2032 | July 2024 | July 2024 |
| Jim Bridger retire Unit 1 year-end 2023 and Unit 2 year-end 2032, North Valmy retire units 1 and 2 year-end 2025 | July 2024 | July 2024 |

As unbuilt resources, uncertainty persists in relation to the remaining 320 MW of solar PURPA projects. Further contract terminations will lead to earlier onsets of system deficiencies and may ultimately require Idaho Power to construct system resources earlier than expected and with larger capacities.

While uncertainty related to the potential over-forecasting of PURPA development is a critical risk element from the perspective of resource adequacy, PURPA development also carries the potential for under-forecasting. The potential for under-forecasting is evidenced by the October 13, 2014, filing of signed contracts for 401 MW of solar PURPA projects, out of the 461 MW in total; over the course of a day, the PURPA forecast grew by 401 MW. While under-forecasting does not jeopardize system resource adequacy, it does increase the likelihood that Idaho Power will encounter issues associated with energy oversupply during system operations. Issues associated with periodic energy oversupply have grown increasingly frequent over recent years. The expansion of variable and intermittent generation will increase this reliability challenge. The flexible-resource needs assessment performed for the 2015 IRP

corroborates concerns related to reliability impacts from periodic energy oversupply. The flexible resource needs assessment is described later in this chapter.

### Boardman to Hemingway transmission line

Significant challenges have been encountered during the permitting phase of the B2H transmission line. Environmental requirements related to siting of the transmission line have the potential to delay the project and increase permitting costs. The completion date of the project is subject to these siting, permitting, and regulatory approval requirements. The needs of the partners, PacifiCorp and BPA, also impact the in-service date.

### Regional Resource Adequacy

Regional resource adequacy is part of the regional transmission planning process. In July 2013, the NWPCC approved a charter for the Resource Adequacy Advisory Committee (RAAC). The RAAC's purpose is to assess power supply adequacy in the Northwest. Idaho Power has participated in the RAAC since its inception and also in the NWPCC's Resource Adequacy Forum, which preceded the RAAC.

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

The RAAC issued a draft report on an assessment of LOLP for the 2020 and 2021 operating years. The LOLP for the 2020 operating year is just under the 5 percent adequacy standard level. For the 2021 operating year, the LOLP increases to a little over 8 percent. The draft RAAC report indicates the increased LOLP for the 2021 operating year is the result of planned retirements of coal-fired generating capacity at Centralia, Washington, and the Boardman power plant. The RAAC adequacy assessment notes that the 2021 LOLP would be brought to below the 5 percent level by adding resources providing the equivalent of 1,150 MW of dispatchable generation. The RAAC also notes the LOLP analysis for both operating years does not include planned, new generating resources in the region, because these resources, while planned, have not yet been sited or licensed.

In general, the Pacific Northwest experiences peak energy demand in the winter, whereas Idaho Power experiences peak demand in the summer. The 2015 IRP analysis indicates Idaho Power resource deficits occur in the summer months, with July being the most critical month. 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 B2H 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/natural gas prices, and low water conditions, resource portfolios containing B2H are the lowest-cost portfolios.

### DSM implementation

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

### New technologies

Many of the portfolios include technologies Idaho Power has limited experience in developing, building, or operating. This lack of direct experience increases the risk associated with the development of these resources, including the following:

- **Price Risk**: Cost estimates for solar are based on a 2014 Lazard report. While this report provides an objective, third-party estimate of resource costs, there is risk that trends in solar pricing may not be properly captured by the Lazard report.

- **Siting Risk**: Several of the technologies involve different risks associated with the type of resource being developed:

    - Fuel types, such as gas, may encounter public and political pressure against a project being located near load centers or being constructed at all.

    - Technologies, such as CHP and ice-based TES, would require a large commercial or industrial customer to partner with Idaho Power.

Geothermal, pumped storage, and canal drop hydro require the facility to be sited at the source of the motive force. These projects are often located in remote locations far from load centers, which increase the development and transmission costs associated with the resource.

## Preferred Portfolio

On the basis of the 2015 IRP's quantitative and qualitative analysis, the preferred portfolio selected by Idaho Power is P6(b). P6(b) balances the cost, risk, and environmental concerns identified in this IRP. The retirement of the North Valmy plant and the completion of B2H in 2025 balances the risks of CAA Section 111(d), increases in unplanned intermittent and variable generation, and is shown to be cost competitive. P6(b) also includes the addition of 60 MW of demand response and 20 MW of ice-based TES in 2030. In 2031, P6(b) also adds a 300-MW CCCT. These resource additions late in the planning period address projected needs for resources providing peaking capability and system flexibility. With expected long-term expansion of variable energy resources, the need for dispatchable resources that provide system flexibility will also increase.

## Analysis of Shoshone Falls Upgrade

For the 2015 IRP, Idaho Power analyzed the benefits and costs of the 50-MW expansion of the Shoshone Falls Power Plant. The incremental electrical generation the plant would produce with

the expansion is, on average, approximately 200 GWh annually. Using the AUROA model, an analysis was performed to determine the value this incremental hydro generation would provide to the system. The incremental generation is assumed to be eligible for RECs and the value of these certificates is included in the benefit calculation. The cost of the project was updated using 2015 IRP assumptions.

The analysis indicates that over the 20-year planning period, the incremental energy produced from the expansion is projected to yield a benefit to the preferred portfolio of approximately $13.8 million on an NPV basis under planning-case assumptions for natural gas price, customer load, and hydroelectric generation. However, as noted in Chapter 5, nearly 75 percent of the incremental energy in an average year will be produced during the six-month period from January through June, with substantially less production during July through September. Therefore, while the analysis indicates some economic benefit from the incremental energy, the 50-MW Shoshone Falls expansion cannot be linked to an IRP-determined resource need, as it provides little to no capacity or energy during peak summer load months.

As a result, Idaho Power will explore the construction of a smaller upgrade to more cost-effectively replace the aging 0.6 MW and 0.4 MW units at Shoshone Falls. The smaller upgrade will allow energy benefits to be realized through a much higher annual capacity factor and fulfill license requirements associated with the beneficial use of streamflow at the project location. Conceptual-level analysis indicates an upgrade having a capacity ranging in size from 1.7 MW to 4.0 MW is well suited for the hydraulic characteristics of the existing facilities. The cost analysis conducted as part of the conceptual-level study indicates energy from the smaller upgrade can be produced at a 40-year levelized cost of approximately $50 to $55 per MWh for the 4-MW upgrade and $60-$65 per MWh for the 1.7-MW upgrade. As indicated in the Action Plan in Chapter 10, Idaho Power will continue to study smaller-upgrade options and seek an amendment of the current FERC license to allow for the construction of a smaller-sized capacity upgrade to commence in 2017.

## 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 2015 IRP, Idaho Power calculated the capacity planning margin resulting from the resource development identified in P6(b), the preferred resource portfolio. When calculating the planning margin, the total resources available to meet demand consist of the additional resources available under the preferred portfolio plus the generation from existing and committed resources, assuming expected-case ($50^{th}$-percentile) water conditions. The generation from existing resources also includes expected firm purchases from regional markets. The resource total is then compared with the expected-case ($50^{th}$-percentile) peak-hour load, with the excess resource capacity designated as the planning margin. The calculated planning margin provides an alternative view of the adequacy of the preferred portfolio,

which was formulated to meet more stringent load conditions under less favorable water conditions.

Idaho Power maintains 330 MW of transmission import capacity above the forecast peak load to cover the worst single planning contingency. The worst single planning contingency is defined as an unexpected loss equal to Idaho Power's share of two units at the Jim Bridger coal facility or the loss of Langley Gulch. The reserve level of 330 MW translates into a reserve margin of over 10 percent, and the reserved transmission capacity allows Idaho Power to import energy during an emergency via the NWPP. A 330-MW reserve margin also results in the attainment of a loss-of-load expectation (LOLE) of roughly 1 day in 10 years, a standard industry measurement. Capacity planning margin calculations for July of each year through the planning period are shown in Table 9.6.

**Table 9.6 Capacity planning margin**

| | July 2015 | July 2016 | July 2017 | July 2018 | July 2019 | July 2020 | July 2021 | July 2022 | July 2023 | July 2024 | July 2025 | July 2026 | July 2027 | July 2028 | July 2029 | July 2030 | July 2031 | July 2032 | July 2033 | July 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load and Resource Balance** | | | | | | | | | | | | | | | | | | | | |
| **Peak-Hour Forecast (50th%)** | (2,923) | (3,001) | (3,044) | (3,074) | (3,107) | (3,142) | (3,196) | (3,241) | (3,265) | (3,315) | (3,344) | (3,380) | (3,446) | (3,469) | (3,506) | (3,586) | (3,603) | (3,665) | (3,711) | (3,737) |
| **Existing Resources** | | | | | | | | | | | | | | | | | | | | |
| **Coal** | | | | | | | | | | | | | | | | | | | | |
| Boardman | 55 | 55 | 55 | 55 | 55 | 55 | – | – | – | – | – | – | – | – | – | – | – | – | – | – |
| 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 | – | – | – | – | – | – | – | – | – |
| **Coal Total** | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 966 | 966 | 966 | 966 | 966 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Gas** | | | | | | | | | | | | | | | | | | | | |
| Langley Gulch | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| Gas Peakers | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 | 416 |
| **Gas Total** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| **Hydroelectric** | | | | | | | | | | | | | | | | | | | | |
| Hydroelectric (50th%)—HCC | 1,192 | 1,194 | 1,199 | 1,199 | 1,202 | 1,199 | 1,196 | 1,193 | 1,190 | 1,187 | 1,184 | 1,181 | 1,178 | 1,175 | 1,172 | 1,169 | 1,167 | 1,164 | 1,161 | 1,158 |
| Hydroelectric (50th%)—Other | 295 | 295 | 295 | 295 | 295 | 295 | 294 | 293 | 293 | 292 | 291 | 290 | 289 | 289 | 288 | 287 | 287 | 286 | 285 | 284 |
| **Hydroelectric Total (50th%)** | 1,487 | 1,488 | 1,493 | 1,493 | 1,497 | 1,494 | 1,490 | 1,486 | 1,482 | 1,479 | 1,475 | 1,471 | 1,467 | 1,464 | 1,460 | 1,457 | 1,453 | 1,450 | 1,446 | 1,442 |
| **CSPP (PURPA) Total** | 156 | 220 | 405 | 405 | 405 | 405 | 405 | 405 | 405 | 405 | 405 | 404 | 404 | 404 | 401 | 400 | 390 | 389 | 380 | 380 |
| **PPAs** | | | | | | | | | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | – | – | – | – | – | – | – |
| Raft River Geothermal | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 |
| Neal Hot Springs Geothermal | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 |
| Clatskanie Exchange—Take | 10 | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – |
| Clatskanie Exchange—Return | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – |
| **PPAs Total** | 33 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 18 | 18 | 18 | 18 | 18 | 18 | 18 |

**Table 9.6 Capacity planning margin (continued)**

| | July 2015 | July 2016 | July 2017 | July 2018 | July 2019 | July 2020 | July 2021 | July 2022 | July 2023 | July 2024 | July 2025 | July 2026 | July 2027 | July 2028 | July 2029 | July 2030 | July 2031 | July 2032 | July 2033 | July 2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Firm Pacific Northwest Import Capability Total** | 243 | 243 | 239 | 234 | 230 | 227 | 224 | 273 | 270 | 266 | 261 | 257 | 254 | 249 | 245 | 242 | 238 | 234 | 230 | 230 |
| **Existing Resource Subtotal** | 3,656 | 3,711 | 3,897 | 3,892 | 3,892 | 3,886 | 3,824 | 3,869 | 3,862 | 3,854 | 3,846 | 3,574 | 3,567 | 3,554 | 3,544 | 3,535 | 3,518 | 3,510 | 3,493 | 3,489 |
| **Monthly Surplus/Deficit** | 733 | 710 | 853 | 818 | 785 | 743 | 628 | 628 | 597 | 540 | 501 | 194 | 121 | 85 | 38 | (51) | (84) | (156) | (218) | (248) |
| **2013 IRP Resources** | | | | | | | | | | | | | | | | | | | | |
| 2025 B2H | – | – | – | – | – | – | – | – | – | – | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| 2030 Demand Response | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | 60 | 60 | 60 | 60 | 60 |
| 2030 Ice-Based TES | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | 20 | 20 | 20 | 20 | 20 |
| 2031 CCT | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | – | 300 | 300 | 300 | 300 |
| **New Resource Subtotal** | **–** | **–** | **–** | **–** | **–** | **–** | **–** | **–** | **–** | **–** | 500 | 500 | 500 | 500 | 500 | 580 | 880 | 880 | 880 | 880 |
| **Remaining Monthly Surplus/Deficit** | 733 | 710 | 853 | 818 | 785 | 743 | 628 | 628 | 597 | 540 | 1,001 | 694 | 621 | 585 | 538 | 529 | 796 | 724 | 662 | 632 |
| **Planning Margin** | 25% | 24% | 28% | 27% | 25% | 24% | 20% | 19% | 18% | 16% | 30% | 21% | 18% | 17% | 15% | 15% | 22% | 20% | 18% | 17% |

## Flexible Resource Needs Assessment

Idaho Power analyzed the need for flexible resources as directed by the OPUC in Order 12-013. Idaho Power determined there are adequate flexible resources to address up-regulation (up-regulation is required when intermittent generation is less than the quantity scheduled and Idaho Power generation must overcome the generation shortfall). Idaho Power determined there are likely to be insufficient down-regulation resources available at certain times of the year. Specifically, down-regulation deficiencies occur during periods of oversupply when all of the Idaho Power generation resources are reduced to safe operating levels, yet company generation plus the intermittent generation exceeds customer load.

Idaho Power analyzed the flexible resource needs using the data developed for the solar integration study. The data consisted of actual load, actual wind, and simulated PV solar generation for 500 MW of solar plant at six geographic locations throughout Idaho Power's service area. The data were developed at five-minute intervals over three water years from October 2010 through September 2013.

The first step in the analysis was to estimate the flexible resource requirement. Idaho Power calculated the flexible need requirement in 5-, 10-, 15-, 30-, 45-, and 60-minute intervals from the dataset, and the results are presented in Figure 9.4. The one-percent likelihood shown in Figure 9.4 is the total likelihood, composed of one-half percent up plus a one-half percent down.

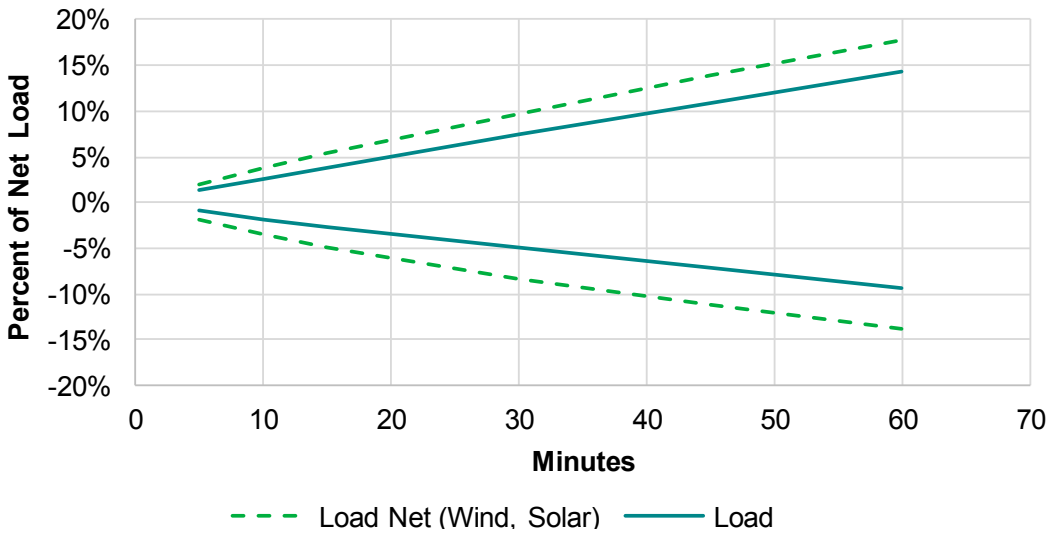



**Figure 9.4 Flexibility need (500 MW solar, existing wind, 1% likelihood)**

Figure 9.4 shows that adding intermittent resources to the Idaho Power system increases the flexibility need, both up and down. Idaho Power has a second solar integration study underway to further analyze the effects of adding intermittent utility-scale solar PV generation to Idaho Power's system.

Idaho Power used a resource dispatch simulation of Idaho Power's system to forecast available system flexibility after adding 500 MW of solar PV to the generation mix. The purpose of the simulation was to assess both the regulation requirement and supply. The simulation was performed using a one-hour time step. Up-regulation and down-regulation quantities were assessed to determine the net result of flexible resource needs and flexible resource supply. A representative graph of system regulation during the spring is shown in Figure 9.5 (April 2012 historical data with the addition of 500 MW of solar PV on the system).

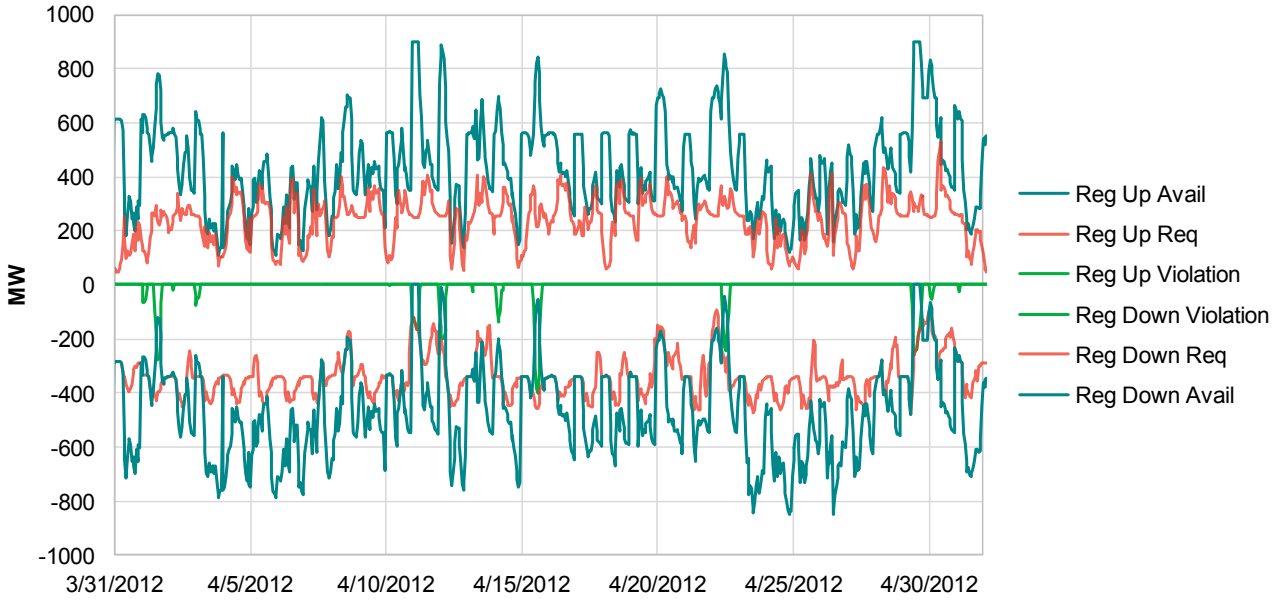



**Figure 9.5 System regulation**

Figure 9.5 shows the five quantities:

1. Up-regulation available
2. Up-regulation requirement
3. Regulation violation (both up and down)
4. Down-regulation requirement
5. Down-regulation available

Figure 9.6 is simplified to focus on the regulation violation by removing the lines showing the regulation requirement and the regulation available.

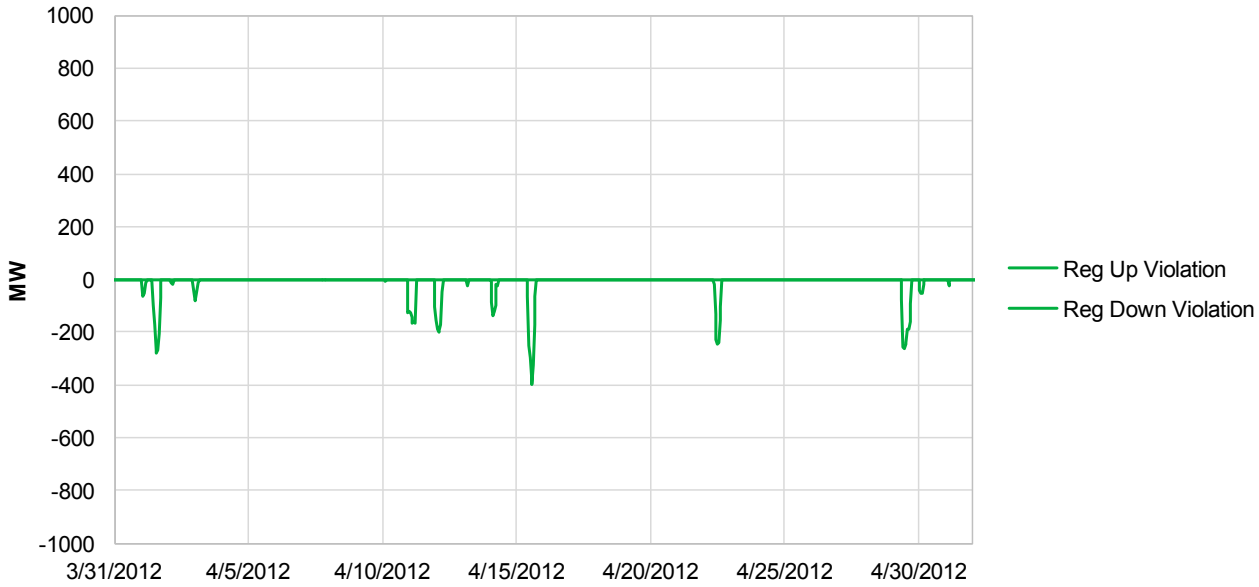



**Figure 9.6 Regulation violations, spring 2012**

Figure 9.6 shows significant down-regulation violations during certain hours of the spring. The down-regulation violations occur during periods of oversupply when all of the Idaho Power generation resources are reduced to safe operating levels, yet company generation plus the intermittent generation exceeds customer load. There are no up-regulation violations during the April study period.

Idaho Power analyzed the other three seasons of the year and determined that regulation is primarily an issue during the spring. The graphs for summer, fall, and winter are shown in figures 9.7 through 9.9.




**Figure 9.7 Regulation violations, summer 2012**




**Figure 9.8 Regulation violations, fall 2011**

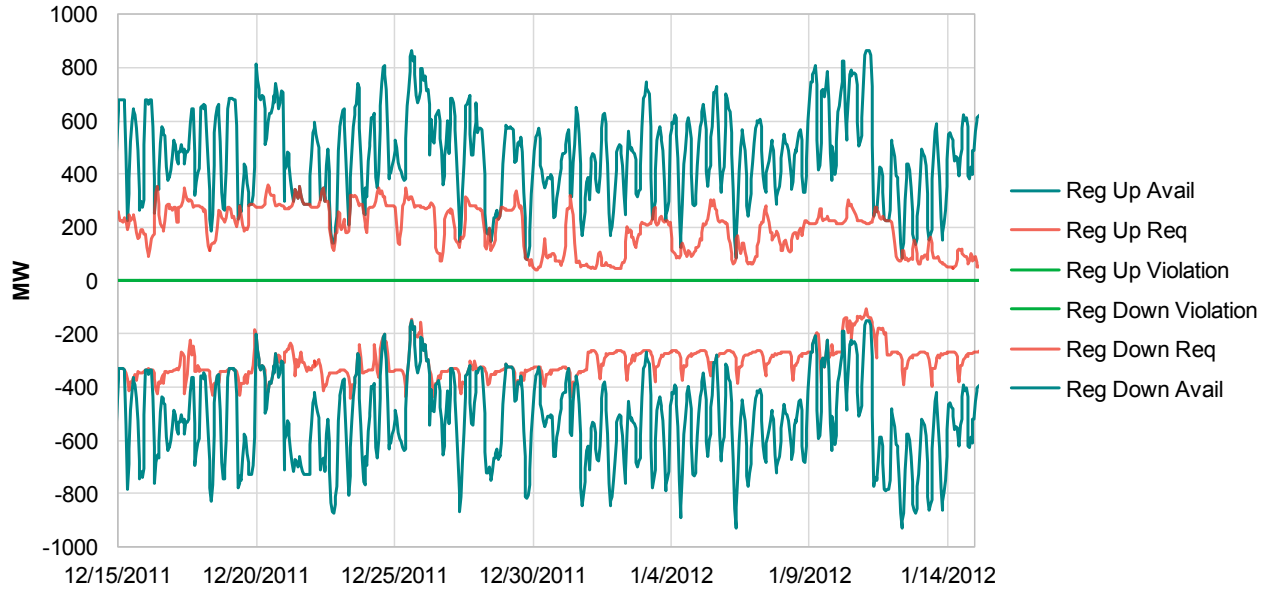



**Figure 9.9 Regulation violations, winter 2011/2012**

As shown in figures 9.7 through 9.9, zero violations are evident through the summer, fall, and winter seasons, except a single small down-regulation violation in one hour of the summer season. The summer down-regulation violation is less than 10 MW; however, down-regulation violations could become an issue during some summer hours. Several times during the four seasons, the regulation available equals the regulation requirement, indicating Idaho Power's system is operating at the regulation limits. The simulations show it is more likely for Idaho Power's system to face down-regulation limits than up-regulation limits.

Idaho Power is currently conducting a second solar integration study. Idaho Power anticipates additional regulation analysis will occur as part of the second solar integration study. Idaho Power expects to update the flexibility analysis with the results of the second solar integration study in the 2017 IRP. Down-regulation is a significant concern during periods of oversupply for Idaho Power and other utilities in the region. Idaho Power is currently investigating methods to address potential down-regulation violations.

## Loss of Load Expectation

Idaho Power used a spreadsheet model[10] to calculate the LOLE for the 11 portfolios studied in the stochastic risk analysis in the 2015 IRP. The assessment assumes critical water conditions at the existing hydroelectric facilities and the planned additions for the selected portfolios. As mentioned in the Capacity Planning Margin 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 2015 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 (equivalent demand forced outage rates), 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 days in a given year, although existing programs allow use up to 15 days. The 10-day assumption was chosen as a conservative reflection of reality where it is assumed some days will be left in reserve for unexpected extreme weather. Ice TES resources were modeled as a reduction to hourly load during afternoon/evening hours in summer months and an increase in hourly load during night hours in summer months. The LOLE analysis is performed monthly to permit capacity de-rates for maintenance or a lack of fuel (water). Resource capacities are assumed to be constant for all hours each month with the exception of demand response and ice TES as explained above, as well as solar PV resources. PV resources are modeled with a capacity that varies by hour for each month according to changing daylight hours and sun position.

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 hours per year.

The results of the LOLE probability analysis are shown in Figure 9.10. Several portfolios result in a LOLE greater than 2 hours per year, which indicates that additional purchases or generation capacity would be necessary in the future to achieve acceptable performance. The results indicate that resource portfolios 2(a), 6(b), 8, 10, 11, and 13 are the best performers with an LOLE under two hours per year over the 20-year planning horizon. Additional data can be found in *Appendix C—Technical Appendix*.

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

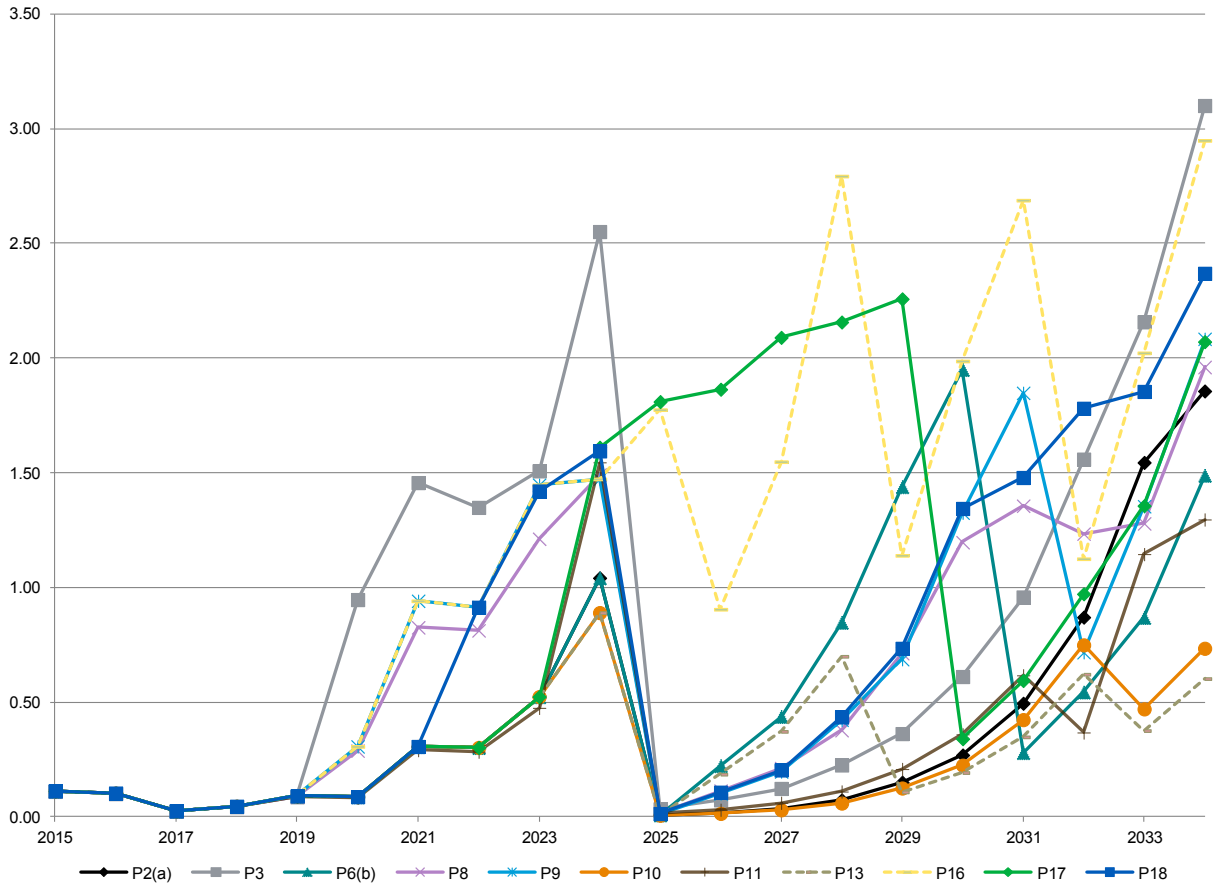



**Figure 9.10 LOLE (hours per year)**

# 10. Preferred Portfolio and Action Plan

## Preferred Portfolio (2015–2034)

Analysis for the 2015 IRP consistently indicates favorable economics associated with two significant resource actions: the B2H transmission line and the early retirement of the North Valmy Power Plant. IRP analysis suggests a strong connection between these resource actions, both of which are characterized by uncertain timetables. Specifically, an acceleration in the completion of the B2H line can be expected to provide the system reliability and access to markets allowing for a corresponding acceleration in the early retirement of North Valmy.

The B2H transmission line and early North Valmy retirement are two key resource actions of portfolio P6(b), the 2015 IRP's preferred resource portfolio. Portfolio P6(b) contains both actions in the year 2025, with the completion of the transmission line preceding the end-of-year coal plant retirement. Portfolio P6(b) contains no other resource actions through the end of the 2020s, adding 60 MW of demand response and 20 MW of ice-based TES in 2030 and a 300-MW CCCT in 2031.

The absence of resource needs in portfolio P6(b) prior to the 2025 retirement of North Valmy is noteworthy. The resource sufficiency through the early 2020s shields portfolio P6(b) from risk exposure associated with the following factors:

1. Uncertainty related to planned but yet-to-be-built PURPA solar; further project cancellations beyond those already observed will have a greater impact on portfolios requiring capacity additions in the early 2020s.

2. Uncertainty related to the EPA's proposed regulation of $CO_2$ emissions from existing power plants under CAA Section 111(d), particularly the effect of the final regulation on operations at coal and natural gas-fired power plants in the proposed interim compliance period beginning in 2020.

3. Uncertainty related to the completion date of the B2H line due to permitting issues and needs of project partners.

4. Uncertainty related to retirement planning for a jointly owned power plant (North Valmy), specifically the challenges associated with arriving at a mutually feasible retirement date.

Uncertainty is a common part of long-term integrated resource planning. Even with the increased uncertainty surrounding the 2015 IRP, the analysis indicates completion of the B2H line and early retirement of the North Valmy Power Plant are prudent actions. The timing of the actions can be appropriately adjusted as conditions related to the four factors listed above become actionable.

## Action Plan (2015–2018)

The action plan for the 2015 to 2018 period includes items specifically related to the preferred portfolio P6(b) and other items irrespective of the portfolio selected. The P6(b) action items

include continued permitting and planning for the B2H transmission line and investigation of North Valmy retirement in collaboration with plant co-owner NV Energy. The pursuit of these items over the action plan period is critical to the successful and timely implementation of the preferred portfolio.

The Gateway West transmission line remains a key future resource to Idaho Power and the region, promoting continued grid reliability in a time of expanding variable energy resources. Therefore, the plan includes continued permitting and planning associated with the Gateway West project.

CAA Section 111(d) will potentially have a pronounced impact on coal and natural gas-fired power plant operations on Idaho Power's system and throughout the nation. Idaho Power will remain involved as a stakeholder as CAA Section 111(d) moves toward finalization and implementation. As stipulations of the final regulation become clearer, and as implementation planning is developed, Idaho Power will assess the impacts of CAA Section 111(d) on the preferred portfolio.

The action plan also includes the following items:

- Continued pursuit of cost-effective energy efficiency, working with stakeholder groups, such as EEAG and regional groups such as NEEA
- Filing to amend the FERC license to adjust the 50-MW Shoshone Falls project expansion and efforts related to the study and construction a smaller upgrade of the project with a scheduled on-line date in the first quarter of 2019
- Completion of SCR retrofits for Jim Bridger units 3 and 4
- Begin economic evaluation of SCR retrofits for Jim Bridger units 1 and 2 (SCR installation required for Unit 1 in 2022 and for Unit 2 in 2021)

Table 10.1 provides actions with dates for the 2015 to 2018 period.

**Table 10.1 Action plan (2015–2018)**

| Year | Resource | Action | Action Number |
|---|---|---|---|
| 2015–2018 | B2H | Ongoing permitting, planning studies, and regulatory filings | 1 |
| 2015–2018 | Gateway West | Ongoing permitting, planning studies, and regulatory filings | 2 |
| 2015–2019 | Energy efficiency | Continue the pursuit of cost-effective energy efficiency. The forecast reduction for 2015–2019 programs is 84 average megawatts (aMW) for energy demand and 126 MW for peak demand. | 3 |
| 2015–2016 | N/A | Coordinate with government agencies on implementation planning for CAA Section 111(d). | 4 |
| 2015 | Shoshone Falls | File to amend FERC license regarding 50-MW expansion | 5 |
| 2015 | Jim Bridger Unit 3 | Complete installation of SCR emission-control technology | 6 |
| 2015-2016 | Shoshone Falls | Study options for smaller upgrade ranging in size up to approximately 4 MW | 7 |
| 2016 | Jim Bridger Unit 4 | Complete installation of SCR emission-control technology | 8 |

**Table 10.1 Action Plan (2015–2018) (continued)**

| Year | Resource | Action | Action Number |
|---|---|---|---|
| 2016 | North Valmy units 1 and 2 | Continue to work with NV Energy to synchronize depreciation dates and determine if a date can be established to cease coal-fired operations | 9 |
| 2017 | Shoshone Falls | Commence construction of a smaller upgrade | 10 |
| 2017 | Jim Bridger units 1 and 2 | Evaluate the installation of SCR technology for units 1 and 2 at Jim Bridger in the 2017 IRP | 11 |
| 2019 | Shoshone Falls | On-line date for smaller upgrade during first quarter | 12 |

Idaho Power has several choices when procuring long-term energy. It can develop and own generation assets, rely on PPA and market purchases, or use a combination of the two strategies. During the action plan period, Idaho Power expects to continue participating in the regional power market and enter into mid- and long-term PPAs. However, 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 2015 IRP analysis indicates favorable results for the B2H transmission line and the early retirement of the North Valmy Power Plant. The analysis also suggests a linkage between the B2H line and the early retirement of North Valmy. Acceleration in the completion of the transmission line could bring about a corresponding acceleration in scheduling for North Valmy retirement.



View of the Hemingway Substation.

Idaho Power has treated the B2H transmission line as an uncommitted resource in every IRP beginning with the 2006 IRP. For every IRP, including the 2015 IRP, the B2H line has been a top-performing resource alternative. The consistency of these analyses 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 B2H transmission line.

Idaho Power strongly supports public involvement in the planning process. Idaho Power thanks the IRPAC members and the public for their contributions to the 2015 IRP. The IRPAC discussed many technical aspects of the 2015 resource plan along with a significant number of political and societal topics at the meetings, portfolio design workshop, and field trip to an Idaho Power facility. Idaho Power's resource plan is better because of the contributions from the IRPAC members and the public.

Idaho Power prepares an IRP every two years, and the next plan will be filed in 2017. As described in this plan, the coming years are characterized by considerable uncertainty

associated with energy-related issues on the state, regional, and national levels. Idaho Power anticipates that as uncertainty related to these issues clears, the 2015 IRP preferred portfolio and action plan may be adjusted in the next IRP filed in 2017, or sooner if directed by the IPUC or OPUC.

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June 2015

# Integrated Resource Plan 2015

## APPENDIX A
## Sales and Load Forecast







## SAFE HARBOR STATEMENT

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

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June 2015

# Integrated Resource Plan 2015

## APPENDIX A
## Sales and Load Forecast

## ACKNOWLEDGMENT

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 *2015 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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# INTRODUCTION

Idaho Power has prepared *Appendix A—Sales and Load Forecast* as part of the *2015 Integrated Resource Plan* (IRP). The sales and load forecast is Idaho Power's best estimate of the future demand for electricity within the company's service area. The forecast covers the 20-year period from 2015 through 2034.

The expected-case monthly average load forecast represents Idaho Power's estimate of the most probable outcome for load growth during the planning period and is based on the most recent economic forecast for Idaho Power's service area. To account for inherent uncertainty and variability, four additional load forecasts were prepared—two that provide a range of possible load growths due to economic uncertainty and two that address the load variability associated with abnormal weather. The high and low economic growth scenarios provide a range of possible load growths over the planning period due to variable economic, demographic, and other non-weather-related influences. The high-growth and low-growth scenarios were prepared based on statistical analyses to empirically reflect uncertainty inherent in the load forecast. The 70$^{th}$-percentile and 90$^{th}$-percentile load forecast scenarios were developed to assist Idaho Power in reviewing the resource requirements that would result from higher loads due to more adverse weather conditions.

While the expected-case load forecast assumes median historical values (50$^{th}$ percentile) for temperatures and median rainfall, the weather scenarios are developed with a 70$^{th}$-percentile and a 90$^{th}$-percentile weather probability assumption. The 70$^{th}$-percentile load forecast assumes monthly loads that can be exceeded in 3 out of 10 years (30% of the time). The 90$^{th}$-percentile load forecast assumes monthly loads that can be exceeded in 1 out of 10 years (10% of the time). Idaho Power uses the 70$^{th}$-percentile load forecast in IRP resource planning to account for the risk associated with weather impacts on load.

In the expected-case scenario, Idaho Power's system load is forecast to increase to 2,240 average megawatts (aMW) by 2034 from 1,786 aMW in 2015, representing an average yearly growth rate of 1.2 percent over the 20-year planning period (2015–2034). In the more critical 70$^{th}$-percentile load forecast used for resource planning, the system load is forecast to reach 2,292 aMW by 2034 (1.2% average annual growth).

The Idaho Power system peak load (95$^{th}$ percentile) is forecast to grow to 4,773 megawatts (MW) in 2034 from the actual system summer peak of 3,407 MW that occurred on Tuesday, July 2, 2013, at 4:00 p.m. In the expected-case scenario, the Idaho Power system peak increases at an average growth rate of 1.5 percent per year over the 20-year planning period (2015–2034).

This year's economic forecast was based on a forecast of national and regional economic activity developed by Moody's Analytics, Inc. The national, state, metropolitan statistical area (MSA) and county econometric projections are tailored to Idaho Power's service area using an in-house economic forecast model and database. Specific demographic projections are also developed for the service area from national and local census data. National economic drivers from Moody's Analytics were also used in the development of *Appendix A—Sales and Load Forecast*. The number of Idaho Power active retail customers is expected to increase from the December 2014 level of 514,700 customers to nearly 710,000 customers by year-end 2034.

Economic growth assumptions influence several classes of service growth rates. The number of households in Idaho is projected to grow at an annual rate of 1.9 percent during the forecast period. The growth in the number of households within individual counties in Idaho Power's service area is projected to grow faster than the remainder of the state over the planning period. In addition, the number of households, incomes, employment, economic output, real retail electricity prices, and customer consumption patterns are used to develop load projections.

In addition to the economic assumptions used to drive the expected-case forecast scenario, several assumptions were incorporated into the forecasts of the residential, commercial, industrial, and irrigation sectors. Further discussions of these assumptions are presented below.

Conservation influences on the load forecast, including Idaho Power energy efficiency demand-side management (DSM) programs, statutory programs, and non-programmatic trends in conservation, are included in the load forecasts of each sector. Idaho Power DSM programs are described in detail in Idaho Power's *Demand-Side Management 2014 Annual Report*, which is incorporated into this IRP document as Appendix B.

During the 20-year forecast horizon, major changes in the electric utility industry (e.g., carbon regulations and subsequent higher electricity prices impacting future electricity demand) could influence the load forecast. In addition, the price and volatility of substitute fuels, such as natural gas, may also impact future demand for electricity. The high degree of uncertainty associated with such changes is reflected in the economic high and low load growth scenarios described previously. The impact of carbon legislation on the load forecast is reflected in the retail electricity price variable for each forecasted customer sector. The alternative sales and load scenarios in *Appendix A—Sales and Load Forecast* were prepared under the assumption that Idaho Power's geographic service area remains unchanged during the planning period.

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

# 2015 IRP SALES AND LOAD FORECAST

## Average Load

The 2015 IRP average annual system load forecast reflects the continued improvement in the service area economy. While economic conditions during the development of the 2013 IRP were positive, they were less optimistic than the actual performance experienced in the interim period leading up to the 2015 IRP. The improved economic and demographic variables driving the 2015 forecast are reflected by a more positive sales outlook throughout the planning period. The stalled recovery in the national and, to a lesser extent, service-area economy caused load growth to stall through 2011. However, in 2012, the recovery was evident, with strength exhibited in most all economic drivers to date. Retail electricity price projections for the 2015 IRP are lower relative to the 2013 IRP, serving to increase the forecast of average loads, especially in the second 10 years of the forecast period.

Significant factors and considerations that influenced the outcome of the 2015 IRP load forecast include the following:

- The load forecast used for the 2015 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 beginning in 2008 held new construction and customer growth to a near standstill until 2012. However, beginning in 2012, acceleration of in-migration and business investment resulted in renewed growth in the residential and commercial connections along with increased industrial activity. By 2017, customer additions are forecast to approach sustainable growth rates experienced prior to the housing bubble (2000–2004).

- The electricity price forecast used to prepare the sales and load forecast in the 2015 IRP reflects the impact of additional plant investment and associated variable costs of integrating new resources identified in the 2013 IRP preferred portfolio, including the expected costs of carbon emissions. As discussed previously, when compared to the electricity price forecast used to prepare the 2013 IRP sales and load forecast, the 2015 IRP price forecast yields lower future prices. The retail prices are most evident in the second 10 years of the planning period and impact the sales forecast positively, a consequence of the inverse relationship between electricity prices and electricity demand.

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

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

- The 2015 irrigation sales forecast is higher than the 2013 IRP forecast throughout the entire forecast period due to the significant trend toward more water-intensive crops, primarily alfalfa and corn, due to growth in the dairy industry. Also, farmers have taken advantage of higher market prices over the past few years and have put high-lift acreage back into production. Additionally, load increases have come from the conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to farmers trying to reduce labor costs.

## Peak-Hour Demands

Peak-day temperatures and the growth in average loads drive the peak forecasting model regressions. The peak forecast results and comparisons with previous forecasts differ for a number of reasons that include the following:

- The 2015 IRP peak-demand forecast considers the impact of committed and implemented energy efficiency DSM programs on peak demand.

- The 2015 IRP peak-demand forecast model explicitly excludes the impact of demand response programs to establish peak impacts. The exclusion allows for planning for demand response programs and supply-side resources in meeting peak demand. Demand response program impacts are accounted for in the IRP load and resource balance and are reflected as a reduction in peak demand.

- The peak model develops peak-scenario impacts based on historical probabilities of peak-day temperatures at the $50^{th}$, $90^{th}$, and $95^{th}$ percentiles of occurrence for each month of the year.

- The all-time system summer peak demand was 3,407 MW (recorded on Tuesday, July 2, 2013, at 4:00 p.m.) and serves as a benchmark for the forecasting model. The previous summer peak demand was 3,245 MW, occurring on Thursday, July 12, 2012, at 4:00 p.m. Historical peak-demand data serve as the basis in the peak-model regressions. Historical new peak loads were reached in July 2007, June 2008, July 2012, and July 2013.

- The summer system peak load growth accelerated from 1998 to 2008 as a record number of residential and commercial customers were added to the system and air conditioning (A/C) became standard in nearly all new residential homes and new commercial buildings.

- Idaho Power uses a median peak-day temperature driver in lieu of an average peak-day temperature driver in the 50/50 peak-demand forecast scenario. The median peak-day temperature has a 50-percent probability of being exceeded. Peak-day temperatures are not normally distributed and can be skewed by one or more extreme observations as referred to in the previous bulleted item; therefore, the median temperature better reflects expected temperatures within the context of probabilistic percentiles. The weighted average peak-day temperature drivers are calculated over the 1984 to 2013 time period (the most recent 30 years).

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# OVERVIEW OF THE FORECAST

The sales and load forecast is constructed by developing a separate forecast for each of the major customer classes: residential, commercial, irrigation, and industrial. Individual energy and peak-demand forecasts are developed for special-contract customers, including Micron Technology, Inc.; Simplot Fertilizer Company (Simplot Fertilizer); and the Idaho National Laboratory (INL). These three special-contract customers are reported as a single forecast category labeled additional firm load. Currently, Idaho Power has no long-term contracts to provide off-system customers with firm energy and demand. The assumptions for each of the individual categories are described in greater detail in the respective sections.

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

Loss factors are determined by Idaho Power's Transmission Planning department. The annual average energy loss coefficients are multiplied by the calendar-month load, yielding the system load, including losses. A system loss study of 2012 was completed in May 2014. The results of the study concluded that on average, the loss coefficients are lower than those applied to the 2013 IRP generation forecast. This resulted in a permanent reduction of nearly 20 aMW to the load forecast annually.

The peak-load forecast was prepared in conjunction with the 2015 sales forecast. Idaho Power has two peak periods: 1) a winter peak, resulting primarily from space-heating demand that normally occurs in December, January, or February and 2) a larger summer peak that normally occurs in late June or July. The summer peak generally occurs when extensive A/C use coincides with significant irrigation demand.

Peak loads are forecast using 12 regression equations and are a function of average peak-day temperatures, the historical monthly average load, and precipitation (summer only). The peak forecast uses statistically derived peak-day temperatures based on the most recent 30 years of climate data for each month. Peak loads for the INL, Micron Technology, and Simplot Fertilizer are forecast based on a historical analysis, customer-provided input, and any contractual considerations.

The primary external factors influencing the forecast are economic and demographic in nature. Moody's Analytics serves as the primary provider for this data. The national, state, MSA, and county economic and demographic projections are tailored to Idaho Power's service area using an in-house economic database. Specific demographic projections are also developed for the service area from national and local census data. Additional data sources used to substantiate Moody's data include the Idaho Department of Labor, Construction Monitor, and Federal Reserve Economic Databases.

## Fuel Prices

Fuel prices, in combination with service-area demographic and economic drivers, impact long-term trends in electricity sales. Changes in relative fuel prices can also have significant impacts on the future demand for electricity. The sales and load forecast is also influenced by the estimated impact of proposed carbon legislation on retail electricity prices. In addition to supply-side influences, carbon-reduction legislation creates an upward trend in retail electricity prices throughout the forecast period, resulting in reduced future electricity sales. Class-level and economic-sector-level regression models were used to identify the relationships between real historical electricity prices and their impact on historical electricity sales. The estimated coefficients from these models were used as drivers in the individual sales forecast models.

Short-term and long-term nominal electricity price increases are generated internally from Idaho Power financial models. The United States (US) Energy Information Administration (EIA) provides the forecasts of long-term changes in nominal natural gas prices. The nominal price estimates are adjusted for projected inflation by applying the appropriate economic deflators to arrive at real fuel prices. The projected average annual growth rates of fuel prices in nominal and real terms (adjusted for inflation) are presented in Table 1. The growth rates shown are for residential fuel prices and can be used as a proxy for fuel-price growth rates in the commercial, industrial, and irrigation sectors.

**Table 1. Residential fuel-price escalation (2015–2034) (average annual percent change)**

| | Nominal | Real* |
|---|---|---|
| Electricity—2015 IRP | 1.9% | 0.0% |
| Electricity—2013 IRP | 2.9% | 1.0% |
| Natural Gas | 3.2% | 1.3% |

* Adjusted for inflation

Figure 1 illustrates the average electricity price paid by Idaho Power's residential customers over the historical period 1979 to 2014 and over the forecast period 2015 to 2034. Both nominal and real prices are shown. In the 2015 IRP, nominal electricity prices are expected to climb to about 14 cents per kilowatt-hour (kWh) by the end of the forecast period in 2034. Real electricity prices (inflation adjusted) are expected to remain flat over the forecast period at an average rate of 0.0 percent annually. In the 2013 IRP, nominal electricity prices were assumed to climb to about 18 cents per kWh by 2034, and real electricity prices (inflation adjusted) were expected to slowly increase over the forecast period at an average rate of 1.0 percent annually. The impact of the lower real electricity price forecast on the 2015 IRP load forecast serves to positively influence the growth in electricity sales, especially in the last 10 years of the forecast period.

The electricity price forecast used to prepare the sales and load forecast in the 2015 IRP reflected the additional plant investment and variable costs of integrating the resources identified in the 2013 IRP preferred portfolio, including the expected costs of carbon emissions. When compared to the electricity price forecast used to prepare the 2013 IRP sales and load forecast, the 2015 IRP price forecast yielded lower future prices. The retail prices are more evidently lower in the

second 10 years of the planning period and impact the sales forecast positively, a consequence of the inverse relationship between electricity prices and electricity demand.

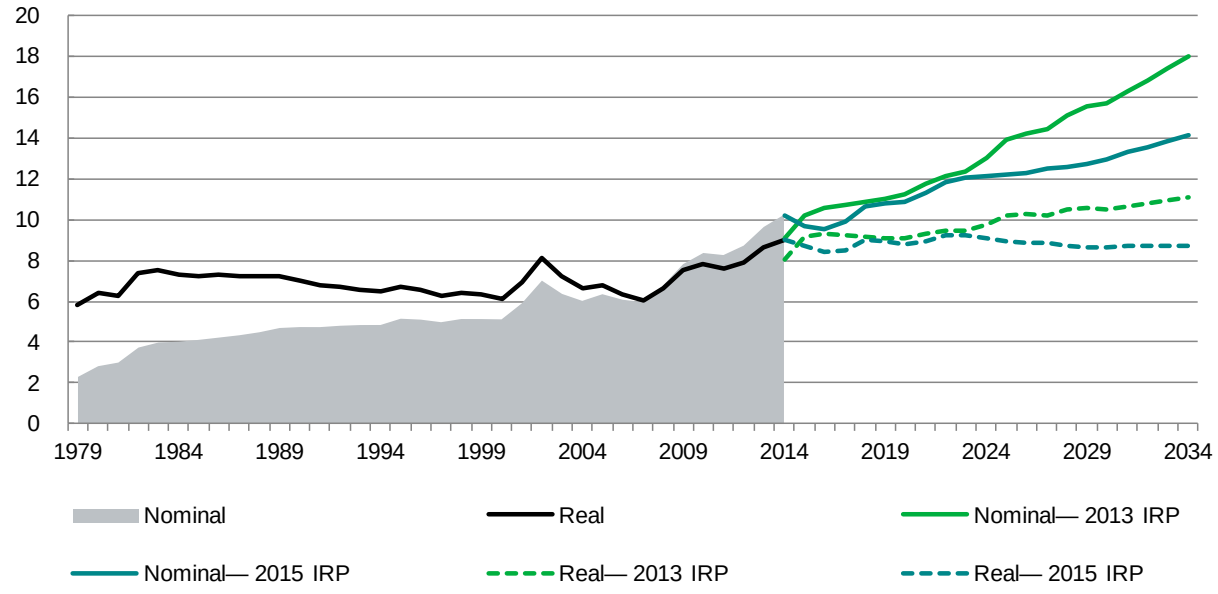



**Figure 1. Forecast residential electricity prices (cents per kWh)**

Electricity prices for Idaho Power customers increased significantly in 2001 and 2002 because of the power cost adjustment (PCA) impact on rates, a direct result of the western US energy crisis of 2000 and 2001. Prior to 2001, Idaho Power's electricity prices were historically quite stable. From 1990 to 2000, electricity prices rose only 8 percent overall, an annual average compound growth rate of 0.8 percent annually.

Figure 2 illustrates the average natural gas price paid by Intermountain Gas Company's residential customers over the historical period 1979 to 2013 and forecast prices from 2014 to 2034. Natural gas prices remained stable and flat throughout the 1990s before moving sharply higher in 2001. Since spiking in 2001, natural gas prices moved downward for a couple of years before moving sharply upward in 2004 through 2006. Since 2006, natural gas prices have experienced a steady decline, matching prices from over a decade ago. Nominal natural gas prices are expected to remain flat through 2017, then rise at a steady pace throughout the remainder of the forecast period until nearly doubling by 2034, growing at an average rate of 3.2 percent per year. Real natural gas prices (adjusted for inflation) are expected to increase over the same period at an average rate of 1.3 percent annually.

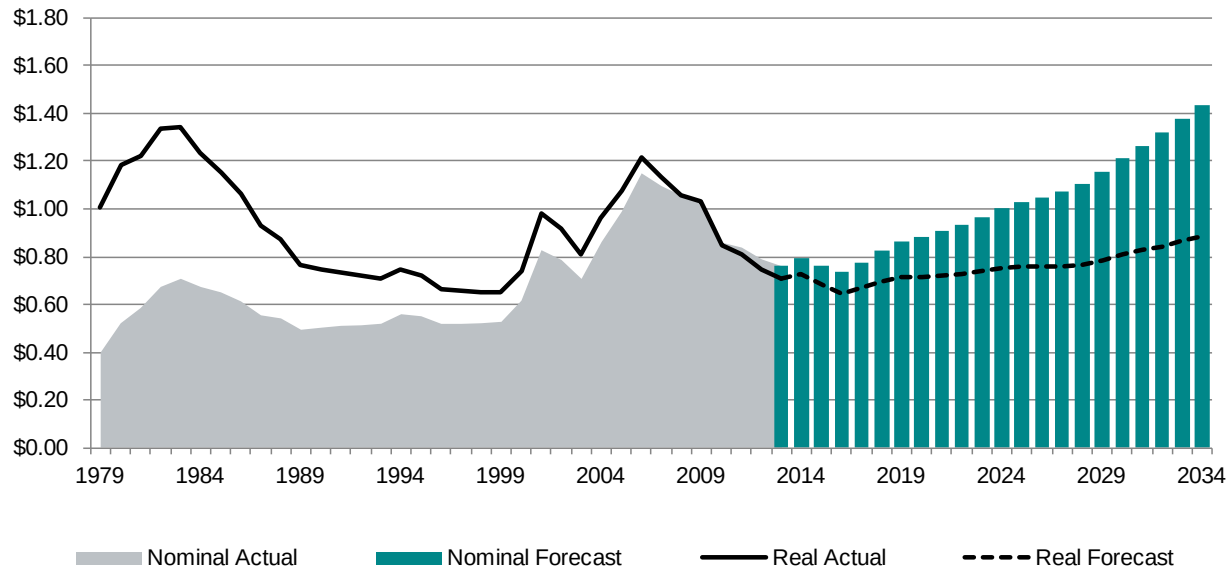



**Figure 2. Forecast residential natural gas prices (dollars per therm)**

If future natural gas price increases outpace electricity price increases, the operating costs of space heating and water heating with electricity would become more advantageous when compared to that of natural gas. However, in the 2015 IRP price forecast, the long-term growth rates of electricity and natural gas prices are nearly identical.

## Electric Vehicles

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

Since the first introduction of the Chevy Volt and Nissan Leaf, the number of PEVs offered in the marketplace has proliferated to over 50 models since 2007. Early in this period, PEVs were sold with unique model names (e.g., VOLT); however, as the market grows, the plug-in technology is increasingly offered as an option to existing models (e.g., Ford Focus).

Initially, the Idaho Power forecast for PEV impact relied on third-party forecasts from the Electric Power Research Institute (EPRI) and Oak Ridge National Laboratory due to a lack of service-area vehicle registration data; however, beginning with the 2011 IRP, sufficient service-area data became available via vehicle registration data provided by the Idaho Transportation Department (ITD). This data provides a basis from which to develop service-area adoption rates and support the collection of charging behavior. The methodology continues to integrate the fuel and technology share forecasts of the Department of Energy's (DOE) National Energy Model (NEM). The Idaho Power vehicle share forecast uses these models as well as a Bass consumer adoption model as informed by registration data. Load impacts from the share model output are derived from assumptions of battery-only and hybrid plug-in shares evident from Idaho Power observations and informed by the DOE.

Currently, the registration data collection methodology is being revised to capture vehicles sold with PEV technology as an option (e.g., Ford Focus). The methodology will require the unique string of characters within the vehicle identification number (VIN) to be identified and serve as a key value in the ITD data extraction.

The PEV forecast in this IRP did include registration data for the Toyota Prius PEV but did not capture all models for which PEV technology is sold as an option; however, to capture the impact of these models on future adoption, the forecast used the forecast national share assumptions from the DOE. The net effect was to rely less on the registration data than the 2013 IRP model and more on third-party assumptions, as was the case in earlier forecasts.

# Forecast Probabilities

## *Load Forecasts Based on Weather Variability*

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

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

Maximum load occurs when the highest recorded levels of heating degree days (HDD) are assumed in winter and the highest recorded levels of cooling and growing degree days (CDD and GDD) combined with the lowest recorded level of precipitation are assumed in summer. Conversely, the minimum load occurs when the lowest recorded levels of HDD are assumed in winter and the lowest recorded levels of CDD and GDD, combined with the highest level of precipitation, are assumed in summer.

For example, at the Boise Weather Service office, the median HDD in December from 1984 to 2013 (the most recent 30 years) was 1,039. The 70$^{th}$-percentile HDD is 1,074 and would be exceeded in 3 out of 10 years. The 90$^{th}$-percentile HDD is 1,268 and would be exceeded in 1 out of 10 years. The 100$^{th}$-percentile HDD (the coldest December over the 30 years) is 1,619 and occurred in December 1985. This same concept was applied in each month throughout the year in only the weather-sensitive customer classes: residential, commercial, and irrigation.

In the 70$^{th}$-percentile residential and commercial load forecasts, temperatures in each month were assumed to be at the 70$^{th}$ percentile of HDD in wintertime and at the 70$^{th}$ percentile of CDD in summertime. In the 70$^{th}$-percentile irrigation load forecast, GDD were assumed to be at the 70$^{th}$ percentile and precipitation at the 30$^{th}$ percentile, reflecting drier-than-median weather. The 90$^{th}$-percentile load forecast was similarly constructed.

Idaho Power loads are highly dependent on weather, and these two scenarios allow the careful examination of load variability and how it may impact future resource requirements. It is important to understand that the probabilities associated with these forecasts apply to any given month. To assume temperatures and precipitation would maintain a 70th-percentile or 90th-percentile level continuously, month after month throughout an entire year, would be much less probable. Monthly forecast numbers are evaluated for resource planning, and caution should be used in interpreting the meaning of the annual average load figures being reported and graphed for the 70th-percentile or 90th-percentile forecasts.

Table 2 summarizes the load scenarios prepared for the 2015 IRP. Three average load scenarios were prepared based on a statistical analysis of the historical monthly weather variables listed. The probability associated with each average load scenario is also indicated in the table. In addition, three peak-demand scenarios were prepared based on a statistical analysis of historical peak-day average temperatures, and the probability associated with each peak-demand scenario is also indicated in Table 2.

**Table 2. Average load and peak-demand forecast scenarios**

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

The analysis of resource requirements is based on the 70th-percentile average load forecast coupled with the 95th-percentile peak-demand forecast to provide a more adverse representation of the average load and peak demand to be considered. In other Idaho Power planning, such as the preparation of the financial forecast or the operating plan, the expected-case (50th percentile) average-load forecast and the 90th-percentile peak-demand forecast are typically used.

## *Load Forecasts Based on Economic Uncertainty*

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

To provide risk assessment to economic uncertainty, two additional load forecasts for Idaho Power's service area were prepared. The forecasts provide a range of possible load growths for the 2015 to 2034 planning period due to high and low economic and demographic conditions. The high and low economic-growth scenarios were prepared based on a statistical analysis to empirically reflect the uncertainty inherent in the load forecast. The average growth rates for the high and low growth scenarios were derived from the historical distribution of one-year growth rates over the past 25 years (1990–2014).

The estimated probabilities for the three load scenarios are reported in Table 2. The standard deviation observed during the historical time period is used to estimate the dispersion around the expected-case scenario. The probability estimates assume the expected forecast is the median growth path (i.e., there is a 50-percent probability the actual growth rate will be less than the expected-case growth rate and a 50-percent chance the actual growth rate will be greater than the expected-case growth rate). In addition, the probability estimates assume the variation in growth rates will be equivalent to the variation in growth rates observed over the past 25 years (1990–2014).

Two views of probable outcomes from the forecast scenarios—the probability of exceeding and the probability of occurrenceare—are reported in Table 3. The probability of exceeding shows the likelihood the actual load growth will be greater than the projected growth rate in the specified scenario. For example, over the next 20 years, there is a 10-percent probability the actual growth rate will exceed the growth rate projected in the high scenario; conversely, there is a 10-percent chance the actual growth rate will fall below that of the low scenario. In other words, over a 20-year period, there is an 80-percent probability the actual growth rate of system load will fall between the growth rates projected in the high and low scenarios. The second probability estimate, the probability of occurrence, indicates the likelihood the actual growth will be closer to the growth rate specified in that scenario than to the growth rate specified in any other scenario. For example, there is a 26-percent probability the actual growth rate will be closer to the high scenario than to any other forecast scenario for the entire 20-year planning horizon. Probabilities for shorter, 1-year, 5-year, and 10-year time periods are also shown in Table 3.

**Table 3. Forecast probabilities**

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

The system load is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as special contracts (including past sales to Astaris, Inc.) and on-system contracts (including past sales to Raft River Coop and the City of Weiser).

Idaho Power system load projections are reported in Table 4 and shown in Figure 3. The expected-case system load-forecast growth rate averages 1.1 percent per year over the 20-year planning period. The low scenario projects that the system load will increase at an average rate of 0.7 percent per year throughout the forecast period. The high scenario projects a load growth of 1.6 percent per year. Idaho Power has experienced both the high- and low-growth rates in the past. These forecasts provide a range of projected growth rates that cover approximately 80 percent of the probable outcomes as measured by Idaho Power's historical experience.

**Table 4. System load growth (aMW)**

| Growth | 2015 | 2019 | 2024 | 2034 | Annual Growth Rate 2015–2034 |
|---|---|---|---|---|---|
| Low | 1,776 | 1,802 | 1,871 | 2,012 | 0.7% |
| Expected | 1,786 | 1,900 | 2,012 | 2,240 | 1.2% |
| High | 1,864 | 2,009 | 2,181 | 2,500 | 1.6% |

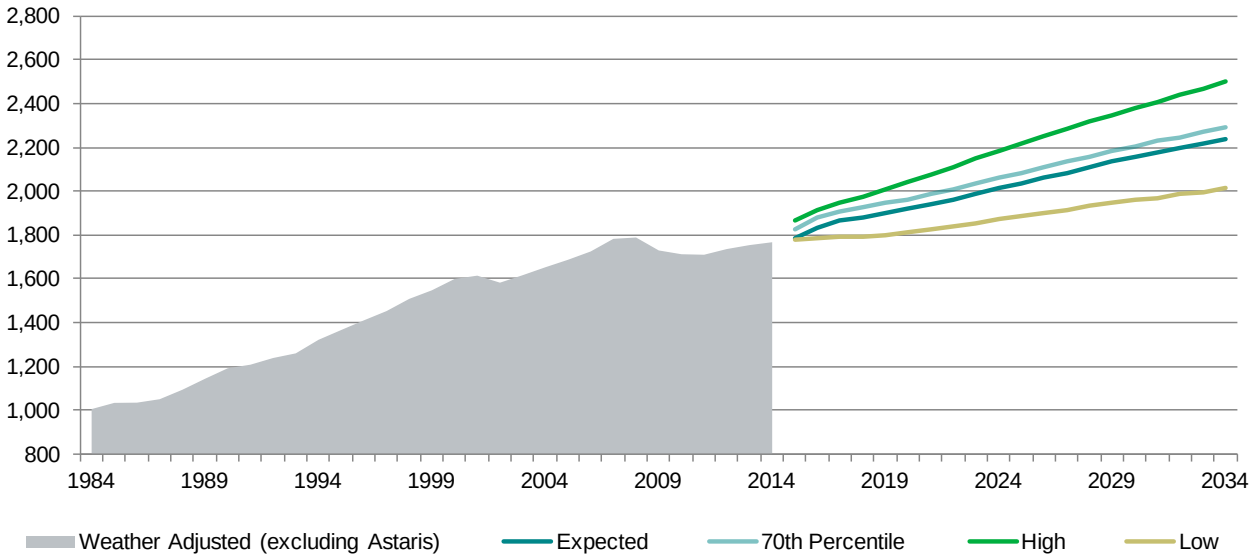



**Figure 3. Forecast system load (aMW)**

# RESIDENTIAL

The expected-case residential load is forecast to increase from 588 aMW in 2015 to 755 aMW in 2034, an average annual compound growth rate of 1.3 percent. In the 70th-percentile scenario, the residential load is forecast to increase from 608 aMW in 2015 to 780 aMW in 2034, matching the expected-case residential growth rate. The residential load forecasts are reported in Table 5 and shown in Figure 4.

**Table 5. Residential load growth (aMW)**

| Growth | 2015 | 2019 | 2024 | 2034 | Annual Growth Rate 2015–2034 |
|---|---|---|---|---|---|
| 90th Percentile | 643 | 689 | 730 | 825 | 1.3% |
| 70th Percentile | 608 | 651 | 689 | 780 | 1.3% |
| Expected Case | 588 | 629 | 666 | 755 | 1.3% |

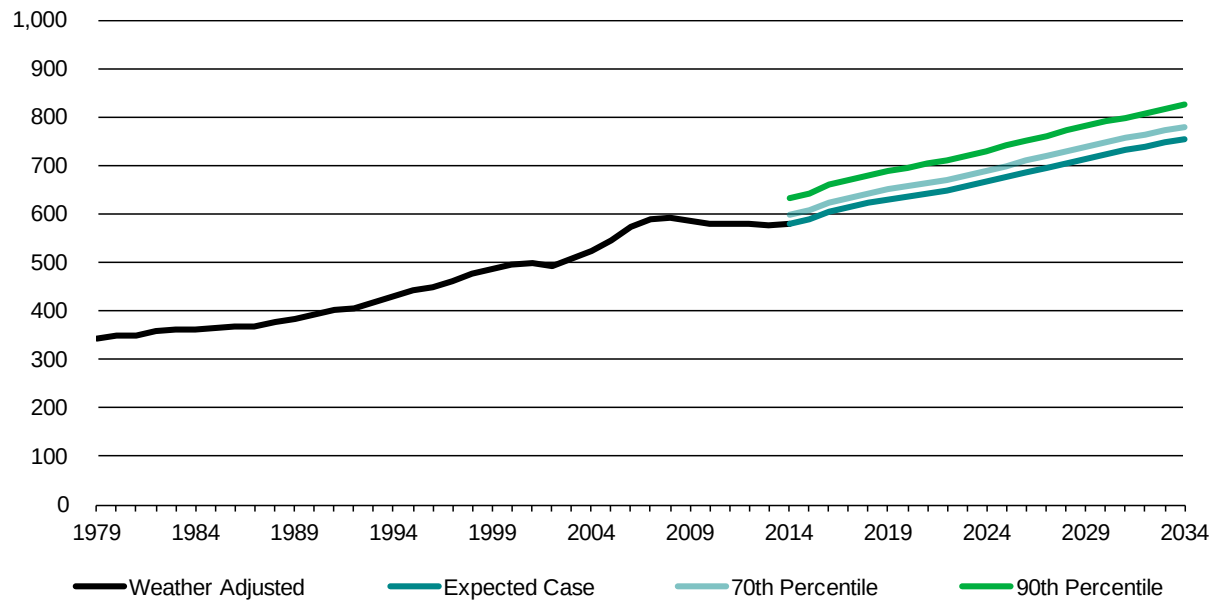



**Figure 4. Forecast residential load (aMW)**

Sales to residential customers made up 32 percent of Idaho Power's system sales in 1984 and 36 percent of system sales in 2014. The residential customer proportion of system sales is forecast to be approximately 37 percent in 2034. The number of residential customers is projected to increase to approximately 591,000 by December 2034.

The average sales per residential customer increased to over 14,800 kWh in 1979 before declining to 13,200 kWh in 2001. In 2002 and 2003, residential use per customer dropped dramatically—over 500 kWh per customer from 2001—the result of two years of significantly higher electricity prices combined with a weak national and service-area economy. The reduction in electricity prices in June 2003 and a recovery in the service-area economy caused residential

use per customer to stabilize and rise through 2007. However, the recession in 2008 and 2009, combined with conservation programs designed to reduce electricity use, slowed the growth in residential use per customer. The average sales per residential customer are expected to slowly decline to approximately 11,200 kWh per year in 2034. Average annual sales per residential customer are shown in Figure 5.

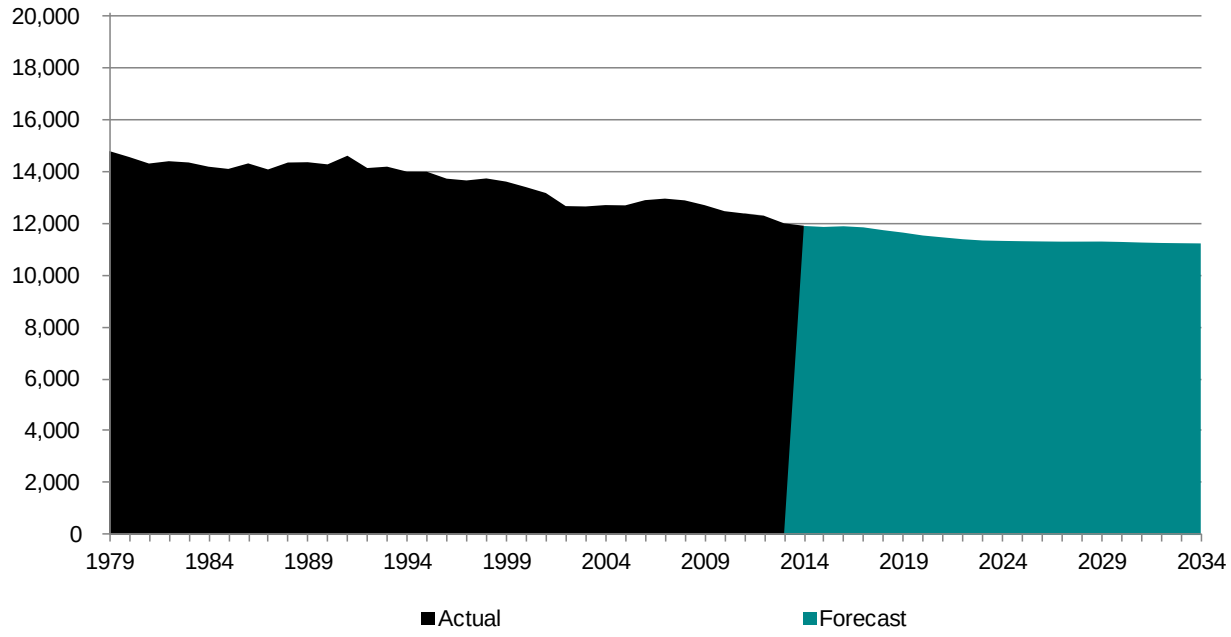



**Figure 5. Forecast residential use per customer (weather-adjusted kWh)**

The residential-use-per-customer forecast is based on a forecast of the number of residential customers and an econometric analysis of residential-sector sales. The number of residential customers being added each year is a direct function of the number of new service-area households as derived from Moody's Analytics' July 2014 forecast of county housing stock and demographic data. The residential-customer forecast for 2015 to 2034 shows an average annual growth rate of 1.6 percent.

The residential sales forecast equation considers several factors affecting electricity sales to the residential sector. Residential sales are a function of HDD (wintertime); CDD (summertime); the number of service-area households as derived from Moody's Analytics' forecasts of county housing stock; the real price of electricity; and the real price of natural gas. The forecast of residential use per customer is arrived at by dividing the residential sales forecast, which considers the impact of forecast DSM, by the residential-customer forecast.

# COMMERCIAL

The commercial category is primarily made up of Idaho Power's small general-service and large general-service customers. Other customers associated with this category include unmetered general-service, street-lighting service, traffic-control signal lighting service, and dusk-to-dawn customer lighting.

In total, within the expected-case scenario, the commercial load is projected to increase from 466 aMW in 2015 to 559 aMW in 2034. The average annual compound-growth rate of the commercial load is 1.0 percent during the forecast period. As summarized in Table 6, the commercial load in the 70th-percentile scenario is projected to increase from 472 aMW in 2015 to 568 aMW in 2034. The commercial load forecasts are illustrated in Figure 6.

**Table 6. Commercial load growth (aMW)**

| Growth | 2015 | 2019 | 2024 | 2034 | Annual Growth Rate 2015–2034 |
|---|---|---|---|---|---|
| 90th Percentile | 483 | 504 | 529 | 583 | 1.0% |
| 70th Percentile | 472 | 492 | 516 | 568 | 1.0% |
| Expected Case | 466 | 485 | 509 | 559 | 1.0% |

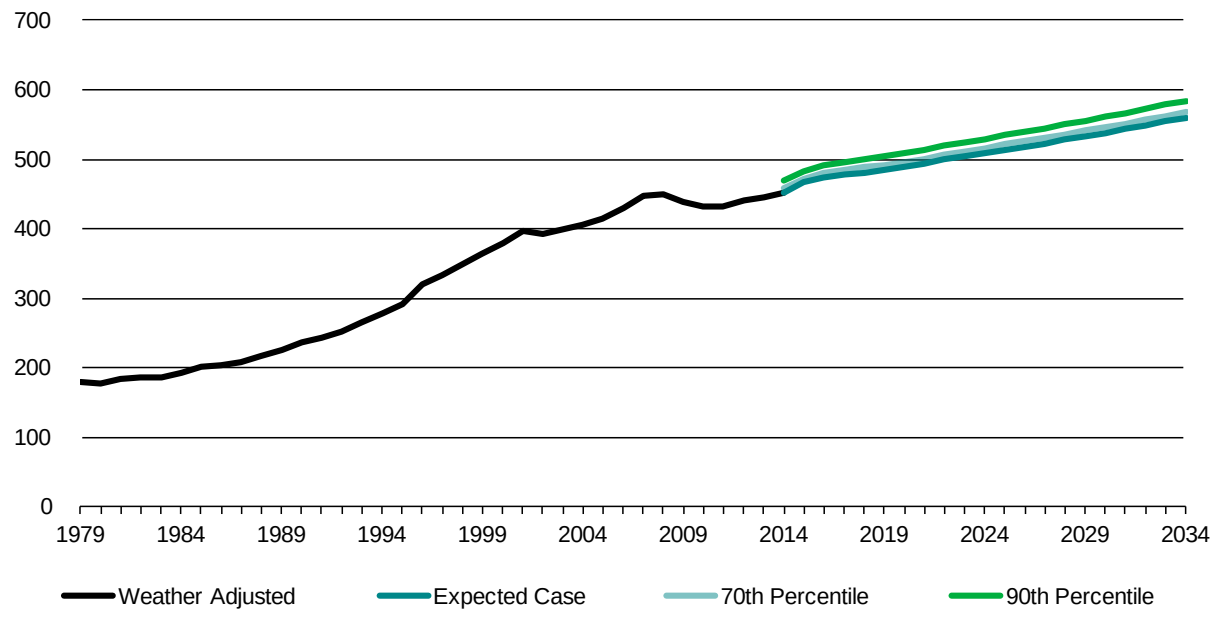



**Figure 6. Forecast commercial load (aMW)**

With a customer base of over 67,000, the commercial class represents the diversity of the service area economy, ranging from residential subdivision pressurized irrigation to manufacturing. Due to this diversity, the category is further segmented into categories associated with common elements of energy-use influences, such as economic variables (e.g., employment), industry (e.g., manufacturing), and building structure characteristics (e.g., offices). Figure 7 shows the breakdown of the categories and their relative sizes based on 2014 billed energy sales.

The commercial-customer forecast for 2015 to 2034 shows an average annual growth rate of 1.7 percent.

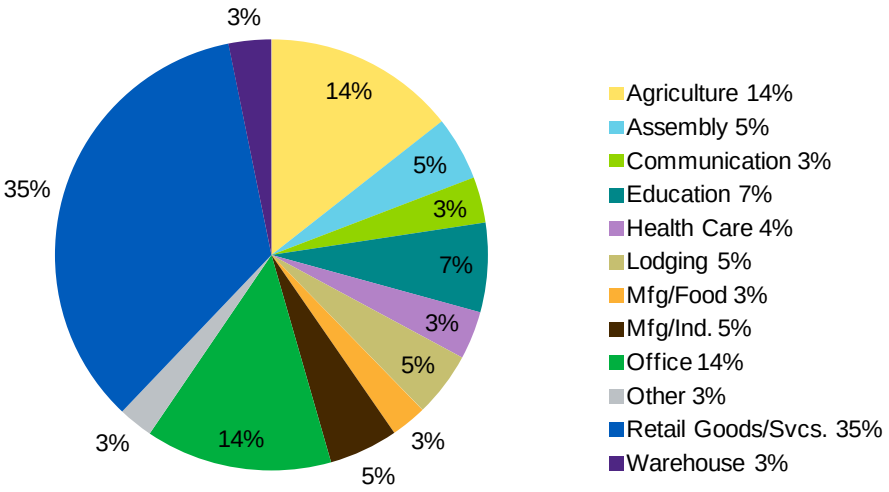



**Figure 7. Commercial building share**

As indicated in Figure 7, retail goods and service providers represent the majority of customers, with 35% of the total in 2014. The number of commercial customers is expected to increase at an average annual rate of 1.7 percent, reaching 94,900 customers by December 2034. Much of the future commercial customer growth is expected to come from retail goods and services. Historically, this category growth is a function of the growth in residential customers. Recent trends indicate continued growth in communications and general manufacturing and small industrial categories.

In 1984, customers in the commercial category consumed approximately 17 percent of Idaho Power system sales, growing to 28 percent by 2014. This share is forecast to remain at the upper end of this range throughout the planning period.

Figure 8 shows historical and forecast average use per customer (UPC) for the entire category. The commercial-use-per-customer metric in Figure 8 represents an aggregated metric for a highly diverse group of customers with significant differences in total energy use per customer, but it is instructive in aggregate for comparative purposes.

The UPC peaked in 2001 at 67,400 kWh and has declined at approximately 0.31 percent compounded annually to 2014. The UPC is forecast to decrease at an annual rate of 0.46 percent over the planning period. For the category as a whole, common elements that drive use down include increases in electricity prices, business-cycle recessions, and the adoption of energy efficiency technology. Within the sub-categories, the UPC varies widely from manufacturing/industrial at 159,500 kWh per customer to communications at 44,250 kWh (2014 basis).

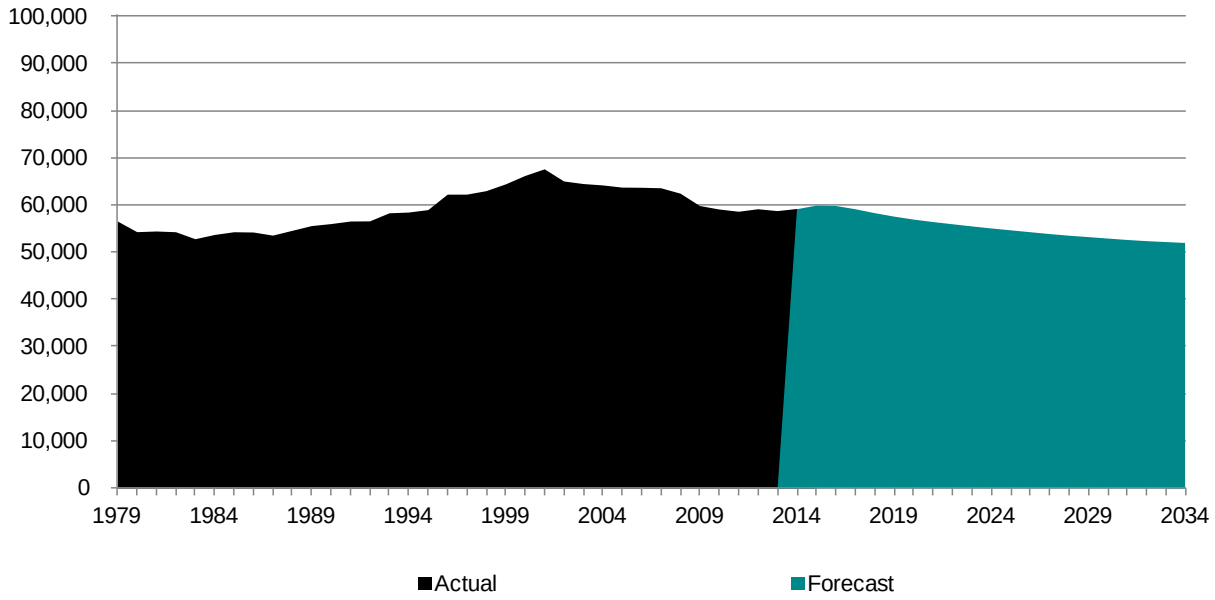



**Figure 8. Forecast commercial use per customer (weather-adjusted kWh)**

Figure 9 shows the diversity in the commercial segments' UPC as well as the trend for these sectors. The figure shows the 2014 UPC for each segment relative to the 2010 UPC. A value of 1.0 indicates the UPC has not changed over this period. The figure supports the general decline of the aggregated trend of Figure 7 but highlights differences in energy and economic dynamics within the commercial category not evident in the residential category.

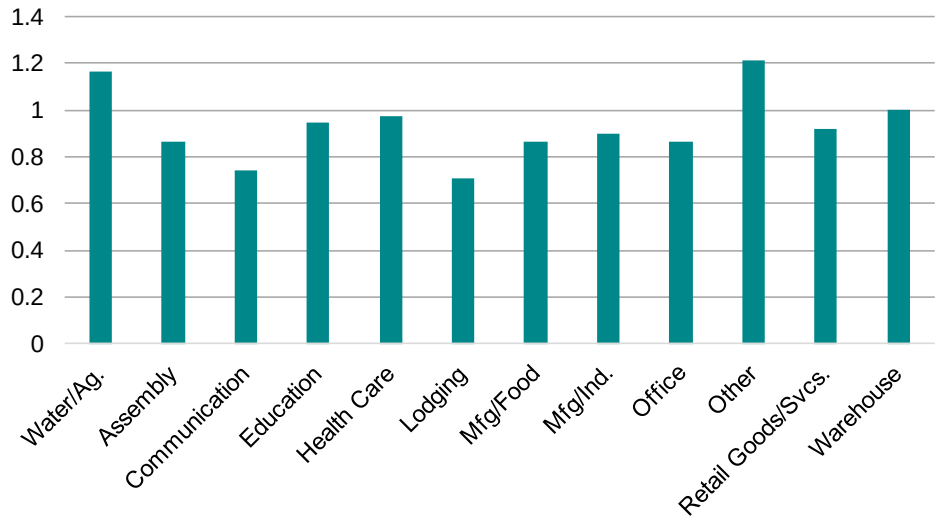



**Figure 9. Commercial categories UPC, 2014 relative to 2010**

Energy efficiency implementation is a large determinant in UPC decline, particularly in high-growth categories, such as retail goods and services, communication, and office, where many structures are new and subject to efficient building code requirements. Increases in the UPC, such as in the water/agriculture (Water/Ag.) category are indicative of an increasing density of pumps and water treatment consolidation. Other influences include a difference in

price sensitivity, sensitivity to business cycles and weather changes, and degree and trends in automation. In addition, aggregate commercial UPC can vary when a customer's use increases to the point where it must, by tariff rules, migrate to an industrial (Rate 19) category.

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

# IRRIGATION

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

The expected-case irrigation load is forecast to increase slowly from 213 aMW in 2015 to 235 aMW in 2034, an average annual compound growth rate of 0.5 percent. The expected-case, 70$^{th}$-percentile, and 90$^{th}$-percentile scenarios forecast slow growth in irrigation load from 2015 to 2034. In the 70$^{th}$-percentile scenario, irrigation load is projected to be 226 aMW in 2015 and 248 aMW in 2034. The individual irrigation load forecasts (Table 7 and Figure 10) illustrate the poorer economic conditions and dramatic reduction in land put into production in the mid-1980s.

**Table 7. Irrigation load growth (aMW)**

| Growth | 2015 | 2019 | 2024 | 2034 | Annual Growth Rate 2015–2034 |
|---|---|---|---|---|---|
| 90$^{th}$ Percentile | 244 | 250 | 254 | 266 | 0.5% |
| 70$^{th}$ Percentile | 226 | 232 | 235 | 248 | 0.5% |
| Expected Case | 213 | 218 | 222 | 235 | 0.5% |

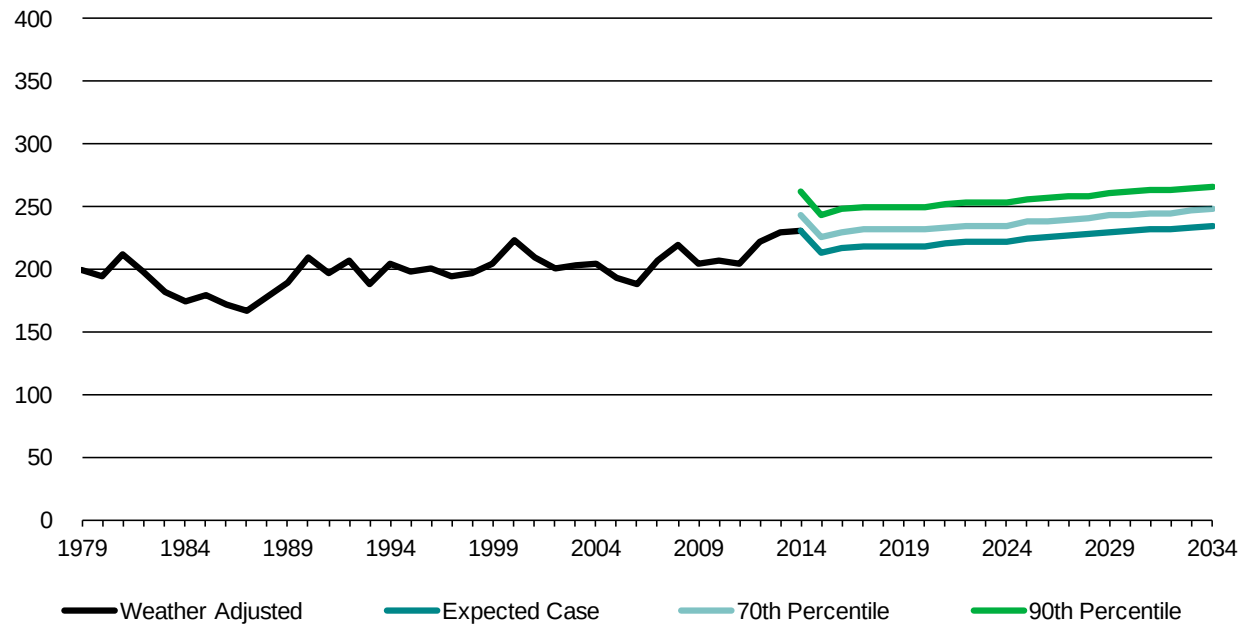



**Figure 10. Forecast irrigation load (aMW)**

The annual average loads in Table 7 and Figure 10 are calculated using the 8,760 hours in a typical year. In the highly seasonal irrigation sector, over 97 percent of the annual energy is billed during the six months from May through October, and nearly half of the annual energy is billed in just two months, July and August. During the summer, hourly irrigation loads can reach nearly 900 MW. In a normal July, irrigation pumping accounts for roughly 25 percent of the energy consumed during the hour of the annual system peak and nearly 30 percent of the energy

consumed during July for general business sales. The monthly forecast load figures are being evaluated for resource planning purposes, not the annual average loads.

The 2015 irrigation sales forecast is higher than the 2013 IRP forecast throughout the forecast period due to the significant trend toward more water-intensive crops, primarily alfalfa and corn, due to growth in the dairy industry. Also, farmers have taken advantage of higher market prices over the past few years and have put high-lift acreage back into production. Additionally, the conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to farmers trying to reduce labor costs, explains most of the increased energy consumption in recent years.

The 2015 irrigation sales forecast model considers several factors affecting electricity sales to the irrigation class, including temperature; precipitation; spring rainfall; *Moody's Gross Product: Agriculture, for Idaho*; *Moody's Producer Price Index: Prices Received by Farmers, All Farm Products*; and the real price of electricity. Considerations were made for the unusually low electricity consumption in the 2001 crop year due to a voluntary load-reduction program.

In early 2001, wholesale electricity prices reached unprecedented levels; Idaho Power, in an attempt to minimize reliance on the market, developed a voluntary load-reduction program that paid irrigators to reduce their electricity consumption in 2001. The voluntary load-reduction program was effective and resulted in a 30-percent, or approximately 500,000-megawatt-hour (MWh), reduction in 2001 irrigation sales. The 2001 irrigation sales and corresponding loads have been adjusted upward by 499,319 MWh to reflect a more normal 2001 irrigation season.

Actual irrigation electricity sales have grown from the 1970 level of 816,000 MWh to a peak amount of 2,097,000 MWh in 2013. Idaho Power projects no growth in irrigated acres in the service area and limited growth in sprinkler irrigation or conversion to sprinkler irrigation.

In 1977, irrigation sales reached a maximum proportion of 20 percent of Idaho Power system sales. In 1984, they represented nearly 16 percent of weather-normalized Idaho Power system sales. In 2014, the irrigation proportion of system sales was 14 percent due to the much higher relative growth in other customer classes. By 2034, irrigation customers are projected to consume about 11 percent of Idaho Power system sales. Figure 17 shows the irrigation customer load proportion.

In 1980, Idaho Power had about 10,850 active irrigation accounts. By 2014, the number of active irrigation accounts had increased to 19,328 and is projected to be nearly 25,000 at the end of the planning period in 2034.

Since 1988, Idaho Power has experienced growth in the number of irrigation customers but very slow growth in total electricity sales (weather-adjusted) to this sector. The number of customers has increased because customers are converting previously furrow-irrigated land to sprinkler-irrigated land. However, the conversion rate is low, and the kWh use per customer is substantially lower than the average existing Idaho Power irrigation customer. This is because water for sprinkler conversions is drawn from canals and not pumped from deep groundwater wells.

In the future, factors related to the conjunctive management of ground and surface water and the possible litigation associated with the resolution will require consideration. Depending on the resolution of these issues, irrigation sales may be impacted.

# INDUSTRIAL

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

In 1975, Idaho Power had about 70 industrial customers, which represented about 10 percent of Idaho Power's system sales. By December 2014, the number of industrial customers had risen to 118, representing approximately 17 percent of system sales. Given the wide range of customer's energy use in the tariff schedule, customer counts are primarily illustrative of the positive economic conditions in the service area. Customers with load greater than Schedule 19 ranges are known as Special contract customers and are addressed in the Additional Firm Load section of this document.

In the expected-case forecast, industrial load grows from 277 aMW in 2015 to 401 aMW in 2034, an average annual growth rate of 2.0 percent (Table 8). To a large degree, industrial load variability is not due to weather conditions as is residential, commercial, and irrigation; therefore, the forecasts in the 70$^{th}$- and 90$^{th}$-percentile weather-scenarios are identical to the expected-case industrial-load scenario. The industrial load forecast is pictured in Figure 11.

**Table 8. Industrial load growth (aMW)**

| Growth | 2015 | 2019 | 2024 | 2034 | Annual Growth Rate 2015–2034 |
|---|---|---|---|---|---|
| Expected Case | 277 | 313 | 341 | 401 | 2.0% |

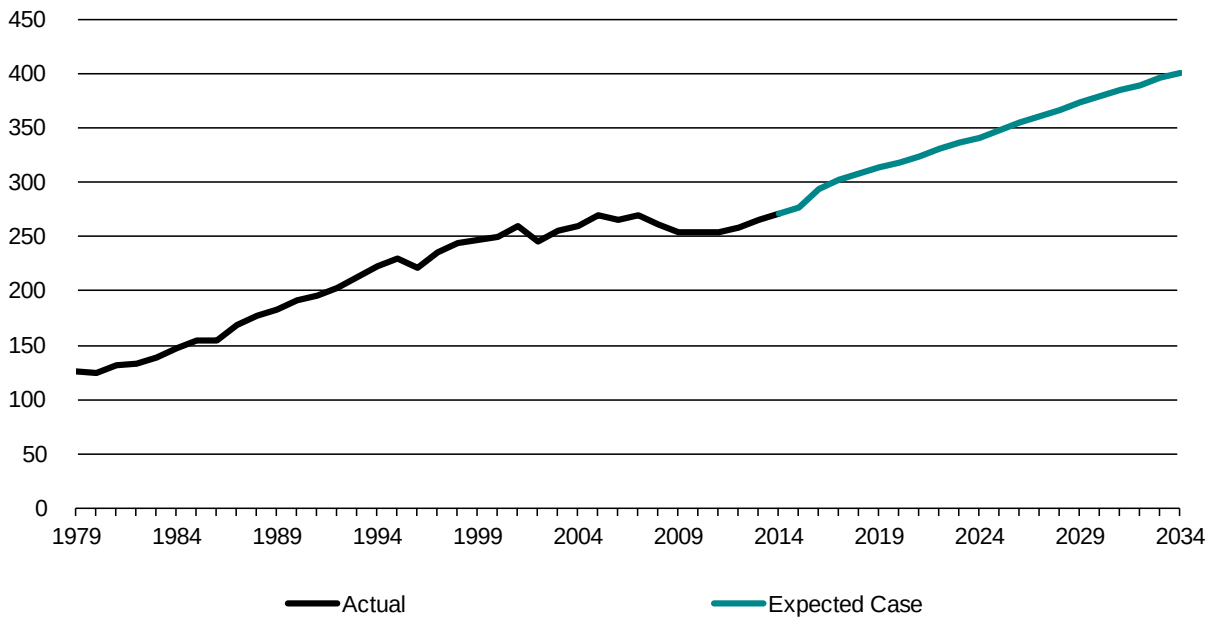



**Figure 11. Forecast industrial load (aMW)**

The industrial category reflects a wide range of business activity ranging from manufacturing to health care. To better specify forecast regression models, the customers are segmented into economic and energy-use profile categories. The industrial energy forecast models integrated the July 2014 national, state, MSA, and county economic time-series from Moody's Analytics and associated derived economic time-series for Idaho Power's service area.

The regression models and associated explanatory variables resulting from the categorization establish the relationship between historical electricity sales and historical independent economic, price, technological, demographic, and other influences in the form of estimated coefficients from the industry group regression models that are applied to the appropriate forecasts of independent time series of energy use.

Figure 12 illustrates the 2014 share of each of the categories within the Rate 19 customers. By far, the largest share of electricity was consumed by the food manufacturing sector (38%), followed by dairy (18%) and electronics/technology (Electech) (7%). The categorization scheme includes a range of industrial building types (assembly, lodging, mercantile, warehouse, office, education, health care). These categorizations provide the basis for capturing, modeling, and forecasting the shifting economic landscape that influences industrial category electricity sales.

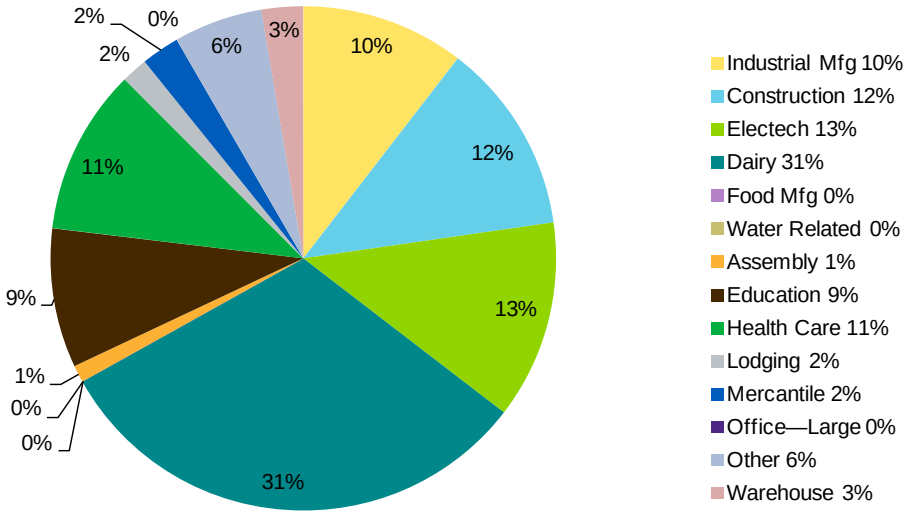



**Figure 12. Industrial electricity consumption by industry group (based on 2014 sales)**

# 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 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 three special-contract customers recognized as firm-load customers. These special-contract customers are Micron Technology, Simplot Fertilizer, and the INL.

In the expected-case forecast, additional firm load is expected to increase from 101 aMW in 2015 to 113 aMW in 2034, an average growth rate of 0.6 percent per year over the planning period (Table 9). The additional firm load energy and demand forecasts in the 70$^{th}$ and 90$^{th}$-percentile scenarios are identical to the expected-load growth scenario. The scenario of projected additional firm load is illustrated in Figure 13.

**Table 9. Additional firm load growth (aMW)**

| Growth | 2015 | 2019 | 2024 | 2034 | Annual Growth Rate 2015–2034 |
|---|---|---|---|---|---|
| Expected Case | 101 | 104 | 115 | 113 | 0.6% |

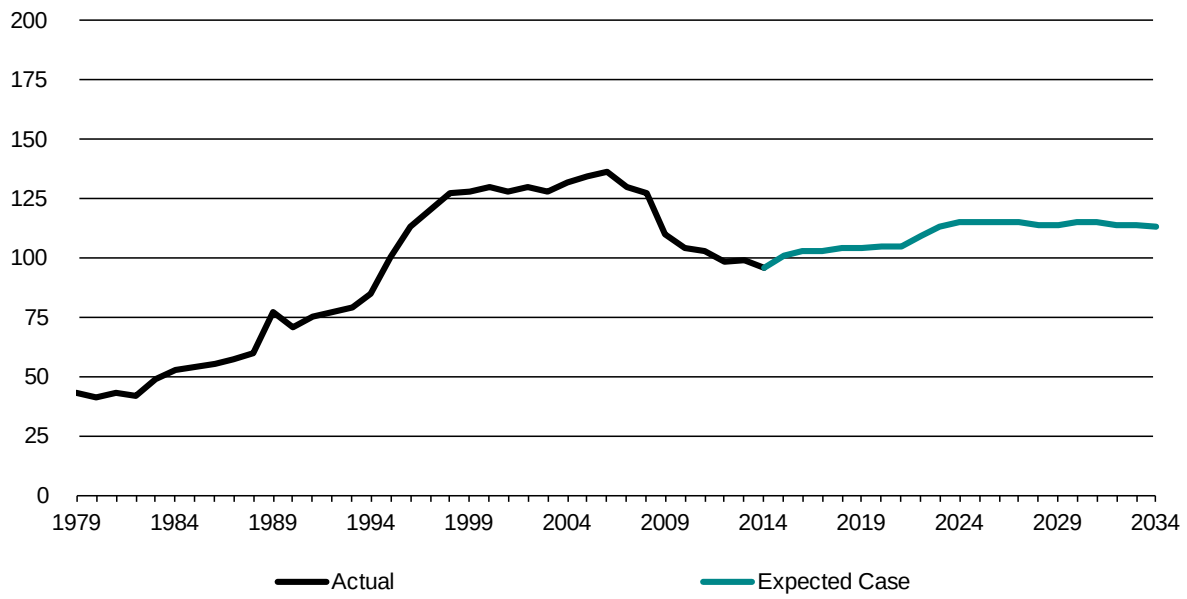



**Figure 13. Forecast additional firm load (aMW)**

## Micron Technology

Micron Technology represents Idaho Power's largest electric load for an individual customer and employs approximately 5,000 workers in the Boise MSA. The company operates its research and development fabrication facility in Boise and performs a variety of other activities, including product design and support, quality assurance, systems integration and related manufacturing, corporate services, 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 through 2016, then stay flat throughout the remainder of the planning period.

## Idaho National Laboratory

The DOE provided an energy-consumption and peak-demand forecast through 2034 for the INL. The forecast calls for loads to slowly rise through 2021, rise dramatically through 2024, and stay near that higher level throughout the remainder of the forecast period.

# COMPANY SYSTEM PEAK

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

The all-time system summer peak demand was 3,407 MW, recorded on Tuesday, July 2, 2013, at 4:00 p.m. The previous summer peak demand was 3,245 MW and occurred on Thursday, July 12, 2012, at 4:00 p.m. The system summer peak load growth accelerated from 1998 to 2008 as a record number of residential, commercial, and industrial customers were added to the system and A/C became standard in nearly all new residential homes and new commercial buildings.

In the 90th-percentile forecast, the system summer peak load is expected to increase from 3,537 MW in 2015 to 4,719 MW in 2034, an average growth rate of 1.5 percent per year over the planning period (Table 10). In the 95th-percentile forecast, the system summer peak load is expected to increase from 3,576 MW in 2015 to 4,773 MW in 2034. The three scenarios of projected system summer peak loads are illustrated in Figure 14. Much of the variation in peak load is due to weather conditions. Notably, the 2001 summer peak was dampened by the nearly 30-percent curtailment in irrigation load due to the 2001 voluntary load-reduction program.

**Table 10. System summer peak load growth (MW)**

| Growth | 2015 | 2019 | 2024 | 2034 | Annual Growth Rate 2015–2034 |
|---|---|---|---|---|---|
| 95th Percentile | 3,576 | 3,847 | 4,151 | 4,773 | 1.5% |
| 90th Percentile | 3,537 | 3,805 | 4,105 | 4,719 | 1.5% |
| 50th Percentile | 3,313 | 3,562 | 3,839 | 4,407 | 1.5% |

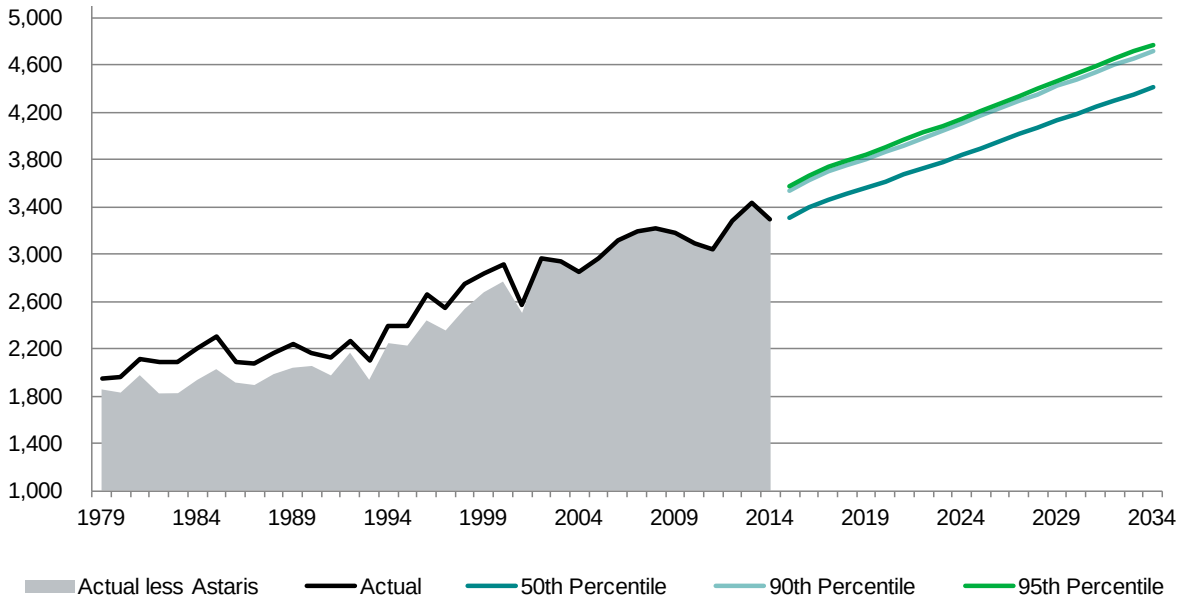



**Figure 14. Forecast system summer peak (MW)**

The all-time system winter peak demand was 2,528 MW, reached on Thursday, December 10, 2009, at 8:00 a.m. As shown in Figure 15, the historical system winter peak load is much more variable than the summer system peak load. This is because the variability of peak-day temperatures in winter months is more significant than the variability of peak-day temperatures in summer months. The wider spread of the winter peak forecast lines in Figure 13 illustrates the higher variability associated with winter peak-day temperatures.

In the 90th-percentile forecast, the system winter peak load is expected to increase from 2,603 MW in 2015 to 3,077 MW in 2034, an average growth rate of 0.9 percent per year over the planning period (Table 11). In the 95th-percentile forecast, the system winter peak load is expected to increase from 2,625 MW in 2015 to 3,100 MW in 2034, an average growth rate of 0.9 percent per year over the planning period (Table 11). The three scenarios of projected system winter peak load are illustrated in Figure 13.

**Table 11. System winter peak load growth (MW)**

| Growth | 2015 | 2019 | 2024 | 2034 | Annual Growth Rate 2015–2034 |
|---|---|---|---|---|---|
| 95th Percentile | 2,625 | 2,723 | 2,853 | 3,100 | 0.9% |
| 90th Percentile | 2,603 | 2,701 | 2,830 | 3,077 | 0.9% |
| 50th Percentile | 2,330 | 2,428 | 2,557 | 2,805 | 1.0% |

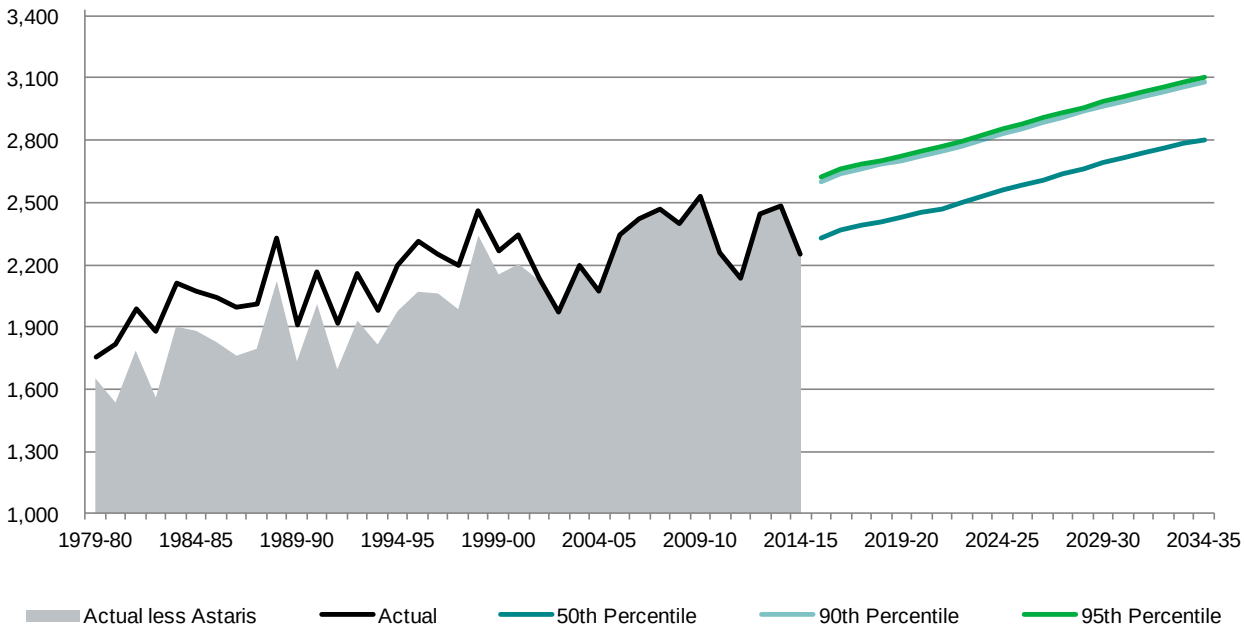



**Figure 15. Forecast system winter peak (MW)**

# COMPANY SYSTEM LOAD

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

The expected-case system load forecast is based on the output of the regression and forecasting models referenced previously and represents Idaho Power's most probable load growth during the planning period. The expected-case forecast system load growth rate averages 1.2 percent per year from 2015 to 2034. Company system load projections are reported in Table 12 and shown in Figure 16.

In the expected-case forecast, the company system load is expected to increase from 1,786 aMW in 2015 to 2,240 aMW in 2034. In the 70$^{th}$-percentile forecast, the company system load is expected to increase from 1,829 aMW in 2015 to 2,292 aMW by 2034, an average growth rate of 1.2 percent per year over the planning period (Table 12).

**Table 12. System load growth (aMW)**

| Growth | 2015 | 2019 | 2024 | 2034 | Annual Growth Rate 2015–2034 |
|---|---|---|---|---|---|
| 90$^{th}$ Percentile | 1,900 | 2,021 | 2,139 | 2,378 | 1.2% |
| 70$^{th}$ Percentile | 1,829 | 1,946 | 2,059 | 2,292 | 1.2% |
| Expected Case | 1,786 | 1,900 | 2,012 | 2,240 | 1.2% |

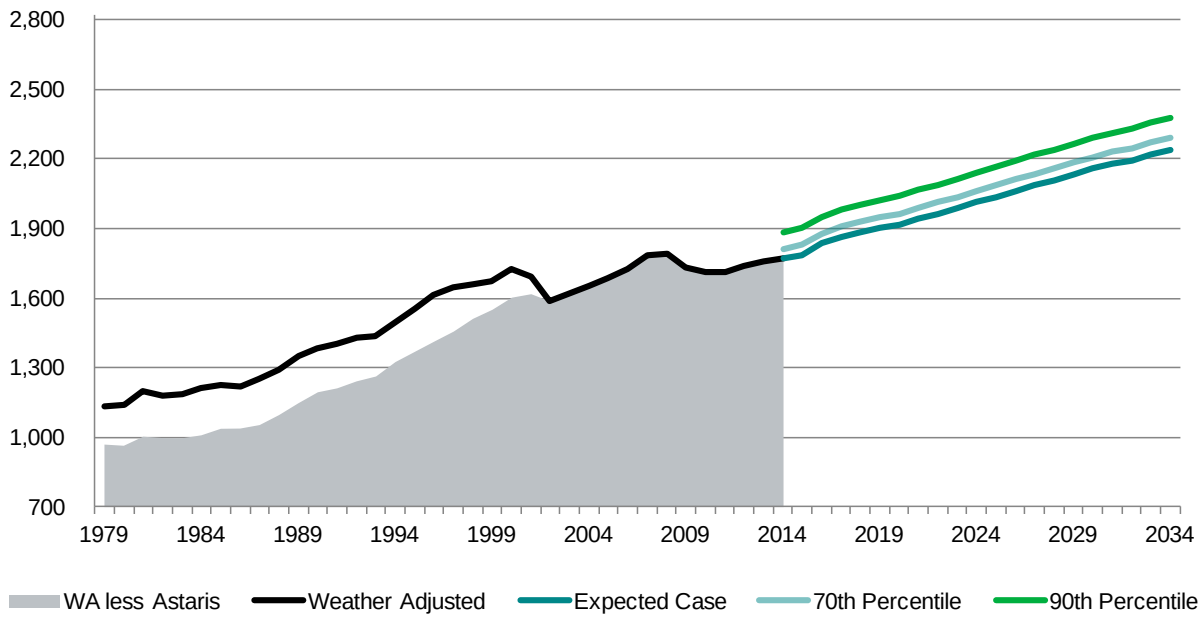



**Figure 16. Forecast system load (aMW)**

The Astaris elemental phosphorous plant (previously FMC) was located at the western edge of Pocatello, Idaho. Although no longer a customer of Idaho Power, Astaris had been Idaho Power's largest individual customer and, in some years, averaged nearly 200 aMW each month. In April 2002, the special contract between Astaris and Idaho Power was terminated. The system load, excluding Astaris, portrays the current underlying general business growth trend within the service area. However, the system load with Astaris is instructive in regard to the impact of a new large-load customer on system load. As noted previously, the forecast excludes any such prospective large-load customers.

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

The composition of system company electricity sales by year is shown in Figure 17. Residential sales are forecast to be nearly 28 percent higher in 2034, gaining 1.5 million MWh over 2015. Commercial sales are also expected to be 20 percent higher, or 0.8 million MWh, than in 2015, followed by industrial (45 percent higher or 1.1 million additional MWh) and irrigation (10 percent higher in 2034 than 2015). Electricity sales to Astaris ended in April 2002.

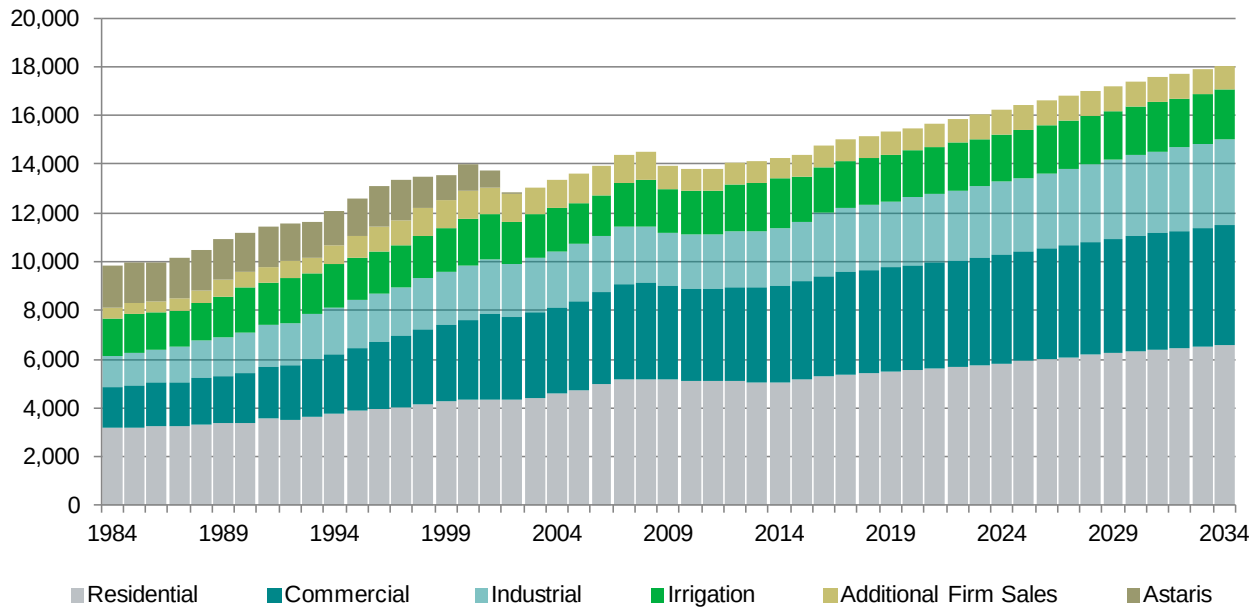



**Figure 17. Composition of system company electricity sales (thousands of MWh)**

The additional firm-load category (which represents sales to Micron Technology, Simplot Fertilizer, and the INL) is forecast to grow by 24 percent from 2015 to 2034.

# CONTRACT OFF-SYSTEM LOAD

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

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

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# ENERGY EFFICIENCY AND DEMAND RESPONSE

Energy efficiency and demand response impacts are treated differently in the forecasting and planning process. Energy efficiency impacts (reductions in energy use) are explicitly integrated into the forecast models. Demand response impacts are explicitly *excluded* from the forecast models; the impacts of demand response are modeled in the load and resource balance as a supply-side resource for reducing peak-demand periods.

## Energy Efficiency

Energy efficiency influences on past and future load consist of utility programs, statutory codes, and manufacturing standards for appliances, equipment, and building materials that reduce energy consumption. As the influence of statutory codes and manufacturing standards on residential and commercial customers has increased in importance relative to utility programs, Idaho Power forecast models have been modified to ensure they capture these influences. Specifically, the models capture the physical flow of energy-efficient products through shipment data to resellers and installers. The source for this data is the DOE (the data also serves as input to the DOE NEM), and the data is refined by Itron for utility-specific applications. This data captures energy-efficient installations regardless of the source (e.g., programs, standards, and codes). However, Idaho Power closely monitors the assumptions and impacts of DOE data to ensure the model correctly captures all energy-efficiency impacts.

Efficiency data for irrigation customers and some commercial and industrial customers (i.e., manufacturing related) is not directly surveyed and collected by the DOE; therefore, models for efficiency impacts have been developed using a methodology established in Itron's white paper, *Incorporating DSM into the Load Forecast*.[1] This approach develops statistical methods to recognize efficiency trends from historical energy efficiency utility acquisition, recognizing that historical trends are embedded in the actual sales data (which serve as the basis for the sector's forecast). Trends associated with future acquisitions from these existing programs (and their cumulative impacts) are similarly developed to compare with historical trends. If there is a significant change in future trends (i.e., trends unseen by the regression model of historical energy and conservation trends), the forecast output is adjusted to realize the trend change embedded in the regression output.

Regardless of the method, efficiency impacts from the models are compared to the DOE's population of utility acquisitions to ensure the models are correctly capturing all energy savings.

Energy savings from utility energy efficiency programs are typically measured and reported at the point of delivery (customer's meter). Therefore, energy efficiency savings are increased by

[1] Stuart McMenamin and Mark Quan. *Incorporating DSM into the Load Forecast*. Itron, https://www.itron.com/na/PublishedContent/Incorporating%20DSM%20into%20the%20Load%20Forecast.pdf (accessed February 3, 2011).

the amount of energy lost in transmitting the electricity from the generation source to the customer's meter.

The influence of new efficiency programs is not typically prepared in time to be available for input into the forecast models. Therefore, the impacts of these new programs are accounted for in the IRP load and resource balance prior to determining the need for additional supply-side resources. The forecast performance of existing and new energy efficiency and demand response programs is shown in the load and resource balance in *Appendix C—Technical Appendix*.

## Demand Response

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

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

A thorough description of each of the energy efficiency and demand response programs is included in *Appendix B—Demand Side Management 2014 Annual Report*.

## Appendix A1. Historical and Projected Sales and Load

**Residential Load**

**Historical Residential Sales and Load, 1974–2014 (weather adjusted)**

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1974 | 160,151 | – | 12,067 | 1,932 | – | 223 |
| 1975 | 167,622 | 4.7% | 12,956 | 2,172 | 12.4% | 250 |
| 1976 | 175,720 | 4.8% | 13,452 | 2,364 | 8.8% | 272 |
| 1977 | 184,561 | 5.0% | 13,698 | 2,528 | 7.0% | 289 |
| 1978 | 194,650 | 5.5% | 14,234 | 2,771 | 9.6% | 321 |
| 1979 | 202,982 | 4.3% | 14,804 | 3,005 | 8.5% | 342 |
| 1980 | 209,629 | 3.3% | 14,575 | 3,055 | 1.7% | 348 |
| 1981 | 213,579 | 1.9% | 14,323 | 3,059 | 0.1% | 350 |
| 1982 | 216,696 | 1.5% | 14,413 | 3,123 | 2.1% | 357 |
| 1983 | 219,849 | 1.5% | 14,364 | 3,158 | 1.1% | 361 |
| 1984 | 222,695 | 1.3% | 14,201 | 3,163 | 0.1% | 360 |
| 1985 | 225,185 | 1.1% | 14,115 | 3,178 | 0.5% | 365 |
| 1986 | 227,081 | 0.8% | 14,328 | 3,254 | 2.4% | 369 |
| 1987 | 228,868 | 0.8% | 14,094 | 3,226 | -0.9% | 369 |
| 1988 | 230,771 | 0.8% | 14,362 | 3,314 | 2.7% | 378 |
| 1989 | 233,370 | 1.1% | 14,374 | 3,354 | 1.2% | 382 |
| 1990 | 238,117 | 2.0% | 14,291 | 3,403 | 1.4% | 393 |
| 1991 | 243,207 | 2.1% | 14,624 | 3,557 | 4.5% | 403 |
| 1992 | 249,767 | 2.7% | 14,149 | 3,534 | -0.6% | 404 |
| 1993 | 258,271 | 3.4% | 14,202 | 3,668 | 3.8% | 418 |
| 1994 | 267,854 | 3.7% | 14,010 | 3,753 | 2.3% | 430 |
| 1995 | 277,131 | 3.5% | 14,007 | 3,882 | 3.4% | 443 |
| 1996 | 286,227 | 3.3% | 13,739 | 3,933 | 1.3% | 449 |
| 1997 | 294,674 | 3.0% | 13,670 | 4,028 | 2.4% | 461 |
| 1998 | 303,300 | 2.9% | 13,748 | 4,170 | 3.5% | 477 |
| 1999 | 312,901 | 3.2% | 13,625 | 4,263 | 2.2% | 487 |
| 2000 | 322,402 | 3.0% | 13,412 | 4,324 | 1.4% | 494 |
| 2001 | 331,009 | 2.7% | 13,184 | 4,364 | 0.9% | 497 |
| 2002 | 339,764 | 2.6% | 12,680 | 4,308 | -1.3% | 491 |
| 2003 | 349,219 | 2.8% | 12,666 | 4,423 | 2.7% | 507 |
| 2004 | 360,462 | 3.2% | 12,719 | 4,585 | 3.6% | 523 |
| 2005 | 373,602 | 3.6% | 12,708 | 4,748 | 3.6% | 545 |
| 2006 | 387,707 | 3.8% | 12,910 | 5,005 | 5.4% | 573 |
| 2007 | 397,286 | 2.5% | 12,969 | 5,152 | 2.9% | 589 |
| 2008 | 402,520 | 1.3% | 12,901 | 5,193 | 0.8% | 591 |
| 2009 | 405,144 | 0.7% | 12,716 | 5,152 | -0.8% | 587 |
| 2010 | 407,551 | 0.6% | 12,484 | 5,088 | -1.2% | 580 |
| 2011 | 409,786 | 0.5% | 12,394 | 5,079 | -0.2% | 579 |
| 2012 | 413,610 | 0.9% | 12,304 | 5,089 | 0.2% | 580 |
| 2013 | 418,892 | 1.3% | 12,016 | 5,033 | -1.1% | 577 |
| 2014 | 425,036 | 1.5% | 11,922 | 5,067 | 0.7% | 578 |

**Residential Load**

**Projected Residential Sales and Load, 2015–2034**

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2015 | 432,909 | 1.9% | 11,884 | 5,145 | 1.5% | 588 |
| 2016 | 442,519 | 2.2% | 11,910 | 5,271 | 2.4% | 603 |
| 2017 | 452,660 | 2.3% | 11,868 | 5,372 | 1.9% | 614 |
| 2018 | 462,757 | 2.2% | 11,759 | 5,442 | 1.3% | 622 |
| 2019 | 472,216 | 2.0% | 11,665 | 5,509 | 1.2% | 629 |
| 2020 | 480,984 | 1.9% | 11,553 | 5,557 | 0.9% | 635 |
| 2021 | 489,217 | 1.7% | 11,481 | 5,617 | 1.1% | 642 |
| 2022 | 497,232 | 1.6% | 11,410 | 5,673 | 1.0% | 648 |
| 2023 | 505,314 | 1.6% | 11,361 | 5,741 | 1.2% | 656 |
| 2024 | 513,361 | 1.6% | 11,345 | 5,824 | 1.4% | 666 |
| 2025 | 521,365 | 1.6% | 11,333 | 5,908 | 1.5% | 675 |
| 2026 | 529,313 | 1.5% | 11,324 | 5,994 | 1.4% | 685 |
| 2027 | 537,191 | 1.5% | 11,316 | 6,079 | 1.4% | 695 |
| 2028 | 544,909 | 1.4% | 11,317 | 6,167 | 1.4% | 705 |
| 2029 | 552,467 | 1.4% | 11,320 | 6,254 | 1.4% | 715 |
| 2030 | 559,841 | 1.3% | 11,304 | 6,328 | 1.2% | 723 |
| 2031 | 566,967 | 1.3% | 11,282 | 6,396 | 1.1% | 731 |
| 2032 | 573,885 | 1.2% | 11,265 | 6,465 | 1.1% | 739 |
| 2033 | 580,611 | 1.2% | 11,256 | 6,535 | 1.1% | 747 |
| 2034 | 587,224 | 1.1% | 11,248 | 6,605 | 1.1% | 755 |

## Commercial Load

### Historical Commercial Sales and Load, 1974–2014 (weather adjusted)

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1974 | 24,096 | – | 49,028 | 1,181 | – | 136 |
| 1975 | 25,045 | 3.9% | 51,219 | 1,283 | 8.6% | 147 |
| 1976 | 26,034 | 3.9% | 52,514 | 1,367 | 6.6% | 157 |
| 1977 | 27,112 | 4.1% | 52,416 | 1,421 | 3.9% | 162 |
| 1978 | 27,831 | 2.7% | 52,477 | 1,460 | 2.8% | 168 |
| 1979 | 28,087 | 0.9% | 56,391 | 1,584 | 8.4% | 180 |
| 1980 | 28,797 | 2.5% | 54,143 | 1,559 | -1.6% | 178 |
| 1981 | 29,567 | 2.7% | 54,285 | 1,605 | 2.9% | 184 |
| 1982 | 30,167 | 2.0% | 54,129 | 1,633 | 1.7% | 186 |
| 1983 | 30,776 | 2.0% | 52,653 | 1,620 | -0.8% | 185 |
| 1984 | 31,554 | 2.5% | 53,552 | 1,690 | 4.3% | 193 |
| 1985 | 32,418 | 2.7% | 54,128 | 1,755 | 3.8% | 201 |
| 1986 | 33,208 | 2.4% | 54,069 | 1,796 | 2.3% | 204 |
| 1987 | 33,975 | 2.3% | 53,411 | 1,815 | 1.1% | 207 |
| 1988 | 34,723 | 2.2% | 54,425 | 1,890 | 4.1% | 216 |
| 1989 | 35,638 | 2.6% | 55,427 | 1,975 | 4.5% | 226 |
| 1990 | 36,785 | 3.2% | 55,849 | 2,054 | 4.0% | 236 |
| 1991 | 37,922 | 3.1% | 56,390 | 2,138 | 4.1% | 244 |
| 1992 | 39,022 | 2.9% | 56,424 | 2,202 | 3.0% | 252 |
| 1993 | 40,047 | 2.6% | 58,126 | 2,328 | 5.7% | 266 |
| 1994 | 41,629 | 4.0% | 58,283 | 2,426 | 4.2% | 278 |
| 1995 | 43,165 | 3.7% | 58,801 | 2,538 | 4.6% | 291 |
| 1996 | 44,995 | 4.2% | 62,062 | 2,792 | 10.0% | 319 |
| 1997 | 46,819 | 4.1% | 62,067 | 2,906 | 4.1% | 332 |
| 1998 | 48,404 | 3.4% | 62,804 | 3,040 | 4.6% | 348 |
| 1999 | 49,430 | 2.1% | 64,238 | 3,175 | 4.5% | 363 |
| 2000 | 50,117 | 1.4% | 66,012 | 3,308 | 4.2% | 379 |
| 2001 | 51,501 | 2.8% | 67,409 | 3,472 | 4.9% | 396 |
| 2002 | 52,915 | 2.7% | 64,845 | 3,431 | -1.2% | 392 |
| 2003 | 54,194 | 2.4% | 64,304 | 3,485 | 1.6% | 398 |
| 2004 | 55,577 | 2.6% | 64,013 | 3,558 | 2.1% | 406 |
| 2005 | 57,145 | 2.8% | 63,552 | 3,632 | 2.1% | 415 |
| 2006 | 59,050 | 3.3% | 63,513 | 3,750 | 3.3% | 429 |
| 2007 | 61,640 | 4.4% | 63,412 | 3,909 | 4.2% | 447 |
| 2008 | 63,492 | 3.0% | 62,270 | 3,954 | 1.2% | 449 |
| 2009 | 64,151 | 1.0% | 59,661 | 3,827 | -3.2% | 438 |
| 2010 | 64,421 | 0.4% | 58,927 | 3,796 | -0.8% | 433 |
| 2011 | 64,921 | 0.8% | 58,455 | 3,795 | 0.0% | 433 |
| 2012 | 65,599 | 1.0% | 58,980 | 3,869 | 1.9% | 440 |
| 2013 | 66,357 | 1.2% | 58,588 | 3,888 | 0.5% | 445 |
| 2014 | 67,113 | 1.1% | 59,036 | 3,962 | 1.9% | 452 |

## Commercial Load

### Projected Commercial Sales and Load, 2015–2034

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2015 | 68,174 | 1.6% | 59,790 | 4,076 | 2.9% | 466 |
| 2016 | 69,407 | 1.8% | 59,719 | 4,145 | 1.7% | 473 |
| 2017 | 70,839 | 2.1% | 59,044 | 4,183 | 0.9% | 478 |
| 2018 | 72,366 | 2.2% | 58,207 | 4,212 | 0.7% | 481 |
| 2019 | 73,896 | 2.1% | 57,478 | 4,247 | 0.8% | 485 |
| 2020 | 75,384 | 2.0% | 56,853 | 4,286 | 0.9% | 490 |
| 2021 | 76,816 | 1.9% | 56,332 | 4,327 | 1.0% | 494 |
| 2022 | 78,209 | 1.8% | 55,865 | 4,369 | 1.0% | 499 |
| 2023 | 79,591 | 1.8% | 55,409 | 4,410 | 0.9% | 504 |
| 2024 | 80,976 | 1.7% | 54,980 | 4,452 | 1.0% | 509 |
| 2025 | 82,364 | 1.7% | 54,581 | 4,496 | 1.0% | 513 |
| 2026 | 83,749 | 1.7% | 54,189 | 4,538 | 1.0% | 518 |
| 2027 | 85,129 | 1.6% | 53,793 | 4,579 | 0.9% | 523 |
| 2028 | 86,500 | 1.6% | 53,447 | 4,623 | 1.0% | 528 |
| 2029 | 87,856 | 1.6% | 53,150 | 4,670 | 1.0% | 533 |
| 2030 | 89,196 | 1.5% | 52,844 | 4,714 | 0.9% | 538 |
| 2031 | 90,513 | 1.5% | 52,544 | 4,756 | 0.9% | 543 |
| 2032 | 91,806 | 1.4% | 52,293 | 4,801 | 0.9% | 548 |
| 2033 | 93,078 | 1.4% | 52,098 | 4,849 | 1.0% | 554 |
| 2034 | 94,332 | 1.3% | 51,910 | 4,897 | 1.0% | 559 |

## Irrigation Load

### Historical Irrigation Sales and Load, 1974–2014 (weather adjusted)

| Year | Maximum Active Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1974 | 8,971 | – | 147,923 | 1,327 | – | 151 |
| 1975 | 9,480 | 5.7% | 153,993 | 1,460 | 10.0% | 167 |
| 1976 | 9,936 | 4.8% | 156,365 | 1,554 | 6.4% | 177 |
| 1977 | 10,238 | 3.0% | 164,994 | 1,689 | 8.7% | 193 |
| 1978 | 10,476 | 2.3% | 153,762 | 1,611 | -4.6% | 184 |
| 1979 | 10,711 | 2.2% | 163,283 | 1,749 | 8.6% | 199 |
| 1980 | 10,854 | 1.3% | 157,784 | 1,713 | -2.1% | 195 |
| 1981 | 11,248 | 3.6% | 165,251 | 1,859 | 8.5% | 212 |
| 1982 | 11,312 | 0.6% | 153,416 | 1,735 | -6.6% | 198 |
| 1983 | 11,133 | -1.6% | 143,575 | 1,598 | -7.9% | 182 |
| 1984 | 11,375 | 2.2% | 135,263 | 1,539 | -3.7% | 175 |
| 1985 | 11,576 | 1.8% | 135,260 | 1,566 | 1.8% | 179 |
| 1986 | 11,308 | -2.3% | 133,203 | 1,506 | -3.8% | 172 |
| 1987 | 11,254 | -0.5% | 130,082 | 1,464 | -2.8% | 167 |
| 1988 | 11,378 | 1.1% | 137,564 | 1,565 | 6.9% | 178 |
| 1989 | 11,957 | 5.1% | 138,406 | 1,655 | 5.7% | 189 |
| 1990 | 12,340 | 3.2% | 148,368 | 1,831 | 10.6% | 209 |
| 1991 | 12,484 | 1.2% | 138,195 | 1,725 | -5.8% | 197 |
| 1992 | 12,809 | 2.6% | 142,280 | 1,822 | 5.6% | 207 |
| 1993 | 13,078 | 2.1% | 125,883 | 1,646 | -9.7% | 188 |
| 1994 | 13,559 | 3.7% | 131,758 | 1,787 | 8.5% | 204 |
| 1995 | 13,679 | 0.9% | 126,751 | 1,734 | -2.9% | 198 |
| 1996 | 14,074 | 2.9% | 125,559 | 1,767 | 1.9% | 201 |
| 1997 | 14,383 | 2.2% | 118,005 | 1,697 | -4.0% | 194 |
| 1998 | 14,695 | 2.2% | 117,169 | 1,722 | 1.4% | 197 |
| 1999 | 14,912 | 1.5% | 120,036 | 1,790 | 4.0% | 204 |
| 2000 | 15,253 | 2.3% | 128,221 | 1,956 | 9.3% | 223 |
| 2001 | 15,522 | 1.8% | 117,764 | 1,828 | -6.5% | 209 |
| 2002 | 15,840 | 2.0% | 111,181 | 1,761 | -3.7% | 201 |
| 2003 | 16,020 | 1.1% | 111,173 | 1,781 | 1.1% | 203 |
| 2004 | 16,297 | 1.7% | 110,079 | 1,794 | 0.7% | 204 |
| 2005 | 16,936 | 3.9% | 99,646 | 1,688 | -5.9% | 193 |
| 2006 | 17,062 | 0.7% | 96,535 | 1,647 | -2.4% | 188 |
| 2007 | 17,001 | -0.4% | 106,506 | 1,811 | 9.9% | 207 |
| 2008 | 17,428 | 2.5% | 110,770 | 1,930 | 6.6% | 220 |
| 2009 | 17,708 | 1.6% | 100,877 | 1,786 | -7.5% | 204 |
| 2010 | 17,846 | 0.8% | 101,364 | 1,809 | 1.3% | 207 |
| 2011 | 18,292 | 2.5% | 98,400 | 1,800 | -0.5% | 205 |
| 2012 | 18,675 | 2.1% | 104,377 | 1,949 | 8.3% | 222 |
| 2013 | 19,017 | 1.8% | 105,797 | 2,012 | 3.2% | 230 |
| 2014 | 19,328 | 1.6% | 104,512 | 2,020 | 0.4% | 231 |

**Irrigation Load**

**Projected Irrigation Sales and Load, 2015–2034**

| Year | Maximum Active Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2015 | 19,566 | 1.2% | 95,218 | 1,863 | -7.8% | 213 |
| 2016 | 19,847 | 1.4% | 95,841 | 1,902 | 2.1% | 217 |
| 2017 | 20,127 | 1.4% | 95,191 | 1,916 | 0.7% | 219 |
| 2018 | 20,408 | 1.4% | 93,999 | 1,918 | 0.1% | 219 |
| 2019 | 20,688 | 1.4% | 92,504 | 1,914 | -0.2% | 218 |
| 2020 | 20,970 | 1.4% | 91,789 | 1,925 | 0.6% | 219 |
| 2021 | 21,250 | 1.3% | 91,179 | 1,938 | 0.7% | 221 |
| 2022 | 21,531 | 1.3% | 90,194 | 1,942 | 0.2% | 222 |
| 2023 | 21,814 | 1.3% | 89,126 | 1,944 | 0.1% | 222 |
| 2024 | 22,092 | 1.3% | 88,442 | 1,954 | 0.5% | 222 |
| 2025 | 22,373 | 1.3% | 87,905 | 1,967 | 0.7% | 225 |
| 2026 | 22,653 | 1.3% | 87,365 | 1,979 | 0.6% | 226 |
| 2027 | 22,933 | 1.2% | 86,784 | 1,990 | 0.6% | 227 |
| 2028 | 23,215 | 1.2% | 86,171 | 2,000 | 0.5% | 228 |
| 2029 | 23,495 | 1.2% | 85,649 | 2,012 | 0.6% | 230 |
| 2030 | 23,777 | 1.2% | 85,060 | 2,022 | 0.5% | 231 |
| 2031 | 24,056 | 1.2% | 84,446 | 2,031 | 0.4% | 232 |
| 2032 | 24,338 | 1.2% | 83,751 | 2,038 | 0.3% | 232 |
| 2033 | 24,617 | 1.1% | 83,159 | 2,047 | 0.4% | 234 |
| 2034 | 24,899 | 1.1% | 82,533 | 2,055 | 0.4% | 235 |

## Industrial Load

### Historical Industrial Sales and Load, 1974–2014 (not weather adjusted)

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1974 | 65 | – | 11,464,249 | 739 | – | 84 |
| 1975 | 71 | 10.5% | 11,014,121 | 785 | 6.1% | 91 |
| 1976 | 73 | 3.0% | 11,681,540 | 858 | 9.3% | 99 |
| 1977 | 85 | 15.1% | 10,988,826 | 929 | 8.3% | 106 |
| 1978 | 99 | 17.6% | 9,786,753 | 972 | 4.7% | 111 |
| 1979 | 109 | 9.6% | 9,989,158 | 1,087 | 11.8% | 126 |
| 1980 | 112 | 2.7% | 9,894,706 | 1,106 | 1.7% | 125 |
| 1981 | 118 | 5.7% | 9,718,723 | 1,148 | 3.9% | 132 |
| 1982 | 122 | 3.5% | 9,504,283 | 1,162 | 1.2% | 133 |
| 1983 | 122 | -0.3% | 9,797,522 | 1,194 | 2.7% | 138 |
| 1984 | 124 | 1.5% | 10,369,789 | 1,282 | 7.4% | 147 |
| 1985 | 125 | 1.2% | 10,844,888 | 1,357 | 5.9% | 155 |
| 1986 | 129 | 2.7% | 10,550,145 | 1,357 | -0.1% | 155 |
| 1987 | 134 | 4.1% | 11,006,455 | 1,474 | 8.7% | 169 |
| 1988 | 133 | -1.0% | 11,660,183 | 1,546 | 4.9% | 177 |
| 1989 | 132 | -0.6% | 12,091,482 | 1,594 | 3.1% | 183 |
| 1990 | 132 | 0.2% | 12,584,200 | 1,662 | 4.3% | 191 |
| 1991 | 135 | 2.5% | 12,699,665 | 1,719 | 3.4% | 196 |
| 1992 | 140 | 3.4% | 12,650,945 | 1,770 | 3.0% | 203 |
| 1993 | 141 | 0.5% | 13,179,585 | 1,854 | 4.7% | 212 |
| 1994 | 143 | 1.7% | 13,616,608 | 1,948 | 5.1% | 223 |
| 1995 | 120 | -15.9% | 16,793,437 | 2,021 | 3.7% | 230 |
| 1996 | 103 | -14.4% | 18,774,093 | 1,934 | -4.3% | 221 |
| 1997 | 106 | 2.7% | 19,309,504 | 2,042 | 5.6% | 235 |
| 1998 | 111 | 4.6% | 19,378,734 | 2,145 | 5.0% | 244 |
| 1999 | 108 | -2.3% | 19,985,029 | 2,160 | 0.7% | 247 |
| 2000 | 107 | -0.8% | 20,433,299 | 2,191 | 1.5% | 250 |
| 2001 | 111 | 3.5% | 20,618,361 | 2,289 | 4.4% | 260 |
| 2002 | 111 | -0.1% | 19,441,876 | 2,156 | -5.8% | 246 |
| 2003 | 112 | 1.0% | 19,950,866 | 2,234 | 3.6% | 255 |
| 2004 | 117 | 4.3% | 19,417,310 | 2,269 | 1.5% | 259 |
| 2005 | 126 | 7.9% | 18,645,220 | 2,351 | 3.6% | 270 |
| 2006 | 127 | 1.0% | 18,255,385 | 2,325 | -1.1% | 265 |
| 2007 | 123 | -3.6% | 19,275,551 | 2,366 | 1.8% | 270 |
| 2008 | 119 | -3.1% | 19,412,391 | 2,308 | -2.4% | 261 |
| 2009 | 124 | 4.0% | 17,987,570 | 2,224 | -3.6% | 254 |
| 2010 | 121 | -2.0% | 18,404,875 | 2,232 | 0.3% | 254 |
| 2011 | 120 | -1.1% | 18,597,050 | 2,230 | -0.1% | 254 |
| 2012 | 115 | -4.2% | 19,757,921 | 2,271 | 1.8% | 258 |
| 2013 | 114 | -0.7% | 20,281,837 | 2,314 | 1.9% | 265 |
| 2014 | 113 | -0.7% | 20,863,653 | 2,363 | 2.1% | 271 |

**Industrial Load**

**Projected Industrial Sales and Load, 2015–2034**

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2015 | 112 | -1.1% | 21,546,339 | 2,413 | 2.1% | 277 |
| 2016 | 113 | 0.9% | 22,776,876 | 2,574 | 6.7% | 294 |
| 2017 | 114 | 0.9% | 23,180,649 | 2,643 | 2.7% | 302 |
| 2018 | 115 | 0.9% | 23,415,713 | 2,693 | 1.9% | 308 |
| 2019 | 115 | 0.0% | 23,815,557 | 2,739 | 1.7% | 313 |
| 2020 | 115 | 0.0% | 24,226,148 | 2,786 | 1.7% | 318 |
| 2021 | 117 | 1.7% | 24,251,880 | 2,837 | 1.8% | 324 |
| 2022 | 117 | 0.0% | 24,697,299 | 2,890 | 1.8% | 330 |
| 2023 | 117 | 0.0% | 25,147,761 | 2,942 | 1.8% | 336 |
| 2024 | 118 | 0.9% | 25,374,712 | 2,994 | 1.8% | 341 |
| 2025 | 120 | 1.7% | 25,397,900 | 3,048 | 1.8% | 348 |
| 2026 | 121 | 0.8% | 25,630,843 | 3,101 | 1.8% | 355 |
| 2027 | 121 | 0.0% | 26,070,612 | 3,155 | 1.7% | 361 |
| 2028 | 121 | 0.0% | 26,512,099 | 3,208 | 1.7% | 366 |
| 2029 | 123 | 1.7% | 26,528,528 | 3,263 | 1.7% | 373 |
| 2030 | 124 | 0.8% | 26,729,282 | 3,314 | 1.6% | 379 |
| 2031 | 125 | 0.8% | 26,914,352 | 3,364 | 1.5% | 385 |
| 2032 | 125 | 0.0% | 27,298,864 | 3,412 | 1.4% | 389 |
| 2033 | 126 | 0.8% | 27,474,833 | 3,462 | 1.4% | 396 |
| 2034 | 127 | 0.8% | 27,632,976 | 3,509 | 1.4% | 401 |

**Additional Firm Sales and Load***

**Historical Additional Firm Sales and Load, 1974–2014**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 1974 | 282 | – | 32 |
| 1975 | 314 | 11.2% | 36 |
| 1976 | 289 | -8.1% | 33 |
| 1977 | 311 | 7.8% | 36 |
| 1978 | 357 | 14.8% | 41 |
| 1979 | 373 | 4.4% | 43 |
| 1980 | 360 | -3.5% | 41 |
| 1981 | 377 | 4.6% | 43 |
| 1982 | 368 | -2.4% | 42 |
| 1983 | 425 | 15.6% | 49 |
| 1984 | 466 | 9.6% | 53 |
| 1985 | 471 | 1.1% | 54 |
| 1986 | 482 | 2.3% | 55 |
| 1987 | 503 | 4.2% | 57 |
| 1988 | 531 | 5.6% | 60 |
| 1989 | 671 | 26.5% | 77 |
| 1990 | 625 | -6.9% | 71 |
| 1991 | 661 | 5.8% | 75 |
| 1992 | 680 | 2.9% | 77 |
| 1993 | 689 | 1.3% | 79 |
| 1994 | 741 | 7.5% | 85 |
| 1995 | 878 | 18.6% | 100 |
| 1996 | 989 | 12.6% | 113 |
| 1997 | 1,048 | 6.0% | 120 |
| 1998 | 1,113 | 6.2% | 127 |
| 1999 | 1,122 | 0.8% | 128 |
| 2000 | 1,143 | 1.9% | 130 |
| 2001 | 1,118 | -2.1% | 128 |
| 2002 | 1,139 | 1.9% | 130 |
| 2003 | 1,120 | -1.7% | 128 |
| 2004 | 1,157 | 3.3% | 132 |
| 2005 | 1,175 | 1.6% | 134 |
| 2006 | 1,189 | 1.2% | 136 |
| 2007 | 1,141 | -4.0% | 130 |
| 2008 | 1,114 | -2.4% | 127 |
| 2009 | 965 | -13.4% | 110 |
| 2010 | 907 | -6.0% | 104 |
| 2011 | 906 | 0.0% | 103 |
| 2012 | 862 | -4.8% | 98 |
| 2013 | 867 | 0.5% | 99 |
| 2014 | 841 | -2.9% | 96 |

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

**Additional Firm Sales and Load***

**Projected Additional Firm Sales and Load, 2015–2034**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 2015 | 881 | 4.7% | 101 |
| 2016 | 902 | 2.4% | 103 |
| 2017 | 906 | 0.4% | 103 |
| 2018 | 909 | 0.4% | 104 |
| 2019 | 910 | 0.0% | 104 |
| 2020 | 921 | 1.2% | 105 |
| 2021 | 923 | 0.2% | 105 |
| 2022 | 958 | 3.8% | 109 |
| 2023 | 987 | 3.0% | 113 |
| 2024 | 1,007 | 2.0% | 115 |
| 2025 | 1,007 | 0.0% | 115 |
| 2026 | 1,004 | -0.3% | 115 |
| 2027 | 1,004 | 0.0% | 115 |
| 2028 | 999 | -0.5% | 114 |
| 2029 | 999 | 0.0% | 114 |
| 2030 | 1,004 | 0.5% | 115 |
| 2031 | 1,004 | 0.0% | 115 |
| 2032 | 999 | -0.5% | 114 |
| 2033 | 999 | 0.0% | 114 |
| 2034 | 994 | -0.5% | 113 |

*Includes Micron Technology, Simplot Fertilizer, and the INL

**Company System Load (excluding Astaris)**

**Historical Company System Sales and Load, 1974–2014 (weather adjusted)**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 1974 | 5,463 | – | 682 |
| 1975 | 6,013 | 10.1% | 751 |
| 1976 | 6,431 | 6.9% | 803 |
| 1977 | 6,878 | 7.0% | 855 |
| 1978 | 7,171 | 4.3% | 898 |
| 1979 | 7,798 | 8.7% | 969 |
| 1980 | 7,793 | -0.1% | 964 |
| 1981 | 8,048 | 3.3% | 1,003 |
| 1982 | 8,021 | -0.3% | 997 |
| 1983 | 7,996 | -0.3% | 996 |
| 1984 | 8,140 | 1.8% | 1,009 |
| 1985 | 8,328 | 2.3% | 1,037 |
| 1986 | 8,394 | 0.8% | 1,038 |
| 1987 | 8,481 | 1.0% | 1,053 |
| 1988 | 8,846 | 4.3% | 1,096 |
| 1989 | 9,250 | 4.6% | 1,147 |
| 1990 | 9,575 | 3.5% | 1,194 |
| 1991 | 9,800 | 2.3% | 1,211 |
| 1992 | 10,009 | 2.1% | 1,241 |
| 1993 | 10,185 | 1.8% | 1,262 |
| 1994 | 10,654 | 4.6% | 1,324 |
| 1995 | 11,053 | 3.7% | 1,368 |
| 1996 | 11,415 | 3.3% | 1,412 |
| 1997 | 11,722 | 2.7% | 1,455 |
| 1998 | 12,189 | 4.0% | 1,510 |
| 1999 | 12,510 | 2.6% | 1,549 |
| 2000 | 12,923 | 3.3% | 1,601 |
| 2001 | 13,070 | 1.1% | 1,616 |
| 2002 | 12,796 | -2.1% | 1,584 |
| 2003 | 13,044 | 1.9% | 1,618 |
| 2004 | 13,361 | 2.4% | 1,654 |
| 2005 | 13,593 | 1.7% | 1,688 |
| 2006 | 13,917 | 2.4% | 1,726 |
| 2007 | 14,379 | 3.3% | 1,784 |
| 2008 | 14,500 | 0.8% | 1,790 |
| 2009 | 13,955 | -3.8% | 1,731 |
| 2010 | 13,831 | -0.9% | 1,713 |
| 2011 | 13,810 | -0.2% | 1,711 |
| 2012 | 14,040 | 1.7% | 1,737 |
| 2013 | 14,113 | 0.5% | 1,755 |
| 2014 | 14,253 | 1.0% | 1,768 |

**Company System Load**

**Projected Company System Sales and Load, 2015–2034**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 2015 | 14,378 | 0.9% | 1,786 |
| 2016 | 14,793 | 2.9% | 1,835 |
| 2017 | 15,019 | 1.5% | 1,864 |
| 2018 | 15,174 | 1.0% | 1,883 |
| 2019 | 15,318 | 0.9% | 1,900 |
| 2020 | 15,474 | 1.0% | 1,918 |
| 2021 | 15,642 | 1.1% | 1,941 |
| 2022 | 15,832 | 1.2% | 1,964 |
| 2023 | 16,024 | 1.2% | 1,988 |
| 2024 | 16,231 | 1.3% | 2,012 |
| 2025 | 16,425 | 1.2% | 2,037 |
| 2026 | 16,617 | 1.2% | 2,061 |
| 2027 | 16,807 | 1.1% | 2,085 |
| 2028 | 16,997 | 1.1% | 2,107 |
| 2029 | 17,198 | 1.2% | 2,133 |
| 2030 | 17,383 | 1.1% | 2,156 |
| 2031 | 17,552 | 1.0% | 2,177 |
| 2032 | 17,715 | 0.9% | 2,195 |
| 2033 | 17,892 | 1.0% | 2,219 |
| 2034 | 18,060 | 0.9% | 2,240 |

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March 15, 2015

APPENDIX B
DSM Annual Report

# Integrated Resource Plan 2015







## SAFE HARBOR STATEMENT

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

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June 2015

APPENDIX B
DSM Annual Report

# Integrated Resource Plan 2015

## ACKNOWLEDGMENT

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 *2015 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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*Supplement 1: Cost-Effectiveness*
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NEEA Market Effects Evaluations (included on CD with Supplement 2)

# GLOSSARY OF ACRONYMS

A/C—Air Conditioning/Air Conditioners

ADM—ADM Associates, Inc.

Ads—Advertisement

AHU—Air Handling Unit

AIA—American Institute of Architects

AMI—Advanced Metering Infrastructure

aMW—Average Megawatt

AR—Agricultural Representative

ASHRAE—American Society of Heating, Refrigeration, and Air Conditioning Engineers

B/C—Benefit/Cost

BCA—Building Contractors Association

BCASEI—Building Contractors Association of Southeast Idaho

BCASWI—Building Contractors Association of Southwestern Idaho

BCW—Boise Center West

BML—Building Metrics Labeling

BOC—Boise Operations Center

BOMA—Building Owners and Managers Association

BPA—Bonneville Power Administration

BSUG—Building Simulation Users Group

CAES—Center for Advanced Energy Studies

CAIS—Certified Agricultural Irrigation Specialist

CAP—Community Action Partnership

CAPAI—Community Action Partnership Association of Idaho, Inc.

CCOA—CCOA—Aging, Weatherization and Human Services

CEERI—CAE's Energy Efficiency Research Institute

CEL—Cost-Effective Limit

CER—Community Education Representative

CFL—Compact Fluorescent Lamp/Light

CHQ—Corporate Headquarters (Idaho Power)

CID—Certified Irrigation Designer

CLEAResult—CLEAResult Consulting, Inc. (acquired Fluid Market Strategies and PECI)

CLRIS—Customer Load and Resource Information System

COP—Coefficient of Performance

CR—Customer Representative (field staff)

CR&EE—Customer Relations and Energy Efficiency Department

CRES—Certified Refrigeration Energy Specialist

CSR—Customer Service Representative (call center)

CTR—Click-Through Rate

CWI—College of Western Idaho

DEAP—Design Excellence Award Program

DHP—Ductless Heat Pump

DOE—Department of Energy

DSM—Demand-Side Management

EA5—EA5 Energy Audit Program

EBR—Existing Building Renewal

ECM—Electronically Commutated Motors

EEAG—Energy Efficiency Advisory Group

EER—Energy Efficiency Ratio

EISA—*Energy Independence and Security Act of 2007*

EM&V—Evaluation, Measurement, and Verification

ETO—Energy Trust of Oregon

EPA—Environmental Protection Agency

EUI—Energy Use Intensity

FCA—Fixed-Cost Adjustment

FFA—Future Farmers of America

FMP—Facility Management Professional

$ft^2$—Square Feet

$ft^3$—Cubic Feet

GIS—Geographic Information System

GMPG—Green Motors Practice Group

GPM—Gallons per Minute

H&CE—Heating & Cooling Efficiency Program

hp—Horsepower

HPWH—Heat Pump Water Heater

HPS—Home Performance Specialist

HSPF—Heating Seasonal Performance Factor

HVAC—Heating, Ventilation, and Air Conditioning

IAC—Industrial Assessment Center

IBCA—Idaho Building Contractors Association

IBOA—International Building Operators Association

IDHW—Idaho Department of Health and Welfare

IDL—Integrated Design Lab (in Boise)

IECC—International Energy Conservation Code

IFMA—International Facility Management Association

INL—Idaho National Laboratory

IPMVP—International Performance Measurement and Verification Protocol

IPUC—Idaho Public Utilities Commission

IRP—Integrated Resource Plan

IRPAC—Integrated Resource Plan Advisory Council

iSTEM—Idaho Science, Technology, Engineering and Mathematics

JACO—JACO Environmental, Inc.

kW—Kilowatt

kWh—Kilowatt-hour

LED—Light-Emitting Diode

LEEF—Local Energy Efficiency Funds

LIHEAP—Low Income Home Energy Assistance Program

M&V—Measurement & Verification

MCR— Major Customer Representative

MDC—MDC Research

MOU—Memorandum of Understanding

MPER—Market Progress Evaluation Report

MVBA—Magic Valley Builders Association

MW—Megawatt

MWh—Megawatt-hour

n/a—Not Applicable

NEB—Non-Energy Benefit

NEEA—Northwest Energy Efficiency Alliance

NEEM—Northwest Energy Efficient Manufactured

NEF—National Energy Foundation

NEMA—National Electrical Manufacturers Association

NWPCC—Northwest Power and Conservation Council

NWRRC—Northwest Regional Retail Collaborative

O&M—Operation and Maintenance

OHCS—Oregon Housing and Community Services

OPUC—Public Utility Commission of Oregon

ORS—Oregon Revised Statute

OSV—On-Site Verification

PCA—Power Cost Adjustment

PCT—Participant Cost Test

PLC—Power-Line Carrier

PSC—Permanent Split Capacitor

PTCS—Performance Tested Comfort System

QA—Quality Assurance

QC—Quality Control

RAP—Resource Action Programs

RBSA—Residential Building Stock Assessment

RETA— Refrigerating Engineers and Technicians Association

RETAC—Regional Emerging Technologies Advisory Committee

RFP—Request for Proposal

Rider—Idaho Energy Efficiency Rider and Oregon Energy Efficiency Rider

RIM—Ratepayer Impact Measure Test

ROCEE—Refrigeration Operator Coaching for Energy Efficiency

ROI—Return on Investment

RPP—Retail Products Platform

RSAT—Regional Sales Allocation Tool

RSE—Runyon Saltzman Einhorn

RTF—Regional Technical Forum

RWLR—Reduced Wattage Lamp Replacement

SCCT—Simple-Cycle Combustion Turbine

SCE—Streamlined Custom Efficiency

SCO—State-Certifying Organization

SEEK—Students for Energy Efficiency Kit

SIR—Savings-to-Investment Ratio

SIS—Scientific Irrigation Scheduling

SKU—Stock Keeping Unit

SOX—*Sarbanes–Oxley Act of 2002*

SRVBCA—Snake River Valley Building Contractors Association

T&D—Transmission and Distribution

TLL—Tool Loan Library

TOD—Time of Day

TRC—Total Resource Cost

TRM—Technical Reference Manual

UC—Utility Cost

UES—Unit Energy Savings

US—United States

USFS—United States Forest Service

VFD—Variable-Frequency Drive

VOC—Volatile Organic Compound

VRF—Variable-Refrigerant Flow

VRI—Variable-Rate Irrigation

VSI—Variable-Speed Irrigation

WAP—Weatherization Assistance Program

WAQC—Weatherization Assistance for Qualified Customers

WRUN—Western Regional Utility Network

WSEEC—Water Supply Energy Efficiency Cohort

WWEEC—Wastewater Energy Efficiency Cohort

# EXECUTIVE SUMMARY

Idaho Power has effectively operated demand-side management (DSM) programs starting with load control programs around 1945 and adding energy efficiency programs beginning in the 1970s. Through the years, the company has maintained a successful DSM portfolio, including both energy efficiency and demand response programs.

Idaho Power's 2014 energy savings exceeded the annual savings target identified in Idaho Power's 2013 *Integrated Resource Plan* (IRP), and the company has exceeded those annual targets 12 out of 13 years. On a cumulative basis, the company's energy savings have exceeded the IRP targets every year since 2002. Additionally in 2014, the Customer Relations and Energy Efficiency (CR&EE) department contributed to the development of the 2015 IRP, including refreshing Idaho Power's *Energy Efficiency Potential Study*.

Idaho Power's portfolio of energy efficiency programs is cost-effective, passing both the total resource cost (TRC) test and the utility cost (UC) test with ratios of 1.89 and 3.49, respectively. Idaho Power's annual energy savings increased by 33 percent in 2014, with the energy efficiency programs saving enough energy to supply electricity to over 9,000 average homes a year. The savings from Idaho Power's energy efficiency programs alone (excluding Northwest Energy Efficiency Alliance [NEEA] savings) increased from 88,938 megawatt-hours (MWh) in 2013 to 118,670 MWh in 2014. Annual energy savings for 2013, including the revised NEEA savings, were 109,506 MWh. In 2014, these savings increased to 138,670 MWh.

Customers' familiarity with Idaho Power's energy efficiency programs meets or exceeds the average of peer utilities according to the J. D. Power and Associates electric utility customer satisfaction studies. Idaho Power has exceeded the average of its peer utilities every year in the last four years with its awareness of business programs, and the company has met or exceeded the average of its peer utilities five out of the last six years with its awareness of residential programs.

In 2014, Idaho Power worked diligently with NEEA and its funders to procure a new plan for regional market transformation. This effort resulted in a 2015 to 2019 NEEA business plan to obtain 145 aMW of energy savings at a cost of about $3 million less over the next five years to Idaho Power customers than the previous five-year business plan.

Idaho Power successfully resumed two of its demand response programs in 2014. The company used all three demand response programs in 2014 for a total demand reduction of 378 megawatts (MW) and an enrolled capacity of 390 MW. The reduced costs of these programs resulted in savings to Idaho Power customers of approximately $6.5 million dollars, with only a slight reduction in capacity of 11 percent from 2012. These strong demand response results are attributable to Idaho Power's collaborative efforts with a multitude of stakeholders.

Idaho Power enhanced its marketing, public relations, and research methods during 2014. These enhancements included the use of public television, new distribution methods for its energy efficiency newspaper inserts, focus groups, and social media. The company will continue with innovative techniques in 2015, including airport signage, broadcast and online radio, television, and feedback from Idaho Power's online customer research panel.

Early in 2014, Idaho Power formed a Program Planning Group to explore new opportunities to expand current energy efficiency programs and offerings. This group ushered new ideas through an assessment

process that will yield new offerings to the DSM program portfolio in 2015. In 2014, Idaho Power also increased the incentive paid under its commercial and industrial programs and made several changes to its commercial/industrial lighting measures based on input from stakeholders.

Energy efficiency program funding comes from the Idaho and Oregon Energy Efficiency Riders (Rider), Idaho Power base rates, and the annual power cost adjustment (PCA). Idaho incentives for the company's demand response programs are recovered through base rates and the annual PCA, while Oregon demand response incentives are funded through the Oregon Rider. Total expenditures from all funding sources on DSM-related activities increased by about 37 percent, from $27 million in 2013 to $37 million in 2014.

Idaho Power takes its responsibility of prudently managing customer funds seriously. The company's actions in 2014, and this report's content, provide evidence supporting the conscientious work Idaho Power employees and leaders have made toward using customers' funds wisely. Some highlights include the demand response settlement, the resulting outcome of restarting the demand response programs, and the establishment of the NEEA contract for the 2015 to 2019 funding cycle. The company believes it is important to provide maximum value to its customers.

This *Demand-Side Management 2014 Annual Report* provides a review of the company's DSM activities and finances throughout 2014 and outlines Idaho Power's plans for DSM activities. This report also satisfies the reporting requirements set out in the Idaho Public Utilities Commission's (IPUC) Order Nos. 29026 and 29419, as well as the Memorandum of Understanding (MOU) signed by IPUC staff and Idaho investor-owned utilities in January 2010. Additionally, a courtesy copy of the report will be provided under Oregon Docket UM 1710 to facilitate review of program and measure cost-effectiveness.

# INTRODUCTION

In 2014, Idaho Power continued its long history of pursuing cost-effective energy efficiency. Through the years, the company has maintained a successful demand-side management (DSM) portfolio, including both energy efficiency and demand response programs. This report focuses on the years after 2002 when the Idaho Energy Efficiency Rider (Rider) began.

More specifically, Idaho Power's *Demand-Side Management 2014 Annual Report* provides a review of the financial and operational performance of Idaho Power's DSM activities and initiatives for 2014. In 2014, Idaho Power offered energy efficiency and demand response programs to all customer sectors. The company sponsored numerous activities under its customer education initiatives to improve customers' energy awareness and to educate them about reducing their electricity usage.

Idaho Power's main objectives for DSM programs are to achieve prudent, cost-effective energy efficiency savings and provide an optimal amount of demand reduction from its demand response programs as determined through the Integrated Resource Plan (IRP) planning process. In addition to cost-effectiveness, Idaho Power pays particular attention to ensuring the best value to Idaho Power's customers. Idaho Power strives to provide customers with programs and information to help them manage their energy usage. The company achieves these objectives through the implementation and careful management of programs that provide energy and demand savings and through outreach and education. Idaho Power endeavors to implement identical programs in its Idaho and Oregon service areas.

Idaho Power's portfolio of energy efficiency programs is cost-effective, passing both the total resource cost (TRC) test and the utility cost (UC) test with ratios of 1.89 and 3.49, respectively. The energy savings from Idaho Power's energy efficiency programs in 2014 were 118,670 megawatt-hours (MWh)—enough to power over 9,000 average homes a year. The savings consisted of 21,267 MWh from the residential sector, 28,577 MWh from the commercial sector, 50,363 MWh from the industrial sector, and 18,464 MWh from the irrigation sector. This represents a 33 percent increase from 2013 savings. The industrial Custom Efficiency program contributed 43 percent of the portfolio savings, while residential lighting contributed 61 percent of the residential savings.

Beyond its energy efficiency incentive programs, Idaho Power increased its energy efficiency presence in the community by providing energy efficiency and program information through 116 outreach activities, including events, presentations, trainings, and other outreach activities documented in the company's Outreach Tracking System. In addition to these activities, Idaho Power staff throughout Idaho Power's service area delivered 164 presentations to local organizations addressing energy efficiency programs and wise energy use. In 2014, Idaho Power's Community Education team provided 67 presentations on *The Power to Make a Difference* to 1,756 students. The community education representatives (CER) and other staff also completed 32 senior citizen presentations on energy efficiency programs and shared information about saving energy to 912 seniors in the company's service area. In September 2014, Idaho Power participated in the FitOne Expo in Boise, Idaho. At this event, the booth theme capitalized on light-emitting diode (LED) lighting imagery from the integrated campaign launched in August and previewed the energy-efficient interactive home graphic in the background. Idaho Power staff at the event educated attendees about the benefits of LED lighting technology and distributed 2,500 LED light bulbs to an engaged and receptive audience.

Raising the knowledge level of commercial customers in the wise use of energy in their daily operations is important to the continued success of Idaho Power's commercial energy efficiency

programs and education. In 2014, the Commercial Education Initiative worked with and supported various organizations, including the University of Idaho's Integrated Design Lab (IDL) in Boise; Building Owners and Managers Association (BOMA); United States (US) Green Building Council; American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE); International Building Operators Association (IBOA); and the International Facility Management Association (IFMA)—Northern Rockies Chapter to increase customers' energy efficiency knowledge.

Idaho Power's internal commitment to energy efficiency and sustainability increased in 2014. Several Idaho Power properties were enhanced in 2014 with the goal of improving energy efficiency. Numerous corporate headquarters (CHQ) remodel projects were completed in 2014. These remodels included high-efficiency lighting; heating, ventilation, and air conditioning (HVAC); and reflective and better-insulated roofing. The CHQ fourth floor was completely remodeled with new recycled carpet, low volatile organic compound (VOC) paint, and low-partition walls for increased light transmission throughout the floor. At the Boise Operations Center (BOC), Idaho Power installed building-wide Direct Digital Control system controls. At Boise Center West (BCW) the chillers and air handlers were replaced with high-efficiency units. Additionally, Idaho Power's CHQ continued to participate in the FlexPeak Management program, reducing its load when the program was used.

The company was successful in redesigning and reestablishing the Irrigation Peak Rewards and A/C Cool Credit programs in 2014. After a one-season suspension of these programs, participation was only slightly reduced. Each of the demand response programs, including FlexPeak Management, was used three times in the 2014 season for a total demand reduction of 378 MW and an enrolled capacity of 390 megawatts (MW).

Idaho Power uses the same report structure each year to fulfill the objectives of the Memorandum of Understanding (MOU) signed on January 25, 2010, by Idaho Power, Idaho Public Utilities Commission (IPUC) staff, and Idaho's other investor-owned utilities. The report consists of the main document and two supplements. *Supplement 1: Cost Effectiveness* shows the standard cost-effectiveness tests for Idaho Power programs and includes a table that reports expenses by funding source and cost category. In 2014, the company continued its commitment to third-party evaluation activities. Included in *Supplement 2: Evaluation* are copies of all of Idaho Power's 2014 evaluations, evaluations conducted by its regional partners, customer surveys and reports, Idaho Power's evaluation plans, general energy efficiency research, and demand response research. Additionally, the report will be provided under Oregon Docket UM 1710 to facilitate review of program and measure cost-effectiveness.

## DSM Programs Performance

Idaho Power offers energy efficiency and demand response opportunities to all major customer sectors: residential, commercial, industrial, and irrigation. The commercial and industrial energy efficiency programs are made available to customers in either of these sectors.

Idaho Power groups its DSM activities into four major categories: energy efficiency, demand response, market transformation, and other programs and activities. The other programs and activities are generally designed to provide customer outreach and education encouraging the efficient use of electricity. These activities are coordinated to advance Idaho Power's long-term commitment to pursue all prudent cost-effective energy efficiency, demand response, and to enhance customer satisfaction.

Figures 1 and 2 show the demand-reduction capacity and historic energy savings overlaid with the company's DSM expenses.

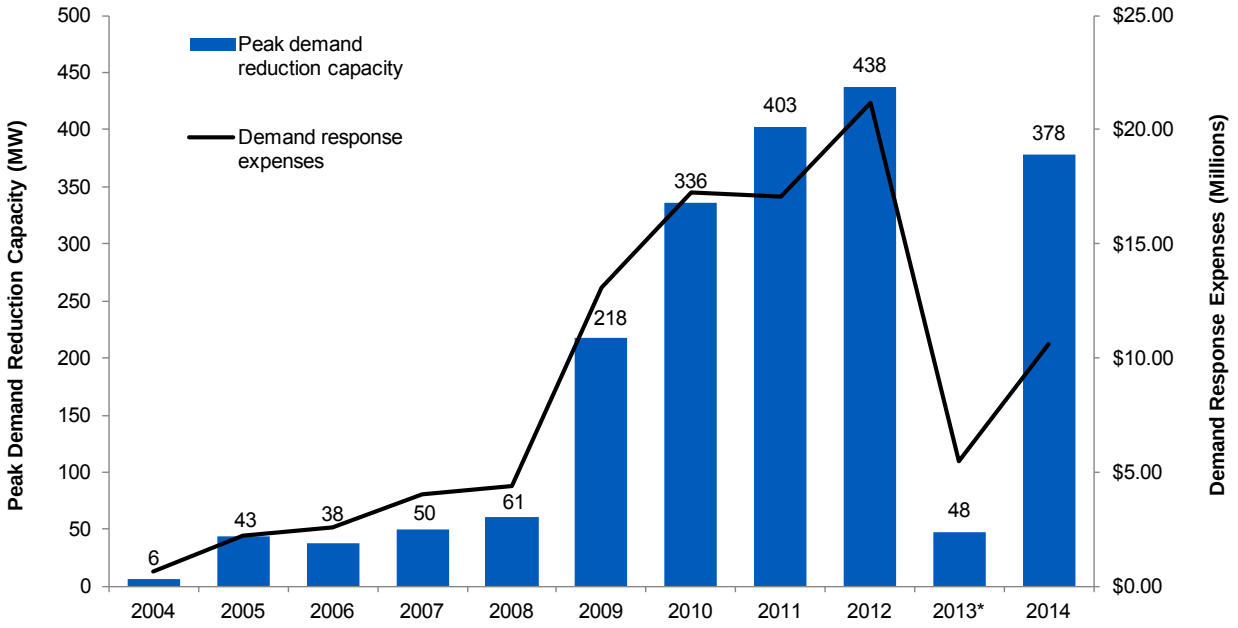



Figure 1. Peak demand-reduction capacity and demand response expenses, 2004–2014 (MW and millions [$])

*In 2013, two of the three demand response programs were temporarily suspended.

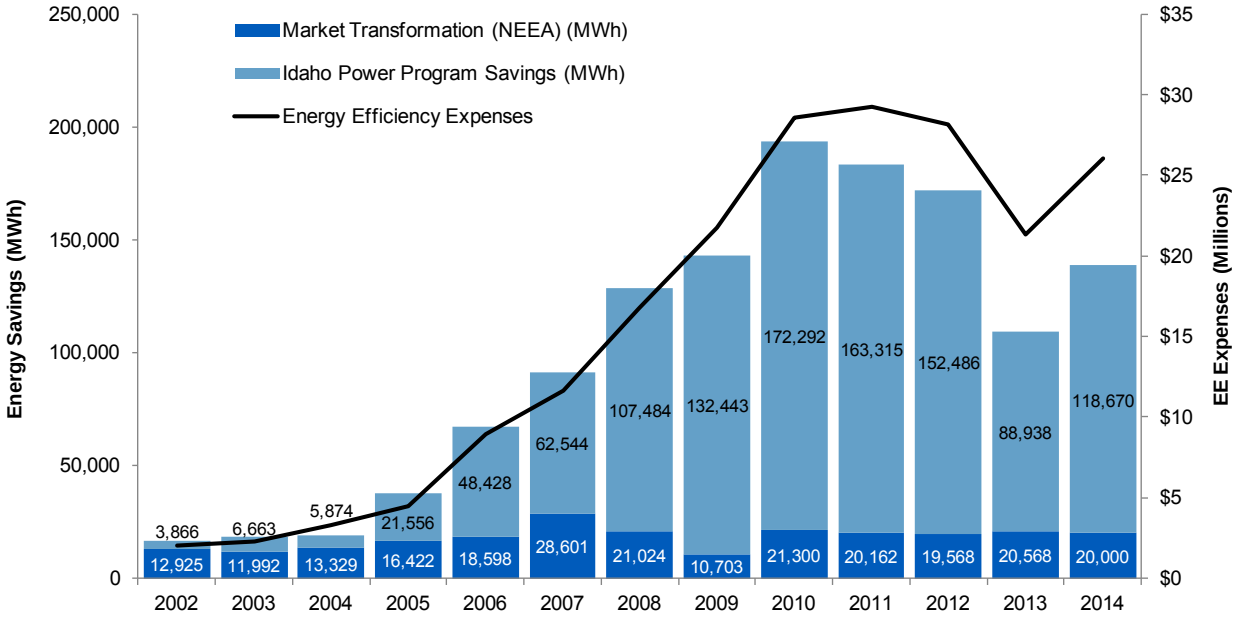



Figure 2. Annual energy savings and energy efficiency program expenses, 2002–2014 (MWh and millions [$])

*In 2013, two of the three demand response programs were temporarily suspended.
Note: 2014 market transformation savings (Northwest Energy Efficiency Alliance [NEEA]) are a preliminary estimate.

Figures 3 and 4 show the company's total DSM expenses for all funding sources, separated between energy efficiency expenses and demand response expenses.

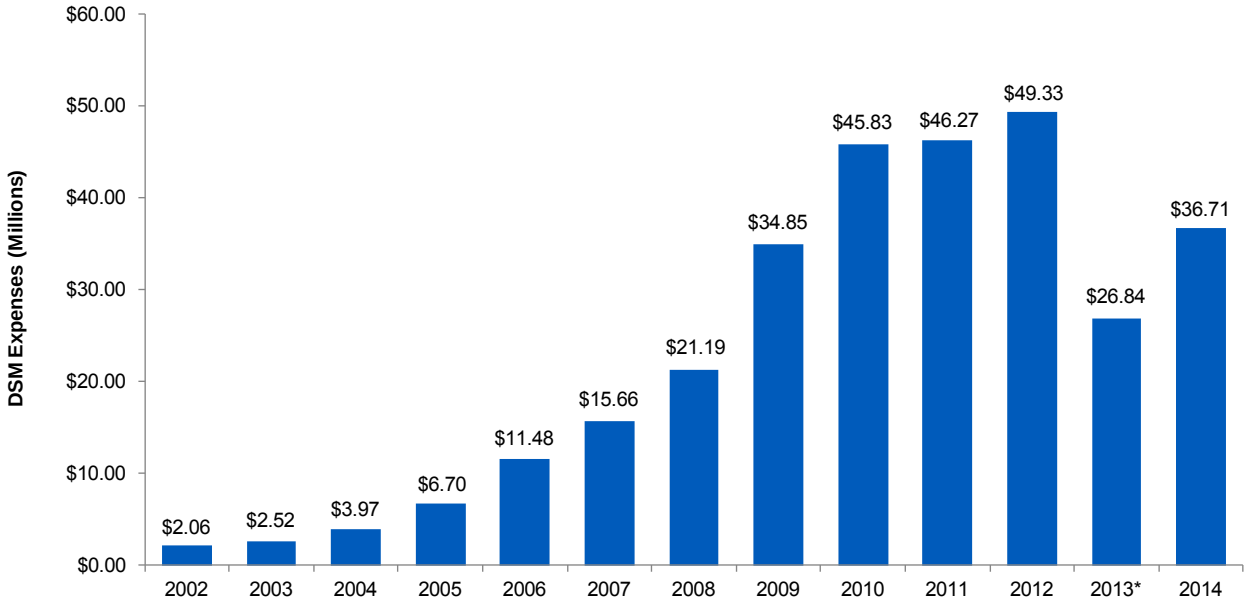



Figure 3. DSM expense history, 2002–2014 (millions of dollars)

*In 2013, two of the three demand response programs were temporarily suspended.

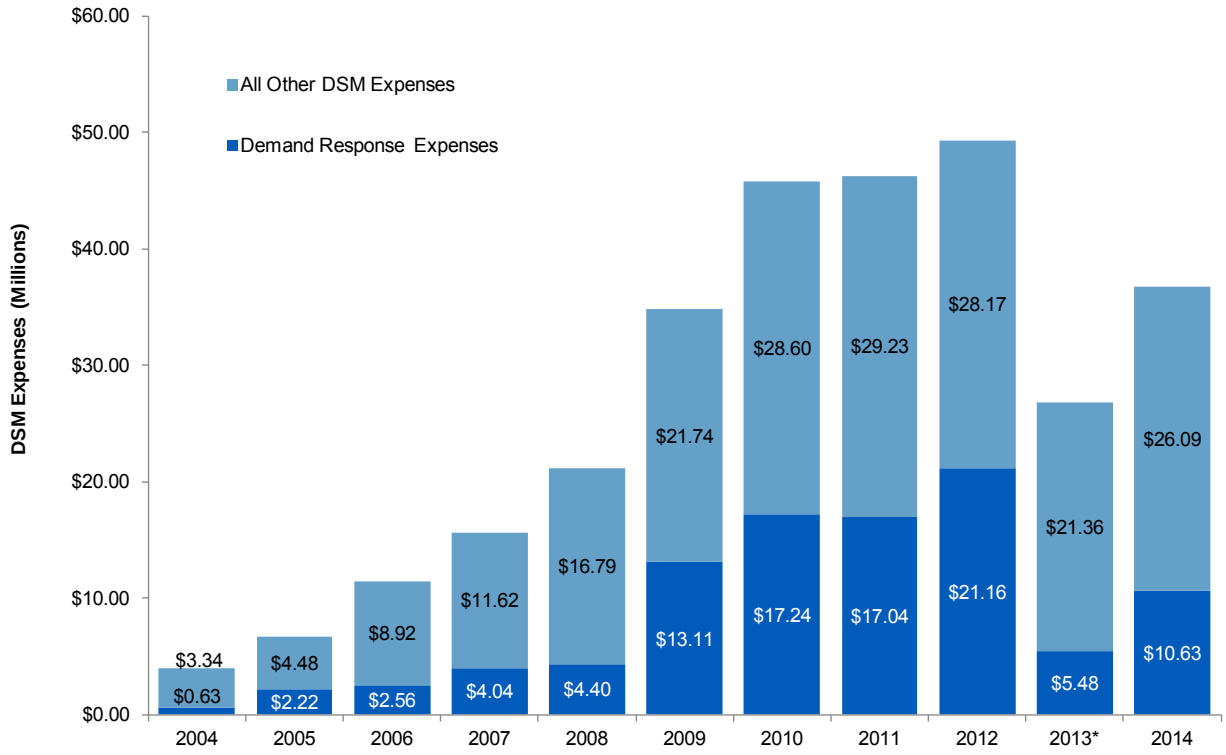



Figure 4. DSM expense history by program type, 2004–2014 (millions of dollars)

*In 2013, two of the three demand response programs were temporarily suspended.

Figure 5 shows Idaho Powers total annual energy efficiency savings in average megawatts (aMW) overlaid with the company's IRP energy-savings targets (aMW).

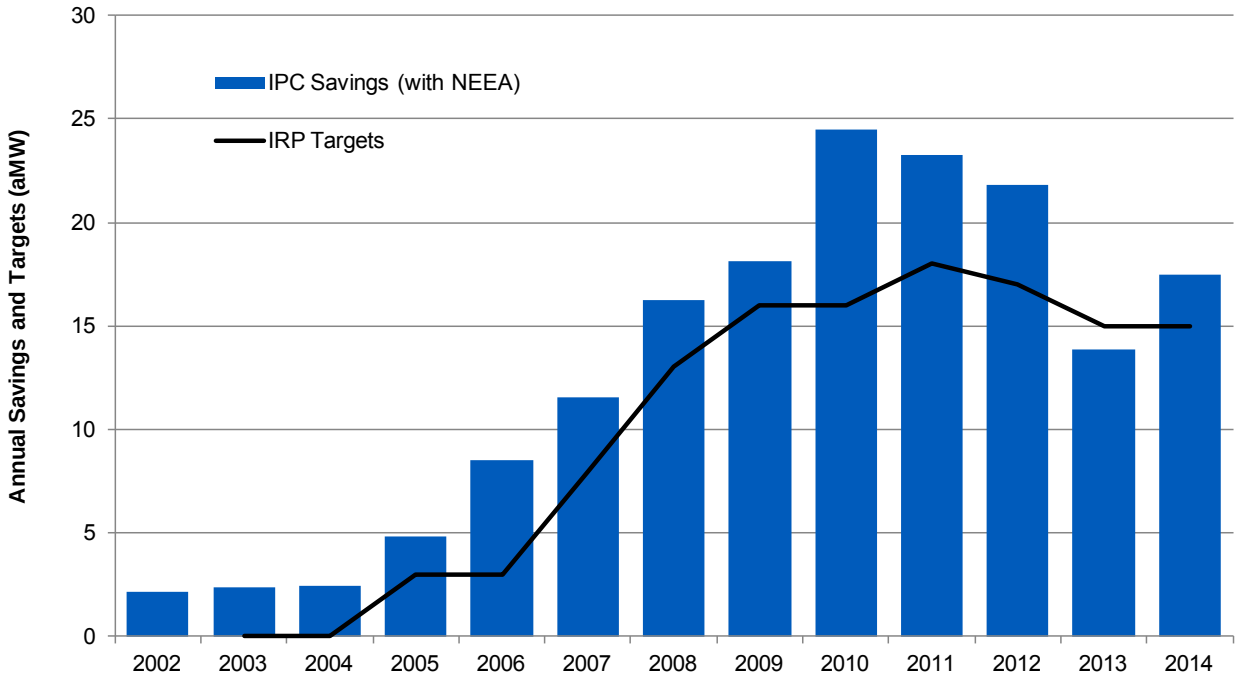



Figure 5. Annual incremental energy efficiency savings (aMW) compared with IRP targets (2002–2014)

Figure 6 shows Idaho Power's total cumulative energy efficiency savings overlaid with the company's cumulative IRP energy-savings targets (aMW).

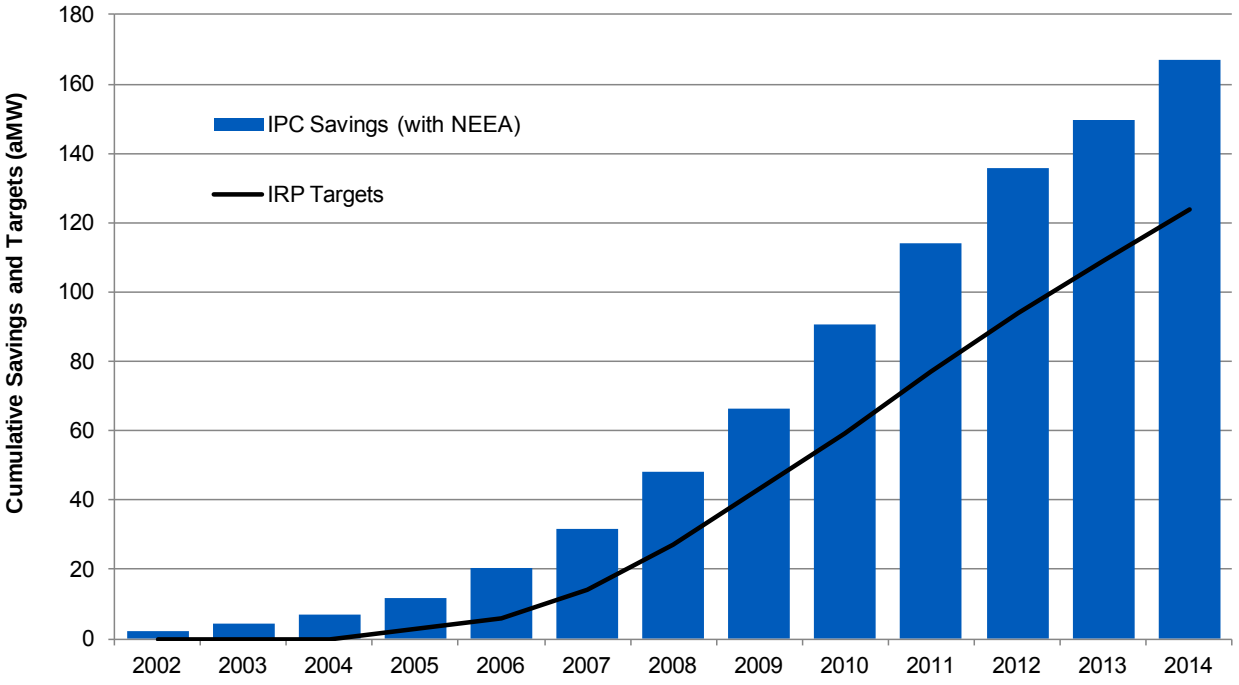



Figure 6. Annual cumulative energy efficiency savings (aMW) compared with IRP targets (2002–2014)

## Demand Response Programs

Idaho Power started its modern demand response programs in 2002 and now has over 10 percent of its all-time peak load available under demand response programs. The goal of demand response at Idaho Power is to minimize or delay the need to build new supply-side peaking resources. The company estimates future capacity needs through the IRP planning process and plans resources to mitigate any system peak deficits that exist. Demand response programs are measured by the amount of demand reduction, in MW, available to the company during system peak periods.

Idaho Power's successful demand response portfolio was acknowledged in an article in the March 6, 2015, issue of Clearing Up, a monthly newsletter produced by ENERGY NEWSDATA. Clearing Up is a weekly newsletter update on energy policy, resource development, and energy market news in the Pacific Northwest region and western Canada. The article stated Idaho Power is the regional utility with the most experience in using demand response to reduce peak loads.

In summer 2014, Idaho Power had a combined maximum demand response capacity of 390 MW at the generation level. The amount of capacity available for demand response varies based on weather, the time of year, and how programs are used and managed. The capacity of 390 MW is calculated using total enrolled MW from participants with an expected maximum realization rate on those participants. This maximum realization rate is not always achieved for every program in any given event. This realization rate is expected to be approximately 73 percent of billing demand for Irrigation Peak Rewards, 100 percent of nominated demand from FlexPeak Management, and 1.1 kW per participant for A/C Cool Credit. In 2014, the actual non-coincidental load reduction from all three programs was approximately 378 MW. This number was lower than 390 MW primarily because the Irrigation Peak Rewards did not achieve its maximum realization rate due to equipment maintenance problems that existed with irrigation devices. On Monday, July 14, 2014, the company used all three of its demand response programs together and achieved a coincident load reduction of approximately 356 MW.

The IRP analysis uses extreme load and weather assumptions to identify the need for resources. In 2014, Idaho Power did not experience extreme conditions; however, the company demonstrated successful operation of the programs on the three minimum events for each program. Program participation and readiness for the A/C Cool Credit and the Irrigation Peak Rewards programs were significant considering these two programs were temporarily suspended for a season. Idaho Power temporarily suspended these two demand response programs for summer 2013 under IPUC Case No. IPC-E-12-29 and Tariff Advice No. 13-04 with the OPUC. However, through IPUC Case No. IPC-E-13-14 (Order No. 32923) and OPUC Case No. UM 1653 (Order No. 13-482), Idaho Power and interested parties reached a settlement agreement to continue the company's demand response programs for 2014 and beyond. In 2014, these programs cost $10.6 million; had the programs been used for the maximum number of hours, the cost would have been approximately $13.8 million. These costs represent approximately $6 million dollars in savings compared to 2012 and are significantly less than the value of $16.7 million agreed on in the settlement agreement.

## Energy Efficiency Programs

Idaho Power's energy efficiency programs focus on reducing energy usage by identifying homes, buildings, equipment, or components for which an energy-efficient design, replacement, or repair can achieve energy savings. Energy efficiency programs sometimes include behavioral components, like in the Residential Energy Efficiency Education Initiative and the Wastewater Energy Efficiency Cohort offering in the Custom Efficiency program. Energy efficiency programs are available to all customer sectors in Idaho Power's service area. Project measures range from entire residential or commercial

building construction to heat pump replacement. Savings from these programs are measured in terms of kilowatt-hour (kWh) or MWh savings. These programs usually supply energy savings throughout the year at different degrees. Idaho Power shapes these savings based on the end-use to estimate energy reduction at specific times of the year and day. Idaho Power's energy efficiency offerings include programs in residential and commercial new construction (lost-opportunity savings), residential and commercial retrofit applications, and irrigation and industrial systems improvement or replacement. Custom programs under the irrigation and industrial sectors offer a wide range of unique opportunities for Idaho Power and its customers to design and execute energy-savings projects.

## Market Transformation

Market transformation achieves energy savings through engaging and influencing large national and regional companies and organizations. These organizations influence the design of energy efficiency into products, services, and practices that improve their energy efficiency. Idaho Power achieves market transformation savings primarily through its participation in the Northwest Energy Efficiency Alliance (NEEA). Idaho Power has been a funding member of NEEA since its inception in 1997.

The fifth year of NEEA's current, five-year funding cycle ended in 2014. As early as 2009, Idaho Power expressed a desire to see a change in the way NEEA services were offered in the 2015 to 2019 funding cycle that would differentiate "core" services of market transformation activities from optional services. This way, utilities could elect to support projects and activities that matched their interests and needs. During 2014, the company continued to advocate for this model through multiple meetings with NEEA, by actively participating on the NEEA Board of Directors and exploring alternative funding models, and by chairing and serving on the Alternative Funding Model Working Group Committee of the NEEA Board of Directors. This effort resulted in a 2015 to 2019 NEEA business plan, which is forecast to obtain 145 aMW of regional energy savings at a cost savings of about $3 million over the next five years to Idaho Power customers as compared to the previous five-year business plan. The NEEA plan also offered some optional programs and activities to prevent overlap of activities when local utilities have the capability to provide the same services at a lower cost or more effectively. In 2014, Idaho Power executed an agreement to continue its participation in NEEA for the 2015 to 2019 funding cycle and chose not to participate in some of the optional programs and activities where it believes it is providing or can provide the same services at a lower cost or more effectively.

## Programs and Activities

Idaho Power recognizes the value of energy efficiency awareness and education in creating behavioral change that helps customers use energy wisely. The goal of other programs and activities is to promote energy efficiency programs, projects, and behavior to customers. These awareness efforts increase customer demand for, and satisfaction with, Idaho Power's programs and activities. These activities include customer outreach, research, project development, and education programs. This category includes the Residential Energy Efficiency Education Initiative, Easy Savings Program, Commercial Education Initiative, Local Energy Efficiency Funds (LEEF), and Student Energy Efficiency Kit (SEEK) program.

## Program Planning Group

In early 2014, Idaho Power convened a Program Planning Group (previously referred to as the New Ideas team) to explore new opportunities to expand current DSM programs and offerings. The group consisted of residential program specialists, commercial and industrial engineers, energy efficiency analysts, marketing specialists, energy efficiency program leaders, and the research

and analysis leader. The group has expanded to include a departmental specialist and a research assistant. Throughout 2014, the group met weekly and formalized a process for new ideas to be evaluated. Among other things, the group identified a process for submitting new offering ideas for consideration, determined a consistent screening process for submitted ideas, and provided a mechanism to record and track the status of opportunities considered, including the rationale for decisions made.

In 2014, 18 new ideas were introduced to the team. Three of those ideas have been identified as viable energy efficiency offerings and will be incorporated into the Heating & Cooling Efficiency (H&CE) Program in 2015. They are Single-Family Home Duct Sealing, which is prescriptive duct-sealing for heat pumps and electric resistance heated homes; Residential Electronically Commutated Motor (ECM), which is the more efficient replacement for a failed permanent split capacitor (PSC) motors with ECMs in forced-air systems; and a Residential Whole House Fan Pilot, which is the installation of a whole house fan between a home's attic and the conditioned space that displaces forced air and zonal direct expansion cooling.

Two other offerings have been presented to the Energy Efficiency Advisory Group (EEAG) and have been implemented or are being implemented in 2015. They are Energy Efficiency Kits for High School, which includes age-appropriate curriculum and energy efficiency kit components (such as LEDs and efficient showerheads), and LED bulbs given away at events for promotional and educational and market transformation purposes. Other ideas include distributing clothes drying racks for promotional and educational purposes, smart thermostats, and a small-business offering.

Idaho Power will continue to use the Program Planning Group to receive, evaluate, and deliver new energy efficiency offerings in 2015 and beyond.

Table 1 provides a list of 2014 DSM programs and their respective sectors, operational type, state each was available, and associated energy savings.

Table 1. 2014 DSM programs by sector, operational type, location, and energy savings/demand reduction

| Program by Sector | Operational Type | State | Savings/Demand Reduction |
|---|---|---|---|
| **Residential** | | | |
| A/C Cool Credit | Demand Response | ID/OR | 44 MW |
| Ductless Heat Pump Pilot | Energy Efficiency | ID/OR | 463 MWh |
| Energy Efficient Lighting | Energy Efficiency | ID/OR | 12,882 MWh |
| Energy House Calls | Energy Efficiency | ID/OR | 579 MWh |
| ENERGY STAR® Homes Northwest | Energy Efficiency | ID/OR | 528 MWh |
| Heating & Cooling Efficiency Program | Energy Efficiency | ID/OR | 1,099 MWh |
| Home Energy Audit | Energy Efficiency | ID | 141 MWh |
| Home Improvement Program | Energy Efficiency | ID | 839 MWh |
| Home Products Program | Energy Efficiency | ID/OR | 652 MWh |
| Local Energy Efficiency Funds | Other Programs and Activities | ID/OR | 96 MWh |
| Oregon Residential Weatherization | Energy Efficiency | OR | 11 MWh |
| Rebate Advantage | Energy Efficiency | ID/OR | 270 MWh |
| Residential Energy Efficiency Education Initiative | Other Programs and Activities | ID/OR | 1,491 MWh |
| See ya later, refrigerator® | Energy Efficiency | ID/OR | 1,391 MWh |
| Shade Tree Project | Other Programs and Activities | ID | n/a |
| Weatherization Assistance for Qualified Customers | Energy Efficiency | ID/OR | 534 MWh |
| Weatherization Solutions for Eligible Customers | Energy Efficiency | ID | 291 MWh |
| **Commercial/Industrial** | | | |
| Building Efficiency | Energy Efficiency | ID/OR | 9,458 MWh |
| Commercial Education Initiative | Other Programs and Activities | ID/OR | n/a |
| Custom Efficiency | Energy Efficiency | ID/OR | 50,363 MWh |
| Easy Upgrades | Energy Efficiency | ID/OR | 19,118 MWh |
| FlexPeak Management | Demand Response | ID/OR | 40 MW |
| Oregon Commercial Audits | Energy Efficiency | OR | n/a |
| **Irrigation** | | | |
| Irrigation Efficiency Rewards | Energy Efficiency | ID/OR | 18,464 MWh |
| Irrigation Peak Rewards | Demand Response | ID/OR | 295 MW |
| **All Sectors** | | | |
| Northwest Energy Efficiency Alliance | Market Transformation | ID/OR | 20,000 MWh |

Table 2 shows the 2014 annual energy savings, percent of energy usage, number of customers, and aMW savings associated with each of the DSM program categories. The table also provides a comparison of the 2014 contribution of each sector in terms of energy usage and its respective size in the number of customers. Unless otherwise noted, all energy savings presented in this report are measured or estimated at the customer's meter, excluding line losses.

Table 2. Program sector summary and energy usage/savings/demand reduction

| | Energy Efficiency Program Impacts | | | | Idaho Power System Sales | | |
|---|---|---|---|---|---|---|---|
| | Program Expenses | Energy Savings (kWh) | Average Energy (aMW) | Peak Load Reduction (MW) | Sector Total (MWh) | Percentage of Energy Usage | Number of Customers |
| Residential | $ 6,372,640 | 21,171,063 | 2.5 | | 5,034,531 | 35.54% | 428,294 |
| Commercial | 4,409,215 | 28,576,553 | 3.3 | 1.2 | 3,962,785 | 27.97% | 67,522 |
| Industrial | 7,173,054 | 50,363,052 | 5.7 | 5.6 | 3,203,975 | 22.61% | 118 |
| Irrigation | 2,446,507 | 18,463,611 | 2.1 | 4.6 | 1,966,297 | 13.88% | 18,773 |
| Market Transformation | 3,305,917 | 20,000,000 | 2.3 | n/a | | | |
| Demand Response | 10,626,070 | n/a | n/a | 378 | | | |
| Other Programs and Activities | 2,379,929 | 95,834 | 0.0 | n/a | | | |
| **Total Program Expenses** | **$ 36,713,332** | **138,670,112** | **16.0** | **390.0** | **14,167,588** | **100.00%** | **514,707** |

## 2014 Regulatory Activities

On March 14, 2014, Idaho Power filed Case No. IPC-E-14-04 with the IPUC requesting an order finding the company had prudently incurred $25,951,486 in DSM expenses in 2013, including $21,748,331 in Idaho Rider expenses and $4,203,155 in demand response program incentive expenses. In Order No. 33161, dated November 4, 2014, the IPUC deemed $25,951,486 as prudently incurred.

The commission issued an Errata to Order No. 33161, dated November 7, 2014, directing Idaho Power and other parties to do an in-depth review of issues raised by staff and other parties in the company's next IRP process. Idaho Power convened a DSM Working Group that met twice in December 2014 and examined how energy efficiency was treated in the resource planning process, as discussed in the Regulatory Overview section of this report.

## Program Evaluation

Idaho Power considers program evaluation an essential component of its DSM operational activities. In accordance with the 2010 MOU with the IPUC staff, the company contracts with third-party contractors to conduct impact, process, and other evaluations on a scheduled and as-required basis.

Third-party contracts are generally awarded using a competitive bid process managed by Idaho Power's Strategic Sourcing department. In some cases, research and analysis is conducted internally and managed by Idaho Power's Research and Analysis team within the Customer Relations and Energy Efficiency (CR&EE) department. Third-party evaluations are specifically managed by the company's energy efficiency evaluator.

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

The company also supports regional and national studies to promote the ongoing cost-effectiveness of programs, the validation of energy savings and demand reduction, and the efficient management of its programs. Idaho Power considers primary and secondary research, cost-effectiveness analyses, potential assessments, impact and process evaluations, and customer surveys as important resources in

providing accurate and transparent program savings estimates. Recommendations and findings from evaluations and research are used to continuously refine Idaho Power's DSM programs.

In 2014, Idaho Power completed five program impact evaluations and three program process evaluations using third-party contractors. Johnson Consulting Group conducted process evaluations of the Home Energy Audit program and Shade Tree Project, Tetra Tech, MA conducted impact evaluations of the residential Energy Efficient Lighting and Northwest ENERGY STAR® Homes programs, CLEAResult Consulting, Inc. (CLEAResult) (acquired Fluid Market Strategies and PECI) conducted impact evaluations of the Irrigation Peak Rewards and A/C Cool Credit program 2014 test events, and Evergreen Economics conducted an impact evaluation on the Custom Efficiency program as well as a process evaluation of the new Streamlined Custom Efficiency (SCE) and Refrigeration Operator Coaching for Energy Efficiency (ROCEE) program offerings. Idaho Power also contracted with Applied Energy Group to update the 2012 energy efficiency potential analysis.

Throughout 2014, Idaho Power administered surveys on several programs to measure program satisfaction. Participant surveys were conducted for A/C Cool Credit, Energy House Calls, Home Energy Audit, Shade Tree Project, Weatherization Assistance for Qualified Customers (WAQC), and Weatherization Solutions for Eligible Customers. In addition to these participant surveys, a non-participant survey was issued for Energy House Calls to gain a better understanding of customers' awareness of the program.

In 2014, Idaho Power received the research results for Custom Efficiency, Building Efficiency, and Easy Upgrades. In 2013, the company selected Market Decisions Corporation to conduct customer research for the Custom Efficiency program and ADM Associates, Inc., to produce a technical reference manual for the Building Efficiency and Easy Upgrades programs.

Final reports from all evaluations, research, and surveys completed in 2014 and an evaluation schedule are provided in *Supplement 2: Evaluation*.

## Customer Satisfaction

In 2014, based on surveys conducted in 2013, Idaho Power ranked sixth out of nine utilities included in the west region midsize segment of the J.D. Power and Associates *2014 Electric Utility Business Customer Satisfaction Study*. Fifty-six percent of the business customer respondents in this study indicated they are aware of Idaho Power's energy efficiency programs, and those customers are more satisfied with Idaho Power than customers who are unaware of the programs. The awareness of Idaho Power's energy efficiency programs not only affects the customer's overall satisfaction with the company but also his/her satisfaction with corporate citizenship.

In 2014, based on surveys conducted in the last six months of 2013 and the first six months of 2014, Idaho Power ranked 8 out of 13 utilities included in the west region midsize segment of the J.D. Power and Associates *2014 Electric Utility Residential Customer Satisfaction Study*. Forty-seven percent of the residential respondents in this study indicated they are aware of Idaho Power's energy efficiency programs, and those customers are more satisfied with Idaho Power than customers who are unaware of the programs. Awareness of Idaho Power's energy efficiency programs improves customers' perceptions regarding price by 13 percent.

Since 1995, Idaho Power has employed Burke, Inc., an independent third-party research vendor, to conduct customer relationship surveys to measure the overall customer relationship and satisfaction with Idaho Power. The Burke Customer Relationship survey measures the satisfaction of a number of

aspects of the customer's relationship with Idaho Power, including energy efficiency at a very high level. However, it is not the intent of this survey to measure all aspects of energy efficiency programs offered by Idaho Power.

The 2014 results of Idaho Power's quarterly customer relationship survey showed a slight increase in overall satisfaction from the previous year. Customers' perception of Idaho Power's energy efficiency efforts increased from 57 percent at the end of 2013 to 62 percent in late 2014. Figure 7 depicts the quarterly change in the percent of customers who indicated Idaho Power met or exceeded their needs concerning energy efficiency efforts encouraged by Idaho Power.

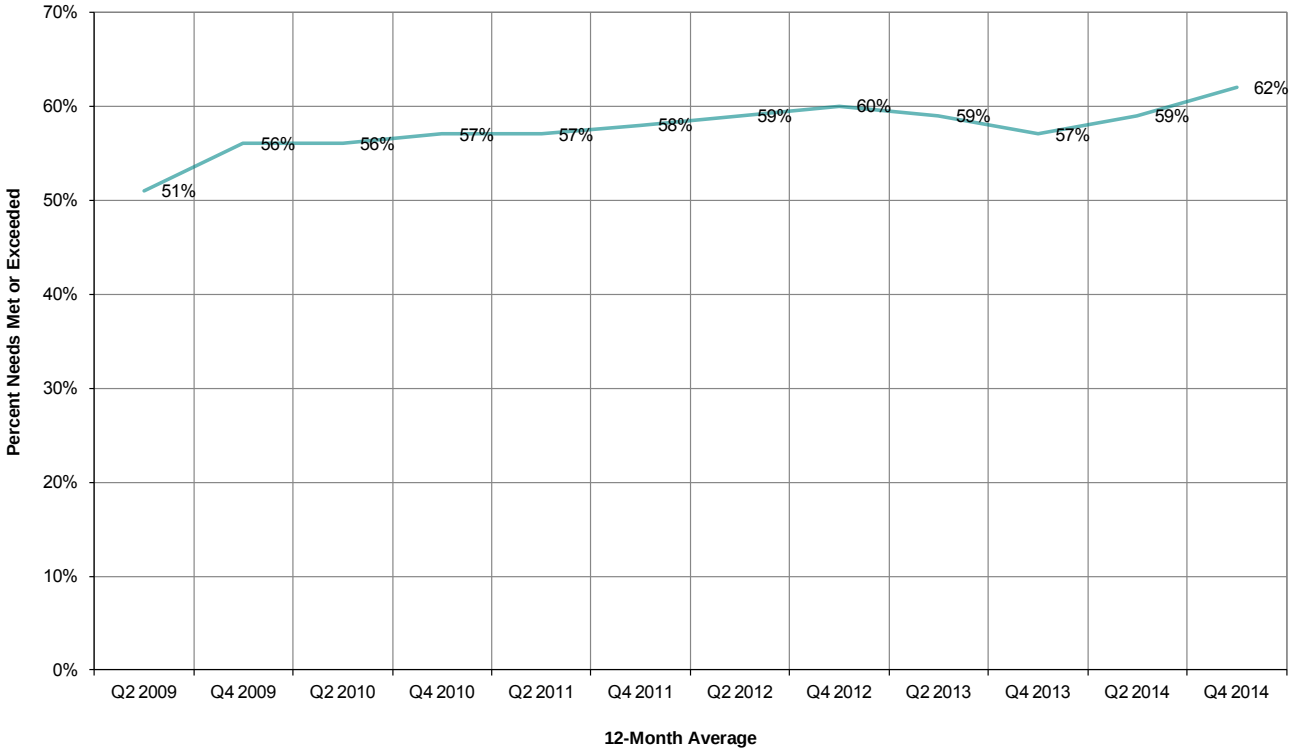



Figure 7. Percent of customers whose needs are met or exceeded by Idaho Power's energy efficiency efforts

Three questions related to energy efficiency programs in the general relationship survey continued in the 2014 survey: 1) Have you participated in any of Idaho Power's energy efficiency programs?, 2) Which energy efficiency program did you participate in?, and 3) Overall, how satisfied are you with the energy efficiency program? In 2014, 37 percent of the survey respondents across all sectors indicated they participated in at least one Idaho Power energy efficiency program. Of survey respondents who participated in at least one Idaho Power energy efficiency program, 90 percent are "very" or "somewhat" satisfied with the program(s).

Due to a concern of over-surveying program participants, and because the measures and specifics of most program designs do not change annually, Idaho Power will not survey most program participants annually. To ensure meaningful research in the future, Idaho Power will conduct program research periodically (every two to three years), unless there have been major program changes.

## Cost-Effectiveness

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

Prior to the actual implementation of energy efficiency or demand response programs, Idaho Power performs a cost-effectiveness analysis to assess whether a potential program design will be cost-effective from the perspective of Idaho Power and its customers. Incorporated in these models are inputs from sources that use the most current and reliable information available. When possible, Idaho Power leverages the experiences of other utilities in the region or throughout the country to help identify specific program parameters.

Idaho Power's goal is for all programs to have benefit/cost (B/C) ratios greater than one for the TRC test, UC test, and participant cost test (PCT) at the program and measure level where appropriate. If a particular measure or program is pursued even though it will not be cost-effective from each of the three tests, Idaho Power works with EEAG to get input. If the measure or program is indeed offered, the company explains why the measure or program was implemented or continued. The company believes this aligns with the expectations delineated in the MOU under IPUC Case No. IPC-E-09-09 and OPUC Order No. 94-590.

When a new program or measure is considered, Idaho Power launches a pilot or a program to evaluate estimates or assumptions in the cost-effectiveness analysis. Following the implementation of a program, cost-effectiveness analyses are reviewed as new inputs from the actual program activity become available, such as actual program expenses, savings, or participation levels. If measures or programs are determined not to be cost-effective after implementation, the program or measures are re-examined, including using input provided from EEAG.

Appendix 4 contains the UC and TRC B/C ratios using actual cost information over the life of each program through 2014. These B/C ratios are provided as a measure of cost-effectiveness for all Idaho Power energy efficiency or demand response programs currently being offered where energy savings and demand reduction are realized. As in 2013, the actual historic savings and expenses are not discounted; only the value of the ongoing savings going forward are discounted to reflect today's dollars. A complete description of Idaho Power's methodology, input assumptions, sources, and results is presented in *Supplement 1: Cost-Effectiveness*.

In 2014, Idaho Power reviewed its policy to update measure energy savings throughout the year. In the past, when energy savings assumptions were updated during the calendar year by third parties, such as the RTF or an evaluator, Idaho Power immediately applied those assumptions retroactively for the entire year. This caused issues when budgets and goals were set at the beginning of the year using one set of assumptions and those assumptions changed mid-year, making it appear some programs were not meeting their original goals. It has been recommended in previous process evaluations that the company "freeze" savings assumptions at a certain point and update assumptions once a year. After reviewing the practices of other utilities around the region and the impact of these frequent updates to program specialists and field staff, the company established a policy to freeze savings assumptions when the budgets and goals are set for the next calendar year unless code and standards changes or program

updates necessitate an immediate need to use updated savings. As a general rule, the 2014 energy savings reported for most programs will use the assumptions set at the beginning of the year. These assumptions will be discussed in more detail in the cost-effectiveness sections for each program.

The method used to determine the cost-effectiveness of the demand response programs was updated in 2014. As part of the public workshops on Case No. IPC-E-13-14, Idaho Power and other stakeholders agreed on a new method for valuing demand response. The settlement agreement was approved in IPUC Order No. 32923 and OPUC Order No. 13-482. Per the settlement agreements, the annual cost of operating the three demand response programs for the maximum allowable 60 hours should be no more than $16.7 million. This $16.7 million value is the levelized annual cost of a 170-MW simple cycle combustion turbine (SCCT) over a 20-year life. In 2014, the cost of operating the three demand response programs was $10.6 million. Idaho Power estimates that if the three programs were dispatched for the full 60 hours, the total costs would have been approximately $13.8 million and would have remained cost-effective.

New DSM alternative costs from Idaho Power's 2013 IRP affected the cost-effectiveness of the company's programs and measures in 2014. The 2013 IRP was acknowledged by the IPUC in Order No. 32980 on February 24, 2014, and by the OPUC in Order No. 14-253 on July 8, 2014. The 2013 IRP planning process resulted in a significant drop in the DSM alternative costs used to value energy efficiency compared with previous IRPs. While impacts vary from program to program depending on measure life and the end uses, decreases of program benefits of up to 40 to 50 percent have been seen. Multiple factors led to the reduction of the DSM alternative costs, but two of the primary impacts included a reduced carbon adder used in the 2013 IRP process and decreases in early-year natural gas price forecasts. While these benefit reductions have placed more burden on program cost-effectiveness, some of the impact has been mitigated by the recent addition of quantified non-energy benefits (NEB) in the region.

Idaho Power's portfolio of energy efficiency programs is cost-effective, passing both the TRC test and the UC test with ratios of 1.89 and 3.49, respectively. The company's energy efficiency programs' sector portfolios were also cost-effective from a TRC test and UC test perspective.

In 2014, most of Idaho Power's energy efficiency programs were cost-effective, except the Ductless Heat Pump (DHP) Pilot, ENERGY STAR Homes Northwest, See ya later, refrigerator ®, and the weatherization programs for income-qualified customers.

The DHP Pilot and the ENERGY STAR Homes Northwest program were both cost-effective under the UC test but failed the TRC test with ratios of 0.70 and 0.83, respectively.

In fall 2013, the RTF approved DHP annual savings estimates for customers not screened for supplemental fuel use. In November, the RTF presented its findings and recommendation on the inclusion of health benefits to be part of the cost-effective benefits in the cost-effective analysis of measures and programs, which would increase the NEBs and increase the TRC. The RTF is waiting on the Northwest Power and Conservation Council's (NWPCC) guidance on the issue.

In 2014, 8 of 243 ENERGY STAR Homes Northwest homes were single-family homes and 235 were townhomes. Due to the lower kWh savings for townhomes versus single-family homes and the ratio of townhomes, the program was shown not to be cost-effective from a TRC perspective for 2014. NEEA is planning to transition the Northwest ENERGY STAR Homes program to the national Environmental Protection Agency (EPA) ENERGY STAR Homes program. A second program, NEEA's Next Step

Home program, is still in the pilot stage. Idaho Power will monitor these potential changes to the program for possible implementation in the future.

See ya later, refrigerator® has a UC and TRC of 0.86. The lower cost-effectiveness ratios in 2014 over 2013 are largely due to the updated 2013 IRP DSM alternative costs. In 2014, the RTF updated the energy-savings assumptions for freezer and refrigerator decommissioning and included estimates for NEBs. The updated energy savings and NEB assumptions will be applied in 2015 along with the planned program changes in 2015. The program is expected to be cost-effective in 2015.

WAQC had a TRC of 0.42, and Weatherization Solutions for Eligible Customers had a TRC of 0.50. The cost-effectiveness ratios were impacted by the change in DSM alternative costs and the updated per-home savings. Despite the fact that Idaho Power adopted the IPUC staff's recommendations from Case No. GNR E-12-01 for calculating the programs' cost-effectiveness and the company worked with third-party contractors to improve the audit tool for the Weatherization Solutions for Eligible Customers program, improve savings estimates, and reduce costs, these programs remain not cost-effective. Refer to the specific program sections for more detail.

Thirty nine measures in various programs are shown not to be cost-effective from either the UC or TRC perspective. These measures will be discontinued, analyzed for additional NEBs, modified to increase potential per-unit savings, or monitored to examine their impact on the specific program's overall cost-effectiveness.

Table 3 shows Idaho Power's cost-effectiveness ratios for the UC, TRC, and PCT perspectives for its energy efficiency programs, by sector, and by portfolio.

Table 3. Idaho Power's cost-effectiveness ratios for the UC, TRC, and PCT perspectives for its energy efficiency programs, by sector and by portfolio

| | 2014 B/C Tests | | |
|---|---|---|---|
| **Program/Sector** | **UC** | **TRC** | **PCT** |
| Ductless Heat Pump Pilot | 1.77 | 0.70 | 1.01 |
| Energy Efficient Lighting | 2.98 | 1.99 | 2.67 |
| Energy House Calls | 2.16 | 2.16 | N/A |
| ENERGY STAR Homes Northwest | 1.64 | 0.83 | 1.41 |
| Heating and Cooling Efficiency Program | 3.74 | 1.09 | 1.45 |
| Home Improvement Program | 4.17 | 1.51 | 2.39 |
| Home Products Program | 1.94 | 4.52 | 7.28 |
| Rebate Advantage | 4.39 | 3.23 | 6.21 |
| See ya later, refrigerator® | 0.86 | 0.86 | N/A |
| Students for Energy Efficiency Kit | 2.18 | 3.02 | N/A |
| Weatherization Assistance for Qualified Customers | 0.51 | 0.42 | N/A |
| Weatherization Solutions for Eligible Customers | 0.46 | 0.50 | N/A |
| **Residential Energy Efficiency Sector** | **1.88** | **1.51** | **2.68** |
| Building Efficiency | 5.05 | 2.08 | 2.27 |
| Custom Efficiency | 4.72 | 2.52 | 2.00 |
| Easy Upgrades | 4.08 | 2.35 | 2.85 |
| **Commercial/Industrial Energy Efficiency Sector** | **4.58** | **2.42** | **2.24** |
| Irrigation Efficiency | 5.67 | 1.83 | 1.63 |
| **Irrigation Energy Efficiency Sector** | **5.67** | **1.83** | **1.63** |
| **Energy Efficiency Portfolio** | **3.49** | **1.89** | **2.09** |

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

## Future Plans

Idaho Power will continue to pursue all prudent cost-effective energy efficiency as identified by third-party potential studies and an appropriate amount of demand response based on the demand response settlement agreement approved in IPUC Order No. 32923 and OPUC Order No. 13-482. The forecast level of energy efficiency and the needed level of demand response are included in Idaho Power's biennial IRP planning process. Idaho Power includes all achievable cost-effective energy savings as identified in its potential studies in each IRP. The IRP is a public document developed in a public process that details Idaho Power's strategy for economically maintaining the adequacy of its power system into the future. The IRP process balances reliability, cost, risk, environmental concerns, and efficiency to develop a preferred portfolio of future resources to meet specific energy needs of Idaho Power's customers.

In 2015, Idaho Power plans to increase participation in, and energy savings from, existing energy efficiency programs and initiatives. The company will continue to explore new potential as identified in the company's third-party energy efficiency potential study and through other third-party resources and conferences and will continue to assess and develop new program offerings through its Program Planning Group.

In 2015, Idaho Power will enhance its marketing and outreach efforts as described in the Marketing section and within each program section. Idaho Power will continue to work with NEEA on its market transformation activities during the 2015 to 2019 funding cycle.

The company will complete its research and evaluation, measurement, and verification (EM&V) projects included in the evaluation plan in *Supplement 2: Evaluation* to align with the expectations of the MOU established in IPUC Case N. IPC-E-09-09.

In 2015, Idaho Power will continue with a number of major remodels on the CHQ buildings downtown starting with the remodel of parts of CHQ sixth and seventh floors. The company will begin remodels on the CHQ eighth floor in 2016. Remodels will incorporate energy efficiency items, such as lower partitions, lighting retrofits, and lighting controls.

# DSM EXPENDITURES

Funding for DSM programs in 2014 came from several sources. The Idaho and Oregon Rider funds are collected directly from customers on their monthly bills. For 2014, the Idaho Rider was 4 percent of base-rate revenues. The 2014 Oregon Rider was 3 percent of base-rate revenues. Additionally, Idaho-related demand response program incentives were paid through base rates and the annual power cost adjustment (PCA) mechanism. Energy efficiency and demand response-related expenses not funded through the Rider are included as part of Idaho Power's ongoing operation and maintenance (O&M) costs.

Total DSM expenses funded from all sources were $36.7 million in 2014. At the beginning of 2014, the Idaho Rider balance was approximately $6.7 million, and by December 31, 2014, the balance was negative $0.8 million. At the beginning of the year, the Oregon Rider negative balance was approximately $3.7 million, and by year-end, the negative balance was $3.9 million.

Table 4 shows the total expenditures funded by the Idaho Rider, $25,556,089; the Oregon Rider, $1,325,865; and non-rider funding, $9,831,379, resulting in Idaho Power's total DSM expenditures of $36,713,333. The non-rider funding category includes Idaho Power demand response incentives, WAQC expenses, and O&M costs.

Table 4. 2014 funding source and energy savings

| Funding Source | Expenses | MWh Savings |
|---|---|---|
| Idaho Rider | $ 25,556,089 | $ 131,383 |
| Oregon Rider | 1,325,865 | 6,753 |
| Non-Rider Funding | 9,831,379 | 534 |
| **Total** | **$ 36,713,333** | **138,670** |

Table 5 and Figure 8 indicate 2014 DSM program expenditures by category. The expenses in the Other Expense category include marketing ($671,408), program evaluation ($350,135), and program training ($318,357). The Purchased Services category includes payments made to NEEA and third-party contractors who help deliver Idaho Power's programs: EnerNOC, Inc., for Irrigation Peak Rewards; JACO Environmental, Inc. (JACO), for See ya later, refrigerator®; Honeywell for A/C Cool Credit; Cascade Energy, Inc., for Custom Efficiency; Evergreen Consulting and RM Energy Consulting for Easy Upgrades; and contractors for WAQC and Weatherization Solutions for Eligible Customers.

Table 5. 2014 DSM program expenditure by category

| | Total | % of Total |
|---|---|---|
| Incentive Expense | $ 21,169,645 | 58% |
| Labor/Administrative Expense | 3,139,448 | 9% |
| Materials & Equipment | 52,473 | 0% |
| Other Expense | 1,610,466 | 4% |
| Purchased Services | 10,741,301 | 29% |
| **Total 2014 Rider Expenditures, by Category** | **$ 36,713,333** | **100%** |

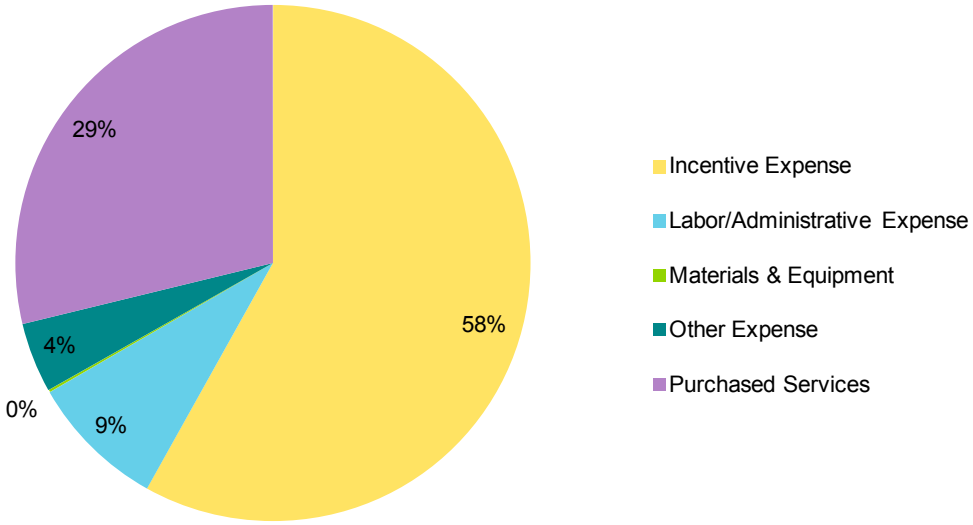



Figure 8. 2014 DSM program expenditures by category

Table 6 and Figure 9 describe the amount and percentage of incentives paid by segment and sector. There are two incentive segments—demand response and energy efficiency—and three sectors—residential, commercial/industrial, and irrigation. The incentives are funded by the Idaho and Oregon Rider, Idaho PCA mechanism, and Idaho Power base rates. Market transformation-related payments made to NEEA and payments made to third-party community action partners under the WAQC and Weatherization Solutions for Eligible Customers programs are not included in the incentive amounts.

Table 6. 2014 DSM program incentives by segment and sector

| | Sector Total | % of Total |
|---|---|---|
| DR[a]—Residential | $ 445,046 | 2% |
| DR—Commercial/Industrial | 1,502,163 | 7% |
| DR—Irrigation | 6,107,828 | 29% |
| EE[b]—Irrigation | 2,170,220 | 10% |
| EE—Residential | 2,333,594 | 11% |
| EE—Commercial/Industrial | 8,610,794 | 41% |
| **Total Incentive Expense** | **$ 21,169,645** | **100%** |

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

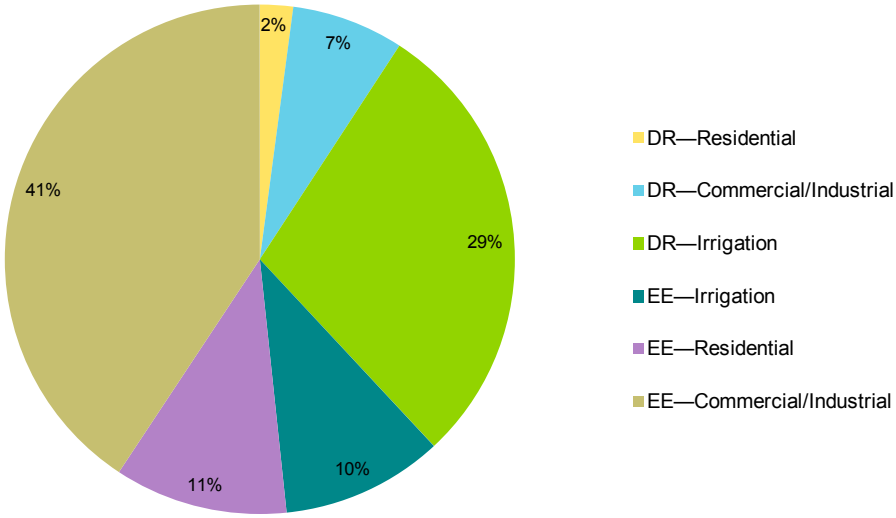



Figure 9. 2014 DSM program incentives by segment and sector

# MARKETING

Idaho Power used a variety of marketing, public relations, and research methods during 2014. The company will continue with innovative techniques in 2015. The following describes a selection of the methods, approaches, and tactics.

In spring 2014, Idaho Power contracted with MDC Research (MDC) to conduct four focus groups in Boise, Caldwell, Pocatello, and Twin Falls. The research objective was to gather customer feedback on current and future communication efforts. Each focus group had 9 or 10 participants. Key findings showed that 1) when prompted, recall of bill inserts and the *Connections* monthly newsletter was very high; 2) customers were most interested in topics related to rate changes, energy efficiency, and how to reduce their bills; 3) there was little differentiation between advertising and other types of communication; 4) many participants did not recall specific advertisements (ad), but the more engaged customers were able to recall specific ads, particularly those dealing with safety and program offerings.

To conduct the focus groups, Idaho Power converted space in the CHQ to administer focus groups. A one-way mirror, chairs, and video/audio equipment were installed.

In the second half of the year, Idaho Power hired a contractor to set up and manage an online panel. The purpose of the panel is to solicit customer feedback on a number of company-wide topics, including energy efficiency. Members of the panel may be sent surveys, print ads, videos, and questions to provide feedback on areas, such as program design, messaging, and graphics.

Idaho Power named the online panel the em**powered** community. The online panel will consist of Idaho Power residential customers who agree to participate in monthly online research on a variety of topics. The panel will incorporate customer opinions, values, and motivators into company planning and strategies at a lower cost and with less lead-time than contracting with different marketing research firms. Monthly surveys/queries of the community are anticipated throughout the year. More details regarding the spring 2015 launch are provided in the 2015 marketing plans section below.

To keep abreast of current trends, Idaho Power attended an International Direct Marketing Association Conference in San Diego, a Community-Based Social Marketing Workshop in Seattle, a live online course on the psychology of marketing, and a live online course on integrated marketing.

In fall 2014, the company took advantage of an earned media opportunity by participating in monthly energy efficiency segments on the KTVB-TV afternoon news program with Idaho Power's customer relations and energy efficiency manager. The segments, which began in October, focused on energy efficiency tips for residential customers, including weatherizing a home, the benefits of LED lighting, and how to receive an Idaho Power energy efficiency guide.

In regard to employee energy efficiency education, in previous years Idaho Power conducted an internal campaign to educate employees about the company's energy efficiency programs. After talking to field employees and regional managers, Idaho Power decided the most effective way to capture employee attention was through a video they could watch on their own time. The company created a humorous educational script mimicking Saturday Night Live's *Weekend Update* sketch. Professional actors, an Idaho Power manager, and an Idaho Power executive played characters in the sketch. The company emailed the video to all employees in fall 2014, and it received positive reviews. As of December 31, 2014, 1,057 employees—over half of the company's employees— viewed the video, thereby enhancing awareness of the programs.

Two guides were designed to educate and motivate customers to participate in energy efficiency programs and take energy efficiency actions at home. Through the customer focus groups conducted in 2014, the company researched the importance of energy efficiency communications and evaluated the readership and effectiveness of energy efficiency guides. One of the findings was that most of the customers in the focus group found the information valuable yet many had not seen the publication.

Historically, Idaho Power used public relations to help make customers aware of the seasonal energy efficiency guides. For the first time in fall 2014, Idaho Power used several marketing tactics to test demand for and explore other distribution channels for the *Fall Energy Efficiency Guide* and the 96-page booklet *30 Simple Things You Can Do to Save Energy*. Marketing tactics used to drive demand for the guide included an ad in the November issue of *Connections* sent to 415,000 customers, over 40,000 bill inserts in residential customer bills in November, and a digital ad campaign from October 25 to November 23 that garnered 514,744 impressions. When referring to online advertising, the term "impressions" indicates the number of times an ad is shown.

The company created a webpage for customers to request printed copies via mail, view past issues, or download a PDF or printable version of these publications. All advertising drove customers to this webpage. A toll-free number was set up for customers who saw the *Connections* ad or received a bill insert and preferred to order via phone. The bill inserts had a form that customers could mail in to request the guide.

Results of the October 31 to November 23, 2014, digital campaign yielded 514,744 total impressions and a 0.19 percent campaign click-through rate (CTR). Overall performance was above average. Audience targeting performed satisfactorily, but re-messaging drove the best results, with an outstanding CTR. Re-messaging means ads are delivered back to consumers that have visited Idaho Power's website and/or specific program pages within idahopower.com, as directed by Idaho Power program managers (maximum 3 to 4 ads per day to individual internet addresses). Total re-messaging impressions were 103,526, and the re-messages CTR was 0.68 percent. Generally, the digital advertising industry average for CTR is 0.07 to 0.10 percent.

Idaho Power tracked visits to the website. A sample of the results gathered from the web tracking from October 24 to November 30 included 1,931 visitors to the home page, 495 clicks on the promo pod—a promotional icon or small image used to draw viewers attention to information on the company's website that the company wishes to promote—on the home page, and 268 visitors to the printable version of the *Fall Energy Efficiency Guide*, all located at idahopower.com/EnergyEfficiency/Residential/Programs/eeClasses/default.cfm.

Because customer testimonials are credible, unbiased recommendations, the company conducted ad hoc interviews to procure customer testimonials at the September 2014 FitOne Expo in Boise. Clips were to be used to create a short video of customer testimonials regarding Idaho Power's energy efficiency programs for viewing on Idaho Power's website. Using the ad hoc interview technique, the company learned customers do not recall program details and were inaccurate regarding the programs. In the future, should Idaho Power decide to revisit customer testimonials, Idaho Power will record interviews in a formal studio, film retakes as needed, and provide customers with time to prepare and recall program information.

The company employed a number of new communication/advertising opportunities in 2014. The company reached out to professional associations to determine how they communicate with members and if there are advertising opportunities in newsletters, webpages, and/or resource guides. Idaho Power met with the lobbyist for the Idaho Retailers Association, Idaho State Pharmacy

Association, and Idaho Lodging & Restaurant Association. This meeting resulted in ongoing communication with Idaho Power providing energy efficiency information for inclusion in a newsletter to association members.

Idaho Power placed a half-page ad in the November and December issues of the Building Contractors Association of Southwestern Idaho (BCASWI) monthly newsletter to promote the company's ENERGY STAR® Homes Northwest program and the builder incentive. The newsletters went to members in Ada, Boise, Camas, Elmore, Gem, and Canyon counties. A full-page insert was placed in the Idaho Chamber of Commerce publication to promote Idaho Power's commercial energy efficiency programs to building owners, managers, tenants, and contractors.

One of the target segments for Idaho Power's Weatherization Solutions for Eligible Customers program is senior citizens. To focus on this segment, Idaho Power sent program information to a number of resources used by senior citizens.

In 2014, 10 digital ad campaigns ran for one to three months each. These included ads on the Yahoo! network and targeted behavioral ads. Specific customer segments were shown Idaho Power ads based on customers' past behavior on the Internet. For example, if a customer within Idaho Power's specific geographic area visited a site about heat pumps or home improvement, an Idaho Power ad for DHPs would appear on subsequent webpages. The site was programmed to follow that user. Audience targeting puts Idaho Power marketing messages in front of the people the company wants to reach when they are most receptive. This was the first time the company advertised ENERGY STAR Homes Northwest on sites such as zillow.com.

During 2014, Idaho Power purchased over 42 unique print ads in newspapers, event program guides, and chamber of commerce inserts. These print ads were placed in trade publications, association newsletters, association event program brochures, *Horizon Air Magazine*, and weekly and daily newspapers. Advertised programs included Building Efficiency, Easy Upgrades, Custom Efficiency, ENERGY STAR Homes Northwest, Irrigation Efficiency, Home Improvement, Home Energy Audit, H&CE Program, and DHP Pilot. Additional ads encompassed all of the energy efficiency residential programs.

In February and September 2014, Idaho Power ran the *Be Energy Smart* and *Use Your Watts Wisely* integrated advertising campaigns to increase awareness of the company's energy efficiency programs as a whole rather than individually. This multi-channel campaign included 15-second spots on Idaho Public Television, newspaper print ads throughout Idaho Power's service area, online ads, Facebook ads, and an editorial focus in the company's monthly *Connections* newsletter. This integrated campaign will continue in 2015.

Cumulative results from the *Be Energy Smart* and *Use Your Watts Wisely* integrated advertising campaigns are indicated in Table 7.

Table 7. Cumulative results from February and September *Be Energy Smart* and *Use Your Watts Wisely* advertising campaign

| Marketing Tactic | February 2014 | | September 2014 | |
|---|---|---|---|---|
| Idaho Public Television | 509,350 | impressions | 335,960 | impressions |
| Print advertising | 628,812 | impressions | 886,220 | impressions |
| Online advertising | 515,199 | impressions | 514,135 | impressions |
| Click-through rate | 0.06% | | 0.18% | |
| Number of clicks | 331 | clicks | 915 | clicks |
| *Connections* | 405,000 | printed | 405,000 | printed |
| Facebook ads | N/A | | 54,407 | customers reached |
| Number of page views on the web | | | | |
| idahopower.com/energyefficiency | 554 | views | 4,277 | views |
| idahopower.com/save | 54 | views | 209 | views |

For television, impressions refers to the sum of audiences, in terms of people or households viewing, where there is exposure to the same commercial or program on multiple occasions. Two gross impressions could mean the same person was in the audience on two occasions or that two different people had been exposed only once. Impressions for print advertising means the circulation of the publication on the days the ad ran multiplied by the number of times the ad ran. September print impressions were higher than February for the same cost because rates were lower at *The Idaho Statesman*; the ad was smaller, so Idaho Power could run more ads for the same cost; Idaho Power had an extra ad on Sunday, which resulted in higher numbers, and Idaho Power added *Idaho Senior News* to the print buy. Idaho Public Television impressions were less in September compared to February because people watch more television in northern climates in February. In addition, Nielsen does not rate public television in September, so the numbers for September from Idaho Public Television are approximated using November Nielsen ratings. Nielsen is a leading global provider of information and insights into what consumers watch and buy.

To make advertising easier for Idaho Power's trade allies, the company launched a contractor portal in 2014. The portal allows trade allies access to a specific area of Idaho Power's website where they can customize pre-approved marketing pieces. New marketing pieces will be added as needed.

In 2014, all Idaho Power commercial energy efficiency programs were revised with updated marketing materials and web content to reflect programmatic changes. Various direct-mail pieces went to customers. A letter was mailed to commercial customers regarding changes to the Easy Upgrades program and resulted in a number of inquiries to the company's customer representatives (CR). A similar mailing highlighting program changes to the Building Efficiency program went to architects and engineers in Idaho Power's service area. Idaho Power also developed a letter for the company's major customer representatives (MCR) to distribute to their customers highlighting changes to the commercial and industrial programs. Idaho Power placed a promo pod on Idaho Power's commercial landing page alerting customers about upcoming commercial program revisions and suggesting customers check back regularly to learn about changes. The company's *ENERGY@WORK* newsletter—mailed to the company's small/medium-size business customers—contained an article informing customers about the changes to the commercial programs and advised them to go to Idaho Power's website for details. A targeted mailing went to hotels and motels at the end of the year. The mailing included the *Energy Efficiency Tips for Hotels* brochure and a flyer inserted in the brochure outlining hotel and motel incentives. A customized cover letter included the name and phone number of the CR for the customer to call with any questions. Idaho Power asked CRs to call their specific hotel and motel

customers the week after the mailing to ascertain if the customer received the mailing, if they felt it was helpful, and if the representative could help them initiate an energy efficiency project.

Similar mailings will continue in 2015, highlighting industries including convenience stores, health care, health care facilities, restaurants, grocery stores, and office buildings. These brochures are online at idahopower.com/EnergyEfficiency/Business/Tips/eeBusinessSpecificTips.cfm.

Historically, Idaho Power used bill inserts to exclusively promote residential programs. Energy efficiency bill inserts were included in every month except December. However, in 2014, Idaho Power expanded the use of bill inserts to include intermittent commercial bill inserts that outline Idaho Power's suite of commercial/industrial programs.

In 2014, 11 new commercial success stories were posted on the company's website. The success stories showcased commercial customers, including Riverstone School, ON Semiconductor, Technichem, Riverside Hotel, North Star Charter School, and CSHQA. The stories are written by a third-party contractor, approved by Idaho Power, placed in a template, sent to the customer for final approval, and posted on the Idaho Power website at idahopower.com/EnergyEfficiency/Business/SuccessStories/default.cfm.

The company created the *Energy Efficiency Solutions* video highlighting three commercial customers in various geographic locations and posted it at idahopower.com/business.

In December 2014, Idaho Power marketing staff met with NEEA marketing personnel in Portland. For the past three years, marketing staff from NEEA and Idaho Power have met in-person annually. Moving forward, Idaho Power and NEEA plan to coordinate marketing activities on initiatives Idaho Power didn't opt out of through monthly conference calls and ongoing work groups.

In 2013, third-party contractor TRC Energy Services was contracted to provide a process evaluation of the H&CE Program and ENERGY STAR Homes Northwest program. In their 2014 report, TRC Energy Services recommended Idaho Power develop a portfolio-level brand for Idaho Power's energy efficiency programs to increase customer awareness of its DSM programs. Idaho Power considered this recommendation and determined Idaho Power's energy efficiency programs are consistently branded to align with the overall company brand. The Idaho Power brand is aligned with the company's vision and mission. To build a strong brand, all of the company's materials need to be consistent and recognizable.

In 2015, the company plans to initiate new marketing tactics in addition to ongoing marketing activities. New approaches include an online panel, airport signage, public radio broadcasts, and additional ad sources. When programs have new measures added or removed, Idaho Power ensures the updates are included in web content and in hard copy materials.

The em**powered** community online panel launches in spring 2015. Starting March 2015, Idaho Power will send at least one survey or other online research request each month to community members. The em**powered** community will provide a readily accessible and reliable group of customers that can respond quickly to online questionnaires and other online research requests. Using an online community allows for a quicker turnaround on focused topics or research. It is also a lower-cost option for ad hoc or quick-turnaround studies. Recruitment is being conducted primarily through bill inserts included in all February residential bills. Postcards are being direct-mailed to customers that currently receive a paperless bill from Idaho Power. Additionally, a promo pod will be placed on idahopower.com. The initial recruitment period for the em**powered** community is February 2 through March 31. Customers who register to become a member of the em**powered** community during this recruitment

period will be eligible to win one of four $250 prizes. Ongoing community members who participate in monthly surveys will be eligible to win one of two $100 prizes per month. Idaho Power employees and their immediate family members are not eligible to participate.

Another new marketing tactic in 2015 is signage at the Boise Airport. Idaho Power will advertise its commercial programs for a year with a large sign above a baggage claim and a large LED backlit sign on the B Concourse. The Boise Airport serves 2.8 million passengers annually, and 42 percent of the passengers are business travelers.

During the focus groups planned for 2015, Idaho Power will test messaging that may motivate customer participation in energy efficiency programs. While secondary research informed messaging in the past, the results from the qualitative study of Idaho Power customers will be considered when writing advertising copy and content for marketing materials.

In the first quarter of 2015, Idaho Power will expand its energy efficiency radio ads throughout the service area by adding public radio to the 2015 marketing mix. Boise State Public Radio broadcasts on over 20 stations to more than 100,000 listeners throughout southern and central Idaho's metropolitan and rural areas. Idaho Power will also use KISU-FM public radio to cover eastern Idaho.

Marketing in 2015 will use new publications dedicated to senior citizens. *Senior Goldmine* is a monthly publication delivered to 10 senior citizen centers and over 100 locations in the Treasure Valley. It is also hand-delivered to over 700 Meals-on-Wheels recipients. The company is researching advertizing in the *Senior Blue Book*, a semi-annual resource directory mailed to over 28,000 seniors and healthcare professionals. Senior publications with distribution outside of the Treasure Valley— such as the *Idaho Senior News*—will also be used.

Commercial marketing for the upcoming year will include advertorials and print ads in *The Idaho Business Review* and *The Business Insider*. New success stories will be produced, and association event sponsorships will remain. Industry-specific mailings will continue, and Facebook ads will be launched to appeal to commercial/industrial customers.

In January 2015, Idaho Power marketing and advertising personnel met with sales representatives from Pandora Internet Radio to initiate and plan an audio-mobile ad and an audio web ad for March 2015. Pandora offers advertising opportunities in the form of banner ads, video ads, and audio ads, with 71,697 monthly unique visitors ages 25 to 54 in Ada county and 27,988 monthly unique visitors in the same age group in Canyon county.

In 2015, Idaho Power will refresh its energy efficiency web pages. This effort started in 2014 and will continue in 2015. The redesign is intended to make navigation and web content more intuitive and easily accessible to users.

# ENERGY EFFICIENCY ADVISORY GROUP

Formed in 2002, the EEAG provides input on formulating and implementing energy efficiency and demand-reduction programs. Currently, EEAG consists of 14 members from Idaho Power's service area and the Pacific Northwest. Members represent a cross section of customers from the residential, industrial, commercial, and irrigation sectors, as well as representatives for seniors, low-income individuals, environmental organizations, state agencies, public utility commissions, and Idaho Power. Idaho Power appreciates the input from EEAG and acknowledges the commitment of time and resources of individual members to participate in EEAG meetings and activities. In 2014, Idaho Power would especially like to thank those EEAG members that participated in the IRP energy efficiency workshops.

EEAG met four times in 2014: February 6, May 20, August 19, and November 12. Additionally, a conference call was held on March 17 and April 24. During these meetings, Idaho Power discussed and requested recommendations on new program and new measure proposals, marketing methods, and specific measure details; provided a status of the Idaho and Oregon Rider funding and expenses; updated ongoing programs and projects; and supplied general information on DSM issues and important issues occurring in the region. Idaho Power relies on input from EEAG to provide a customer and public-interest review of energy efficiency and demand response programs and expenses. The minutes from the 2014 EEAG meetings are included in *Supplement 2: Evaluation*.

During the February 6 EEAG meeting, the results of a process evaluation done for both of Idaho Power's weatherization programs was presented by Johnson Consulting. The impact evaluation for the Irrigation Efficiency program was presented by ADM.

On March 17, members of EEAG participated in a conference call to discuss potential modifications to the Building Efficiency and Easy Upgrades programs. This conference call also contained a confidential discussion about the company's proposal to transfer $20 million of Idaho Rider funds to customers through the 2014/2015 PCA.

A conference call was held on April 24, 2014, to review NEEA's proposed business plan for the 2015 to 2019 funding cycle. The proposed business plan focuses on four strategic markets with a draft budget between $145 and $169 million. Also included in the proposed business plan are a few optional initiatives for funders.

At the May 20 EEAG meeting, Idaho Power's *Energy Efficiency Potential Study* conducted by EnerNOC, Inc., was a main topic of discussion. A subset of EEAG members met on May 19 to review the potential study and discuss ideas that could close the gap between the economic and achievable potential as indentified in the study.

At the August 19 EEAG meeting, there was a demand response update highlighting the success of all three programs—Irrigation Peak Rewards, A/C Cool Credit, and FlexPeak Management—for the 2014 season. Idaho Power had approximately 390 MWs of demand response capacity enrolled in the three programs.

During the November 12 EEAG meeting, four new program ideas were highlighted during the New Program Ideas Update. Idaho Power's *Demand Response as Operating Reserves Report* was also presented. This report was filed with the IPUC in September 2014 and the OPUC in October 2014, as a requirement from the *Demand Response Programs Settlement Agreement*.

In addition to EEAG, Idaho Power solicits further customer input by meeting directly with stakeholder groups in the residential, commercial, industrial, and irrigation customer sectors. Idaho Power has also enhanced its relationships with trade allies, trade organizations, and regional groups committed to increasing the use of energy efficiency programs and measures to reduce electricity load.

# DSM ANNUAL REPORT STRUCTURE

The structure of Idaho Power's *Demand-Side Management 2014 Annual Report* remains mostly unchanged from the 2013 report. It aligns with the reporting requirements included in the MOU with the IPUC staff and Idaho's other investor-owned utilities.

This main *Demand-Side Management 2014 Annual Report* is organized primarily by the customer sectors residential, commercial/industrial, and irrigation. Each sector has a description, which is followed by information regarding programs in that sector. Each program description includes a chart containing 2014 and 2013 program metrics in tabular format, followed by a general description, 2014 activities, cost-effectiveness, customer satisfaction/evaluation, and 2015 plans. Each program section contains detailed information relating to program changes and the reasoning behind those changes, including information on cost-effectiveness and evaluation. Following the sector and program sections of the report are descriptions of Idaho Power's activities in market transformation, other programs and activities, and Idaho Power's regulatory initiatives. Appendices 1 through 5 follow the written sections and contain tabular information on 2014 expenses and savings and historic information for all energy efficiency programs and demand response activities at Idaho Power.

Historically, Idaho Power divided its service area into five regions: 1) Canyon, consisting primarily of Canyon and Gem counties; 2) Western, consisting of the company's Oregon jurisdiction and Adams, Valley, and Payette counties; 3) Capital, consisting of Boise, Mountain Home, and the surrounding area; 4) Southern, consisting of the Twin Falls and Sun Valley area; and 5) Eastern, consisting of the Pocatello, Blackfoot, and Salmon areas.

Idaho Power currently divides its service area into three geographic regions: 1) Canyon–West, which combines the former Canyon and Western regions; 2) Capital, which retains the same geographic area; and 3) South–East, which combines the former Southern and Eastern regions. Because of the historical geographic demarcations, the five historical regions are referred to throughout this report.

Appendices 1 through 5 remain generally unchanged in form and contain financial, energy savings, demand reduction, levelized costs, and program-life B/C ratios from the UC and TRC perspectives. Appendix 5 contains detailed financial and energy savings information separated by Idaho Power's two jurisdictions, Idaho and Oregon.

Included again this year are two supplements and an attached CD. *Supplement 1: Cost Effectiveness* contains detailed annual cost-effectiveness information by program and energy-saving measures, as well as detailed financial information separated by expense category and jurisdiction. Provided in Supplement 1 are the B/C ratios from the UC, TRC, ratepayer impact measure test (RIM), and PCT perspectives. As of 2014, Idaho Power is using the DSM alternate costs and other financial inputs from Idaho Power's 2013 IRP.

*Supplement 2: Evaluation* contains Idaho Power's evaluation plans, copies of completed program evaluation reports, research reports, and reports created by Idaho Power or third parties. A CD containing market progress evaluation reports (MPER) and other reports provided by NEEA is attached to Supplement 2.

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# RESIDENTIAL SECTOR OVERVIEW

## Description

Idaho Power serves a little over one million people in southern Idaho and eastern Oregon. At the end of 2014, the company was serving 428,294 residential customers in its service area. During 2014, Idaho Power added 6,106 residential customers. This was almost identical growth to 2013 when the company added 6,168 new residential customers. The regional economy continues to improve, and the company is seeing a steady increase of new, residential customers and more housing starts. In 2014, the residential segment represented 36 percent of Idaho Power's total electricity usage.

In 2014, residential customers used 5.6 percent less energy than in 2013. This lower usage can be attributed to a variety of reasons, including, but not limited to, energy efficiency program activities, customer education, and milder temperatures. Idaho Power also continued its education and promotion of energy efficiency programs/information to all residential customers through a variety of marketing channels during the year. Idaho Power's marketing efforts are described in the Marketing and individual program sections of this report.

Table 8 shows a summary of 2014 participants, costs, and savings from the residential energy efficiency programs.

## Programs

Table 8. 2014 residential program summary

| | | | Total Cost | | Savings | |
|---|---|---|---|---|---|---|
| **Program** | **Participants** | | **Utility** | **Resource** | **Annual Energy (kWh)** | **Peak Demand (MW)** |
| **Demand Response** | | | | | | |
| A/C Cool Credit | 29,642 | participants | $1,465,646 | $ 1,465,646 | | 44 |
| **Total** | | | **$1,465,646** | **$ 1,465,646** | | **44** |
| **Energy Efficiency** | | | | | | |
| Ductless Heat Pump Pilot | 179 | homes | 251,446 | 884,211 | 462,747 | |
| Energy Efficient Lighting | 1,161,553 | bulbs | 1,909,823 | 7,148,427 | 12,882,151 | |
| Energy House Calls | 297 | homes | 197,987 | 197,987 | 579,126 | |
| ENERGY STAR® Homes Northwest | 243 | homes | 343,277 | 689,021 | 332,682 | |
| ENERGY STAR® Homes Northwest (gas fuel) | 282 | homes | | | 195,372 | |
| Heating & Cooling Efficiency Program | 230 | projects | 362,014 | 1,247,560 | 1,099,464 | |
| Home Energy Audit (direct install savings) | 354 | homes | | | 141,077 | |
| Home Improvement Program | 555 | homes | 324,717 | 896,246 | 838,929 | |
| Home Products Program | 10,061 | appliances/ showerheads | 227,176 | 302,289 | 652,129 | |
| Oregon Residential Weatherization | 13 | homes | 5,462 | 9,723 | 11,032 | |
| Rebate Advantage | 44 | homes | 63,231 | 89,699 | 269,643 | |
| See ya later, refrigerator® | 3,194 | refrigerators/freezers | 576,051 | 576,051 | 1,390,760 | |
| Student Energy Efficiency Kits* | 6,312 | | | | 1,491,225 | |
| Weatherization Assistance for Qualified Customers | 255 | homes/non-profits | 1,320,112 | 1,997,108 | 533,800 | |
| Weatherization Solutions for Eligible Customers | 118 | homes | 791,344 | 791,344 | 290,926 | |
| **Total** | | | **$6,372,640** | **$14,829,666** | **21,171,063** | |

**Notes:**
See Appendix 3 for notes on methodology and column definitions.
Totals may not add up due to rounding.
*Student Energy Efficiency kits are offered through the Residential Energy Efficiency Education Initiative.

Programs available to residential customers in 2014 included 13 energy efficiency programs, the Residential Energy Efficiency Educational Initiative, the Easy Savings Program, and the Shade Tree Project. Residential efficiency programs included Energy House Calls; Rebate Advantage; ENERGY STAR® Homes Northwest; Home Products Program; Home Improvement Program; Energy Efficient Lighting; WAQC; Weatherization Solutions for Eligible Customers; DHP Pilot; Oregon Residential Weatherization; H&CE Program; See ya later, refrigerator®, and the new Home Energy Audit program.

Idaho Power markets its residential energy efficiency programs to its customers through online advertising, print ads, radio and television commercials, media and public relations, billboards, retail events, customer visits, meetings with trade allies and contractors, participation in home and garden shows, remodeling events, and county fairs.

Bill communication included monthly bill inserts and messages; energy efficiency guides; and articles in the *Connections* customer newsletter, including two issues (February and September) devoted entirely to energy efficiency topics and programs. *Connections* is mailed in bills monthly to approximately 415,000 customers and available online for those who request paperless billing. Energy efficiency guides included the *Spring/Summer Energy Efficiency Guide* (April) and the *Fall/Winter Energy Efficiency Guide* (October). Table 9 shows a summary of bill inserts by month, program, topic, and number of inserts sent.

Table 9. Summary of bill communications sent in 2014

| Month | Program/Topic | Total Inserts |
|---|---|---|
| January | Energy efficiency summary | 383,424 |
| | See ya later, refrigerator® | 20,069 |
| February | See ya later, refrigerator® | 41,091 |
| March | See ya later, refrigerator® | 142,707 |
| April | Home Improvement Program | 350,177 |
| | See ya later, refrigerator® | 219,595 |
| May | Ductless heating | 363,225 |
| | ENERGY STAR Homes Northwest | 363,258 |
| June | Home Improvement Program | 352,566 |
| | See ya later, refrigerator® | 364,240 |
| July | See ya later, refrigerator® | 164,236 |
| | Commercial energy efficiency | 40,147 |
| | Home Products Program | 364,235 |
| August | See ya later, refrigerator®—Dog | 178,786 |
| | See ya later, refrigerator®—Man | 190,402 |
| September | Weatherization | 353,813 |
| | Energy House Calls | 365,491 |
| October | See ya later, refrigerator® | 364,587 |
| | Commercial energy efficiency | 40,142 |
| November | *Fall/Winter Energy Efficiency Guide* | 40,650 |

Throughout the year, public relations and media opportunities were identified to create awareness of energy efficiency programs and encourage the wise use of energy. From the weekly *News Briefs* email sent to all media in Idaho Power's service area to targeted media alerts and releases (also posted online), content was provided for news stories to inform and educate Idaho Power customers. The company

successfully pitched the concept of a monthly energy efficiency segment on the KTVB-TV afternoon news program with Idaho Power's CR&EE manager. The segments, which began in October, focused on energy efficiency tips for residential customers, including weatherizing your home, the benefits of LED lighting and how to receive an Idaho Power energy efficiency guide. Broadcasting both in the Boise and Twin Falls markets, the show reached 20,000 to 30,000 viewers each time.

In October, Idaho Power celebrated national Energy Awareness Month with the annual student art contest, which featured a category, "Ways to Save Energy." Idaho Power promoted the event in *News Briefs* and issued news releases in support of local award presentations for students and their winning artwork, which was displayed at local events and recognized in the media.

Social media in 2014 continued to be an effective method of informing and educating stakeholders on the company's energy efficiency programs, incentives, and events. Idaho Power Facebook fans climbed to over 11,100, up from 7,600 in 2013. Twitter followers also grew from 1,900 in 2013 to over 3,000 in 2014. On YouTube, the most popular video continued to be the educational clip on DHPs. The video has been viewed over 20,000 times for an estimated 41,531 minutes watched. Ensuring quality content is a team effort, with the social-media specialist working with program specialists and marketing staff to ensure messaging alignment for key campaigns and energy efficiency events throughout the year.

In 2014, the online myAccount tool was the focus of a comprehensive communications campaign, from advertising to public relations. One important message of the campaign was "Understand Your Use." Customers were encouraged to learn how they use energy by completing a Home Profile and to use Idaho Power's tips, advice, and programs to save energy. An entire issue of *Connections* (May) featured myAccount and ways customers can save on their energy bill. The same messaging appeared in myAccount bill inserts (June and October), the KTVB segments, online promotional links, advertising, and a new display panel designed for the company's special events exhibit. In August, an *eNews* internal video was produced about myAccount with the same messaging about ways to save, and the video was posted externally on YouTube. By the end of the year, Idaho Power offered a new mobile version of its website with myAccount functionality available.

Presentations to community groups and businesses continued to be a major emphasis during 2014. Idaho Power CRs and CERs made hundreds of presentations in communities served by the company.

The Home Energy Audit program launched in early 2014. The program was based on insights gained from the Boise City Home Audit project conducted in 2011 and 2012. For details regarding the Boise City Home Audit project, view the *Demand-Side Management 2012 Annual Report*, pages 125 to 127, and the *Demand-Side Management 2013 Annual Report*, page 25.

In 2014, Idaho Power distributed 2,041 shade trees to residential customers through the expanded Shade Tree Project. Using results from a state-sponsored urban tree-canopy study and online tools developed by the Arbor Day Foundation, the Shade Tree Project encouraged the strategic planting of trees to reduce summertime residential energy use.

Idaho Power conducts the Burke Customer Relationship survey each year. In 2014, 59 percent of residential survey respondents indicated Idaho Power is meeting or exceeding their needs with information on how to use energy wisely and efficiently.

Sixty-one percent of residential respondents indicated Idaho Power is meeting or exceeding their needs by encouraging energy efficiency with its customers. While 43 percent of Idaho Power residential customers surveyed in 2014 indicated Idaho Power is meeting or exceeding their needs in offering

energy efficiency programs, 28 percent of the residential survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of the residential survey respondents who have participated in at least one Idaho Power energy efficiency program, 81 percent are "very" or "somewhat" satisfied with the program.

# A/C Cool Credit

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (participants) | 29,642 | n/a |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | 44 | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $962,286 | $537,163 |
| Oregon Energy Efficiency Rider | $56,988 | $29,731 |
| Idaho Power Funds | $446,372 | $96,964 |
| Total Program Costs—All Sources | $1,465,646 | $663,858 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Levelized Cost ($/kWh) | n/a | n/a |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | |
| Total Resource Benefit/Cost Ratio | n/a | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

## *Description*

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

In alignment with the settlement agreement reached in Case No. IPC-E-13-14, changes were made to the program in 2014. To create consistency among Idaho Power's demand response programs, the cycling season was reduced from June 1 through August 31 to June 15 through August 15. The maximum number of cycling hours available per season was reduced from 120 hours to 60 hours. A minimum of three cycling events per season was set, and the incentive was reduced from $21 per season to $15 per season. The incentive is paid as a bill credit of $5 on the July, August, and September bills. The program continued to be available to reduce energy demand during critical summer peak periods. As before, the program is not available on weekends or holidays, and the maximum length of an event remains at four hours.

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

## 2014 Program and Marketing Activities

In early winter, the company sent letters to program participants regarding the new program details and the implications for customers. As agreed to in the settlement agreement, Idaho Power did not actively market the A/C Cool Credit program in 2014; however, customer communication and retention was active. Idaho Power attempted to recruit customers who had moved into a home that already had a load-control device installed and recruit previous participants who changed residences to a location that did not have a load-control device. Idaho Power also completed the replacement of any remaining radio-paging switches on current participants' residences with advanced metering infrastructure (AMI)-compatible devices in 2014.

Before the cycling season began, participants were sent a postcard reminding them of the program specifics. Also, in the company's June 9 *News Briefs* weekly email to all media throughout Idaho Power's service area, the company included a reminder to customers participating in the program that A/C season had arrived and the program was in effect. Three cycling events occurred in 2014 on July 14, July 31, and August 11. At the end of the summer, a thank you card was sent to program participants. The company followed up with a *News Briefs* item on September 3 crediting the demand response programs for effectively helping offset energy use during periods of high electrical demand that summer.

## Cost-Effectiveness

The methods used to determine the cost-effectiveness of the demand response programs was updated in 2014. As part of the public workshops in conjunction with Case No. IPC-E-13-14, Idaho Power and other stakeholders agreed on a new method for valuing demand response. The settlement agreement, as approved in IPUC Order No. 32923, defined the annual cost of operating the three demand response programs for the maximum allowable 60 hours must not be more than $16.7 million. This $16.7 million value is the levelized annual cost of a 170 MW deferred resource over a 20-year life. In 2014, the cost of operating the three demand response programs was $10.6 million. It is estimated that if the three programs were dispatched for the full 60 hours, the total costs would have been approximately $13.8 million, and the programs would have remained cost-effective.

The A/C Cool Credit program was dispatched for 9 event hours and achieved a maximum demand reduction of 44 MW. The total expense for 2014 was $1,465,646 and would have remained the same if the program was fully used for 60 hours because there is no variable incentive paid for events beyond the three required events.

## Customer Satisfaction and Evaluations

In fall 2014, a customer satisfaction survey, along with a postage-paid envelope, was mailed to 5,000 current A/C Cool Credit participants. The response rate was over 36 percent, with 1,810 responses.

Survey participants were asked "What was the main reason you participated in the A/C Cool Credit program?" Over 38 percent of respondents indicated it seemed like the right thing to do. Approximately 30 percent of respondents indicated to earn the bill credit. Over 28 percent indicated to reduce overall electrical usage on hot summer days. The remaining respondents selected "other" as their main reason.

When asked how many days participants would estimate Idaho Power cycled their A/C unit during the past summer, nearly 65 percent stated they didn't know. Over 17 percent of respondents estimated there were 1 to 5 events. Just over 8 percent thought there were over 10 events.

The survey respondents were satisfied with the program, with over 89 percent indicating they were "very" or "somewhat" satisfied with the program. Participants were asked how significantly they were impacted by the program this past summer, and nearly 82 percent of respondents indicated "very little" or "not at all." Eighty-eight percent indicated they receive the right amount of information about the program. Results of the survey are in *Supplement 2: Evaluation*.

Idaho Power contracted with CLEAResult (acquired PECI), to complete an impact evaluation of the 2014 A/C Cool Credit program. The goal of the impact evaluation was to calculate the estimated demand reduction achieved by three A/C Cool Credit curtailment test events and update the program's existing predictive model to account for the 2014 curtailment event results.

PECI completed analyses of curtailment events held on July 14, July 31, and August 11, 2014, each with a three-hour duration. Results of the analyses showed maximum single-hour demand reductions of 1.33 kilowatts (kW), 0.91 kW, and 1.07 kW per participant, respectively, for the three events. The average hourly demand reduction was 1.25 kW, 0.86 kW, and 1.00 kW per participant, respectively. Due to the distinct weather patterns between the Boise and Pocatello/Twin Falls regions, each curtailment event analysis includes region-specific results.

The impact evaluation demonstrated that Idaho Power's A/C Cool Credit program functions as intended, and, if properly maintained, can be relied on to provide dispatchable demand reduction to the electricity grid.

## 2015 Program and Marketing Strategies

Per the terms of the settlement agreement, Idaho Power will not actively promote the A/C Cool Credit program to solicit new participants through marketing but will accept new participants who request to participate, regardless of whether they were previous participants in the program. Attempts will be made to recruit previous participants who have moved, as well as new customers moving into homes that already have a load-control device installed.

Idaho Power will maintain the existing A/C Cool Credit program, equipment, and participation by providing an opportunity for all current program participants to continue to participate if they choose. This strategy aligns with the settlement agreement reached in Case No. IPC-E-13-14. The company will be able to continue using the investment that Idaho Power's customers have made in the existing equipment in the field.

# Ductless Heat Pump Pilot

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 179 | 215 |
| Energy Savings (kWh) | 462,747 | 589,142 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $235,099 | $230,761 |
| Oregon Energy Efficiency Rider | $9,614 | $6,814 |
| Idaho Power Funds | $6,733 | $0 |
| Total Program Costs—All Sources | $251,446 | $237,575 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.042 | $0.032 |
| Total Resource Levelized Cost ($/kWh) | $0.148 | $0.132 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.77 | |
| Total Resource Benefit/Cost Ratio | 0.70 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2009 | |

## *Description*

Idaho Power joined the Northwest DHP Pilot project in 2009 and implemented the pilot throughout its service area. The company extended the project as an Idaho Power DHP Pilot through 2014. A primary goal of the Northwest DHP Pilot project is to promote DHP technology as an energy-saving alternative for customers who primarily heat their homes with electricity. In 2014, Idaho Power offered customers a $750 incentive payment to have a qualified DHP installed.

The program targets existing homes heated with electric zonal systems. Typically, these homes do not have air ducting and therefore cannot easily have a forced-air heat pump system installed. This provides the opportunity to encourage the use of DHPs. The types of electric zonal systems in the targeted homes include baseboards, ceiling cables, and wall-mounted units. Homes heated with fossil fuel forced-air systems or electric forced-air systems do not qualify. Qualifications include having one DHP indoor unit installed in the main living area of the home, since this is where most occupants spend most of their time.

Other Northwest DHP Pilot goals are to identify how much energy this technology saves to determine an RTF deemed-savings amount and to obtain customer satisfaction and behavioral patterns regarding the units.

Field monitoring of selected homes throughout the Pacific Northwest, an analysis of billing data, and other evaluations occurred from 2009 through 2014. In 2014, NEEA published a final summary report and a third market progress evaluation report. Detailed information about the regional DHP effort is located at goingductless.com and neea.org.

## 2014 Program and Marketing Activities

The DHP Pilot had a decrease of 37 applications in 2014 compared to the prior year. This was primarily due to a one-time 40-installation project that was received in 2013 and not repeated in 2014. The 2013 project involved converting baseboard heat to DHPs in 40 living units that were in 10 fourplex properties. Marketing expenses for the DHP Pilot increased by $36,065 in 2014 when compared to the prior year. This increase caused total annual expenses to exceed 2013 expenses even though fewer incentives were processed in 2014.

Knowing contractors are a vital marketing asset, contractor visits were made throughout 2014 to better understand how Idaho Power can support participating contractors in promoting the DHP Pilot. As a result, Idaho Power developed a contractor portal housed on Idaho Power's website. The portal was launched August 2014. It allowed authorized contractors access to a specific area of Idaho Power's website where they could customize pre-approved marketing pieces with their own business name, address and phone number. Two fliers were offered for use by participating contractors in the DHP Pilot. The offering was part of a combined portal launch with the H&CE Program and Home Improvement Program.

Expanding the network of participating contractors remained a key growth strategy for the DHP Pilot. The goal was to support contractors currently in the DHP Pilot while adding new contractors. To accelerate the expansion of the participating contractor network, Idaho Power provided three DHP Pilot orientation training sessions to participating and prospective contractors. Expansion strategies resulted in the addition of three companies to the list of participating contractors (4 percent increase). Three training sessions were offered in 2014 as compared to 11 in 2013. The decrease in the number of new companies was a result of successful trainings and contractor additions completed in 2012 and 2013. About a dozen companies have contacted Idaho Power and are pending addition to the program. Future meetings with potential contractors could yield additional participants.

To hasten the residential adoption of the DHP technology in the Idaho Power service area, a key strategy was to communicate with other tiers of the supply chain. In the Idaho Power service area, there are numerous wholesalers supplying DHPs to the contractors. Idaho Power met with several of these wholesalers in Idaho Power's service area to share helpful information and to encourage them to promote DHPs to their contracting customers.

Marketing tactics for Idaho Power's DHP Pilot varied. Approximately 3,000 radio ads ran on over 20 radio stations for six weeks throughout Idaho Power's service area. During spring 2014, a digital behavioral ad campaign was launched. The DHP Pilot had 781,461 ads viewed by people browsing the internet over the course of two months from this ad campaign.

A direct-mail campaign was conducted in April 2014. Over 27,000 letters were sent to homeowners of electrically heated homes. In addition, information about the DHP Pilot was included in a postcard sent to people who purchased a home within the previous six months. Bill inserts and newspaper ads rounded out the ongoing marketing and promotion of the DHP Pilot.

In May, the company issued a press release in southeast Idaho recognizing NEEA's *Northwest DHP 2014 Idaho Installer of the Year* that provides services to Idaho Power's customers in that area. In addition, a *Heat Pumps: Cozy and Cool* article appeared in the September energy efficiency issue.

The *Demand-Side Management 2013 Annual Report* mentioned possible changes to the DHP webpages. Changes to the DHP webpages were not made in 2014 because on a separate project, the company began

working on a website redesign to improve navigation on the energy efficiency website. The decision was made to wait until that work was completed before any changes were made to DHP webpages. The *Demand-Side Management 2013 Annual Report* also stated contractors would be asked to comment on the portal during 2014. Comments were not pursued due to the portal launching in the third quarter of the year, which limited contractors' time to try the portal in 2014.

## Cost-Effectiveness

The 2014 savings estimates and reported deemed savings values were unchanged from the 2013 values. During 2014, the RTF reviewed the savings models for DHP with updates occurring in May, June, and December around the calibration of savings models, screening for supplemental fuel use, and the assumptions around other efficiency measures occurring in DHP homes. The RTF's decisions and resulting changes in savings will be applied in 2015. Idaho Power calculated the participant costs for the TRC by averaging one-unit installations that occurred in Idaho Power's service area over the two-year period 2013 to 2014. The average installation cost over the time period was $4,285.

In 2014, Idaho Power included RTF-approved NEBs, accounting for annual avoided supplemental fuel costs and avoided capital expenses of A/C purchases that would have occurred in the absence of the installation of a DHP system. A current sub-committee was formed in 2014 to address the possible inclusion of NEBs for decreased health impacts from reduced wood-burning emissions. In November, the RTF presented its findings and recommendation on the inclusion of health benefits to be part of the cost-effective benefits in the cost-effective analysis of measures and programs. The RTF is waiting the council's guidance on the issue.

After including the RTF-approved NEBs, the DHP measure is not cost-effective from a TRC perspective. However, Idaho Power determined DHPs meet at least one of the cost-effectiveness exceptions outlined in OPUC Order No. 94-590. Idaho Power originally filed UM-1710 to request cost-effectiveness exceptions with the OPUC on November 4, 2014, and subsequently re-filed it on February 11, 2015. The case is still pending. For cost-effective details, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

As part of the DHP Pilot, Idaho Power's third-party contractor conducted on-site verification (OSV) on at least 10 percent of the completed installations in Idaho Power's service area in 2014 to ensure installations complied with program requirements. The OSVs were beneficial for customers and the contractors. The inspector provided customers with information about how to maximize the benefits of their new DHP. The contractors received feedback from the inspector and reviewed the installation requirements of the DHP Pilot.

In 2014, NEEA provided two reports updating the DHP Pilot. The following are highlights from the reports.

### NEEA Report E14-274, released February 2014

NEEA published a summary report addressing five key components of the DHP Pilot. The report includes market progress, laboratory testing, field monitoring, billing analysis, and cost analysis/NEBs. Each component is described individually in the report with detailed summaries. Several NEEA reports were published since the beginning of the DHP Pilot in 2009 addressing the five components. The February report recapped prior information and discussed DHP products, potential energy savings,

and potential sustainability of DHPs in the Northwest region. A copy of the NEEA Report E14-274 is included on the CD accompanying *Supplement 2: Evaluation*.

### NEEA Report E14-278, released April 2014

This report was the third MPER for NEEA's Northwest DHP Initiative (the Initiative). The report presents the findings of surveys and interviews conducted with a mix of homeowners who owned or did not own DHPs. Feedback collected from installing contractors, utilities, wholesalers, and manufacturers is presented in the report. The report details the effectiveness and progress of the Initiative's ability to transform the target market. A copy of the NEEA Report E14-278 is included on the CD accompanying *Supplement 2: Evaluation*.

## *2015 Program and Marketing Strategies*

Idaho Power will sponsor and provide training sessions and orientations to the DHP Pilot program for new and existing contractors to assist them in meeting program requirements and further their product knowledge.

Expanding the network of participating contractors remains a key strategy for the DHP Pilot. The goal is to support contractors currently in the DHP Pilot while adding new contractors. Performance of the DHP Pilot is substantially dependent on the contractor's ability to promote and leverage the DHP Pilot. Frequent individual contractor meetings will be held in 2015.

The strategy to promote the residential adoption of the DHP technology in Idaho Power's service area includes communicating with the complete supply chain. To accelerate the wholesaler's ability to increase contractor awareness of DHPs and the DHP Pilot, Idaho Power will meet with the wholesalers and share information.

The 2015 marketing strategy will include proven tactics previously used and new methods. Since homeowners make more improvements to their home during the first two years of ownership, the company plans to continue to target new customers in their first six months of new-home ownership. Postcards will be mailed to these new customers, raising awareness of the incentives available to them. The strategy will include many marketing tactics, such as bill inserts, print ads in newspapers, and direct-mail letters. Social media, such as Facebook, will be used. A DHP display will be used at several residential home and garden and home improvement trade shows.

New marketing pieces will be added to the contractor portal over time as needed.

# Energy Efficient Lighting

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (bulbs) | 1,161,553 | 1,083,906 |
| Energy Savings (kWh) | 12,882,151 | 9,995,753 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,860,046 | $1,331,113 |
| Oregon Energy Efficiency Rider | $45,959 | $25,812 |
| Idaho Power Funds | $3,818 | $0 |
| Total Program Costs—All Sources | $1,909,823 | $1,356,926 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.018 | $0.016 |
| Total Resource Levelized Cost ($/kWh) | $0.066 | $0.058 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 2.98 | |
| Total Resource Benefit/Cost Ratio | 1.99 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2002 | |

## *Description*

The Energy Efficient Lighting program strives for residential energy savings through the replacement of less-efficient lighting with more efficient technology. The most recent studies indicate consumer usage patterns. According to the *NEEA 2011 Residential Building Stock Assessment: Single-Family Characteristics and Energy Use* study, the average Idaho home has 63 bulb sockets. The *2010 Idaho Power Residential End-Use Survey* shows 88 percent of customers have less than 20 compact fluorescent light (CFL) bulbs installed, indicating there is still potential to install more energy-efficient bulbs. Changing these bulbs represents a low-cost, easy way for all customers to achieve energy savings.

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

The Energy Efficiency Lighting program follows a markdown model that provides incentives directly to the manufacturers or retailers, with savings passed on to the customer at the point of purchase. The benefits of this model are low administration costs, better availability of products to the customer, and the ability to provide an incentive for specific products.

## 2014 Program and Marketing Activities

In 2014, the Energy Efficient Lighting program provided almost 61 percent of all energy savings derived from residential energy efficiency customer programs.

Idaho Power continued to participate in the Bonneville Power Administration (BPA) Simple Steps, Smart Savings™ promotion focusing on ENERGY STAR CFL and LED bulbs and LED light fixtures. CLEAResult managed the promotion. CLEAResult is responsible for retailer and manufacturer contracts, marketing materials at the point of purchase, and providing support and training to retailers.

In 2014, Idaho Power continued to respond to recommendations made in the 2013 process evaluation conducted by TRC Energy Services. TRC Energy Services found that the program is generally successful. Since the inception of this program in 2010, the program has consistently exceeded kWh savings goals. The recommendations and Idaho Power's actions and considerations in 2014 are described below.

One recommendation was to continue to investigate options to bring LED products into the program while maintaining cost-effectiveness. In February 2014, Idaho Power added LED bulbs into the promotion in Oregon and Idaho service areas. LED bulbs comprised 13 to 29 percent of light bulb sales each month. LED fixtures were introduced in the Idaho service area March 2014 and comprised less than 1 percent of lighting sales each month through the rest of the year.

TRC Energy Services recommended increasing coordination with retailers to find mutually beneficial in-store advertising solutions and to speak with corporate representatives from a few large retailers to understand the restrictions on advertising, then work with retailers to overcome these barriers. Through its contractor, Idaho Power reached out to corporate representatives to find mutually beneficial advertising solutions. In 2014, all but two of the retailers in the Simple Steps, Smart Savings promotion allowed for some form of in-store advertising. All but five allowed for utility logos. Those that did not allow for utility logos allowed for wording such as "brought to you by your local utility." Retailers cited shopper consistency across the nation and protecting their brand as reasons to set advertising guidelines.

In addition, in 2014, Idaho Power continued to work with the region to address utility programs within the retail sector through participation in the Northwest Regional Retail Collaborative (NWRRC) facilitated by NEEA and by following promotions initiated by the Western Regional Utility Network (WRUN). Both the NWRRC and WRUN sought to develop collaborative approaches to working with manufactures and retailers to increase uptake of energy-efficient products in the retail market.

Through CLEAResult, several special promotions were conducted at the retail stores through Simple Steps, Smart Savings. These promotions generally involved special product placement and signs. For example, in March and September, Fred Meyer stores had special endcap displays with promotional products. Costco used pallet displays in February. Home Depot held a truckload event in September. These types of promotions and special product placement help increase the visibility and sales of promotional products. CLEAResult staff also conducted 1,017 store visits in 2014 to check on stock, point-of-purchase signs, and displays.

TRC Energy Services recommended Idaho Power further investigate opportunities to bring more grocery chains and small retailers into the program or to work with participating retailers of these types to overcome participation barriers and increase program sales. In 2014, Idaho Power worked with 18 participating retailers, representing 144 individual store locations throughout Idaho Power's service area. The majority—63 percent of retailers in the program—are smaller grocery, drug, and small hardware stores.

Regionally, the *2012–2013 Northwest Residential Lighting Market Tracking Study* shows the majority of customers purchase light bulbs at do-it-yourself, mass merchants, and wholesale club stores. Smaller stores have lost market share for lighting products. Regionally, lighting sales at smaller stores have decreased from 28 percent in 2006 to 14 percent in 2012, the most recent year data is available. Larger stores tend to have a larger product selection and more competitive pricing.

Instead of focusing on increasing sales at smaller stores, Idaho Power evaluated its distribution of retail stores to ensure customers had access to promotional products. Idaho Power studied the geographic distribution of participating retailers and confirmed there were participating stores located throughout Idaho Power's service area with the exception of the Salmon area.

In addition, to help facilitate customer access to the promotion under Simple Steps, Smart Savings, Idaho Power launched its first online offering with Costco. With this offering, Idaho Power customers who purchased bulbs online through Costco could access Idaho Power incentives. For the Costco promotion, after selecting the shipping zip code, the customer was prompted to pick their utility service area, thereby emphasizing the tie between Idaho Power and the discounted price.

TRC Energy Services recommended Idaho Power consider adopting changes in RTF metrics for future cycles (not retroactively). In early 2015, Idaho Power established a policy that as a general rule, beginning for 2014 reporting of energy savings from energy efficiency programs, Idaho Power will freeze the savings metrics annually. This means that all savings for a given year will not be changed mid-year. This policy conforms to recommendations from third-party evaluators and seems consistent with other energy efficiency providers in the region.

Another recommendation from TRC Energy Services was to consider assigning the task of reviewing the invoices to junior or administrative staff so the program specialist would have more time to follow other recommendations provided. Idaho Power reviewed this recommendation and believes it is important that the staff with the most expertise review invoices to ensure customer funds are prudently spent; therefore, the program specialist continued to perform the invoice review in 2014. Furthermore, the specific process referenced by TRC Energy Services is a control that is necessary to meet the financial reporting requirements of the *Sarbanes–Oxley Act of 2002* (SOX). Idaho Power has fiduciary responsibility and must ensure all of its legal and regulatory requirements are met.

TRC Energy Services recommended Idaho Power ensure consistent language and terminology for product type categories through drop-down menus or similar strategies and provide future contractors with a data dictionary or other description of database terms. Idaho Power's program database is standardized to the promotion. The database covers program participation from 2009 onward and reflects several different promotions and promotion implementers. As a result, the data classifications tie directly to the original classifications used by the implementer at the time of sale. This allows Idaho Power to differentiate between different promotions and timeframes and tie data directly back to the original source files. A data dictionary will be developed in 2015.

Additional activities in 2014 included education and marketing. Idaho Power and CLEAResult conducted four education events at Costco stores in Pocatello, Twin Falls, Nampa, and Boise. At each event, Idaho Power and CLEAResult personnel talked with customers and staffed a table with literature, promotional items, and a lighting display.

Additional marketing and customer education by Idaho Power included the company's website, a redesigned program brochure, and discussions with customers at community events. The program brochure, which focused on how to shop for an energy-efficient bulb, was redesigned to include LEDs

and the Federal Trade Commission-required *Lighting Facts Label*. This label makes it easier for consumers to choose between different light bulbs by displaying common metrics (energy used, lumens, and color temperature.)

The September issue of Idaho Power's *Connections* customer newsletter and the *Fall/Winter Energy Efficiency Guide* featured lighting. Topics in both publications included understanding how to shop for the right bulb, lighting design basics, LEDs, and lighting controls. In the November *Connections*, the back page promoted the guide with the image of a large LED light bulb. The weekly media *News Briefs* email included stories on energy-efficient lighting on October 28 (guide focuses on lighting), December 1 (tips for safe holiday lighting), and December 8 (LED holiday lights use less energy). In addition, monthly energy efficiency segments on the afternoon KTVB-TV news program (broadcast in Boise and Twin Falls) mentioned energy-efficient lighting on October 27, November 13, and December 9—reaching from 20,000 to 30,000 viewers per program.

Additional 2014 program activities included customer education through distribution of bulbs to customers. Through Idaho Power's local events, bulbs were given directly to customers at a range of venues. Venues included energy efficiency presentations at senior centers and environmental and health fairs. In 2014, 1,524 CFL bulbs and 3,234 LED bulbs were distributed through this route. This included 2,500 LED bulbs distributed along with educational materials at the FitOne Expo in Boise.

## Cost-Effectiveness

Throughout 2013, the RTF analyzed the savings for residential LED bulbs. Savings were finalized in October 2013. Idaho Power reviewed the savings and cost assumptions and determined residential LEDs are cost-effective. LEDs were added to the program in early 2014.

In 2014, the RTF updated and revisited the assumptions for both CFLs and LEDs to standardize and reduce the number of measures. The number of lamp types was reduced from 10 to 5 categories. The lumen categories within each bulb type were merged and reduced from six groups of lumen ranges to three groups. All other assumptions regarding baseline bulb, hours of use, lamp life, lamp cost, room type, and space conditioning remained the same. In grouping these measures, the RTF used a weighted average from the Residential Building Stock Assessment (RBSA).

Several lamp types were included in the program that had no corresponding savings or cost assumptions available from the RTF. These non-RTF lamp types include high-lumen CFL bulbs and LED reflector fixtures. In Tetra Tech's evaluation of the 2013 program activities, the evaluators recalculated the energy savings Idaho Power associated with the high-lumen bulbs. After the evaluation, Idaho Power requested that Tetra Tech review the non-RTF bulbs included in the program. Tetra Tech recommended that the RTF savings and cost assumptions for either the "general purpose and dimmable" bulbs or the "reflector and outdoor" bulbs be assigned to the LED reflector fixtures. After reviewing the hours of use for reflector bulbs and discussing the potential uses of reflector fixtures, Idaho Power decided to assign the "reflector and outdoor" LED bulb savings to these fixtures.

As discussed in the Introduction, Idaho Power reviewed its policy of updating savings and cost assumptions and decided to freeze savings at the beginning of each year. However, this decision was made after efforts had been made to re-map the bulbs sold in 2014 to the new RTF categories. As a result, the savings for this measure reflect the changes approved by the RTF in mid-2014. For detailed cost-effectiveness assumptions, metrics, and sources, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

In 2014, Idaho Power administered an impact evaluation of 2013 ex-ante energy savings using third-party Tetra Tech to validate ex-post results. Overall, Tetra Tech found the program has well-established design and delivery processes, supported by the program tracking systems, program documentation, and savings tools and that processes are operating efficiently and with careful attention to detail.

The impact evaluation indicated ex-post verified savings were 10,047,811 kWh compared to 9,995,753 kWh ex-ante claimed savings, resulting in a gross realization rate of over 100 percent. The driver of the difference in the overall kWh realization rate from 100 percent was an adjustment made to non-RTF high-wattage lamps.

To facilitate more accurate, transparent, and consistent program reporting, Tetra Tech identified the recommendations below for program improvement.

Tetra Tech recommended working with the administration contractor to track allocation methods and negotiations that relate to allocations. While the administration contractor included the allocation used for each monthly report for each retailer and product model number, Tetra Tech stated Idaho Power should receive and retain a full accounting of Idaho Power's and the administration contractor's understandings of allocation and resolve any variances as part of monthly quality assurance (QA) checks.

Idaho Power reviewed this recommendation and found no action was necessary. Idaho Power already receives the full Regional Sales Allocation Tool (RSAT) used by CLEAResult, which includes a full accounting of the assumptions used to assign allocations. The tool is commissioned by the BPA and is updated approximately once per year. Idaho Power receives newly released versions and reviews the allocations for its retailers. Idaho Power has the opportunity to work with the tool developer to address any concerns. Idaho Power has always and will continue to verify allocations applied to sales as part of its monthly verification check.

Another recommendation by Tetra Tech was to consider updates to the Energy Efficient Lighting program tracking system. Tetra Tech stated that with the recent shift in RTF deemed savings amounts for lighting from wattage to lumen based, Idaho Power should consider adding lumens to the tracking database for each stock keeping unit (SKU) and work to identify future RTF changes in collaboration with the administration contractor. Idaho Power added lumens to the program database in January 2014.

Additionally, Tetra Tech recommended Idaho Power continue to comprehensively track retailer reports and RTF savings but consider a shared system that aligns all specifications that lead to reported energy savings. Tetra Tech also said to consider a database or similar system that the administration contractor and Idaho Power could share to enable additions of SKUs and available technical data to drive consistency between administration contractor reporting and Idaho Power tracking data for all factors.

Idaho Power reviewed this recommendation and found that new reports developed by CLEAResult in 2014 address this concern. Starting in 2014, Idaho Power began to receive a monthly current products list of all potential models in the promotion. Data includes lumens, model numbers, and bulb/fixture descriptions. Since the promotion began, Idaho Power has received detailed sales data directly from the contractor database each month with its invoice. The monthly invoice detail will continue to be compared against the raw sales data as reported by the retailer or manufacturer as part of the invoice reconciliation process.

Tetra Tech suggested Idaho Power consider alternative reviews of unique non-RTF lamps and characterizations. They stated that when identifying lamps that are not identified by the RTF, Idaho Power should take care when lamps are substantially different from an RTF category and verify lamp efficacy against manufacturer specifications and general performance. Idaho Power reviewed this recommendation and found quality concerns are covered by the program requirement that all lamps in the promotion be ENERGY STAR certified. Those without a deemed savings tend to be styles with specialty applications, such as high wattage. Due to lack of data, the RTF set the savings to not applicable (N/A) for some product categories. However, bulbs without deemed RTF savings values, "non-RTF lamps," have passed the ENERGY STAR qualifications for certification. These qualifications include testing procedures, general performance requirements, and minimum efficiency standards.

For non-RTF lamps, Tetra Tech recommended Idaho Power consider directly calculating energy savings using standard industry approaches or working with others to develop region-wide savings values. They stated that for lamps that fall well beyond the RTF categories or *Energy Independence and Security Act of 2007* (EISA) affected baseline lamps, Idaho Power should consider several options, including 1) working with NEEA and/or the RTF to develop lamp adjustment factors and baseline assumptions based on regional market knowledge; 2) conducting independent market research to understand the use of these lamps; and/or 3) using energy savings calculations based on general engineering principles and underlying RTF market adjustment and performance factors. In response to this recommendation, Idaho Power contracted with Tetra Tech to evaluate savings for non-RTF lamps using general engineering principles and the underlying RTF market adjustment and performance factors. Results will be available in early 2015.

A copy of the complete report is included in *Supplement 2: Evaluation*.

## 2015 Program and Marketing Strategies

Idaho Power will continue to participate in Simple Steps, Smart Savings in 2015. CLEAResult was awarded the BPA implementation contract for 2015. Idaho Power will enter into a new promotion contract with CLEAResult beginning April 1, 2015. No disruption in services will occur.

Idaho Power will continue to monitor the number of participating retailers and geographic spread of these retailers. The company will reach out to stores in the Salmon area and invite them to participate in the promotion. Idaho Power will also work regionally to develop online promotions that allow customers to access promotional pricing regardless of location.

In 2015, Idaho Power will participate in the NWRRC and follow the work of WRUN. Involvement in the NWRRC and WRUN will help facilitate research into transitioning the Energy Efficient Lighting program to a more comprehensive retailer markdown program with additional product categories and will help Idaho Power test online retail platforms.

Marketing and education tactics in 2015 will focus on helping customers purchase the right bulb for their need. CLEAResult will continue to manage marketing at retailers, including point-of-purchase signs, special product placement, and displays.

# Energy House Calls

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 297 | 411 |
| Energy Savings (kWh) | 579,126 | 837,261 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $186,732 | $164,173 |
| Oregon Energy Efficiency Rider | $8,174 | $35,822 |
| Idaho Power Funds | $3,080 | $0 |
| Total Program Costs—All Sources | $197,987 | $199,995 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.024 | $0.017 |
| Total Resource Levelized Cost ($/kWh) | $0.024 | $0.017 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 2.16 | |
| Total Resource Benefit/Cost Ratio | 2.16 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2002 | |

## *Description*

The Energy House Calls program gives homeowners of electrically-heated manufactured homes an opportunity to reduce electricity use by improving the home's efficiency. Specifically, this program provides free duct-sealing and additional efficiency measures to Idaho Power customers living in Idaho or Oregon in a manufactured or mobile home using an electric furnace or heat pump. Participation is limited to one time per premise.

Services and products offered through the Energy House Calls program include duct testing and sealing according to Performance Tested Comfort System (PTCS) standards set by the RTF and adopted by the BPA; installation of a CFL bulb; two replacement furnace filters with installation instructions; testing water heater temperatures for the proper setting; and energy efficiency educational materials appropriate for manufactured-home occupants. The value of the service to the customer is dependent on the complexity of the repair. Although participation in the program is free, a typical cost for a similar service call would be $400 to $600. Idaho Power provides the customer with the contractor contact information via the Idaho Power website and marketing material. The customer then schedules an appointment directly with one of the recognized, certified sub-contractors specifically trained to provide these services in their region. The contractor verifies the customer's eligibility by initially testing the home to determine if it qualifies for duct-sealing. The actual energy savings and benefits realized by each customer depend on the measures installed and the repairs and/or adjustments made.

## 2014 Program and Marketing Activities

Energy House Calls serviced 297 manufactured homes during 2014, resulting in 579,126 kWh savings. An additional 33 homes were serviced with a test only. Of the homes served, 44 percent were located in the Treasure Valley and 56 percent were outside the Treasure Valley, with 34 percent east of Ada County and 22 percent west of Canyon County. Idaho Power marketed the program, coordinated sub-contractors' performance of local duct-sealing and energy efficiency services for this program, processed sub-contractor paperwork, and paid sub-contractors directly for work performed.

Participation declined in 2014 relative to 2013, with 297 and 411 homes completed, respectively. During the 11 years the program has been active, 10,779 homes have been serviced. Although it is difficult to pinpoint market saturation, there is a concern the program may be in its declining years. Concern over declining numbers prompted specific action in 2014, including an increase of marketing activities planned for the upcoming year and a review of new measures that may provide an increase in savings and encourage reluctant customers.

A variety of marketing tactics were employed to cultivate and capture the interest of a declining target audience. In the first quarter of 2014, 1,225 flyers were sent to churches, senior centers, and mobile home parks to enlist their aid in recruiting participants through their networks.

In spring 2014, Idaho Power tested advertising on Facebook based on results from a Foremost Insurance study that reported 79 percent of residents living in manufactured homes use Facebook and 42 percent visit social media multiple times per day. The results were positive, with 146,663 impressions and 515 click-throughs to the program landing page. The CTR was 0.029 compared to a good industry average of 0.02 to 0.024. Due to the CTR, the ads were rescheduled for November 1 through December 31.

In August, the non-participant survey was distributed to 4,000 potential participants with marketing and contact information in the packet. Contractors reported an uptick in scheduled appointments shortly after the survey was fielded. Collateral was redesigned to emphasize that program participation is free—a concern brought forward by respondents of the non-participant survey.

A September bill insert was sent to all residential customers in Idaho and Oregon. In November, 10,592 postcards were sent directly to all residents of electrically-heated manufactured homes that have not yet participated in the program. Postcards were delivered in either English or Spanish, as appropriate.

As in the past, door hangers continued to be delivered by the contractors to homes in areas where they were completing Energy House Calls visits. Idaho Power delivered postcards from the marketing campaign to Community Action Partnership (CAP) agencies for distribution to customers who need assistance but do not meet the qualifications to receive weatherization assistance through those agencies. In addition, Idaho Power CRs and customer service representatives (CSR) knowledgeable about the program continued to offer the program to qualified customers.

Although Idaho Power considered Spanish radio opportunities in Canyon County, the company decided to focus efforts on establishing monthly television segments to reach a larger audience. Television interviews began in October and are scheduled to continue into 2015. All direct-mail postcards and the participant and non-participant surveys were available in Spanish and delivered directly to homes identified in Idaho Power's database as Spanish-speaking customers.

## Cost-Effectiveness

In 2014, Idaho Power used the same RTF-deemed savings for manufactured-home PTCS duct-sealing as was used in 2013. However, the average savings per home are slightly reduced in 2014 from 2013 due to the size and location of the manufactured homes serviced. Savings are greater in colder heating zones and for double and triple-wide homes than they are for single-wide homes. For more detailed information about the cost-effectiveness savings and assumptions, see *Supplement 1: Cost-Effectiveness*.

Comments received in Case No. IPC-E-14-04 suggested Idaho Power should increase its incentive for this program due to the continued strength of its TRC ratio. Although the incentive for a free program cannot be increased, Idaho Power looked into incorporating additional measures to enhance the value for future program participants. The inclusion of these additional measures will be implemented in 2015.

## Customer Satisfaction and Evaluations

To monitor QA in 2014, third-party verifications were conducted by Momentum, LLC on approximately 6 percent of the 297 participant homes, resulting in 18 home inspections. Homes were selected at random. The QA reports indicate customers were pleased with the work sub-contractors completed in their homes. Each home inspection included an on-site visual confirmation that the reported work had been completed. Weather permitting, blower door and duct blaster tests were also conducted to verify the results submitted by the sub-contractor.

In August, a program satisfaction survey was mailed to 367 customers that had participated in the program from July 2013 through July 2014. The survey and letter were printed in both English and Spanish. The letters included a link giving the participants an option to complete the survey online. One hundred forty-three participants provided feedback, resulting in a response rate of nearly 39 percent. Key findings included the following:

- Nearly 93 percent of the respondents indicated they were either “very satisfied” or “somewhat satisfied” with their overall program experience, and nearly 88 percent were “very likely” to recommend the program to friends or family.
- When asked to select their reasons for participating in the program, just over 92 percent of respondents indicated that reducing energy costs was a motivating factor.
- Nearly 86 percent of respondents indicated it was “very easy” to participate in the program.
- Following their Energy House Calls participation, just over 57 percent of respondents had noticed a change in comfort in their home. Of those that noticed a change, nearly 98 percent reported that the comfort in their home was either “much better” or “somewhat better” following their participation in the program.
- Finally, respondents “strongly agreed” nearly 75 to 82 percent of the time that the service specialists that completed work on their home were punctual, courteous, professional, and thorough.

In August, a non-participant survey was mailed to 4,000 customers that had not participated in the Energy House Calls program. The survey and letter were printed in both English and Spanish, and the letter included a link giving customers an option to complete the survey online. The non-participant

survey had a response rate of nearly 14 percent, with 542 customers completing the survey. Key findings identified included the following:

- Just over 82 percent of respondents lived in homes built prior to 1999, 66 percent lived on private land, and just over 87 percent owned their homes.
- Approximately 12 percent of respondents indicated they had primary heating systems other than central furnaces with ducts or heat pumps. These customers are ineligible for the program.
- Nearly 84 percent of respondents indicated that based on what they knew of the program, they were "very likely" or "somewhat likely" to participate in the program.
- Nearly 82 percent of respondents indicated lowering energy costs would be a "very motivating" factor for participation. Over 77 percent indicated no/low cost to participate would also be a "very motivating" factor for participation.
- When customers were asked to identify their preferences for how Idaho Power should communicate with them about programs and issues impacting their bills, about 48 percent of respondents said they preferred "promotional material in their Idaho Power bill" and nearly 61 percent indicated a preference for a letter or postcard in the mail.
- Over 63 percent of respondents were unaware of the program prior to receiving the survey.
- For those that were aware of the program, they were asked to select all of the reasons for not participating in the program. Over 26 percent indicated they didn't know the program was free, nearly 25 percent did not fully understand the program, and almost 12 percent did not see the benefits of participating.

## 2015 Program and Marketing Strategies

During the 11 years Energy House Calls has been in operation, 10,779 electrically-heated manufactured homes have been serviced through the program. Each year, Idaho Power prepares its direct-mail marketing list by analyzing kWh use of homes designated as manufactured or mobile in Idaho Power's customer information system to find those that appear to be electrically heated. After removing those homes that had already participated in the program, the 2014 direct-mail list contained 10,808 customers, indicating that approximately 50 percent of eligible homes had already been served by the program. An additional percentage of these homes may have had their ducts sealed through Idaho Power's low-income programs, as a few respondents from the non-participant survey indicated they had already participated in a duct-sealing program. Idaho Power will continue to monitor these numbers, but as response rates continue to decline across the service area, there is concern the market may be reaching saturation.

In 2015, more products and services will be offered to program participants during each scheduled visit. Specifically, contractors will install LEDs in main living areas. When water is heated with electricity, contractors will be able to wrap the inlet/discharge pipes from the water heater tank and install high-efficiency showerheads and faucet aerators.

Marketing tactics will continue to include potential participants' most-preferred methods for receiving information—promotional materials in the Idaho Power bill or a letter/postcard in the mail. However, to boost participation in a market that is moving toward saturation, marketing efforts will

double and emphasis will be placed on the variety of services offered. Two bill inserts will advertise program benefit and expected savings, and free participation will be highlighted. A targeted mail campaign direct to residents of manufactured homes that have not yet participated in the program will be conducted in spring and fall. Contractors and CRs will continue to distribute door hangers in mobile home parks and will take every opportunity to distribute program literature at appropriate events and presentations. Additionally, flyers and posters will be mailed to organizations with constituents that may benefit from the program.

Throughout the year, the program will explore new ways to reach customers and continue to look for additional cost-effective measures that can add value to the program.

# ENERGY STAR® Homes Northwest

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 243 | 267 |
| Energy Savings (kWh) | 528,054* | 365,370 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $330,523 | $344,217 |
| Oregon Energy Efficiency Rider | $7,612 | $4,664 |
| Idaho Power Funds | $5,141 | $4,000 |
| Total Program Costs—All Sources | $343,277 | $352,882 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.055 | $0.053 |
| Total Resource Levelized Cost ($/kWh) | $0.111 | $0.104 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.64 | |
| Total Resource Benefit/Cost Ratio | 0.83 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

* Includes savings from 282 certified gas-heated ENERGY STAR homes in 2014.

## *Description*

ENERGY STAR® Homes Northwest is a regionally coordinated initiative supported by a partnership between Idaho Power and NEEA's Northwest ENERGY STAR Homes to improve and promote the construction of energy-efficient homes using guidelines set forth by the EPA. This program targets the lost-opportunity energy savings and summer-demand reduction that results by increasing the efficiency of the residential-building envelope and air-delivery system above current building codes and building practices. An ENERGY STAR certified home is a home that has been inspected and tested by an independent, third-party ENERGY STAR rater/home performance specialist (HPS) to meet the stringent ENERGY STAR requirements. This third-party rater is hired by the builder to perform these duties.

The ENERGY STAR Homes Northwest residential construction program promotes homes that use electric heat pump technology and are at least 15 percent more energy efficient than those built to standard Idaho and Oregon code. The program specifications for ENERGY STAR Homes Northwest are verified by the HPS and are certified by the Washington State University Extension Energy Program and Building Energy, Inc., organizations that conduct the certification inspections throughout Idaho and Oregon for the EPA. ENERGY STAR homes are more efficient, comfortable, and durable than homes constructed to standard Idaho building codes.

Homes that earn the ENERGY STAR label include six required specifications: 1) effective insulation, 2) high-performance windows, 3) air-tight construction and sealed ductwork, 4) energy-efficient lighting, 5) ENERGY STAR qualified appliances, and 6) efficient heating and cooling equipment.

To encourage builders to construct ENERGY STAR homes, builders participating in ENERGY STAR Homes Northwest in 2014 received a $1,000 incentive per home built to the Northwest ENERGY STAR Single and Multi-Family Homes Requirements with heat pump technology. Builders who entered their homes in a Parade of Homes received the standard $1,000 incentive plus an additional $500 marketing incentive to cover their expenses for ENERGY STAR signage and brochures. Another benefit to the builders is the right from ENERGY STAR Homes Northwest to use the logo and the ENERGY STAR name to promote themselves as an ENERGY STAR qualified builder.

The Idaho Power program collaborates with many local entities for program promotion, including ENERGY STAR Homes Northwest and builders. A large part of the program's role in 2014 was to provide marketing materials and support for the building contractors associations (BCA) throughout the Idaho Power service area.

## 2014 Program and Marketing Activities

A majority of the homes certified in 2014 were townhomes. This trend toward ENERGY STAR townhome certifications is a regional trend. In 2014, 5 of the 240 ENERGY STAR home certifications in Idaho were single-family homes. The decrease in the number of participating homes in 2014 as compared to 2013 is due to fewer ENERGY STAR Homes, employing heat pump technology, being certified in Idaho Power's service area. The trend the past couple of years has been toward an increase in multi-family construction Idaho Power's service area. In 2013, seven multi-family ENERGY STAR developments were constructed. In 2014, five multi-family ENERGY STAR developments were constructed, resulting in 61 fewer homes being certified in 2014.

The company maintained a strong presence in the building industry by supporting the Idaho Building Contractors Association (IBCA) and several of its local affiliates throughout Idaho Power's service area in 2014. The company presented the Energy Efficient Design and Construction Awards to builders who integrated energy efficiency features in their parade homes at the BCASWI Parade of Homes awards banquet. In addition, the company participated in the BCASWI builder's expo, and the Snake River Valley Building Contractors Association (SRVBCA) builder's expo. The company also supported Parade of Homes events with full-page ENERGY STAR ads in the Parade of Homes magazines of the following BCAs: The Magic Valley Builders Association Parade of Homes (MVBA), the BCASWI Parade of Homes, SRVBCA Parade of Homes, and the Building Contractors Association of Southeast Idaho (BCASEI) Parade of Homes. Bill messages were added to residential customer's billing statements informing them of Parade of Homes events in their area. In addition, the company sponsored the IBCA annual winter and summer meetings. A half-page ad was placed in the BCASWI monthly November and December newsletters to promote the program and the builder incentive.

In fall 2014, a bill insert was sent to all residential customers in the Idaho Power service area promoting the ENERGY STAR Homes Northwest program. The company ran print ads for four weeks in real estate sections of daily newspapers in Boise; Pocatello; Canyon County; and Ontario, Oregon. During this same timeframe, a digital behavioral ad campaign ran for two months across Idaho Power's service area, totaling 2,683,717 impressions/ads served and including such real estate sites as zillow.com. A letter to residential builders was mailed in spring 2014 reminding builders of the benefits of building ENERGY STAR homes and of the available builder incentive.

Idaho Power administered a process evaluation of the ENERGY STAR Homes Northwest program in 2013. This evaluation was performed by third-party contractor TRC Energy Services. In general, TRC Energy Services found the ENERGY STAR Homes Northwest program was successfully meeting goals and delivering energy savings. TRC Energy Services noted this was particularly impressive given

the challenges of the recent market downturn and the exclusion of customers with natural gas heat from the program. Based on the results of this evaluation, TRC Energy Services provided several recommendations for program improvement. The recommendations and Idaho Power's responses are described below.

TRC Energy Services recommended continued support from the company for the multi-family and townhome market, identification of other markets that could be building electrically heated homes, and targeting marketing efforts toward these sectors. In 2014, the company continued to support the multi-family ENERGY STAR homes market through certification of 235 multi-family homes and through its continued support of local BCAs.

The evaluators recommended Idaho Power develop an argument for the value of the ENERGY STAR label and verification and provide this (through talking points or a one-page flyer) to CRs, HPSs, and builders and to work with other entities to develop these talking points. Idaho Power determined the marketing materials, and the talking points developed by Idaho Power and Northwest ENERGY STAR Homes, currently available to CRs, HPSs, and builders appropriately addressed the argument for the value of the ENERGY STAR homes certification.

TRC Energy Services recommended Idaho Power provide continued support for the HPSs, meet with them one-on-one to understand their barriers to participation, and work with them to overcome these barriers. In particular, revisit the QA procedure for the program. In 2014, Idaho Power continued to maintain good relationships with the active HPSs and communicated multiple times throughout the year through email, phone calls, and face-to face visits. NEEA manages the QA function of the Northwest ENERGY STAR Homes program. While Idaho Power uses the QA results for its program compliance within the company's service area, the procedures used are dictated by NEEA. The company will encourage NEEA to communicate with the raters concerning QA procedural issues.

The evaluators recommended Idaho Power update the contractor list so it contains only builders that provide accurate information about the program, and to periodically update this list (e.g., biannually) by reaching out to contractors. In response to this recommendation, the builder list on the company ENERGY STAR Homes Northwest website is now a link to the Northwest ENERGY STAR Homes builder listing, which is current and updated frequently.

Another recommendation was to test the hypothesis reported by Idaho Power staff that multi-family builders are the primary group building homes with heat pumps by analyzing the residential nonparticipant survey results and through interviews with BCA staff. Idaho Power concluded multi-family homes with heat pumps versus single-family homes with heat pumps being submitted for ENERGY STAR Homes certification via the Northwest ENERGY STAR Homes database strongly indicated a current regional trend that multi-family builders are the primary group building heat pump homes.

The evaluators recommended using the regional program database to identify builders that are building electrically heated homes in Idaho Power's service area but do not qualify for the Idaho Power program. Idaho Power ascertained that all homes built using heat pump technology and meeting all Northwest ENERGY STAR Homes criteria currently qualify for the Idaho Power program.

TRC Energy Services recommended Idaho Power develop new relationships between the CRs, program specialist staff, key homebuilders, heat pump contractors, and heat pump suppliers and to reconnect with previously participating builders. In 2014, the program specialist and the CRs continued to establish and maintain new and existing relationships primarily through BCA builder events and industry-related meetings. The primary relationship within the ENERGY STAR Homes Northwest

program and company staff was with builders. CRs also formed relationships with heat pump contractors through the Idaho Power heating and cooling program. The company sent out a letter to all current and past ENERGY STAR Homes Northwest builder participants in April 2014 to update them on the program and the incentives offered.

Another recommendation was to provide additional builder training addressing the benefits of heat pump technology, electric heat pump home design, and design strategies to reduce electricity use in homes. While there was no on-site, heat pump specific training done in Idaho Power's service area in 2014, Northwest ENERGY STAR offered a DHP webinar in November 2014. All Northwest ENERGY STAR builder and HVAC contractor partners were encouraged to attend this event.

Last, the evaluators recommended Idaho Power provide CRs with goals for marketing the program, such as contacting a certain number of builders or presenting at a BCA meeting about the program; have CRs use the heat-pump flyer as a talking point with builders; and have CRs attend program trainings or heat-pump presentations with builders to learn about the program and develop relationships with local builders. Of note, Idaho Power CRs don't have specific goals that require them to contact a certain number of builders, but they are asked to be involved in their local BCA chapter where the opportunity to meet and establish relationships with builders is high. The CRs have been and continue to be active in the local BCA chapters where they come into direct contact with a majority of builders in their area. When program trainings are held, CRs are invited and encouraged by Idaho Power to attend.

## Cost-Effectiveness

Idaho Power used the same cost-effectiveness savings assumptions from the RTF for ENERGY STAR Homes Northwest for 2014 as were used in 2013. While savings assumptions remained the same for 2014, the RTF-calculated NEBs were added to the cost-effectiveness calculations to account for water and avoided maintenance savings over the lives of these efficient homes. The inclusion of NEBs helped improve cost-effectiveness for the different building packages and climate combinations from a TRC perspective, but the townhome/multi-family homes in the Bose–Nampa–Caldwell climate zone, which is the primary home submitted since 2012, is still not cost-effective from a TRC perspective.

Idaho Power has participated in ENERGY STAR Homes Northwest, a regionally coordinated initiative, supported by a partnership between Idaho Power and NEEA, since 2004. The company has been a continued proponent and driver of the increased awareness of the ENERGY STAR Homes Northwest brand. The majority of electrically heated ENERGY STAR Homes Northwest certifications are from several large multi-family builders exclusively building homes to ENERGY STAR specifications employing electric heat pump technology.

Because of Idaho Power's support of NEEA and the ENERGY STAR Homes Northwest brand, Idaho Power is claiming savings for 282 natural gas-heated, ENERGY STAR certified homes certified in Idaho Power's Idaho service area in 2014. These savings account for 195,372 kWh of annual savings from efficient cooling equipment, insulation, windows, doors, water heating, ventilation, appliances, and lighting. NEEA does not claim these savings, and they will be included in the program savings totals in appendices 3 and 4.

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

## Customer Satisfaction and Evaluations

The HPS works with builders to ensure the ENERGY STAR homes are compliant with the Northwest ENERGY STAR Homes specification. Along with verifying the installation of building components and

equipment through on-site inspections, prior to being certified, the HPS ensures the home passes a blower door test, an air-duct leakage test, and combustion back-draft tests.

The state-certifying organizations (SCO) perform QA inspections. The Washington State University Energy Extension Program is under contract with NEEA to perform QA and technical assistance duties within Idaho. For QA purposes, 5 percent of homes certified in the ENERGY STAR Homes Northwest program are reviewed by the Washington State University Energy Extension Program. This is a technical verification of the homes. All of the homes randomly chosen for QA in Idaho Power's service area passed the QA inspection process in 2014.

In 2014, the Customer Research and Analysis team administered an impact evaluation using Tetra Tech to provide third-party analysis. The findings from this evaluation found that the ENERGY STAR Homes Northwest program has well-established program design and delivery processes that are supported by the program tracking systems, program documentation, and savings tools. The impact evaluation approach emphasized compliance with the RTF energy savings as the basis for verification of savings.

Results of the impact evaluation indicated that 2013 ex-post verified savings were 353,828 kWh compared to 365,370 kWh ex-ante claimed savings, resulting in a gross realization rate of 96.8 percent. The driver of the difference in the overall kWh realization rate was adjustments made to seven townhomes removed from the program savings.

Tetra Tech also identified several recommendations for the ENERGY STAR Homes Northwest program as a result of the impact evaluation. The evaluator recommended continuing to use the program tracking system for savings assignments and noted that in 2014, Idaho Power made recent improvements to their energy efficiency programs database to assist in automating savings assignments and prevent the need to develop savings assignments outside the database. Tetra Tech also noted that improving the database usability and allowing for the automation of look-up functions to occur within the database will also assist in reducing potential error, enhance the quality review process, and help facilitate reviews. This will also ensure other parameters are entered correctly by allowing for data checks across fields. The evaluator stated that an additional result would be avoiding misalignment between participating homes and the assigned savings values. In response, in 2014 Idaho Power enhanced database functionality and will continue to automate database tracking systems as needed.

Tetra Tech recommended the continued use of RTF categories and continued use of the RTF proven measure savings, but recommended Idaho Power develop savings assignments and calculations with a clear alignment with the RTF savings values for single-family and multi-family homes. Tetra Tech stated that a unified participant tracking and savings workbook could contain such information and provide an efficient and standardized approach that can address potential future program regional complexity. Idaho Power uses the RTF proven measure savings, and the independent values for single-family and multi-family savings are assigned in the DSM Customer Load and Resource Information System (CLRIS) application based on housing type.

Another recommendation was to investigate methods for obtaining project-level documentation. Tetra Tech stated the program and a future evaluation effort may benefit by having greater access to project-level details covering project eligibility and greater technical details. For the benefit of the program and evaluators, Tetra Tech recommended Idaho Power work with NEEA and their contractors to improve the level of detail captured for each project and made available to Idaho Power for the Builder Option Package inspection results for each home. In response, Idaho Power considered this recommendation and determined the documentation provided for each certified ENERGY STAR home, via the Northwest ENERGY STAR Homes database, provides the necessary detail for Idaho Power to pay incentives to builders. This documentation, the *Northwest ENERGY STAR Homes Program Report*,

denotes that all testing and inspection on the home meets or exceeds all minimum values of ENERGY STAR Home certification. This report also denotes the certified status of the home, states that each program checklist was completed successfully, and provides the performance testing results.

Last, the evaluators recommended working to increase QA inspections within the company's service area and working with NEEA and their contractors to better understand the protocols and information obtained and documented during QA inspections in Idaho Power's service area. This recommendation is to ensure appropriate home parameters are captured for the current and future needs of Idaho Power evaluations and that a minimum number of Idaho Power ENERGY STAR certified homes are QA inspected each year. The evaluator recommended that, absent the ability of Idaho Power to ensure a minimum level of service for QA, Idaho Power should consider conducting and documenting its own QA process using the same protocols as the NEEA initiative. In response to the recommendation, in 2014 Idaho Power began discussions with NEEA to ensure a representative number of QA inspections of heat pump homes in Idaho Power's service area that qualify for the Idaho Power incentive. A copy of the complete report is included in *Supplement 2: Evaluation*.

## 2015 Program and Marketing Strategies

Builders involved in ENERGY STAR Homes Northwest during 2015 in Idaho Power's service area will receive a $1,000 incentive per home built to the Northwest ENERGY STAR Homes specifications using heat pump technology standards. Builders showcasing their electric heat pump home in a BCA Parade of Homes event will receive the standard $1,000 incentive plus an additional $500 parade marketing incentive.

Idaho Power plans to continue marketing efforts to help promote ENERGY STAR homes to home builders and new homebuyers. These marketing efforts include Parade of Homes ads in parade magazines for the BCASWI, SRVBCA, MVBA, and the BCASEI. The company also plans to continue supporting the general events and activities of the IBCA and its local affiliates. Marketing materials will be available for use by builders. Bill inserts will be sent to all residential customers in May. Bill messaging is planned in June, July, and August to support the various BCA Parade of Homes events throughout Idaho Power's service area.

A direct-mail letter to builders is planned for 2015. This direct-mail piece will highlight the requirements and the Idaho Power builder incentive for building to Northwest ENERGY STAR Homes specifications. In addition, the program will be promoted in the *Idaho Business Review* in issues targeting residential contractors and builders.

NEEA is planning a 2015 transition of the Northwest ENERGY STAR Homes program to the national EPA ENERGY STAR Homes program and to local market partners/stakeholders. NEEA will continue to provide program and technical oversight of ENERGY STAR Home Northwest through 2015 with plans to then transfer oversight to the national program. The program will be available for builders if they so choose to continue building ENERGY STAR certified homes under the national program.

A second program, NEEA's Next Step Home program, is still in the pilot stage. At the end of 2014, NEEA began developing the Phase III recruitment plan to continue building participation and awareness in the Next Step Home pilot. Homes built during Phase III will incorporate Next Step Home minimum requirements, guidelines, and best practices learned from Phase I and II. Despite NEEA recruiting efforts, there are no builders who have, as of yet, signed on to build a Next Step Home in Idaho Power's service area.

# Heating & Cooling Efficiency Program

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 230 | 210 |
| Energy Savings (kWh) | 1,099,464 | 1,003,730 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $340,551 | $317,973 |
| Oregon Energy Efficiency Rider | $14,627 | $11,700 |
| Idaho Power Funds | $6,836 | $0 |
| Total Program Costs—All Sources | $362,014 | $329,674 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.022 | $0.022 |
| Total Resource Levelized Cost ($/kWh) | $0.075 | $0.050 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 3.74 | |
| Total Resource Benefit/Cost Ratio | 1.09 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2007 | |

## *Description*

The H&CE Program provides incentives to residential customers for the purchase and proper installation of qualified heating and cooling equipment.

The objective of the program is to acquire energy savings by providing customers with energy-efficient alternatives for electric space heating. Incentive payments are provided to both residential customers and HVAC participating contractors who install eligible equipment. The eligible measures in 2014 include air-source heat pumps, open-loop water-source heat pumps, and evaporative coolers.

Heating and A/C companies authorized by Idaho Power as participating contractors for the program are required to perform all installations, with the exception of evaporative coolers, which can be self-installed.

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

- Customer incentive for replacing an existing air-source heat pump with a new air-source heat pump is $250 for a minimum efficiency 8.5 heating seasonal performance factor (HSPF).
- Customer incentives for replacing an existing electric, oil, or propane heating system with a new air-source heat pump is $400 for a minimum efficiency 8.5 HSPF. Participating homes with oil or propane heating systems must be located in areas where natural gas is unavailable.

- Incentive for customers or builders of new construction installing an air-source heat pump in a new home is $400 for a minimum efficiency 8.5 HSPF.

- Customer incentive for replacing an existing air-source heat pump with a new open-loop water-source heat pump is $500 for a minimum efficiency 3.5 coefficient of performance (COP).

- The customer incentive for replacing an existing electric, oil, or propane heating system with a new open-loop water-source heat pump is $1,000 for a minimum efficiency 3.5 COP. Participating homes with oil or propane heating systems must be located in areas where natural gas is unavailable.

- The incentive for customers with new construction installing an open-loop water-source heat pump in a new home is $1,000 for a minimum efficiency 3.5 COP.

- The evaporative-cooler customer incentive is $150.

## 2014 Program and Marketing Activities

The expansion of Idaho Power's network of participating contractors remained a key growth strategy for the program. Idaho Power's goal was to support contractors currently in the program while adding new contractors. The company held meetings with several prospective contractors to support this strategy. Idaho Power added eight companies to the list of participating contractors in 2014.

Idaho Power held nine training sessions for contractors in 2014. For a company to be eligible to join the program as a participating contractor, they must have participated in this required training that provides general instructions on heat pumps and program guidelines. These training sessions remain an important part of the program because they create opportunities to invite additional contractors into the program.

To increase contractor participation in the program, stronger relationships with the equipment wholesalers was necessary. In Idaho Power's service area, there are numerous wholesalers supplying heat pumps to the contractors. Idaho Power met with several of these wholesalers in Idaho Power's service area to share helpful information and to encourage them to promote the program to their contracting customers.

Idaho Power uses Honeywell, Inc., a third-party contractor, to review the incentive applications and perform OSVs. This contractor provides direct support to participating contractors and the residential program participants. Honeywell offers local assistance through representative visits to contractors at their businesses as needed. Using a program database via a portal developed by Idaho Power, Honeywell reviews and submits incentive applications for Idaho Power payment. This allows Idaho Power to maintain the database within the company's system, which is secure yet accessible to the third-party contractor.

Multiple marketing tactics were used for Idaho Power's HC&E Program. Approximately 3,000 radio ads ran on over 20 radio stations for six weeks throughout Idaho Power's service area. In spring 2014, a digital behavioral ad campaign was launched and resulted in 771,211 ads displayed on pages viewed by people browsing the internet over two months.

A contractor portal was launched in 2014. The portal allowed authorized contractors access to a specific area of Idaho Power's website where they could customize pre-approved marketing pieces with their own business name, address, and phone number. Two door hangers were offered for insulation

contractors, two door hangers for window contractors, and two fliers for participating contractors in the HC&E Program. The *Demand-Side Management 2013 Annual Report* stated the contractors would be asked to comment on the portal during 2014. Comments were not pursued due to the portal launching the third quarter of the year, which limited contractors' time to try the portal in 2014.

The *Demand-Side Management 2013 Annual Report* mentioned possible changes to the HC&E webpages. Changes to the HC&E webpages were not made in 2014 because on a separate project, the company began working on a website redesign to improve navigation on the Energy Efficiency website. The decision was made to wait until that work was completed before any changes were made to HC&E webpages. The website navigation changes did not result in any changes being made to the Energy Efficiency website during 2014.

A direct-mail campaign was conducted in April 2014. Over 27,000 letters were sent to homeowners of electrically heated homes. In addition, information about the heat pump program was included in a postcard sent to people who purchased a home within the previous six months. Bill inserts and newspaper ads rounded out the ongoing marketing and promotion of the HC&E Program.

Idaho Power administered a process evaluation of the H&CE Program in 2013, performed by third-party contractor TRC Energy Services. Based on the evaluation results received in 2014, TRC Energy Services identified program trends, successes, and barriers, then developed recommendations to address the barriers.

It was recommended Idaho Power gain a better understanding of the eligible market, such as customers with electric, oil, or propane heat and their barriers for program participation, to better target marketing efforts. In response to this recommendation, Idaho Power participated in seven local trade shows and benefited from one-on-one discussions with residential homeowner attendees.

The evaluators recommended Idaho Power provide contractors with co-branded marketing materials, case studies, or cost calculation examples to assist them with their marketing efforts. A new online contractor portal was already in development and was launched on the Idaho Power website late summer 2014. This password-protected portal provided participating contractors with pre-designed colored marketing fliers printable by the contractor for distribution. Fliers could be personalized with the contractor's business name, address, logo, and phone number.

TRC Energy Services recommended Idaho Power consider requiring contractors to attend refresher training and/or deliver a minimum number of projects per year to continue to be listed on the program website. In 2014, the H&CE Program incorporated this recommendation by providing nine refresher training sessions and requiring each participating contractor to submit a minimum of one application per year beginning in 2015 to avoid being placed on inactive status.

Another recommendation was that program requirements be described clearly and prominently in marketing collateral and on the website. In response to this recommendation, all marketing collateral and web content were reviewed. Improvements were made to ensure the reader realized incentive requirements apply.

It was recommended that Idaho Power CRs be engaged in the contractor training sessions routinely provided by Idaho Power. Idaho Power invited the CRs to sessions in 2014, and several CRs attended the sessions.

TRC Energy Services recommended Idaho Power annually contact the participating contractors to ensure there is at least one installing technician trained by the program. This recommendation was made due to employee turnover experienced with some participating contractors. Idaho Power provided training where there was a lack of a trained technician.

The evaluators recommended surveys be initiated to gather various types of program feedback from participating contractors. This has not been implemented because Idaho Power decided face-to-face meetings between participating contractors, the CRs, and the program specialist gathered program feedback promptly and effectively.

It was recommended a cash-based incentive be offered to participating contractors in an attempt to drive additional and more specific types of participation. Idaho Power has not implemented this recommendation because research data was unavailable in the Idaho Power service area that identifies what the common reason is for variability in contractor participation and what the key motivation tactics should be. Going forward, Idaho Power will investigate if a contractor incentive is needed to increase participation in its programs.

## Cost-Effectiveness

Idaho Power used the same cost-effectiveness unit energy saving (UES) assumptions for the H&CE Program during 2014 as were used in 2013. For 2014, Idaho Power calculated participant-cost averages used for the cost-effectiveness analysis based on Idaho Power-specific project data over two years (2013–2014) to estimate typical project costs instead of relying on regional averages.

Due to the lower alternative costs from the 2013 IRP, water-source heat pumps and heat pump conversions to 8.50 HSPF became non cost-effective. However, Idaho Power determined that heat pumps meet at least one of the cost-effectiveness exceptions outlined in OPUC Order No. 94-590. Idaho Power filed UM-1710 to request a cost-effectiveness exception with the OPUC on November 4, 2014, and subsequently re-filed it on February 11, 2015. The case is still pending. For more detailed information about the cost-effectiveness savings, sources, calculations, and assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Honeywell performed random OSVs on 10 percent of the completed installations in the Idaho Power service area. These OSVs verified the information submitted on the paperwork matched what was installed at customers' sites. Overall, the OSV results were favorable with respect to the contractors' quality of work. The program specialist continues to work with contractors to help them understand the importance of accurate documentation.

## 2015 Program and Marketing Strategies

Idaho Power will sponsor and provide training to new and existing contractors in the program to assist them in meeting program requirements and further their product knowledge. Sessions will be held on-site at contractor businesses and at Idaho Power facilities.

Expanding the network of participating contractors remains a key strategy for the program because the performance of the program is substantially dependent on the contractors' abilities to promote and leverage the measures offered. Idaho Power's goal is to support contractors currently in the program while continuing to add new contractors. To meet this objective, the program specialist, along with

Idaho Power CRs, will arrange frequent individual meetings to discuss the program with contractors in 2015.

To increase participation in the program in the Idaho Power service area, the program specialist will work to strengthen relationships with equipment wholesalers. To accelerate the wholesalers' abilities to increase contractor awareness of the program, the program specialist will meet with the wholesalers and share information.

The 2015 marketing strategy will include proven tactics previously used and new methods. Since homeowners make more improvements to their home during the first two years of ownership, the company plans to continue to target new customers in the first six months of new-home ownership. Postcards will be mailed to these new customers, raising awareness of the incentives available to them. The strategy will include many marketing tactics, such as bill inserts, print ads in newspapers, and direct-mail letters. Social media, such as Facebook, will also be used.

New marketing pieces will be added to the contractor portal over time as needed. In 2015, it has not yet been determined if/when portal feedback would be formally solicited from the contractors.

# Home Energy Audit

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 354 | n/a |
| Energy Savings (kWh) | 141,077 | n/a |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $164,579 | n/a |
| Oregon Energy Efficiency Rider* | −$248 | n/a |
| Idaho Power Funds | $6,318 | n/a |
| Total Program Costs—All Sources | $170,648 | n/a |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Levelized Cost ($/kWh) | n/a | n/a |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | |
| Total Resource Benefit/Cost Ratio | n/a | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho | |
| Program Inception | 2014 | |

* Reversal of a 2013 charge to the Oregon Rider.

## *Description*

The Home Energy Audit is an in-home energy evaluation by a certified, third-party HPS. It is used to identify areas of concern and provide specific recommendations to improve the efficiency, comfort, and health of the home. An audit includes a visual inspection of the crawl space and attic, a health and safety inspection, and a blower door test to identify and locate air leaks. In addition to the energy evaluation, some energy-saving improvements are installed at no additional cost to the customer if appropriate. After the audit is complete, the customer is supplied with a written report of the HPS's findings and recommendations. Available improvements include installation of the following:

- Up to 20 CFLs
- One high-efficiency showerhead
- Pipe insulation from the water heater to the home wall (approximately 3 feet)

The current Home Energy Audit program is based on the insights gained from the Boise City Home Audit project conducted in 2011 and 2012, as described in the *Demand-Side Management 2012 Annual Report*. To qualify for the Home Energy Audit program, participants must live in Idaho and be an Idaho Power customer of record for the home. The home must be an existing all-electric, site-built home. Renters may participate with prior written landlord permission. Single-family homes, duplexes, triplexes, and fourplexes qualify. Manufactured homes, new construction, or buildings with more than four units do not qualify. Multi-family homes heated by a central heating unit or that aren't separately metered are not eligible.

Participating customers pay $99 for the audit and installation of measures, with the remaining cost covered by the Home Energy Audit program. Energy audits of this type normally cost $300 or more, not including the select energy-saving measures, materials, and labor. The cost of the materials potentially installed at each home is approximately $84.

## 2014 Program and Marketing Activities

In January 2014, the program launched in Blackfoot with an open house at the Bingham County Senior Center. The public was invited by direct-mail letters, newspaper ads, an article in the Blackfoot Chamber of Commerce newsletter, and posters located in the Bingham County Senior Center. The open house was later written up in the *Morning News* in Blackfoot. Three additional open houses were held in Homedale, Gooding, and Salmon. In addition to letters, newspaper ads, and posters, radio spots were used in Salmon, as well as a press release sent to local media.

Participants for the program were recruited through small batches of 1,000 to 2,000 direct-mail letters. Customers interested in participating were directed to a website for additional information and the online application. Those who did not have internet access or were uncomfortable using the application online were able to call Idaho Power and apply via phone.

Seven energy audit companies were selected to serve the program. Audits were randomly assigned to the HPSs serving each area, grouping locations for each HPS to save on travel time and expense.

In 2014, 354 audits were completed, surpassing the 2014 goal of completing 300 energy audits. The average age of participating homes was 36 years old. The homes were built between 1900 and 2013. Home sizes ranged from 700 square feet ($ft^2$) to 7,920 $ft^2$, with 2,463 $ft^2$ being the average home size. Figure 10 shows the number of participating homes located in various counties, demonstrating considerable program expansion from a Boise-based audit project to a program reaching the edges of the Idaho Power service area.

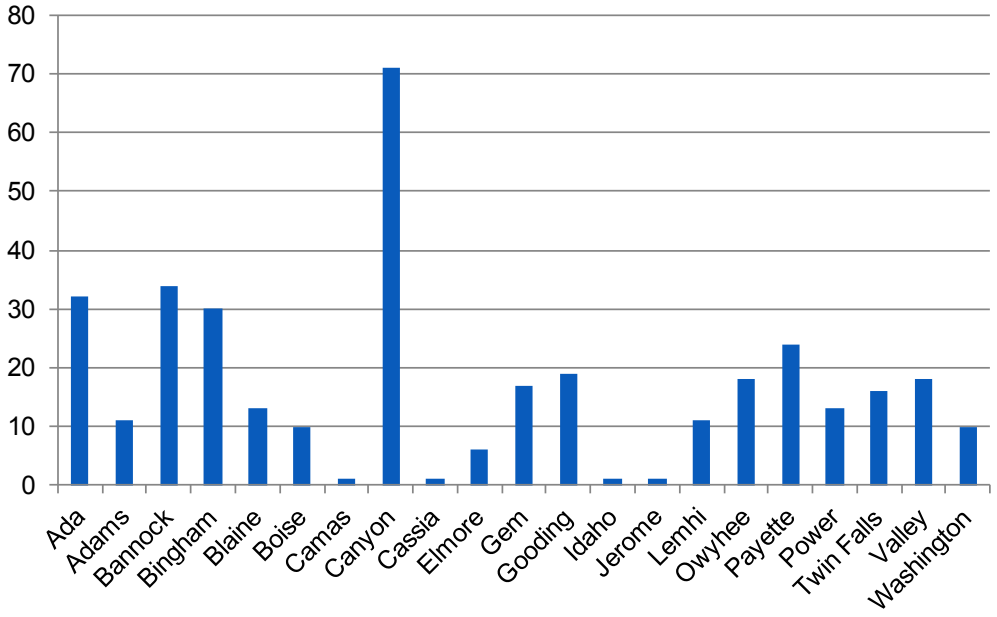



Figure 10. Summary of participating homes by county

The program was designed for all-electric homes only. All written communication sent to customers and the website included that the program was limited to all-electric homes. If the application was taken over

the phone, the customer was asked if their home had electric heat and water heating, and non-electric sources were turned down. In addition, when the HPS contacted the customer to schedule the appointment, the customer was asked if the home had electric heat and water heating. Non-electric sources were turned down. The electrically heated homes used a variety of heating styles, with heat pumps being the most common (153), then furnaces (99) and wall heaters (96). Eight of the 354 participating homes audited were not electrically heated homes, despite numerous efforts to ensure participants had all-electric homes.

Each HPS collected data on appliances and lighting in each home. The average number of incandescent lights per home was 24, and the average number of fluorescent lights was 12. When performing an audit, the HPS determined which available measures were appropriate for the home, and if the homeowner approved, those measures were installed. Figure 11 indicates the total quantity of items installed by measure.

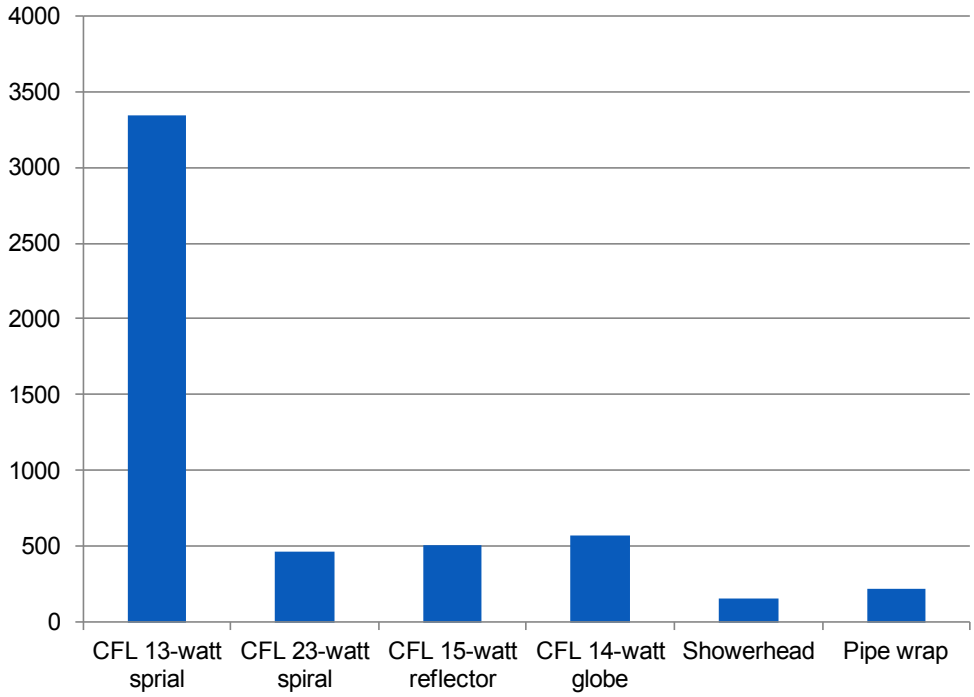



Figure 11. Measures installed in participating homes

The QA goal for the program was inspection of 10 percent of all audits, translating into approximately 35 audits in 2014. Twenty-seven QAs were completed in 2014, with all audits passing inspection. The 10 percent audit goal was unmet in 2014 because it was challenging to find participants willing to allow the auditor into their home for a 1- to 2-hour audit, especially if the participant worked outside the home.

## Cost-Effectiveness

In IPUC Order No. 32667, the commission encouraged "the Company to take other opportunities to improve customer's energy I.Q. and to educate them about the Company's energy efficiency programs." One of the goals of the Home Energy Audit program is to increase participants' understanding of how their home uses energy, and if eligible, encourage their participation in Idaho Power's energy efficiency programs. As an educational and marketing program, the traditional cost-effectiveness tests have not been applied to the program.

For the items installed directly in the homes, Idaho Power used the RTF savings for direct-install bulbs, which range 17 to 29 kWh per year. The RTF savings for 2.0 gallons-per-minute (GPM) showerheads directly installed in a home are 139 kWh per year. In Idaho Power's *Energy Efficiency Potential Study*, Applied Energy Group (AEG) estimates that pipe wraps save 150 kWh per year.

## Customer Satisfaction and Evaluations

A survey designed to assess customers' experience with program enrollment, scheduling, the auditor, the report value, and information learned was sent in July and November to a total of 225 program participants. Ninety-five participants responded to the survey, resulting in a response rate just over 42 percent. Program strengths and areas for improvement were also assessed. Participants that supplied an email address were sent the survey online. Those without an email address were sent a hardcopy of the survey with a postage-paid envelope. Results were reviewed for the program as a whole and for responses related to individual HPSs.

When asked a series of questions about their experience with the program, just under 94 percent of respondents "strongly agreed" or "somewhat agreed" they would recommend the program to a friend or relative, and just under 94 percent of respondents "strongly agreed" or "somewhat agreed" they were satisfied with their overall experience with the program.

Almost 97 percent of the respondents indicated it was "very easy" or "somewhat easy" to apply for the program. Individual program audit report results were available online, and a hard copy of the report was mailed to participants who did not supply an email address. Of the 95 survey respondents, 55 customers rated the difficulty of accessing the report online. Of those 55 customers, just under 77 percent of customers indicated that accessing the report online was "very easy" or "somewhat easy."

HPSs were rated on a number of attributes, including courteousness, professionalism, explanation of work/measurement to be performed, explanation of audit recommendations, and overall experience with the HPS. Respondents rated their HPSs as "good" or "excellent" 96 to 100 percent of the time.

When asked how strongly they agree or disagree with statements around what they learned during the audit process, just over 95 percent of respondents "strongly agreed" or "somewhat agreed" they were more informed about the energy use in their home. Almost 88 percent indicated they "strongly agreed" or "somewhat agreed" they were more informed about energy efficiency programs available through Idaho Power. Just under 87 percent indicated they "strongly agreed" or "somewhat agreed" they learned what no- to low-cost actions they could take.

After the audit, just over 51 percent of respondents indicated they visited the Idaho Power website, approximately 61 percent unplugged appliances when not in use, 42 percent signed up for myAccount, and almost 75 percent shared their experience with relatives and/or friends. Sixty-five percent of the respondents indicated they replaced additional incandescent light bulbs with CFLs or LEDs. Nearly forty-one percent indicated they serviced their heating equipment, and 38 percent serviced cooling equipment. Additional information on the actions that respondents indicated they already completed or planned to do within the next year are shown in the survey results included in *Supplement 2: Evaluation*.

Survey participants were asked to identify all of the benefits they experienced from participating in the program. Almost seventy-six percent of respondents indicated the biggest benefit they found in the audit was personal satisfaction, with nearly 71 percent citing raised awareness of energy use, just over 58 percent citing cost savings, 57 percent citing home improvement, approximately 42 percent citing

comfort, and just over 39 percent citing benefit to the environment. When survey participants were asked to identify all of the barriers they encounter when making energy-saving changes in their home, nearly 74 percent of respondents indicated the biggest barrier was cost. Figure 12 below shows benefits experienced by category and percent.

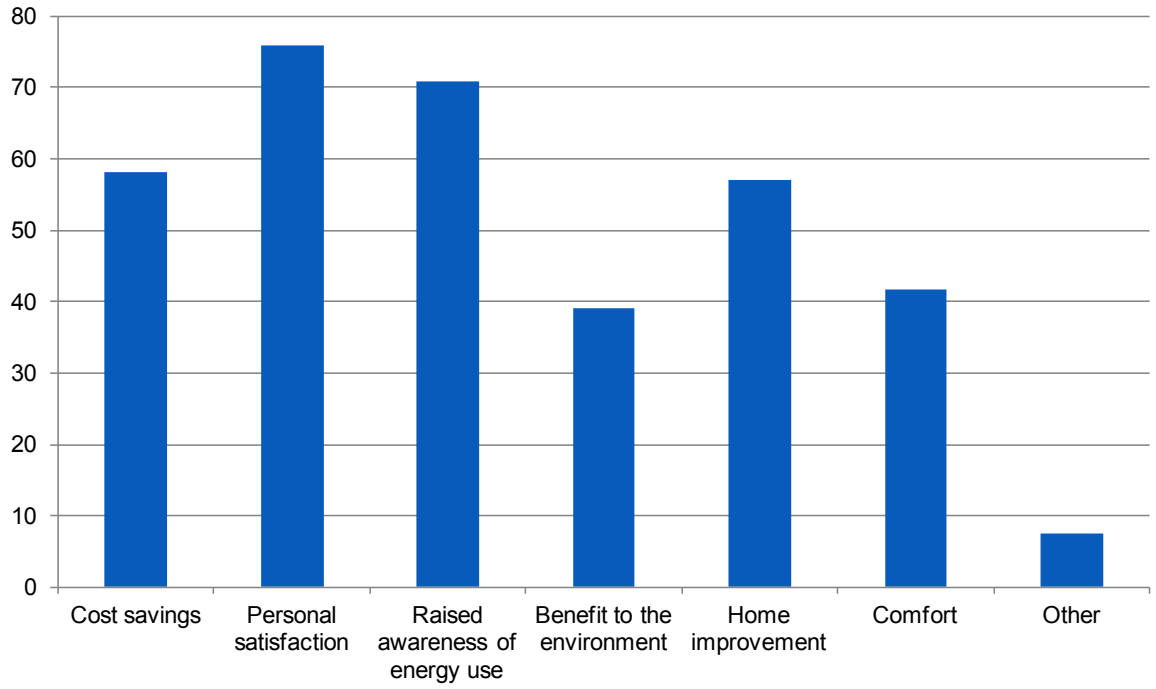



Figure 12. Program participants' benefits experienced

In 2014, Idaho Power administered a process evaluation of the Home Energy Audit program. The analysis was performed by Johnson Consulting Group. The overall conclusion of the evaluation was that the Home Energy Audit program is well designed and well run. The evaluation stated a key finding was the program had a successful launch because the design leveraged the "lessons learned" from the Boise City Audit Project. An additional finding from the evaluation was that the Home Energy Audit program incorporated most of the marketing best practices shown to be effective in promoting successful weatherization, energy audits, and "whole house" program approaches. Johnson Consulting Group also found customer and contractor feedback to be positive based on in-depth interviews. The final key finding of the evaluation was that the program participation process was quick and easy. Johnson Consulting Group's evaluation offered several recommendations for consideration. The first recommendation was to change the program name to *not* include the word audit. However, after careful review of the terms customers repeatedly used when asking for this type of service when calling or writing, Idaho Power learned that the word "audit" was the most-used term by customers. Thus, "audit" is included in the program's name.

The rest of the recommendations were around direct-install measures, customer surveys, follow up, and HPS work. For the direct-install measures, it was recommended to review the mix of measures available to ensure they are still cost-effective, appropriate, and correct for the homes. Pipe wrap had already been identified not fitting all pipes, and a larger size was made available. LEDs were also identified as a potential direct-install measure, and a cost analysis was reviewed.

Johnson Consulting Group's evaluation recommended considering a formal customer survey to assess satisfaction levels and to identify barriers preventing customer follow-through on auditor

recommendations. Idaho Power decided it wouldn't be prudent to spend additional funds for another survey because the current participant survey conducted in-house is sufficient to assess these items. Another recommendation was to develop a protocol or procedure for reaching out to customers and encouraging them to follow up on the energy efficiency recommendations. A procedure was developed to address customer follow-up and incorporated into the new HPS contracts for 2015.

The final recommendations were around additional training and guidance for the HPS. Two of the recommendations were around controlling what the HPS included in the customer's report. While guidelines are provided, such as to educate and encourage participation in energy efficiency programs, the HPSs are independent contractors and therefore have some leeway in what the contractors include in an audit. The basic parts of the audit are consistent for all auditors so all participants have a consistent experience. However, each home is different, plus the auditor is on-site inspecting the home and talking to the customer. Based on what the auditor observes and conversations with the customer, auditors need the latitude to personalize the recommendations as much as possible. Additional training on the audit software and its capabilities occurred in 2014. Although it was covered in the Statement of Work, one auditor was still unaware he was allowed to market his services to customers post-audit. That information has been directly reiterated with all auditors. The 2015 program changes resulting from a review of the process evaluation recommendations are described in detail below. A copy of the complete report is included in *Supplement 2: Evaluation*.

## 2015 Program and Marketing Strategies

With the cost of LEDs decreasing and customer interest in this technology increasing, two LEDs and 18 CFLs will be available for each participating home starting January 1, 2015. This change was made due to customer and HPS feedback and a recommendation from the process evaluation to review the mix of measures available.

Starting January 1, a new procedure for reaching out to customers to follow up on the audit recommendations as recommended by the process evaluation requires the HPS to perform a follow-up call to participants approximately 10 to 14 days after their audit. This change is expected to provide several benefits. First, the HPS will be able to verify the customers received reports. Second, the call provides a prompt and an opportunity for participants to ask their HPS additional questions. Third, the call allows the HPS to verify customers' understanding of the specific recommendations for their homes and what actions they can take next.

To account for the additional time the follow-up calls will take—and to make the fees more in-line with industry standards—the fee to the auditor will be increased in 2015 from $101 to $201. The customer fee will remain at $99.

While the HPSs were provided a program handbook to study, the program process evaluation showed it would be beneficial to provide the information verbally to each HPS. In early 2015, each HPS will take part in a live training session. The training will focus on ensuring a deep understanding of the program, including goals, standards, the timeline, and program flow. It will include information on other energy efficiency programs to promote and the use of myAccount. It will also include feedback from the surveys and areas for improvement.

A trade show booth backdrop and interactive webpages have been created using a cutaway house design to promote the Home Energy Audit program as well as demonstrate energy-saving tips for customers. These new tools will be used and promoted in 2015.

# Home Improvement Program

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 555 | 365 |
| Energy Savings (kWh) | 838,929 | 616,044 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $315,616 | $299,032 |
| Oregon Energy Efficiency Rider | $0 | $0 |
| Idaho Power Funds | $9,101 | $465 |
| Total Program Costs—All Sources | $324,717 | $299,497 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.020 | $0.025 |
| Total Resource Levelized Cost ($/kWh) | $0.055 | $0.090 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 4.17 | |
| Total Resource Benefit/Cost Ratio | 1.51 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho | |
| Program Inception | 2008 | |

## *Description*

The Home Improvement Program offers incentives to homeowners for upgrading insulation and windows in electrically heated homes. To qualify for an incentive under this program, the home must be a single-family home, a multi-family structure three stories or under, or a manufactured home in Idaho Power's service area in Idaho. The home must have an electric heating system serving at least 80 percent of the home's conditioned floor area. The heating system can be a permanently installed electric furnace, heat pump, or electric zonal heating system. Insulation must be professionally installed between conditioned and unconditioned space by an insulation contractor.

Participating insulation contractors must successfully complete a two-day contractor training course delivered by CLEAResult and Idaho Power. Customers must use a participating contractor to qualify for the Idaho Power incentive, processed by Idaho Power.

The program details include the following:

- Customer incentives for attic insulation, wall insulation, and under-floor insulation require prescriptive air- and duct-sealing.
- Customer incentives to Idaho residential customers in the Idaho Power service area for additional insulation professionally installed are 15 cents per $ft^2$ for attic insulation, 50 cents per $ft^2$ for wall and under-floor insulation, and 30 cents per linear foot for air- and duct-sealing.

- Existing attic insulation must be an R-20 or less to qualify, and the final R-Value must meet the local energy code. Idaho Power's service area consists of climate zones 5 and 6, resulting in an R-38 requirement for climate zone 5 and R-49 requirement for climate zone 6.
- The existing insulation level in walls must be R-5 or less, and the final R-Value must be R-19.
- The existing insulation level under floors must be R-5 or less, and the final R-Value must be R-30.
- Customer incentives are $2.50 per $ft^2$ of window area to Idaho residential customers for installing energy-efficient windows and/or sliding glass doors with a U-Factor of 0.30 or lower.
- Pre-existing windows/sliding glass doors must be single- or double-pane aluminum or single-pane wood.

## 2014 Program and Marketing Activities

At the beginning of the year, webpages for the Home Improvement Program were updated and improved to make customer navigation easier. A contractor portal was launched in 2014. The portal allowed contractors access to a specific area of Idaho Power's website where they could customize pre-approved marketing pieces with their own business name, address, and phone number. Currently offered on the portal for use are two door hangers for insulation contractors, two door hangers for window contractors, and two fliers for HVAC contractors. New marketing pieces will be added over time as needed. A video was produced at the beginning of the year to highlight program measures and to provide customers with a visual of how the upgrades are performed. This video can be viewed at idahopower.com/homeimprovement. A Facebook ad campaign ran from June to September, reaching approximately 310,563 customers. A series of newspaper ads ran multiple times during 2014. Newspaper ads were placed in publications that serve rural areas where there is a higher concentration of electrically heated homes (a program eligibility requirement). Digital behavioral ads ran during mid-March to the end of May. The number of impressions/ads served totaled 771,024. Two information bill inserts were sent out, one in February and one in June, and a targeted direct-mail letter was sent in fall 2014. In addition, window clings and retail signage were created and used in retail locations in eastern Idaho.

## Cost-Effectiveness

In 2014, Idaho Power used the same savings and cost-effectiveness assumptions as were used in 2013. For all measures, deemed-savings values specific to Idaho Power's heating and cooling climate zones the company used published by the RTF, including cooling savings based on the RTF's deemed-savings specifications for single-family home weatherization UES values. Incremental costs for the calculation of TRCs were estimated from customer project data for insulation projects, while regional RTF cost averages were used for efficient windows. Idaho Power did not have adequate window costs for baseline efficiency windows. For more detailed information about the cost-effectiveness calculations and assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

For QA purposes, third-party contractors performed random reviews of 5 percent of all installations completed in the Home Improvement Program. QA contractors verified the correct installation of

measures. In addition, the QA contractor assisted and educated the contractors on program requirements. Of the 37 QA inspections completed in 2014, no issues were reported.

The program incentive application form included an optional question asking customers how they heard about the program. Of the 555 applications, 506 customers answered the marketing question. The results are as follows:

- 219 respondents (43%) heard about the program from a program contractor.
- 148 respondents (29%) heard about the program from an Idaho Power bill insert.
- 58 respondents (11%) heard about the program from the Idaho Power website.
- 44 respondents (9%) received a referral from a friend or acquaintance.
- 9 respondents (2%) heard about the program from a home improvement show or fair.
- 6 respondents (1%) heard about the program from a newspaper or online ad.
- 22 respondents (4%) heard about the program from a direct mailer.

## *2015 Program and Marketing Strategies*

Numerous marketing activities are planned for 2015. Two informational bill inserts are planned. A targeted direct-mail letter is scheduled for February. Online ads will include both Facebook and behavioral network ads. Print ads will be placed in rural publications to target customers with electrically heated homes. The contractor portal will be populated with additional marketing pieces. Marketing materials will be updated as needed.

# Home Products Program

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (appliances/showerheads) | 10,061 | 13,792 |
| Energy Savings (kWh) | 652,129 | 885,980 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $212,787 | $391,348 |
| Oregon Energy Efficiency Rider | $9,250 | $14,117 |
| Idaho Power Funds | $5,139 | $50 |
| Total Program Costs—All Sources | $227,176 | $405,515 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.031 | $0.041 |
| Total Resource Levelized Cost ($/kWh) | $0.041 | $0.071 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.94 | |
| Total Resource Benefit/Cost Ratio | 4.52 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2008 | |

## *Description*

The Home Products Program provides an incentive payment to Idaho and Oregon residential customers for purchasing ENERGY STAR® qualified appliances. ENERGY STAR qualified appliances and products must meet higher, stricter efficiency criteria than federal standards. In 2014, the measures and related incentives included ENERGY STAR qualified refrigerators ($30) and freezers ($20).

Participants have two options to submit their application. They may complete a mail-in incentive application and submit it to Idaho Power with an itemized copy of the sales receipt or submit an online application and scanned copy of their receipt via email. If the purchase qualifies, the customer receives an incentive check by mail.

The Home Products Program also includes promotions using retailer markdowns and retailer/manufacturer incentives. Markdowns reduce retail-end prices to the customer at the point of purchase. Retailer/manufacturer incentives drive the manufacture, distribution, and promotion of more energy-efficient consumer products at the retail level. One measure offered through the retailer markdown model is low-flow showerheads. Low-flow showerheads are part of the Simple Steps, Smart Savings™ markdown promotion administered by the BPA. Simple Steps, Smart Savings is coordinated by CLEAResult.

Idaho Power works in collaboration with NEEA on the Retail Products Platform (RPP). This initiative launched in 2014 and provides a direct incentive to retailers for selling the most energy-efficient products.

## 2014 Program and Marketing Activities

Through the Home Products Program, Idaho Power paid 3,292 appliance incentives during 2014, resulting in 77,574 kWh annual savings. Ninety percent of incentives were for refrigerators, and 10 percent were for freezers. Additionally, Idaho Power paid incentives on 6,769 showerheads sold under the regional BPA Simple Steps, Smart Savings promotion, resulting in 574,555 annual kWh savings. This promotion uses the same retailer markdown model used in the Energy Efficiency Lighting program.

In 2014, Home Products Program participation decreased by 27 percent compared to 2013 participation. This is due primarily to the inclusion of clothes washers in the program through the first quarter 2013. In 2013, 20 percent of participation was due to incentives paid on 2,624 clothes washers. Idaho Power also found that purchases came from fewer stores in 2014. Some retailers, such as the Pocatello Sears, closed. However, retailers may have become less engaged when clothes washers were removed from the program.

In 2014, incentive processing was brought in-house. This decision was due in part to the removal of clothes washers from the promotion in 2013, resulting in fewer applications.

An option on the application allowed customers to donate their entire incentive to Project Share, an energy assistance partnership between Idaho Power and the Salvation Army. In 2014, Home Products Program participants donated $1,340 to this cause. The Home Products Program sent a Project Share donation thank-you card to customers who donated their incentive.

Idaho Power promoted the program to residential customers via retail store salespeople, a bill insert in July, and the Idaho Power *Connections* newsletter. Idaho Power staff promoted the program directly to customers through community events and other outreach activities. Historically, bill inserts account for about 4 to 5 percent of program enrollments. One bill insert detailing the program was mailed to all residential customers in July 2014. However, a bill insert was also sent in November 2013, which also impacted participation in 2014. As a result, 14 percent of program participants reported hearing about the program from bill inserts in 2014.

Home Products Program marketing efforts included online display ads and visual ads that pop up based on specific search behaviors, such as previous visits to Idaho Power's website or appliance-related searches. The campaign ran from September 25, 2013, through January 7, 2014, and could have influenced 2014 program participation. The campaign resulted in 771,884 impressions and 3,029 clicks for a CTR of 0.39 percent. The industry average for this type of online advertising is 0.07 to 0.10 percent.

In 2014, Idaho Power participated in the NWRRC, facilitated by NEEA, and followed the work by the WRUN. The NWRRC identifies and pursues opportunities that can best be achieved by working collaboratively in the region. WRUN is a network of western utilities, primarily serving California. Both the NWRRC and WRUN seek to develop collaborative approaches to working with manufacturers and retailers to increase the uptake of energy-efficient products in the retail market.

With WRUN, Idaho Power participated in its first upstream appliance promotion with Sears and Samsung, offering an incentive on select Samsung clothes washers. The promotion was coordinated by WRUN. Utilities such as Idaho Power were allowed to opt-in. Under the promotion, Sears and Idaho Power each offered a $50 incentive, giving the customer a $100 discount taken at the point of purchase. Sears provided utility-branded tent cards to display on qualifying units. The promotion ran from

September 12 to 26 at three Idaho Sears stores located in Boise, Twin Falls, and Pocatello. However, the Pocatello Sears store was in the process of closing during the promotion and had no sample stock available on the floor. In total, four qualifying models were sold during the promotion. While this may represent a small number of total units, the promotion allowed Idaho Power to gain valuable experience in upstream appliance promotions, including establishing contracts with a national retailer, managing in-store point-of-purchase materials, and training retail staff.

In 2014, NEEA launched the RPP. The RPP is based on the Consumer Electronics Energy Forward Initiative, which ended in 2013. The RPP uses mid-stream incentives to influence retail stocking practices, ultimately driving manufacturing and standards for a portfolio of energy-efficient products sold through the retail channel. For more information on the initiative, view the *NEEA Residential Activities in Idaho* section of this *Demand-Side Management 2014 Annual Report*.

In 2014, new federal appliance standards for refrigerators and freezers went into effect. As a result, Idaho Power began to explore new cost-effective program delivery options. Two models were explored. The first continued a mail-in incentive program, providing incentives based on a qualified products list using the Consortium for Energy Efficiency product tiers. Idaho Power also proposed an upstream model similar to the Simple Steps, Smart Savings lighting promotion. Upstream promotions can often be delivered at lower administrative costs than mail-in rebate programs.

Both program designs were presented at the EEAG August 19 meeting. After the new efficiency standards were enacted, the RTF published new deemed savings values for refrigerators and freezers. Idaho Power determined the qualified products list approach would not meet its cost-effectiveness thresholds. Idaho Power again met with EEAG November 12 and propose retiring the current measures and moving toward upstream promotions in 2015.

## Cost-Effectiveness

Idaho Power used the same cost-effectiveness UES assumptions as were used in 2013 for the refrigerators, freezers, and showerheads.

In September 2014, the federal standards for refrigerators and freezers increased 20 to 30 percent depending on the product class. The RTF discussed the impact of these federal standard changes, which raised the baseline used to calculate the electric energy savings estimates. As a result of these higher standards, the annual gross energy savings for refrigerators dropped from 29 to 21 kWh per year, and freezers dropped from 40 to 23 kWh per year. The lower alternate costs from the 2013 IRP as well as the lower savings estimates from the RTF resulted in the measures no longer being cost-effective under the mail-in incentive model. Idaho Power will continue to evaluate the cost-effectiveness of these measures under other program delivery methods that may be less expensive than the mail-in incentive model.

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

## Customer Satisfaction and Evaluations

Due to program changes in 2014, a planned customer satisfaction survey was re-evaluated. As mentioned above, with the updated savings assumptions for freezers and refrigerators from the RTF and the new 2013 DSM alternative costs from the IRP, freezers and refrigerators were determined not to be cost-effective. The measures will no longer be available to customers beginning January 2015,

and the program will transition away from a mail-in incentive request format. As a result of these changes, a program satisfaction survey was not administered.

Information collected from a question on the incentive application form indicated salespeople are a proven marketing channel. Sixty-three percent of program participants that submitted an incentive application reported hearing about the program from a retail sales person. To support this channel, Idaho Power CRs visited participating retailers multiple times in 2014 to distribute program applications and discuss program requirements. Figure 13 indicates how customers heard about the program in 2014.

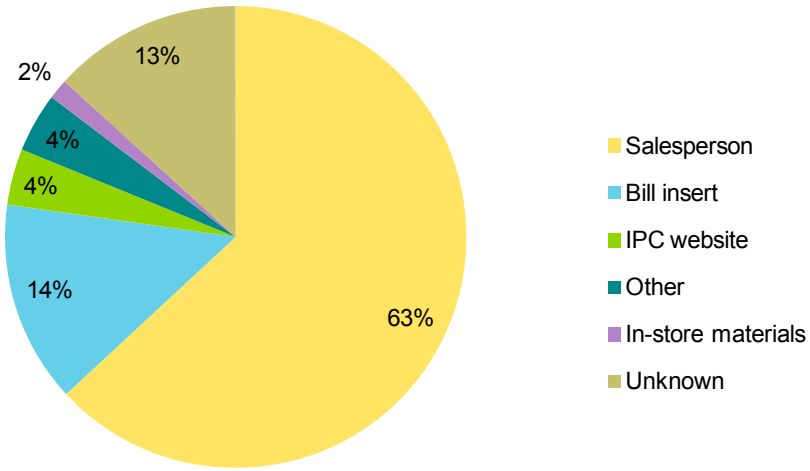



Figure 13. How customers heard about program, 2014

## 2015 Program and Marketing Strategies

Beginning January 1, 2015, Idaho Power will no longer offer incentives on refrigerators and freezers to its Idaho customers. Incentives will be paid on qualifying appliances purchased on or before Dec. 31, 2014. Beginning January 14, 2015, Idaho Power will no longer offer incentives on refrigerators and freezers to its Oregon customers. Incentives will be paid on qualifying appliances purchased on or before January 13, 2015. Applications must be received within 120 days of purchase.

In December 2014, the BPA announced changes to its Simple Steps, Smart Savings program. The program will continue to be administered by CLEAResult. BPA anticipates that clothes washers, refrigerators, and freezers will be brought into the Simple Steps, Smart Savings program beginning June 2015. Idaho Power expects to have the details of the appliance promotion at the end of first quarter of 2015 and will run the appropriate cost-effectiveness tests. If cost-effective, Idaho Power plans to opt in to the regional appliance promotion.

In 2015, Idaho Power will continue to participate in the NWRRC, follow the work by WRUN, and serve on NEEA's work group.

# Oregon Residential Weatherization

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (audits/projects) | 13 | 14 |
| Energy Savings (kWh) | 11,032 | 14,907 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $0 | $0 |
| Oregon Energy Efficiency Rider | $5,234 | $8,248 |
| Idaho Power Funds | $228 | $768 |
| Total Program Costs—All Sources | $5,462 | $9,017 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.028 | $0.035 |
| Total Resource Levelized Cost ($/kWh) | $0.050 | $0.055 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | |
| Total Resource Benefit/Cost Ratio | n/a | |
| **Program Characteristics** | | |
| Program Jurisdiction | Oregon | |
| Program Inception | 1980 | |

## *Description*

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

## *2014 Program and Marketing Activities*

During May, Idaho Power sent every Oregon residential customer an informational brochure about energy audits and home weatherization financing. Thirteen Oregon customers responded. Each customer returned a card from the brochure indicating interest in a home energy audit, weatherization loan, or incentive payment. Thirteen audits and responses to customer inquiries to the program were completed, with five incentives paid.

Idaho Power issued five incentives totaling $1,614.61 for 11,032 kWh savings. Three incentives and related savings were for ceiling insulation measures. One incentive was for floor insulation, and one incentive was paid for a combination of wall and floor insulation. There were no loans made through this program during 2014.

## Cost-Effectiveness

The Oregon Residential Weatherization program is a statutory program described in Oregon Schedule 78. The cost-effectiveness of this program is defined within this schedule. Pages 3 and 4 of the schedule list the measures determined to be cost-effective and the specified measure-life cycles for specific measures. This schedule also includes the cost-effective limit (CEL) for measure lives of 7, 15, 25, and 30 years.

Thirteen audits were conducted with five savings projects completed. Projects consisted of increasing attic, floor, and wall insulation. The projects combined for an annual energy savings of 11,032 kWh at a levelized TRC per kWh of 4.9 cents over the 30-year attic-insulation measure life as defined by Oregon Schedule 78.

The CEL for insulation (30-year measure life) is $1.30 per annual kWh saved. Since the actual levelized cost of energy savings for the 2014 projects was 4.9 cents from the TRC perspective, these projects are considered cost-effective.

## 2015 Program and Marketing Strategies

Plans for the upcoming year include notifying customers in their May bill about the program. Idaho Power will complete requested audits and fulfill all cost-effective incentive and loan applications.

# Rebate Advantage

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 44 | 42 |
| Energy Savings (kWh) | 269,643 | 269,891 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $57,155 | $58,674 |
| Oregon Energy Efficiency Rider | $5,324 | $2,097 |
| Idaho Power Funds | $753 | $0 |
| Total Program Costs—All Sources | $63,231 | $60,770 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.014 | $0.014 |
| Total Resource Levelized Cost ($/kWh) | $0.020 | $0.021 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 4.39 | |
| Total Resource Benefit/Cost Ratio | 3.23 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

## *Description*

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

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

Idaho Power residential customers who purchased a new, all-electric, ENERGY STAR qualified manufactured home in 2014 and sited it in Idaho Power's service area were eligible for $1,000 through the Rebate Advantage program. Salespersons received $200 for each qualified home they sold.

## *2014 Program and Marketing Activities*

During 2014, Idaho Power paid 44 incentives on new manufactured homes, which accounted for 269,643 annual kWh savings. In 2014, all Rebate Advantage collateral was updated, including table-top

posters, brochures, call-out cards for inside model homes, and outdoor vinyl banners. A bill insert, shared with Energy House Calls, was sent to all Idaho and Oregon Customers in September 2014. Idaho Power tested a digital advertising campaign with this target market because according to the *2014 Manufactured Home Market Facts Report* by Foremost®, 79 percent of manufactured home residents use Facebook and 42 percent visit social media multiple times per day. A digital advertising campaign was run from December 15, 2014, to January 15, 2015. Total impressions were 541,400 with 846 clicks for a CTR of 0.16 percent. Generally, in the digital advertising industry, the average CTR is 0.07 percent to 0.10 percent.

Idaho Power continued to support dealerships in 2014 by providing them with Rebate Advantage brochures and applications as needed. CRs visited these dealerships to distribute material, promote the program, and answer salespersons' questions.

## Cost-Effectiveness

In 2014, Idaho Power used the same savings and assumptions as were used in 2013. All cost-effectiveness analyses were based on the January 2011 approval decision by the RTF. The measures remained cost-effective for 2014. The measure is currently under review, and the RTF extended the sunset date for the measure until March 2015. For details, see *Supplement 1: Cost-Effectiveness*.

## 2015 Program and Marketing Strategies

Customers who purchase a new, all-electric, ENERGY STAR qualified manufactured home in 2015 and site it in Idaho Power's service area will continue to be eligible for $1,000. Salespersons will continue to receive a $200 incentive for each qualified home they sell.

In 2015, Idaho Power intends to continue the digital advertising due to a very solid response in 2014. Two informational bill inserts are planned for 2015. The first one will be distributed in February, and the second distributed in the fall. An informational direct-mail letter will be sent to manufactured home dealerships in August. In addition, targeted direct online ads will be placed. Program collateral will be updated throughout 2015 as needed.

# See ya later, refrigerator®

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (refrigerators/freezers) | 3,194 | 3,307 |
| Energy Savings (kWh) | 1,390,760 | 1,442,344 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $562,002 | $571,304 |
| Oregon Energy Efficiency Rider | $12,410 | $17,750 |
| Idaho Power Funds | $1,639 | $0 |
| Total Program Costs—All Sources | $576,051 | $589,054 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.062 | $0.061 |
| Total Resource Levelized Cost ($/kWh) | $0.062 | $0.061 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 0.86 | |
| Total Resource Benefit/Cost Ratio | 0.86 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2009 | |

## *Description*

The See ya later, refrigerator® program acquires energy savings through the removal of qualified refrigerators and stand-alone freezers in residential homes throughout Idaho Power's service area.

Idaho Power contracts with JACO to provide most services for this program, including customer service and scheduling, unit pickup, unit recycling, reporting, marketing assistance, and incentive payments. Marketing assistance is provided by JACO through Runyon Saltzman Einhorn (RSE). RSE is a marketing company that assists utility appliance recycling programs throughout the country. Idaho Power provides participant confirmation, additional marketing, and internal program administration.

Applicants enroll online or by phone. Idaho Power screens each applicant to confirm eligibility. JACO screens each applicant to confirm the refrigerator or freezer unit under consideration meets all program eligibility requirements, including being residential-grade, a minimum of 10 cubic feet ($ft^3$) as measured using inside dimensions, no larger than 30 $ft^3$, and in working condition. Customers receive a $30 incentive check mailed after the removal of the unit. The program targets older, extra units for maximum savings.

## *2014 Program and Marketing Activities*

The program reclaimed or recycled up to 95 percent of the components of each unit collected. In 2014, this amounted to more than 435,000 pounds of materials. Reclaimed materials may include oils or refrigerants that can be distilled and reused. See ya later, refrigerator® program participation declined by

3 percent between 2013 and 2014. This represents the natural ebb and flow of programs, demonstrated in Figure 14.

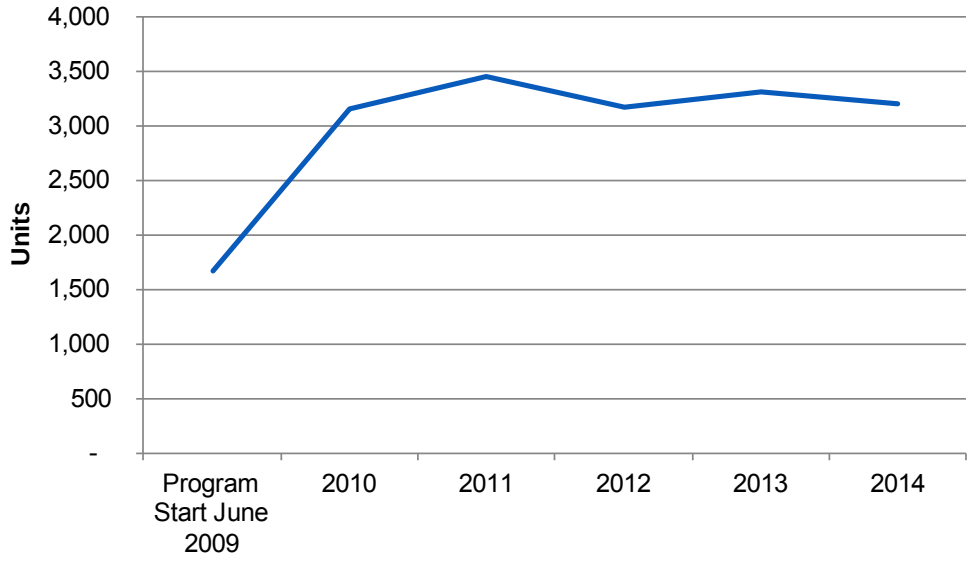



Figure 14. See ya later, refrigerator® participation by year June 2009

Idaho Power continued to offer See ya later, refrigerator® participants the option to receive their $30 incentive or donate it to Project Share. Project Share is an energy assistance program in partnership with the Salvation Army that helps customers who need help paying for energy services, including fuel bills and furnace repairs. In 2014, over 4 percent of Idaho Power's See ya later, refrigerator® participants chose this option, raising $4,230 for Project Share.

Idaho Power used an integrated, layered approach to market the program in 2014. All marketing tactics in 2014 used like imagery and messaging to build awareness and recognition. The messaging focused on convenience. Survey data showed 52 percent of participants reported they received the most value from the convenience of the program. Idaho Power and RSE used bill inserts, newspaper advertising, radio, direct mail, and earned media through two television spots to promote the program.

Bill inserts were sent during February, March, April, June, July, August, and October. In late May, a direct-mail postcard was sent to a highly targeted audience. The target audience for the program has been identified as older, empty-nesters who own their home. The mailing was sent to higher energy users and longer-term customers of Idaho Power that were likely to represent the target audience. The direct-mail had a response rate of approximately 1 percent. Program cards were included in energy-kits given to low-income customers.

Awareness tactics, such as radio and newspaper ads, ran from April through August. Handheld fans with program information were distributed at summer events, including several county fairs. In July, Idaho Power representatives and JACO staff appeared in live television broadcasts in the Twin Falls and Pocatello/Idaho Falls markets promoting the program and demonstrating how materials from refrigerators can be recycled and reused.

RSE managed a nine-month online Google AdWords™ campaign. Google AdWords™ brings up an ad based on specific combinations of search terms. The campaign resulted in 8,497 impressions and a CTR of nearly 6 percent.

## Cost-Effectiveness

Idaho Power used the same savings and other cost-effective assumptions for the 2014 reporting year as were used in 2013. However, with the implementation of acknowledged 2013 IRP avoided costs, the program measures for both decommissioning freezers and refrigerators became not cost-effective in 2014 from the UC and TRC perspectives. For details and program assumptions, see *Supplement 1: Cost-Effectiveness*.

Looking forward, the company evaluated different program options to increase the program's cost-effectiveness for 2015. Two options explored included restricting the ages of qualifying units and changing incentive levels. At the August 19 and November 12, 2014, EEAG meetings, Idaho Power discussed proposed program changes for 2015.

For cost-effective details and assumptions, see *Supplement 1: Cost-Effectiveness.*

## Customer Satisfaction and Evaluations

No formal evaluations were conducted in 2014 for this program. However, JACO tracks individual statistics for each unit collected, including information on how customers heard about the program and when customers enrolled. Statistics about the unit collected include the age of the unit, its location on the customer's property, and other data.

The 2014 unit data showed that 21 percent of units the program picked up were stand-alone freezers, and 79 percent of the units were refrigerators. Fifty-eight percent of the units were secondary, 29 percent were primary, and 13 percent were unknown. In 2014, 50 percent of the units collected were manufactured from 1965 to 1990, which generally represents the least efficient years of refrigerator manufacturing. By comparison, in 2013, 55 percent of the units were of this vintage.

JACO and Idaho Power also track data related to the marketing effectiveness of the program. Results of customer tracking information indicate 49 percent of customers learned of the program through bill inserts. Nineteen percent of customers learned of the program through a friend or neighbor. Although appliance retailers also refer customers to the program, Idaho Power does not pursue this marketing channel because the program focuses on the removal of secondary units rather than replacing existing units. Retailers sell new units to replace older units. In addition, a retailer selling a new unit will usually pick up and recycle the old one.

Seventy percent of customers who enrolled used the toll-free telephone number, and 30 percent used the online enrollment form. Idaho Power uses the customer information JACO collects and the surveys from Idaho Power evaluations to target future marketing efforts and increase the effectiveness of marketing.

Figure 15 indicates ways customers heard about the program. The Other category includes sources, such as community events, repeat customers, the truck wrap ad, and unknown sources.

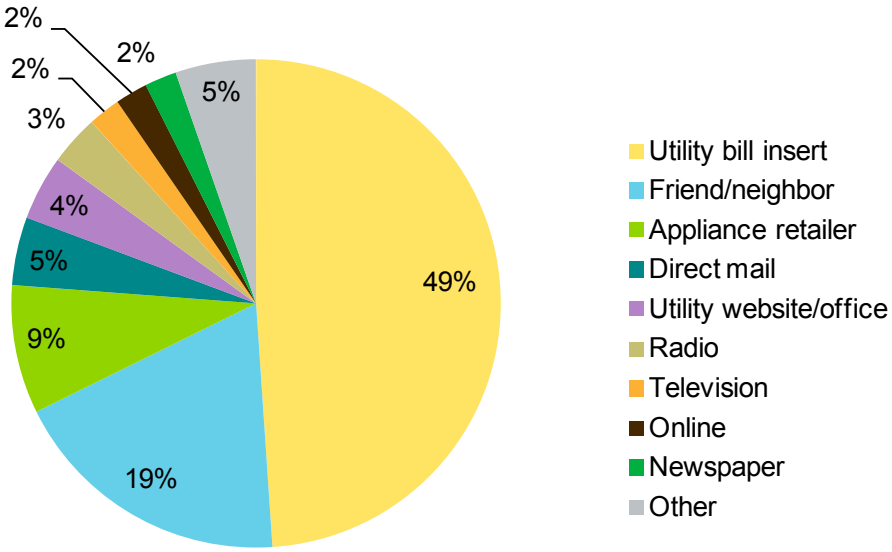



Figure 15. How customers heard about See ya later, refrigerator®

## 2015 Program and Marketing Strategies

Idaho Power will contract with JACO to provide services in 2015. To increase program cost-effectiveness, starting February 1, Idaho Power will no longer offer participants a $30 incentive for participating.

Marketing tactics in 2015 will include six bill inserts. The truck that picks up the refrigerators will continue to display a truck wrap—a large Idaho Power See ya later, refrigerator® ad—on its side. The truck wrap will be redesigned in January. This low-cost marketing tactic is expected to account for about 1 percent of program participation. Program information will continue to be included in over 2,000 energy kits distributed to low-income customers. The program will be promoted at community events and by Idaho Power's CRs. Idaho Power will also focus on online marketing tactics, including promotional advertising on Idaho Power's website, Facebook postings, and Google AdWords.

# Shade Tree Project

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 2,041 | 220 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $143,750 | n/a |
| Oregon Energy Efficiency Rider | $66 | n/a |
| Idaho Power Funds | $3,474 | n/a |
| Total Program Costs—All Sources | $147,290 | n/a |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Levelized Cost ($/kWh) | n/a | n/a |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | |
| Total Resource Benefit/Cost Ratio | n/a | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho | |
| Program Inception | 2013 | |

## *Description*

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

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

The Shade Tree Project was launched in Ada and Canyon counties, offering free shade trees to residential customers. Participants enroll using the online Energy Saving Trees Tool and pick up their tree at specific events. In the fall 2013 pilot, 220 trees were distributed to residential customers.

In 2014, the Shade Tree Project expanded. Idaho Power distributed 2,041 shade trees to residential customers.

## *2014 Program and Marketing Activities*

The best time to plant shade trees is in the spring and fall. Therefore, Idaho Power held two offerings in 2014. The spring shade tree offering was held in April 2014 and resulted in 1,058 trees distributed. The fall offering was held in October, and 983 trees were distributed.

Trees were purchased from regional growers in advance of each event. Species offered depended on availability at time of purchase. Idaho Power worked with its own arborists, along with city and state arborists, to select a range of tall growing, deciduous trees that should work well with the climate and soils of the two counties.

Idaho Power used direct mail to market this program in 2014 and used the state-sponsored Treasure Valley Urban Tree Canopy Assessment to develop a mailing list. The assessment is a geographic information system (GIS)-based study that mapped land use throughout the Treasure Valley including existing trees and vegetation, buildings, roads, waterways, and parking lots. The study identified areas where a tree can be planted and if that tree can be a large-growing shade tree. Idaho Power used the study to identify potential planting sites on residential properties situated to the west of the home. The mailing list was created from the results.

To enroll, customers accessed an online Energy Saving Trees Tool developed by the Arbor Day Foundation. Using this tool, participants mapped their home, selected from a list of available trees, and evaluated the potential energy savings associated with planting in different locations. During enrollment, participants learned how trees planted to the west and east save more energy over time than trees planted to the south and north. In 2014, customers could reserve up to two trees.

Participants picked up their tree at prescheduled events held throughout the Treasure Valley. Four pickup events were held in the spring and three in the fall, conducted on different days at different locations. By offering several pickup days, locations, and times, about 90 percent of participants enrolled and picked up their tree.

Ensuring the tree is planted properly helps it grow to provide maximum energy savings. At the tree pickup events, participants received additional education on where to plant trees for maximum energy savings and other tree care guidance from experts. Local specialists included city arborists from Boise, Kuna, Nampa, and Meridian; Idaho Power utility arborists; Canyon County master gardeners; and College of Western Idaho (CWI) horticulture students.

## *Customer Satisfaction and Evaluations*

In early 2014, a survey was emailed to 205 customers that participated in the first Shade Tree Project offering in fall 2013. The response rate was just over 63 percent with 130 respondents. Survey participants were asked, “How likely would you be to recommend Idaho Power’s Shade Tree Project to a friend or relative?” Just over 89 percent indicated they “definitely would” and just over 10 percent indicated they “probably would.” After reviewing these survey results, the survey was revised to remove questions with little value and to capture additional information from participants. The revised survey was sent in summer 2014 to 577 customers that participated in the spring 2014 offering. The response rate was nearly 61 percent with 351 respondents. When asked how much they would agree or disagree with statements about the Shade Tree Project, just over 95 percent of respondents “strongly agreed” and just over 4 percent “somewhat agreed” they would recommend the project to a friend or family. Nearly 93 percent indicated they “strongly agreed” and just over 6 percent “somewhat agreed” they were satisfied with their overall experience with the Shade Tree Project.

In 2014, the Customer Research and Analysis team administered a process evaluation contracting with Johnson Consulting Group for analysis. The findings from the process evaluation were, overall, the Shade Tree Project is well designed and well managed. Key findings and recommendations from the evaluation, along with Idaho Power’s responses, are described below.

The evaluators found Idaho Power successfully leveraged industry best practices to design and develop the Shade Tree Project. Program design was developed by combining internal resources from a diverse group of Idaho Power staff with input from critical external stakeholders involved in urban forestry projects throughout the region.

Evaluators indicated Idaho Power staff are responsive and flexible and have adapted this project based on both experience and customer feedback. The staff continues to refine the program delivery model, increasing the number of trees offered to customers and improving the program marketing and educational materials. In addition, the Shade Tree Project delivery strategy is consistent with the industry best practices for shade tree programs.

Johnson Consulting Group determined the online program enrollment was quick and easy. Citing Idaho Power's survey of program participants, nearly two-thirds, 60 percent, of the survey respondents were able to enroll in the program in ten minutes or less. Nearly three quarters, 72 percent, of survey respondents found the online enrollment tool very easy to use. Overall, the participants reported high satisfaction rates for the Shade Tree Project and were very satisfied with both the planting care and education they received at the distribution events.

Johnson Consulting Group noted a few respondents were dissatisfied with the quality of the trees provided. Upon further review, Idaho Power found that the comments around quality of tree related to the size of the tree. Trees came in 3- to 5-gallon containers and ranged in size from approximately 4 to 10 feet. The trees were sized so participants could safely transport and plant the trees. To address this concern, information on tree size was added to the direct-mail letter and main program landing webpage to help set participant expectations.

Based on the process evaluation findings, the Johnson Consulting Group evaluation team developed the following recommendations to improve program operations.

They recommended Idaho Power staff should standardize the current program evaluation questionnaires to allow for consistent feedback and tracking across all program events. This includes asking questions to all customers to assess satisfaction, determining the actual planting locations for all trees provided, and exploring more fully the reasons for participation.

Idaho Power agrees with this recommendation and plans to use a consistent survey starting in 2015. The company ran a small Shade Tree pilot in 2013 and issued a survey to all participants. After that survey, some small modifications were made to the survey questions with the intent of clarifying questions to obtain better data and seeking new information that would be relevant to a larger program design. Idaho Power will issue a third survey in early 2015 to capture participant feedback from the fall 2014 offering and will again refine a few questions based on specific feedback from Johnson Consulting Group. Specifically, the survey was designed in 2013 around one tree per participant. In 2014, the program was expanded to allow two trees per participant. Survey questions were adjusted for this program change. The company does not anticipate any future survey modifications but will maintain the flexibility to ensure the survey captures the data needed to manage and improve the program.

Johnson Consulting Group recommended Idaho Power staff develop a pre-screening tool to maximize energy savings potential at the initial application stage. The evaluator stated given both the survey responses and the experience with other shade tree programs, Idaho Power staff should try to maximize energy savings at the initial screening by incorporating the strategies used by other shade tree programs, such as pre-screening for customers who do not intend to plant trees with western, northwestern,

or southwestern orientation. The evaluator suggested Idaho Power staff should also assess actual free ridership rates through customer surveys in future program evaluations.

While Idaho Power agrees it is important to maximize energy savings and has taken several steps throughout the program design to do so, the company looked at other shade tree programs and has not yet found a pre-screening solution that would result in west planting locations that does not increase the cost of the project. Programs that require specific planting locations conduct one or more site visits to each participant's home and/or plant the tree for customers. For example, the Sacramento Municipal Utility District's program conducts up to three site visits—one to determine proper placement; one to deliver trees; and, for some customers, a third visit to verify planting.

Idaho Power also has concerns that a screening question at the time of enrollment alone may not lead to the desired results. Without site verification at the time of tree delivery and planting, it would be difficult to verify customers would answer a screening question truthfully.

Idaho Power uses many methods to encourage customers to plant in the most optimum location for energy efficiency. First, the program is marketed to those customers identified using the urban tree canopy assessment as having a western planting location. Messaging throughout the program includes the phrase *West is Best*. The enrollment tool uses community-based social marketing techniques, including interactive feedback, commitments, and prompts to promote western planting locations.

Second, although western planting locations result in maximum energy savings, significant savings can occur to the east and some, albeit less, savings can be achieved planting to the south and north. Idaho Power will continue to look for opportunities to maximize energy savings and promote plantings to the west of the home. The company will continue to monitor other shade tree programs and delivery models for best practices to minimize free ridership and maximize energy savings.

Johnson Consulting Group recommended Idaho Power staff should implement a QA/QC process to provide ongoing tracking of the distributed trees and that this QA/QC process should include follow up with all program participants via a customer survey and a sample of on-site visits to verify planting orientation and tree health. The evaluator noted the QA/QC process can also help to provide more accurate estimates of actual tree planting locations and therefore provide a more accurate estimate of overall program effectiveness.

Idaho Power agrees with this recommendation and currently has QA/QC procedures in place. The company follows up with all participants through an online survey after the each offering. In 2015, Idaho Power plans to conduct site visits to a subset of participant homes to measure tree planting location, planting quality, and tree health.

Two of the evaluators' recommendations regarded data collection. First, according to Johnson Consulting Group, the Shade Tree Project should develop a standard database that consistently tracks the disposition of trees and key program metrics in a standard manner. The evaluator stated that as this program evolves from a pilot to a full-scale program, it is critical to develop a standardized program tracking tool that tracks key program milestones, customer feedback, and electric and non-electric savings and allows easy comparison between offerings.

Second, Johnson Consulting Group also recommended Idaho Power staff should try to quantify the non-electric benefits associated with this program as a way to enhance its overall cost-effectiveness. The evaluator noted the technical assessments included detailed models demonstrating the significant non-electric benefits that shade tree programs provide and Idaho Power staff should leverage this

information and include the quantification of program non-electric benefits attributed to this project, including reductions in carbon emissions, carbon sequestration, and other benefits quantified in the US Forest Service (USFS) i-Tree™ model.

In regard to these two recommendations, Idaho Power continues to build upon prior work to move toward the evaluators' recommendation around data in the following manner. Idaho Power has captured program metrics for each offering, including customer data, tree type, tree planting location, marketing tactics, event pickup location, and enrollment date, as well as 20-year energy benefits (as determined by the model). In 2014, Idaho Power worked with the Arbor Day Foundation to create additional reports for each offering to track energy savings and environmental benefits. The Arbor Day tool is based on the i-Tree model, in which benefits for each tree distributed are calculated based on species and planting location. Benefits are forecasted for years 5, 10, 15, and 20. Environmental benefits include carbon benefits per pound, storm water runoff mitigated per gallon, and air pollutants per pound. Once these reports were finalized in fall 2014, Idaho Power merged the data with the other program metrics to create a central tracking system. In 2015, Idaho Power will create a data dictionary—describing each term and field used—for this database and will continue to add results from each offering going forward.

## 2015 Program and Marketing Strategies

Idaho Power plans to continue the Shade Tree Project in 2015, using the Arbor Day enrollment tool and events to distribute the trees. Idaho Power will continue to market the program by direct mail and focus on customers identified using the urban tree-canopy assessment. In addition, Idaho Power maintains a waiting list of customers that either heard about the program through a friend or relative or did not enroll in the fall offering before it subscribed. Idaho Power will reach out to these customers through direct mail or email. Should enrollment response rates not be as successful as past years, Idaho Power will consider targeted advertising on Facebook.

This project relies on strong partnerships with the cities, counties, CWI, and others. These groups provide guidance on tree selection and donate volunteer hours. Together, Idaho Power, local arborists and others interested in green infrastructure have formed the Treasure Valley Canopy Network (Network) to enhance the region's urban forest. The Network, through the Southwest Resource Conservation and Development and Idaho State Department of Lands, received a Western Competitive States Grant through the USFS. The grant proposal was the top ranked proposal submitted. Grant funds will be used to support urban tree planting for energy savings, develop local resources for tree procurement and storage, and develop additional educational materials. In 2015, the grant funds will offset some Idaho Power costs and allow Idaho Power to explore ways to procure trees locally at a lower cost. It will also be used to sustain the partnerships needed for this project.

Idaho Power will continue to collect metrics to evaluate program success and effectiveness. A survey will be sent in early 2015 to the fall 2014 participants. A survey will be sent to participants in the spring and fall 2015 offerings. In summer 2015, Idaho Power will conduct site visits to a statistically valid sample of past participant homes to confirm planting location and evaluate tree planting quality and tree health. This data will help inform assumptions used to evaluate energy savings from this program. Idaho Power is collecting data to evaluate energy savings from this project. With the available costs and savings assumptions, shade trees were added as a measure in the 2014 potential study that was prepared for the 2015 IRP. Based on currently planned tree distributions, it was estimated that just over 5 million kWh could be saved over 20 years.

# Weatherization Assistance for Qualified Customers

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes/non-profits) | 255 | 254 |
| Energy Savings (kWh) | 533,800 | 681,736 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $0 | $0 |
| Oregon Energy Efficiency Rider | $0 | $0 |
| Idaho Power Funds | $1,320,112 | $1,391,677 |
| Total Program Costs—All Sources | $1,320,112 | $1,391,677 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.149 | $0.125 |
| Total Resource Levelized Cost ($/kWh) | $0.225 | $0.184 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 0.51 | |
| Total Resource Benefit/Cost Ratio | 0.42 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 1989 | |

## *Description*

The WAQC program provides funding to install weatherization measures in qualified, owner-occupied and rental homes that are electrically heated. In 2014, qualified households included those with incomes up to 200 percent of the federal poverty-level guidelines. Energy efficiency enhancements allow qualified families to maintain a comfortable home environment while saving energy and money otherwise spent on heating, cooling, and lighting. Participants receive energy efficiency education to help save energy in their homes. Funding is also provided for the weatherization of buildings that house non-profit organizations who serve special-needs populations. In compliance with IPUC Order No. 29505, Idaho Power funds the CAP agencies to administer the WAQC program in its service area.

WAQC is modeled after the DOE weatherization program. The DOE program is managed through the Idaho Department of Health and Welfare (IDHW) in Idaho and by the Oregon Housing and Community Services (OHCS) in Oregon. Federal funds are allocated to the IDHW and OHCS, then to CAP agencies based on US Census data of population and poverty levels within each CAP agency's geographic area. The CAP agencies serve as the administrators of the state Weatherization Assistance Program (WAP) and oversee local weatherization crews and contractors, providing services and measures that improve energy efficiency of the homes. The WAQC funding provided by Idaho Power allows these state agencies to leverage their federal weatherization dollars and serve more Idaho Power customers who heat their homes with electricity by supplementing federal Low Income Home Energy Assistance Program (LIHEAP) weatherization funds.

Energy-saving home measures provided by this program include upgrades to windows, doors, wall insulation, ceiling insulation, floor insulation, infiltration, ducts, water heaters, and pipes;

furnace tune-ups, modification, and replacement; and the installation of CFL bulbs. The Idaho WAP calculates savings with the EA5 energy audit program (EA5). Consistent with the Idaho WAP, WAQC offers several measures that have costs but do not save energy or for which savings cannot be measured. Included in this category are health and safety, vents, furnace repair, and home energy audits. Health and safety measures are necessary to ensure weatherization activities do not cause unsafe situations in a customer's home or compromise a household's existing indoor air quality. Other non-energy-saving measures are allowed under this program to help facilitate the effective performance of those measures yielding energy savings.

Energy-saving measures provided to non-profit buildings under this program include upgrades to windows, doors, wall insulation, ceiling insulation, floor insulation, infiltration, ducts, water heaters, and pipes; furnace tune-ups, modification, and replacement; and the installation of CFL bulbs. Non-profit building measures that have costs but do not save energy or for which savings cannot be measured are health and safety, vents, furnace repair, and energy audits.

For more details on the WAQC program, view the most recent regulatory report, *Weatherization Assistance for Qualified Customers 2013 Annual Report*, dated April 1, 2014, located in *Supplement 2: Evaluation*. The new *Weatherization Assistance for Qualified Customers 2014 Annual Report* will be filed on April 1, 2015.

## 2014 Program and Marketing Activities

During 2014, CAP agencies weatherized 239 electrically heated homes in Idaho and 11 in Oregon, totaling 250 weatherized homes. Five Idaho buildings housing non-profit organizations that serve special-needs populations were also weatherized in 2014.

Idaho Power continued the focus on addressing recommendations from a 2012 impact evaluation conducted by D&R International and a 2013 process evaluation conducted by Johnson Consulting. A contract was signed with Kearns ENTerprises™ to develop a Home Audit tool to be used in Idaho Power's Weatherization Solutions for Eligible Customers program starting in 2015. The updated tool was designed to capture key data and more details regarding measures installed for health and safety. Updated calculations for estimates of energy savings and measure information to more accurately report program effectiveness were built into the program. The new WxSol Home Audit Tool (HAT 14.1) was distributed in January 2015 to contractors participating in the Weatherization Solutions for Eligible Customers program and will be tested throughout 2015 in that program. The WAQC program will use the tool if the state adopts it.

In January 2014, in Oregon, Idaho Power moved funds from the non-profit pooled fund to the fund used to weatherize homes of electrically-heated qualified customers. This funding shift allowed additional funds to be spent on home efficiency improvements of qualified customers in Oregon.

Idaho Power marketed WAQC throughout 2014 at resource fairs, community special-needs populations' service provider meetings, and CAP agency functions to reach customers who may benefit from the program. Marketing for this program was conducted in cooperation with weatherization managers. Working with the CCOA—Aging, Weatherization and Human Services (CCOA), a Weiser project was identified to be featured in an internal *eNews* video. Once produced, it was released on YouTube and promoted through social media in October.

## Cost-Effectiveness

The WAQC program has been proven to provide real and substantial per-home savings, but due to the costs of comprehensive whole-house weatherization, the program remains not cost-effective from either a UC or TRC perspective. In 2014, additional billing analysis was conducted on 2012 participants' billing data. This analysis was based on a recommendation from the 2012 impact evaluation conducted by D&R International. The evaluation recommended using a control group to account for non-weather related changes in energy use not attributable to the program's weatherization measures. The 2012 impact evaluation performed a billing analysis on 2011 projects. The average realized annual savings in all housing types was 2,684 kWh per home. For the update billing analysis, Idaho Power wanted to know if savings could be further differentiated between housing stock (single family versus manufactured home), occupant size, heating footprint of the home, and the number of occupants in the home. All billing analysis and data preparation was done in accordance with the *Whole-building Retrofit with Consumption Data Analysis Evaluation Protocol* document published in April 2013 by the DOE (energy.gov/eere/about-us/ump-protocols).

Analysis results showed that manufactured home savings per home were similar to the previous 2012 evaluation results at 2,568 kWh per year. Single-family homes, when analyzed independently from manufactured homes, revealed fewer savings than the 2012 evaluation results at 1,551 kWh per year per home. The effects of further segregating savings analyses by the heating footprint of the home, number of occupants, and climate was shown not to be statistically significant. Idaho Power plans to continue to monitor savings from this program through further billing analyses. Additionally, the RTF contract staff is analyzing manufactured home audit data from 2011 to 2012 that will provide useful insights into how to potentially incorporate the measure-level audit data into future billing analyses.

To analyze program cost-effectiveness, the recommendations from IPUC staff's report and IPUC Order No. 32788 are used for cost-effectiveness analysis for 2014. For further details on the cost-effectiveness assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Idaho Power used two independent, third-party verification companies to randomly check approximately 10 percent of weatherization jobs submitted for payment by the program. These verifiers discussed the program with participating customers and confirmed installed measures in their homes. Home verifiers visited 43 homes for feedback about the program. When customers were asked how much they learned about saving electricity, 32, or over 74 percent, answered they learned "a lot" or "some." When asked about how many ways they tried to save electricity, 34, or approximately 79 percent, responded "a lot" or "some."

As recommended by Johnson Consulting Group in a 2013 process evaluation, a new customer survey was developed to assess major indicators of customer satisfaction and program operations consistently throughout the service area. The 2014 Weatherization Programs Customer Survey was provided to all WAQC participants in all regions upon completion of weatherization in their homes. Survey questions gathered information about how customers learned of the program, reasons for participating, how much customers learned about saving energy in their homes, and the likelihood of household members changing behaviors to use energy wisely. Demographic information was gathered to determine future marketing strategies.

Idaho Power received survey results from 237 of the 250 households weatherized by the program in 2014. Of the 237 surveys received back from customers, 228 were from Idaho customers and 9 were from Oregon customers. Some key highlights include the following:

- Over 47 percent of respondents learned of the program from a friend or relative, and another almost 15 percent learned of the program from an agency flyer. Nearly 6 percent learned about the weatherization program by receiving a letter in the mail.

- Almost 90 percent of the respondents reported their primary reason for participating in the weatherization program was to reduce utility bills, and over 45 percent wanted to improve the comfort of their home.

- Almost 74 percent reported they learned how air leaks affect energy usage, and just over 65 percent indicated they learned how insulation affects energy usage during the weatherization process. Another almost 57 percent of respondents said they learned how to use energy wisely.

- Over 79 percent reported they were very likely to change habits to save energy, and almost 80 percent reported they have shared all the information about energy use with members of their household.

- Over 86 percent of the respondents reported they think the weatherization they received will significantly affect the comfort of their home, and nearly 94 percent said they were very satisfied with the program.

- Over 86 percent of the respondents reported that the habit they were most likely to change was turning off lights when not in use, and over 61 percent said that washing full loads of clothes was a habit they were likely to change to save energy. Turning the thermostat up in the summer was reported by nearly 51 percent, and turning the thermostat down in the winter was reported by almost 58 percent as a habit they and members of the household were most likely to change to save energy.

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

Idaho Power participates in the Idaho state monitoring process, which involves representatives from the CAP agencies, Community Action Partnership Association of Idaho, Inc. (CAPAI), and IDHW reviewing homes weatherized by each of the CAP agencies. Results of the state monitoring review show all CAP-agency weatherization departments are weatherizing in accordance with federal guidelines.

Additionally, the DOE audits state agencies each year. The DOE audits include field work, paperwork, and billing audits, which show that the Idaho WAP and therefore, WAQC, is in compliance with DOE standards.

## 2015 Program and Marketing Strategies

WAQC will continue using DOE guidelines and leveraging each weatherization job with state WAP funding on each job. The budget and projected number of jobs for 2015 will remain the same as 2014.

Idaho Power will continue working in partnership with the IDHW, OHCS, CAPAI, and individual CAP agency personnel to maintain the targets and guidelines and improve the cost-effectiveness of the WAQC program.

Idaho Power will continue involvement with the State of Idaho's Policy Advisory Council that serves as an oversight group for weatherization activities in Idaho. Through this forum, Idaho Power participates in the weatherization policy for the State of Idaho.

The company plans to continue to selectively market WAQC throughout 2015. The program will be promoted at resource fairs, community special-needs populations' service provider meetings, and CAP agency functions to reach customers who may benefit from the program. Marketing for this program will be conducted in cooperation with weatherization managers.

# Weatherization Solutions for Eligible Customers

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 118 | 166 |
| Energy Savings (kWh) | 290,926 | 303,116 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $757,748 | $1,239,132 |
| Oregon Energy Efficiency Rider | $0 | $0 |
| Idaho Power Funds | $33,596 | $28,659 |
| Total Program Costs—All Sources | $791,344 | $1,267,791 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.163 | $0.256 |
| Total Resource Levelized Cost ($/kWh) | $0.163 | $0.256 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 0.46 | |
| Total Resource Benefit/Cost Ratio | 0.50 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho | |
| Program Inception | 2008 | |

## *Description*

Weatherization Solutions for Eligible Customers is an energy efficiency program designed to serve Idaho Power residential customers who are below poverty level, at poverty level, or slightly above poverty level. The program is designed to mirror WAQC. Potential participants are interviewed by the contractor to determine household eligibility as well as ensure the home is electrically heated. If the home is eligible, an auditor inspects the home to determine what energy-saving upgrades will save energy, improve indoor air quality, and increase comfort for the residents. The installation of energy efficiency measures and repairs are allowed as long as the improvements have a savings-to-investment ratio (SIR) of 1.0 or higher. The amount spent on each home is limited to an annual average of Idaho Power's portion of the cost per home. Homes considered for this program are electrically heated and either owned or rented. If rented, the landlord's permission is needed to perform the upgrades, along with an agreement to maintain the unit's current rent for a minimum of one year.

Idaho customers eligible for this program have earned incomes between 175 percent and 250 percent of the federal poverty level. These customers typically do not have expendable income to participate in other residential energy efficiency programs, and they live in similar housing as WAQC customers.

## *2014 Program and Marketing Activities*

The program served customers in Idaho Power's service area in Idaho, including Canyon, Southern, and Capital regions, as well as most of the Eastern region. In 2014, the program participation decreased from 166 in 2013 to 118 in 2014. This was due to some challenges in finding income-eligible customers in portions of Idaho Power's service area. Income guidelines overlap between the Weatherization Solutions

for Eligible Customers program and WAQC, therefore some of those eligible customers were served by WAQC. Additionally, reliance on word-of-mouth communication between prior customers and potential customers, which was a helpful method in the past, was less effective in 2014. Future marketing activities will be increased by Idaho Power and weatherization managers to locate more customers eligible to participate in the Weatherization Solutions for Eligible Customers program.

Table 10 shows the number of jobs and costs associated with measures installed in homes (production costs). Also shown are job average costs and total payments to contractors for the year.

Table 10. 2014 weatherization solutions financial breakdown

| Contractor | Number of Jobs | Production Costs | Average Job Cost | Administrative Payment to Contractor | Total Payment |
|---|---|---|---|---|---|
| Energy Zone | 55 | $ 317,757 | $ 5,777 | $ 31,776 | $ 349,533 |
| Home Energy Management | 35 | 185,276 | 5,294 | 18,528 | 203,803 |
| Power Savers | 23 | 130,176 | 5,660 | 13,018 | 143,194 |
| Savings Around Power | 5 | 28,994 | 5,799 | 2,899 | 31,894 |
| **Total** | **118** | **$ 662,204** | **$ 5,612** | **$ 66,220** | **$ 728,424** |

**Note:** Average Job Cost calculations based on the direct cost of installed measures without the administrative payment.

In response to the 2012 impact evaluation and the 2013 process evaluation, Idaho Power contracted with an outside programmer to complete a new home audit tool for use in the program. Throughout 2014, Idaho Power staff worked with Kearns ENTerprises™ to incorporate the evaluation recommendations into an audit tool for use in 2015. In January 2015, the new tool, WxSol Home Audit Tool (HAT 14.1), was distributed to the four program contractors for use in 2015.

Updates in the audit tool include more specific housing types, the most current measure life of individual measures, and an updated chart of heating degree days. LED lighting was added to the CFL measure to incorporate new bulbs and associated savings. A health and safety menu was included to better capture non-energy saving upgrades necessary to the weatherization process and to further research and quantify NEBs of the program. A percentage limit was programmed for contractor support costs on each measure, and a 10-percent funding participation mandate was added for landlords when a home is not owner occupied. The refrigerator replacement measure was updated to reflect more accurate savings.

In 2014, Idaho Power contracted with the University of Idaho IDL to develop a Weatherization HVAC Replacement Savings Calculator that is interactive with each measure upgraded in a home that receives a new HVAC system. This tool is expected to be completed in early 2015, and Idaho Power will use it to compare savings reported by the new WxSol Home Audit Tool (HAT 14.1) in anticipation of improving the accuracy of savings being reported by the program.

Marketing approaches in 2014 included a newsletter, bill inserts, and ads. For example, an energy efficiency edition of the *Connections* customer newsletter was in the February bill; a bill insert was added in April and September mailings, an ad ran in *Idaho Senior News*, and a three-day ad ran in the *Idaho State Journal*.

Contractor personnel left flyers with previous participants to spread information about the program to families and friends who might be eligible. Word-of-mouth continued to be a helpful marketing tool for the program in 2014. Several articles about the program were featured in various local publications. The program was promoted at Idaho Power and CAP agency outreach booths and resource fairs.

One of the target customer groups for Idaho Power's Weatherization Solutions program is seniors. To more directly focus on this customer group, information about the program was emailed to a number of resources used by seniors. This resulted in an assisted living provider with facilities throughout southern Idaho supplying program information in their monthly newsletter to residents, families, business partners, and healthcare providers. A health/hospice program included Idaho Power program information in their newsletter emailed to professionals/resources that work with senior citizens. Idaho Power placed print ads in the *Idaho State Journal* in October to promote program participation in eastern Idaho.

## Cost-Effectiveness

The billing analysis conducted in 2014 by Idaho Power on 2012 projects showed higher savings over the results published in the 2012 impact evaluation conducted by D&R International. However, due to the costs of comprehensive whole-house weatherization, the program remains not cost-effective from either a UC or TRC perspective. In 2014, Idaho Power conducted an additional billing analysis on 2012 participants. The company applied the recommendation from the 2012 impact evaluation by using a control group to account for non-weather related changes in energy use not attributable to the program's weatherization measures. The 2012 impact evaluation performed a billing analysis on 2011 projects. The average realized annual savings in all housing types was 1,826 kWh per home. For the update billing analysis, Idaho Power wanted to know if savings could be further differentiated between housing stock (single family versus manufactured home), occupant size, heating footprint of the home, and the number of occupants in the home. All billing analysis and data preparation was done in accordance with the *Whole-building Retrofit with Consumption Data Analysis Evaluation Protocol* document published in April 2013 by the DOE (energy.gov/eere/about-us/ump-protocols).

Analysis results showed that manufactured homes savings per home exceeded the previous 2012 evaluation results at 3,426 kWh per year. Single-family homes, when analyzed independently from manufactured homes, revealed higher savings than the 2012 evaluation results at 2,108 kWh per year per home. The effects of further segregating savings analyses by heating footprint of the home, number of occupants, and climate was shown not to be statistically significant.

To analyze program cost-effectiveness, the recommendations from IPUC staff's report and IPUC Order No. 32788 are used for cost-effectiveness analyses for 2014. For further details on the cost-effectiveness assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Two independent companies continued to perform random verifications of weatherized homes and visit with customers about the program. In 2014, 28 homes were verified, and 21, or 75 percent, of those customers reported they learned "a lot" or "some" about using energy wisely in their home. Twenty-six, or 93 percent, reported they had tried "a lot" or "some" ways to save energy in their home.

As recommended by Johnson Consulting Group in the 2013 process evaluation, a new customer survey was developed to consistently assess major indicators of customers' satisfaction and program operations throughout the service area. The 2014 Weatherization Programs Customer Survey was provided to all program participants in all regions on completion of weatherization in their homes. Survey questions gathered information about how customers learned of the program, reasons for participating, how much customers learned about saving energy in their homes, and the likelihood of household members changing behaviors to use energy wisely. Demographic information was gathered to determine future marketing strategies.

Idaho Power received survey results from 115 of the 118 households weatherized by the program in 2014. Some key highlights include the following:

- Almost 34 percent of respondents learned of the program through a letter in the mail and another almost 26 percent learned of the program from a friend or relative.
- Over 84 percent of the respondents reported their primary reason for participating in the weatherization program was to reduce utility bills.
- Just over 70 percent indicated they learned how insulation affects energy usage during the weatherization process, and 68 percent reported they learned how air leaks affect energy usage. Another almost 61 percent of respondents said they learned how to use energy wisely.
- Over 68 percent reported they were very likely to change habits to save energy, and almost 65 percent reported they have shared all of the information about energy use with members of their household.
- Almost 89 percent of the respondents reported they think the weatherization they received will significantly affect the comfort of their home, and nearly 96 percent said they were very satisfied with the program.

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

## 2015 Program and Marketing Strategies

Contractors will use the new WxSol Home Audit Tool (HAT 14.1) throughout 2015.
The Weatherization HVAC Replacement Savings Calculator developed by the IDL will be used to compare energy savings of the WxSol Home Audit Tool (HAT 14.1) when an HVAC system is upgraded in a home. As recommended in former program evaluations, the new calculator will provide more accurate savings estimates for the program.

In 2015, marketing plans include emails, ads, bill inserts, and distribution of the program brochures. Targeting various customer segments with bill insert and direct mailings has been helpful in the past in increasing program participation and will be used in 2015. A printed bill message is scheduled for May, and bill inserts will go out in February and again in the fall. Webpages for the Weatherization Solutions for Eligible Customers program will be refreshed during the coming year.

Idaho Power will create a program brochure and provide it to contractors for use in their individual regional marketing campaigns. Idaho Power will mail a letter to customers in April, July, and September whose energy consumption indicates electrically heated homes. The program will be promoted at senior centers and resource and energy fairs throughout the year, and a redesign of the energy efficiency pages of the Idaho Power website is scheduled.

Publications dedicated and directed to senior readers that have not been used in the past will be used in 2015. *Senior Goldmine* is a monthly publication delivered to 10 senior centers and over 100 other locations in the Treasure Valley. It is also hand-delivered to over 700 Meals-on-Wheels recipients. The company will also advertise in the *Senior Blue Book*, a semi-annual resource directory mailed to over 28,000 seniors and healthcare professionals. In 2015, February, May, August, and November ads in the *Idaho Senior News* are scheduled. This publication focuses on a demographic of senior readers ages 50 and older with a readership of over 80,000 statewide.

# COMMERCIAL/INDUSTRIAL SECTOR OVERVIEW

## Description

Idaho Power's commercial sector consists of over 67,522 customers. In 2014, the commercial sector's number of customers increased by 788, an increase of a little over 1 percent from 2013. The energy usage of commercial customers varies from a few kWh each month to several hundred thousand kWh per month. The commercial sector represents 30 percent of Idaho Power's total electricity usage in 2014.

The industrial and Special Contracts customers are Idaho Power's largest individual energy consumers. There are approximately 116 industrial customers. These customers can use millions of kWh a month and account for 17.9 percent of Idaho Power's total electricity usage in 2014.

Three major programs targeting different energy efficiency projects are available to commercial/industrial customers in the company's Idaho and Oregon service areas. Easy Upgrades offers a menu of typical retrofit measures with prescriptive incentive amounts for lighting, HVAC, building shells, variable-speed/frequency drives (VFD), plug loads, and food-service equipment. These energy-saving measures give customers the option of choosing the best selections for incorporating energy efficiency into their business. The Custom Efficiency program offers financial incentives for large commercial and industrial energy users undertaking more complex projects to improve the efficiency of their electrical systems or processes. Incentive levels are 70 percent of the project cost or 18 cents per kWh for first-year savings, whichever is less. During 2014, Idaho Power combined how the Easy Upgrades and Custom Efficiency programs treat lighting projects so they are processed together and the incentives and criteria are the same. The Building Efficiency program is available for new construction projects and large remodels. These projects typically capture lost-opportunity savings and encourage business owners to incorporate energy efficiency measures that are more efficient than current commercial building codes require. This program continues to be successful, incorporating qualified energy-saving improvements for lighting, cooling, building shells, and energy-management control options.

Idaho Power continues to offer the statutory Oregon Commercial Audits program to medium and small commercial customers. The program identifies opportunities for commercial building owners to achieve energy savings.

In 2014, FlexPeak Management, a demand response program, was offered to Idaho and Oregon commercial and industrial customers. Idaho Power contracted with EnerNOC, Inc., a third-party aggregator, to reduce peak demand at critical times. EnerNOC, in turn, contracted directly with Idaho Power's commercial and industrial customers to achieve demand reduction. For 2015, Idaho Power has proposed to internally run and manage the program.

The Custom Efficiency program continued to represent the highest total energy savings among commercial and industrial programs in 2014, with a total savings of 50,363 MWh. The Easy Upgrades program continued to lead the sector in projects completed with 1,095 projects. Combined, all programs completed 1,295 projects that achieved 78,940 MWh of energy savings. Table 11 shows a summary of savings and expenses from the three commercial and industrial energy efficiency programs that produce direct savings and one demand response program.

# Programs

Table 11. 2014 commercial/industrial program

| Program | Participants | Total Cost | | Savings | |
|---|---|---|---|---|---|
| | | Utility | Resource | Energy (kWh) | Demand (MW) |
| **Demand Response** | | | | | |
| FlexPeak Management | 93 sites | $ 1,563,211 | $ 1,563,211 | n/a | 40 |
| **Total** | | **$ 1,563,211** | **$ 1,563,211** | | **40** |
| **Energy Efficiency** | | | | | |
| Building Efficiency | 69 projects | 1,258,273 | 3,972,822 | 9,458,059 | 1.2 |
| Easy Upgrades | 1,095 projects | 3,150,942 | 5,453,380 | 19,118,494 | |
| Custom Efficiency | 131 projects | 7,173,054 | 13,409,922 | 50,363,052 | 5.6 |
| **Total** | | **$ 11,582,269** | **$ 22,836,124** | **78,939,605** | **6.8** |

**Note:** See Appendix 3 for notes on methodology and column definitions.

Although 2014 was a good year for Idaho Power's commercial and industrial energy efficiency programs, Idaho Power program managers recognized early in 2014 that some changes needed made to the programs. The company took action by increasing incentives to most measures in all three programs, removing non-cost effective measures, modifying how lighting retrofit projects were processed, adding trade ally outreach for lighting, and offering a cohort to wastewater treatment plants.
The commercial and industrial programs continued to develop and strengthen Idaho Power's strategic partnerships. These partnerships include the IDL, engineering and architectural firms, a vast network of trade allies, the Northern Rockies Chapter of International Facilities Managers Association, the IBOA, and most importantly, Idaho Power customers. Training and education continued to be an important aspect of the company's programs in 2014. Trade ally meetings included training on lighting design and lighting controls. These training classes qualified for continuing education credits for eligible, licensed trade allies. Building Efficiency sponsored a number of outreach training sessions conducted by the IDL. Last, Custom Efficiency continued to offer a host of industrial training sessions that were well attended.

The Green Rewind offering is available to Idaho Power's agricultural, commercial, and industrial customers. The sectors' combined 29 Green Rewind motors achieved a total annual savings of 91,582 kWh in 2014, with 14 commercial/industrial sector motors contributing 56,499 kWh per year and 15 irrigation sector motors contributing 35,083 kWh per year.

Twenty-one service centers in Idaho Power's service area have the necessary equipment and training to participate in the Green Rewind offering. An estimated 1,200 motor rewinds are occurring annually within these service centers. Currently, four service centers have signed on as Green Motors Practice Group (GMPG) members in Idaho Power's service area. The GMPG will also expand the number of service centers participating in the GMPG's Green Motors Initiative, leading to market transformation and additional southern Idaho and eastern Oregon kWh savings.

Motor service centers are paid $2 per horsepower (hp) by the GMPG for each National Electrical Manufacturers Association (NEMA) Standard hp-rated motor up to 5,000 hp for industrial and agricultural uses that receive a verified Green Rewind. Customers are paid $1 per hp from the service center that completed their rewind. The GMPG requires all service centers to sign and adhere to the GMPG Annual Member Commitment Quality Assurance agreement. The GMPG follows up with a quality check and QA.

Idaho Power continued research on the potential to expand incentives in the Building Efficiency program in 2014 for multi-family dwellings in new construction and major remodel projects. In 2013, it was determined that most multifamily construction uses natural gas as a heat source, resulting in minimal electricity savings based on cooling measures alone. Because of this, multi-family projects do not pass Idaho Power's cost-effectiveness tests.

Customer satisfaction research by sector includes the Idaho Power quarterly customer relationship surveys that ask questions about customer perceptions related to Idaho Power's energy efficiency programs. Sixty percent of Idaho Power's large commercial and industrial customers surveyed in 2014 for the Burke Customer Relationship survey indicated Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Fifty-six percent of survey respondents indicated Idaho Power was meeting or exceeding their needs with information on how to use energy wisely and efficiently. Seventy-three percent of respondents indicated Idaho Power was meeting or exceeding their needs by encouraging energy efficiency with its customers. Overall, 77 percent of the large commercial and industrial survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of the large commercial and industrial survey respondents who have participated in at least one Idaho Power energy efficiency program, 94 percent are "very" or "somewhat" satisfied with the program.

The results from surveying Idaho Power's small business customers indicated 52 percent of these customers said Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Fifty-one percent of survey respondents indicated Idaho Power was meeting or exceeding their needs with information on how to use energy wisely and efficiently. Sixty percent of respondents indicated Idaho Power was meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 22 percent of the small business survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of small business survey respondents who have participated in at least one Idaho Power energy efficiency program, 82 percent are "very" or "somewhat" satisfied with the program.

Customers' familiarity with Idaho Power's business energy efficiency programs meets or exceeds the average of its peer utilities according to the J. D. Power and Associates Electric Utility Business Customer Satisfaction Study. Idaho Power has exceeded the average of its peer utilities every year in the last four years with its awareness of business programs.

# Building Efficiency

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 69 | 59 |
| Energy Savings (kWh) | 9,458,059 | 10,988,934 |
| Demand Reduction (MW) | 1.2 | 1.1 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,212,907 | $1,489,195 |
| Oregon Energy Efficiency Rider | $31,052 | $17,839 |
| Idaho Power Funds | $14,315 | $0 |
| Total Program Costs—All Sources | $1,258,273 | $1,507,035 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.012 | $0.012 |
| Total Resource Levelized Cost ($/kWh) | $0.037 | $0.032 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 5.05 | |
| Total Resource Benefit/Cost Ratio | 2.08 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2004 | |

## *Description*

The Building Efficiency program enables customers in Idaho Power's service area to apply energy-efficient design features and technologies in new commercial or industrial construction, expansion, or major remodeling projects. The program offers a menu of measures and incentives for lighting, cooling, building shell, controls, appliances, and refrigeration-efficiency options. These measures may otherwise be lost opportunities for savings on customers' projects. Commercial and industrial customers taking service under, or who will take service under, Schedule 7 (Small General Service), Schedule 9 (Large General Service), Schedule 19 (Large Power Service), or Special Contracts customers are eligible to participate. Program marketing is targeted toward architects, engineers, and other design professionals.

Twenty prescriptive measures are offered through this program. The measures are interior-light load reduction, exterior-light load reduction, daylight photo controls, occupancy sensors, high-efficiency exit signs, efficient AC and heat pump units, efficient variable refrigerant flow (VRF) units, efficient chillers, air-side economizers, direct evaporative coolers, reflective roof treatment, energy-management control systems, guest room energy management systems, HVAC VFDs, efficient laundry machines, ENERGY STAR® under-counter dishwashers, ENERGY STAR commercial dishwashers, refrigeration head pressure controls, refrigeration floating suction controls, and efficient condensers.

The IDL has been a useful resource for the Building Efficiency program. Idaho Power is a primary sponsor of the IDL, which provides technical assistance and training seminars focused on energy efficiency to local architects, engineers, and designers through Lunch & Learn sessions and the

Idaho Building Simulations Users Group (BSUG). Sessions are outlined in the IDL section of *Supplement 2: Evaluation*.

## 2014 Program and Marketing Activities

The Building Efficiency program completed 69 projects, resulting in 9,458,059 kWh in annual energy savings in Idaho and Oregon. Although the program showed a slight decrease in total kWh savings from 2013, the program increased the total number of projects by 17 percent from 59 projects in 2013. New construction and major renovation project design and construction life is much longer than small retrofits and often encompasses multiple calendar years.

The Building Efficiency program was modified in 2014, adding six new incentive measures. Idaho Power contracted with ADM to provide a technical reference manual (TRM) to address recommendations provided in the ADM impact evaluation in 2012. The TRM was completed in 2014 and provided updated savings for existing measures and savings for new measures that were added to the program.

Research conducted at the end of 2012 revealed that one barrier to participation is the amount of uncompensated time it took to fill out and submit supporting project documentation. Idaho Power addressed this barrier in 2014 by adding a "Professional Assistance Incentive" equal to 10 percent of the participant's total incentive, up to a maximum amount of $2,500, to improve participants' satisfaction with the incentive process. Modifications to the program were posted on Idaho Power's website, in the fall edition of the *ENERGY@WORK* commercial newsletter, and in a letter mailed directly to engineers and architects throughout Idaho Power's service area. Idaho Power worked with the American Institute of Architects—Idaho Chapter to have the program revisions posted to their website at aiaidaho.com/.

Idaho Power marketing and program staff participated in bi-monthly conference calls in support of the Kilowatt Crackdown™ competition. A video highlighting positive participant experiences was produced by the company and shown at the 2014 BOMA Symposium. In addition to the video, Idaho Power was a symposium sponsor and as such, had a full-page ad in the program magazine. The Kilowatt Crackdown™ Awards luncheon held April 16 recognized the top three highest-performing buildings, the top three most improved buildings, and two special recognition rewards. Idaho Power issued a news release that day to recognize the winners and encourage additional coverage of the competition. Idaho Power scheduled two additional training sessions with BOMA members in 2014.

Building Efficiency was marketed as a single program and as part of Idaho Power's suite of commercial energy efficiency programs. Ads that include all of Idaho Power commercial programs appeared in association directories, *Horizon Air* magazine, Boise Metro Chamber of Commerce monthly magazine, the *Business Insider*, the *Idaho Business Review*, and bill inserts.

Additional commercial/industrial sector success stories were added to the Idaho Power website in 2014, with one specific to a Building Efficiency program new construction project titled *CSHQA architects and engineers design sustainability into their own offices*. Copies of the 2014 success stories are provided in *Supplement 2: Evaluation*.

In 2014, Idaho Power created a new commercial video showing how energy efficiency can be incorporated into new construction or as a retrofit. The Hailey Interpretive Center, a Building Efficiency program participant, was one of three projects featured on the video. The IDL was also featured in the video.

Technical training and assistance continue to be important in educating design professionals in energy efficiency design for new construction and major renovations. Influencing a project early in the design phase will have the most impact and least amount of lost opportunity. Twenty technical training lunches were completed in 2014, with 281 attendees, including architects, engineers, interior designers, and project managers. Technical training sessions were held in Boise, Pocatello, and Ketchum. The Building Efficiency program, in conjunction with the Custom Efficiency program, sponsored the Idaho BSUG through the IDL. Topics and sessions are outlined in the IDL section of *Supplement 2: Evaluation*.

The Building Efficiency program supports a number of associations and events, including placing ads in the American Institute of Architects (AIA) directory and sponsoring the AIA Honor awards, Grow Smart awards, BOMA symposium, and ASHRAE Technical Conference.

## Cost-Effectiveness

To calculate energy savings for the Building Efficiency program, Idaho Power verifies the incremental efficiency of each measure over a code or standard-practice installation baseline. Savings are calculated through two main methods. When available, savings are calculated using actual measurement parameters, including the efficiency of the installed measure compared to code efficiency. Another method for calculating savings is based on industry-standard assumptions when precise measurements are unavailable. Since Building Efficiency is a prescriptive program and the measures are being installed in new buildings, there are no baselines of previous measureable kWh usage in the building. Therefore, industry-standard assumptions from the International Energy Conservation Code (IECC) are used to calculate the savings achieved over how the building would have used energy absent of efficiency measures.

Building Efficiency incentives are based on a variety of methods depending on the measure type. Incentives are calculated mainly through a dollar-per-unit equation using square footage, tonnage, operating hours, or kilowatt reduction.

In 2014, under contract with Idaho Power, ADM completed a TRM for Building Efficiency, which provides savings and costs related to existing and new measures for the Building Efficiency program. The TRM was evaluated in 2014, and cost-effectiveness analyses were performed on all measures addressed through the TRM. The analyses resulted in modifications to several existing measures, the removal of one measure, and the addition of six measures to the updated 2014 Building Efficiency program.

Several measures that are not cost-effective remain in the program. These measures include daylight photo controls, high-efficiency A/C units, and high-efficiency heat pump units. After reviewing these measures, Idaho Power determined these measures met at least one of the cost-effectiveness exceptions outlined in OPUC Order No. 94-590. These modification and cost-effectiveness exceptions were approved by the OPUC in Advice No. 14-10 for 2014 and went into effect in Idaho in July 2014 and in Oregon in November 2014. Complete measure-level details for cost-effectiveness can be found in *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Building Efficiency continued random installation verification on 10 percent of projects in 2014. The purpose of the verifications is to confirm program guidelines and requirements are adequate and ensure participants are able to provide accurate and precise information with regard to energy efficiency

measure installations. The IDL completed on-site field verifications on 7 of the 69 projects, which encompass approximately 10 percent of the total completed projects in the program. Out of the seven projects verified, six projects were installed with only minor or no discrepancies compared to how they were declared on the final application. The minor discrepancies resulted in a total increase of energy-efficient measures for six of the seven projects. Only one project was installed with less energy-efficient measures than declared. The project involved the installation of additional lighting fixtures and did not meet the program guidelines. Random project installation verification will continue in 2015.

## 2015 Program and Marketing Strategies

The following strategies are planned for 2015:

- Continue to perform random post-project verifications on a minimum of 10 percent of completed projects.
- Continue to sponsor technical training through the IDL to address the energy efficiency education needs of design professionals throughout the Idaho Power service area.
- Continue to support Kilowatt Crackdown participants through continued coaching and technical support to further energy efficiency projects.
- Support organizations focused on promoting energy efficiency in commercial construction.
- Place print ads in the *Idaho Business Review* when the editorial content is dedicated to commercial property developers and engineers/architects.
- Actively support the 2015 Idaho Energy and Green Building Conference as a member of the conference planning committee. Participate in planning the conference agenda and energy efficiency sessions.
- Continue to sponsor the BOMA symposium and offer energy efficiency training and support to the real estate market.

# Custom Efficiency

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 131 | 73 |
| Energy Savings (kWh)* | 50,363,052 | 21,370,350 |
| Demand Reduction (MW) | 5.6 | 2.4 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $6,705,219 | $2,402,903 |
| Oregon Energy Efficiency Rider | $418,537 | $60,245 |
| Idaho Power Funds | $49,299 | $3,077 |
| Total Program Costs—All Sources | $7,173,054 | $2,466,225 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.013 | $0.010 |
| Total Resource Levelized Cost ($/kWh) | $0.024 | $0.024 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 4.72 | |
| Total Resource Benefit/Cost Ratio | 2.52 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

* Includes 56,499 kWh from Green Motors projects.

## *Description*

The Custom Efficiency program targets energy savings by implementing customized energy efficiency projects at customers' sites. The program is an opportunity for commercial and industrial customers in Idaho and Oregon to lower their electrical usage and receive a financial incentive by completing energy efficiency projects. Incentives reduce customers' payback periods for projects that might not be completed otherwise. Program offerings include training and education regarding energy efficiency, energy auditing services for project identification and evaluation, and financial incentives for project implementation.

Interested customers submit pre-applications to Idaho Power for potential projects that have been identified by the customer, Idaho Power, or by a third-party consultant. Idaho Power engineers work with customers and vendors to gather sufficient information to support the energy-savings calculations.

Project implementation begins after Idaho Power reviews and approves a pre-approval application finalizing the terms and conditions of the applicant's and Idaho Power's obligations. A payment application is later submitted when the project is installed and operating. In some cases, large, complex projects may take as long as two years to complete. Every project is verified post-completion by Idaho Power staff or an Idaho Power contractor. Lighting projects are typically pre- and post-inspected by an Idaho Power contractor or an Idaho Power representative. Incentive levels for the Custom Efficiency program were increased from 12 cents per kWh per year saved to 18 cents per kWh per year saved in July 2014; however, the 70-percent project cost cap remained in place. The lighting incentives for Custom Efficiency changed in July 2014. All standard lighting measures are now paid at

the stated prescriptive amount, which were revised in July 2014. All non-standard measures for interior lighting are now paid at the rate of 18 cents per kWh for first-year savings, up to 70 percent of the cost. All non-standard measures for exterior lighting are paid at the rate of 12 cents per kWh for the first-year savings, up to 70 percent of the cost.

## 2014 Program and Marketing Activities

Custom Efficiency had a very successful year in 2014. A total of 131 projects, including nine Oregon projects, were completed by 95 customers. Program energy savings increased in 2014 by 135 percent over 2013, from 21,370 MWh to 50,306 MWh.

Savings for the Custom Efficiency program can vary greatly based simply on the timing of projects as evidenced by the drastic difference in program savings year to year. In 2014, 145 new applications were submitted, totaling 64,729 MWh. There were 150 submitted projects in the pipeline for Custom Efficiency at the end of 2014, representing almost 67,665 MWh of potential future savings.

The Custom Efficiency program may also have reached some level of saturation through program maturity, as over 95 percent of the large-power service customers have engaged in the program. With the high percentage of industrial customers that have completed projects in the program, deeper energy savings will be challenging to achieve.

Table 12 indicates the program's 2014 annual energy savings by primary project measures.

Table 12. 2014 Custom Efficiency annual energy savings by primary project measure

| Program Summary by Measure | Number of Projects | kWh Saved |
|---|---|---|
| Lighting | 53 | 11,107,700 |
| Refrigeration | 19 | 24,158,395 |
| HVAC | 4 | 1,247,404 |
| Compressed air | 12 | 3,446,633 |
| Fan | 10 | 3,326,987 |
| Controls | 2 | 1,850,541 |
| Pump | 3 | 1,629,045 |
| VFD | 27 | 2,733,098 |
| Other | 1 | 806,750 |
| Total[a] | 131 | 50,306,553 |

[a] Does not include Green Rewind project counts and savings.

Key components in facilitating customer implementation of energy efficiency projects are facility energy auditing, customer technical training, and education services. The 2014 activities in the key components are described below.

### Facility Energy Auditing

In 2014, five scoping audits and seven detailed audits were completed on behalf of Idaho Power customers. These audits identified over 24,000 MWh per year of savings potential, and most of the customers engaging in these audits have used the information to move forward with projects or have expressed interest in moving forward in the near future. A Scoping Audit and an Energy Management Assessment was provided to 11 facilities as part of the Wastewater Energy Efficiency Cohort (WWEEC) offering.

### Customer technical training and education services

Technical training and education continue to be important in helping Idaho Power industrial customers identify where they may have energy efficiency opportunities within their facilities. The training is coordinated by the NEEA Industrial Training Project, and Idaho Power is a co-sponsor. Idaho Power provides funds for extra NEEA trainings in the Idaho Power service area. Additionally, Idaho Power pays customers' attendance fee in the classroom-based training sessions. Seven technical classroom-based training sessions were completed in 2014. Two of these classes were two-day classes, and the rest were one-day classes. Topics included compressed air, air-cooled refrigeration systems, pump systems, and fan system efficiency. A schedule of training events is posted on Idaho Power's website.

The level of attendance in 2014 remained high, with 115 Idaho Power-sponsored seats for customers and various Idaho Power staff, consultants, and trade allies out of the 119 total attendees. Customer feedback indicated average overall satisfaction levels of 99 percent.

Additionally, 2014 encompassed Phase IV of the webinar pilot plan coordinated by NEEA. Three webinars were presented free to all attendees. Topics included VFDs, efficient industrial lighting, and energy auditing and troubleshooting. There were 24 Idaho Power end-use customers, multiple Idaho Power personnel, and various consultants attending the webinar recordings. Idaho Power posted the webinar recordings and PDFs on the commercial and industrial training page on the Idaho Power website.

Figure 16 shows the number of Idaho Power-sponsored attendee seats filled as compared to other utility companies for the 2014 in-class NEEA industrial trainings. This figure uses data from ECOVA™'s summary of the trainings provided in the *NEEA Regional Industrial Training Update, December 2014* included in *Supplement 2: Evaluation*.

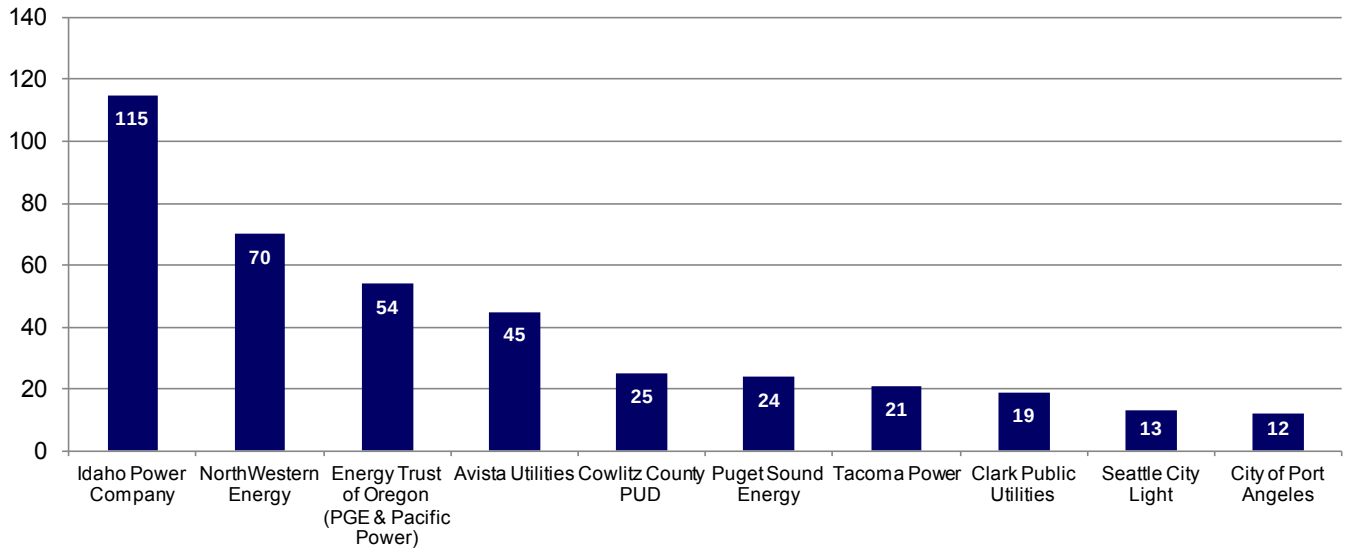



Figure 16. NEEA chart of attendees (in-class seats filled) by attendee sponsor[1]

[1] Data source: NEEA Regional Industrial Training Update, December 2014

Figure 17 shows the number of Idaho Power-sponsored attendee seats filled as compared to other utility companies for the three 2014 webinar-based NEEA industrial trainings. This figure uses data from ECOVA's summary of the trainings provided in the NEEA Regional Industrial Training Update, December 2014, included in *Supplement 2: Evaluation*.

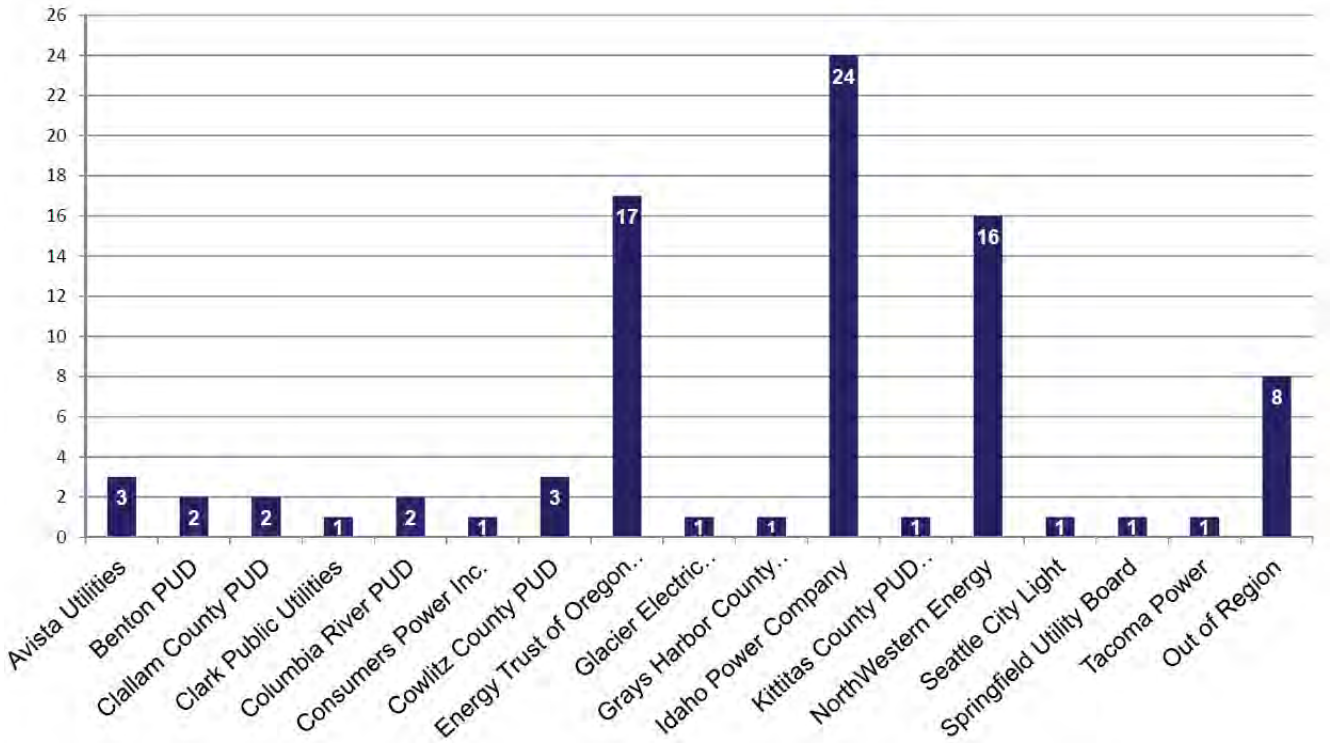



Figure 17. NEEA chart of attendees (webinar-based seats filled) by attendee sponsor[2]

In 2014, Idaho Power sponsored a Refrigeration training at the CWI during the September Treasure Valley Refrigerating Engineers and Technicians Association (RETA) chapter meeting.

In November in Boise, Idaho Power also co-sponsored a two-day RETA Certified Refrigeration Energy Specialist (CRES) review class training with NEEA with 13 customers in attendance. The purpose of the training was to review refrigeration energy efficiency concepts and to prepare the attendees for the RETA CRES exam. The requirement for signing up for the free training was for the students to apply for the CRES exam.

Custom Efficiency program engineers and the MCRs set up numerous target visits with the large commercial and industrial customers in 2014. The visits ranged from commercial/industrial efficiency program training to a comprehensive targeted technical training session for a larger audience on potential energy-savings opportunities for different measure types, such as refrigeration, pumps and fans, compressed air, HVAC, lighting, etc. Because of WWEEC, Custom Efficiency program engineers also set up multiple program marketing meetings with the area civil engineering firms specializing in water and wastewater designs to educate them on the efficiency programs, audit process, energy efficiency opportunities, and tools and resources available to them.

[2] Data source: NEEA Regional Industrial Training Update, December 2014

Under the IDL, Idaho Power participated in the BSUG. The goal was to facilitate the Idaho BSUG, which was designed to improve the energy efficiency-related simulation skills of local design and engineering professionals. In 2014, 11 sessions were hosted by the IDL. For one session, the IDL hosted the remote viewing of sessions taught by the Building Energy Simulation Forum in Portland. The sessions were made available remotely and were attended by 179 professionals in-person and 318 professionals remotely. Details regarding BSUG topics and additional details are located in the Other Programs and Activities section of the report and in *Supplement 2: Evaluation*.

The IDL provided a Tool Loan Library (TLL). The goal was to operate and maintain a measurement equipment tool loan library, including a web-based equipment tool loan tracking system, and provide technical training on how each tool is intended to be used. There were a total of 286 tools loaned in 2014 as part of 37 total loans. Fourteen new tools were purchased or acquired in 2014. Details regarding the types and number of loans, types of tools, and additional IDL activities are located in the Other Programs and Activities section of the report and in *Supplement 2: Evaluation*.

As stated in the sector overview, Green Rewind is available to Idaho Power's Custom Efficiency customers. This measure maintains the motor's original efficiency by ensuring certain standards and methods in the motor rewind process. There were 14 Green Rewind motors in the commercial/industrial sector in 2014, contributing 56,499 kWh in annual savings.

In 2013, Custom Efficiency launched two new offerings to increase the total program savings in 2014 and beyond. Early in 2013, the ROCEE offering was rolled out to Idaho Power's larger customers with complex refrigeration systems in the western half of Idaho Power's service area. This was a two-year engagement with the eight participating customers. ROCEE provided a series of technical training workshops with a cohort cluster training approach. Workshops included visits to participants' refrigeration engine rooms to gain hands-on experience viewing and discussing energy efficiency concepts. The goal of the training was to equip refrigeration operators with the skills necessary to identify and implement energy efficiency opportunities on their own and to ensure these energy and cost savings are maintained long term. Sessions included technical training, hands-on learning exercises to demonstrate simple low- and no-cost actions to diagnose problems and save energy, and peer-to-peer sharing of lessons learned as the classes progressed.

ROCEE provided energy audits of the participants' facilities in conjunction with a qualified refrigeration system expert. Customers were able to immediately implement low-cost and no-cost energy efficiency improvements by actions as simple as processing set-point changes. Participants had technician and engineering support between each workshop, facilitated by an expert team of energy engineers. Energy savings were tracked via an energy model that was constructed for each participating facility using third-party energy management software that Idaho Power provided as part of the cohort. In some cases, bottom-up calculations or sub-system data logging captured the savings. The incentives and the energy savings for year one of the offering totaled $13,886 and 3,678,985 kWh per year. In all cases, the incentive was capped on 70 percent of the eligible costs. Year two incentives and savings will be processed in 2015. Additionally, some ROCEE participants completed capital projects that were encouraged and discussed in the workshops and energy audits. These projects' savings are captured in the main Custom Efficiency program savings.

The second program offering rolled out in 2013 was SCE. This offering targets projects that may have typically been too small to participate in the Custom Efficiency program due to the resources required to adequately determine measure savings. Idaho Power has contracted SCE out to a company to manage the data collection and analysis for each project. SCE provides custom incentives for small compressed air system improvements, fast-acting doors in cold-storage spaces, refrigeration controllers for walk-in

coolers, and process-related VFDs. In 2014, the SCE offering processed 46 projects, totaling 4,698,478 kWh per year of savings and $540,375 in incentives paid.

In January 2014, Custom Efficiency launched the WWEEC program offering to increase the total program savings. Similar to ROCEE, WWEEC is a cohort training approach to low-cost or no-cost energy improvements. WWEEC is a two-year engagement with 11 Idaho Power service area municipalities. WWEEC provided a series of five technical training workshops with a cohort training approach. In addition, WWEEC provided energy audits in conjunction with a qualified wastewater system expert and an Energy Management Assessment conducted by a Strategic Energy Management professional for each participating facility. Customers were able to immediately implement low-cost and no-cost energy efficiency improvements by actions as simple as turning off equipment or adjusting control points for systems. They also implemented many energy management principles, including forming an energy team, setting energy goals, and establishing energy policies in their organization for persistence of savings. Energy savings were tracked via Idaho Power provided third-party software and an individual energy model for each facility. WWEEC contributed several capital projects to Idaho Power incentive programs from some of the WWEEC participants. Additionally, pre-planning meetings were held with consultants and municipalities for upcoming new wastewater construction projects.

2014 was the third year the Idaho Power CR&EE department filled a summer internship position with a university mechanical engineering student. A Custom Efficiency engineer served as the intern mentor. The intern was involved with many aspects of the day to-day program operation, including, but not limited to, measurement and verification of energy efficiency aspects related to Custom Efficiency program lighting projects; attendance at customer meetings related to energy efficiency; familiarization with, and communication for, all three commercial incentive programs; calculation and review of energy-saving projects; exposure to program marketing and planning activities; and administrative work related to the Custom Efficiency program.

The Custom Efficiency program has achieved a high service-area penetration rate. As stated previously, through 2014, over 95 percent of the large-power service customers have submitted applications for a project. Idaho Power staff met with all of the Special Contracts customers to discuss energy efficiency programs and opportunities. Specifically, only 2 of the 107 large-power service customers have not submitted an energy efficiency project, and all three Special Contracts customers have submitted projects. The company staff are actively working to support these customers in new ways.

Idaho Power's Custom Efficiency program is unique from the company's other energy efficiency programs by providing individualized energy efficiency solutions to a somewhat limited number of customers. Idaho Power's MCRs often act as the company's sales force. Marketing supports the MCRs by providing collateral to help them inform customers of the measures and benefits available to them.

The Custom Efficiency program was updated in July 2014, increasing incentive rates to 18 cents per kWh for first-year savings from 12 cents per kWh for first-year savings. As a result, marketing materials and web content were updated to reflect programmatic changes. A letter was sent to MCRs to distribute to their customers to increase awareness of changes to the commercial/industrial programs. Also, a PowerPoint presentation was created for the engineers and MCRs to use as part of their target visits with customers to highlight ongoing program activities and program changes.

In 2014, two new pieces of collateral were created for the Custom Efficiency program: 1) a flyer describing the types of incentives available under the Streamlined Custom Efficiency offering, and 2) a general overview brochure described the Custom Efficiency program. The flyer detailed the

types of improvements that fit under the Streamlined Custom Efficiency program offering, eligibility, and the application process. A new Custom Efficiency brochure was created to easily provide an overview of the program without reading through pages of text. Both of these documents were designed with the same look and feel. MCRs took flyers and brochures with them on customer visits. Both documents are available at idahopower.com/EnergyEfficiency/Business/Programs/CustomEfficiency/default.cfm.

As incentives were received, some commercial customers wanted to publicize the work they have done to become more energy efficient. Upon request, Idaho Power created large-format checks that are used for media events and or board meetings. Idaho Power also worked with customers on coordinating media events.

In early January, Idaho Power reached out to administration offices of cities in the company's service area participating in the Custom Efficiency WWEEC in Boise to encourage media opportunities in their communities. An alert was sent to all press outlets on January 27, the first day of the workshop, in the form of a media advisory, to inform the media of a public relations opportunity, with contact information for each city's public information officer and/or mayor's office representative. At the workshop, Idaho Power interviewed participants for testimonials to be included in an internal *eNews* video that was posted on YouTube in April and the link shared with workshop participants and promoted on social media. The video is titled *Partnering for Efficiency—Wastewater Plants* and is posted at youtube.com/watch?v=ES46PET3B70. In September, a press release was sent to all media on the day of the last of the five workshops held in Boise providing more information about the work being done by Idaho Power partnering with participants to improve energy efficiency throughout the service area. The press release included a link to the YouTube video. Local media was invited to join a tour of one of the local wastewater treatment plants; video footage was taken during the tour and a link to the footage was provided to any media that did not attend. In October, Idaho Power helped create a press release template for the participants to report out their results to local media.

Custom Efficiency has been marketed as a single program and also as part of Idaho Power's suite of commercial energy efficiency programs. Ads that include all Idaho Power commercial programs have appeared in association directories, *Horizon Air* magazine, Boise Metro Chamber of Commerce monthly magazine, the *Business Insider*, the *Idaho Business Review*, and bill inserts. Also, industry-specific energy efficiency brochures were developed in 2014 for several industries, including grocery stores, convenience stores, offices, hotels, restaurants, and healthcare facilities. These brochures are being distributed by CRs and MCRs and are available on the company's website here: idahopower.com/EnergyEfficiency/Business/Tips/eeBusinessSpecificTips.cfm.

## Cost-Effectiveness

All projects submitted through the Custom Efficiency program must meet cost-effectiveness requirements, which include TRC, UC, and PCT tests from a project perspective. The program requires that all costs related to the energy efficiency implementation and energy-savings calculations are gathered and submitted with the program application. Payback is calculated with and without incentives, along with the estimated dollar savings for installing energy efficiency measures. As the project progresses, any changes to the project are used to recalculate energy savings and incentives before the incentives are paid to the participant. To aid in gathering or verifying the data required to conduct cost-effectiveness and energy-savings calculations, third-party engineering firms are sometimes used via a scoping audit, detailed audit, or engineering measurement and verification services available under the Custom Efficiency program. Details for cost-effectiveness are in *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Each project in the Custom Efficiency program is reviewed to ensure energy savings are achieved. Idaho Power engineering staff or a third-party consultant calculate the energy savings. Through the verification process, end-use measure information, project photographs, and project costs are collected.

On many projects, especially the larger and more complex projects, Idaho Power or a third-party consultant conducts on-site power monitoring and data collection before and after project implementation. The measurement and verification process helps ensure the achievement of projected energy savings. Verifying applicants' information confirms that demand reduction and energy savings are obtained and are within program guidelines. If changes in scope take place in a project, a recalculation of energy savings and incentive amounts occurs based on the actual installed equipment and performance. The measurement and verification reports provided to Idaho Power include a verification of energy savings, costs, estimates of measure life, and any final recommendations to ensure the persistence of savings.

Because the customers who participate in the Custom Efficiency program are some of Idaho Power's largest customers, program managers or MCRs solicit customer satisfaction feedback for the Custom Efficiency program. This is authenticated in customers' willingness to allow posting the customers' success stories on the Idaho Power website. In 2014, seven new success stories described energy efficiency projects submitted by Custom Efficiency program participants. An example of a success story posted in 2014, *A chilling story of ON Semiconductor and Idaho Power incentives*, refers to a project ON Semiconductor completed. Idaho Power provided $53,255 in incentives for energy efficiency measures that reduced costs. The facility expects to save over $25,000 in annual utility bills. Copies of the 2014 success stories are provided in *Supplement 2: Evaluation*.

Qualitative research for the Custom Efficiency program began in late 2013. MDC was selected through a competitive request for proposal (RFP) process. The research served to provide a deeper understanding of customers' awareness and knowledge of the program offering and benefits as well as gauge customer satisfaction with the program and equipment installed. Customer feedback was collected on the program processes and preferred method of communication. The research involved one-on-one interviews with program participants based on the nature of the equipment installed and the industry. MDC interviewed 26 large commercial and industrial program participants in several industries, such as manufacturing, services, and retail trade. In addition, MDC conducted one-on-one interviews with 10 eligible commercial and industrial customers that have not yet participated in the Custom Efficiency program.

As a qualitative study, the following key findings only reflect the general thoughts of those that participated in the interviews and are not representative of the entire program. Overall, the 26 participants were "highly satisfied" with the Custom Efficiency program processes. Some participants cited their own internal processes as more difficult than the program's steps. The "vast majority" that worked directly with an Idaho Power representative were "highly satisfied." The consensus was that when an Idaho Power representative is involved, they tend to "fully drive the process." For both participants and non-participants, the return on investment (ROI) is the primary factor considered before participating. The 10 non-participants interviewed believed they would be "somewhat likely" to participate in the program in the future. They need more guidance around the qualified equipment, probable ROI, and probable upfront costs to help make that decision. Respondents were mixed on an "ideal" outreach strategy; however, most would pay attention to an in-person visit from Idaho Power.

Comprehensive results of all findings related to the Custom Efficiency program research were delivered in early 2014, and a copy of the report is provided in *Supplement 2: Evaluation*.

## 2015 Program and Marketing Strategies

Additional program offerings are currently under consideration for implementation in 2015. These efforts will be targeted at maintaining a high level of customer participation as well as achieving year- over-year program goals.

Items currently under consideration include the following: additional contractors for energy studies and measurement and verification (M&V) efforts; retro-commissioning offering; and new cohorts including ROCEE II (target Southern Region), Compressed Air (could be a stand-alone offering), Data Centers (could be a stand-alone offering), and Water Supply Energy Efficiency Cohort (WSEEC).

The second year of energy savings for the ROCEE offering will be reported and incentives paid in 2015. The first year of energy savings for the WWEEC offering will be reported and incentives paid around mid-year 2015.

The SCE offering will continue to be offered in 2015, and new measures, processes, and other improvements will be evaluated to continuously improve the effectiveness of this offering.

In addition, Idaho Power plans to continue expanding the Custom Efficiency program through a number of activities and continued development of strategic partnerships. These activities will include direct marketing of the Custom Efficiency program by Idaho Power MCRs to further educate customers on Idaho Power energy efficiency programs, including identification of potential ways the customer can reduce energy costs and drive program participation. A target visit brochure will be developed for the MCRs to use with their customers. The brochure will allow the customer to customize the visit by letting Idaho Power know the type of training and energy information they would like to know more about.

Idaho Power will continue to provide site visits by Custom Efficiency engineers and energy scoping audits for project identification and energy-savings opportunities; M&V of larger complex projects; technical training for customers; funding for detailed energy audits for larger, complex projects; and delivery of NEEA-sponsored Strategic Energy Management improvement practices to customers.

In 2015, additional industry-specific energy efficiency tip brochures will be revised and mailed to targeted customers, along with an insert highlighting possible incentives.

In 2015, an article on the WWEEC offering will be created to discuss the cohort approach on energy efficiency and energy management training with the municipal wastewater segment. A brochure outlining energy efficiency tips and benefits for the wastewater sector will be produced and posted to a new Idaho Power webpage. Hard copies will be printed and distributed at events and through CRs and MCRs as needed.

Each year, the company designs and pays for a “Top 10” ad that appears in the *Idaho Business Review*. This ad publicly congratulates companies that had the most energy savings throughout the year. The company will continue this tradition in 2015. Success stories will continue to be written and produced throughout 2015. These stories focus on businesses that took advantage of Idaho Power’s Custom Efficiency program and the resulting benefits. Success stories are posted on Idaho Power’s website so the highlighted businesses can print and use them to publicize their energy-efficient projects. Idaho Power will continue to assist customers with public relations opportunities by creating certificates for display within the building and having an Idaho Power representative speak at press events if requested.

The Custom Efficiency team will be mentoring another engineering intern in 2015. These internships are important mechanisms that help drive work-force development in the energy efficiency profession.

Idaho Power will continue to support the IDL in 2015. In addition to the specific tasks outlined in the IDL description in the Other Program and Activities section of the main report and in *Supplement 2: Evaluation*, the IDL provides foundational services to customers in the Idaho Power service area. The IDL will provide energy modeling assistance for large, new-construction projects. The energy modeling is used by the Custom Efficiency team to support the claimed energy savings that are not covered by the existing measures through the Building Efficiency program.

The Custom Efficiency team will continue to support the Center for Advanced Energy Studies (CAES) Industrial Assessment Center (IAC) by marketing their IAC services during both customer site visits and at technical training workshops. The IAC is part of the CAES's Energy Efficiency Research Institute (CEERI), which is a collaboration between Idaho's three state research universities where students provide energy audits and general recommendations to improve operations for mid-sized, local, manufacturing companies.

# Easy Upgrades

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 1,095 | 1,392 |
| Energy Savings (kWh) | 19,118,494 | 21,061,946 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $3,020,323 | $3,258,427 |
| Oregon Energy Efficiency Rider | $112,623 | $101,363 |
| Idaho Power Funds | $17,996 | $0 |
| Total Program Costs—All Sources | $3,150,942 | $3,359,790 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.015 | $0.014 |
| Total Resource Levelized Cost ($/kWh) | $0.025 | $0.029 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 4.08 | |
| Total Resource Benefit/Cost Ratio | 2.35 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2007 | |

## *Description*

Easy Upgrades is Idaho Power's prescriptive measure program for the commercial and industrial retrofit market. Customers can also apply for incentives for non-standard lighting incentives. The program encourages commercial and industrial customers in Idaho and Oregon to implement energy efficiency retrofits by offering specific incentives on a defined list of measures, except for the non-standard lighting. Eligible measures cover a variety of energy-saving opportunities in lighting, HVAC, building shell, VFDs, food-service equipment, and other commercial measures. A complete list of the measures offered through the Easy Upgrades program is included in *Supplement 1: Cost-Effectiveness*.

Idaho Power commercial and industrial customers and Special Contracts customers are eligible. For projects with expected incentive payments of $1,000 or more, or Complete Lighting Upgrade projects, applicants must submit a pre-approval application prior to installing the project. For projects not requiring pre-approval, customers may elect to skip the pre-approval application process and submit the payment application and accompanying documentation. Customers may assign their incentive payment to a third party (e.g., their contractor or supplier), as approved by Idaho Power.

## *2014 Program and Marketing Activities*

To increase customer and trade ally participation in the Easy Upgrades program, several changes were made to the program in 2014. Idaho Power increased incentives for numerous measures, added new measures, adjusted processes to enhance project submission and review, and added more trade ally outreach support.

The following are highlights of the modifications to lighting measures:

- For purposes of encouraging/rewarding more robust energy savings per project, and after considering how to adopt a form of a comprehensive lighting incentive in the program, Idaho Power added the Complete Lighting Upgrade bonus incentive. This new incentive applied to projects where all the interior inefficient lighting was retrofitted with more cost-effective, efficient technologies, including the incorporation of controls, where applicable. The Complete Lighting Upgrade was a bonus incentive given in addition to the calculated incentive on the lighting tool.

- To increase trade ally and customer participation, the program reviewed all lighting measures to determine if incentive increases could be made. The review resulted in increased incentives on several standard incentive measures and an increase to the non-standard incentive for interior lighting retrofits.

- The program segmented lighting incentives based on an interior or exterior application installation.

- To expedite project submission and reduce trade ally wait time to begin a project, the program eliminated the requirement for projects less than the $1,000 incentive with non-standard measures to be submitted for pre-approval. This change was heartedly received by participating trade allies and has resulted in quicker turnaround of project implementation.

In 2013, Idaho Power contracted with ADM to review the non-lighting Easy Upgrades measures and compile a TRM for these measures. Based on information provided by ADM and the RTF measure list, changes were made to several non-lighting measures. Highlights of the modifications to the non-lighting measures are described below.

New measures were added to the program, such as non-process chillers, electric combination and convection ovens, fryers, steamers, energy-free stock tanks, efficient electric water heaters, and commercial showerheads.

Some measures were removed from the program due to no longer meeting cost-effective criteria. Discontinued measures include refrigeration cases, refrigerators, door gasket repair, roof insulation, standard windows, and window shade screens.

Several measures were modified to reflect the updated TRM data and subsequent cost-effectiveness analysis. Idaho Power increased incentives for refrigeration line insulation, auto-closers, and floating head/suction pressure controls. The company moved VFDs installed on process applications to the Custom Efficiency program due to the highly variable nature of those applications. Idaho Power revised the eligibility and incentive level for qualifying efficient air conditioners, heat pumps, and HVAC controls.

The primary reason the project count decreased in 2014 compared to 2013 can be attributed to the delay in rolling out the 2014 program changes. Idaho Power announced the proposed program changes to participating lighting trade allies beginning in March. At that time, the expected effective date for the changes was the end of May; however, due to various delays, including the filing of OPUC Advice No. 14-06, and the company's desire to have uniform programs in both Idaho and Oregon jurisdictions, the program changes did not become effective until the end of July. Most trade allies and customers

delayed implementing lighting retrofit projects until the program changes became effective because of the increased incentive offered.

In addition to the reduction in lighting project submissions, the program experienced reduction in HVAC and food-service applications. The reason for the decline in these areas is attributed to the program changes in these categories (e.g., the removal of several measures for cost-effectiveness and/or adjustment to incentive or requirements). In 2013, the program had 140 food-service projects. In 2014, the program had 55 (the gasket seal measure went away). In 2013, there were 86 HVAC projects, and in 2014 there were 47.

Following the success from the *It's So Easy Lighting Campaign* targeted-town approach offered to the Pocatello area in fall 2013, the Easy Upgrades program expanded this offer to the Payette/Ontario and Twin Falls areas in spring 2014. In preparation for each week-long event, Idaho Power CRs and interested local trade allies in the two areas identified customers who would benefit from a lighting retrofit. The customers were offered a free facility lighting audit, a lighting consultation, or an expedited inspection of a proposed energy efficiency project. The local lighting trade allies were informed of the event and asked to participate.

The *It's So Easy Lighting Campaign* resulted in many positive outcomes for the program. Ninety-one visits were made to customer facilities in the participating two areas. Customers were appreciative of the offer made to them by Idaho Power. Customers gained tangible project information for decision-making with regard to undertaking a lighting retrofit. Trade allies appreciated the dedicated support the program gave them during the events.

The Easy Upgrades program facilitated 17 program workshops and technical classes across the Idaho Power service area targeting lighting trade allies, electrical contractors, and large customers. Offerings included six program workshops, one lighting 101 class, two lighting controls classes, and eight power quality classes. The program received feedback from trade allies requesting power quality education. The trade allies involved with energy efficiency projects involving VFDs were required to comply with power quality requirements. Idaho Power's power quality engineers developed a class to address this need, and the program facilitated delivery of the classes in 2014. The technical lighting and power quality classes qualified for continuing education credits for licensed electrician and electrical contractor trade allies. These classes and workshops resulted in 470 attendees receiving valuable industry-related training.

In addition to the formal training classes held, Idaho Power staff contacted over 110 trade allies in the field, via telephone, at the trade ally's business, or at a customer location to further educate them on program criteria and to respond to their inquiries. Contacts were made to strengthen relationships, encourage program participation, increase knowledge of the Easy Upgrades program, and to receive trade ally feedback about the market, the program, and trade allies' experiences. This targeted outreach was to electrical contractors, electrical distributors, and HVAC contractors.

Idaho Power also partnered with the IDL by sponsoring Daylight Harvesting Controls System classes. These classes provided education and training for electrical contractors and the design community on the concepts of daylight-harvesting control systems. IDL details are located in a description in the Other Programs and Activities section of the *Demand-Side Management 2014 Annual Report* and in *Supplement 2: Evaluation*.

Idaho Power continued to contract with Evergreen Consulting Group, LLC to provide ongoing lighting specialist expertise, project support, and trade ally training. In fall 2014, Idaho Power expanded its

contract with Evergreen Consulting Group to locate personnel in Idaho Power's service area to perform ongoing trade ally outreach to lighting trade allies. The trade ally outreach position enabled Idaho Power to increase support to its largest trade ally group—those working on lighting retrofit projects. Idaho Power continued to contract with Honeywell, Inc., to perform non-lighting project reviews and pre- and post-non-lighting project inspections. Idaho Power continued to contract with RM Energy Consulting to support lighting project review, lighting inspections, and audits for the targeted-town events.

Some inspections matched the information in the submitted paperwork, while other inspections showed discrepancies in submitted paperwork. To ensure projects in the program met program specifications and to verify conditions in the field were as stated on the program application, the Easy Upgrades program conducted 297 pre-inspections and 419 post-inspections, representing 552 unique customers in 2014. The program adjusted the incentive and kWh savings on projects with discrepancies to reflect actual field findings. Idaho Power took various steps to increase the accuracy and thoroughness of incoming paperwork to the program. Program personnel communicated the importance of being accurate on project submittals with trade allies at its annual program update workshops, as well as during communications with trade allies throughout the year. Program staff commended trade allies on submitting accurate and thorough paperwork as well as provided feedback and encouragement to trade allies whose paperwork would benefit from increased accuracy. The new trade ally support person began meeting with trade allies on a more frequent basis to provide ongoing education on program processes, paperwork submittal, and program requirements. In addition, the new outreach support person met with contractors who were new to the program to help them gain a thorough understanding of the program and requirements.

Several marketing tactics were used to promote and create awareness of the Easy Upgrades program in 2014. These included traditional approaches, such as running print ads in the *Business Insider* and *The Idaho Statesman* business section, a cover story in the fall edition of Idaho Power's commercial newsletter *ENERGY@WORK*, and marketing Easy Upgrades in combination with Idaho Power's other commercial/industrial energy efficiency programs. In fall 2014, a full-page Easy Upgrades ad appeared on the back cover of the *Small Business Administration's Resource Guide*. Ads that included all Idaho Power commercial/industrial programs appeared in various association directories, *Horizon Air* magazine, Boise Metro Chamber of Commerce monthly magazine, *Business Insider*, *Idaho Business Review*, and bill inserts.

The program implemented targeted direct mailing as a new strategy in 2014. A direct-mail letter was sent to 22,000 business customers announcing the 2014 program changes. This direct-mail strategy proved most successful in terms of getting customers to act. The letter briefly notified customers of the recently implemented program changes, included several customer testimonials, and specifically listed the Idaho Power CR and the CR's phone number for that particular recipient. Customers were encouraged to call their CR and find out more information about the Easy Upgrades program. Because the direct-mail letter was targeted and specific, customers did not need to look up anything—they were able to make a phone call and find out information right away.

In fourth quarter 2014, a targeted mailing was sent to hotel and motel businesses. The mailing included the brochure *Energy Efficiency Tips for Hotels*. A flyer was inserted in the middle of the brochure that outlined specific Easy Upgrades incentives relevant to the lodging industry market segment.

As part of its Commercial Lighting work group, NEEA continued work on its Reduced Wattage Lamp Replacement (RWLR) Pilot Initiative and development of the Top Tier Trade Ally Initiative Program.

An Idaho Power employee was on this working group, and the company is updated on progress at periodic conference calls and meetings. Details are provided later in the NEEA section of this report.

Idaho Power contracted in 2013 with Opinion Dynamics to conduct an Easy Upgrades process evaluation. Based on the results, the following recommendations were addressed in 2014.

Opinion Dynamics recommended Idaho Power consider adding or shifting staff resources (or subcontractors) to contractor-related outreach. The program contracted with Evergreen Consulting Group for local trade ally outreach support.

The evaluators recommended increasing the Easy Upgrades marketing and outreach budget. Opinion Dynamics stated that "A prudent use of additional marketing funds would be to boost contractor outreach." This recommendation was implemented in 2014 by securing dedicated trade ally outreach support and by increasing the Easy Upgrades marketing budget for 2015.

Opinion Dynamics recommended Idaho Power consider workflow and customer relationship management tools to help staff administer the program to increase efficiencies. Opinion Dynamics recommended it would be ideal to have all program management functions take place within one system. Opinion Dynamics recommended Idaho Power investigate what types of enhancements could be made to CLRIS so the management functions could happen with the existing system or, alternately, they noted there are a number of software packages available with workflow and customer relationship management capabilities. Idaho Power believes it is more reasonable and economical to enhance its existing system, which is tied into Idaho Power's customer billing system, than to invest in a third-party developed system. The company is constantly making enhancements to CLRIS and continues to explore further development.

## Cost-Effectiveness

In 2014, Idaho Power reviewed and modified most of the measures offered in the Easy Upgrades program. Idaho Power contracted with Evergreen Consulting Group to review the assumptions within the lighting tool for all the current and proposed standard lighting measure offerings. For the lighting measures, Idaho Power segmented the lighting incentives based on an interior or exterior application installation. Based on the difference in hours of use and end-use load shapes, the benefits associated with the energy savings with interior lighting measures are greater than comparable exterior lighting applications. The incentives for many interior lighting measures were increased to reflect the higher value of these lighting applications. The incentives for exterior lighting measures remained the same. The initial analysis of the standard lighting measures within the tool showed the measures to be cost-effective based on the average input watts and hours of operation. The actual savings for each lighting project are calculated based on the input watts of existing light fixtures, the replacement light fixture, and the actual hours of operation. As a result of these changes, there are over 100 lighting combinations under Easy Upgrades' Standard Lighting Incentives worksheet. In *Supplement 1: Cost-Effectiveness*, these lighting measures have been grouped under 26 similar categories.

In 2014, ADM completed a TRM for Easy Upgrades that provides savings and costs related to existing and new non-lighting measures for the Easy Upgrades program. The TRM was evaluated in 2014, and cost-effectiveness analyses were performed on all measures addressed through the TRM. Additionally, Idaho Power reviewed the list of commercial measures with deemed savings from the RTF that were not currently offered in the program. The analyses resulted in modifications to several existing measures, the removal of non cost-effective measures, and the addition of several measures as listed under the 2014 Program and Marketing Activities section.

Several lighting and non-lighting measures that are not cost-effective remain in the program. These measures include several lighting combinations with mostly exterior applications, high-efficiency A/C units, high-efficiency heat pump units, and wall insulation. After reviewing these measures, Idaho Power determined the measures met at least one of the cost-effectiveness exceptions outlined in OPUC Order No. 94-590. These modifications and cost-effectiveness exceptions were approved by the OPUC in Advice No-14-06 for 2014 and went into effect in Idaho in July and in Oregon in August 2014.

Complete measure-level details for cost-effectiveness can be found in *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Although the program did not solicit formal customer satisfaction surveys in 2014, the program received unsolicited customer and trade ally comments throughout the year indicating their satisfaction with the program. In addition, CRs and program staff asked customers about their experience with the program, their contractor, and their retrofit project during inspection visits and phone conversations.

In 2014, three new success stories describing energy efficiency projects were developed and posted to the company's website. The first 2014 success story, titled *Industrial detergent manufacturer cleans up with Idaho Power Easy Upgrades incentive*, references the lighting retrofit project completed at detergent formulator, Technichem Corporation. Company president, Brian Rencher, said, "I would recommend the Easy Upgrades program to anyone who has been hesitant about it, or has an old building. Or even a not-so-old building."

The second success story, titled *Using less energy to create better lighting is a win/win for Riverstone International School*, speaks of another lighting upgrade project. Todd Predovich, Riverstone International School's facilities manager, said, "When I got the proposal and I saw what Idaho Power's incentive was going to be, it felt like a win/win kind of deal." He said they took out half the bulbs and still got brighter classrooms. Todd described that the first day of class after they installed the new lights, the middle school art teacher asked what was done to her classroom. She noticed the difference in the quality of the light, which, in the case of new lighting technologies, can resemble daylight.

The third success story posted in 2014, titled *North Star Charter School graduates to a better lighting system*, refers to the lighting upgrade in North Star Charter School's gymnasium. Dan Conti, the school's athletic director, noted the gym is used for varied and wide purposes—from chess tournaments, quilt shows, and weddings to sports. Dan said, "We got our [incentive check] less than two weeks after the project was completed, so we could use the money to pay the contractor. It worked out nice." Copies of the 2014 success stories are provided in *Supplement 2: Evaluation*.

## 2015 Program and Marketing Strategies

Idaho Power will evaluate the viability to implement new program offerings and strategies and will look at ways to increase penetration in hard-to-reach small businesses. A customer satisfaction survey is planned to be implemented in 2015.

Marketing strategies for 2015 may include some or all of the following: trade ally trade show, direct mail to small and medium businesses, focus on trade ally outreach, program update workshops, print ads in the *Idaho Business Review* and/or major regional newspapers highlighting customer success stories and trade ally thank you ads, and Idaho Power monthly newsletter and bill inserts.

# FlexPeak Management

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (sites) | 93 | 100 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | 40 | 48 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $50,964 | $108,842 |
| Oregon Energy Efficiency Rider | $78,131 | $137,184 |
| Idaho Power Funds | $1,434,116 | $2,497,589 |
| Total Program Costs—All Sources | $1,563,211 | $2,743,615 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Levelized Cost ($/kWh) | n/a | n/a |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | |
| Total Resource Benefit/Cost Ratio | n/a | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2009 | |

## *Description*

FlexPeak Management is a demand response program administered by Idaho Power through a third-party aggregator. It is a voluntary program available in Idaho and Oregon service areas designed for Idaho Power's industrial and large commercial customers capable of reducing their electrical energy loads for short periods during summer peak load days. The program objective is to reduce the demand on Idaho Power's system during periods of extreme peak electricity use. The program is active June 15 to August 15 between 2:00 p.m. and 8:00 p.m. on non-holiday weekdays. Customers receive notification of a demand-reduction event two hours prior to the start of the event, and events last between two and four hours. Reduction events may be called a maximum of 60 hours per season.

In November 2008, EnerNOC, Inc. was selected through a competitive RFP process to implement the program. Idaho Power entered into a five-year contract with EnerNOC in February 2009. In May 2009, the IPUC approved the contract in Order No. 30805. In June 2010, the program was approved by the OPUC in Order No. 10-206.

EnerNOC is responsible for developing and implementing all marketing plans, securing all participants, installing and maintaining all equipment behind Idaho Power's meter used to reduce demand, tracking participation, and reporting results to Idaho Power. Idaho Power initiates demand response events by notifying EnerNOC, who then supplies the requested load reduction to the Idaho Power system.

EnerNOC meets with prospective customers to identify their potential to reduce electrical energy load during active program hours with minimal impact to their business operations. Customers initially enroll in the program by entering into a contract with EnerNOC. EnerNOC then installs energy-monitoring

equipment at the customer site, simulates a demand response event to ensure customer satisfaction and performance, and officially enrolls the facility in the program.

Each week during the active season, EnerNOC commits a demand-reduction amount in MW to Idaho Power that EnerNOC is obligated to meet during a demand-reduction event. EnerNOC is subject to financial penalties for failing to reach the committed MW reduction.

When Idaho Power anticipates the need for capacity, it notifies EnerNOC of the date and time of the event. Idaho Power has access to near real-time energy-usage data and can continuously monitor the success of the demand-reduction event in aggregate. Customers can also continuously monitor their demand-reduction performance using their individual, near real-time energy-usage data through EnerNOC's proprietary software. This metering data and software are available to participating customers throughout the year.

## 2014 Program and Marketing Activities

In 2014, Idaho Power worked with EnerNOC to implement changes that would better align the program with the Settlement Agreement approved by the IPUC in Case No. IPC-E-13-14. The changes included extending the contract termination date through the end of 2014, reducing payments to EnerNOC, amending the payment structure, removing the lower bound of EnerNOC's committed load reduction, modifying the program availability dates to June 15 through August 15, and allowing notification of dispatch of a demand response event to occur through a web portal.

During the first week of the program, EnerNOC committed to provide a meter-level reduction of 29.6 MW. This weekly commitment, or nomination, was comprised of 92 facility sites, of which 90 participated in the program in 2013, and two were added in 2014. The weekly nomination at the end of the season was 25.7 MW and was comprised of 93 facility sites.

EnerNOC was contractually obligated to commit to provide a maximum meter-level reduction of 35 MW for each week in 2014. Their weekly commitments ranged from 25.6 MW to 30 MW. Their commitment peaked the first week in July at 30 MW.

Idaho Power called three demand response events for the FlexPeak Management program in 2014. The first two events occurred in July, and the third event occurred in August. EnerNOC exceeded the committed MW reduction in two of the three events. For the third event, EnerNOC did not reach their committed MW reduction; performance was 96 percent of the committed level. The highest hourly reduction achieved was 39.6 MW, calculated using 9.7-percent line losses (36.1 MW at the meter).

## Cost-Effectiveness

The methods used to determine the cost-effectiveness of the demand response programs was updated in 2014. As part of the public workshops in conjunction with Case No. IPC-E-13-14, Idaho Power and other stakeholders agreed on a new method for valuing demand response. The settlement agreement, as approved in IPUC Order No. 32923, defined the annual cost of operating the three demand response programs for the maximum allowable 60 hours must be no more than $16.7 million. This $16.7 million value is the levelized annual cost of a 170 MW deferred resource over a 20-year life. In 2014, the cost of operating the three demand response programs was $10.6 million. It is estimated that if the three programs were dispatched for the full 60 hours, the total costs would have been approximately $13.8 million, and the programs would have remained cost-effective because there is no variable incentive paid for events beyond the three required events.

The FlexPeak Management program was dispatched for 12 event hours and achieved a maximum demand reduction of 40 MW. The total expense for 2014 was $1,563,211.

## Customer Satisfaction and Evaluations

EnerNOC sent a post-season survey via email to 93 participants representing all the sites enrolled in the program for 2014. Thirteen participants responded for a 14-percent response rate. All of these responses were slightly down from the previous year:

- When asked how prepared they felt for the demand response event on a scale of 1 to 10, 10 being "fully prepared," the average response was 9.2.
- When asked how likely they were to recommend EnerNOC to a peer or business partner on a scale of 1 to 10, 10 being "definitely will," the average response was 8.7.
- When asked how clear the initial notification they received from EnerNOC was on the day of the event on a scale of 1 to 10, 10 being "very clear," the average response was 8.2.
- When asked how satisfied they were with how EnerNOC managed the demand response event on a scale of 1 to 10, 10 being "very satisfied," the average response was 8.8.

A summary of the results is in *Supplement 2: Evaluation*. Also included in the supplement is the *FlexPeak Management Annual Report*.

## 2015 Program and Marketing Strategies

Idaho Power has proposed to internally run and manage the FlexPeak Management program, changing the name to the Flex Peak program starting in 2015. As of December 31, 2014, Idaho Power's contractual obligation agreement with EnerNOC ended. Idaho Power reviewed and received feedback from EEAG on the idea of running the program internally during a conference call on January 9, 2015. Idaho Power filed an application with the IPUC on February 4, 2015 (IPUC Case No. IPC-E-15-03), and filed an advice with the OPUC on March 10, 2015. Prior to this decision in fall 2014, the company conducted an informal inquiry with 25 of the largest participants in the FlexPeak Management program. The company asked them how they might respond to a change in the way the program was designed and managed. The responses generally indicated they would likely participate even if the program changed and they were not provided with the same monitoring and coaching services EnerNOC had provided. The feedback supported Idaho Power's proposal to internally run the Flex Peak Program. Current Flex Peak Program customers were notified on February 11, 2015, that EnerNOC would no longer be managing the program and that the company had filed an application with the IPUC to internally manage the Flex Peak Program.

There are several benefits to a company-managed program. First, the company has identified significant annual cost savings. These cost savings directly impact customer-provided funds. Second, the company-offered program would require each participating customer to adhere to the terms and conditions, and receive payments, as available under the Idaho and Oregon tariff schedules publically available. Last, the company welcomes any opportunity to cross-market energy efficiency programs and strengthen the communication and relationship with its customers directly.

Pending IPUC and OPUC approval, the Flex Peak Program will be available from June 15 through August 15, Monday through Friday, from 2:00 p.m. to 8:00 p.m., excluding holidays. Each dispatch

event will last up to four hours per participant within the available program hours. Dispatch events will not occur more than 60 hours per season. In the event of a system emergency, demand response capacity from the Flex Peak Program will be available. Idaho Power will conduct a minimum of three dispatch events per season. There will be two hours of advance notice to participants.

As per the settlement agreement, Idaho Power has proposed to maintain the current capacity of 35 MW during the 2015 program season. The company believes it can retain current participants and enroll new customers to meet this 35 MW amount. In 2015, Idaho Power will market the Flex Peak Program as needed to acquire enough participation to meet the 35 MW target. The marketing strategies will include a variety of channels, including field interaction by CRs and MCRs, and direct mailers.

# Oregon Commercial Audits

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (audits) | 16 | 18 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $0 | $0 |
| Oregon Energy Efficiency Rider | $9,464 | $5,090 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $9,464 | $5,090 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Levelized Cost ($/kWh) | n/a | n/a |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | |
| Total Resource Benefit/Cost Ratio | n/a | |
| **Program Characteristics** | | |
| Program Jurisdiction | Oregon | |
| Program Inception | 1983 | |

## *Description*

The Oregon Commercial Audits program identifies opportunities for commercial building owners to achieve energy savings. This is a statutory program as required by ORS 469.865 offered under Oregon Schedule No. 82. Through this program, free energy audits provide evaluations and educational services to customers. Annual mailings to each customer in the commercial sector communicate program benefits and offerings.

## *2014 Program and Marketing Activities*

Idaho Power sent out its annual mailing to 1,574 Oregon commercial customers in late September 2014. Customers were notified of the availability of no-cost energy audits and were provided with the Idaho Power publication *Saving Energy Dollars*. Sixteen customers requested an audit, and five customers requested only the brochure. Of the 16 audits, 12 audits were completed by Idaho Power, and 4 were completed by a third-party contractor. The costs were up in 2014 over 2013 because an ongoing invoice for audits performed late in 2013 was not paid for until early 2014.

Idaho Power contracts with EnerTech Services to perform a portion of the requested audits. Energy audits include a review of the customer's past billing data and an inspection of the building shell, HVAC equipment, operating schedules if available, and lighting systems. Additionally, specific business operating practices that can be incorporated to improve energy use are discussed. During the audits, customers receive Idaho Power energy efficiency program information.

## Cost-Effectiveness

As previously stated, the Oregon Commercial Audits program is a statutory program offered under Oregon Schedule 82. Since the required parameters of the Commercial Energy Audit Program are specified in Oregon Schedule 82 and the company abides by these specifications, this program is deemed to be cost-effective. Idaho Power claims no energy savings from this program.

## Customer Satisfaction and Evaluations

Audits provide the opportunity to discuss utility incentives available to customers who install qualifying energy efficiency measures. Both activities can lead to energy efficiency projects being undertaken. Customers are generally pleased with the audit process. This is especially true when the business owner is fully engaged in the audit. Business owners can make the decisions to change operating practices or make capital improvements designed to use energy wisely. Additionally, the audits help identify energy-saving opportunities that may not be obvious to the business owner.

## 2015 Program and Marketing Strategies

The Oregon Commercial Audits program will continue to be an important avenue for Idaho Power to help customers identify energy-saving opportunities. The audits help pinpoint favorable energy-saving actions that customers may pursue through customer behavioral changes or potential capital projects, such as replacing inefficient lighting. Additionally, the audit process will be used to introduce customers to Idaho Power's energy efficiency incentive programs. The program will be marketed through the annual customer notification.

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# IRRIGATION SECTOR OVERVIEW

## Description

The irrigation sector is composed of agricultural customers operating water-pumping or water-delivery systems to irrigate agricultural crops or pasturage. End-use equipment primarily consists of agricultural irrigation pumps and center pivots. The irrigation sector does not include water pumping for non-agricultural purposes, such as the irrigation of lawns, parks, cemeteries, golf courses, or domestic water supply.

In December 2014, the active and inactive irrigation service locations totaled 18,773 system-wide. This was an increase of 1.5 percent compared to 2013, primarily due to the addition of service locations for pumps and pivots to convert land previously furrow-irrigated to sprinkler irrigation systems. Irrigation customers accounted for 1,966,297 MWh of energy usage in 2014, which was a decrease from 2013 by over 6 percent due to a cooler, wetter summer. This sector represented nearly 14 percent of Idaho Power's total electricity usage and about 25 percent of the summer coincident peak demand. Energy usage for this sector has not grown significantly in many years; however, there is substantial yearly variation in usage due primarily to the impact of weather on customer irrigation needs.

Idaho Power offers two programs to the irrigation sector: 1) Irrigation Peak Rewards, a demand response program designed to provide a system peak resource and 2) Irrigation Efficiency Rewards, an energy efficiency program designed to encourage the replacement or improvement of inefficient systems and components. Idaho Power also pays incentives to customers participating in the Green Rewind offering in which motor service centers are paid $2 per hp for each NEMA Standard hp-rated motor up to 5,000 hp for agricultural uses that receives a verified Green Rewind. Participation in Green Rewind ensures the motor's original efficiency is maintained if it is rewound at an approved service center.

In 2014, the Irrigation Peak Rewards program was back in full operation after temporarily being suspended for the 2013 season to address need and cost in light of the company's load and resource balance from the *2013 IRP* showing the company had adequate resources in the near-term. In spring 2014, Idaho Power successfully marketed to the majority of prior participants to continue their participation in the programs, with only an approximated 9-percent drop in potential load reduction from 2013 even though incentives to participate were reduced.

The Irrigation Efficiency Rewards program, in operation since 2003, experienced annual savings that were nearly the same, with 18,511 MWh in 2013 and 18,464 MWh in 2014. During 2014, the Irrigation Efficiency Rewards program contributed 18,428 MWh, while the 15 motors in Green Rewind contributed 35,083 kWh per year of energy savings.

Table 13 summarizes the overall expenses and program performance for both the energy efficiency and demand response programs provided to irrigation customers.

# Programs

Table 13. 2014 irrigation program summary

| Program | Participants | Total Cost | | Savings | |
|---|---|---|---|---|---|
| | | Utility | Resource | Annual Energy (kWh) | Peak Demand (MW) |
| **Demand Response** | | | | | |
| Irrigation Peak Rewards | 2,225 service points | $ 7,597,213 | $ 7,597,213 | n/a | 295 |
| **Total** | | **$ 7,597,213** | **$ 7,597,213** | **n/a** | **295** |
| **Energy Efficiency** | | | | | |
| Irrigation Efficiency Rewards | 1,128 projects | $ 2,446,507 | $18,459,781 | 18,463,611 | 4.6 |
| **Total** | | **$ 2,446,507** | **$18,459,781** | **18,463,611** | **4.6** |

**Note:** See Appendix 3 for notes on methodology and column definitions.

Each year, the company conducts a customer relationship survey. Overall, 52 percent of Idaho Power irrigation customers surveyed in 2014 for the Burke Customer Relationship survey indicated Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Fifty-one percent of survey respondents indicated Idaho Power is meeting or exceeding their needs with information on how to use energy wisely and efficiently. Sixty percent of respondents indicated Idaho Power is meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 40 percent of the irrigation survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of irrigation survey respondents who have participated in at least one Idaho Power energy efficiency program, 92 percent are “very” or “somewhat” satisfied with the program.

In response to a 2013 phone survey conducted by Hansa GCR regarding non-participants of Idaho Power irrigation energy efficiency program options, in 2014 Idaho Power identified irrigation customers that had not participated in either irrigation program. The company’s agricultural representatives (ARs) contacted a few potential customers in each region to ensure awareness of the Idaho Power offerings. To provide information in detail to Idaho Power irrigation customers, in 2014 the company created two irrigation-specific newsletters. Newsletters included energy efficiency information and other important information of interest to irrigation customers.

In 2015, Idaho Power ARs will continue contacting non-participants potentially eligible for program participation and will continue providing a newsletter at least twice a year.

# Irrigation Efficiency Rewards

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 1,128 | 995 |
| Energy Savings (kWh)[a] | 18,463,611 | 18,511,221 |
| Demand Reduction (MW) | 4.6 | 3.0 |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $2,256,235 | $2,277,059 |
| Oregon Energy Efficiency Rider | $144,392 | $134,789 |
| Idaho Power Funds | $45,880 | $29,539 |
| Total Program Costs—All Sources | $2,446,507 | $2,441,386 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.016 | $0.016 |
| Total Resource Levelized Cost ($/kWh) | $0.119 | $0.098 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 5.67 | |
| Total Resource Benefit/Cost Ratio | 1.83 | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2003 | |

[a] Includes kWh savings from Green Rewind projects.

# Description

The Irrigation Efficiency Rewards program encourages energy-efficient equipment use and design in irrigation systems. Qualified irrigators in Idaho Power's Idaho and Oregon service area can receive financial incentives and reduce their electricity usage. Incentives for the Irrigation Efficiency Rewards program help customers recover a portion of the costs of installing a new, more efficient irrigation system or energy-efficient improvements to existing systems.

Two options help meet the needs for major or minor changes to new or existing systems. The Custom Incentive Option addresses extensive retrofits of existing systems or new irrigation systems, providing component upgrades and large-scale improvements. For new systems, the incentive is 25 cents per the first year of kWh saved above standard installation methods, not to exceed 10 percent of the new system's cost. For existing system upgrades, the incentive is 25 cents per the first year of kWh saved, or $450 per kW demand reduction, whichever is greater, but not to exceed 75 percent of the total project cost. The qualifying energy efficiency measures include any hardware changes that result in a reduction of the potential kWh usage of an irrigation system.

Idaho Power reviews, analyzes, and makes recommendations on each application. On each completed project, before final payment, all project information is reviewed. Prior usage history, actual invoices, and, in many situations, post-usage demand data are available to verify savings and incentives.

The Menu Incentive Option covers a significant portion of the costs of repairing and replacing specific components that help the irrigation system use less energy. This option is designed for systems where

small maintenance upgrades provide energy savings from 11 separate measures. These measures are as follows:

- New flow-control type nozzles
- New nozzles for impact, rotating, or fixed-head sprinklers
- New or rebuilt impact or rotating type sprinklers
- New or rebuilt wheel-line levelers
- New complete low-pressure pivot package
- New drains for pivots or wheel-lines
- New riser caps and gaskets for hand-lines, wheel-lines, and portable mainlines
- New wheel-line hubs
- New pivot gooseneck and drop tube
- Leaky pipe repair
- New center pivot base boot gasket

Payments are calculated on pre-determined average kWh savings per component.

In addition to incentives, the program offers customer education, training, and irrigation-system assessments. Idaho Power ARs sponsor, coordinate, conduct, and present educational workshops for irrigation customers, providing expert information and training across Idaho Power's service area. Energy audits conducted by Idaho Power ARs evaluate prospective customers' potential savings. ARs from Idaho Power also engage agricultural irrigation equipment dealers in training sessions, increasing their knowledge of energy efficient designs and awareness of the program and promoting the program through the irrigation equipment distribution channels. Marketing efforts include direct mailings, ads in agricultural publications, and participation in agricultural workshops and conferences.

Because the irrigation sector is a load comprised primarily of motors, Idaho Power participates in Green Rewinds. It is an opportunity that enables customers to maintain the motor's original efficiency by ensuring proper rewind of the electric motor. Motor service centers are paid $2 per hp for each NEMA Standard hp-rated motor 15 hp to 5,000 hp that receives a verified Green Rewind. The RTF approved the Green Motors Practices rewinding as an energy efficiency measure and approved a table of deemed savings for industrial and agricultural applications. In 2013, the RTF updated the deemed-savings values.

## 2014 Program and Marketing Activities

In 2012, the RTF approved a plan to re-evaluate the deemed savings for each measure under the Menu Incentive Option. Idaho Power met with the RTF in early 2013 and evaluated the research done by the University of Idaho to study the savings impacts of the measures provided in the Menu Incentive Option. In April 2013, the RTF approved the updated savings under the RTF Small Saver category. The 2013 RTF-deemed savings have a slightly different component itemization for some measures.

For example, nozzle replacements, sprinklers, and replacement regulators were combined under one sprinkler package, and gasket and drain replacements were separated into two measures. ADM conducted an impact evaluation in 2013. In this evaluation, it was recommended Idaho Power align measures to be consistent with how the RTF has deemed savings. Idaho Power presented the RTF updated savings values and proposed program changes at the EEAG meeting February 6, 2014. After the EEAG presentation, the program was filed with the OPUC as Advice No. 14-04 and was approved effective May 16, 2014. The 2014 energy savings values reflect the new RTF values for 2014.

Of the 1,128 irrigation efficiency projects completed in 2014, 1,000 were associated with the Menu Incentive Option, providing an estimated 14,051 MWh of energy savings and 2.75 MW of demand reduction. The Custom Incentive Option had 128 projects, of which 70 were new irrigation systems and 58 were on existing systems. This option provided 4,377 MWh of energy savings and 1.83 MW of demand reduction for the year. Also during 2014, irrigation customers contributed 35,083 kWh of energy savings from 15 motors participating in the Green Rewind opportunity.

Idaho Power ARs, the program specialist, and the agricultural engineer participated in training that maintains their Certified Irrigation Designer (CID) and Certified Agricultural Irrigation Specialist (CAIS) certifications. This training allows Idaho Power to maintain its high level of expertise in the irrigation industry and is sponsored by the nationally based Irrigation Association.

Idaho Power continued to market the program by varying the location of workshops and offering new presentations to irrigation customers. In 2014, Idaho Power provided seven workshops promoting the Irrigation Efficiency Rewards program throughout the service area. Approximately 250 customers attended workshops in Blackfoot, Aberdeen, Eden, Twin Falls, Mountain Home, Nampa, and Ontario. Idaho Power also accepted invitations to present the program at four workshops sponsored by agricultural groups in Shoshone, Hailey, Ontario, and Burley. Exhibitor booths were displayed at regional agricultural trade shows, including the Eastern Idaho Agriculture Expo, Western Idaho Agriculture Expo, the Agri-Action Ag show, the Treasure Valley Irrigation Conference, and the Idaho Irrigation Equipment Association show and conference. In addition, ARs made target visits or communicated with a selected number of non-program participants to increase customer education. A database of irrigation dealers and vendors was maintained for direct-mail purposes. Irrigation dealers and vendors are a key component to the successful marketing of the program; therefore, direct mailings containing the most up-to-date program information, brochures, and dealer-specific meetings ensured correct program promotion.

The Irrigation Efficiency Rewards brochure was updated in spring 2014 and distributed to all irrigation rate schedule customers using direct mail. Idaho Power ARs also distributed large quantities to irrigation dealers and vendors in the service area.

In 2014, the newsletter *Irrigation News* was created to improve customer satisfaction with all irrigation customers in Idaho and Oregon. The newsletter shares valuable information specifically for irrigation customers to help clarify processes, help customers better understand their bill, provide information on energy efficiency and energy efficiency programs, clarify rates, and provide information on safety. The newsletter stimulated numerous opportunities to communicate and dialogue with irrigation customers on the variety of topics to help improve customer relations and promote the Irrigation Efficiency Rewards program. Media outreach included an Irrigation Efficiency Rewards success story provided to Capital Press about a project in Richfield, Idaho, that upgraded a farm’s irrigation system.

The total number of print publications that marketed the Irrigation Efficiency Rewards program consisted of 10 print ads in five agricultural print publications. Idaho Power also used two opportunities

in radio advertising during Agri-Action and the Future Farmers of America (now FFA) National FFA Week. New creative advertising material was launched in fall 2014 to promote Idaho Power's Irrigation Efficiency Rewards program. Four ads were created that targeted Idaho-specific crops, including potatoes, sugar beets, hay, and corn. Digital ads using the new creative material are being tested with the target audience to determine if they respond well to digital information sources. Digital ads are running in *The Capital Press* from December 19, 2014, to January 16, 2015, with a guaranteed 60,000 impressions during the cycle.

At the end of 2014, a postcard was mailed to all irrigation dealers and vendors thanking them for the integral role they play in the success of this program.

In 2013, Idaho Power conducted an impact evaluation of the Irrigation Efficiency Rewards program. This evaluation was performed by third-party contractor ADM. Data for the study was collected through a review of program materials and interviews with participating agricultural customers, agricultural trade allies, and Idaho Power staff. Based on the results of this evaluation, ADM provided recommendations for program improvement. Their recommendations and Idaho Power's 2014 responses are described below.

The evaluators suggested Idaho Power consider including NEBs as part of a comprehensive cost-effectiveness test for the program and that currently, there is no known previously published research conducted on NEBs for irrigation systems. ADM indicated the RTF provides values for societal costs and benefits for menu components. However, Idaho Power has identified the RTF benefits being referred to are already considered as part of the power system benefits and costs and are not considered NEBs. Idaho Power converted its previous NEB assumptions to a per-kWh basis as recommended by ADM and is currently collecting customer-calculated NEBs to more accurately account for these benefits. A new brochure and application providing an opportunity for customers to identify NEBs, such as yield, labor, and other benefits, was direct-mailed to all irrigation customers in May 2014.

ADM recommended that Idaho Power update the menu component incentives and expected savings to match the RTF. ADM noted that the 2013 version of the RTF combined the existing nozzle measure, low-pressure regulator measure, and sprinkler-head measures into a new "sprinkler package" measure. The application for the 2014 irrigation program should be revised to match the measures covered under the RTF. To comply with this ADM recommendation, changes to the Irrigation Efficiency Rewards program aligning the measures and expected savings to the RTF recommendations were presented to EEAG at the February 6, 2014, EEAG meeting. These changes were filed with the OPUC and approved in Advice No. 14-04, effective May 16, 2014, and are reflected in the new program brochure.

## Cost-Effectiveness

Idaho Power calculates cost-effectiveness using different savings and benefits assumptions and measurements under the Custom Incentive Option and the Menu Incentive Option of Irrigation Efficiency Rewards.

Each application under the Custom Incentive Option received by Idaho Power undergoes an assessment to estimate the energy savings that will be achieved through a customer's participation in the program. On existing system upgrades, Idaho Power estimates the effectiveness of a project using a service point's previous five years of electricity usage history on a case-by-case basis depending on the applicant's history. On new system installations, the company uses standard practices as the baseline and determines the efficiency of the applicant's proposed project. Based on the specific equipment to be installed, the company calculates the estimated post-installation energy consumption of the system. The company verifies the completion of the system design through aerial photographs, maps, and field

visits by Idaho Power ARs to ensure the irrigation system is installed and used in the manner the applicant's documentation describes.

Each application under the Menu Incentive Option received by Idaho Power also undergoes an assessment to ensure deemed savings are appropriate and reasonable. Payments are calculated on a prescribed basis by measure. In some cases, the energy-savings estimates in the Menu Incentive Option are adjusted downward from deemed RTF savings to better reflect known information in how the components are actually being used. For example, a half-circle center pivot may use half as much energy as a full-circle center pivot, or acres irrigated using spring water for a portion of the season reduces seasonal pumping kWh usage. All deemed savings are based on seasonal operating hour assumptions by region. If a system's usage history indicates it has lower operating hours than the assumptions, like the examples above, the deemed savings are adjusted.

Based on the deemed savings from the RTF, all the measures offered under the Menu Incentive Option are cost-effective with the exception of rebuilt or new brass impact sprinklers. Idaho Power determined these brass sprinklers meet at least one of the cost-effectiveness exceptions outlined in OPUC Order No. 94-590. Idaho Power filed UM-1710 to request a cost-effectiveness exception with the OPUC on November 4, 2014, and subsequently re-filed it on February 11, 2015. The case is still pending. For details on the cost-effectiveness assumptions for the Menu Incentive Option, see *Supplement 1: Cost-Effectiveness*.

## 2015 Program and Marketing Strategies

Marketing plans for 2015 include conducting 7 to 10 customer-based irrigation workshops. Additionally, Idaho Power will continue to participate in five regional agricultural trade shows. These workshops and trade shows enable discussions between Idaho Power representatives, the company's customers, irrigation dealers, and trade allies while continually educating them about irrigation best practices, the program, and ways to participate. Each year, workshops are conducted in different local areas. Subjects and presentations are updated to offer new ideas.

Idaho Power will work closely with customers who have participated in the Irrigation Efficiency Rewards program to create success stories by highlighting efficient irrigation system designs for program promotion.

The Idaho Power *Irrigation News* newsletter will continue to provide a direct line of communication on valuable information that will clarify processes, help customers better understand their bill, provide information on energy efficiency and energy efficiency programs, clarify rates, and provide information on safety, specifically for irrigation customers.

Idaho Power will continue to work with the Scientific Irrigation Scheduling (SIS) sub-committee consisting of RTF members, utility representatives, and professional experts to determine the potential for SIS programs.

A 2015 media plan was created aimed at increasing the impact of advertising on this program. Idaho Power will continue to promote the program in print ads in agricultural-focused editions of Idaho newspapers and agriculture magazines. The effectiveness of online ads will be evaluated with this target audience.

In early 2015, Idaho Power will test the effectiveness of translating various agriculture workshops and presentations into Spanish. The company will look at how this is received and make appropriate decisions moving forward.

# Irrigation Peak Rewards

| | 2014 | 2013 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (service points) | 2,225 | n/a |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | 295 | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,374,724 | $407,496 |
| Oregon Energy Efficiency Rider | $104,995 | $30,117 |
| Idaho Power Funds | $6,117,494 | $1,634,494 |
| Total Program Costs—All Sources | $7,597,213 | $2,072,107 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Levelized Cost ($/kWh) | n/a | n/a |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | |
| Total Resource Benefit/Cost Ratio | n/a | |
| **Program Characteristics** | | |
| Program Jurisdiction | Idaho/Oregon | |
| Program Inception | 2004 | |

## *Description*

Idaho Power's 2014 Irrigation Peak Rewards program is a voluntary program available to Idaho and Oregon agricultural irrigation customers with service locations that had participated in the past. The purpose of the program is to minimize or delay the need to build new supply-side resources. By reducing demand on the most extreme load days in the most extreme summer conditions, the Irrigation Peak Rewards program can reduce the amount of generation and transmission resources Idaho Power needs to build. The program pays irrigation customers a financial incentive for the ability to turn off specified irrigation pumps with the use of one or more load control devices during the program season of June 15 through August 15. The Irrigation Peak Rewards program provides approximately 300 MW of load reduction, which is a capacity near 9 percent of Idaho Power's all-time system peak. This program, along with Idaho Power's other demand response program, has eliminated or delayed the need to build supply-side resources.

In 2013, Idaho Power filed IPUC Case No. IPC-E-12-29 to temporarily suspend the program to allow time to work with stakeholders and interested parties to determine how the program should operate in the future. These workshops resulted in settlement agreements reached in Idaho Case No. IPC-E-13-14 and Oregon UM 1653. The Irrigation Peak Rewards program was again offered as a demand response program in 2014, with some modifications. Program modifications resulted in an approximately $5 million in savings with only an approximately 9-percent drop in participation.

Per the terms in the settlement agreement, Idaho Power agricultural irrigation customers in both Idaho and Oregon that had service locations that participated in the past were eligible for participation in 2014. Customers could chose between two options: 1) an Automatic Dispatch Option that allows Idaho

Power to remotely turn off participants' pumps or 2) a Manual Dispatch Option designed for large-service locations with 1,000 hp or greater that allows participating customers, after being notified by Idaho Power, to choose which pumps to manually turn off during a load control event. Historically, customers could choose a third option, the Electronic Timer Option. In 2014, this was discontinued. Customers who had service locations that had participated in the past in the Electronic Timer Option had the ability to participate by selecting the Automatic Dispatch Option.

For customers participating in the dispatch options, load control events could occur up to four hours per day, up to 15 hours per week, but no more than 60 hours per season. Only service locations that had participated in the past were eligible to participate in the program for 2014. Participating customers were guaranteed to experience at least three events per season. Dispatchable load control events could happen between 1:00 p.m. and 9:00 p.m. on weekdays and Saturday. The incentive structure consisted of fixed and variable payments. The fixed portion was paid based on participation during each of the first three events. The variable incentive was applied based on participation in events following the first three. Customers who chose to participate until 9:00 p.m. could receive a higher variable incentive for events that occurred after the first three. A control device attached to the customer's individual pump electrical panels allowed Idaho Power to remotely control the pumps. Participants in the Manual Dispatch Option were required to nominate the amount of kW they were enrolling in the program by June 1 of the program year.

Program rules allow participants the ability to opt out of dispatch events up to five times per service point. The first three opt-outs each incur a penalty fee of $5 per kW, while the remaining two opt-outs each incur a penalty fee of $1 per kW based on the current month's billing kW. The opt-out penalty fees may be prorated to correspond with the dates of program operation and are completed through manual bill adjustments. The fees will never exceed the amount of the incentive that would have been paid.

The incentive amounts that participating customers received per participating service location are listed in Table 14.

Table 14. 2014 program incentives

| Option | Fixed Demand Credit ($/billing kW) | Fixed Energy Credit ($/billing kWh) | Variable Energy Credit ($/billing kWh) | Extended Hour Variable Energy Credit ($/billing kWh) |
|---|---|---|---|---|
| Automatic and manual options ..... | $5.00 | $0.0076 | $0.148 | $0.198 |

## 2014 Program and Marketing Activities

After the Irrigation Peak Program suspension in 2013, Idaho Power used workshops, trade shows, and direct customer mailings to make a concerted effort to encourage past participants to re-enroll in 2014. Despite reinstating the program with a reduction in incentive amounts and modifications to the event notification, most past participants re-enrolled to participate in 2014. The number of service points enrolled to participate in the program for 2014 was 2,225. This accounted for approximately 81 percent of the eligible service points. Three load control events occurred in July 2014, with the highest load reduction occurring on July 10 and providing an estimated 295 MW on July 10.

In 2014, the program was only marketed to customers who had service locations that had participated in the program in the past. Idaho Power provided information about the 2014 Irrigation Peak Rewards program at seven workshops throughout the service area. Approximately 250 customers attended workshops in Blackfoot, Aberdeen, Eden, Twin Falls, Mountain Home, Nampa, and Ontario.

Idaho Power also accepted invitations to present the program at four workshops sponsored by agricultural groups in Shoshone, Hailey, Ontario, and Burley. Exhibitor booths were displayed at regional agricultural trade shows, including the Eastern Idaho Agriculture Expo, Western Idaho Agriculture Expo, the Agri-Action Ag show, the Treasure Valley Irrigation Conference, and the Idaho Irrigation Equipment Association show and conference. Additionally, numerous one-on-one conversations with Idaho Power ARs informed customers of the 2014 program eligibility requirements and program offering.

An information flyer was made visually more appealing and easier to read by using a brochure format for existing Peak Rewards participants in December 2014. In October *Connections*, the program received recognition in the article *Demand Response Programs Ease Summer Peak*.

## Cost-Effectiveness

The methods used to determine the cost-effectiveness of the demand response programs was updated in 2014. As part of the public workshops in conjunction with Case No. IPC-E-13-14, Idaho Power and other stakeholders agreed on a new method for valuing demand response. The settlement agreement, as approved in IPUC Order No. 32923, defined the annual cost of operating the three demand response programs for the maximum allowable 60 hours must not be more than $16.7 million. This $16.7 million value is the levelized annual cost of a 170 MW deferred resource over a 20-year life. In 2014, the cost of operating the three demand response programs was $10.6 million. It is estimated that if the three programs were dispatched for the full 60 hours, the total costs would have been approximately $13.8 million, and the programs would have remained cost-effective.

The Irrigation Peak Rewards program was dispatched for 12 event hours and achieved a maximum demand reduction of 295 MW. The total expense for 2014 was $7,597,213 and would have been approximately $10.8 million if the program was fully used for 60 hours.

## Customer Satisfaction and Evaluations

Each year, Idaho Power produces an internal annual report for the Irrigation Peak Rewards program. This report includes a load-reduction analysis, cost-effectiveness information, and program changes. A copy is included in *Supplement 2: Evaluation*.

In 2014, Idaho Power contracted PECI to complete an impact evaluation of the 2014 Peak Rewards program. The goals of the impact evaluation were to determine the demand reduction (in MW) during three actual called events and determine the counterfactual realization rate if an event been called on each business day during the program's June 15 through August 15 season.

PECI completed analyses of curtailment events held on July 2, July 10, and July 14, 2014, each containing four dispatch groups that curtailed enrolled irrigation pumps in rolling four-hour increments. The results of the curtailment event analyses showed maximum meter level demand reductions of 257.9 MW, 268.9 MW, and 250.5 MW, respectively, for the three events, which do not include system losses of 9.7 percent.

Due to the Irrigation Peak Rewards program suspension in 2013, annual device maintenance did not occur for nearly two years, resulting in a 7-percent device failure rate, as indicated in the evaluation report, lowering the overall realization rates. The past analysis of the program realization rates indicates they would be higher if device maintenance were at normal levels, resulting in fewer device failures.

As part of the impact evaluation, PECI developed a counterfactual realization rate analysis that demonstrated that the time period within an irrigation season has a large influence on the realization rate. With 2014 device failures excluded, realization rates ranged from 65 percent at the beginning of the program season to a peak realization rate of 74 percent during the first two weeks of July. The counterfactual realization rate in the last quarter of the season (August 1–15) dropped off significantly to 34 percent with device failures included. This was due to a high percentage of pumps being shut off during the first two weeks of August due to crop maturity and uncharacteristically extreme rainfall of 2 to 4 inches in southern and eastern Idaho. This resulted in a skewed realization rate that was an exception to what has been determined in past analyses.

The results of the impact evaluation showed Idaho Power's Irrigation Peak Rewards program functioned as intended, and, if properly maintained, can be relied on to provide dispatchable demand reduction to the electricity grid. The evaluation also identified opportunities to maximize the demand reduction benefit the program delivers to the electricity grid. First, Idaho Power may increase the program's realization rate by working to address device failure problems. The uncharacteristically high number of device failures in 2014 provided valuable information on how to identify and address device failures. In an effort to increase realization rates by minimizing device failures, Idaho Power may also decide to use more AMI devices for load control in the future.

Finally, as seen in the counterfactual realization rate analysis results, maximum load reduction potential is realized during the peak of the irrigation season. This time period generally equates to the last week of June through the middle of July, which usually correlates to Idaho Powers' overall system peaks.

## *2015 Program and Marketing Strategies*

Idaho Power will continue to work with past participants in this program who are eligible to participate in 2015 to encourage their participation.

Idaho Power will conduct 8 to 10 workshops throughout the company's regions to familiarize customers to the program details and eligibility requirements. Through direct mail, each eligible customer will receive an informational packet containing a personalized letter, sign-up worksheet, informational brochure, and contract agreement encouraging their participation for the 2015 program season. Idaho Power ARs will continue one-on-one customer contact to inform and encourage program participation.

In early 2015, Idaho Power will test the effectiveness of translating various agriculture workshops and presentations into Spanish. The company will look at how this is received and make appropriate decisions moving forward.

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# MARKET TRANSFORMATION

## Northwest Energy Efficiency Alliance

NEEA encourages and supports cost-effective market transformation efforts in Idaho, Oregon, Washington, and Montana. Through partnerships with local utilities, NEEA motivates the marketplace adoption of energy-saving services and technologies and encourages regional education and marketing platforms. NEEA provides training and marketing resources across residential, commercial, and industrial sectors. Idaho Power accomplishes market transformation in its service area through membership and coordinated activities with NEEA. Idaho Power has been a funding member of NEEA since its inception in 1997.

The fifth year of NEEA's current, five-year funding cycle ended in 2014. As early as 2009 Idaho Power expressed a desire to see a change in the way NEEA services were offered that would differentiate "core" services of market transformation activities from optional services, whereby utilities could elect to support projects and activities that matched their interests and needs. During 2014, the company continued to advocate for this model through multiple meetings with NEEA, by actively participating on the NEEA Board of Directors and exploring alternative funding models, and by chairing and serving on the Alternative Funding Model Working Group Committee of the NEEA Board of Directors. The end result of these efforts was that the NEEA *2015–2019 Business Plan* offered optional programs and activities. Idaho Power executed an agreement to continue its participation in NEEA and chose not to participate in some optional programs and activities where it believes it is providing or can provide the same services at a lower cost or more effectively for the 2015 to 2019 funding cycle. This delivers significant energy-savings potential and ultimately saves Idaho Power customers $3,304,560 when compared to the 2010 to 2014 funding cycle agreement.

NEEA performs several MPERs on various energy efficiency efforts each year. In addition to the MPERs, NEEA provides market-research reports, generally through third-party contractors, for energy efficiency initiatives throughout the Pacific Northwest. Each of the reports applicable to Idaho is included in the NEEA Market Effects Evaluations in *Supplement 2: Evaluation*.

Idaho Power has participated by phone, online, or in person in a variety of NEEA activities. In 2014, Idaho Power energy efficiency staff served on NEEA's Board of Directors, the Regional Portfolio Advisory Committee, Residential Advisory Committee, Commercial Advisory Committee, Industrial Advisory Committee, Irrigation Advisory Committee, Cost-Effectiveness and Evaluation Advisory Committee, Consumer Electronics Energy Forward Initiative, Conduit online community, Regional Emerging Technologies Advisory Committee (RETAC), NWRRC, Northwest Heat Pump Water Heater Group, Code Collaborative, and Regional Lighting Strategy Working Group and participated in NEEA-sponsored studies and research.

Idaho Power also participates in NEEA's Northwest Research Group. This group meets throughout the year to catalogue and coordinate energy efficiency research projects regionally. Idaho Power collaborates with regional utilities doing similar program evaluations or that may face similar program challenges.

### *Commercial and Industrial NEEA Activities in Idaho*

NEEA continued to provide support for commercial energy efficiency activities in Idaho in 2014. This included partial funding of the IDL and local BetterBricks® trainings and workshops.

Technical training and education continue to be important to Idaho Power's industrial customers, helping them identify energy efficiency opportunities within their facilities. Seven technical training classes were completed in 2014. Topics included compressed air, air-cooled refrigeration systems, pump systems, and fan system efficiency. The level of attendance at these classes remained high, with 119 participants attending the classes. See the Custom Efficiency program section for more details regarding the technical training classes.

Additionally, 2014 encompassed Phase IV of the webinar pilot plan coordinated by NEEA. Three webinars were presented free to all attendees. Topics included VFDs, efficient industrial lighting, and energy auditing and troubleshooting. There were 24 total Idaho Power region participants that attended the webinar sessions in 2014.

Idaho Power co-sponsored with NEEA a two-day RETA CRES review class training with 13 customers in attendance. The training reviewed refrigeration energy efficiency concepts and prepared the attendees for the RETA CRES Exam.

Idaho Power participated as a member of the NEEA Commercial Lighting Working Group. This group formed through collaboration with stakeholders to identify opportunities and strategic needs to support the region's success in commercial lighting. NEEA launched its first strategy from this report in November 2013, a market test of a midstream RWLR Initiative. The initiative goal is to change the pricing, stocking, and sales practices of reduced-wattage fluorescent T-8 lamps in the maintenance market. Targeted electrical distributors across the region were selected for participation. No distributor in Idaho Power's service area was selected for participation. Results of this pilot will be available in 2015. The pilot results will be used to determine whether NEEA, in coordination with stakeholders, will scale this program in 2015 across the region to try to transform this largely untapped market. NEEA's second strategy, Top-Tier Trade Ally Training, is in the development stage. This strategy will provide advanced lighting training to high-performing trade allies throughout the region, with an end result of achieving deeper energy savings in commercial lighting retrofit projects. Development of this strategy will continue throughout most of 2015, with implementation of pilot trainings in Idaho in 2016.

Idaho Power continued its partnership with BOMA of Boise and NEEA to offer continued coaching and support to the Kilowatt Crackdown™ participants in 2014. In 2013, 43 buildings competed in the competition, which included benchmarking their building in ENERGY STAR® Portfolio Manager and implementing low-cost and no-cost efficiency measures. In 2014, this effort was continued with ongoing coaching and support to further their energy efficiency efforts.

NEEA's pilot project in Idaho for their Existing Building Renewal (EBR) initiative was ongoing in 2014. This initiative is aimed at developing and testing new industry tools for commercial property owners engaging in deep energy retrofits. The Idaho project will be phased in through 2016. Idaho Power worked with The Idaho Statesman's *Business Insider* to feature the EBR initiative as their January cover story, along with other articles about *Retrofitting for the Future*. The issue appeared January 15, the same day Idaho Power issued a press release recognizing a local commercial real estate firm for its participation in the initiative.

In 2014, NEEA continued to have demonstrations on projects on variable-rate irrigation (VRI) and variable-speed irrigation (VSI) at various locations. VRI works by allowing a varied amount of water coming out of each sprinkler along an irrigation pivot. VSI is where the speed of the pivot irrigation system is varied as it makes a rotation for irrigation. The potential for energy savings exists with both technologies if different areas of the field have different water requirements. Information from NEEA indicated additional technical development was required and the adoption of the technology

would be challenging. The NEEA Board of Directors voted to remove the Initiative from the portfolio in the *2015–2019 Business Plan*. NEEA staff completed the 2014 demonstrations and a series of final reports that document the qualitative and quantitative findings from the three years of the Initiative. A copy of the reports will be included on the CD accompanying *Supplement 2: Evaluation* in next year's *Demand-Side Management 2015 Annual Report*.

NEEA also worked with Oregon State University to develop a common set of data standards for vendors or manufactures to better integrate technologies such as soil sensors, flow meters, pumping systems, and pivot systems—including VRI & VSI—to promote the combination of irrigation technologies for increased efficiency of water use. In 2015, through its scanning efforts, NEEA will continue to evaluate the usefulness and usability of the data standards.

## Residential NEEA Activities in Idaho

NEEA supported a variety of residential programs and associated activities in Idaho Power's service area in 2014. NEEA is directly involved in providing additional funding and support for ENERGY STAR® Homes Northwest, the DHP Pilot, and the Heat Pump Water Heater (HPWH) research project. Idaho Power served on workgroups for the DHP, HPWH, Retail Product Portfolio, RETAC, and a short-term dryer specification workgroup. Idaho Power participated in the Conduit online community and the Northwest Regional Retail Collaborative.

NEEA provides ENERGY STAR Homes Northwest builder and contractor training, manages the regional-homes database, develops regional marketing campaigns, and coordinates the various building specifications and requirements with the EPA and utilities in Idaho, Montana, Oregon, and Washington. Most of these activities are managed through a third-party implementer hired by NEEA.

NEEA is taking energy-efficient homes to the next step above ENERGY STAR with its Next Step Homes pilot program. The goal of this innovative pilot program is to identify the most cost-effective ways to achieve maximum energy savings in residential new construction. NEEA recruited builders throughout the Northwest to build to a high-performance specification, then installed monitoring devices in the homes to track energy-saving performance. NEEA is currently trying to recruit a Next Step Homes builder in Idaho Power's service area.

NEEA has coordinated the DHP Pilot research project since 2009, which includes data collection, design, results analysis, savings calculations, and ongoing promotional activities. Idaho Power was a member of the NEEA Ductless Heat Pump Workgroup during 2014. The goal of the pilot is to encourage the adoption of these products while displacing the use of existing electric-resistance zonal heating systems in homes. NEEA created and launched a regional marketing program, which was conducted during summer and fall 2014. The goal of the program was to increase consumer awareness of DHPs. The promotion included the use of social media, as well as radio, television, and website ads. Idaho Power currently offers a $750 cash incentive for qualified homeowners who install a qualified DHP system.

NEEA coordinated a residential HPWH research project in the Northwest region that started around five years ago. Idaho Power was represented on the NEEA HPWH Workgroup during 2014. A goal of the project is to promote the adoption of higher-efficiency HPWHs over traditional resistance-heat water heaters. Another goal is to provide a business case to the DOE encouraging the DOE to make the federal standards and test methods for domestic electric water heaters more stringent. The research project includes data collection, design, analysis, savings calculations, and promotions. NEEA's promotions included rebates to residential homeowners who had certain HPWHs installed. The promotion required

the HPWH to be installed by a contractor trained by NEEA. NEEA also arranged for a HPWH discount program to be offered through retailers. The research project was conducted in 2014 and will continue in 2015. Idaho Power is monitoring this research closely to determine when a northern tier HPWH will be developed that is reliable and applicable to Idaho Power's climate zones.

NEEA developed a baseline forecast in fall 2012 describing the naturally occurring market adoption of HPWHs over a 20-year span. The baseline forecast excluded any market influence from utilities or NEEA initiatives. NEEA published the *NEEA Heat Pump Water Heater Baseline Forecast Research*, created by Evergreen Economics, on October 23, 2014. A copy of NEEA Report E14-300 is included on the CD accompanying *Supplement 2: Evaluation*.

NEEA performed field research beginning in fall 2013 to evaluate the ability for HPWHs to provide demand response to the electric grid. Field research involved fitting 20 homes in the Northwest with HPWHs. The water heaters received communication control signals from a remote third party. Units were tested for their ability to increase and decrease water heating electric load by adjusting storage tank temperature set points. On September 29, 2014, NEEA published the *Heat Pump Water Heaters for Demand Response and Energy Storage* created by Ecofys. A copy of the NEEA Report E14-296 is included on the CD accompanying *Supplement 2: Evaluation*.

In 2014, NEEA launched the RPP. Idaho Power participated in the advisory workgroup for the RPP. The RPP is based on the Consumer Electronics Energy Forward Initiative, which ended in 2013. The RPP used mid-stream incentives to influence retail stocking practices, ultimately driving manufacturing and standards for a portfolio of energy-efficient products sold through the retail channel.

The 2014 RPP goal was to expand and test the upstream approach with different product categories and different retailer types. To maintain relationships with electronics retailers developed under the Consumer Electronics Energy Forward Initiative, the RPP offered incentives on televisions and home theaters in box/soundbars. To test the model at big box, do-it-yourself retailers, the RPP offered incentives on air purifiers and dishwashers.

Idaho Power also participated in NEEA's Residential Advisory Committee meetings and activities throughout 2014. Additionally, one member of the residential programs team, one member of the commercial/industrial programs team, and one analyst attended NEEA's Efficiency Exchange in May 2014. In September 2014, the DSM residential lighting program specialist and a DSM program analyst participated in a one-day lighting summit hosted by NEEA. Summit participants explored ways to capture full-category retail sales data for light bulbs.

Idaho Power participated in RETAC, the purpose of which is to discuss and provide feedback on various emerging technologies in the region. RETAC met twice in 2014 to review the emerging technology pipeline for BPA, NEEA, and the NWPCC *Seventh Power Plan*. Technologies of particular interest to the group include $CO_2$ heat pumps, high-performance manufactured homes, LEDs and advanced controls, and home energy management systems.

An Idaho Power residential specialist was involved with the NWRRC in 2014. This collaborative forum evaluates and coordinates regional retail strategy. Activities of this group included two multi-year pilot projects. The first was aimed at understanding market lift promotions. The second aimed at improving retail contractors' participation in utility programs. The group also serves as the advisory workgroup to NEEA's RPP initiative.

## NEEA Funding

In 2014, Idaho Power began the fifth year of the 2010 to 2014 *Regional Energy Efficiency Initiative Agreement* with NEEA. Per this agreement, Idaho Power is committed to fund NEEA based on a quarterly estimate of expenses up to the five-year total direct funding amount of $16.5 million in support of NEEA's implementation of market transformation programs in Idaho Power's service area. Of this amount in 2014, 100 percent was funded through the Idaho and Oregon riders.

In 2014, Idaho Power paid $3,305,917 to NEEA. The Idaho jurisdictional allocation of the payments was $3,140,621, while $165,296 was paid for the Oregon jurisdiction. Other expenses associated with NEEA activities, such as administration and travel, were paid from Idaho and Oregon Riders.

Final NEEA savings for 2014 will be released in June 2015. For the annual report, preliminary funder share savings for 2014 were assumed to be similar to 2013 final savings. In the *Demand-Side Management 2013 Annual Report*, the NEEA preliminary funding share savings reported were 18,346 MWh. The revised estimate included in this report for 2013 final funding share NEEA savings is 20,568 MWh. Preliminary estimates reported by NEEA for 2014 indicate Idaho Power's share of regional market transformation MWh savings for 2014 is 20,000 MWh. Idaho Power relies on NEEA to report the energy savings and other benefits of NEEA's regional portfolio of initiatives. For further information about NEEA, visit their website at neea.org.

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# OTHER PROGRAMS AND ACTIVITIES

## Residential Energy Efficiency Education Initiative

Idaho Power recognizes the value of general energy efficiency awareness and education in creating behavioral change and customer demand for, and satisfaction with, its programs. The Residential Energy Efficiency Education Initiative promotes energy efficiency to the residential sector. This is achieved by creating and delivering educational materials and programs that result in wise and informed choices regarding energy use and increase Idaho Power's energy efficiency program participation.

The Residential Energy Efficiency Education Initiative continued to produce semiannual energy efficiency guides in 2014. These guides were primarily distributed via insertion in local newspapers and at events across Idaho Power's service area. Process improvements implemented in 2014 include the following:

- Enhanced design elements identified in 2013 were repeated in the 2014 guides to further the publication's identity and strengthen readership recognition.
- Idaho Power's Technical Editing team provided expertise and training to improve readability.
- All past guides were updated to encourage continued use as presentation handouts and one-on-one distribution by Idaho Power's CRs.
- Focus groups provided feedback about the guide's format and content.
- Guide circulation was increased in two ways: 1) the *New Plymouth News* was added to the list of local newspapers distributing the energy efficiency guide and 2) the guide was included with each free, non-subscriber delivery of the *Blackfoot Morning News* and *Meridian Press*.

The *Spring/Summer Energy Efficiency Guide*—Inserted into 14 newspapers and delivered to 215,539 homes on April 27, 2014. The guide focused on helping customers understand how their behavior impacts their electricity bill. The guide highlighted Idaho Power's myAccount as a tool to help learn about energy use, answered questions about how and why weather impacts energy use, offered tips for keeping costs down during extreme weather, and encouraged customers to consider the value proposition for energy efficiency when buying, selling, and remodeling their homes. It also contained a suggested "path" for becoming energy efficient at home.

The *Fall/Winter Energy Efficiency Guide*—Inserted into 16 newspapers and delivered to 237,144 homes on October 26, 2014. The guide focused on ways to keep heating bills down on a limited budget and specifically targeted lighting as an all-around energy efficiency opportunity available to all. The guide offered suggestions for benchmarking home energy use using myAccount and current energy codes. It also presented Idaho Power's various residential programs via a simple, colorful chart to help customers compare relative costs, benefits, and eligibility details for each program.

The release of each guide received public relations support through numerous communication channels, including an item in the weekly *News Briefs* email to all media (April 21 and October 28) and a feature during the monthly live studio energy efficiency segment on KTVB-TV on October 27. The November issue of Idaho Power's *Connections* customer newsletter included an image display for the guide as well.

In 2014, 10,351 additional guides were distributed at energy efficiency presentations and events, up from 3,447 in 2013. This increase is an indication of their ongoing value and success of the strategy to prolong the shelf-life of these guides. Links to current guides were given prominent positions on Idaho Power's website during the appropriate seasons. Additionally, the full selection of energy efficiency guides was made available for viewing and download via Idaho Power's website.

As part of Idaho Power's Account Manager team, the Residential Energy Efficiency Education Initiative staff played a key role by gathering research from neighboring utilities and organizing customer and employee focus groups. These groups provided insight into how customers interacted with the tool and what features might best be used to market the tool. Following the focus groups, the tool's name was changed from Account Manager to myAccount and two of three key messages for the advertising campaign were focused around educating customers about their individual home's energy use.

As a result of customer comments gleaned from the spring focus groups conducted by MDC (discussed in-depth in the Marketing section), marketing tactics were used in November to expand the distribution channels and test the demand for the *Fall Energy Efficiency Guide* and the 96-page booklet *30 Simple Things You Can Do to Save Energy*. The following marketing tactics were used to drive demand for these publications:

- A display image appeared in the November issue of the *Connections* customer newsletter, which was delivered to approximately 415,000 customers.
- Bill inserts were placed in over 40,000 residential customer bills.
- A digital ad campaign ran from October 25 to November 23.

All advertising drove customers to a webpage where they could request printed copies mailed directly to their homes. They could also view the publications online or download printable versions. For those customers without internet access, a toll-free number was provided and an order form was included on the bill insert. Based on the marketing campaign, another 587 *Fall/Winter Energy Efficiency Guides* and 582 *30 Simple Things You Can Do To Save Energy* were mailed by request directly to customers.

The Residential Energy Efficiency Education Initiative distributed energy efficiency messages through a variety of other communication methods during 2014. Increased customer awareness of energy-saving ideas was accomplished via continued distribution of the third printing of the 96-page booklet *30 Simple Things You Can Do To Save Energy*, a joint publishing project between Idaho Power and The Earthworks Group. During the year, 9,070 English and 623 Spanish copies were distributed directly to customers via community events and local libraries; by CRs during in-home visits; by participating contractors in the Home Improvement Program, Energy House Calls, H&CE Program, and See ya later, refrigerator® program; through direct web requests; and in response to inquiries received by Idaho Power's customer service center.

Idaho Power continues to recognize that educated employees are effective advocates for Idaho Power's energy efficiency programs. To keep energy efficiency top-of-mind among employees, an educational video was produced. Each employee received a personal email invitation to view the video and become an ambassador for energy efficiency by learning about the company's energy efficiency programs.

The Kill A Watt™ Meter Program remained active in 2014. Idaho Power's customer service center and field staff continued to encourage customers to learn about the energy used by specific appliances and activities within their homes by visiting a local library to check out a Kill A Watt meter. A second

hands-on table display was developed and made available to assist libraries in engaging patrons, promoting energy efficiency, and increasing circulation of the energy efficiency kits. Additionally, the Kill A Watt meters were featured during a live studio news program on KTVB-TV in Idaho Power's monthly energy efficiency segment with Idaho Power's CR&EE manager.

As in previous years, Idaho Power took the lead in strengthening the energy education partnership with secondary school educators through continued participation on the Idaho Science, Technology, Engineering and Mathematics (iSTEM) Steering Committee. In 2014, 16 teachers completed the 4-day, 2-credit professional development seminar facilitated by Idaho Power and co-sponsored by Intermountain Gas and the Idaho National Lab (INL).

Idaho Power continued its co-sponsorship of the US Green Building Council lecture series, *Sustainable Energy Sustainable Homes*. In 2014, Idaho Power provided additional support to extend the reach through web-based video broadcasting of live seminars and recorded content and PowerPoint slides available for online reference. The eight workshops, facilitated by local trade experts, provided information and expertise to encourage energy efficiency upgrades. These sessions continue to be popular with homeowners, builders, developers, and architects, with 143 attending in 2014. Idaho Power also opened discussions regarding a new partnership with the City of Meridian to produce an energy-related video emphasizing wise energy use as part of the city's *It Starts at Home* campaign.

Idaho Power continued to engage communities in energy efficiency discussions at many community events throughout Idaho Power's service area. In April, Idaho Power continued to sponsor the Portneuf Valley Community Environmental Fair and actively promoted attendance at this event with a bill message for communities surrounding Pocatello. Idaho Power's Pocatello CRs staffed the booth and promoted wise energy use and participation in energy efficiency programs.

In September 2014, Idaho Power participated in the FitOne Expo in Boise, Idaho. The event continued to be important due to the size of the audience and because Idaho Power surveys confirmed that the demographics of attendees continued to align with Idaho Power's residential energy efficiency target audience. In 2014, the booth theme capitalized on LED lighting imagery from the integrated campaign launched in August and previewed the energy efficient interactive home graphic in the background. Idaho Power staff at the event educated attendees about the benefits of LED lighting technology and distributed 2,500 LED light bulbs to an engaged and receptive audience.

Idaho Power further increased its energy efficiency presence in the community by providing energy efficiency and program information through 116 outreach activities, including events, presentations, trainings, and other outreach activities documented in the Outreach Tracking System. In addition to these activities, Idaho Power field staff throughout Idaho Power's service area delivered 164 presentations to local organizations addressing energy efficiency programs and wise energy use. In 2014, Idaho Power's Community Education team provided 67 presentations on *The Power to Make a Difference* to 1,756 students. The CERs and other staff also completed 32 senior citizen presentations on energy efficiency programs and shared information about saving energy to a total of 912 seniors in the company's service area. Additionally, Idaho Power's energy efficiency program managers responded with detailed answers to 288 customer questions about energy efficiency and related topics received via Idaho Power's website.

As part of National Energy Awareness Month in October, Idaho Power held its fourth annual student art contest in the Idaho Power service area, bringing energy education into the classroom and inspiring students and families to think more about energy. "Ways to Save Energy" was one of the categories, and both overall and regional winning students and their teachers were recognized.

The Residential Energy Efficiency Education Initiative continued to provide energy efficiency tips in response to media inquiries. In addition to supplying information for various Idaho Power publications, such as the *News Scan* weekly employee newsletter, the *Connections* customer newsletter, and Idaho Power's Facebook page, articles were written for the North End Neighborhood Association newsletter (circulation 5,300 print/341 electronic). Energy efficiency tips were provided for three of the monthly KTVB-TV news live studio interview segments.

Idaho Power also researched the possibility of working with a vendor to produce energy efficiency kits and age-appropriate curriculum for high school students. The idea was presented to EEAG as a potential new program in the August. With EEAG input, Idaho Power met with local high school teachers to refine the potential offering and revisited it with EEAG again in November. The next step in exploring this potential offering is to convene a committee of teachers for the purpose of gathering input, identifying appropriate deliverables, and preparing an RFP.

The initiative's 2015 goals are to increase program participation and promote education and energy-saving ideas that result in energy-efficient and conservation-oriented behaviors and choices. In addition to producing and distributing educational materials, the initiative will play an integral role in providing LED lighting education and distributing LED bulbs to customers. Idaho Power will improve the accessibility of educational information available to customers on the company's website and work with the Program Planning Group to explore behavioral program opportunities that may include an enhanced kit program, promotion of myAccount, home energy reports, or a pilot program to test another behavioral message, such as clothes drying rack adoption.

## Student Energy Efficiency Kit Program

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

For the 2013 to 2014 school year addressed in this report, Idaho Power partnered with the National Energy Foundation (NEF) for the 2013 fall semester and Resource Action Programs (RAP) for the 2014 spring semester. NEF's partnership for the fall 2013 semester ended Idaho Power's test year, and RAP was selected as Idaho Power's long-term partner beginning January 2014.

During the 2013 to 2014 school year, 6,312 kits were delivered to 208 classrooms in 73 schools within Idaho Power's service area, resulting in 1,491 MWh of first-year savings. In fall 2013, program participants were recruited by invitation from a regional Idaho Power CER, resulting in 2,419 student participants. In spring 2014, the program was marketed to all elementary schools with open enrollment, resulting in 3,696 student participants.

Once a class enrolled in the program, teachers received curriculum and supporting materials. Students received classroom study materials, a workbook, and a take-home kit containing three CFLs, a high-efficiency showerhead, an LED nightlight, a furnace filter alarm, a digital thermometer for measuring water, refrigerator and freezer temperatures, a water-flow rate test bag, and a shower timer. At the conclusion of the program, students and teachers returned feedback to the vendor indicating how the program was received and which measures had been installed. Each vendor used this feedback to provide a comprehensive program summary report showing program results and savings.

Teachers said they liked the program. Fall feedback indicated 97 percent of teachers said the content was good or excellent and they would recommend the program to colleagues. Spring feedback indicated 100 percent of teachers would recommend the program to other colleagues and 97 percent would conduct the program again. Student engagement was high as well—73 percent of student surveys were returned in the fall and 81 percent were returned in the spring.

Both NEF and RAP calculated annual savings based on information collected from the participants' home surveys and the installation rate of the kit items. Questions on the survey include the number of individuals in each home, water-heater fuel type, flow rate of the old showerhead, and the wattage of the bulb replaced. Based on this information, NEF estimates that fall 2013 participants saved 635,782 kWh per year. RAP estimates that spring 2014 participants saved 855,443 kWh per year. The total annual savings of 1,491,225 kWh appears under the Residential Energy Efficiency Education Initiative in the Appendices.

A copy of the complete report is included in *Supplement 2: Evaluation*.

## Easy Savings Program

As a result of IPUC Case No. IPC-E-08-10 under Order Nos. 30722 and 30754, Idaho Power committed to fund energy efficiency education for customers receiving energy assistance through the federal LIHEAP and provide $125,000 to CAP agencies in the Idaho Power service area on a prorated basis. This order specified that Idaho Power provide educational information to customers who heat their homes with electricity provided by Idaho Power. This is being accomplished through the development and distribution of kits containing low-cost, self-install energy efficiency items and educational materials.

The Easy Savings Program straddles two calendar years. The LIHEAP program starts in November each year at CAP agencies, while Idaho Power summarizes activities based on a January to December cycle. However, the following report summarizes activities from November 2013 through October 2014 and covers future plans for the 2014 to 2015 program.

Three main desired outcomes of the Easy Savings Program are to educate recipients about saving energy in their homes by using energy wisely, allow hands-on experience while installing low-cost measures, and reduce the energy burden for energy assistance/LIHEAP applicants.

Each kit contained the following low-cost/no-cost energy saving items and a survey:

- CFLs (13 W and 18 W)
- Hot-water temperature card and refrigerator thermometer
- Rope caulk and outlet draft stoppers
- Kitchen faucet aerator and high-efficiency showerhead
- LED nightlight and reminder magnets for the laundry
- *Quick Start Guide* to installation
- Mail-in survey

By April 2014, all 2,127 kits from the 2013 to 2014 program year were distributed by regional CAP agencies to Idaho Power customers approved to receive LIHEAP benefits on their Idaho Power bills.

The mail-in survey inquiring about installation experiences and actions taken to reduce energy use was included in the kits. Returned surveys were used to track the effectiveness and educational impact of the program.

There were 202 completed surveys received from customers describing their experience in installing kit items in their homes during the 2013 to 2014 program. The survey included questions about whether the customer took specific actions to reduce energy use as a result of receiving the kit as well as questions confirming the installation of kit items.

Ninety-two percent of household respondents reported they have, or will, lower their heat during the day, and 84 percent reported they will lower their heat at night. Eighty-five percent of the households reported installing both CFLs provided in the kit, and another 7 percent said they installed one of the CFLs. Eighty percent of the households reported installing the high-efficiency showerhead.

Overall, survey results showed that over 62 percent of the households that received the kits and returned a survey installed five or more kit items. Seventy-nine percent of the respondent households reported learning a lot about saving energy and money in their home after completing the *Easy Savings Quick Start Guide*. Copies of the survey and survey results can be found in *Supplement 2: Evaluation*.

During the 2013 to 2014 program, three gift certificates valued at $100 each were provided by CAPAI to encourage survey completion. A drawing from all returned surveys was held July 2014. Three households won a $100 gift certificate.

For the 2014 to 2015 program, checks totaling $125,000 were sent by Idaho Power in September 2014 to the five Idaho regional CAP agencies. Each agency used 30 percent of the agency's allotment to cover expenses for administering the program at their agency. By the end of September 2014, an order for 2,067 kits was placed by CAP agencies. Kits were shipped from the vendor and received at CAP agencies in November 2014 for distribution to customers throughout the 2014 to 2015 LIHEAP season. One LED bulb replaced the CFLs this year.

Upon completion of kit distribution and receipt of corresponding survey results for the 2014 to 2015 program, Idaho Power and CAPAI will consider program changes for the future.

## Commercial Education Initiative

Since 2008, the Commercial Education Initiative has informed and educated commercial customers regarding energy efficiency, increased awareness of and participation in existing commercial energy efficiency and demand response programs, and enhanced customer satisfaction regarding the company's energy efficiency initiatives.

This initiative is also used to educate and support trade allies and key stakeholders working in the energy efficiency market. A major strength of the initiative is the emphasis on building strategic relationships. Additionally, program specialists work closely with Idaho Power CRs assigned to commercial market segments to capitalize on their established relationships with customers.

The Commercial Education Initiative oversees the distribution of informational materials and works directly with trade allies and other market players who, in turn, support and promote Idaho Power's

energy efficiency programs. Routinely, individual site visits are conducted to educate customers on energy-saving opportunities at their business.

In 2014, Idaho Power carried out its plan to capitalize on effective customer projects by developing 11 success stories highlighting customers' energy efficiency projects for posting on Idaho Power's website. Copies of the success stories are provided in *Supplement 2: Evaluation*.

Other marketing efforts included a March and a November *ENERGY@WORK* newsletter created and mailed to all commercial customers. These newsletters had business-specific articles of interest, with an emphasis on energy efficiency. Idaho Power's customer newsletter, *Connections*, is distributed monthly in customers' bills. In 2014, two editions were devoted exclusively to energy efficiency content.

Raising the knowledge level of commercial customers in the wise use of energy in their daily operations is important to the continued success of Idaho Power's commercial energy efficiency programs. The Commercial Education Initiative works with and supports multiple stakeholders and organizations to increase customers' energy efficiency knowledge. Examples of key stakeholders include the IDL, BOMA, US Green Building Council, ASHRAE, IBOA, and the IFMA Northern Rockies Chapter. Through funding provided by Idaho Power, the IDL performs several tasks aimed at increasing the energy efficiency knowledge of architects, engineers, trade allies, and customers. Specific activities include sponsoring a BSUG, conducting Lunch & Learn sessions held at various design and engineering firms, and offering a TLL. The TLL gives customers access to equipment that enables them to measure and monitor energy consumption on various systems within their operation.

In 2014, the Commercial Education Initiative supported two organizations that provide professional accreditation to their members. The IBOA offers Building Operator Certification to train building operators in the energy efficiency operation of their facilities. The IFMA teaches four modules of its Facility Management Professional (FMP) credential. The FMP training equips facility managers with the knowledge and skill sets to promote, justify, and implement sustainable and energy efficiency projects and programs within their facilities.

Plans for 2015 include 1) working with Idaho Power marketing specialists to increase customer awareness of the company's energy efficiency programs and their specific offerings; 2) coordinating training opportunities for CRs and trade allies to increase their energy expertise; 3) continuing to support key stakeholders that train, educate, and support the advancement of energy efficiency practices; 4) conducting outreach and education activities through the IDL; and 5) supporting customers via facility walk-throughs, including energy audits.

## Regional Technical Forum

The BPA and the NWPCC established the RTF in 1999. Since 2004, Idaho Power has supported the RTF by providing annual financial support, regularly attending monthly meetings, and participating on various sub-committees.

The forum's purpose is to advise the BPA; the NWPCC; the region's utilities; and organizations, including NEEA and the Energy Trust of Oregon (ETO); on technical matters related to energy efficiency. Activities include the development of standardized protocols for verifying and evaluating energy savings and tracking conservation and resource goals. Additionally, the RTF provides feedback and suggestions for improving the effectiveness of regional energy efficiency programs. The RTF also recommends a list of eligible energy efficiency measures and the estimated savings associated with those measures. Idaho Power uses the information provided by the RTF when conducting research and

analysis on new and current measures. The RTF meets monthly to review and provide comments on analyses and other materials prepared by the NWPCC, BPA staff, and RTF contractors. Idaho Power uses the savings estimates and calculations provided by the RTF when applicable to the Idaho climate zones and load characteristics. In 2014, Idaho Power staff participated in all of the RTF's meetings and was involved in various sub-committees, including the RTF Policy Advisory Committee.

In 2014, the RTF continued efforts to bring measures and documentation in line with the protocols and guidelines put in place in 2012. Additionally, the RTF wrapped up the work began in 2013 to calibrate the residential building energy model commonly referred to as the SEEM model for existing and new construction single family homes. The results from the region-wide 2011 RBSA study, which included on-site home inspections of a regional representative sample of single-family, multi-family, and manufactured homes, were analyzed by the RTF to calibrate the SEEM model inputs. The SEEM calibration impacts all of Idaho Power's residential weatherization and HVAC measures. Idaho Power participated in the SEEM Affected Measures Workgroup throughout the process and provided feedback on the proposed methodologies and support documentation prepared by RTF contract staff. The results for SEEM calibration for manufactured-home savings are expected to be completed by RTF staff in 2015.

Additionally, Idaho Power representatives participated in the SIS sub-committee. SIS is a behavior-based agricultural program to optimize irrigation. A calculator converts water reduction to kWh savings. The current RTF SIS protocol is out of compliance with the current RTF guidelines. BPA, in partnership with the RTF, developed a research plan and standard protocol to bring the measure into compliance. BPA plans to implement the study during the 2016 growing season with the sample segmented based on the "high" and "medium to low" water-level crops within the two geographic areas in the population: the Columbia Basin and southern Idaho. Idaho Power representatives will continue to participate and lend their expertise to the sub-committee in 2015.

## University of Idaho Integrated Design Lab

Idaho Power is a founding supporter of the IDL. The IDL is dedicated to the development of high-performance energy-efficient buildings in the Intermountain West. Idaho Power has worked with the lab since its inception in 2004 as part of efforts to educate customers about the value of energy efficiency to businesses, as well as to the businesses' customers. On January 21, Idaho Power helped sponsor the 10th anniversary celebration of the IDL in Boise, participating in the open house and tour of the facility. Company representatives recognized the lab's commitment to high-performance energy-efficient building through research, education, and outreach efforts in the Intermountain West. Idaho Power issued a media advisory, inviting members of the press to attend the event and share the story of the IDL's success.

In 2014, Idaho Power entered into an agreement with the IDL to perform the following 14 tasks.

### *Building Metrics Labeling*

The goal of this task was to expand on the 2012 and 2013 development of Building Metrics Labeling (BML), a graphical display of four building metrics on a single sheet. The metrics displayed are Energy Use Intensity (EUI), ENERGY STAR® score, Walkability, and Space Daylit Area. The purpose of the BML sheet is to increase awareness of building energy use and promote energy efficiency during the sale or lease of commercial properties.

In 2013, a beta version web-based portal for self-directed use of a building's data to create BML sheets was created. The final version became available for public use in early 2014.

In addition to finalizing the portal, the IDL followed up with previous users of the BML sheets and supported new users. The IDL promoted the BML sheet at a BOMA monthly luncheon meeting and to the City of Boise in conjunction with an educational Lunch & Learn session. It was also marketed at the 2014 BOMA Symposium and the Kilowatt Crackdown™ Awards ceremony. The report is located in the IDL section of *Supplement 2: Evaluation*.

## Lunch & Learn

The goal of the Lunch & Learn task was to educate architects, engineers, and other design and construction professionals about energy efficiency topics through a series of educational lunch sessions. This series includes sessions outside the Treasure Valley.

In 2014, 20 technical training lunches were scheduled in Boise, Pocatello, and Ketchum. The trainings were coordinated directly with architecture and engineering firms and organizations and were attended by a total of 281 architects, engineers, interior designers, project managers, and others. Nineteen sessions were held in 2014. Due to a 2014 scheduling conflict, one remaining session is scheduled for January 29, 2015.

Fourteen sessions were offered in Boise, two in Pocatello, three in Ketchum, and one in Chubbuck. The topics of the lunch sessions (and quantity of each) were: *High Performance Retrofits* (1), *Integrated Design Principle* (2), *Integrated Design Lab Overview* (2), *Radiant System Design Considerations* (2), *Daylight Sensing Electric Lighting Controls* (2), *High Performance Classrooms* (2), *Climate Responsive Design—Tools and Methods* (1), *M&V + Tool Loan Library* (1), *Architectural HVAC Integration Strategies* (2), *Integrated Design Case Studies* (2), *Daylight in Buildings: Schematic Design* (1), *Daylight in Buildings: Getting the Details Right* (1), and *Benchmarking, M&V, + Tool Loan Library* (1). The report is located in the IDL section of *Supplement 2: Evaluation*.

## Fall Educational Series

The goal of the Fall Educational Series was to educate architects, engineers, building owners, building operators, designers, and construction professionals about energy efficiency through a series of publicly available evening lectures.

In 2014, the title of the series was *Design Decisions and Outcomes*, which focused on design decisions and strategies for energy efficiency. Four sessions were held that featured topics that supported this concept. The topics were *Developer Choices and Local Stories, Design for Off: A Seattle HVAC Case Study, Outstanding Local Projects*, and *Integrated Lighting Practices*. Each session consisted of 1.5 hours of lecture followed by time for questions. The sessions were held at Idaho Power's CHQ and were offered live, as well as broadcasted webinars. The live and remotely broadcasted presentations had 92 total participants. The report is located in the IDL section of *Supplement 2: Evaluation*.

## Building Simulation Users Group

The goal of this task was to facilitate the Idaho BSUG, which is designed to improve the energy efficiency-related simulation skills of local design and engineering professionals.

In 2014, 11 monthly BSUG sessions were hosted by the IDL. In most cases, the IDL taught the sessions themselves or brought in outside speakers. The sessions were made available remotely and were

attended by 179 professionals in person and 318 professionals remotely. Evaluations forms were completed by attendees for each session. On a scale of 1 to 5, with 5 being excellent and 1 being poor, averaging results from all seven questions, the average session rating was 4.0 for 2014.

Finally, each presentation was archived on the BSUG 2.0 website along with general BSUG-related content. The BSUG 2.0 site logged 2,150 total visits with 1,132 specific to Idaho users in 2014. The report is located in the IDL section of *Supplement 2: Evaluation*.

## Foundational Services

The goal of this task was to provide energy efficiency technical assistance and project-based training to building industry professionals and customers. When the IDL receives requests for their involvement in building projects, the projects are categorized into one of three types. Phase I projects are simple requests that can be addressed with minimal IDL time. Phase II projects are more complex requests that require more involvement and resources from the lab. Phase III projects are significantly more complex and must be co-funded by the customer.

In 2014, the IDL provided technical assistance on 37 Phase I projects, 9 Phase II projects, and 3 Phase III projects. Overall, 35 percent of the projects were on new buildings and 65 percent were on existing buildings. The report is located in the IDL section of *Supplement 2: Evaluation*.

## Building Efficiency Verification

The goal of this task was to continue random installation verification of over 10 percent of Building Efficiency applications provided incentives. This consisted of conducting a full review of documentation and complete on-site inspections to validate whether noted systems and components had been installed. The purpose of this verification was to confirm program guidelines and requirements were adequately facilitating participants to provide accurate and precise information with regard to energy efficiency measure installations.

This task also included the review of all daylight photo-control incentives to verify site conditions and improve the quality of design and installation.

The IDL completed on-site field verifications for the Building Efficiency program as summarized in the Building Efficiency program's Customer Satisfaction and Evaluations section presented earlier in this *Demand-Side Management 2014 Annual Report*. The report is located in the IDL section of *Supplement 2: Evaluation*.

## Tool Lending Library

The goal of this task was to operate and maintain a measurement equipment TLL, including a web-based equipment tool loan-tracking system, and provide technical training on how each tool is intended to be used.

The inventory of the TLL, which has been built up in previous years, now consists of over 900 individual pieces of equipment. The tools are available for customers, engineers, architects, and contractors in Idaho Power's service area to borrow at no cost to aid in the evaluation of energy efficiency projects and equipment they are considering.

There were 37 tool loan requests in 2014, which included a total of 286 tools loaned. There were 14 tools purchased or acquired in 2014 for the TLL. The tools were loaned to engineering firms or

equipment representatives, educational institutions, industrial plants, and office/commercial facilities. The report is located in the IDL section of *Supplement 2: Evaluation*.

## Simulation Quality Assurance

The goal of this task was to provide energy simulation QA by conducting pre- and post-measurements and verifications to compare modeled savings to realized savings on selected projects. The IDL accomplished this by reviewing energy simulation techniques used to estimate facility consumption, conducting on-site measurements used to calibrate and validate the energy model, performing energy management system data extraction, analyzing actual bill and weather data, and creating a report detailing findings and lessons learned from each project.

The information gained from these activities is conveyed to the local design community through other education and outreach tasks, such as the BSUG and Lunch & Learn sessions, both described above. Additionally, system issues have been uncovered and corrected due to the investigation associated with these efforts, which helps ensure persistence of energy savings. In 2014, four highly visible and innovative projects were analyzed, consisting of a local architectural and engineering firms' new radiant cooling system, a university classroom building, and two mid-sized commercial buildings. The report is located in the IDL section of *Supplement 2: Evaluation*.

## Heat Pump Calculator

The goal of this task was to develop an Excel-based heat pump analysis tool to calculate energy usage and savings based on site-specific variables for commercial buildings. It was determined there was a lack of sophisticated heat pump energy-use calculators available with the capability of comparing the energy use of heat pumps in commercial buildings against other technologies in a quick, simple fashion. The tool was developed in 2013 and underwent testing in early 2014. Feedback from validation testing has been integrated into the current version of the tool. The report is located in the IDL section of *Supplement 2: Evaluation*.

## Planning and Commissioning for Daylight Harvesting

The goal of the Daylight Harvesting task in 2014 was to expand on the previous task of creating a hands-on demonstration and training for electrical contractors by offering on-site classes for them to learn the necessary skills to successfully install and commission daylight harvesting lighting-control systems.

Nine Daylight Harvesting classes were held in 2014. These classes were attended by 29 participants, representing 102 continuing education hours. The various control systems in the IDL space provided a great venue to educate electrical contractors and the design community on daylight-harvesting technology. Classes were held in a two-part series: Part 1 provided in-class training, and Part 2 provided hands-on commissioning education. The report is located in the IDL section of *Supplement 2: Evaluation*.

## Customer Representative Training

The goal of the Idaho Power CR training task in 2014 was to develop and provide training to Idaho Power CRs to identify common energy efficiency opportunities in commercial buildings. The training consisted of three classroom style modules: Module 1: Pre-Walk Benchmarking and Analysis, Module 2: Typical Building Systems and Efficiency Opportunities, and Module 3: Specialty Systems and Efficiency Opportunities. This training was delivered across the Idaho Power

service area. The twelve classroom-style trainings had a total of 55 attendees. Nine on-site field trainings were conducted in conjunction with the classroom-style trainings and had a total of 45 attendees. The report is located in the IDL section of *Supplement 2: Evaluation.*

### Residential Heat Pump Calculator

In 2014, the IDL created a computer-based residential energy calculator. This tool calculates energy consumption for residential houses. It has the ability to accept various descriptive user inputs—for example, attic insulation and window performance in an existing house. It also enables the user to compare the energy consumption of a house with various types of heating and cooling systems. The tool will be evaluated in 2015 to determine if any enhancements are needed.

### Residential Heat Pump Calculator—Weatherization Solutions & Home Improvement Programs Module

The IDL created a computer-based residential energy calculator in 2014. This tool calculates energy consumption for residential houses for pre- and post-weatherization. The tool has the ability to accept various descriptive user inputs to calculate estimated savings based on the interaction between potential upgrades and various heat systems.

### Residential Electronically Commutated Motors

In 2014, the IDL investigated ECMs at the request of Idaho Power. These motors are sometimes used in residential forced-air heating and cooling systems. These motors can be an energy-efficient option when compared to other types of motors used in the air handlers for these systems. An air handler is a device that circulates air through ductwork. Idaho Power is evaluating the ECM motor for a potential new measure to be added to the H&CE Program. The work the IDL performed was to help determine if an ECM motor would be a suitable energy-saving replacement motor for the traditional permanent split capacitor motor. The results of their work will be reviewed in 2015. The report is located in the IDL section of *Supplement 2: Evaluation*.

The contract between Idaho Power and the IDL will continue through 2015. In 2015, the IDL will continue or expand work on the BML sheets, Lunch & Learn sessions, BSUG, foundational services, building efficiency verification, TLL, heat pump calculator, and daylight demonstrations. In addition, they will begin work on four new tasks—Commercial Real Estate Support, IBOA and IFMA Organization/Chapter Support, Targeted Energy Expansion of Daylight Pattern Guide, and Whole House Fan Energy Savings.

## Local Energy Efficiency Funds

The purpose of LEEF is to provide modest funding for short-term projects and activities that do not fit within other categories of energy efficiency programs but still provide energy savings or a defined benefit to the promotion of energy-efficient behaviors or activities. Idaho Power received three applications for LEEF in 2014 and awarded funds to one applicant.

Meridian Food Bank requested funding to replace one of their existing upright freezer units with a new, more energy-efficient unit. Idaho Power met with the Meridian Food Bank at their facility to gather more information on the project. Given the ongoing need for this type of replacement at the Food Bank and the positive community impact this operation serves, it was decided that an alternate method of funding would be more appropriate. As of December 31, 2014, the Idaho Power CR for this site worked

with the customer and Idaho Power executives to investigate a potential corporate donation to support this facility's efforts.

A high-performance builder in the Wood River Valley area submitted an application regarding substantial energy efficiency measures associated with a large, new-construction residence. Energy efficiency measures included reduced heating loads due to premium construction methods and materials, highly efficient ground-source heat pumps, and ECMs. Idaho Power convened a working group of residential and commercial engineers and cost-effectiveness analysts from Idaho Power's energy efficiency department to review the application and request additional information. Energy calculations were supported by energy modeling software, RESNET, and an estimated 95,834 kWh per year in heating system savings. After a thorough review of the details surrounding this LEEF request, the team approved funding for $9,100.

The third project submitted regarded potential lighting retrofits in Boise High School's auditorium. A brief review revealed the project would qualify for existing commercial lighting incentives. The applicant was asked to submit the project to Idaho Power's energy efficiency commercial program staff.

## Building-Code Improvement Activity

Since 2005, the State of Idaho has been on a cycle of adopting a state-specific version of the IECC. The Idaho Building Code Board convened another Energy Code Collaborative in 2013 in an effort to address implementation of the new series of building-related codes. Idaho Power participated and offered support in those collaborative meetings, which included members of the building industry, local building officials, code development officials, and other interested stakeholders. The Energy Code Collaborative is an ongoing collaborative in which Idaho Power participates.

The Energy Code Collaborative brought forth its recommendations to the Idaho Building Code Board, which included the adoption of the *2012 IECC Residential Code* with amendments and the *2012 IECC Commercial Code* in 2013. The recommendation was adopted by the Idaho Building Code Board and was presented in the 2014 legislature session. Legislature passed the rules effective March 21, 2014, and the changes will go into effect January 1, 2015.

## Idaho Power's Internal Energy Efficiency Commitment

Several Idaho Power properties were enhanced in 2014 with the goal of improving energy efficiency. During the Payette Operations Center remodel, ceiling insulation was increased from R-20 to R-38, and a Watt-Stopper lighting-control system was added. At four substation buildings across the service area, old black built-up roofs were replaced with white metal roofs for reflection purposes.

Numerous CHQ remodel projects were completed in 2014. Plaza I was remodeled, and the old T-12 and T-8 lighting fixtures were replaced with LED fixtures controlled by a lighting system. Plaza II was remodeled, and the old T-12 system was replaced with LED fixtures. The existing natural gas-fired rooftop unit was replaced with a higher efficiency rooftop packaged heat pump unit rated at an energy efficiency ratio (EER) of 16 that has a payback cost of 14 months. The Plaza II roof was replaced with a reflective, better-insulated thermoplastic polyolefin roof to open the floor plan to the rafters in the barrel-shaped building. All the three-lamp T-12 fixtures on CHQ fourth floor and sixth floor were replaced with two-lamp T-8 fixtures. The CHQ fourth floor was completely remodeled with new recycled carpet, low-VOC paint, and low-partition walls for increased light transmission throughout the floor.

An outcome of the Energy Efficiency Audit conducted at the BOC with Tikker Engineering in 2013 was the installation of building-wide direct digital control system controls at the BOC. While not all of the suggested energy efficiency measures were addressed, the company incorporated measures that would provide the most value. Total energy reduction with the changes implemented at the BOC was estimated at 300,000 kWh annually.

At BCW, the chillers and air handlers were replaced. The new equipment exceeded ASHRAE standards for efficiency and were quieter than the previous chillers. Cooling and heating problems in the Grid Operations area were corrected. While no baseline was taken from the original air handling units (AHU) and chillers, the new air handlers run at 60 percent of the amperage compared to the old equipment. Idaho Power will continue to monitor the performance of the new chillers and AHUs in 2015.

In 2015, Idaho Power will continue with a number of major remodels on the CHQ buildings downtown, starting with the remodel of parts of CHQ sixth floor and seventh floors. The company will begin remodels on the CHQ eighth floor going into 2016. Remodels will incorporate energy efficiency items, such as lower partitions, lighting retrofits, and lighting controls.

Through the Sustainability Initiative Project implemented in 2012, Idaho Power has helped fund and execute sustainable, employee-driven initiatives aimed at increasing efficiencies and lowering company costs. Each year, the Sustainability team puts out a call for projects. Qualifying initiatives must demonstrate a financial benefit to the company, as well as either an environmental or social gain, or preferably both. Approved projects are given financial assistance through “incubation funding,” and the Sustainability team provides consulting services—if necessary—to speed implementation. A new document, available in print and online, catalogues three years of sustainability initiatives, with a brief description of each. From 2012’s Greenleaf wet-meadows project to last year’s rollout of electric vehicles and charging stations, all 26 initiatives are listed.

Employee-suggested sustainability initiative projects yielded several sustainability programs in 2014, including three programs with annual energy savings. At BCW, computer room “occupancy programming” was incorporated into the building management system. This allows one of several air-conditioning units to remain idle when the system detects the room is unoccupied, bringing an annual energy savings estimate at over 33,000 kWh. Idaho Power installed VFDs at the company’s data centers, with a combined savings of over 240,000 kWh annually.

# REGULATORY OVERVIEW

Idaho Power believes there are three essential components of an effective regulatory model for DSM: 1) the timely recovery of DSM program costs, 2) the removal of financial disincentives, and 3) the availability of financial incentives. By working with its stakeholders and regulators through negotiations and filings, Idaho Power continues to seek to move DSM regulatory treatment toward achieving all of these goals.

## Timely Recovery of DSM Program Costs: Energy Efficiency Rider and Prudence Determination of Expenditures

Since 2002, Idaho Power has recovered most of its DSM program costs through the Rider with the intended result of providing a more timely recovery of DSM costs. In addition, since January 1, 2012, funding of Idaho demand response program incentives is included in base rates and tracked in the annual PCA mechanism.

### *Annual DSM Expense Review Filing and Order No. 33161*

On March 14, 2014, Idaho Power filed Case No. IPC-E-14-04 with the IPUC requesting an order finding the company had prudently incurred $25,951,486 in DSM expenses in 2013, including $21,748,331 in Rider expenses and $4,203,155 in demand response program incentive expenses. The filing included three reports: *Demand-Side Management 2013 Annual Report*, *Supplement 1: Cost Effectiveness*, and *Supplement 2: Evaluation*. Due to a previous IPUC decision in Case No. IPC-E-13-08 to decline Idaho Power's request to deem prudent the increases in the company's Rider-funded labor-related expenses for 2011, 2012, and 2013, Idaho Power did not request a prudence determination for labor-related expenses of $269,432 in the filing. In Order No. 33161, dated November 4, 2014, the IPUC deemed $25,951,486 as prudently incurred and stated:

> The Commission notes that Idaho Power issued a strong rebuttal of these claims, offering several reasons to explain the recent decline in its DSM expenditures and a defense of its marketing efforts. While the Commission is cognizant of the recent decline in energy savings, acknowledged by the Company in its Application, we are encouraged by the Company's reply comments that its commitment to cost-effective DSM has not waned and that it has a renewed interest in taking action to procure all cost-effective DSM.

### *Errata to Order No. 33161*

In an Errata to Order No. 33161, dated November 7, 2014, the Commission amended the original Order to read:

> The Commission is cognizant of the recent decline in energy savings, acknowledged by the Company in its Application, and notes that Idaho Power issued a strong rebuttal of these claims, offering several reasons to explain the recent decline in its DSM expenditures and a defense of its marketing efforts. We are encouraged that the reply comments seem to demonstrate the Company's renewed interest in procuring all cost-effective DSM.

> In this case, the Commission restricts its findings to the prudency of the Company's 2013 expenditures. The Commission agrees that the issues raised by Staff and other parties are significant and warrant a more in-depth review. We direct the parties to do so in the context of the Company's next Integrated Resource Plan filing.

## Energy Efficiency Working Group

In response to the Errata, Idaho Power organized an Energy Efficiency Working Group, inviting members of the IRP Advisory Committee (IRPAC), EEAG, and other interested parties to participate. The Energy Efficiency Working Group held two sessions to conduct an in-depth review of the issues referenced in the Errata to Order No. 33161. The sessions were open to the public and held at Idaho Power's CHQ on December 3 and 18.

The first workshop session included a discussion of a broad range of energy efficiency and resource planning issues that can be classified into two general categories: 1) strategies related to program delivery and 2) the treatment of energy efficiency in the resource planning process. Because the IRP process does not address program delivery issues, it was suggested to narrow the focus of the discussion to only the treatment of energy efficiency in the resource planning process. The strategies related to the successful delivery of programs will be better addressed by EEAG.

The second workshop session agenda included a comparison of potential studies from other regional utilities; a description about how Idaho Power's incorporates energy efficiency in the IRP; a comparison of how other regional utilities incorporate energy efficiency in long-range planning; a review of Idaho Power's investigation into including Transmission and Distribution (T&D) investment deferral into the benefits in the energy efficiency cost-effectiveness analysis; and offered an open discussion time to address other issues. The information presented at the second meeting prompted extensive discussion among participants and ultimately served to inform Idaho Power's next steps.

Idaho Power believes its current treatment of energy efficiency in the resource planning process appropriately balances the need for responsible and effective resource planning and the desire to prudently pursue all cost-effective energy efficiency. Idaho Power recognizes that achieving those balanced objectives on an ongoing basis requires continued review and evaluation of the planning process and an awareness of related industry best practices.

Idaho Power is committed to investigate the extent to which transmission and/or distribution benefits result from energy efficiency measures and programs, as well as the approximate value of such benefits. When available, the company will present the results of this investigation to the IRPAC.

The company is also committed to continue to discuss the program delivery issues identified by workshop participants and by IPUC staff and some interveners in comments filed in Case No. IPC-E-14-04. The company plans to use EEAG as the forum to provide customers, IPUC and OPUC staff, and other interested stakeholders an opportunity to provide advice and recommendations to Idaho Power in formulating, implementing, and evaluating energy efficiency and demand response programs and activities.

## Energy Efficiency Rider-Funds Transfer

On April 15, 2014, Idaho Power filed the annual PCA Case No. IPC-E-14-05 with the IPUC. As part of that case, the company proposed that the commission approve a one-time transfer of $20 million of

surplus Idaho Rider funds to customers as a credit, or reduction, in the 2014/2015 PCA on customers' bills. In Order No. 33049, the commission approved the one-time transfer.

## Removal of Financial Disincentives: Fixed-Cost Adjustment

To address the removal of financial disincentives, Idaho Power has in place a fixed-cost adjustment (FCA) mechanism in Idaho. Under the FCA, rates for Idaho residential and small general-service customers are adjusted annually up or down to recover or refund the difference between the fixed costs authorized by the IPUC in the most recent general rate case and the fixed costs Idaho Power actually received the previous year through weather-normalized energy sales. This mechanism removes the financial disincentive that exists when Idaho Power promotes energy efficiency programs that are designed to reduce customer usage. The FCA is a permanent mechanism limited to the residential and small general-service customer classes in Idaho in recognition of the fact that, for these customers, a large percentage of fixed costs are recovered through their volumetric energy charges.

On May 30, 2014, the IPUC issued Order No. 33047 approving the company's request to implement FCA rates beginning June 1, 2014, for the 2013 fixed-cost deferrals. The overall rate adjustment was a 1.18 percent increase for residential and small general-service customers to collect a combined $14.9 million. This adjustment was an increase of $6 million from the previous year's FCA. Residential customers experienced a rate increase of 0.1143 cents per kWh, while small general-service customers experienced an increase of 0.1447 cents per kWh. The rate will be in place until May 31, 2015.

## Promotion of Energy Efficiency through Electricity Rate Design

Idaho Power believes rates offered to customers should reflect their cost of service in order to provide cost-based price signals and encourage the wise and efficient use of energy.

Since 2012, Idaho Power has offered a Time-of-Day (TOD) Pilot pricing plan to residential customers in Idaho. The overall goal of this TOD pricing plan is to use the AMI system to offer customers a choice of pricing plans while providing them with better tools to manage their energy usage, provide the company with the opportunity to further study the effects of a time-variant rate on customers' usage, and help shape the company's future communication efforts. The plan provides participants the opportunity to move their usage from higher-priced, on-peak time periods to lower-priced, off-peak time periods and possibly lower their bills. Idaho Power sent out a mailing in late spring of 2014 reminding participants that higher summer rates go into effect June 1. The spring mailing promoted the use of myAccount and reminded customers to use electricity wisely. A description of this plan is at Idaho Power's website (idahopower.com/TOD).

In July 2014, Idaho Power concluded the final impact study of the residential TOD pilot. The study was a customer behavior study that evaluated how the TOD pricing impacted energy consumption for participants in the plan. Participant's response to the TOD pricing signal was determined using a quasi-experimental study design structure with a TOD participant treatment group and a closely matched non-participant control group. Idaho Power also calculated the billing revenue impact of this pilot by calculating a shadow bill for each of the customers on the TOD pricing plan versus the standard residential three-tiered pricing plan in Idaho.

Key findings are summarized below:

- There was no statistically significant change in overall energy consumption observed in the study participants on the TOD rates.

- For the study group as a whole, the data analyzed showed a **reduction** in energy use from peak time periods by the analyzed participants of the pricing plan verses the control group. All but 2 out of 12 months showed statistically significant reductions in energy use during peak periods. Over the 12-month study period, this combined reduction in peak-time-period consumption was approximately 3 percent of the total kWh use.

- For the study group as a whole, the data analyzed showed an **increase** in energy use during off-peak time periods by the analyzed participants of the pricing plan verses the control group. Five out of the 12 months showing statistically significant increases. During the 12-month study period, this combined increase in off-peak time-period consumption was approximately 1 percent of the total kWh.

- The overall response rate to the residential TOD pricing pilot plan solicitation was 1.3 percent.

- The study estimates that there was a revenue reduction of $119,000 when actual TOD energy billings of all TOD pilot participants are compared with standard plan shadow energy bill calculations for all TOD pilot participants during the 12 months of the study, September 2012 through August 2013.

As of the end of 2014, over 1,500 Idaho customers were TOD plan participants.

# APPENDICES

This report includes five appendices. Appendix 1 contains financial information for 2014, showing the beginning balance, ending balance, and the expenditures for the Idaho and Oregon Riders and NEEA payments and credits. Appendix 2 also contains financial information showing expenses by funding source for each of Idaho Power's energy efficiency and demand response programs or activities. Appendix 3 shows participation, UC, TRC, energy and demand savings, measure life, and levelized costs for Idaho Power's current energy efficiency programs and activities for 2014. Appendix 4 shows similar data as Appendix 3 but also includes data for past years' program performance and B/C ratios from the UC and TRC perspectives for active programs. Appendix 5 contains program savings and costs separated into Idaho Power's Idaho and Oregon jurisdictions and by funding source. In these appendices, the data has been rounded to the nearest whole unit, which may result in minor rounding differences.

Additional information is contained in the supplements provided in separate documents in two formats. *Supplement 1: Cost-Effectiveness* contains detailed cost-effectiveness information by program and energy-savings measure. Provided in Supplement 1 are the B/C ratios from the UC, TRC, RIM, and PCT perspectives. The *2014 DSM Detailed Expenses* by program table reports expenses by funding source and separates the company's DSM expenses by expense type, incentive expenses, labor/administration, materials, other expenses, and purchased services. *Supplement 2: Evaluation* contains copies of Idaho Power's third-party evaluations and reports. A CD is attached in Supplement 2 and contains copies of *NEEA Market Effects Evaluations*. A searchable, linked table with the title, study manager, evaluation type, and other information are included with each supplement.

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## **Appendix 1.** Idaho Rider, Oregon Rider, and NEEA payment amounts (January–December, 2014)

| | | |
|---|---|---|
| **Idaho Energy Efficiency Rider** | | |
| 2014 Beginning Balance | $ | 6,685,745 |
| 2014 Funding plus Accrued Interest as of 12-31-14 | | 38,088,113 |
| **Total 2014 Funds** | | **44,773,858** |
| 2014 Expenses as of 12-31-14 | | (25,556,089) |
| Rider Transfer to PCA (IPUC Order 33049) | | (20,000,000) |
| **Ending Balance as of 12-31-2014** | **$** | **(782,231)** |
| **Oregon Energy Efficiency Rider** | | |
| 2014 Beginning Balance | $ | (3,694,183) |
| 2014 Funding plus Accrued Interest as of 12-31-14 | | 1,112,512 |
| **Total 2014 Funds** | | **(2,581,671)** |
| 2014 Expenses as of 12-31-14 | | (1,325,865) |
| **Ending Balance as of 12-31-2014** | **$** | **(3,907,536)** |
| **NEEA Payments** | | |
| 2014 NEEA Payments as of 12-31-2014 | $ | 3,305,917 |
| **Total** | **$** | **3,305,917** |

## **Appendix 2.** 2014 DSM expenses by funding source (dollars)

| Sector/Program | Idaho Rider | Oregon Rider | Non-Rider Funds | Total |
|---|---|---|---|---|
| **Energy Efficiency/Demand Response** | | | | |
| **Residential** | | | | |
| A/C Cool Credit | $ 962,286 | $ 56,988 | $ 446,372 | $ 1,465,646 |
| Ductless Heat Pump Pilot | 235,099 | 9,614 | 6,733 | 251,446 |
| Energy Efficient Lighting | 1,860,046 | 45,959 | 3,818 | 1,909,823 |
| Energy House Calls | 186,732 | 8,174 | 3,080 | 197,987 |
| ENERGY STAR® Homes Northwest | 330,523 | 7,612 | 5,141 | 343,277 |
| Heating & Cooling Efficiency Program | 340,551 | 14,627 | 6,836 | 362,014 |
| Home Energy Audit | 164,579 | (248) | 6,318 | 170,648 |
| Home Improvement Program | 315,616 | 0 | 9,101 | 324,717 |
| Home Products Program | 212,787 | 9,250 | 5,139 | 227,176 |
| Oregon Residential Weatherization | 0 | 5,234 | 228 | 5,462 |
| Rebate Advantage | 57,155 | 5,323 | 753 | 63,231 |
| See ya later, refrigerator® | 562,002 | 12,410 | 1,639 | 576,051 |
| Shade Tree Program | 143,750 | 66 | 3,474 | 147,290 |
| Weatherization Assistance for Qualified Customers | 0 | 0 | 1,320,112 | 1,320,112 |
| Weatherization Solutions for Eligible Customers | 757,748 | 0 | 33,596 | 791,344 |
| **Commercial/Industrial** | | | | |
| Building Efficiency | 1,212,907 | 31,052 | 14,315 | 1,258,273 |
| Custom Efficiency | 6,705,219 | 418,537 | 49,299 | 7,173,054 |
| Easy Upgrades | 3,020,323 | 112,623 | 17,996 | 3,150,942 |
| FlexPeak Management | 50,964 | 78,131 | 1,434,116 | 1,563,211 |
| Oregon Commercial Audit | 0 | 9,464 | 0 | 9,464 |
| **Irrigation** | | | | |
| Irrigation Efficiency Rewards | 2,256,235 | 144,392 | 45,880 | 2,446,507 |
| Irrigation Peak Rewards | 1,374,724 | 104,995 | 6,117,494 | 7,597,213 |
| **Energy Efficiency/Demand Response Total** | **$ 20,749,245** | **$ 1,074,203** | **$ 9,531,441** | **$ 31,354,889** |
| **Market Transformation** | | | | |
| NEEA | 3,140,621 | 165,296 | 0 | 3,305,917 |
| **Market Transformation Total** | **$ 3,140,621** | **$ 165,296** | **$ 0** | **$ 3,305,917** |
| **Other Programs and Activities** | | | | |
| **Residential** | | | | |
| Residential Energy Efficiency Education Initiative | 394,895 | 14,844 | 13,352 | 423,091 |
| **Commercial/Industrial** | | | | |
| Commercial Education Initiative | 72,613 | 3,829 | 163 | 76,606 |
| **Other** | | | | |
| Energy Efficient Direct Program Overhead | 427,506 | 21,711 | 29,441 | 478,658 |
| Local Energy Efficiency Funds | 9,100 | 0 | 0 | 9,100 |
| **Other Programs and Activities Total** | **$ 904,114** | **$ 40,384** | **$ 42,956** | **$ 987,455** |
| **Indirect Program Expenses** | | | | |
| Commercial/Industrial Energy Efficient Overhead | 75,578 | 6,209 | 40,612 | 122,399 |
| Energy Efficient Accounting & Analysis | 693,729 | 39,512 | 198,119 | 931,360 |
| Energy Efficiency Advisory Group | 5,702 | 301 | 0 | 6,003 |
| Residential Energy Efficient Overhead | 79,137 | 5,203 | 18,251 | 102,590 |
| Special Accounting Entries | (92,037) | (5,242) | 0 | (97,280) |
| **Indirect Program Expenses Total** | **$ 762,109** | **$ 45,982** | **$ 256,982** | **$ 1,065,072** |
| **Grand Total** | **$ 25,556,089** | **$ 1,325,865** | **$ 9,831,379** | **$ 36,713,333** |

## **Appendix 3.** 2014 DSM program activity

| Program | Participants | Total Costs | | Savings | | Measure Life (Years) | Nominal Levelized Costs[a] | |
|---|---|---|---|---|---|---|---|---|
| | | Utility[b] | Resource[c] | Annual Energy (kWh) | Peak Demand[d] (MW) | | Utility ($/kWh) | Total Resource ($/kWh) |
| **Demand Response** | | | | | | | | |
| A/C Cool Credit[1] | 29,642 homes | $ 1,465,646 | $ 1,465,646 | n/a | 44 | n/a | n/a | n/a |
| Irrigation Peak Rewards[1] | 2,225 service points | 7,597,213 | 7,597,213 | n/a | 295 | n/a | n/a | n/a |
| FlexPeak Management[1] | 93 sites | 1,563,211 | 1,563,211 | n/a | 40 | n/a | n/a | n/a |
| **Total** | | **$ 10,626,070** | **$ 10,626,070** | **n/a** | **378** | | | |
| **Energy Efficiency** | | | | | | | | |
| **Residential** | | | | | | | | |
| Ductless Heat Pump Pilot | 179 homes | 251,446 | 884,211 | 462,747 | | 15 | $ 0.042 | $ 0.148 |
| Energy Efficient Lighting | 1,161,553 bulbs | 1,909,823 | 7,148,427 | 12,882,151 | | 8 | 0.018 | 0.066 |
| Energy House Calls | 297 homes | 197,987 | 197,987 | 579,126 | | 18 | 0.024 | 0.024 |
| ENERGY STAR® Homes Northwest | 243 homes | 343,277 | 689,021 | 332,682 | | 36 | 0.055 | 0.111 |
| ENERGY STAR® Homes Northwest (gas fuel)[2] | 282 homes | | | 195,372 | | | | |
| Heating & Cooling Efficiency Program | 230 projects | 362,014 | 1,247,560 | 1,099,464 | | 20 | 0.022 | 0.075 |
| Home Energy Audit (direct-install savings)[3] | 354 audits | | | 141,077 | | | | |
| Home Improvement Program | 555 projects | 324,717 | 896,246 | 838,929 | | 45 | 0.020 | 0.055 |
| Home Products Program | 10,061 appliances/showerheads | 227,176 | 302,289 | 652,129 | | 12 | 0.031 | 0.041 |
| Oregon Residential Weatherization | 13 homes | 5,462 | 9,723 | 11,032 | | 30 | 0.028 | 0.050 |
| Rebate Advantage | 44 homes | 63,231 | 89,699 | 269,643 | | 25 | 0.014 | 0.020 |
| See ya later, refrigerator® | 3,194 refrigerators/freezers | 576,051 | 576,051 | 1,390,760 | | 6 | 0.062 | 0.062 |
| Student Energy Efficiency Kits[4] | 6,312 kits | | | 1,491,225 | | | | 0.225 |
| Weatherization Assistance for Qualified Customers | 255 homes/non-profits | 1,320,112 | 1,997,108 | 1,327,171 | | 25 | 0.149 | 0.225 |
| Weatherization Solutions for Eligible Customers | 118 homes | 791,344 | 791,344 | 290,926 | | 25 | 0.163 | 0.163 |
| **Sector Total** | | **$ 6,372,640** | **$ 14,829,666** | **21,171,063** | | **11** | **$ 0.028** | **$ 0.065** |
| **Commercial** | | | | | | | | |
| Building Efficiency | 69 projects | 1,258,273 | 3,972,822 | 9,458,059 | 1.2 | 12 | 0.012 | 0.037 |
| Easy Upgrades | 1,095 projects | 3,150,942 | 5,453,380 | 19,118,494 | | 12 | 0.015 | 0.025 |
| **Sector Total** | | **$ 4,409,215** | **$ 9,426,202** | **28,576,553** | **1.2** | **12** | **$ 0.014** | **$ 0.029** |
| **Industrial** | | | | | | | | |
| Custom Efficiency[5] | 131 projects | 7,173,054 | 13,409,922 | 50,363,052 | 5.6 | 12 | 0.013 | 0.024 |
| **Sector Total** | | **$ 7,173,054** | **$13,409,922** | **50,363,052** | **5.6** | **12** | **$ 0.013** | **$ 0.024** |

## **Appendix 3.** 2014 DSM program activity (continued)

| Program | Participants | Total Costs | | Savings | | Measure Life (Years) | Nominal Levelized Costs[a] | |
|---|---|---|---|---|---|---|---|---|
| | | Utility[b] | Resource[c] | Annual Energy (kWh) | Peak Demand[d] (MW) | | Utility ($/kWh) | Total Resource ($/kWh) |
| **Irrigation** | | | | | | | | |
| Irrigation Efficiency Rewards[6] | 1,128 projects | 2,446,507 | 18,459,781 | 18,463,611 | 4.6 | 8 | 0.016 | 0.119 |
| **Sector Total** | | **$ 2,446,507** | **$ 18,459,781** | **18,463,611** | **4.6** | **8** | **$ 0.016** | **$ 0.119** |
| **Energy Efficiency Portfolio Total** | | **$ 20,401,416** | **$ 56,125,571** | **118,574,278** | | **11** | **$ 0.016** | **$ 0.044** |
| **Market Transformation** | | | | | | | | |
| Northwest Energy Efficiency Alliance[7] | | $ 3,305,917 | $ 3,305,917 | 20,000,000 | | | | |
| **Other Programs and Activities** | | | | | | | | |
| **Residential** | | | | | | | | |
| Home Energy Audit | | 170,648 | 170,648 | | | | | |
| Local Energy Efficiency Funds | | 9,100 | 9,100 | 95,834 | | | | |
| Residential Energy Efficiency Education Initiative | | 423,091 | 423,091 | | | | | |
| Shade Tree Project | | 147,290 | 147,290 | | | | | |
| **Commercial** | | | | | | | | |
| Commercial Education Initiative | | 76,606 | 76,606 | | | | | |
| Oregon Commercial Audits | 16 audits | 9,464 | 9,464 | | | | | |
| **Other** | | | | | | | | |
| Energy Efficiency Direct Program Overhead | | 478,658 | 478,658 | | | | | |
| **Total Program Direct Expense** | | **$ 35,648,260** | **$ 71,372,415** | **138,670,112** | **390** | | | |
| Indirect Program Expenses | | $ 1,065,072 | | | | | | |
| **Total DSM Expense** | | **$ 36,713,333** | | | | | | |

[a] Levelized Costs are based on financial inputs from Idaho Power's 2013 IRP and calculations include line-loss adjusted energy savings.
[b] The Total Utility Cost is the cost incurred by Idaho Power to implement and manage a DSM program.
[c] The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.
[d] Summer Peak Demand is reported where program MW reduction is calculated specifically by project. Demand response program reductions are reported with 9.7-percent peak loss assumptions.
[1] Peak demand represents the peak performance of the program.
[2] Savings claimed for gas-heated certified homes that were not provided a direct incentive payment by Idaho Power.
[3] Savings claimed for direct-install measures during home energy audits.
[4] Savings for energy kits provided as part of the Residential Energy Efficiency Education Initiative program.
[5] Custom Efficiency savings includes 15 Green Motors participants totaling 56,499 kWh of annual savings, not counted in project totals.
[6] Irrigation Efficiency includes 14 Green Motors participants totaling 35,083 kWh of annual savings, not counted in project totals.
[7] Savings are preliminary estimates. Final savings for 2014 will be provided by NEEA in June 2015.

## **Appendix 4.** Historical DSM expense and performance, 2002–2014

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | Measure Life (Years) | Levelized Costs[a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost[c] | Resource Cost[d] | Annual Energy (kWh) | Average Energy[e] (aMW) | Peak Demand[f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Demand Response** | | | | | | | | | | | |
| A/C Cool Credit | | | | | | | | | | | |
| 2003 | 204 | $ 275,645 | $ 275,645 | | | 0.0 | | | | | |
| 2004 | 420 | 287,253 | 287,253 | | | 0.5 | | | | | |
| 2005 | 2,369 | 754,062 | 754,062 | | | 3.1 | | | | | |
| 2006 | 5,369 | 1,235,476 | 1,235,476 | | | 6.3 | | | | | |
| 2007 | 13,692 | 2,426,154 | 2,426,154 | | | 12.2 | | | | | |
| 2008 | 20,195 | 2,969,377 | 2,969,377 | | | 25.5 | | | | | |
| 2009 | 30,391 | 3,451,988 | 3,451,988 | | | 38.5 | | | | | |
| 2010 | 30,803 | 2,002,546 | 2,002,546 | | | 39.0 | | | | | |
| 2011 | 37,728 | 2,896,542 | 2,896,542 | | | 24.0 | | | | | |
| 2012 | 36,454 | 5,727,994 | 5,727,994 | | | 44.9 | | | | | |
| 2013 | n/a | 663,858 | 663,858 | | | n/a | | | | | |
| 2014 | 29,642 | 1,465,646 | 1,465,646 | | | 43.7 | | | | | |
| **Total** | | **$ 24,156,541** | **$ 24,156,540** | | | | | | | | |
| FlexPeak Management | | | | | | | | | | | |
| 2009 | 33 | 528,681 | 528,681 | | | 19.3 | | | | | |
| 2010 | 60 | 1,902,680 | 1,902,680 | | | 47.5 | | | | | |
| 2011 | 111 | 2,057,730 | 2,057,730 | | | 58.8 | | | | | |
| 2012 | 102 | 3,009,822 | 3,009,822 | | | 52.8 | | | | | |
| 2013 | 100 | 2,743,615 | 2,743,615 | | | 48.0 | | | | | |
| 2014 | 93 | 1,563,211 | 1,563,211 | | | 39.6 | | | | | |
| **Total** | | **$ 11,805,739** | **$ 11,805,739** | | | | | | | | |
| Irrigation Peak Rewards | | | | | | | | | | | |
| 2004 | 58 | 344,714 | 344,714 | | | 5.6 | | | | | |
| 2005 | 894 | 1,468,282 | 1,468,282 | | | 40.3 | | | | | |
| 2006 | 906 | 1,324,418 | 1,324,418 | | | 31.8 | | | | | |
| 2007 | 947 | 1,615,881 | 1,615,881 | | | 37.4 | | | | | |
| 2008 | 897 | 1,431,840 | 1,431,840 | | | 35.1 | | | | | |
| 2009 | 1,512 | 9,655,283 | 9,655,283 | | | 160.2 | | | | | |
| 2010 | 2,038 | 13,330,826 | 13,330,826 | | | 249.7 | | | | | |
| 2011 | 2,342 | 12,086,222 | 12,086,222 | | | 320.0 | | | | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | Measure Life (Years) | Levelized Costs[a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost[c] | Resource Cost[d] | Annual Energy (kWh) | Average Energy[e] (aMW) | Peak Demand[f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Demand Response** | | | | | | | | | | | |
| Irrigation Peak Rewards | | | | | | | | | | | |
| 2012 | 2,433 | $ 12,423,364 | $ 12,423,364 | | | 339.9 | | | | | |
| 2013 | n/a | 2,072,107 | 2,072,107 | | | n/a | | | | | |
| 2014 | 2,225 | 7,597,213 | 7,597,213 | | | 295.0 | | | | | |
| **Total** | | **$ 63,350,149** | **$ 63,350,149** | | | | | | | | |
| **Residential Efficiency** | | | | | | | | | | | |
| Ductless Heat Pump Pilot | | | | | | | | | | | |
| 2009 | 96 | 202,005 | 451,605 | 409,180 | 0.05 | | 18 | $ 0.031 | $ 0.086 | | |
| 2010 | 104 | 189,231 | 439,559 | 364,000 | 0.04 | | 20 | 0.044 | 0.103 | | |
| 2011 | 131 | 191,183 | 550,033 | 458,500 | 0.05 | | 20 | 0.028 | 0.081 | | |
| 2012 | 127 | 159,867 | 617,833 | 444,500 | 0.05 | | 20 | 0.024 | 0.094 | | |
| 2013 | 215 | 237,575 | 992,440 | 589,142 | 0.07 | | 15 | 0.032 | 0.132 | | |
| 2014 | 179 | 251,446 | 884,211 | 462,747 | 0.05 | | 15 | 0.042 | 0.148 | | |
| **Total** | **852** | **$ 1,231,307** | **$ 3,935,681** | **2,728,069** | | | **15** | **$ 0.044** | **$ 0.138** | **2.52** | **0.76** |
| Energy Efficiency Packets | | | | | | | | | | | |
| 2002 | 2,925 | 755 | 755 | 155,757 | 0.02 | | 7 | 0.001 | 0.001 | | |
| **Total** | **2,925** | **$ 755** | **$ 755** | **155,757** | | | **7** | **$ 0.001** | **$ 0.001** | | |
| Energy Efficient Lighting | | | | | | | | | | | |
| 2002 | 11,618 | 243,033 | 310,643 | 3,299,654 | 0.38 | | 7 | 0.012 | 0.015 | | |
| 2003 | 12,662 | 314,641 | 464,059 | 3,596,150 | 0.41 | | 7 | 0.014 | 0.021 | | |
| 2004 | | | | | | | | | | | |
| 2005 | 43,760 | 73,152 | 107,810 | 1,734,646 | 0.20 | | 7 | 0.007 | 0.010 | | |
| 2006 | 178,514 | 298,754 | 539,877 | 6,302,794 | 0.72 | | 7 | 0.008 | 0.014 | | |
| 2007 | 219,739 | 557,646 | 433,626 | 7,207,439 | 0.82 | | 7 | 0.012 | 0.017 | | |
| 2008 | 436,234 | 1,018,292 | 793,265 | 14,309,444 | 1.63 | | 7 | 0.011 | 0.013 | | |
| 2009 | 549,846 | 1,207,366 | 1,456,796 | 13,410,748 | 1.53 | | 5 | 0.020 | 0.024 | | |
| 2010 | 1,190,139 | 2,501,278 | 3,976,476 | 28,082,738 | 3.21 | | 5 | 0.020 | 0.031 | | |
| 2011 | 1,039,755 | 1,719,133 | 2,764,623 | 19,694,381 | 2.25 | | 5 | 0.015 | 0.024 | | |
| 2012 | 925,460 | 1,126,836 | 2,407,355 | 16,708,659 | 1.91 | | 5 | 0.012 | 0.025 | | |
| 2013 | 1,085,225 | 1,356,926 | 4,889,501 | 9,995,753 | 1.14 | | 8 | 0.016 | 0.058 | | |
| 2014 | 1,161,553 | 1,909,823 | 7,148,427 | 12,882,151 | 1.47 | | 8 | 0.018 | 0.066 | | |
| **Total** | **6,854,505** | **$ 12,326,880** | **$ 25,292,458** | **137,224,557** | | | **8** | **$ 0.013** | **$ 0.027** | **4.24** | **2.07** |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Efficiency** | | | | | | | | | | | |
| Energy House Calls | | | | | | | | | | | |
| 2002 | 17 | $ 26,053 | $ 26,053 | 25,989 | 0.00 | | 20 | $ 0.082 | $ 0.082 | | |
| 2003 | 420 | 167,076 | 167,076 | 602,723 | 0.07 | | 20 | 0.023 | 0.023 | | |
| 2004 | 1,708 | 725,981 | 725,981 | 2,349,783 | 0.27 | | 20 | 0.025 | 0.025 | | |
| 2005 | 891 | 375,610 | 375,610 | 1,775,770 | 0.20 | | 20 | 0.017 | 0.017 | | |
| 2006 | 819 | 336,701 | 336,701 | 777,244 | 0.09 | | 20 | 0.035 | 0.035 | | |
| 2007 | 700 | 336,372 | 336,372 | 699,899 | 0.08 | | 20 | 0.039 | 0.039 | | |
| 2008 | 1,099 | 484,379 | 484,379 | 883,038 | 0.10 | | 20 | 0.045 | 0.045 | | |
| 2009 | 1,266 | 569,594 | 569,594 | 928,875 | 0.11 | | 20 | 0.052 | 0.052 | | |
| 2010 | 1,602 | 762,330 | 762,330 | 1,198,655 | 0.14 | | 20 | 0.054 | 0.054 | | |
| 2011 | 881 | 483,375 | 483,375 | 1,214,004 | 0.14 | | 20 | 0.027 | 0.027 | | |
| 2012 | 668 | 275,884 | 275,884 | 1,192,039 | 0.14 | | 18 | 0.016 | 0.016 | | |
| 2013 | 411 | 199,995 | 199,995 | 837,261 | 0.10 | | 18 | 0.017 | 0.017 | | |
| 2014 | 297 | 197,987 | 197,987 | 579,126 | 0.07 | | 18 | 0.024 | 0.024 | | |
| **Total** | **10,779** | **$ 4,941,337** | **$ 4,941,337** | **13,064,406** | | | **18** | **$ 0.033** | **$ 0.033** | **2.31** | **2.31** |
| ENERGY STAR Homes Northwest | | | | | | | | | | | |
| 2003 | | 13,597 | 13,597 | 0 | | | | | | | |
| 2004 | 44 | 140,165 | 335,437 | 101,200 | 0.01 | | 25 | 0.103 | 0.246 | | |
| 2005 | 200 | 253,105 | 315,311 | 415,600 | 0.05 | | 25 | 0.045 | 0.056 | | |
| 2006 | 439 | 469,609 | 602,651 | 912,242 | 0.10 | | 25 | 0.038 | 0.049 | | |
| 2007 | 303 | 475,044 | 400,637 | 629,634 | 0.07 | | 25 | 0.056 | 0.047 | | |
| 2008 | 254 | 302,061 | 375,007 | 468,958 | 0.05 | | 25 | 0.048 | 0.059 | | |
| 2009 | 474 | 355,623 | 498,622 | 705,784 | 0.08 | | 25 | 0.039 | 0.055 | | |
| 2010 | 630 | 375,605 | 579,495 | 883,260 | 0.10 | | 25 | 0.033 | 0.051 | | |
| 2011 | 308 | 259,762 | 651,249 | 728,030 | 0.08 | | 32 | 0.020 | 0.051 | | |
| 2012 | 410 | 453,186 | 871,310 | 537,447 | 0.06 | | 35 | 0.046 | 0.089 | | |
| 2013 | 267 | 352,882 | 697,682 | 365,370 | 0.04 | | 36 | 0.053 | 0.104 | | |
| 2014 | 243 | 343,277 | 689,021 | 332,682 | 0.04 | | 36 | 0.055 | 0.111 | | |
| **Total** | **3,572** | **$ 3,793,916** | **$ 6,030,020** | **6,080,207** | | | **36** | **$ 0.041** | **$ 0.065** | **2.35** | **1.48** |
| ENERGY STAR Homes Northwest (gas fuel) | | | | | | | | | | | |
| 2014 | 282 | | | 195,372 | | | | | | | |
| **Total** | **282** | **$ 0** | **$ 0** | **195,372** | | | | | | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Efficiency** | | | | | | | | | | | |
| Heating & Cooling Efficiency | | | | | | | | | | | |
| 2006 | | $ 17,444 | $ 17,444 | | | | | | | | |
| 2007 | 4 | 488,211 | 494,989 | 1,595 | 0.00 | | 18 | $27.344 | $27.710 | | |
| 2008 | 359 | 473,551 | 599,771 | 561,440 | 0.06 | | 18 | 0.073 | 0.092 | | |
| 2009 | 349 | 478,373 | 764,671 | 1,274,829 | 0.15 | | 18 | 0.034 | 0.054 | | |
| 2010 | 217 | 327,669 | 1,073,604 | 1,104,497 | 0.13 | | 20 | 0.025 | 0.083 | | |
| 2011 | 130 | 195,770 | 614,523 | 733,405 | 0.08 | | 20 | 0.018 | 0.056 | | |
| 2012 | 141 | 182,281 | 676,530 | 688,855 | 0.08 | | 20 | 0.018 | 0.066 | | |
| 2013 | 210 | 329,674 | 741,586 | 1,003,730 | 0.11 | | 20 | 0.022 | 0.050 | | |
| 2014 | 230 | 362,014 | 1,247,560 | 1,099,464 | 0.13 | | 20 | 0.022 | 0.075 | | |
| **Total** | **1,640** | **$ 2,854,988** | **$ 6,230,678** | **6,467,815** | | | **20** | **$ 0.036** | **$ 0.079** | **2.67** | **1.22** |
| Home Improvement Program | | | | | | | | | | | |
| 2008 | 282 | 123,454 | 157,866 | 317,814 | 0.04 | | 25 | 0.029 | 0.037 | | |
| 2009 | 1,188 | 321,140 | 550,148 | 1,338,876 | 0.15 | | 25 | 0.019 | 0.032 | | |
| 2010 | 3,537 | 944,716 | 2,112,737 | 3,986,199 | 0.46 | | 45 | 0.016 | 0.035 | | |
| 2011 | 2,275 | 666,041 | 2,704,816 | 917,519 | 0.10 | | 45 | 0.038 | 0.155 | | |
| 2012 | 840 | 385,091 | 812,827 | 457,353 | 0.05 | | 45 | 0.044 | 0.093 | | |
| 2013 | 365 | 299,497 | 1,061,314 | 616,044 | 0.07 | | 45 | 0.025 | 0.090 | | |
| 2014 | 555 | 324,717 | 896,246 | 838,929 | 0.10 | | 45 | 0.020 | 0.055 | | |
| **Total** | **9,042** | **$ 3,064,656** | **$ 8,295,954** | **8,472,734** | | | **45** | **$ 0.023** | **$ 0.062** | **2.21** | **0.81** |
| Home Products Program | | | | | | | | | | | |
| 2007 | | 9,275 | 9,275 | 0 | | | | | | | |
| 2008 | 3,034 | 250,860 | 468,056 | 541,615 | 0.06 | | 15 | 0.044 | 0.082 | | |
| 2009 | 9,499 | 511,313 | 844,811 | 1,638,038 | 0.19 | | 15 | 0.031 | 0.051 | | |
| 2010 | 16,322 | 832,161 | 1,025,151 | 1,443,580 | 0.16 | | 15 | 0.057 | 0.070 | | |
| 2011 | 15,896 | 638,323 | 1,520,977 | 1,485,326 | 0.17 | | 15 | 0.034 | 0.080 | | |
| 2012 | 16,675 | 659,032 | 817,924 | 887,222 | 0.10 | | 14 | 0.061 | 0.075 | | |
| 2013 | 13,792 | 405,515 | 702,536 | 885,980 | 0.10 | | 12 | 0.041 | 0.071 | | |
| 2014 | 10,061 | 227,176 | 302,289 | 652,129 | 0.07 | | 12 | 0.031 | 0.041 | | |
| **Total** | **85,279** | **$ 3,533,655** | **$ 5,691,019** | **7,533,890** | | | **12** | **$ 0.052** | **$ 0.083** | **1.71** | **1.06** |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Efficiency** | | | | | | | | | | | |
| Oregon Residential Weatherization | | | | | | | | | | | |
| 2002 | 24 | $ (662) | $ 23,971 | 4,580 | | | 25 | $ 0.010 | $ 0.389 | | |
| 2003 | | (943) | | | | | | | | | |
| 2004 | 4 | 1,057 | 1,057 | | | | | | | | |
| 2005 | 4 | 612 | 3,608 | 7,927 | 0.00 | | 25 | 0.006 | 0.034 | | |
| 2006 | | 4,126 | 4,126 | | | | | | | | |
| 2007 | 1 | 3,781 | 5,589 | 9,971 | 0.00 | | 25 | 0.028 | 0.042 | | |
| 2008 | 3 | 7,417 | 28,752 | 22,196 | 0.00 | | 25 | 0.025 | 0.096 | | |
| 2009 | 1 | 7,645 | 8,410 | 2,907 | 0.00 | | 25 | 0.203 | 0.223 | | |
| 2010 | 1 | 6,050 | 6,275 | 320 | 0.00 | | 30 | 0.011 | 0.062 | | |
| 2011 | 8 | 7,926 | 10,208 | 21,908 | 0.00 | | 30 | 0.021 | 0.027 | | |
| 2012 | 5 | 4,516 | 11,657 | 11,985 | 0.00 | | 30 | 0.022 | 0.056 | | |
| 2013 | 14 | 9,017 | 14,369 | 14,907 | 0.00 | | 30 | 0.035 | 0.055 | | |
| 2014 | 13 | 5,462 | 9,723 | 11,032 | 0.00 | | 30 | 0.028 | 0.050 | | |
| **Total** | **78** | **$ 56,004** | **$ 127,745** | **107,733** | | | **30** | **$ 0.036** | **$ 0.082** | **2.76** | **1.21** |
| Rebate Advantage | | | | | | | | | | | |
| 2003 | 73 | 27,372 | 79,399 | 227,434 | 0.03 | | 45 | 0.008 | 0.022 | | |
| 2004 | 105 | 52,187 | 178,712 | 332,587 | 0.04 | | 45 | 0.010 | 0.034 | | |
| 2005 | 98 | 46,173 | 158,462 | 312,311 | 0.04 | | 45 | 0.009 | 0.032 | | |
| 2006 | 102 | 52,673 | 140,289 | 333,494 | 0.04 | | 45 | 0.010 | 0.027 | | |
| 2007 | 123 | 89,269 | 182,152 | 554,018 | 0.06 | | 45 | 0.010 | 0.021 | | |
| 2008 | 107 | 90,888 | 179,868 | 463,401 | 0.05 | | 45 | 0.012 | 0.025 | | |
| 2009 | 57 | 49,525 | 93,073 | 247,348 | 0.03 | | 25 | 0.015 | 0.029 | | |
| 2010 | 35 | 39,402 | 66,142 | 164,894 | 0.02 | | 25 | 0.018 | 0.031 | | |
| 2011 | 25 | 63,469 | 85,044 | 159,325 | 0.02 | | 25 | 0.024 | 0.033 | | |
| 2012 | 35 | 37,241 | 71,911 | 187,108 | 0.02 | | 25 | 0.012 | 0.024 | | |
| 2013 | 42 | 60,770 | 92,690 | 269,891 | 0.03 | | 25 | 0.014 | 0.021 | | |
| 2014 | 44 | 63,231 | 89,699 | 269,643 | 0.03 | | 25 | 0.014 | 0.020 | | |
| **Total** | **846** | **$ 672,200** | **$ 1,417,441** | **3,521,454** | | | **25** | **$ 0.014** | **$ 0.030** | **7.67** | **3.64** |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Efficiency** | | | | | | | | | | | |
| See ya later, refrigerator® | | | | | | | | | | | |
| 2009 | 1,661 | $ 305,401 | $ 305,401 | 1,132,802 | 0.13 | | 8 | $ 0.041 | $ 0.041 | | |
| 2010 | 3,152 | 565,079 | 565,079 | 1,567,736 | 0.18 | | 8 | 0.054 | 0.054 | | |
| 2011 | 3,449 | 654,393 | 654,393 | 1,712,423 | 0.20 | | 8 | 0.046 | 0.046 | | |
| 2012 | 3,176 | 613,146 | 613,146 | 1,576,426 | 0.18 | | 8 | 0.046 | 0.046 | | |
| 2013 | 3,307 | 589,054 | 589,054 | 1,442,344 | 0.16 | | 6 | 0.061 | 0.061 | | |
| 2014 | 3,194 | $576,051 | 576,051 | 1,390,760 | 0.16 | | 6 | 0.062 | 0.062 | | |
| **Total** | **17,939** | **$ 3,303,124** | **$ 3,303,124** | **8,822,491** | | | **6** | **$ 0.069** | **$ 0.069** | **1.17** | **1.17** |
| Weatherization Solutions for Eligible Customers | | | | | | | | | | | |
| 2008 | 16 | 52,807 | 52,807 | 71,680 | 0.01 | | 25 | 0.057 | 0.057 | | |
| 2009 | 41 | 162,995 | 162,995 | 211,719 | 0.02 | | 25 | 0.059 | 0.059 | | |
| 2010 | 47 | 228,425 | 228,425 | 313,309 | 0.04 | | 25 | 0.056 | 0.056 | | |
| 2011 | 117 | 788,148 | 788,148 | 1,141,194 | 0.13 | | 25 | 0.042 | 0.042 | | |
| 2012 | 141 | 1,070,556 | 1,070,556 | 257,466 | 0.03 | | 25 | 0.254 | 0.254 | | |
| 2013 | 166 | 1,267,791 | 1,267,791 | 303,116 | 0.03 | | 25 | 0.240 | 0.240 | | |
| 2014 | 118 | $791,344 | 791,344 | 290,926 | 0.03 | | 25 | 0.163 | 0.163 | | |
| **Total** | **646** | **$ 4,362,066** | **$ 4,362,066** | **2,589,410** | | | **25** | **$ 0.125** | **$ 0.125** | **0.76** | **0.76** |
| Window AC Trade-Up Pilot | | | | | | | | | | | |
| 2003 | 99 | 6,687 | 10,492 | 14,454 | | | 12 | 0.051 | 0.079 | | |
| **Total** | **99** | **$ 6,687** | **$ 10,492** | **14,454** | | | **12** | **$ 0.051** | **$ 0.079** | | |
| **Residential—Weatherization Assistance for Qualified Customers (WAQC)** | | | | | | | | | | | |
| WAQC—Idaho | | | | | | | | | | | |
| 2002 | 197 | 235,048 | 492,139 | | | | | | | | |
| 2003 | 208 | 228,134 | 483,369 | | | | | | | | |
| 2004 | 269 | 498,474 | 859,482 | 1,271,677 | 0.15 | | 25 | 0.029 | 0.050 | | |
| 2005 | 570 | 1,402,487 | 1,927,424 | 3,179,311 | 0.36 | | 25 | 0.033 | 0.045 | | |
| 2006 | 540 | 1,455,373 | 2,231,086 | 2,958,024 | 0.34 | | 25 | 0.037 | 0.056 | | |
| 2007 | 397 | 1,292,930 | 1,757,105 | 3,296,019 | 0.38 | | 25 | 0.029 | 0.040 | | |
| 2008 | 439 | 1,375,632 | 1,755,749 | 4,064,301 | 0.46 | | 25 | 0.025 | 0.032 | | |
| 2009 | 427 | 1,260,922 | 1,937,578 | 4,563,832 | 0.52 | | 25 | 0.021 | 0.033 | | |
| 2010 | 373 | 1,205,446 | 2,782,597 | 3,452,025 | 0.39 | | 25 | 0.026 | 0.060 | | |
| 2011 | 273 | 1,278,112 | 1,861,836 | 2,648,676 | 0.30 | | 25 | 0.036 | 0.053 | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | Measure Life (Years) | Levelized Costs[a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost[c] | Resource Cost[d] | Annual Energy (kWh) | Average Energy[e] (aMW) | Peak Demand[f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Residential—Weatherization Assistance for Qualified Customers (WAQC)** | | | | | | | | | | | |
| WAQC—Idaho | | | | | | | | | | | |
| 2012 | 228 | $ 1,321,927 | $ 1,743,863 | 621,464 | 0.07 | | 25 | $ 0.159 | $ 0.210 | | |
| 2013 | 245 | 1,336,742 | 1,984,173 | 657,580 | 0.08 | | 25 | 0.152 | 0.226 | | |
| 2014 | 244 | 1,267,212 | 1,902,615 | 509,620 | 0.06 | | 25 | 0.185 | 0.277 | | |
| **Total** | **4,410** | **$ 14,158,439** | **$ 21,719,016** | **27,222,529** | | | **25** | **$ 0.039** | **$ 0.059** | **2.91** | **1.89** |
| WAQC—Oregon | | | | | | | | | | | |
| 2002 | 31 | 24,773 | 47,221 | 68,323 | 0.01 | | 25 | 0.027 | 0.051 | | |
| 2003 | 29 | 22,255 | 42,335 | 102,643 | 0.01 | | 25 | 0.016 | 0.031 | | |
| 2004 | 17 | 13,469 | 25,452 | 28,436 | 0.00 | | 25 | 0.035 | 0.067 | | |
| 2005 | 28 | 44,348 | 59,443 | 94,279 | 0.01 | | 25 | 0.035 | 0.047 | | |
| 2006 | | | | | | | 25 | | | | |
| 2007 | 11 | 30,694 | 41,700 | 42,108 | 0.00 | | 25 | 0.054 | 0.074 | | |
| 2008 | 14 | 43,843 | 74,048 | 73,841 | 0.01 | | 25 | 0.040 | 0.068 | | |
| 2009 | 10 | 33,940 | 46,513 | 114,982 | 0.01 | | 25 | 0.023 | 0.031 | | |
| 2010 | 27 | 115,686 | 147,712 | 289,627 | 0.03 | | 25 | 0.030 | 0.038 | | |
| 2011 | 14 | 46,303 | 63,981 | 134,972 | 0.02 | | 25 | 0.026 | 0.035 | | |
| 2012 | 10 | 48,214 | 76,083 | 26,840 | 0.00 | | 25 | 0.134 | 0.212 | | |
| 2013 | 9 | 54,935 | 67,847 | 24,156 | 0.00 | | 25 | 0.170 | 0.210 | | |
| 2014 | 11 | 52,900 | 94,493 | 24,180 | 0.00 | | 25 | 0.162 | 0.290 | | |
| **Total** | **211** | **$ 531,360** | **$ 786,828** | **1,024,387** | | | **25** | **$ 0.038** | **$ 0.057** | **2.79** | **1.89** |
| WAQC—BPA Supplemental | | | | | | | | | | | |
| 2002 | 75 | 55,966 | 118,255 | 311,347 | 0.04 | | 25 | 0.013 | 0.028 | | |
| 2003 | 57 | 49,895 | 106,915 | 223,591 | 0.03 | | 25 | 0.017 | 0.036 | | |
| 2004 | 40 | 69,409 | 105,021 | 125,919 | 0.01 | | 25 | 0.041 | 0.062 | | |
| **Total** | **172** | **$ 175,270** | **$ 330,191** | **660,857** | | | **25** | **$ 0.020** | **$ 0.037** | **5.62** | **2.98** |
| **WAQC—All Total** | | **$ 14,865,069** | **$ 22,836,035** | **28,907,773** | | | **25** | **$ 0.038** | **$ 0.059** | **2.93** | **1.91** |
| **Commercial** | | | | | | | | | | | |
| Air Care Plus Pilot | | | | | | | | | | | |
| 2003 | 4 | 5,764 | 9,061 | 33,976 | | | 10 | 0.021 | 0.033 | | |
| 2004 | | 344 | 344 | | | | | | | | |
| **Total** | **4** | **$ 6,108** | **$ 9,405** | **33,976** | | | **10** | **$ 0.022** | **$ 0.034** | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | Measure Life (Years) | Levelized Costs[a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost[c] | Resource Cost[d] | Annual Energy (kWh) | Average Energy[e] (aMW) | Peak Demand[f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Commercial** | | | | | | | | | | | |
| Building Efficiency | | | | | | | | | | | |
| 2004 | | $ 28,821 | $ 28,821 | | | | | | | | |
| 2005 | 12 | 194,066 | 233,149 | 494,239 | 0.06 | 0.2 | 12 | $ 0.043 | $ 0.052 | | |
| 2006 | 40 | 374,008 | 463,770 | 704,541 | 0.08 | 0.3 | 12 | 0.058 | 0.072 | | |
| 2007 | 22 | 669,032 | 802,839 | 2,817,248 | 0.32 | 0.5 | 12 | 0.015 | 0.040 | | |
| 2008 | 60 | 1,055,009 | 1,671,375 | 6,598,123 | 0.75 | 1.0 | 12 | 0.017 | 0.028 | | |
| 2009 | 72 | 1,327,127 | 2,356,434 | 6,146,139 | 0.70 | 1.3 | 12 | 0.024 | 0.043 | | |
| 2010 | 70 | 1,509,682 | 3,312,963 | 10,819,598 | 1.24 | 0.9 | 12 | 0.016 | 0.035 | | |
| 2011 | 63 | 1,291,425 | 3,320,015 | 11,514,641 | 1.31 | 0.9 | 12 | 0.010 | 0.026 | | |
| 2012 | 84 | 1,592,572 | 8,204,883 | 20,450,037 | 2.33 | 0.6 | 12 | 0.007 | 0.036 | | |
| 2013 | 59 | 1,507,035 | 3,942,880 | 10,988,934 | 1.25 | 1.1 | 12 | 0.012 | 0.032 | | |
| 2014 | 69 | 1,258,273 | 3,972,822 | 9,458,059 | 1.08 | 1.2 | 12 | 0.012 | 0.037 | | |
| **Total** | **551** | **$ 10,807,051** | **$ 28,309,952** | **79,991,559** | | | **12** | **$ 0.015** | **$ 0.039** | **4.99** | **1.90** |
| Easy Upgrades | | | | | | | | | | | |
| 2006 | | 31,819 | 31,819 | | | | | | | | |
| 2007 | 104 | 711,494 | 1,882,035 | 5,183,640 | 0.59 | 0.8 | 12 | 0.015 | 0.040 | | |
| 2008 | 666 | 2,992,261 | 10,096,627 | 25,928,391 | 2.96 | 4.5 | 12 | 0.013 | 0.043 | | |
| 2009 | 1,224 | 3,325,505 | 10,076,237 | 35,171,627 | 4.02 | 6.1 | 12 | 0.011 | 0.032 | | |
| 2010 | 1,535 | 3,974,410 | 7,655,397 | 35,824,463 | 4.09 | 7.8 | 12 | 0.013 | 0.024 | | |
| 2011 | 1,732 | 4,719,466 | 9,519,364 | 38,723,073 | 4.42 | | 12 | 0.011 | 0.022 | | |
| 2012 | 1,838 | 5,349,753 | 9,245,297 | 41,568,672 | 4.75 | | 12 | 0.012 | 0.020 | | |
| 2013 | 1,392 | 3,359,790 | 6,738,645 | 21,061,946 | 2.40 | | 12 | 0.014 | 0.029 | | |
| 2014 | 1,095 | 3,150,942 | 5,453,380 | 19,118,494 | 2.18 | | 12 | 0.015 | 0.025 | | |
| **Total** | **9,586** | **$ 27,615,440** | **$ 60,698,801** | **222,580,306** | | | **12** | **$ 0.014** | **$ 0.030** | **5.48** | **2.49** |
| Holiday Lighting | | | | | | | | | | | |
| 2008 | 14 | 28,782 | 73,108 | 259,092 | 0.03 | | 10 | 0.014 | 0.035 | | |
| 2009 | 32 | 33,930 | 72,874 | 142,109 | 0.02 | | 10 | 0.031 | 0.066 | | |
| 2010 | 25 | 46,132 | 65,308 | 248,865 | 0.03 | | 10 | 0.024 | 0.034 | | |
| 2011 | 6 | 2,568 | 2,990 | 66,189 | 0.01 | | 10 | 0.004 | 0.005 | | |
| **Total** | **77** | **$ 111,412** | **$ 214,280** | **716,255** | | | **10** | **$ 0.019** | **$ 0.037** | **2.85** | **1.48** |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | Measure Life (Years) | Levelized Costs[a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost[c] | Resource Cost[d] | Annual Energy (kWh) | Average Energy[e] (aMW) | Peak Demand[f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Commercial** | | | | | | | | | | | |
| Oregon Commercial Audit | | | | | | | | | | | |
| 2002 | 24 | $ 5,200 | $ 5,200 | | | | | | | | |
| 2003 | 21 | 0 | 4,000 | | | | | | | | |
| 2004 | 7 | 0 | 0 | | | | | | | | |
| 2005 | 7 | 5,450 | 5,450 | | | | | | | | |
| 2006 | 6 | | | | | | | | | | |
| 2007 | | 1,981 | 1,981 | | | | | | | | |
| 2008 | | 58 | 58 | | | | | | | | |
| 2009 | 41 | 20,732 | 20,732 | | | | | | | | |
| 2010 | 22 | 5,049 | 5,049 | | | | | | | | |
| 2011 | 12 | 13,597 | 13,597 | | | | | | | | |
| 2012 | 14 | 12,470 | 12,470 | | | | | | | | |
| 2013 | 18 | 5,090 | 5,090 | | | | | | | | |
| 2014 | 16 | 9,464 | 9,464 | | | | | | | | |
| **Total** | **188** | **$ 79,091** | **$ 83,091** | | | | | | | | |
| Oregon School Efficiency | | | | | | | | | | | |
| 2005 | | 86 | 86 | | | | | | | | |
| 2006 | 6 | 24,379 | 89,771 | 223,368 | 0.03 | | 12 | $ 0.012 | $ 0.044 | | |
| **Total** | **6** | **$ 24,465** | **$ 89,857** | **223,368** | | | **12** | **$ 0.012** | **$ 0.044** | | |
| **Industrial** | | | | | | | | | | | |
| Custom Efficiency | | | | | | | | | | | |
| 2003 | | 1,303 | 1,303 | | | | | | | | |
| 2004 | 1 | 112,311 | 133,441 | 211,295 | 0.02 | | 12 | 0.058 | 0.069 | | |
| 2005 | 24 | 1,128,076 | 3,653,152 | 12,016,678 | 1.37 | | 12 | 0.010 | 0.033 | | |
| 2006 | 40 | 1,625,216 | 4,273,885 | 19,211,605 | 2.19 | | 12 | 0.009 | 0.024 | | |
| 2007 | 49 | 3,161,866 | 7,012,686 | 29,789,304 | 3.40 | 3.6 | 12 | 0.012 | 0.026 | | |
| 2008 | 101 | 4,045,671 | 16,312,379 | 41,058,639 | 4.69 | 4.8 | 12 | 0.011 | 0.044 | | |
| 2009 | 132 | 6,061,467 | 10,848,123 | 51,835,612 | 5.92 | 6.7 | 12 | 0.013 | 0.024 | | |
| 2010 | 223 | 8,778,125 | 17,172,176 | 71,580,075 | 8.17 | 9.5 | 12 | 0.014 | 0.027 | | |
| 2011 | 166 | 8,783,811 | 19,830,834 | 67,979,157 | 7.76 | 7.8 | 12 | 0.012 | 0.026 | | |
| 2012 | 126 | 7,092,581 | 12,975,629 | 54,253,106 | 6.19 | 7.6 | 12 | 0.012 | 0.021 | | |
| 2013 | 73 | 2,466,225 | 5,771,640 | 21,370,350 | 2.43 | 2.4 | 12 | 0.010 | 0.024 | | |
| 2014 | 131 | 7,173,054 | 13,409,922 | 50,363,052 | 5.75 | 5.6 | 12 | 0.013 | 0.024 | | |
| **Total** | **1,066** | **$ 50,429,705** | **$111,395,170** | **419,668,873** | | | **12** | **$ 0.013** | **$ 0.029** | **5.76** | **2.61** |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | Measure Life (Years) | Levelized Costs[a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost[c] | Resource Cost[d] | Annual Energy (kWh) | Average Energy[e] (aMW) | Peak Demand[f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Irrigation** | | | | | | | | | | | |
| Irrigation Efficiency Program | | | | | | | | | | | |
| 2003 | 2 | $ 41,089 | $ 54,609 | 36,792 | 0.00 | 0.0 | 15 | $ 0.106 | $ 0.141 | | |
| 2004 | 33 | 120,808 | 402,978 | 802,812 | 0.09 | 0.4 | 15 | 0.014 | 0.048 | | |
| 2005 | 38 | 150,577 | 657,460 | 1,012,883 | 0.12 | 0.4 | 15 | 0.014 | 0.062 | | |
| 2006 | 559 | 2,779,620 | 8,514,231 | 16,986,008 | 1.94 | 5.1 | 8 | 0.024 | 0.073 | | |
| 2007 | 816 | 2,001,961 | 8,694,772 | 12,304,073 | 1.40 | 3.4 | 8 | 0.024 | 0.103 | | |
| 2008 | 961 | 2,103,702 | 5,850,778 | 11,746,395 | 1.34 | 3.5 | 8 | 0.026 | 0.073 | | |
| 2009 | 887 | 2,293,896 | 6,732,268 | 13,157,619 | 1.50 | 3.4 | 8 | 0.026 | 0.077 | | |
| 2010 | 753 | 2,200,814 | 6,968,598 | 10,968,430 | 1.25 | 3.3 | 8 | 0.030 | 0.096 | | |
| 2011 | 880 | 2,360,304 | 13,281,492 | 13,979,833 | 1.60 | 3.8 | 8 | 0.020 | 0.113 | | |
| 2012 | 908 | 2,373,201 | 11,598,185 | 12,617,164 | 1.44 | 3.1 | 8 | 0.022 | 0.110 | | |
| 2013 | 995 | 2,441,386 | 15,223,928 | 18,511,221 | 2.11 | 3.0 | 8 | 0.016 | 0.098 | | |
| 2014 | 1,128 | 2,446,507 | 18,459,781 | 18,463,611 | 2.11 | 4.6 | 8 | 0.016 | 0.119 | | |
| **Total** | **7,960** | **$ 21,313,865** | **$ 96,439,079** | **130,586,841** | | | **8** | **$ 0.024** | **$ 0.108** | **4.65** | **1.54** |
| **Other Programs** | | | | | | | | | | | |
| Building Operator Training | | | | | | | | | | | |
| 2003 | 71 | 48,853 | 48,853 | 1,825,000 | 0.21 | | 5 | 0.006 | 0.006 | | |
| 2004 | 26 | 43,969 | 43,969 | 650,000 | 0.07 | | 5 | 0.014 | 0.014 | | |
| 2005 | 7 | 1,750 | 4,480 | 434,167 | 0.05 | | 5 | 0.001 | 0.002 | | |
| **Total** | **104** | **$ 94,572** | **$ 97,302** | **2,909,167** | | | **5** | **$ 0.007** | **$ 0.007** | | |
| Commercial Education Initiative | | | | | | | | | | | |
| 2005 | | 3,497 | 3,497 | | | | | | | | |
| 2006 | | 4,663 | 4,663 | | | | | | | | |
| 2007 | | 26,823 | 26,823 | | | | | | | | |
| 2008 | | 72,738 | 72,738 | | | | | | | | |
| 2009 | | 120,584 | 120,584 | | | | | | | | |
| 2010 | | 68,765 | 68,765 | | | | | | | | |
| 2011 | | 89,856 | 89,856 | | | | | | | | |
| 2012 | | 73,788 | 73,788 | | | | | | | | |
| 2013 | | 66,790 | 66,790 | | | | | | | | |
| 2014 | | 76,606 | 76,606 | | | | | | | | |
| **Total** | | **$ 604,110** | **$ 604,110** | | | | | | | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Other Programs** | | | | | | | | | | | |
| Comprehensive Lighting | | | | | | | | | | | |
| 2011 | | $ 2,404 | $ 2,404 | | | | | | | | |
| 2012 | | 64,094 | 64,094 | | | | | | | | |
| **Total** | | **$ 66,498** | **$ 66,498** | | | | | | | | |
| Distribution Efficiency Initiative | | | | | | | | | | | |
| 2005 | | 21,552 | 43,969 | | | | | | | | |
| 2006 | | 24,306 | 24,306 | | | | | | | | |
| 2007 | | 8,987 | 8,987 | | | | | | | | |
| 2008 | | (1,913) | (1,913) | | | | | | | | |
| **Total** | | **$ 52,932** | **$ 75,349** | | | | | | | | |
| DSM Direct Program Overhead | | | | | | | | | | | |
| 2007 | | 56,909 | 56,909 | | | | | | | | |
| 2008 | | 169,911 | 169,911 | | | | | | | | |
| 2009 | | 164,957 | 164,957 | | | | | | | | |
| 2010 | | 117,874 | 117,874 | | | | | | | | |
| 2011 | | 210,477 | 210,477 | | | | | | | | |
| 2012 | | 285,951 | 285,951 | | | | | | | | |
| 2013 | | 380,957 | 380,957 | | | | | | | | |
| 2014 | | 478,658 | 478,658 | | | | | | | | |
| **Total** | | **$ 1,865,694** | **$ 1,865,694** | | | | | | | | |
| Home Energy Audit | | | | | | | | | | | |
| 2013 | | 88,740 | 88,740 | | | | | | | | |
| 2014 | 354 | 170,648 | 170,648 | 141,077 | | | | | | | |
| **Total** | **354** | **$ 259,388** | **$ 259,388** | **141,077** | | | | | | | |
| Shade Tree | | | | | | | | | | | |
| 2014 | 2,041 | 147,290 | 147,290 | | | | | | | | |
| **Total** | **2,041** | **$ 147,290** | **$ 147,290** | | | | | | | | |

**Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Other Programs** | | | | | | | | | | | |
| Other C&RD and CRC BPA | | | | | | | | | | | |
| 2002 | | $ 55,722 | $ 55,722 | | | | | | | | |
| 2003 | | 67,012 | 67,012 | | | | | | | | |
| 2004 | | 108,191 | 108,191 | | | | | | | | |
| 2005 | | 101,177 | 101,177 | | | | | | | | |
| 2006 | | 124,956 | 124,956 | | | | | | | | |
| 2007 | | 31,645 | 31,645 | | | | | | | | |
| 2008 | | 6,950 | 6,950 | | | | | | | | |
| **Total** | | **$ 495,654** | **$ 495,654** | | | | | | | | |
| Residential Economizer Pilot | | | | | | | | | | | |
| 2011 | | 101,713 | 101,713 | | | | | | | | |
| 2012 | | 93,491 | 93,491 | | | | | | | | |
| 2013 | | 74,901 | 74,901 | | | | | | | | |
| **Total** | | **$ 270,105** | **$ 270,105** | | | | | | | | |
| Residential Education Initiative | | | | | | | | | | | |
| 2005 | | 7,498 | 7,498 | | | | | | | | |
| 2006 | | 56,727 | 56,727 | | | | | | | | |
| 2007 | | | | | | | | | | | |
| 2008 | | 150,917 | 150,917 | | | | | | | | |
| 2009 | | 193,653 | 193,653 | | | | | | | | |
| 2010 | | 222,092 | 222,092 | | | | | | | | |
| 2011 | | 159,645 | 159,645 | | | | | | | | |
| 2012 | | 174,738 | 174,738 | | | | | | | | |
| 2013 | | 416,166 | 416,166 | | | | | | | | |
| 2014 | 6,312 | 423,091 | 423,091 | 1,491,225 | | | | | | | |
| **Total** | **6,312** | **$ 1,804,527** | **$ 1,804,527** | **1,491,225** | | | | | | | |
| Solar 4R Schools | | | | | | | | | | | |
| 2009 | | 42,522 | 45,522 | | | | | | | | |
| **Total** | | **$ 42,522** | **$ 45,522** | | | | | | | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs: Utility Cost[c] | Total Costs: Resource Cost[d] | Savings and Demand Reduction: Annual Energy (kWh) | Savings and Demand Reduction: Average Energy[e] (aMW) | Savings and Demand Reduction: Peak Demand[f] (MW) | Measure Life (Years) | Levelized Costs[a]: Total Utility ($/kWh) | Levelized Costs[a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios[b]: Utility | Program Life Benefit/Cost Ratios[b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Other Programs** | | | | | | | | | | | |
| Local Energy Efficiency Fund | | | | | | | | | | | |
| 2003 | 56 | $ 5,100 | $ 5,100 | | | | | | | | |
| 2004 | | 23,449 | 23,449 | | | | | | | | |
| 2005 | 2 | 14,896 | 26,756 | 78,000 | 0.01 | | 10 | $ 0.024 | $ 0.042 | | |
| 2006 | 480 | 3,459 | 3,459 | 19,027 | 0.00 | | 7 | 0.009 | 0.009 | | |
| 2007 | 1 | 7,520 | 7,520 | 9,000 | 0.00 | | 7 | 0.135 | 0.135 | | |
| 2008 | 2 | 22,714 | 60,100 | 115,931 | 0.01 | | 15 | 0.019 | 0.049 | | |
| 2009 | 1 | 5,870 | 4,274 | 10,340 | 0.00 | | 12 | 0.064 | 0.047 | | |
| 2010 | 1 | 251 | 251 | | 0.00 | | | | | | |
| 2011 | 1 | 1,026 | 2,052 | 2,028 | | | 30 | 0.036 | 0.071 | | |
| 2012 | | | | | | | | | | | |
| 2013 | | | | | | | | | | | |
| 2014 | 1 | 9,100 | 9,100 | 95,834 | | | 18 | | | | |
| **Total** | **545** | **$ 93,385** | **$ 142,061** | **330,160** | | | **14** | **$ 0.028** | **$ 0.043** | **2.71** | **1.78** |
| **Market Transformation** | | | | | | | | | | | |
| NEEA | | | | | | | | | | | |
| 2002 | | $ 1,286,632 | $ 1,286,632 | 12,925,450 | 1.48 | | | | | | |
| 2003 | | 1,292,748 | 1,292,748 | 11,991,580 | 1.37 | | | | | | |
| 2004 | | 1,256,611 | 1,256,611 | 13,329,071 | 1.52 | | | | | | |
| 2005 | | 476,891 | 476,891 | 16,422,224 | 1.87 | | | | | | |
| 2006 | | 930,455 | 930,455 | 18,597,955 | 2.12 | | | | | | |
| 2007 | | 893,340 | 893,340 | 28,601,410 | 3.27 | | | | | | |
| 2008 | | 942,014 | 942,014 | 21,024,279 | 2.40 | | | | | | |
| 2009 | | 968,263 | 968,263 | 10,702,998 | 1.22 | | | | | | |
| 2010 | | 2,391,217 | 2,391,217 | 21,300,366 | 2.43 | | | | | | |
| 2011 | | 3,108,393 | 3,108,393 | 20,161,728 | 2.30 | | | | | | |
| 2012 | | 3,379,756 | 3,379,756 | 19,567,984 | 2.23 | | | | | | |
| 2013 | | 3,313,058 | 3,313,058 | 20,567,965 | 2.35 | | | | | | |
| 2014 | | 3,305,917 | 3,305,917 | 20,000,000 | 2.28 | | | | | | |
| **Total** | | **$ 23,545,294** | **$ 23,545,294** | **235,193,011** | | | | | | | |
| Consumer Electronic Initiative | | | | | | | | | | | |
| 2009 | | 160,762 | 160,762 | | | | | | | | |
| **Total** | | **$ 160,762** | **$ 160,762** | | | | | | | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | Measure Life (Years) | Levelized Costs[a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost[c] | Resource Cost[d] | Annual Energy (kWh) | Average Energy[e] (aMW) | Peak Demand[f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Annual Totals** | | | | | | | | | | | |
| 2002 | | $ 1,932,520 | $ 2,366,591 | 16,791,100 | 1.92 | 0.0 | | | | | |
| 2003 | | 2,566,228 | 3,125,572 | 18,654,343 | 2.12 | 0.0 | | | | | |
| 2004 | | 3,827,213 | 4,860,912 | 19,202,780 | 2.19 | 6.6 | | | | | |
| 2005 | | 6,523,348 | 10,383,577 | 37,978,035 | 4.34 | 44.3 | | | | | |
| 2006 | | 11,174,181 | 20,950,110 | 67,026,303 | 7.65 | 44.4 | | | | | |
| 2007 | | 14,896,816 | 27,123,018 | 91,145,357 | 10.40 | 58.5 | | | | | |
| 2008 | | 20,213,216 | 44,775,829 | 128,508,579 | 14.67 | 74.9 | | | | | |
| 2009 | | 33,821,062 | 53,090,852 | 143,146,365 | 16.34 | 235.5 | | | | | |
| 2010 | | 44,643,541 | 68,981,324 | 193,592,637 | 22.10 | 357.7 | | | | | |
| 2011 | | 44,877,117 | 79,436,532 | 183,476,312 | 20.94 | 419.6 | | | | | |
| 2012 | | 47,991,350 | 77,336,341 | 172,054,327 | 19.64 | 453.6 | | | | | |
| 2013 | | 26,100,091 | 54,803,353 | 109,505,690 | 12.23 | 54.5 | | | | | |
| 2014 | | 35,648,260 | 71,372,414 | 138,670,112 | 15.60 | 389.7 | | | | | |
| **Total Direct Program** | | **$ 294,214,943** | **$518,606,427** | **1,319,751,941** | | | | | | | |
| **Indirect Program Expenses** | | | | | | | | | | | |
| DSM Overhead and Other Indirect | | | | | | | | | | | |
| 2002 | | 128,855 | | | | | | | | | |
| 2003 | | (41,543) | | | | | | | | | |
| 2004 | | 142,337 | | | | | | | | | |
| 2005 | | 177,624 | | | | | | | | | |
| 2006 | | 309,832 | | | | | | | | | |
| 2007 | | 765,561 | | | | | | | | | |
| 2008 | | 980,305 | | | | | | | | | |
| 2009 | | 1,025,704 | | | | | | | | | |
| 2010 | | 1,189,310 | | | | | | | | | |
| 2011 | | 1,389,135 | | | | | | | | | |
| 2012 | | 1,335,509 | | | | | | | | | |
| 2013 | | 741,287 | | | | | | | | | |
| 2014 | | $1,065,072 | | | | | | | | | |
| **Total** | | **$ 9,208,988** | | | | | | | | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2014 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reduction | | | Measure Life (Years) | Levelized Costs[a] | | Program Life Benefit/Cost Ratios[b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost[c] | Resource Cost[d] | Annual Energy (kWh) | Average Energy[e] (aMW) | Peak Demand[f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Total Expenses** | | | | | | | | | | | |
| 2002 | | $ 2,061,375 | | | | | | | | | |
| 2003 | | 2,524,685 | | | | | | | | | |
| 2004 | | 3,969,550 | | | | | | | | | |
| 2005 | | 6,700,972 | | | | | | | | | |
| 2006 | | 11,484,013 | | | | | | | | | |
| 2007 | | 15,662,377 | | | | | | | | | |
| 2008 | | 21,193,521 | | | | | | | | | |
| 2009 | | 34,846,766 | | | | | | | | | |
| 2010 | | 45,832,851 | | | | | | | | | |
| 2011 | | 46,266,252 | | | | | | | | | |
| 2012 | | 49,326,859 | | | | | | | | | |
| 2013 | | 26,841,378 | | | | | | | | | |
| 2014 | | 36,713,333 | | | | | | | | | |
| **Total 2002–2014** | | **$ 303,423,931** | | | | | | | | | |

[a] Levelized Costs are based on financial inputs from Idaho Power's 2013 IRP and calculations include line loss adjusted energy savings.

[b] Program life benefit/cost ratios are provided for active programs only.

[c] The Total Utility Cost is all cost incurred by Idaho Power to implement and manage a DSM program.

[d] The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.

[e] Average Demand = Annual Energy/8,760 annual hours.

[f] Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season. Peak demand reduction for demand response programs is reported at the generation level assuming peak line losses.

[1] Savings are preliminary estimates. Final savings for 2014 will be provided by NEEA in June 2015.

## **Appendix 5.** 2014 DSM program activity by state jurisdiction

| Program | Idaho Participants | Idaho Utility Costs | Idaho Demand Reduction/ Annual Energy Savings | Oregon Participants | Oregon Utility Costs[a] | Oregon Demand Reduction/ Annual Energy Savings |
|---|---|---|---|---|---|---|
| **Demand Response** | | | **(MW)** | | | **(MW)** |
| A/C Cool Credit | 29,239 homes | $ 1,408,658 | 43.0 | 403 homes | $ 56,988 | 0.6 |
| Irrigation Peak Rewards | 2,194 service points | 7,490,394 | 293.4 | 31 service points | 106,819 | 1.6 |
| FlexPeak Management | 35 sites | 1,485,080 | 28.9 | 5 sites | 78,131 | 10.7 |
| **Total** | | **$ 10,384,132** | **365.3** | | **$ 241,938** | **12.9** |
| **Energy Efficiency** | | | **(kWh)** | | | **(kWh)** |
| **Residential** | | | | | | |
| Ductless Heat Pump Pilot | 174 homes | 241,832 | 447,092 | 5 homes | 9,614 | 15,655 |
| Energy Efficient Lighting | 1,128,724 bulbs | 1,863,864 | 12,565,310 | 32,829 bulbs | 45,959 | 316,841 |
| Energy House Calls | 282 homes | 189,812 | 555,081 | 15 homes | 8,174 | 24,045 |
| ENERGY STAR® Homes Northwest | 240 homes | 335,665 | 322,980 | 3 homes | 7,612 | 9,702 |
| ENERGY STAR® Homes Northwest (gas fuel) | 282 homes | 0 | 195,372 | 0 homes | 0 | 0 |
| Heating & Cooling Efficiency Program | 224 projects | 347,387 | 1,067,900 | 6 projects | 14,627 | 31,564 |
| Home Energy Audit (direct install savings) | 381 audits | 0 | 141,077 | 0 audits | 0 | 0 |
| Home Improvement Program | 555 projects | 324,717 | 838,929 | 0 projects | 0 | 0 |
| Home Products Program | 9,794 appliances/ showerheads | 217,926 | 634,244 | 267 appliances/ showerheads | 9,250 | 17,885 |
| Oregon Residential Weatherization | 0 home | 0 | 0 | 13 home | 5,462 | 11,032 |
| Rebate Advantage | 40 homes | 57,907 | 245,109 | 4 homes | 5,323 | 24,534 |
| Student Energy Efficiency Kits | 6,312 kits | 0 | 1,491,225 | 0 kits | 0 | 0 |
| See ya later refrigerator® | 3,138 refrigerators/ freezers | 563,641 | 1,366,044 | 56 refrigerators/ freezers | 12,410 | 24,716 |
| Weatherization Assistance for Qualified Customers | 244 homes/non-profits | 1,267,212 | 509,620 | 11 homes/non-profits | 52,900 | 24,180 |
| Weatherization Solutions for Eligible Customers | 118 homes | 791,344 | 290,926 | 0 homes | 0 | 0 |
| **Sector Total** | | **$ 6,201,308** | **20,670,908** | | **$ 171,332** | **500,154** |
| **Commercial** | | | | | | |
| Building Efficiency | 66 projects | 1,227,222 | 9,377,053 | 3 projects | 31,052 | 81,005 |
| Easy Upgrades | 1,055 projects | 3,038,319 | 18,709,206 | 40 projects | 112,623 | 409,288 |
| **Sector Total** | | **$ 4,265,541** | **28,086,259** | | **$ 143,674** | **490,293** |
| **Industrial** | | | | | | |
| Custom Efficiency | 122 projects | 6,754,517 | 46,194,507 | 9 projects | 418,537 | 4,168,545 |
| **Sector Total** | | **$ 6,754,517** | **46,194,507** | | **$ 418,537** | **4,168,545** |

## **Appendix 5.** 2014 DSM program activity by state jurisdiction (continued)

| Program | Idaho | | | Oregon | | |
|---|---|---|---|---|---|---|
| | Participants | Utility Costs | Demand Reduction/ Annual Energy Savings | Participants | Utility Costs[a] | Demand Reduction/ Annual Energy Savings |
| **Irrigation** | | | | | | |
| Irrigation Efficiency Rewards | 1,093 projects | 2,301,126 | 17,845,297 | 35 projects | 145,381 | 618,314 |
| **Sector Total** | | **$ 2,301,126** | **17,845,297** | | **$ 145,381** | **618,314** |
| **Market Transformation** | | | | | | |
| Northwest Energy Efficiency Alliance[1] | | 3,140,621 | 19,000,000 | | 165,296 | 1,000,000 |
| **Other Programs and Activities** | | | | | | |
| **Residential** | | | | | | |
| Home Energy Audit | | 170,897 | | | (248) | |
| Local Energy Efficiency Funds | | 9,100 | 95,834 | | 0 | |
| Residential Energy Efficiency Education Initiative | | 408,246 | | | 14,845 | |
| Shade Tree Project | | 147,224 | | | 66 | |
| **Commercial** | | | | | | |
| Commercial Education Initiative | | 72,776 | | | 3,829 | |
| Oregon Commercial Audits | | 0 | | | 9,464 | |
| **Other** | | | | | | |
| Energy Efficiency Direct Program Overhead | | 456,947 | | | 21,711 | |
| **Total Program Direct Expense** | | **$ 34,312,435** | | | **$ 1,335,825** | |
| Indirect Program Expenses | | 1,012,004 | | | 53,068 | |
| **Total Annual Savings** | | | **131,892,805** | | | **6,777,306** |
| **Total DSM Expense** | | **$ 35,324,439** | | | **$ 1,388,894** | |

[a] Levelized Costs are based on financial inputs from Idaho Power's 2011 IRP and calculations include line loss adjusted energy savings.

[1] Savings are preliminary estimates. Final savings for 2014 will be provided by NEEA in June 2015.

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APPENDIX C
Technical Report

# Integrated Resource Plan 2015







## SAFE HARBOR STATEMENT

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

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APPENDIX C
Technical Report

# Integrated Resource Plan 2015

## ACKNOWLEDGMENT

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 *2015 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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# INTRODUCTION

*Appendix C–Technical Appendix* contains supporting data and explanatory materials used to develop Idaho Power's *2015 Integrated Resource Plan* (IRP).

The main document, the IRP, contains a full narrative of Idaho Power's resource planning process. Additional information regarding the 2015 IRP sales and load forecast is contained in *Appendix A–Sales and Load Forecast*, and details on Idaho Power's demand-side management efforts are explained in *Appendix B–Demand-Side Management 2014 Annual Report*. The IRP, including the three appendices, was filed with the Idaho and Oregon public utility commissions in June 2015.

For information or questions concerning the resource plan or the resource planning process, contact Idaho Power:

Idaho Power—Resource Planning

1221 West Idaho Street

Boise, Idaho 83702

208-388-2623

irp@idahopower.com

# IRP ADVISORY COUNCIL AND MEMBERS

Idaho Power has involved representatives of the public in the IRP planning process since the early 1990s. This public forum has come to be known as the IRP Advisory Council (IRPAC). The IRPAC generally meets monthly during the development of the IRP and the meetings are open to the public. Members of the council include political, environmental, and customer representatives, as well as representatives of other public-interest groups.

As part of preparing the 2015 IRP, Idaho Power hosted a field trip to the Swan Falls hydroelectric project and museum.. Idaho Power also hosted 12 IRPAC meetings, including a resource portfolio design workshop. Idaho Power and members from the IRPAC also met in several small break-out sessions to discuss certain topics in greater detail. Idaho Power values these opportunities to convene, and the IRPAC members and the public have made significant contributions to this plan.

Idaho Power believes working with members of the IRPAC and the public is very rewarding, and the IRP is better because of the public involvement. Idaho Power and the members of the IRPAC recognize that outside perspective is valuable, but also recognize that final decisions on the IRP are made by Idaho Power.

### Customer Representatives

| | |
|---|---|
| Agricultural Representative | Sid Erwin |
| Boise State University | Barry Burbank |
| Glanbia | Jim Bergin |
| Idaho National Laboratory | Kurt Myers |
| Micron | Clancy Kelley |
| Simplot | Don Sturtevant/Don Strickler |

### Public Interest Representatives

| | |
|---|---|
| Boise Metro Chamber of Commerce | Ray Stark |
| Idaho Conservation League | Ben Otto |
| Idaho Department of Commerce | Chrissy Bowers |
| Idaho Legislature | Representative Robert Anderst |
| Idaho Office of Energy Resources | John Chatburn |
| Idaho Technology Council | Jay Larsen |
| Northwest Power and Conservation Council | Shirley Lindstrom/Jim Yost |
| Oil and Gas Industry Advisor | David Hawk |
| Oregon State University – Malheur Experiment Station | Clint Shock |
| Snake River Alliance | Ken Miller |
| University of Idaho Center for Ecohydraulics Research | Daniele Tonina |
| University of Idaho Integrated Design Lab | Kevin Van Den Wymelenberg |
| Water Issues Advisor | Vince Alberdi |

### Regulatory Commission Representatives

| | |
|---|---|
| Idaho Public Utilities Commission | Stacey Donohue |
| Public Utility Commission of Oregon | Michael Breish |

# IRP Advisory Council Meeting Schedule and Agenda

| Meeting Dates | | Agenda Items |
|---|---|---|
| 2014 | Thursday, August 7 | Introductions/meeting overview<br>Welcome and opening remarks<br>IRP process explanation<br>System load and operation<br>Demand response update<br>Natural gas forecast<br>Solar workgroup recap |
| 2014 | Thursday, September 4 | Review of August IRPAC meeting<br>Solar workgroup recap<br>Coal study workgroup recap<br>Natural gas forecast<br>Overview of Idaho Power generation and transmission<br>Resource stack introduction |
| 2014 | Wednesday, October 1 | Field trip to Swan Falls hydroelectric project and museum |
| 2014 | Thursday, October 2 | Review of September IRPAC meeting<br>2015 IRP load forecast<br>Resource stack capital costs<br>IRP risk factors |
| 2014 | Thursday, November 6 | Review of October IRPAC meeting<br>Coal study<br>Demand-side management<br>Water supply forecast<br>Cloud seeding<br>Hydro generation forecast |
| 2014 | Thursday, December 4 | Review of November IRPAC meeting<br>Recap of DSM working group meeting<br>Clean Air Act Section 111(d)<br>500-kV transmission projects<br>Power markets |
| 2015 | Thursday, January 8 | Review of December IRPAC meeting<br>Recap of DSM working group meetings<br>Energy efficiency potential study final results<br>PURPA/PPA forecast<br>Resource stack |
| 2015 | Wednesday, January 28 | Portfolio design workshop |
| 2015 | Thursday, February 5 | Review of January IRPAC meeting<br>AURORA overview<br>Load and resource balance<br>Portfolio design |
| 2015 | Thursday, March 12 | Review of February IRPAC meeting<br>Conservation voltage reduction update<br>2015 IRP resource portfolios<br>Portfolio analysis overview |

| Meeting Dates | | Agenda Items |
|---|---|---|
| 2015 | Thursday, April 2 | Review of March IRPAC meeting<br>Portfolio analysis results<br>Sustainability at Idaho Power<br>Hells Canyon Complex relicensing |
| 2015 | Thursday, May 7 | Review of April IRPAC meeting<br>Clean Air Act Section 111(d) sensitivity analysis<br>Stochastic risk analysis<br>Asset replacement deferment<br>End of feeder solar project<br>Flexibility analysis<br>Operational impacts of oversupply |
| 2015 | Thursday, June 4 | Review of May IRPAC meeting<br>Preferred portfolio discussion<br>Tipping point analysis<br>Natural gas outlook from Potential Gas Committee<br>Shoshone Falls expansion<br>Loss of load expectation analysis<br>2015 IRP action plan<br>Input for the 2017 IRP and public process |

# PUBLIC POLICY ISSUES

## Clean Air Act Section 111(d) Sensitivities Assumptions

### *Section 111(d) Sensitivities*

Because of the uncertainty associated with the EPA's proposed regulation of $CO_2$ under the *Clean Air Act of 1970* (CAA) Section 111(d), a range of sensitivities was modeled. Each sensitivity is based on multiple assumptions as provided in this section. It is noted that portfolio cost results associated with each sensitivity are contingent upon underlying assumptions of the sensitivity; stipulations for the final CAA Section 111(d) regulation may differ greatly from those assumed for these sensitivities, leading possibly to markedly different costs in practice.

#### Null Sensitivity (No CAA Section 111(d))

- No existing regulations require any modifications to operations or equipment
- No pending or future regulations (i.e., CAA Section 111(d)) will require any modifications to operations or equipment
- Analyzed to provide a comparison with portfolios complying with CAA Section 111(d)-based regulations on $CO_2$ emissions

#### State-by-State Mass-Based Compliance

- Compliance determined within state boundaries
- Compliance cannot cross state lines and plant reductions cannot be shifted across state lines
- Converting from rate base to mass base using percent reduction from rate goals established by proposed regulation
- No requirements for renewable energy or energy efficiency
- Generation is capped at the target levels
    - North Valmy targets—574,382 MWh/year for 2020-2029 and 533,343 MWh/year for 2030 through IRP planning period end
    - Jim Bridger targets—3,914,502 MWh/year for 2020-2029 and 3,675,608 MWh/year for 2030 through IRP planning period end
    - Langley Gulch target alternatives
        - 30 percent annual capacity factor for 2020 through IRP planning period end (837,018 MWh/year)
        - 55 percent annual capacity factor for 2020 through IRP planning period end (1,534,533 MWh/year)
        - 70 percent annual capacity factor for 2020 through IRP planning period end (1,953,042 MWh/year)

### System-Wide Mass-Based Compliance

- Determine total $CO_2$ reduction for Idaho Power system
- Compliance is determined by meeting Idaho Power system $CO_2$ emission target
- Compliance can cross state lines and plant $CO_2$ reductions can be shifted across state lines
- Converting from rate base to mass base using percent reduction from rate goals established by proposed regulation
- No requirements for renewable energy or energy efficiency
- Idaho Power system emissions are capped at the target levels
    - 6,332,020 tons $CO_2$ for 2020–2029
    - 5,925,874 tons $CO_2$ for 2030 through IRP planning period end
- Early shutdown of units enables other units to increase generation

### Emissions Intensity Compliance Utilizing the EPA's Compliance Building Blocks

- All building blocks required to meet compliance
- Rate reductions established based on the goal calculations by the EPA
- The state of Idaho is able to count previously constructed PURPA projects as part of building block 3
- Renewable energy (building block 3) and energy efficiency (building block 4) in Idaho grow to EPA projected levels
- No renewable energy or energy efficiency requirements for states where Idaho Power has no customers (Wyoming, Nevada)
- CAA Section 111(d) $CO_2$ attributes can cross state lines
- Affected unit generation and renewable energy/energy efficiency are variable as long as interim and final rates are met
- Idaho Power is not responsible for meeting interim or final goals for Wyoming, Nevada, or Oregon
- Since Boardman has an agreed upon closure date, Idaho Power has no rate requirements to meet in Oregon
- Interim goals are relaxed with agreed upon retirement dates for Boardman and North Valmy set at 2020 and 2025 respectively (note that pre-2025 North Valmy retirement also allows a relaxing of interim goals)
- Building block 1 (6 percent efficiency improvement) cannot be met or sustained and is reset to 0 percent
- Jim Bridger generation reduced from 2012 levels for pro-rata share of 95 MW natural gas plant under construction in Wyoming (building block 2)
- Generation capped at the target levels
    - North Valmy target—814,264 MWh/year until retirement (retirement no later than 2025)

- Jim Bridger target—4,488,392 MW/year for 2020 through IRP planning period end
- Langley Gulch target alternatives
  - 30 percent annual capacity factor for 2020 through IRP planning period end (837,018 MWh/year)
  - 55 percent annual capacity factor for 2020 through IRP planning period end (1,534,533 MWh/year)
  - 70 percent annual capacity factor for 2020 through IRP planning period end (1,953,042 MWh/year)

# Flow Modeling

## Models

Idaho Power uses two primary models for forecasting future flows for the IRP. The Snake River Planning Model (SRPM) is used to forecast surface water flows and the Enhanced Snake Plain Aquifer Model (ESPAM) is used to forecast the impact of various aquifer management practices implemented on the Eastern Snake Plain Aquifer (ESPA). The SRPM was updated in late 2012 to include hydrologic conditions for years 1928 through 2009. ESPAM was also updated with the release of ESPAM 2.1 in late 2012. Beginning with the 2009 IRP, Idaho Power began running the SRPM and ESPAM as a combined modeling system. The combined model seeks to maximize diversions for aquifer recharge and system conversions without creating additional model irrigation shortages over a modeled reference condition.

## Model Inputs

The model inputs used in this effort are similar to the inputs used in the 2011 and 2013 IRP but those inputs continued to be refined to reflect future system conditions and management policies. The general inputs to the model are reach declines, weather modification, aquifer recharge, system conversions, and retirement of land from irrigation.

Future reach declines were determined using a variety of statistical analysis. Trend data indicate reach gains into American Falls Reservoir and from Milner Dam to Lower Salmon Falls Dam demonstrated a statistically significant decline for the period of 1980 to 2013. Reach gains into American Falls Reservoir declined on average 23 cubic feet per second per month (cfs/month) with declines ranging from 12 to 34 cfs/month. Reach gains from Milner Dam to Lower Salmon Falls Dam for American declined on average 34 cubic feet per second per month (cfs/month) with declines ranging from 22 to 53 cfs/month. Declines in these two reaches met strict, predefined criteria and were therefore included as inputs into the model.

Weather modification was added to the model at different levels of development. For IRP years 2015 through 2019, weather modification was increased to reflect projected levels of fully built-out programs in Eastern Idaho, the Wood River Valley, and the Boise Basin. Beyond IRP year 2019, weather modification levels in these three basins were held constant through the rest of the IRP forecast period. The level of weather modification was held constant at the current level in the Payette River Basin throughout the IRP forecast period. The amount of weather modification added to each year is

based on the total runoff for each year from 1928 through 2009. At full build out the Payette basin increase total discharge by an average of 271,567 acre-ft/year. The Upper Snake, Wood River, and Boise Basins, respectively, add an average of 453,130 acre-ft/year; 108,900 acre-ft/year; and 218,249 acre-ft/year by IRP year 2019.

Aquifer recharge was added to the model at levels reflected in the 2014 Idaho Water Resource Board Preliminary Draft—Managed Recharge Plan. In the 2015 IRP, recharge expanded to include wintertime recharge from winter time diversions at Milner Dam. Recharge peaks in IRP year 2021 at approximately 209,839 acre-ft and then slowly declines as diminishing reach gains limit the amount of water available for aquifer recharge.

System conversion projects involve the conversion of ground water supplied irrigated land to surface supplied irrigated land. The number of acres modeled and potential water savings was based on data provided by the Idaho Department of Water Resources (IDWR). The current model assumes a total of 14,767 acres of converted land on the ESPA with a total water savings of 2.0 acre-ft or water per acre of irrigated land (acre-ft/ac). Additional conversion projects are added to the model and from 2020 to 2034 they are held constant at 16,687 acres. Diversions for conversion projects are limited by water availability to meet the demand. Diversions for conversion projects peak in 2020 at 32,440 acre-ft. Diversions for conversion project generally declines after 2020 at declines in reach gains reduces water availability for diversion.

The model accounts for approximately 15,140 acres that are currently in the Conservation Reserve Enhancement Program (CREP). These acres are idled under a 15-year contract with the U.S. Department of Agriculture. Each idled acre is credited in the ESPAM model for reducing irrigation withdrawal from the ESPA by 2.0 acre-ft/year. Many of the CREP contracts were initiated in 2006 and are set to retire beginning in 2020. The current model phases out CREP acres over a four-year period and includes no idled acres by IRP year 2024. The reduction in CREP acres further results in reducing the amount of water available for other management activities such as aquifer recharge and system conversions. Also included in this model run are 750 acres of short-term projects to reduce water use by ground water appropriators. The projects may include the elimination of end gun on center pivots or drying pivot corners. These short-term projects run from 2015 to 2023.

## Model Results

The combined model allows for the ability to include future management activities, and the resulting reach gains from those management activities into Idaho Power's 2015 IRP. Management activities, such as recharge and system conversions, do not significantly change the total annual volume of water expected to flow through the Hells Canyon Complex, but instead change the timing and location of reach gains within the system. Other future management activities, such as weather modification and CREP do directly impact the annual volume of water expected through the Hells Canyon Complex as well as the timing and location of gains within the system.

Overall flow through the Hells Canyon Complex increases from IRP year 2015 through 2019 in response to increased weather modification in the Upper Snake, Wood and Boise River Basins. Flows peak in 2019 with the 50 percent exceedance flows into Brownlee Reservoir as just over 11.9 million acre-ft/year. In 2034, those flows have declined to approximately 11.3 million acre-ft/year,

with most of the declines attributable to declining flows into American Falls and the Milner to Lower Salmon Falls reach.

## 2015 Model Parameters

| IRP Year | Managed Recharge (acft/yr) | | | Weather Modification (acft/yr) | System Conversions (Ac) | CREP (Ac) | Reach Declines (acft/yr) | |
|---|---|---|---|---|---|---|---|---|
| | Above American Falls | Below American Falls | Total | | | | American Falls Inflows | Below Milner Inflows |
| 2015 | 34,060 | 29,793 | 63,852 | 715,209 | 14,767 | 15,890 | 102,644 | 152,147 |
| 2016 | 33,896 | 29,772 | 63,668 | 840,784 | 14,767 | 15,890 | 119,751 | 177,504 |
| 2017 | 34,339 | 69,965 | 104,304 | 960,948 | 14,767 | 15,890 | 136,858 | 202,862 |
| 2018 | 35,417 | 94,061 | 129,478 | 1,017,289 | 15,407 | 15,890 | 153,966 | 228,220 |
| 2019 | 43,433 | 168,533 | 211,966 | 1,051,936 | 16,047 | 15,890 | 171,073 | 253,578 |
| 2020 | 42,926 | 167,127 | 210,052 | 1,051,936 | 16,687 | 12,033 | 188,180 | 278,936 |
| 2021 | 42,989 | 166,850 | 209,839 | 1,051,936 | 16,687 | 8,312 | 205,287 | 304,293 |
| 2022 | 42,795 | 166,640 | 209,435 | 1,051,936 | 16,687 | 4,531 | 222,395 | 329,651 |
| 2023 | 42,599 | 166,983 | 209,582 | 1,051,936 | 16,687 | 2,056 | 239,502 | 355,009 |
| 2024 | 42,265 | 164,705 | 206,970 | 1,051,936 | 16,687 | 0 | 256,609 | 380,367 |
| 2025 | 42,272 | 164,293 | 206,565 | 1,051,936 | 16,687 | 0 | 273,717 | 405,724 |
| 2026 | 42,271 | 163,541 | 205,812 | 1,051,936 | 16,687 | 0 | 290,824 | 431,082 |
| 2027 | 42,021 | 162,395 | 204,416 | 1,051,936 | 16,687 | 0 | 307,931 | 456,440 |
| 2028 | 42,240 | 162,839 | 205,079 | 1,051,936 | 16,687 | 0 | 325,039 | 481,798 |
| 2029 | 42,389 | 163,178 | 205,567 | 1,051,936 | 16,687 | 0 | 342,146 | 507,156 |
| 2030 | 42,129 | 162,217 | 204,346 | 1,051,936 | 16,687 | 0 | 359,253 | 532,513 |
| 2031 | 41,716 | 161,734 | 203,450 | 1,051,936 | 16,687 | 0 | 376,360 | 557,871 |
| 2032 | 41,715 | 161,600 | 203,315 | 1,051,936 | 16,687 | 0 | 393,468 | 583,229 |
| 2033 | 41,887 | 161,659 | 203,545 | 1,051,936 | 16,687 | 0 | 410,575 | 608,587 |
| 2034 | 42,189 | 163,380 | 205,570 | 1,051,936 | 16,687 | 0 | 427,682 | 633,944 |

# SALES AND LOAD FORECAST DATA

## Average Annual Forecast Growth Rates

| | 2015–2020 | 2015–2025 | 2015–2034 |
|---|---|---|---|
| **Sales** | | | |
| Residential Sales | 1.57% | 1.40% | 1.33% |
| Commercial Sales | 1.02% | 1.00% | 0.98% |
| Irrigation Sales | 0.62% | 0.51% | 0.49% |
| Industrial Sales | 2.91% | 2.36% | 1.99% |
| Additional Firm Sales | 0.89% | 1.35% | 0.64% |
| System Sales | 1.48% | 1.34% | 1.20% |
| Total Sales | 1.48% | 1.34% | 1.20% |
| **Loads** | | | |
| Residential Load | 1.56% | 1.40% | 1.32% |
| Commercial Load | 1.02% | 0.99% | 0.98% |
| Irrigation Load | 0.56% | 0.51% | 0.49% |
| Industrial Load | 2.78% | 2.32% | 1.97% |
| Additional Firm Sales | 0.89% | 1.35% | 0.64% |
| System Load Losses | 1.37% | 1.25% | 1.16% |
| System Load | 1.43% | 1.32% | 1.19% |
| Total Load | 1.43% | 1.32% | 1.19% |
| **Peaks** | | | |
| System Peak | 1.78% | 1.66% | 1.53% |
| Total Peak | 1.78% | 1.66% | 1.53% |
| Winter Peak | 0.91% | 0.93% | 0.88% |
| Summer Peak | 1.78% | 1.66% | 1.53% |
| **Customers** | | | |
| Residential Customers | 2.13% | 1.88% | 1.62% |
| Commercial Customers | 2.03% | 1.91% | 1.72% |
| Irrigation Customers | 1.40% | 1.35% | 1.28% |
| Industrial Customers | 0.53% | 0.69% | 0.66% |

# Expected-Case Load Forecast

| Monthly Summary[1] | 1/2015 | 2/2015 | 3/2015 | 4/2015 | 5/2015 | 6/2015 | 7/2015 | 8/2015 | 9/2015 | 10/2015 | 11/2015 | 12/2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 753 | 705 | 609 | 510 | 440 | 462 | 669 | 543 | 457 | 481 | 590 | 843 |
| Commercial | 482 | 470 | 446 | 433 | 428 | 454 | 534 | 475 | 461 | 453 | 448 | 503 |
| Irrigation | 2 | 2 | 5 | 89 | 302 | 536 | 659 | 544 | 311 | 77 | 5 | 3 |
| Industrial | 277 | 274 | 276 | 262 | 256 | 281 | 279 | 282 | 279 | 288 | 283 | 285 |
| Additional Firm | 105 | 103 | 99 | 101 | 95 | 100 | 98 | 98 | 101 | 100 | 104 | 103 |
| Loss | 139 | 133 | 122 | 119 | 131 | 160 | 199 | 171 | 138 | 118 | 121 | 150 |
| **System Load** | **1,759** | **1,688** | **1,556** | **1,513** | **1,652** | **1,994** | **2,438** | **2,113** | **1,747** | **1,517** | **1,551** | **1,887** |
| Light Load | 1,634 | 1,551 | 1,421 | 1,369 | 1,493 | 1,801 | 2,206 | 1,870 | 1,557 | 1,365 | 1,429 | 1,741 |
| Heavy Load | 1,858 | 1,791 | 1,663 | 1,618 | 1,790 | 2,135 | 2,621 | 2,304 | 1,898 | 1,627 | 1,658 | 2,002 |
| **Total Load** | **1,759** | **1,688** | **1,556** | **1,513** | **1,652** | **1,994** | **2,438** | **2,113** | **1,747** | **1,517** | **1,551** | **1,887** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,264 | 2,342 | 2,072 | 2,017 | 2,649 | 3,109 | 3,537 | 2,995 | 2,887 | 2,117 | 2,170 | 2,603 |
| **Total Peak Load** | **2,264** | **2,342** | **2,072** | **2,017** | **2,649** | **3,109** | **3,537** | **2,995** | **2,887** | **2,117** | **2,170** | **2,603** |

| Monthly Summary[1] | 1/2016 | 2/2016 | 3/2016 | 4/2016 | 5/2016 | 6/2016 | 7/2016 | 8/2016 | 9/2016 | 10/2016 | 11/2016 | 12/2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 771 | 721 | 623 | 521 | 451 | 475 | 688 | 558 | 468 | 492 | 603 | 860 |
| Commercial | 490 | 477 | 453 | 440 | 435 | 462 | 543 | 483 | 469 | 461 | 456 | 509 |
| Irrigation | 2 | 2 | 5 | 90 | 308 | 547 | 673 | 556 | 317 | 79 | 5 | 3 |
| Industrial | 296 | 283 | 294 | 279 | 273 | 300 | 297 | 301 | 298 | 307 | 302 | 293 |
| Additional Firm | 110 | 105 | 105 | 104 | 97 | 94 | 101 | 101 | 99 | 101 | 105 | 109 |
| Loss | 143 | 136 | 125 | 122 | 135 | 164 | 204 | 175 | 142 | 121 | 124 | 153 |
| **System Load** | **1,813** | **1,724** | **1,605** | **1,557** | **1,700** | **2,042** | **2,507** | **2,175** | **1,794** | **1,561** | **1,594** | **1,927** |
| Light Load | 1,683 | 1,584 | 1,466 | 1,409 | 1,536 | 1,844 | 2,268 | 1,924 | 1,600 | 1,404 | 1,469 | 1,778 |
| Heavy Load | 1,924 | 1,828 | 1,706 | 1,666 | 1,841 | 2,186 | 2,712 | 2,355 | 1,950 | 1,684 | 1,695 | 2,044 |
| **Total Load** | **1,813** | **1,724** | **1,605** | **1,557** | **1,700** | **2,042** | **2,507** | **2,175** | **1,794** | **1,561** | **1,594** | **1,927** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,334 | 2,378 | 2,125 | 2,072 | 2,714 | 3,211 | 3,630 | 3,087 | 2,978 | 2,167 | 2,218 | 2,640 |
| **Total Peak Load** | **2,334** | **2,378** | **2,125** | **2,072** | **2,714** | **3,211** | **3,630** | **3,087** | **2,978** | **2,167** | **2,218** | **2,640** |

| Monthly Summary[1] | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 785 | 733 | 634 | 531 | 460 | 485 | 704 | 571 | 478 | 500 | 613 | 873 |
| Commercial | 495 | 481 | 457 | 444 | 439 | 466 | 547 | 488 | 474 | 466 | 460 | 514 |
| Irrigation | 2 | 2 | 5 | 91 | 311 | 551 | 678 | 560 | 320 | 79 | 5 | 3 |
| Industrial | 304 | 300 | 302 | 287 | 280 | 308 | 305 | 309 | 306 | 315 | 310 | 299 |
| Additional Firm | 111 | 110 | 106 | 105 | 97 | 94 | 102 | 102 | 100 | 101 | 105 | 109 |
| Loss | 145 | 139 | 127 | 123 | 137 | 166 | 207 | 178 | 144 | 123 | 126 | 155 |
| **System Load** | 1,842 | 1,765 | 1,630 | 1,581 | 1,725 | 2,071 | 2,543 | 2,207 | 1,822 | 1,585 | 1,619 | 1,953 |
| Light Load | 1,710 | 1,621 | 1,489 | 1,431 | 1,558 | 1,871 | 2,301 | 1,953 | 1,624 | 1,426 | 1,492 | 1,802 |
| Heavy Load | 1,955 | 1,872 | 1,732 | 1,701 | 1,856 | 2,217 | 2,752 | 2,390 | 1,980 | 1,710 | 1,722 | 2,082 |
| **Total Load** | 1,842 | 1,765 | 1,630 | 1,581 | 1,725 | 2,071 | 2,543 | 2,207 | 1,822 | 1,585 | 1,619 | 1,953 |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,360 | 2,414 | 2,148 | 2,093 | 2,755 | 3,266 | 3,696 | 3,137 | 3,027 | 2,193 | 2,242 | 2,664 |
| **Total Peak Load** | 2,360 | 2,414 | 2,148 | 2,093 | 2,755 | 3,266 | 3,696 | 3,137 | 3,027 | 2,193 | 2,242 | 2,664 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 794 | 741 | 641 | 537 | 467 | 493 | 715 | 580 | 485 | 506 | 620 | 884 |
| Commercial | 498 | 483 | 459 | 447 | 442 | 470 | 551 | 492 | 478 | 469 | 463 | 518 |
| Irrigation | 2 | 2 | 5 | 91 | 311 | 552 | 679 | 560 | 320 | 79 | 5 | 3 |
| Industrial | 309 | 306 | 308 | 292 | 286 | 314 | 311 | 315 | 312 | 321 | 316 | 304 |
| Additional Firm | 112 | 110 | 106 | 105 | 98 | 94 | 102 | 102 | 100 | 102 | 106 | 110 |
| Loss | 147 | 140 | 129 | 125 | 138 | 168 | 209 | 179 | 146 | 124 | 127 | 157 |
| **System Load** | **1,863** | **1,783** | **1,647** | **1,597** | **1,741** | **2,090** | **2,568** | **2,228** | **1,841** | **1,602** | **1,637** | **1,975** |
| Light Load | 1,730 | 1,638 | 1,504 | 1,445 | 1,573 | 1,888 | 2,323 | 1,972 | 1,641 | 1,441 | 1,508 | 1,823 |
| Heavy Load | 1,968 | 1,892 | 1,750 | 1,719 | 1,874 | 2,238 | 2,778 | 2,413 | 2,015 | 1,718 | 1,740 | 2,106 |
| **Total Load** | **1,863** | **1,783** | **1,647** | **1,597** | **1,741** | **2,090** | **2,568** | **2,228** | **1,841** | **1,602** | **1,637** | **1,975** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,367 | 2,425 | 2,157 | 2,099 | 2,786 | 3,302 | 3,752 | 3,170 | 3,062 | 2,212 | 2,250 | 2,681 |
| **Total Peak Load** | **2,367** | **2,425** | **2,157** | **2,099** | **2,786** | **3,302** | **3,752** | **3,170** | **3,062** | **2,212** | **2,250** | **2,681** |

| Monthly Summary[1] | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 803 | 748 | 647 | 543 | 473 | 500 | 727 | 589 | 492 | 511 | 626 | 893 |
| Commercial | 502 | 487 | 462 | 450 | 446 | 474 | 556 | 496 | 483 | 473 | 467 | 523 |
| Irrigation | 2 | 2 | 5 | 91 | 310 | 551 | 677 | 559 | 319 | 79 | 5 | 3 |
| Industrial | 315 | 311 | 313 | 297 | 291 | 319 | 316 | 320 | 317 | 327 | 321 | 309 |
| Additional Firm | 112 | 110 | 106 | 105 | 98 | 94 | 102 | 102 | 100 | 102 | 106 | 110 |
| Loss | 149 | 142 | 130 | 126 | 139 | 169 | 211 | 181 | 147 | 126 | 129 | 159 |
| **System Load** | **1,883** | **1,800** | **1,664** | **1,612** | **1,756** | **2,107** | **2,589** | **2,247** | **1,858** | **1,618** | **1,654** | **1,996** |
| Light Load | 1,748 | 1,654 | 1,519 | 1,459 | 1,587 | 1,903 | 2,342 | 1,989 | 1,656 | 1,455 | 1,523 | 1,842 |
| Heavy Load | 1,989 | 1,910 | 1,777 | 1,725 | 1,890 | 2,270 | 2,783 | 2,434 | 2,034 | 1,735 | 1,758 | 2,128 |
| **Total Load** | **1,883** | **1,800** | **1,664** | **1,612** | **1,756** | **2,107** | **2,589** | **2,247** | **1,858** | **1,618** | **1,654** | **1,996** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,514 | 2,388 | 2,072 | 1,992 | 2,950 | 3,362 | 3,555 | 3,161 | 2,907 | 2,090 | 2,260 | 2,668 |
| **Total Peak Load** | **2,514** | **2,388** | **2,072** | **1,992** | **2,950** | **3,362** | **3,555** | **3,161** | **2,907** | **2,090** | **2,260** | **2,668** |

| Monthly Summary[1] | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 810 | 753 | 652 | 547 | 477 | 505 | 735 | 596 | 497 | 515 | 630 | 901 |
| Commercial | 507 | 490 | 466 | 454 | 450 | 479 | 561 | 501 | 488 | 478 | 471 | 528 |
| Irrigation | 2 | 2 | 5 | 92 | 312 | 554 | 681 | 562 | 321 | 80 | 5 | 3 |
| Industrial | 320 | 306 | 318 | 302 | 296 | 325 | 322 | 326 | 322 | 332 | 327 | 315 |
| Additional Firm | 113 | 108 | 107 | 107 | 99 | 96 | 103 | 103 | 101 | 103 | 107 | 111 |
| Loss | 150 | 142 | 131 | 127 | 140 | 171 | 213 | 183 | 149 | 127 | 130 | 161 |
| **System Load** | **1,902** | **1,801** | **1,680** | **1,628** | **1,774** | **2,129** | **2,615** | **2,271** | **1,878** | **1,634** | **1,670** | **2,019** |
| Light Load | 1,766 | 1,655 | 1,534 | 1,473 | 1,603 | 1,923 | 2,366 | 2,009 | 1,674 | 1,470 | 1,539 | 1,863 |
| Heavy Load | 2,009 | 1,909 | 1,794 | 1,742 | 1,921 | 2,279 | 2,811 | 2,477 | 2,041 | 1,753 | 1,786 | 2,142 |
| **Total Load** | **1,902** | **1,801** | **1,680** | **1,628** | **1,774** | **2,129** | **2,615** | **2,271** | **1,878** | **1,634** | **1,670** | **2,019** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,414 | 2,457 | 2,193 | 2,135 | 2,848 | 3,372 | 3,862 | 3,236 | 3,129 | 2,248 | 2,288 | 2,725 |
| **Total Peak Load** | **2,414** | **2,457** | **2,193** | **2,135** | **2,848** | **3,372** | **3,862** | **3,236** | **3,129** | **2,248** | **2,288** | **2,725** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 818 | 759 | 658 | 552 | 483 | 512 | 746 | 604 | 503 | 520 | 636 | 911 |
| Commercial | 512 | 494 | 470 | 458 | 455 | 483 | 566 | 506 | 494 | 482 | 476 | 534 |
| Irrigation | 2 | 2 | 5 | 92 | 314 | 557 | 685 | 566 | 323 | 80 | 5 | 3 |
| Industrial | 326 | 323 | 324 | 308 | 301 | 331 | 328 | 332 | 328 | 338 | 333 | 320 |
| Additional Firm | 113 | 112 | 108 | 107 | 99 | 96 | 103 | 103 | 101 | 103 | 107 | 112 |
| Loss | 152 | 144 | 132 | 128 | 142 | 173 | 215 | 185 | 150 | 128 | 131 | 162 |
| **System Load** | **1,923** | **1,834** | **1,697** | **1,645** | **1,793** | **2,152** | **2,643** | **2,296** | **1,899** | **1,652** | **1,688** | **2,041** |
| Light Load | 1,785 | 1,685 | 1,550 | 1,489 | 1,620 | 1,944 | 2,391 | 2,032 | 1,693 | 1,486 | 1,555 | 1,884 |
| Heavy Load | 2,041 | 1,946 | 1,803 | 1,760 | 1,942 | 2,304 | 2,842 | 2,504 | 2,064 | 1,782 | 1,795 | 2,166 |
| **Total Load** | **1,923** | **1,834** | **1,697** | **1,645** | **1,793** | **2,152** | **2,643** | **2,296** | **1,899** | **1,652** | **1,688** | **2,041** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,429 | 2,473 | 2,207 | 2,148 | 2,882 | 3,415 | 3,922 | 3,275 | 3,168 | 2,268 | 2,302 | 2,744 |
| **Total Peak Load** | **2,429** | **2,473** | **2,207** | **2,148** | **2,882** | **3,415** | **3,922** | **3,275** | **3,168** | **2,268** | **2,302** | **2,744** |

| Monthly Summary[1] | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 825 | 765 | 663 | 557 | 488 | 518 | 756 | 612 | 508 | 524 | 641 | 920 |
| Commercial | 516 | 498 | 474 | 462 | 459 | 488 | 571 | 511 | 499 | 487 | 480 | 539 |
| Irrigation | 2 | 2 | 5 | 92 | 315 | 559 | 687 | 567 | 324 | 80 | 5 | 3 |
| Industrial | 332 | 329 | 330 | 314 | 307 | 337 | 334 | 338 | 334 | 345 | 339 | 326 |
| Additional Firm | 119 | 117 | 112 | 111 | 102 | 99 | 106 | 106 | 104 | 107 | 112 | 117 |
| Loss | 153 | 146 | 134 | 130 | 143 | 174 | 217 | 187 | 152 | 129 | 133 | 164 |
| **System Load** | **1,948** | **1,856** | **1,718** | **1,666** | **1,814** | **2,176** | **2,672** | **2,322** | **1,922** | **1,672** | **1,710** | **2,070** |
| Light Load | 1,809 | 1,705 | 1,569 | 1,507 | 1,639 | 1,965 | 2,417 | 2,055 | 1,714 | 1,505 | 1,575 | 1,910 |
| Heavy Load | 2,067 | 1,969 | 1,825 | 1,781 | 1,964 | 2,330 | 2,890 | 2,515 | 2,089 | 1,805 | 1,818 | 2,196 |
| **Total Load** | **1,948** | **1,856** | **1,718** | **1,666** | **1,814** | **2,176** | **2,672** | **2,322** | **1,922** | **1,672** | **1,710** | **2,070** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,448 | 2,491 | 2,225 | 2,162 | 2,917 | 3,456 | 3,981 | 3,313 | 3,207 | 2,291 | 2,320 | 2,770 |
| **Total Peak Load** | **2,448** | **2,491** | **2,225** | **2,162** | **2,917** | **3,456** | **3,981** | **3,313** | **3,207** | **2,291** | **2,320** | **2,770** |

| Monthly Summary[1] | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 834 | 772 | 670 | 563 | 494 | 526 | 767 | 622 | 515 | 529 | 647 | 933 |
| Commercial | 521 | 502 | 478 | 466 | 463 | 493 | 576 | 516 | 505 | 492 | 485 | 545 |
| Irrigation | 2 | 2 | 5 | 92 | 315 | 559 | 688 | 568 | 324 | 81 | 5 | 3 |
| Industrial | 338 | 335 | 336 | 319 | 312 | 343 | 340 | 344 | 340 | 351 | 345 | 332 |
| Additional Firm | 123 | 121 | 116 | 114 | 105 | 102 | 109 | 109 | 107 | 110 | 115 | 121 |
| Loss | 155 | 147 | 135 | 131 | 145 | 176 | 220 | 188 | 154 | 131 | 134 | 166 |
| **System Load** | **1,974** | **1,879** | **1,740** | **1,686** | **1,835** | **2,199** | **2,700** | **2,347** | **1,945** | **1,693** | **1,732** | **2,100** |
| Light Load | 1,833 | 1,726 | 1,589 | 1,526 | 1,658 | 1,987 | 2,443 | 2,077 | 1,734 | 1,524 | 1,595 | 1,938 |
| Heavy Load | 2,095 | 1,994 | 1,848 | 1,814 | 1,974 | 2,355 | 2,921 | 2,542 | 2,114 | 1,827 | 1,841 | 2,239 |
| **Total Load** | **1,974** | **1,879** | **1,740** | **1,686** | **1,835** | **2,199** | **2,700** | **2,347** | **1,945** | **1,693** | **1,732** | **2,100** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,475 | 2,514 | 2,247 | 2,183 | 2,953 | 3,498 | 4,041 | 3,352 | 3,246 | 2,314 | 2,343 | 2,799 |
| **Total Peak Load** | **2,475** | **2,514** | **2,247** | **2,183** | **2,953** | **3,498** | **4,041** | **3,352** | **3,246** | **2,314** | **2,343** | **2,799** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 845 | 782 | 678 | 571 | 501 | 535 | 781 | 633 | 523 | 536 | 655 | 946 |
| Commercial | 526 | 506 | 482 | 470 | 468 | 498 | 582 | 521 | 511 | 497 | 490 | 550 |
| Irrigation | 2 | 2 | 5 | 93 | 317 | 562 | 691 | 571 | 326 | 81 | 5 | 3 |
| Industrial | 344 | 329 | 342 | 325 | 318 | 349 | 346 | 350 | 346 | 357 | 351 | 338 |
| Additional Firm | 126 | 119 | 118 | 117 | 107 | 104 | 111 | 111 | 109 | 112 | 118 | 124 |
| Loss | 157 | 148 | 137 | 133 | 147 | 178 | 222 | 191 | 155 | 133 | 136 | 169 |
| **System Load** | **2,001** | **1,886** | **1,762** | **1,708** | **1,857** | **2,226** | **2,733** | **2,376** | **1,970** | **1,715** | **1,755** | **2,130** |
| Light Load | 1,858 | 1,733 | 1,609 | 1,545 | 1,678 | 2,011 | 2,472 | 2,103 | 1,757 | 1,543 | 1,617 | 1,966 |
| Heavy Load | 2,114 | 1,999 | 1,882 | 1,826 | 1,999 | 2,398 | 2,938 | 2,574 | 2,157 | 1,840 | 1,866 | 2,271 |
| **Total Load** | **2,001** | **1,886** | **1,762** | **1,708** | **1,857** | **2,226** | **2,733** | **2,376** | **1,970** | **1,715** | **1,755** | **2,130** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,507 | 2,537 | 2,272 | 2,208 | 2,991 | 3,546 | 4,105 | 3,397 | 3,291 | 2,338 | 2,370 | 2,830 |
| **Total Peak Load** | **2,507** | **2,537** | **2,272** | **2,208** | **2,991** | **3,546** | **4,105** | **3,397** | **3,291** | **2,338** | **2,370** | **2,830** |

| Monthly Summary[1] | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 857 | 791 | 687 | 578 | 509 | 544 | 795 | 644 | 532 | 543 | 663 | 959 |
| Commercial | 531 | 510 | 486 | 474 | 472 | 504 | 587 | 527 | 516 | 502 | 494 | 556 |
| Irrigation | 2 | 2 | 5 | 94 | 319 | 566 | 696 | 574 | 328 | 81 | 5 | 3 |
| Industrial | 350 | 347 | 348 | 331 | 323 | 355 | 352 | 357 | 353 | 364 | 358 | 344 |
| Additional Firm | 126 | 124 | 118 | 117 | 107 | 104 | 111 | 111 | 109 | 112 | 118 | 124 |
| Loss | 159 | 150 | 138 | 134 | 148 | 180 | 225 | 193 | 157 | 134 | 137 | 171 |
| **System Load** | **2,025** | **1,924** | **1,783** | **1,727** | **1,879** | **2,252** | **2,766** | **2,405** | **1,995** | **1,736** | **1,776** | **2,157** |
| Light Load | 1,881 | 1,768 | 1,628 | 1,563 | 1,698 | 2,034 | 2,502 | 2,129 | 1,779 | 1,562 | 1,636 | 1,991 |
| Heavy Load | 2,140 | 2,041 | 1,904 | 1,847 | 2,022 | 2,427 | 2,973 | 2,624 | 2,168 | 1,861 | 1,898 | 2,288 |
| **Total Load** | **2,025** | **1,924** | **1,783** | **1,727** | **1,879** | **2,252** | **2,766** | **2,405** | **1,995** | **1,736** | **1,776** | **2,157** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,535 | 2,559 | 2,294 | 2,230 | 3,027 | 3,594 | 4,168 | 3,442 | 3,335 | 2,361 | 2,394 | 2,857 |
| **Total Peak Load** | **2,535** | **2,559** | **2,294** | **2,230** | **3,027** | **3,594** | **4,168** | **3,442** | **3,335** | **2,361** | **2,394** | **2,857** |

| Monthly Summary[1] | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 868 | 801 | 696 | 586 | 517 | 553 | 809 | 655 | 540 | 550 | 671 | 973 |
| Commercial | 536 | 514 | 490 | 478 | 477 | 509 | 593 | 532 | 522 | 507 | 499 | 562 |
| Irrigation | 2 | 2 | 5 | 94 | 321 | 569 | 700 | 578 | 330 | 82 | 5 | 3 |
| Industrial | 356 | 353 | 354 | 337 | 329 | 362 | 358 | 363 | 359 | 370 | 364 | 350 |
| Additional Firm | 126 | 123 | 118 | 116 | 107 | 103 | 111 | 110 | 108 | 112 | 118 | 124 |
| Loss | 161 | 152 | 140 | 136 | 150 | 182 | 227 | 195 | 159 | 136 | 139 | 173 |
| **System Load** | **2,050** | **1,945** | **1,803** | **1,747** | **1,900** | **2,278** | **2,798** | **2,434** | **2,019** | **1,756** | **1,796** | **2,184** |
| Light Load | 1,903 | 1,787 | 1,646 | 1,581 | 1,717 | 2,058 | 2,532 | 2,154 | 1,800 | 1,580 | 1,654 | 2,015 |
| Heavy Load | 2,165 | 2,064 | 1,926 | 1,868 | 2,058 | 2,439 | 3,008 | 2,655 | 2,194 | 1,883 | 1,920 | 2,317 |
| **Total Load** | **2,050** | **1,945** | **1,803** | **1,747** | **1,900** | **2,278** | **2,798** | **2,434** | **2,019** | **1,756** | **1,796** | **2,184** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,561 | 2,578 | 2,315 | 2,251 | 3,064 | 3,643 | 4,231 | 3,486 | 3,379 | 2,384 | 2,416 | 2,883 |
| **Total Peak Load** | 2,561 | 2,578 | 2,315 | 2,251 | 3,064 | 3,643 | 4,231 | 3,486 | 3,379 | 2,384 | 2,416 | 2,883 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 880 | 810 | 704 | 593 | 524 | 562 | 823 | 667 | 548 | 557 | 679 | 987 |
| Commercial | 541 | 518 | 493 | 482 | 481 | 514 | 598 | 537 | 528 | 511 | 504 | 567 |
| Irrigation | 2 | 2 | 5 | 95 | 323 | 573 | 704 | 581 | 332 | 82 | 5 | 3 |
| Industrial | 363 | 359 | 360 | 342 | 335 | 368 | 364 | 369 | 365 | 376 | 370 | 356 |
| Additional Firm | 126 | 123 | 118 | 116 | 107 | 103 | 111 | 110 | 108 | 112 | 118 | 124 |
| Loss | 163 | 154 | 141 | 137 | 152 | 184 | 230 | 198 | 161 | 137 | 141 | 175 |
| **System Load** | **2,074** | **1,966** | **1,823** | **1,766** | **1,922** | **2,304** | **2,830** | **2,462** | **2,043** | **1,776** | **1,816** | **2,211** |
| Light Load | 1,926 | 1,806 | 1,664 | 1,598 | 1,736 | 2,081 | 2,560 | 2,179 | 1,821 | 1,598 | 1,673 | 2,041 |
| Heavy Load | 2,202 | 2,086 | 1,937 | 1,889 | 2,081 | 2,467 | 3,043 | 2,686 | 2,220 | 1,916 | 1,931 | 2,346 |
| **Total Load** | **2,074** | **1,966** | **1,823** | **1,766** | **1,922** | **2,304** | **2,830** | **2,462** | **2,043** | **1,776** | **1,816** | **2,211** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,587 | 2,598 | 2,335 | 2,271 | 3,100 | 3,690 | 4,293 | 3,530 | 3,423 | 2,406 | 2,437 | 2,910 |
| **Total Peak Load** | **2,587** | **2,598** | **2,335** | **2,271** | **3,100** | **3,690** | **4,293** | **3,530** | **3,423** | **2,406** | **2,437** | **2,910** |

| Monthly Summary[1] | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 892 | 820 | 713 | 601 | 532 | 572 | 838 | 678 | 557 | 564 | 687 | 1,000 |
| Commercial | 546 | 522 | 498 | 486 | 486 | 519 | 603 | 542 | 534 | 517 | 508 | 573 |
| Irrigation | 2 | 2 | 5 | 95 | 324 | 575 | 708 | 584 | 334 | 83 | 5 | 3 |
| Industrial | 369 | 352 | 367 | 348 | 340 | 374 | 371 | 375 | 371 | 383 | 376 | 362 |
| Additional Firm | 125 | 118 | 117 | 116 | 106 | 103 | 110 | 110 | 108 | 111 | 117 | 123 |
| Loss | 165 | 155 | 143 | 139 | 153 | 186 | 233 | 200 | 163 | 139 | 142 | 178 |
| **System Load** | **2,098** | **1,969** | **1,843** | **1,785** | **1,943** | **2,329** | **2,862** | **2,490** | **2,067** | **1,796** | **1,837** | **2,239** |
| Light Load | 1,948 | 1,809 | 1,683 | 1,616 | 1,755 | 2,104 | 2,590 | 2,204 | 1,843 | 1,615 | 1,692 | 2,066 |
| Heavy Load | 2,227 | 2,088 | 1,958 | 1,921 | 2,090 | 2,494 | 3,097 | 2,697 | 2,246 | 1,938 | 1,953 | 2,387 |
| **Total Load** | **2,098** | **1,969** | **1,843** | **1,785** | **1,943** | **2,329** | **2,862** | **2,490** | **2,067** | **1,796** | **1,837** | **2,239** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,615 | 2,617 | 2,357 | 2,293 | 3,137 | 3,738 | 4,355 | 3,574 | 3,466 | 2,428 | 2,460 | 2,937 |
| **Total Peak Load** | **2,615** | **2,617** | **2,357** | **2,293** | **3,137** | **3,738** | **4,355** | **3,574** | **3,466** | **2,428** | **2,460** | **2,937** |

| Monthly Summary[1] | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 904 | 830 | 722 | 609 | 540 | 581 | 852 | 690 | 566 | 571 | 696 | 1,013 |
| Commercial | 551 | 526 | 502 | 491 | 491 | 524 | 609 | 548 | 540 | 522 | 513 | 579 |
| Irrigation | 2 | 2 | 5 | 96 | 326 | 579 | 712 | 588 | 336 | 83 | 5 | 3 |
| Industrial | 375 | 371 | 373 | 354 | 346 | 381 | 377 | 382 | 378 | 389 | 383 | 367 |
| Additional Firm | 125 | 123 | 117 | 116 | 106 | 103 | 110 | 110 | 108 | 111 | 117 | 123 |
| Loss | 167 | 157 | 145 | 140 | 155 | 188 | 235 | 202 | 165 | 140 | 144 | 180 |
| **System Load** | **2,124** | **2,009** | **1,864** | **1,806** | **1,965** | **2,356** | **2,896** | **2,520** | **2,092** | **1,817** | **1,858** | **2,265** |
| Light Load | 1,972 | 1,846 | 1,702 | 1,634 | 1,775 | 2,128 | 2,620 | 2,230 | 1,865 | 1,634 | 1,712 | 2,090 |
| Heavy Load | 2,244 | 2,131 | 1,980 | 1,943 | 2,114 | 2,523 | 3,133 | 2,730 | 2,291 | 1,948 | 1,976 | 2,415 |
| **Total Load** | **2,124** | **2,009** | **1,864** | **1,806** | **1,965** | **2,356** | **2,896** | **2,520** | **2,092** | **1,817** | **1,858** | **2,265** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,642 | 2,638 | 2,378 | 2,314 | 3,174 | 3,788 | 4,419 | 3,621 | 3,512 | 2,452 | 2,483 | 2,963 |
| **Total Peak Load** | **2,642** | **2,638** | **2,378** | **2,314** | **3,174** | **3,788** | **4,419** | **3,621** | **3,512** | **2,452** | **2,483** | **2,963** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 914 | 838 | 729 | 616 | 547 | 589 | 865 | 701 | 573 | 577 | 702 | 1,024 |
| Commercial | 556 | 530 | 506 | 495 | 496 | 530 | 615 | 554 | 546 | 527 | 518 | 585 |
| Irrigation | 2 | 2 | 5 | 96 | 328 | 582 | 716 | 591 | 338 | 84 | 5 | 3 |
| Industrial | 381 | 377 | 379 | 360 | 352 | 387 | 383 | 388 | 384 | 395 | 389 | 373 |
| Additional Firm | 126 | 123 | 118 | 116 | 107 | 103 | 111 | 110 | 108 | 112 | 118 | 124 |
| Loss | 169 | 159 | 146 | 142 | 157 | 190 | 238 | 205 | 167 | 142 | 145 | 182 |
| **System Load** | **2,147** | **2,029** | **1,883** | **1,825** | **1,986** | **2,381** | **2,927** | **2,548** | **2,115** | **1,836** | **1,878** | **2,290** |
| Light Load | 1,994 | 1,864 | 1,720 | 1,651 | 1,794 | 2,151 | 2,648 | 2,255 | 1,886 | 1,652 | 1,730 | 2,113 |
| Heavy Load | 2,268 | 2,153 | 2,012 | 1,951 | 2,137 | 2,565 | 3,147 | 2,759 | 2,316 | 1,969 | 1,997 | 2,442 |
| **Total Load** | **2,147** | **2,029** | **1,883** | **1,825** | **1,986** | **2,381** | **2,927** | **2,548** | **2,115** | **1,836** | **1,878** | **2,290** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,666 | 2,657 | 2,398 | 2,333 | 3,210 | 3,834 | 4,481 | 3,663 | 3,554 | 2,473 | 2,504 | 2,987 |
| **Total Peak Load** | **2,666** | **2,657** | **2,398** | **2,333** | **3,210** | **3,834** | **4,481** | **3,663** | **3,554** | **2,473** | **2,504** | **2,987** |

| Monthly Summary[1] | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 923 | 845 | 736 | 621 | 553 | 597 | 877 | 710 | 580 | 582 | 708 | 1,035 |
| Commercial | 561 | 534 | 510 | 499 | 500 | 535 | 620 | 559 | 552 | 532 | 523 | 591 |
| Irrigation | 2 | 2 | 5 | 97 | 329 | 584 | 719 | 593 | 339 | 84 | 5 | 3 |
| Industrial | 387 | 382 | 384 | 365 | 357 | 392 | 389 | 394 | 389 | 401 | 395 | 378 |
| Additional Firm | 126 | 123 | 118 | 116 | 107 | 103 | 111 | 110 | 108 | 112 | 118 | 124 |
| Loss | 170 | 160 | 148 | 143 | 158 | 192 | 240 | 207 | 169 | 143 | 147 | 184 |
| **System Load** | **2,169** | **2,047** | **1,901** | **1,842** | **2,005** | **2,404** | **2,956** | **2,573** | **2,137** | **1,854** | **1,896** | **2,314** |
| Light Load | 2,014 | 1,880 | 1,736 | 1,666 | 1,811 | 2,172 | 2,674 | 2,277 | 1,905 | 1,668 | 1,747 | 2,135 |
| Heavy Load | 2,281 | 2,172 | 2,030 | 1,970 | 2,144 | 2,590 | 3,159 | 2,807 | 2,307 | 1,988 | 2,016 | 2,443 |
| **Total Load** | **2,169** | **2,047** | **1,901** | **1,842** | **2,005** | **2,404** | **2,956** | **2,573** | **2,137** | **1,854** | **1,896** | **2,314** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,685 | 2,672 | 2,414 | 2,349 | 3,244 | 3,877 | 4,540 | 3,703 | 3,594 | 2,493 | 2,521 | 3,009 |
| **Total Peak Load** | **2,685** | **2,672** | **2,414** | **2,349** | **3,244** | **3,877** | **4,540** | **3,703** | **3,594** | **2,493** | **2,521** | **3,009** |

| Monthly Summary[1] | 1/2032 | 2/2032 | 3/2032 | 4/2032 | 5/2032 | 6/2032 | 7/2032 | 8/2032 | 9/2032 | 10/2032 | 11/2032 | 12/2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 932 | 852 | 742 | 627 | 559 | 605 | 889 | 720 | 587 | 587 | 714 | 1,045 |
| Commercial | 566 | 538 | 514 | 503 | 505 | 540 | 626 | 564 | 558 | 537 | 528 | 597 |
| Irrigation | 2 | 2 | 5 | 97 | 330 | 586 | 721 | 595 | 340 | 84 | 6 | 3 |
| Industrial | 392 | 375 | 390 | 370 | 362 | 398 | 394 | 399 | 395 | 407 | 400 | 384 |
| Additional Firm | 125 | 118 | 117 | 116 | 106 | 103 | 110 | 110 | 108 | 111 | 117 | 123 |
| Loss | 172 | 160 | 149 | 144 | 160 | 194 | 242 | 209 | 170 | 145 | 148 | 186 |
| **System Load** | **2,189** | **2,045** | **1,917** | **1,858** | **2,023** | **2,426** | **2,983** | **2,598** | **2,158** | **1,871** | **1,913** | **2,338** |
| Light Load | 2,033 | 1,879 | 1,751 | 1,681 | 1,828 | 2,191 | 2,699 | 2,299 | 1,924 | 1,683 | 1,763 | 2,157 |
| Heavy Load | 2,302 | 2,181 | 2,037 | 1,987 | 2,177 | 2,598 | 3,189 | 2,833 | 2,329 | 2,019 | 2,024 | 2,468 |
| **Total Load** | **2,189** | **2,045** | **1,917** | **1,858** | **2,023** | **2,426** | **2,983** | **2,598** | **2,158** | **1,871** | **1,913** | **2,338** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,706 | 2,687 | 2,430 | 2,365 | 3,277 | 3,918 | 4,599 | 3,741 | 3,633 | 2,513 | 2,538 | 3,032 |
| **Total Peak Load** | **2,706** | **2,687** | **2,430** | **2,365** | **3,277** | **3,918** | **4,599** | **3,741** | **3,633** | **2,513** | **2,538** | **3,032** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2033 | 2/2033 | 3/2033 | 4/2033 | 5/2033 | 6/2033 | 7/2033 | 8/2033 | 9/2033 | 10/2033 | 11/2033 | 12/2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 941 | 859 | 749 | 633 | 566 | 613 | 902 | 730 | 594 | 593 | 721 | 1,056 |
| Commercial | 572 | 543 | 518 | 508 | 510 | 546 | 632 | 570 | 564 | 543 | 533 | 604 |
| Irrigation | 2 | 2 | 5 | 97 | 332 | 589 | 724 | 598 | 342 | 85 | 6 | 3 |
| Industrial | 398 | 394 | 396 | 376 | 367 | 404 | 400 | 405 | 401 | 413 | 406 | 389 |
| Additional Firm | 125 | 123 | 117 | 116 | 106 | 103 | 110 | 110 | 108 | 111 | 117 | 123 |
| Loss | 174 | 163 | 150 | 146 | 161 | 196 | 245 | 211 | 172 | 146 | 150 | 187 |
| **System Load** | **2,212** | **2,083** | **1,936** | **1,876** | **2,043** | **2,450** | **3,013** | **2,624** | **2,181** | **1,890** | **1,932** | **2,362** |
| Light Load | 2,054 | 1,914 | 1,768 | 1,697 | 1,846 | 2,213 | 2,726 | 2,322 | 1,945 | 1,700 | 1,780 | 2,180 |
| Heavy Load | 2,336 | 2,210 | 2,057 | 2,006 | 2,198 | 2,623 | 3,240 | 2,842 | 2,354 | 2,039 | 2,044 | 2,494 |
| **Total Load** | **2,212** | **2,083** | **1,936** | **1,876** | **2,043** | **2,450** | **3,013** | **2,624** | **2,181** | **1,890** | **1,932** | **2,362** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,728 | 2,704 | 2,448 | 2,383 | 3,312 | 3,963 | 4,659 | 3,782 | 3,674 | 2,534 | 2,557 | 3,055 |
| **Total Peak Load** | **2,728** | **2,704** | **2,448** | **2,383** | **3,312** | **3,963** | **4,659** | **3,782** | **3,674** | **2,534** | **2,557** | **3,055** |

| Monthly Summary[1] | 1/2034 | 2/2034 | 3/2034 | 4/2034 | 5/2034 | 6/2034 | 7/2034 | 8/2034 | 9/2034 | 10/2034 | 11/2034 | 12/2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 950 | 866 | 756 | 639 | 572 | 621 | 915 | 740 | 602 | 598 | 727 | 1,067 |
| Commercial | 577 | 547 | 523 | 513 | 515 | 552 | 638 | 576 | 571 | 548 | 538 | 610 |
| Irrigation | 2 | 2 | 5 | 98 | 333 | 591 | 727 | 600 | 343 | 85 | 6 | 3 |
| Industrial | 403 | 399 | 401 | 381 | 372 | 409 | 405 | 411 | 406 | 419 | 412 | 395 |
| Additional Firm | 124 | 122 | 117 | 115 | 106 | 102 | 110 | 110 | 107 | 110 | 116 | 122 |
| Loss | 176 | 164 | 152 | 147 | 163 | 198 | 247 | 213 | 174 | 147 | 151 | 189 |
| **System Load** | **2,233** | **2,100** | **1,953** | **1,893** | **2,061** | **2,473** | **3,042** | **2,650** | **2,203** | **1,907** | **1,950** | **2,387** |
| Light Load | 2,073 | 1,930 | 1,783 | 1,713 | 1,863 | 2,234 | 2,752 | 2,345 | 1,964 | 1,716 | 1,796 | 2,202 |
| Heavy Load | 2,359 | 2,229 | 2,075 | 2,037 | 2,205 | 2,648 | 3,271 | 2,870 | 2,377 | 2,058 | 2,062 | 2,532 |
| **Total Load** | **2,233** | **2,100** | **1,953** | **1,893** | **2,061** | **2,473** | **3,042** | **2,650** | **2,203** | **1,907** | **1,950** | **2,387** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,749 | 2,720 | 2,464 | 2,399 | 3,345 | 4,005 | 4,719 | 3,822 | 3,714 | 2,553 | 2,575 | 3,077 |
| **Total Peak Load** | **2,749** | **2,720** | **2,464** | **2,399** | **3,345** | **4,005** | **4,719** | **3,822** | **3,714** | **2,553** | **2,575** | **3,077** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

# Annual Summary

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 5,144,709 | 5,270,572 | 5,372,014 | 5,441,649 | 5,508,610 | 5,556,959 | 5,616,876 | 5,673,430 | 5,740,794 | 5,823,961 |
| Commercial | 4,076,100 | 4,144,898 | 4,182,636 | 4,212,195 | 4,247,398 | 4,285,793 | 4,327,161 | 4,369,098 | 4,410,017 | 4,452,065 |
| Irrigation | 1,863,039 | 1,902,156 | 1,915,919 | 1,918,336 | 1,913,727 | 1,924,815 | 1,937,547 | 1,941,972 | 1,944,197 | 1,953,855 |
| Industrial | 2,413,190 | 2,573,787 | 2,642,594 | 2,692,807 | 2,738,789 | 2,786,007 | 2,837,470 | 2,889,584 | 2,942,288 | 2,994,216 |
| Additional Firm | 880,500 | 901,900 | 905,900 | 909,500 | 909,600 | 920,600 | 922,700 | 957,500 | 986,600 | 1,006,800 |
| **System Sales** | 14,377,538 | 14,793,313 | 15,019,064 | 15,174,487 | 15,318,124 | 15,474,174 | 15,641,753 | 15,831,584 | 16,023,896 | 16,230,898 |
| **Total Sales** | **14,377,538** | **14,793,313** | **15,019,064** | **15,174,487** | **15,318,124** | **15,474,174** | **15,641,753** | **15,831,584** | **16,023,896** | **16,230,898** |
| **Generation Month Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 5,154,280 | 5,295,641 | 5,377,433 | 5,446,875 | 5,512,460 | 5,579,744 | 5,621,345 | 5,678,710 | 5,747,258 | 5,849,294 |
| Commercial | 4,079,899 | 4,158,522 | 4,184,382 | 4,214,240 | 4,249,614 | 4,299,933 | 4,329,571 | 4,371,459 | 4,412,441 | 4,466,707 |
| Irrigation | 1,863,058 | 1,902,215 | 1,915,920 | 1,918,334 | 1,913,732 | 1,924,874 | 1,937,549 | 1,941,973 | 1,944,202 | 1,953,915 |
| Industrial | 2,426,435 | 2,579,462 | 2,646,735 | 2,696,599 | 2,742,683 | 2,790,251 | 2,841,768 | 2,893,931 | 2,946,571 | 2,998,631 |
| Additional Firm | 880,500 | 901,900 | 905,900 | 909,500 | 909,600 | 920,600 | 922,700 | 957,500 | 986,600 | 1,006,800 |
| **System Sales** | 14,404,172 | 14,837,741 | 15,030,370 | 15,185,549 | 15,328,090 | 15,515,403 | 15,652,934 | 15,843,573 | 16,037,072 | 16,275,347 |
| **Total Sales** | **14,404,172** | **14,837,741** | **15,030,370** | **15,185,549** | **15,328,090** | **15,515,403** | **15,652,934** | **15,843,573** | **16,037,072** | **16,275,347** |
| Loss | 1,244,160 | 1,278,960 | 1,294,764 | 1,307,629 | 1,319,635 | 1,335,210 | 1,346,414 | 1,360,666 | 1,375,528 | 1,395,261 |
| **Required Generation** | 15,648,332 | 16,116,700 | 16,325,134 | 16,493,178 | 16,647,725 | 16,850,613 | 16,999,348 | 17,204,238 | 17,412,599 | 17,670,608 |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | |
| Residential | 588 | 603 | 614 | 622 | 629 | 635 | 642 | 648 | 656 | 666 |
| Commercial | 466 | 473 | 478 | 481 | 485 | 490 | 494 | 499 | 504 | 509 |
| Irrigation | 213 | 217 | 219 | 219 | 218 | 219 | 221 | 222 | 222 | 222 |
| Industrial | 277 | 294 | 302 | 308 | 313 | 318 | 324 | 330 | 336 | 341 |
| Additional Firm | 101 | 103 | 103 | 104 | 104 | 105 | 105 | 109 | 113 | 115 |
| Loss | 142 | 146 | 148 | 149 | 151 | 152 | 154 | 155 | 157 | 159 |
| **System Load** | 1,786 | 1,835 | 1,864 | 1,883 | 1,900 | 1,918 | 1,941 | 1,964 | 1,988 | 2,012 |
| Light Load | 1,621 | 1,665 | 1,691 | 1,709 | 1,725 | 1,741 | 1,761 | 1,782 | 1,804 | 1,826 |
| Heavy Load | 1,916 | 1,968 | 2,000 | 2,020 | 2,038 | 2,057 | 2,081 | 2,106 | 2,133 | 2,157 |
| **Total Load** | **1,786** | **1,835** | **1,864** | **1,883** | **1,900** | **1,918** | **1,941** | **1,964** | **1,988** | **2,012** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | |
| System Peak (1 Hour) | 3,537 | 3,630 | 3,696 | 3,752 | 3,805 | 3,862 | 3,922 | 3,981 | 4,041 | 4,105 |
| **Total Peak Load** | **3,537** | **3,630** | **3,696** | **3,752** | **3,805** | **3,862** | **3,922** | **3,981** | **4,041** | **4,105** |

| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 5,908,438 | 5,993,931 | 6,078,974 | 6,166,782 | 6,253,879 | 6,328,432 | 6,396,305 | 6,464,673 | 6,535,425 | 6,605,069 |
| Commercial | 4,495,518 | 4,538,294 | 4,579,379 | 4,623,210 | 4,669,570 | 4,713,503 | 4,755,847 | 4,800,838 | 4,849,140 | 4,896,765 |
| Irrigation | 1,966,693 | 1,979,082 | 1,990,214 | 2,000,471 | 2,012,334 | 2,022,468 | 2,031,444 | 2,038,333 | 2,047,116 | 2,054,980 |
| Industrial | 3,047,748 | 3,101,332 | 3,154,544 | 3,207,964 | 3,263,009 | 3,314,431 | 3,364,294 | 3,412,358 | 3,461,829 | 3,509,388 |
| Additional Firm | 1,006,800 | 1,004,100 | 1,004,100 | 998,800 | 998,800 | 1,004,100 | 1,004,100 | 998,800 | 998,800 | 993,500 |
| **System Sales** | 16,425,196 | 16,616,739 | 16,807,211 | 16,997,227 | 17,197,592 | 17,382,934 | 17,551,990 | 17,715,002 | 17,892,310 | 18,059,702 |
| **Total Sales** | **16,425,196** | **16,616,739** | **16,807,211** | **16,997,227** | **17,197,592** | **17,382,934** | **17,551,990** | **17,715,002** | **17,892,310** | **18,059,702** |
| **Generation Month Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 5,915,091 | 6,000,558 | 6,085,816 | 6,193,260 | 6,259,745 | 6,333,805 | 6,401,722 | 6,490,712 | 6,540,950 | 6,610,536 |
| Commercial | 4,497,988 | 4,540,679 | 4,581,913 | 4,638,404 | 4,672,117 | 4,715,970 | 4,758,459 | 4,816,547 | 4,851,901 | 4,899,689 |
| Irrigation | 1,966,699 | 1,979,087 | 1,990,219 | 2,000,532 | 2,012,339 | 2,022,472 | 2,031,447 | 2,038,393 | 2,047,120 | 2,054,984 |
| Industrial | 3,052,167 | 3,105,721 | 3,158,950 | 3,212,504 | 3,267,250 | 3,318,543 | 3,368,258 | 3,416,438 | 3,465,751 | 3,513,496 |
| Additional Firm | 1,006,800 | 1,004,100 | 1,004,100 | 998,800 | 998,800 | 1,004,100 | 1,004,100 | 998,800 | 998,800 | 993,500 |
| **System Sales** | 16,438,745 | 16,630,145 | 16,820,998 | 17,043,500 | 17,210,252 | 17,394,891 | 17,563,986 | 17,760,890 | 17,904,522 | 18,072,204 |
| **Total Sales** | **16,438,745** | **16,630,145** | **16,820,998** | **17,043,500** | **17,210,252** | **17,394,891** | **17,563,986** | **17,760,890** | **17,904,522** | **18,072,204** |
| Loss | 1,409,006 | 1,425,605 | 1,441,996 | 1,461,742 | 1,475,765 | 1,491,301 | 1,505,731 | 1,523,214 | 1,535,214 | 1,549,909 |
| **Required Generation** | 17,847,751 | 18,055,750 | 18,262,994 | 18,505,242 | 18,686,016 | 18,886,192 | 19,069,716 | 19,284,105 | 19,439,736 | 19,622,113 |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | |
| Residential | 675 | 685 | 695 | 705 | 715 | 723 | 731 | 739 | 747 | 755 |
| Commercial | 513 | 518 | 523 | 528 | 533 | 538 | 543 | 548 | 554 | 559 |
| Irrigation | 225 | 226 | 227 | 228 | 230 | 231 | 232 | 232 | 234 | 235 |
| Industrial | 348 | 355 | 361 | 366 | 373 | 379 | 385 | 389 | 396 | 401 |
| Additional Firm | 115 | 115 | 115 | 114 | 114 | 115 | 115 | 114 | 114 | 113 |
| Loss | 161 | 163 | 165 | 166 | 168 | 170 | 172 | 173 | 175 | 177 |
| **System Load** | 2,037 | 2,061 | 2,085 | 2,107 | 2,133 | 2,156 | 2,177 | 2,195 | 2,219 | 2,240 |
| Light Load | 1,849 | 1,871 | 1,892 | 1,912 | 1,936 | 1,957 | 1,976 | 1,992 | 2,014 | 2,033 |
| Heavy Load | 2,185 | 2,210 | 2,236 | 2,260 | 2,288 | 2,312 | 2,328 | 2,347 | 2,373 | 2,396 |
| **Total Load** | **2,037** | **2,061** | **2,085** | **2,107** | **2,133** | **2,156** | **2,177** | **2,195** | **2,219** | **2,240** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | |
| System Peak (1 Hour) | 4,168 | 4,231 | 4,293 | 4,355 | 4,419 | 4,481 | 4,540 | 4,599 | 4,659 | 4,719 |
| **Total Peak Load** | 4,168 | 4,231 | 4,293 | 4,355 | 4,419 | 4,481 | 4,540 | 4,599 | 4,659 | 4,719 |

# 70th Percentile Load Forecast

| Monthly Summary[1] | 1/2015 | 2/2015 | 3/2015 | 4/2015 | 5/2015 | 6/2015 | 7/2015 | 8/2015 | 9/2015 | 10/2015 | 11/2015 | 12/2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 781 | 730 | 622 | 519 | 460 | 491 | 698 | 565 | 472 | 492 | 606 | 863 |
| Commercial | 492 | 479 | 450 | 440 | 437 | 462 | 541 | 481 | 467 | 457 | 452 | 507 |
| Irrigation | 2 | 2 | 6 | 106 | 348 | 577 | 678 | 555 | 324 | 84 | 5 | 3 |
| Industrial | 277 | 274 | 276 | 262 | 256 | 281 | 279 | 282 | 279 | 288 | 283 | 285 |
| Additional Firm | 105 | 103 | 99 | 101 | 95 | 100 | 98 | 98 | 101 | 100 | 104 | 103 |
| Loss | 143 | 137 | 124 | 122 | 138 | 168 | 205 | 174 | 142 | 120 | 123 | 153 |
| **System Load** | **1,800** | **1,724** | **1,575** | **1,549** | **1,734** | **2,079** | **2,498** | **2,156** | **1,785** | **1,541** | **1,573** | **1,914** |
| Light Load | 1,672 | 1,584 | 1,438 | 1,402 | 1,567 | 1,878 | 2,260 | 1,908 | 1,591 | 1,387 | 1,449 | 1,766 |
| Heavy Load | 1,902 | 1,829 | 1,683 | 1,657 | 1,878 | 2,226 | 2,686 | 2,351 | 1,940 | 1,653 | 1,682 | 2,030 |
| **Total Load** | **1,800** | **1,724** | **1,575** | **1,549** | **1,734** | **2,079** | **2,498** | **2,156** | **1,785** | **1,541** | **1,573** | **1,914** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,330 | 2,400 | 2,128 | 2,027 | 2,682 | 3,163 | 3,576 | 3,029 | 2,901 | 2,133 | 2,233 | 2,625 |
| **Total Peak Load** | **2,330** | **2,400** | **2,128** | **2,027** | **2,682** | **3,163** | **3,576** | **3,029** | **2,901** | **2,133** | **2,233** | **2,625** |

| Monthly Summary[1] | 1/2016 | 2/2016 | 3/2016 | 4/2016 | 5/2016 | 6/2016 | 7/2016 | 8/2016 | 9/2016 | 10/2016 | 11/2016 | 12/2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 799 | 745 | 636 | 531 | 472 | 505 | 718 | 581 | 484 | 504 | 619 | 881 |
| Commercial | 500 | 486 | 457 | 447 | 444 | 470 | 550 | 489 | 475 | 465 | 459 | 514 |
| Irrigation | 2 | 2 | 6 | 108 | 355 | 588 | 692 | 567 | 331 | 85 | 6 | 3 |
| Industrial | 296 | 283 | 294 | 279 | 273 | 300 | 297 | 301 | 298 | 307 | 302 | 293 |
| Additional Firm | 110 | 105 | 105 | 104 | 97 | 94 | 101 | 101 | 99 | 101 | 105 | 109 |
| Loss | 147 | 139 | 127 | 125 | 142 | 172 | 210 | 179 | 145 | 123 | 126 | 156 |
| **System Load** | **1,854** | **1,761** | **1,624** | **1,594** | **1,782** | **2,128** | **2,568** | **2,218** | **1,833** | **1,585** | **1,617** | **1,954** |
| Light Load | 1,722 | 1,618 | 1,483 | 1,443 | 1,611 | 1,922 | 2,324 | 1,963 | 1,634 | 1,426 | 1,489 | 1,803 |
| Heavy Load | 1,968 | 1,867 | 1,726 | 1,705 | 1,930 | 2,279 | 2,779 | 2,403 | 1,992 | 1,711 | 1,719 | 2,073 |
| **Total Load** | **1,854** | **1,761** | **1,624** | **1,594** | **1,782** | **2,128** | **2,568** | **2,218** | **1,833** | **1,585** | **1,617** | **1,954** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,400 | 2,437 | 2,181 | 2,082 | 2,748 | 3,266 | 3,669 | 3,122 | 2,992 | 2,183 | 2,281 | 2,663 |
| **Total Peak Load** | **2,400** | **2,437** | **2,181** | **2,082** | **2,748** | **3,266** | **3,669** | **3,122** | **2,992** | **2,183** | **2,281** | **2,663** |

| Monthly Summary[1] | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 814 | 758 | 647 | 540 | 481 | 516 | 734 | 594 | 494 | 512 | 630 | 894 |
| Commercial | 505 | 490 | 460 | 451 | 448 | 475 | 555 | 494 | 480 | 469 | 464 | 518 |
| Irrigation | 2 | 2 | 6 | 109 | 357 | 592 | 697 | 571 | 333 | 86 | 6 | 3 |
| Industrial | 304 | 300 | 302 | 287 | 280 | 308 | 305 | 309 | 306 | 315 | 310 | 299 |
| Additional Firm | 111 | 110 | 106 | 105 | 97 | 94 | 102 | 102 | 100 | 101 | 105 | 109 |
| Loss | 149 | 142 | 129 | 127 | 144 | 174 | 213 | 182 | 148 | 125 | 128 | 158 |
| **System Load** | **1,884** | **1,802** | **1,649** | **1,618** | **1,808** | **2,159** | **2,606** | **2,251** | **1,861** | **1,609** | **1,642** | **1,980** |
| Light Load | 1,750 | 1,656 | 1,506 | 1,464 | 1,634 | 1,950 | 2,358 | 1,992 | 1,659 | 1,448 | 1,513 | 1,827 |
| Heavy Load | 2,000 | 1,912 | 1,752 | 1,741 | 1,946 | 2,312 | 2,820 | 2,439 | 2,022 | 1,737 | 1,746 | 2,111 |
| **Total Load** | **1,884** | **1,802** | **1,649** | **1,618** | **1,808** | **2,159** | **2,606** | **2,251** | **1,861** | **1,609** | **1,642** | **1,980** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,426 | 2,472 | 2,204 | 2,103 | 2,788 | 3,320 | 3,736 | 3,172 | 3,042 | 2,209 | 2,305 | 2,686 |
| **Total Peak Load** | **2,426** | **2,472** | **2,204** | **2,103** | **2,788** | **3,320** | **3,736** | **3,172** | **3,042** | **2,209** | **2,305** | **2,686** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 823 | 766 | 654 | 547 | 488 | 524 | 747 | 604 | 501 | 518 | 636 | 905 |
| Commercial | 508 | 492 | 463 | 454 | 452 | 478 | 559 | 498 | 485 | 473 | 467 | 523 |
| Irrigation | 2 | 2 | 6 | 109 | 357 | 593 | 698 | 571 | 334 | 86 | 6 | 3 |
| Industrial | 309 | 306 | 308 | 292 | 286 | 314 | 311 | 315 | 312 | 321 | 316 | 304 |
| Additional Firm | 112 | 110 | 106 | 105 | 98 | 94 | 102 | 102 | 100 | 102 | 106 | 110 |
| Loss | 151 | 144 | 130 | 128 | 145 | 176 | 215 | 183 | 149 | 126 | 129 | 160 |
| **System Load** | **1,906** | **1,821** | **1,667** | **1,635** | **1,826** | **2,180** | **2,631** | **2,274** | **1,880** | **1,626** | **1,660** | **2,003** |
| Light Load | 1,770 | 1,673 | 1,522 | 1,479 | 1,650 | 1,969 | 2,381 | 2,012 | 1,676 | 1,463 | 1,529 | 1,848 |
| Heavy Load | 2,013 | 1,931 | 1,771 | 1,759 | 1,965 | 2,334 | 2,847 | 2,463 | 2,059 | 1,744 | 1,765 | 2,136 |
| **Total Load** | **1,906** | **1,821** | **1,667** | **1,635** | **1,826** | **2,180** | **2,631** | **2,274** | **1,880** | **1,626** | **1,660** | **2,003** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,433 | 2,483 | 2,213 | 2,109 | 2,820 | 3,356 | 3,793 | 3,205 | 3,076 | 2,228 | 2,313 | 2,703 |
| **Total Peak Load** | **2,433** | **2,483** | **2,213** | **2,109** | **2,820** | **3,356** | **3,793** | **3,205** | **3,076** | **2,228** | **2,313** | **2,703** |

| Monthly Summary[1] | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 833 | 774 | 661 | 553 | 495 | 533 | 759 | 614 | 508 | 523 | 643 | 913 |
| Commercial | 512 | 496 | 466 | 457 | 455 | 483 | 564 | 503 | 490 | 477 | 471 | 528 |
| Irrigation | 2 | 2 | 6 | 109 | 356 | 592 | 696 | 570 | 333 | 86 | 6 | 3 |
| Industrial | 315 | 311 | 313 | 297 | 291 | 319 | 316 | 320 | 317 | 327 | 321 | 309 |
| Additional Firm | 112 | 110 | 106 | 105 | 98 | 94 | 102 | 102 | 100 | 102 | 106 | 110 |
| Loss | 152 | 145 | 132 | 129 | 147 | 177 | 217 | 185 | 151 | 128 | 131 | 161 |
| **System Load** | **1,926** | **1,838** | **1,683** | **1,650** | **1,842** | **2,198** | **2,654** | **2,294** | **1,898** | **1,642** | **1,677** | **2,024** |
| Light Load | 1,789 | 1,689 | 1,537 | 1,493 | 1,664 | 1,985 | 2,401 | 2,030 | 1,692 | 1,478 | 1,545 | 1,867 |
| Heavy Load | 2,035 | 1,950 | 1,798 | 1,765 | 1,982 | 2,368 | 2,853 | 2,484 | 2,078 | 1,761 | 1,783 | 2,158 |
| **Total Load** | **1,926** | **1,838** | **1,683** | **1,650** | **1,842** | **2,198** | **2,654** | **2,294** | **1,898** | **1,642** | **1,677** | **2,024** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,456 | 2,500 | 2,231 | 2,127 | 2,849 | 3,387 | 3,847 | 3,234 | 3,108 | 2,246 | 2,332 | 2,723 |
| **Total Peak Load** | **2,456** | **2,500** | **2,231** | **2,127** | **2,849** | **3,387** | **3,847** | **3,234** | **3,108** | **2,246** | **2,332** | **2,723** |

| Monthly Summary[1] | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 839 | 779 | 665 | 557 | 500 | 539 | 769 | 621 | 513 | 527 | 647 | 922 |
| Commercial | 517 | 500 | 470 | 461 | 460 | 487 | 569 | 507 | 495 | 482 | 475 | 533 |
| Irrigation | 2 | 2 | 6 | 109 | 358 | 595 | 700 | 573 | 335 | 86 | 6 | 3 |
| Industrial | 320 | 306 | 318 | 302 | 296 | 325 | 322 | 326 | 322 | 332 | 327 | 315 |
| Additional Firm | 113 | 108 | 107 | 107 | 99 | 96 | 103 | 103 | 101 | 103 | 107 | 111 |
| Loss | 154 | 145 | 133 | 130 | 148 | 179 | 219 | 187 | 152 | 129 | 132 | 163 |
| **System Load** | **1,946** | **1,839** | **1,700** | **1,667** | **1,860** | **2,221** | **2,681** | **2,318** | **1,919** | **1,659** | **1,693** | **2,047** |
| Light Load | 1,807 | 1,690 | 1,552 | 1,508 | 1,681 | 2,006 | 2,425 | 2,051 | 1,710 | 1,493 | 1,560 | 1,889 |
| Heavy Load | 2,055 | 1,950 | 1,816 | 1,782 | 2,015 | 2,378 | 2,882 | 2,528 | 2,085 | 1,779 | 1,811 | 2,171 |
| **Total Load** | **1,946** | **1,839** | **1,700** | **1,667** | **1,860** | **2,221** | **2,681** | **2,318** | **1,919** | **1,659** | **1,693** | **2,047** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,479 | 2,515 | 2,249 | 2,145 | 2,882 | 3,426 | 3,905 | 3,270 | 3,143 | 2,264 | 2,351 | 2,747 |
| **Total Peak Load** | **2,479** | **2,515** | **2,249** | **2,145** | **2,882** | **3,426** | **3,905** | **3,270** | **3,143** | **2,264** | **2,351** | **2,747** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 847 | 785 | 671 | 562 | 506 | 547 | 780 | 630 | 520 | 532 | 653 | 931 |
| Commercial | 522 | 504 | 474 | 465 | 464 | 493 | 574 | 513 | 501 | 486 | 480 | 539 |
| Irrigation | 2 | 2 | 6 | 110 | 360 | 599 | 704 | 577 | 337 | 87 | 6 | 3 |
| Industrial | 326 | 323 | 324 | 308 | 301 | 331 | 328 | 332 | 328 | 338 | 333 | 320 |
| Additional Firm | 113 | 112 | 108 | 107 | 99 | 96 | 103 | 103 | 101 | 103 | 107 | 112 |
| Loss | 155 | 147 | 134 | 132 | 150 | 181 | 221 | 189 | 154 | 130 | 133 | 165 |
| **System Load** | **1,967** | **1,873** | **1,717** | **1,684** | **1,880** | **2,245** | **2,710** | **2,344** | **1,940** | **1,677** | **1,711** | **2,070** |
| Light Load | 1,826 | 1,721 | 1,568 | 1,524 | 1,699 | 2,028 | 2,452 | 2,074 | 1,730 | 1,509 | 1,577 | 1,910 |
| Heavy Load | 2,088 | 1,987 | 1,824 | 1,801 | 2,036 | 2,404 | 2,914 | 2,557 | 2,109 | 1,810 | 1,819 | 2,195 |
| **Total Load** | **1,967** | **1,873** | **1,717** | **1,684** | **1,880** | **2,245** | **2,710** | **2,344** | **1,940** | **1,677** | **1,711** | **2,070** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,495 | 2,531 | 2,263 | 2,158 | 2,916 | 3,469 | 3,965 | 3,310 | 3,182 | 2,284 | 2,365 | 2,766 |
| **Total Peak Load** | **2,495** | **2,531** | **2,263** | **2,158** | **2,916** | **3,469** | **3,965** | **3,310** | **3,182** | **2,284** | **2,365** | **2,766** |

| Monthly Summary[1] | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 855 | 791 | 677 | 567 | 512 | 554 | 791 | 639 | 526 | 536 | 658 | 941 |
| Commercial | 527 | 508 | 478 | 469 | 469 | 498 | 580 | 518 | 506 | 491 | 484 | 544 |
| Irrigation | 2 | 2 | 6 | 110 | 361 | 600 | 706 | 578 | 338 | 87 | 6 | 3 |
| Industrial | 332 | 329 | 330 | 314 | 307 | 337 | 334 | 338 | 334 | 345 | 339 | 326 |
| Additional Firm | 119 | 117 | 112 | 111 | 102 | 99 | 106 | 106 | 104 | 107 | 112 | 117 |
| Loss | 157 | 149 | 135 | 133 | 151 | 182 | 223 | 191 | 155 | 132 | 135 | 167 |
| **System Load** | **1,992** | **1,895** | **1,738** | **1,704** | **1,902** | **2,270** | **2,740** | **2,371** | **1,964** | **1,698** | **1,733** | **2,098** |
| Light Load | 1,850 | 1,741 | 1,587 | 1,542 | 1,718 | 2,050 | 2,479 | 2,098 | 1,751 | 1,527 | 1,597 | 1,936 |
| Heavy Load | 2,115 | 2,011 | 1,847 | 1,823 | 2,060 | 2,430 | 2,964 | 2,567 | 2,134 | 1,832 | 1,843 | 2,226 |
| **Total Load** | **1,992** | **1,895** | **1,738** | **1,704** | **1,902** | **2,270** | **2,740** | **2,371** | **1,964** | **1,698** | **1,733** | **2,098** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,513 | 2,550 | 2,281 | 2,173 | 2,952 | 3,510 | 4,026 | 3,348 | 3,221 | 2,307 | 2,383 | 2,792 |
| **Total Peak Load** | **2,513** | **2,550** | **2,281** | **2,173** | **2,952** | **3,510** | **4,026** | **3,348** | **3,221** | **2,307** | **2,383** | **2,792** |

| Monthly Summary[1] | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 864 | 798 | 684 | 574 | 518 | 562 | 803 | 649 | 533 | 542 | 664 | 954 |
| Commercial | 532 | 512 | 482 | 473 | 473 | 503 | 585 | 523 | 512 | 496 | 489 | 550 |
| Irrigation | 2 | 2 | 6 | 110 | 361 | 600 | 707 | 579 | 338 | 87 | 6 | 3 |
| Industrial | 338 | 335 | 336 | 319 | 312 | 343 | 340 | 344 | 340 | 351 | 345 | 332 |
| Additional Firm | 123 | 121 | 116 | 114 | 105 | 102 | 109 | 109 | 107 | 110 | 115 | 121 |
| Loss | 159 | 151 | 137 | 134 | 153 | 184 | 226 | 193 | 157 | 133 | 136 | 169 |
| **System Load** | **2,019** | **1,918** | **1,760** | **1,725** | **1,923** | **2,294** | **2,769** | **2,397** | **1,987** | **1,719** | **1,755** | **2,128** |
| Light Load | 1,874 | 1,762 | 1,607 | 1,561 | 1,738 | 2,072 | 2,505 | 2,121 | 1,772 | 1,546 | 1,617 | 1,964 |
| Heavy Load | 2,143 | 2,035 | 1,870 | 1,857 | 2,070 | 2,457 | 2,996 | 2,596 | 2,159 | 1,855 | 1,866 | 2,270 |
| **Total Load** | **2,019** | **1,918** | **1,760** | **1,725** | **1,923** | **2,294** | **2,769** | **2,397** | **1,987** | **1,719** | **1,755** | **2,128** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,541 | 2,572 | 2,303 | 2,194 | 2,987 | 3,552 | 4,086 | 3,387 | 3,261 | 2,330 | 2,406 | 2,822 |
| **Total Peak Load** | **2,541** | **2,572** | **2,303** | **2,194** | **2,987** | **3,552** | **4,086** | **3,387** | **3,261** | **2,330** | **2,406** | **2,822** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 876 | 808 | 692 | 581 | 527 | 572 | 817 | 661 | 541 | 548 | 672 | 967 |
| Commercial | 537 | 516 | 486 | 477 | 478 | 508 | 590 | 528 | 518 | 501 | 494 | 556 |
| Irrigation | 2 | 2 | 6 | 111 | 363 | 603 | 710 | 582 | 340 | 88 | 6 | 3 |
| Industrial | 344 | 329 | 342 | 325 | 318 | 349 | 346 | 350 | 346 | 357 | 351 | 338 |
| Additional Firm | 126 | 119 | 118 | 117 | 107 | 104 | 111 | 111 | 109 | 112 | 118 | 124 |
| Loss | 161 | 151 | 139 | 136 | 154 | 186 | 228 | 195 | 159 | 135 | 138 | 171 |
| **System Load** | **2,046** | **1,925** | **1,783** | **1,747** | **1,947** | **2,322** | **2,803** | **2,427** | **2,013** | **1,741** | **1,778** | **2,159** |
| Light Load | 1,900 | 1,769 | 1,628 | 1,581 | 1,759 | 2,097 | 2,536 | 2,148 | 1,794 | 1,566 | 1,638 | 1,992 |
| Heavy Load | 2,161 | 2,041 | 1,904 | 1,869 | 2,095 | 2,502 | 3,014 | 2,629 | 2,204 | 1,867 | 1,891 | 2,302 |
| **Total Load** | **2,046** | **1,925** | **1,783** | **1,747** | **1,947** | **2,322** | **2,803** | **2,427** | **2,013** | **1,741** | **1,778** | **2,159** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,573 | 2,596 | 2,328 | 2,218 | 3,025 | 3,600 | 4,151 | 3,431 | 3,305 | 2,354 | 2,433 | 2,853 |
| **Total Peak Load** | **2,573** | **2,596** | **2,328** | **2,218** | **3,025** | **3,600** | **4,151** | **3,431** | **3,305** | **2,354** | **2,433** | **2,853** |

| Monthly Summary[1] | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 887 | 817 | 701 | 589 | 535 | 582 | 832 | 672 | 550 | 555 | 680 | 981 |
| Commercial | 542 | 520 | 490 | 482 | 483 | 513 | 596 | 534 | 524 | 506 | 499 | 561 |
| Irrigation | 2 | 2 | 6 | 111 | 365 | 607 | 715 | 586 | 342 | 88 | 6 | 3 |
| Industrial | 350 | 347 | 348 | 331 | 323 | 355 | 352 | 357 | 353 | 364 | 358 | 344 |
| Additional Firm | 126 | 124 | 118 | 117 | 107 | 104 | 111 | 111 | 109 | 112 | 118 | 124 |
| Loss | 163 | 154 | 140 | 138 | 156 | 189 | 231 | 198 | 161 | 136 | 140 | 173 |
| **System Load** | **2,071** | **1,964** | **1,803** | **1,767** | **1,969** | **2,349** | **2,837** | **2,457** | **2,037** | **1,761** | **1,799** | **2,186** |
| Light Load | 1,923 | 1,804 | 1,647 | 1,599 | 1,779 | 2,122 | 2,567 | 2,174 | 1,817 | 1,585 | 1,658 | 2,017 |
| Heavy Load | 2,188 | 2,084 | 1,926 | 1,890 | 2,119 | 2,531 | 3,050 | 2,679 | 2,214 | 1,889 | 1,924 | 2,319 |
| **Total Load** | **2,071** | **1,964** | **1,803** | **1,767** | **1,969** | **2,349** | **2,837** | **2,457** | **2,037** | **1,761** | **1,799** | **2,186** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,601 | 2,617 | 2,350 | 2,240 | 3,062 | 3,648 | 4,215 | 3,476 | 3,349 | 2,377 | 2,456 | 2,880 |
| **Total Peak Load** | **2,601** | **2,617** | **2,350** | **2,240** | **3,062** | **3,648** | **4,215** | **3,476** | **3,349** | **2,377** | **2,456** | **2,880** |

| Monthly Summary[1] | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 899 | 827 | 709 | 597 | 543 | 592 | 847 | 684 | 558 | 562 | 688 | 994 |
| Commercial | 547 | 524 | 494 | 486 | 487 | 518 | 602 | 539 | 530 | 511 | 503 | 567 |
| Irrigation | 2 | 2 | 6 | 112 | 367 | 610 | 719 | 589 | 344 | 89 | 6 | 3 |
| Industrial | 356 | 353 | 354 | 337 | 329 | 362 | 358 | 363 | 359 | 370 | 364 | 350 |
| Additional Firm | 126 | 123 | 118 | 116 | 107 | 103 | 111 | 110 | 108 | 112 | 118 | 124 |
| Loss | 165 | 156 | 142 | 139 | 158 | 191 | 234 | 200 | 163 | 138 | 141 | 176 |
| **System Load** | **2,095** | **1,985** | **1,823** | **1,787** | **1,991** | **2,376** | **2,871** | **2,486** | **2,062** | **1,781** | **1,820** | **2,213** |
| Light Load | 1,946 | 1,824 | 1,665 | 1,617 | 1,799 | 2,146 | 2,597 | 2,200 | 1,838 | 1,603 | 1,677 | 2,042 |
| Heavy Load | 2,214 | 2,106 | 1,948 | 1,911 | 2,157 | 2,544 | 3,086 | 2,712 | 2,241 | 1,911 | 1,946 | 2,348 |
| **Total Load** | **2,095** | **1,985** | **1,823** | **1,787** | **1,991** | **2,376** | **2,871** | **2,486** | **2,062** | **1,781** | **1,820** | **2,213** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,627 | 2,637 | 2,370 | 2,261 | 3,099 | 3,697 | 4,278 | 3,521 | 3,393 | 2,399 | 2,479 | 2,906 |
| **Total Peak Load** | **2,627** | **2,637** | **2,370** | **2,261** | **3,099** | **3,697** | **4,278** | **3,521** | **3,393** | **2,399** | **2,479** | **2,906** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 910 | 836 | 718 | 604 | 551 | 602 | 862 | 697 | 567 | 569 | 696 | 1,008 |
| Commercial | 552 | 528 | 498 | 490 | 492 | 524 | 607 | 544 | 535 | 516 | 508 | 573 |
| Irrigation | 2 | 2 | 6 | 112 | 369 | 614 | 723 | 592 | 346 | 89 | 6 | 3 |
| Industrial | 363 | 359 | 360 | 342 | 335 | 368 | 364 | 369 | 365 | 376 | 370 | 356 |
| Additional Firm | 126 | 123 | 118 | 116 | 107 | 103 | 111 | 110 | 108 | 112 | 118 | 124 |
| Loss | 167 | 157 | 143 | 141 | 160 | 193 | 236 | 202 | 165 | 139 | 143 | 178 |
| **System Load** | **2,120** | **2,006** | **1,843** | **1,806** | **2,013** | **2,403** | **2,904** | **2,515** | **2,086** | **1,801** | **1,840** | **2,241** |
| Light Load | 1,969 | 1,843 | 1,683 | 1,635 | 1,819 | 2,170 | 2,627 | 2,226 | 1,860 | 1,621 | 1,696 | 2,068 |
| Heavy Load | 2,250 | 2,129 | 1,959 | 1,932 | 2,180 | 2,573 | 3,122 | 2,743 | 2,267 | 1,944 | 1,957 | 2,377 |
| **Total Load** | **2,120** | **2,006** | **1,843** | **1,806** | **2,013** | **2,403** | **2,904** | **2,515** | **2,086** | **1,801** | **1,840** | **2,241** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,653 | 2,656 | 2,391 | 2,281 | 3,136 | 3,744 | 4,341 | 3,565 | 3,437 | 2,422 | 2,500 | 2,932 |
| **Total Peak Load** | **2,653** | **2,656** | **2,391** | **2,281** | **3,136** | **3,744** | **4,341** | **3,565** | **3,437** | **2,422** | **2,500** | **2,932** |

| Monthly Summary[1] | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 922 | 846 | 727 | 612 | 560 | 612 | 877 | 709 | 576 | 576 | 705 | 1,022 |
| Commercial | 558 | 532 | 502 | 494 | 497 | 529 | 613 | 550 | 541 | 521 | 513 | 579 |
| Irrigation | 2 | 2 | 6 | 113 | 371 | 617 | 727 | 595 | 347 | 89 | 6 | 3 |
| Industrial | 369 | 352 | 367 | 348 | 340 | 374 | 371 | 375 | 371 | 383 | 376 | 362 |
| Additional Firm | 125 | 118 | 117 | 116 | 106 | 103 | 110 | 110 | 108 | 111 | 117 | 123 |
| Loss | 169 | 158 | 145 | 142 | 161 | 195 | 239 | 205 | 167 | 141 | 144 | 180 |
| **System Load** | **2,145** | **2,010** | **1,864** | **1,826** | **2,035** | **2,429** | **2,937** | **2,544** | **2,111** | **1,822** | **1,861** | **2,268** |
| Light Load | 1,991 | 1,846 | 1,702 | 1,652 | 1,839 | 2,194 | 2,657 | 2,251 | 1,882 | 1,639 | 1,714 | 2,093 |
| Heavy Load | 2,276 | 2,130 | 1,980 | 1,965 | 2,190 | 2,601 | 3,177 | 2,755 | 2,294 | 1,966 | 1,979 | 2,419 |
| **Total Load** | **2,145** | **2,010** | **1,864** | **1,826** | **2,035** | **2,429** | **2,937** | **2,544** | **2,111** | **1,822** | **1,861** | **2,268** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,680 | 2,675 | 2,412 | 2,303 | 3,172 | 3,792 | 4,404 | 3,609 | 3,481 | 2,444 | 2,523 | 2,960 |
| **Total Peak Load** | **2,680** | **2,675** | **2,412** | **2,303** | **3,172** | **3,792** | **4,404** | **3,609** | **3,481** | **2,444** | **2,523** | **2,960** |

| Monthly Summary[1] | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 934 | 856 | 736 | 620 | 568 | 622 | 893 | 721 | 585 | 583 | 713 | 1,034 |
| Commercial | 563 | 537 | 506 | 499 | 502 | 535 | 619 | 556 | 548 | 526 | 518 | 585 |
| Irrigation | 2 | 2 | 6 | 113 | 372 | 620 | 731 | 599 | 349 | 90 | 6 | 3 |
| Industrial | 375 | 371 | 373 | 354 | 346 | 381 | 377 | 382 | 378 | 389 | 383 | 367 |
| Additional Firm | 125 | 123 | 117 | 116 | 106 | 103 | 110 | 110 | 108 | 111 | 117 | 123 |
| Loss | 171 | 161 | 147 | 144 | 163 | 197 | 242 | 207 | 169 | 143 | 146 | 182 |
| **System Load** | **2,170** | **2,050** | **1,885** | **1,847** | **2,058** | **2,457** | **2,972** | **2,575** | **2,136** | **1,843** | **1,883** | **2,294** |
| Light Load | 2,015 | 1,883 | 1,721 | 1,671 | 1,860 | 2,220 | 2,688 | 2,279 | 1,905 | 1,658 | 1,734 | 2,117 |
| Heavy Load | 2,293 | 2,174 | 2,002 | 1,987 | 2,215 | 2,631 | 3,215 | 2,789 | 2,339 | 1,976 | 2,002 | 2,447 |
| **Total Load** | **2,170** | **2,050** | **1,885** | **1,847** | **2,058** | **2,457** | **2,972** | **2,575** | **2,136** | **1,843** | **1,883** | **2,294** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,708 | 2,697 | 2,434 | 2,325 | 3,210 | 3,842 | 4,469 | 3,655 | 3,527 | 2,468 | 2,546 | 2,985 |
| **Total Peak Load** | **2,708** | **2,697** | **2,434** | **2,325** | **3,210** | **3,842** | **4,469** | **3,655** | **3,527** | **2,468** | **2,546** | **2,985** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 944 | 864 | 743 | 627 | 575 | 631 | 907 | 732 | 593 | 589 | 720 | 1,045 |
| Commercial | 568 | 541 | 511 | 503 | 507 | 540 | 625 | 561 | 554 | 532 | 523 | 591 |
| Irrigation | 2 | 2 | 6 | 114 | 374 | 623 | 734 | 602 | 351 | 90 | 6 | 3 |
| Industrial | 381 | 377 | 379 | 360 | 352 | 387 | 383 | 388 | 384 | 395 | 389 | 373 |
| Additional Firm | 126 | 123 | 118 | 116 | 107 | 103 | 111 | 110 | 108 | 112 | 118 | 124 |
| Loss | 173 | 162 | 148 | 145 | 165 | 199 | 245 | 209 | 171 | 144 | 148 | 184 |
| **System Load** | **2,194** | **2,070** | **1,904** | **1,866** | **2,080** | **2,483** | **3,004** | **2,603** | **2,160** | **1,862** | **1,902** | **2,320** |
| Light Load | 2,037 | 1,902 | 1,739 | 1,688 | 1,879 | 2,243 | 2,717 | 2,304 | 1,926 | 1,675 | 1,753 | 2,141 |
| Heavy Load | 2,318 | 2,196 | 2,034 | 1,995 | 2,238 | 2,676 | 3,229 | 2,819 | 2,365 | 1,997 | 2,023 | 2,474 |
| **Total Load** | **2,194** | **2,070** | **1,904** | **1,866** | **2,080** | **2,483** | **3,004** | **2,603** | **2,160** | **1,862** | **1,902** | **2,320** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,732 | 2,715 | 2,453 | 2,344 | 3,246 | 3,888 | 4,531 | 3,698 | 3,569 | 2,489 | 2,567 | 3,009 |
| **Total Peak Load** | **2,732** | **2,715** | **2,453** | **2,344** | **3,246** | **3,888** | **4,531** | **3,698** | **3,569** | **2,489** | **2,567** | **3,009** |

| Monthly Summary[1] | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 953 | 871 | 750 | 633 | 582 | 640 | 919 | 743 | 600 | 594 | 726 | 1,056 |
| Commercial | 573 | 545 | 514 | 508 | 511 | 545 | 630 | 567 | 560 | 537 | 528 | 597 |
| Irrigation | 2 | 2 | 6 | 114 | 376 | 626 | 738 | 604 | 353 | 91 | 6 | 3 |
| Industrial | 387 | 382 | 384 | 365 | 357 | 392 | 389 | 394 | 389 | 401 | 395 | 378 |
| Additional Firm | 126 | 123 | 118 | 116 | 107 | 103 | 111 | 110 | 108 | 112 | 118 | 124 |
| Loss | 175 | 164 | 149 | 147 | 166 | 201 | 247 | 211 | 173 | 145 | 149 | 186 |
| **System Load** | **2,216** | **2,088** | **1,922** | **1,883** | **2,099** | **2,507** | **3,033** | **2,629** | **2,182** | **1,880** | **1,920** | **2,344** |
| Light Load | 2,057 | 1,918 | 1,755 | 1,704 | 1,897 | 2,265 | 2,744 | 2,327 | 1,945 | 1,691 | 1,769 | 2,163 |
| Heavy Load | 2,330 | 2,215 | 2,053 | 2,014 | 2,246 | 2,702 | 3,242 | 2,868 | 2,355 | 2,016 | 2,042 | 2,474 |
| **Total Load** | **2,216** | **2,088** | **1,922** | **1,883** | **2,099** | **2,507** | **3,033** | **2,629** | **2,182** | **1,880** | **1,920** | **2,344** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,751 | 2,730 | 2,469 | 2,359 | 3,280 | 3,931 | 4,592 | 3,737 | 3,608 | 2,509 | 2,584 | 3,031 |
| **Total Peak Load** | **2,751** | **2,730** | **2,469** | **2,359** | **3,280** | **3,931** | **4,592** | **3,737** | **3,608** | **2,509** | **2,584** | **3,031** |

| Monthly Summary[1] | 1/2032 | 2/2032 | 3/2032 | 4/2032 | 5/2032 | 6/2032 | 7/2032 | 8/2032 | 9/2032 | 10/2032 | 11/2032 | 12/2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 962 | 878 | 756 | 639 | 589 | 648 | 932 | 753 | 607 | 600 | 732 | 1,067 |
| Commercial | 579 | 549 | 519 | 512 | 516 | 551 | 636 | 572 | 566 | 542 | 533 | 603 |
| Irrigation | 2 | 2 | 6 | 115 | 377 | 627 | 740 | 606 | 354 | 91 | 6 | 3 |
| Industrial | 392 | 375 | 390 | 370 | 362 | 398 | 394 | 399 | 395 | 407 | 400 | 384 |
| Additional Firm | 125 | 118 | 117 | 116 | 106 | 103 | 110 | 110 | 108 | 111 | 117 | 123 |
| Loss | 176 | 164 | 151 | 148 | 168 | 203 | 249 | 214 | 174 | 147 | 150 | 188 |
| **System Load** | **2,236** | **2,087** | **1,939** | **1,900** | **2,118** | **2,530** | **3,062** | **2,654** | **2,203** | **1,897** | **1,938** | **2,367** |
| Light Load | 2,076 | 1,917 | 1,770 | 1,719 | 1,914 | 2,286 | 2,770 | 2,349 | 1,965 | 1,707 | 1,785 | 2,185 |
| Heavy Load | 2,352 | 2,224 | 2,060 | 2,032 | 2,280 | 2,709 | 3,273 | 2,895 | 2,378 | 2,047 | 2,050 | 2,499 |
| **Total Load** | **2,236** | **2,087** | **1,939** | **1,900** | **2,118** | **2,530** | **3,062** | **2,654** | **2,203** | **1,897** | **1,938** | **2,367** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,772 | 2,745 | 2,486 | 2,375 | 3,313 | 3,972 | 4,651 | 3,776 | 3,647 | 2,529 | 2,601 | 3,054 |
| **Total Peak Load** | **2,772** | **2,745** | **2,486** | **2,375** | **3,313** | **3,972** | **4,651** | **3,776** | **3,647** | **2,529** | **2,601** | **3,054** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2033 | 2/2033 | 3/2033 | 4/2033 | 5/2033 | 6/2033 | 7/2033 | 8/2033 | 9/2033 | 10/2033 | 11/2033 | 12/2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 971 | 885 | 763 | 645 | 596 | 657 | 946 | 764 | 614 | 605 | 738 | 1,078 |
| Commercial | 584 | 554 | 523 | 517 | 522 | 557 | 642 | 578 | 572 | 547 | 538 | 609 |
| Irrigation | 2 | 2 | 6 | 115 | 378 | 630 | 743 | 609 | 355 | 91 | 6 | 3 |
| Industrial | 398 | 394 | 396 | 376 | 367 | 404 | 400 | 405 | 401 | 413 | 406 | 389 |
| Additional Firm | 125 | 123 | 117 | 116 | 106 | 103 | 110 | 110 | 108 | 111 | 117 | 123 |
| Loss | 178 | 167 | 152 | 149 | 170 | 205 | 252 | 216 | 176 | 148 | 152 | 190 |
| **System Load** | **2,259** | **2,124** | **1,957** | **1,918** | **2,139** | **2,556** | **3,093** | **2,682** | **2,227** | **1,916** | **1,957** | **2,392** |
| Light Load | 2,097 | 1,952 | 1,787 | 1,735 | 1,933 | 2,308 | 2,798 | 2,373 | 1,985 | 1,724 | 1,803 | 2,208 |
| Heavy Load | 2,386 | 2,254 | 2,079 | 2,051 | 2,302 | 2,736 | 3,325 | 2,905 | 2,403 | 2,068 | 2,070 | 2,525 |
| **Total Load** | **2,259** | **2,124** | **1,957** | **1,918** | **2,139** | **2,556** | **3,093** | **2,682** | **2,227** | **1,916** | **1,957** | **2,392** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,794 | 2,763 | 2,504 | 2,393 | 3,348 | 4,017 | 4,713 | 3,817 | 3,688 | 2,549 | 2,620 | 3,077 |
| **Total Peak Load** | **2,794** | **2,763** | **2,504** | **2,393** | **3,348** | **4,017** | **4,713** | **3,817** | **3,688** | **2,549** | **2,620** | **3,077** |

| Monthly Summary[1] | 1/2034 | 2/2034 | 3/2034 | 4/2034 | 5/2034 | 6/2034 | 7/2034 | 8/2034 | 9/2034 | 10/2034 | 11/2034 | 12/2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 980 | 892 | 769 | 651 | 603 | 666 | 959 | 774 | 622 | 610 | 744 | 1,089 |
| Commercial | 590 | 559 | 528 | 521 | 527 | 563 | 648 | 584 | 579 | 553 | 543 | 616 |
| Irrigation | 2 | 2 | 6 | 115 | 379 | 632 | 746 | 611 | 356 | 92 | 6 | 3 |
| Industrial | 403 | 399 | 401 | 381 | 372 | 409 | 405 | 411 | 406 | 419 | 412 | 395 |
| Additional Firm | 124 | 122 | 117 | 115 | 106 | 102 | 110 | 110 | 107 | 110 | 116 | 122 |
| Loss | 180 | 168 | 153 | 151 | 171 | 207 | 254 | 218 | 178 | 150 | 153 | 192 |
| **System Load** | **2,280** | **2,142** | **1,974** | **1,935** | **2,159** | **2,579** | **3,123** | **2,708** | **2,249** | **1,934** | **1,974** | **2,416** |
| Light Load | 2,117 | 1,968 | 1,803 | 1,751 | 1,950 | 2,330 | 2,825 | 2,396 | 2,005 | 1,740 | 1,819 | 2,230 |
| Heavy Load | 2,409 | 2,273 | 2,098 | 2,082 | 2,309 | 2,762 | 3,357 | 2,933 | 2,427 | 2,087 | 2,088 | 2,563 |
| **Total Load** | **2,280** | **2,142** | **1,974** | **1,935** | **2,159** | **2,579** | **3,123** | **2,708** | **2,249** | **1,934** | **1,974** | **2,416** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,815 | 2,778 | 2,520 | 2,409 | 3,382 | 4,060 | 4,773 | 3,857 | 3,728 | 2,569 | 2,638 | 3,100 |
| **Total Peak Load** | **2,815** | **2,778** | **2,520** | **2,409** | **3,382** | **4,060** | **4,773** | **3,857** | **3,728** | **2,569** | **2,638** | **3,100** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2015 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

# Annual Summary

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh)–70th Percentile** | | | | | | | | | | |
| Residential | 5,317,055 | 5,447,177 | 5,552,704 | 5,625,914 | 5,695,969 | 5,747,179 | 5,809,857 | 5,869,137 | 5,939,209 | 6,025,044 |
| Commercial | 4,131,001 | 4,201,012 | 4,239,992 | 4,270,776 | 4,307,093 | 4,346,536 | 4,388,927 | 4,431,884 | 4,473,825 | 4,516,895 |
| Irrigation | 1,977,605 | 2,016,722 | 2,030,485 | 2,032,902 | 2,028,293 | 2,039,381 | 2,052,113 | 2,056,538 | 2,058,763 | 2,068,421 |
| Industrial | 2,413,190 | 2,573,787 | 2,642,594 | 2,692,807 | 2,738,789 | 2,786,007 | 2,837,470 | 2,889,584 | 2,942,288 | 2,994,216 |
| Additional Firm | 880,500 | 901,900 | 905,900 | 909,500 | 909,600 | 920,600 | 922,700 | 957,500 | 986,600 | 1,006,800 |
| **System Sales** | 14,719,352 | 15,140,599 | 15,371,675 | 15,531,900 | 15,679,743 | 15,839,703 | 16,011,067 | 16,204,643 | 16,400,686 | 16,611,376 |
| **Total Sales** | **14,719,352** | **15,140,599** | **15,371,675** | **15,531,900** | **15,679,743** | **15,839,703** | **16,011,067** | **16,204,643** | **16,400,686** | **16,611,376** |
| **Generation Month Sales (MWh)–70th Percentile** | | | | | | | | | | |
| Residential | 5,326,729 | 5,472,945 | 5,558,208 | 5,631,202 | 5,699,862 | 5,770,615 | 5,814,359 | 5,874,448 | 5,945,701 | 6,051,025 |
| Commercial | 4,134,835 | 4,214,880 | 4,241,773 | 4,272,855 | 4,309,340 | 4,360,932 | 4,391,367 | 4,434,274 | 4,476,279 | 4,531,807 |
| Irrigation | 1,977,624 | 2,016,781 | 2,030,486 | 2,032,900 | 2,028,299 | 2,039,440 | 2,052,115 | 2,056,539 | 2,058,768 | 2,068,481 |
| Industrial | 2,426,435 | 2,579,462 | 2,646,735 | 2,696,599 | 2,742,683 | 2,790,251 | 2,841,768 | 2,893,931 | 2,946,571 | 2,998,631 |
| Additional Firm | 880,500 | 901,900 | 905,900 | 909,500 | 909,600 | 920,600 | 922,700 | 957,500 | 986,600 | 1,006,800 |
| **System Sales** | 14,746,123 | 15,185,968 | 15,383,103 | 15,543,056 | 15,689,784 | 15,881,839 | 16,022,310 | 16,216,691 | 16,413,918 | 16,656,744 |
| **Total Sales** | **14,746,123** | **15,185,968** | **15,383,103** | **15,543,056** | **15,689,784** | **15,881,839** | **16,022,310** | **16,216,691** | **16,413,918** | **16,656,744** |
| Loss | 1,276,987 | 1,312,390 | 1,328,626 | 1,341,950 | 1,354,358 | 1,370,388 | 1,381,874 | 1,396,485 | 1,411,705 | 1,431,876 |
| **Required Generation** | 16,023,110 | 16,498,358 | 16,711,729 | 16,885,006 | 17,044,142 | 17,252,227 | 17,404,184 | 17,613,176 | 17,825,623 | 18,088,620 |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | |
| Residential | 608 | 623 | 634 | 643 | 651 | 657 | 664 | 671 | 679 | 689 |
| Commercial | 472 | 480 | 484 | 488 | 492 | 496 | 501 | 506 | 511 | 516 |
| Irrigation | 226 | 230 | 232 | 232 | 232 | 232 | 234 | 235 | 235 | 235 |
| Industrial | 277 | 294 | 302 | 308 | 313 | 318 | 324 | 330 | 336 | 341 |
| Additional Firm | 101 | 103 | 103 | 104 | 104 | 105 | 105 | 109 | 113 | 115 |
| Loss | 146 | 149 | 152 | 153 | 155 | 156 | 158 | 159 | 161 | 163 |
| **System Load** | 1,829 | 1,878 | 1,908 | 1,928 | 1,946 | 1,964 | 1,987 | 2,011 | 2,035 | 2,059 |
| Light Load | 1,660 | 1,705 | 1,731 | 1,749 | 1,766 | 1,782 | 1,803 | 1,825 | 1,847 | 1,869 |
| Heavy Load | 1,962 | 2,014 | 2,047 | 2,068 | 2,087 | 2,106 | 2,131 | 2,157 | 2,183 | 2,208 |
| **Total Load** | **1,829** | **1,878** | **1,908** | **1,928** | **1,946** | **1,964** | **1,987** | **2,011** | **2,035** | **2,059** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | |
| System Peak (1 Hour) | 3,576 | 3,669 | 3,736 | 3,793 | 3,847 | 3,905 | 3,965 | 4,026 | 4,086 | 4,151 |
| **Total Peak Load** | **3,576** | **3,669** | **3,736** | **3,793** | **3,847** | **3,905** | **3,965** | **4,026** | **4,086** | **4,151** |

| | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh)–70th Percentile** | | | | | | | | | | |
| Residential | 6,112,140 | 6,200,195 | 6,287,755 | 6,378,017 | 6,467,506 | 6,544,386 | 6,614,509 | 6,685,063 | 6,757,939 | 6,829,662 |
| Commercial | 4,561,364 | 4,605,150 | 4,647,240 | 4,692,068 | 4,739,417 | 4,784,329 | 4,827,637 | 4,873,585 | 4,922,833 | 4,971,401 |
| Irrigation | 2,081,259 | 2,093,648 | 2,104,780 | 2,115,037 | 2,126,900 | 2,137,034 | 2,146,010 | 2,152,899 | 2,161,682 | 2,169,546 |
| Industrial | 3,047,748 | 3,101,332 | 3,154,544 | 3,207,964 | 3,263,009 | 3,314,431 | 3,364,294 | 3,412,358 | 3,461,829 | 3,509,388 |
| Additional Firm | 1,006,800 | 1,004,100 | 1,004,100 | 998,800 | 998,800 | 1,004,100 | 1,004,100 | 998,800 | 998,800 | 993,500 |
| **System Sales** | 16,809,311 | 17,004,425 | 17,198,419 | 17,391,886 | 17,595,632 | 17,784,280 | 17,956,550 | 18,122,705 | 18,303,083 | 18,473,496 |
| **Total Sales** | **16,809,311** | **17,004,425** | **17,198,419** | **17,391,886** | **17,595,632** | **17,784,280** | **17,956,550** | **18,122,705** | **18,303,083** | **18,473,496** |
| **Generation Month Sales (MWh)–70th Percentile** | | | | | | | | | | |
| Residential | 6,118,814 | 6,206,840 | 6,294,611 | 6,405,135 | 6,473,380 | 6,549,762 | 6,619,925 | 6,711,729 | 6,763,457 | 6,835,118 |
| Commercial | 4,563,863 | 4,607,563 | 4,649,803 | 4,707,547 | 4,741,992 | 4,786,824 | 4,830,276 | 4,889,591 | 4,925,621 | 4,974,352 |
| Irrigation | 2,081,265 | 2,093,654 | 2,104,785 | 2,115,098 | 2,126,905 | 2,137,039 | 2,146,014 | 2,152,960 | 2,161,686 | 2,169,550 |
| Industrial | 3,052,167 | 3,105,721 | 3,158,950 | 3,212,504 | 3,267,250 | 3,318,543 | 3,368,258 | 3,416,438 | 3,465,751 | 3,513,496 |
| Additional Firm | 1,006,800 | 1,004,100 | 1,004,100 | 998,800 | 998,800 | 1,004,100 | 1,004,100 | 998,800 | 998,800 | 993,500 |
| **System Sales** | 16,822,910 | 17,017,877 | 17,212,249 | 17,439,084 | 17,608,327 | 17,796,269 | 17,968,573 | 18,169,518 | 18,315,315 | 18,486,015 |
| **Total Sales** | **16,822,910** | **17,017,877** | **17,212,249** | **17,439,084** | **17,608,327** | **17,796,269** | **17,968,573** | **18,169,518** | **18,315,315** | **18,486,015** |
| Loss | 1,445,886 | 1,462,827 | 1,479,556 | 1,499,718 | 1,513,980 | 1,529,833 | 1,544,571 | 1,562,443 | 1,574,650 | 1,589,634 |
| **Required Generation** | 18,268,795 | 18,480,705 | 18,691,805 | 18,938,803 | 19,122,307 | 19,326,102 | 19,513,144 | 19,731,961 | 19,889,966 | 20,075,650 |
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | |
| Residential | 698 | 709 | 719 | 729 | 739 | 748 | 756 | 764 | 772 | 780 |
| Commercial | 521 | 526 | 531 | 536 | 541 | 546 | 551 | 557 | 562 | 568 |
| Irrigation | 238 | 239 | 240 | 241 | 243 | 244 | 245 | 245 | 247 | 248 |
| Industrial | 348 | 355 | 361 | 366 | 373 | 379 | 385 | 389 | 396 | 401 |
| Additional Firm | 115 | 115 | 115 | 114 | 114 | 115 | 115 | 114 | 114 | 113 |
| Loss | 165 | 167 | 169 | 171 | 173 | 175 | 176 | 178 | 180 | 181 |
| **System Load** | 2,085 | 2,110 | 2,134 | 2,156 | 2,183 | 2,206 | 2,228 | 2,246 | 2,271 | 2,292 |
| Light Load | 1,893 | 1,915 | 1,936 | 1,957 | 1,981 | 2,002 | 2,022 | 2,039 | 2,061 | 2,080 |
| Heavy Load | 2,237 | 2,263 | 2,288 | 2,313 | 2,342 | 2,366 | 2,382 | 2,402 | 2,428 | 2,452 |
| **Total Load** | **2,085** | **2,110** | **2,134** | **2,156** | **2,183** | **2,206** | **2,228** | **2,246** | **2,271** | **2,292** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | |
| System Peak (1 Hour) | 4,215 | 4,278 | 4,341 | 4,404 | 4,469 | 4,531 | 4,592 | 4,651 | 4,713 | 4,773 |
| **Total Peak Load** | **4,215** | **4,278** | **4,341** | **4,404** | **4,469** | **4,531** | **4,592** | **4,651** | **4,713** | **4,773** |

# LOAD AND RESOURCE BALANCE DATA

## Monthly Average Energy Load and Resource Balance

| | 1/2015 | 2/2015 | 3/2015 | 4/2015 | 5/2015 | 6/2015 | 7/2015 | 8/2015 | 9/2015 | 10/2015 | 11/2015 | 12/2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 11 | 11 | 11 | 11 | 13 | 15 | 16 | 15 | 12 | 10 | 10 | 11 |
| Load Forecast (70th% w/EE) | (1,800) | (1,724) | (1,575) | (1,549) | (1,734) | (2,079) | (2,498) | (2,156) | (1,785) | (1,541) | (1,573) | (1,914) |
| Total non-forecasted trended EE | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net Load Forecast (70th% w/ EE)** | (1,800) | (1,724) | (1,575) | (1,549) | (1,734) | (2,079) | (2,498) | (2,156) | (1,785) | (1,541) | (1,573) | (1,914) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 960 | 960 | 933 | 777 | 867 | 960 | 960 | 960 | 812 | 789 | 936 | 960 |
| **Total Gas** | 516 | 286 | 280 | 281 | 279 | 516 | 496 | 515 | 277 | 281 | 284 | 525 |
| Hydro (70th%)—HCC | 569 | 702 | 591 | 720 | 873 | 601 | 526 | 369 | 455 | 407 | 343 | 483 |
| Hydro (70th%)—Other | 217 | 291 | 237 | 263 | 314 | 328 | 279 | 210 | 224 | 219 | 202 | 208 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 71 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 786 | 994 | 828 | 983 | 1,187 | 929 | 876 | 580 | 679 | 626 | 545 | 691 |
| **CSPP (PURPA)** | 202 | 244 | 248 | 303 | 299 | 301 | 258 | 219 | 241 | 223 | 205 | 198 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange—Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| **Total PPAs** | **76** | **73** | **54** | **49** | **62** | **65** | **62** | **61** | **55** | **36** | **46** | **74** |
| **Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 2,538 | 2,556 | 2,342 | 2,393 | 2,694 | 2,771 | 2,651 | 2,334 | 2,063 | 1,955 | 2,015 | 2,447 |
| **Monthly Surplus/Deficit** | 738 | 832 | 767 | 844 | 960 | 692 | 153 | 178 | 278 | 414 | 442 | 534 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 738 | 832 | 767 | 844 | 960 | 692 | 153 | 178 | 278 | 414 | 442 | 534 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2016 | 2/2016 | 3/2016 | 4/2016 | 5/2016 | 6/2016 | 7/2016 | 8/2016 | 9/2016 | 10/2016 | 11/2016 | 12/2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 19 | 18 | 18 | 18 | 21 | 23 | 24 | 23 | 19 | 17 | 17 | 18 |
| Load Forecast (70th% w/EE) | (1,854) | (1,761) | (1,624) | (1,594) | (1,782) | (2,128) | (2,568) | (2,218) | (1,833) | (1,585) | (1,617) | (1,954) |
| Total non-forecasted trended EE | 7 | 7 | 7 | 7 | 8 | 9 | 9 | 9 | 7 | 7 | 7 | 7 |
| **Net Load Forecast (70th% w/ EE)** | (1,847) | (1,754) | (1,618) | (1,587) | (1,775) | (2,120) | (2,559) | (2,209) | (1,825) | (1,579) | (1,610) | (1,947) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 958 | 958 | 725 | 607 | 735 | 958 | 958 | 958 | 799 | 788 | 945 | 958 |
| **Total Gas** | 516 | 286 | 280 | 281 | 279 | 516 | 496 | 515 | 277 | 281 | 284 | 516 |
| Hydro (70th%)—HCC | 570 | 713 | 596 | 728 | 883 | 606 | 525 | 369 | 453 | 406 | 344 | 483 |
| Hydro (70th%)—Other | 218 | 307 | 243 | 265 | 316 | 328 | 279 | 210 | 224 | 219 | 202 | 208 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 787 | 1,019 | 839 | 994 | 1,198 | 934 | 804 | 579 | 677 | 625 | 545 | 690 |
| **CSPP (PURPA)** | 208 | 253 | 258 | 315 | 313 | 316 | 304 | 263 | 277 | 251 | 221 | 259 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 2,539 | 2,583 | 2,168 | 2,257 | 2,578 | 2,779 | 2,614 | 2,369 | 2,080 | 1,999 | 2,058 | 2,493 |
| **Monthly Surplus/Deficit** | 692 | 829 | 551 | 670 | 803 | 659 | 55 | 159 | 255 | 421 | 448 | 546 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 692 | 829 | 551 | 670 | 803 | 659 | 55 | 159 | 255 | 421 | 448 | 546 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 24 | 24 | 23 | 23 | 26 | 28 | 30 | 29 | 24 | 22 | 22 | 24 |
| Load Forecast (70th% w/EE) | (1,884) | (1,802) | (1,649) | (1,618) | (1,808) | (2,159) | (2,606) | (2,251) | (1,861) | (1,609) | (1,642) | (1,980) |
| Total non-forecasted trended EE | 19 | 19 | 18 | 18 | 20 | 22 | 24 | 22 | 19 | 17 | 17 | 19 |
| **Net Load Forecast (70th% w/ EE)** | (1,865) | (1,784) | (1,632) | (1,600) | (1,788) | (2,137) | (2,583) | (2,229) | (1,842) | (1,592) | (1,625) | (1,961) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 958 | 958 | 926 | 751 | 754 | 958 | 958 | 958 | 958 | 958 | 958 | 958 |
| **Total Gas** | 525 | 286 | 280 | 281 | 279 | 507 | 505 | 515 | 277 | 281 | 284 | 516 |
| Hydro (70th%)—HCC | 567 | 710 | 601 | 731 | 895 | 614 | 526 | 370 | 449 | 407 | 343 | 486 |
| Hydro (70th%)—Other | 215 | 311 | 240 | 268 | 318 | 329 | 279 | 211 | 224 | 219 | 193 | 203 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 782 | 1,021 | 841 | 999 | 1,213 | 943 | 805 | 581 | 673 | 626 | 536 | 689 |
| **CSPP (PURPA)** | 263 | 339 | 372 | 455 | 472 | 486 | 454 | 400 | 393 | 343 | 281 | 259 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 2,598 | 2,671 | 2,485 | 2,546 | 2,770 | 2,949 | 2,773 | 2,507 | 2,352 | 2,263 | 2,121 | 2,492 |
| **Monthly Surplus/Deficit** | 733 | 888 | 854 | 946 | 982 | 812 | 191 | 278 | 511 | 671 | 496 | 531 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 733 | 888 | 854 | 946 | 982 | 812 | 191 | 278 | 511 | 671 | 496 | 531 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 32 | 31 | 29 | 31 | 36 | 41 | 43 | 41 | 33 | 29 | 29 | 31 |
| Load Forecast (70th% w/EE) | (1,906) | (1,821) | (1,667) | (1,635) | (1,826) | (2,180) | (2,631) | (2,274) | (1,880) | (1,626) | (1,660) | (2,003) |
| Total non-forecasted trended EE | 29 | 29 | 27 | 28 | 33 | 37 | 40 | 37 | 31 | 26 | 26 | 29 |
| **Net Load Forecast (70th% w/ EE)** | (1,876) | (1,792) | (1,640) | (1,606) | (1,793) | (2,142) | (2,592) | (2,237) | (1,850) | (1,600) | (1,633) | (1,974) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 958 | 958 | 893 | 738 | 784 | 958 | 958 | 958 | 958 | 958 | 957 | 958 |
| **Total Gas** | 525 | 286 | 280 | 281 | 279 | 507 | 505 | 506 | 277 | 281 | 284 | 525 |
| Hydro (70th%)—HCC | 567 | 710 | 600 | 733 | 900 | 612 | 525 | 369 | 447 | 408 | 343 | 485 |
| Hydro (70th%)—Other | 216 | 309 | 234 | 270 | 319 | 329 | 279 | 211 | 224 | 220 | 192 | 200 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 783 | 1,019 | 834 | 1,003 | 1,219 | 941 | 804 | 580 | 671 | 628 | 535 | 685 |
| **CSPP (PURPA)** | 263 | 339 | 372 | 455 | 472 | 486 | 454 | 400 | 393 | 343 | 281 | 259 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 2,599 | 2,669 | 2,445 | 2,537 | 2,806 | 2,947 | 2,772 | 2,497 | 2,350 | 2,264 | 2,120 | 2,497 |
| **Monthly Surplus/Deficit** | 722 | 877 | 806 | 931 | 1,013 | 805 | 180 | 260 | 500 | 664 | 486 | 522 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 722 | 877 | 806 | 931 | 1,013 | 805 | 180 | 260 | 500 | 664 | 486 | 522 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 39 | 38 | 36 | 37 | 43 | 48 | 51 | 48 | 40 | 34 | 35 | 38 |
| Load Forecast (70th% w/EE) | (1,926) | (1,838) | (1,683) | (1,650) | (1,842) | (2,198) | (2,654) | (2,294) | (1,898) | (1,642) | (1,677) | (2,024) |
| Total non-forecasted trended EE | 41 | 40 | 38 | 40 | 47 | 52 | 55 | 52 | 43 | 37 | 37 | 40 |
| **Net Load Forecast (70th% w/ EE)** | (1,885) | (1,798) | (1,645) | (1,610) | (1,795) | (2,146) | (2,598) | (2,242) | (1,855) | (1,606) | (1,640) | (1,983) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 956 | 956 | 909 | 838 | 733 | 956 | 956 | 956 | 956 | 956 | 956 | 956 |
| **Total Gas** | 525 | 286 | 280 | 281 | 279 | 516 | 505 | 506 | 277 | 281 | 284 | 525 |
| Hydro (70th%)—HCC | 569 | 711 | 600 | 735 | 907 | 616 | 526 | 370 | 442 | 409 | 344 | 479 |
| Hydro (70th%)—Other | 215 | 302 | 221 | 263 | 321 | 330 | 280 | 211 | 224 | 221 | 186 | 193 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 784 | 1,012 | 821 | 998 | 1,227 | 946 | 806 | 581 | 666 | 629 | 530 | 671 |
| **CSPP (PURPA)** | 263 | 339 | 372 | 455 | 472 | 486 | 454 | 400 | 393 | 343 | 281 | 259 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 2,598 | 2,660 | 2,448 | 2,632 | 2,764 | 2,959 | 2,773 | 2,497 | 2,343 | 2,264 | 2,113 | 2,481 |
| **Monthly Surplus/Deficit** | 713 | 863 | 802 | 1,021 | 969 | 814 | 175 | 255 | 488 | 659 | 473 | 498 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 713 | 863 | 802 | 1,021 | 969 | 814 | 175 | 255 | 488 | 659 | 473 | 498 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 48 | 47 | 44 | 47 | 54 | 61 | 66 | 62 | 50 | 43 | 43 | 47 |
| Load Forecast (70th% w/EE) | (1,946) | (1,839) | (1,700) | (1,667) | (1,860) | (2,221) | (2,681) | (2,318) | (1,919) | (1,659) | (1,693) | (2,047) |
| Total non-forecasted trended EE | 47 | 45 | 43 | 45 | 53 | 59 | 64 | 60 | 48 | 42 | 42 | 45 |
| **Net Load Forecast (70th% w/ EE)** | (1,899) | (1,794) | (1,657) | (1,622) | (1,808) | (2,161) | (2,617) | (2,258) | (1,870) | (1,618) | (1,652) | (2,001) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 807 | 786 | 54 | 54 | 337 | 811 | 851 | 807 | 781 | 348 | 394 | 807 |
| **Total Gas** | 494 | 145 | 87 | – | 87 | 510 | 494 | 512 | 135 | – | 90 | 503 |
| Hydro (70th%)—HCC | 566 | 709 | 600 | 733 | 905 | 614 | 525 | 369 | 436 | 409 | 344 | 472 |
| Hydro (70th%)—Other | 213 | 291 | 218 | 261 | 320 | 329 | 279 | 210 | 222 | 220 | 186 | 193 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 779 | 1,000 | 818 | 994 | 1,224 | 943 | 804 | 579 | 658 | 628 | 529 | 665 |
| **CSPP (PURPA)** | 263 | 339 | 372 | 455 | 472 | 486 | 454 | 400 | 393 | 343 | 281 | 259 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 259 | 58 | 0 | 0 | 0 | 0 | 0 | 243 | 295 | 0 |
| **Existing Resource Subtotal** | 2,413 | 2,336 | 1,657 | 1,622 | 2,173 | 2,804 | 2,655 | 2,351 | 2,018 | 1,618 | 1,652 | 2,304 |
| **Monthly Surplus/Deficit** | 514 | 542 | 0 | 0 | 365 | 643 | 38 | 93 | 148 | 0 | 0 | 303 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 514 | 542 | 0 | 0 | 365 | 643 | 38 | 93 | 148 | 0 | 0 | 303 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 55 | 54 | 51 | 54 | 63 | 71 | 76 | 71 | 58 | 49 | 50 | 54 |
| Load Forecast (70th% w/EE) | (1,967) | (1,873) | (1,717) | (1,684) | (1,880) | (2,245) | (2,710) | (2,344) | (1,940) | (1,677) | (1,711) | (2,070) |
| Total non-forecasted trended EE | 55 | 53 | 51 | 53 | 62 | 70 | 75 | 70 | 57 | 49 | 49 | 53 |
| **Net Load Forecast (70th% w/ EE)** | (1,912) | (1,820) | (1,666) | (1,631) | (1,819) | (2,175) | (2,636) | (2,274) | (1,884) | (1,628) | (1,662) | (2,016) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 753 | 732 | – | – | 283 | 756 | 797 | 753 | 726 | 294 | 407 | 753 |
| **Total Gas** | 494 | 145 | 87 | – | 87 | 510 | 494 | 512 | 135 | – | 90 | 494 |
| Hydro (70th%)—HCC | 564 | 707 | 589 | 731 | 903 | 611 | 524 | 367 | 430 | 409 | 344 | 469 |
| Hydro (70th%)—Other | 211 | 285 | 208 | 259 | 319 | 328 | 278 | 209 | 221 | 219 | 185 | 192 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 775 | 992 | 797 | 990 | 1,222 | 939 | 802 | 576 | 651 | 627 | 529 | 661 |
| **CSPP (PURPA)** | 263 | 339 | 372 | 455 | 472 | 486 | 454 | 400 | 393 | 343 | 281 | 259 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 345 | 126 | 0 | 0 | 37 | 0 | 0 | 309 | 293 | 0 |
| **Existing Resource Subtotal** | 2,355 | 2,274 | 1,666 | 1,631 | 2,116 | 2,746 | 2,636 | 2,294 | 1,957 | 1,628 | 1,662 | 2,237 |
| **Monthly Surplus/Deficit** | 443 | 455 | 0 | 0 | 297 | 571 | 0 | 20 | 73 | 0 | 0 | 221 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 443 | 455 | 0 | 0 | 297 | 571 | 0 | 20 | 73 | 0 | 0 | 221 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 62 | 60 | 57 | 60 | 70 | 79 | 85 | 79 | 64 | 55 | 56 | 60 |
| Load Forecast (70th% w/EE) | (1,992) | (1,895) | (1,738) | (1,704) | (1,902) | (2,270) | (2,740) | (2,371) | (1,964) | (1,698) | (1,733) | (2,098) |
| Total non-forecasted trended EE | 64 | 63 | 60 | 62 | 73 | 82 | 88 | 82 | 67 | 57 | 58 | 63 |
| **Net Load Forecast (70th% w/ EE)** | (1,928) | (1,833) | (1,679) | (1,642) | (1,829) | (2,188) | (2,652) | (2,288) | (1,897) | (1,640) | (1,675) | (2,035) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 753 | 732 | – | – | 283 | 756 | 797 | 753 | 726 | 294 | 371 | 753 |
| **Total Gas** | 503 | 145 | 87 | – | 87 | 510 | 494 | 512 | 135 | – | 90 | 494 |
| Hydro (70th%)—HCC | 562 | 705 | 587 | 728 | 901 | 608 | 522 | 366 | 425 | 409 | 343 | 467 |
| Hydro (70th%)—Other | 210 | 286 | 203 | 257 | 318 | 327 | 278 | 208 | 220 | 218 | 184 | 191 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 771 | 991 | 790 | 986 | 1,219 | 935 | 800 | 574 | 645 | 627 | 528 | 658 |
| **CSPP (PURPA)** | 263 | 339 | 372 | 455 | 472 | 486 | 454 | 400 | 393 | 343 | 281 | 259 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 363 | 142 | 0 | 0 | 56 | 0 | 0 | 322 | 344 | 0 |
| **Existing Resource Subtotal** | 2,360 | 2,273 | 1,679 | 1,642 | 2,113 | 2,743 | 2,652 | 2,292 | 1,950 | 1,640 | 1,675 | 2,234 |
| **Monthly Surplus/Deficit** | 433 | 441 | 0 | 0 | 284 | 555 | 0 | 3 | 53 | 0 | (0) | 199 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 433 | 441 | 0 | 0 | 284 | 555 | 0 | 3 | 53 | 0 | (0) | 199 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 68 | 67 | 63 | 66 | 77 | 87 | 93 | 87 | 71 | 61 | 61 | 67 |
| Load Forecast (70th% w/EE) | (2,019) | (1,918) | (1,760) | (1,725) | (1,923) | (2,294) | (2,769) | (2,397) | (1,987) | (1,719) | (1,755) | (2,128) |
| Total non-forecasted trended EE | 75 | 73 | 69 | 72 | 84 | 95 | 102 | 95 | 77 | 66 | 67 | 73 |
| **Net Load Forecast (70th% w/ EE)** | (1,944) | (1,845) | (1,691) | (1,653) | (1,839) | (2,199) | (2,667) | (2,302) | (1,910) | (1,652) | (1,688) | (2,055) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 753 | 732 | – | – | 283 | 756 | 797 | 753 | 726 | 294 | 385 | 753 |
| **Total Gas** | 503 | 145 | 87 | – | 87 | 501 | 503 | 512 | 135 | – | 90 | 494 |
| Hydro (70th%)—HCC | 559 | 703 | 586 | 726 | 899 | 605 | 521 | 364 | 419 | 409 | 344 | 459 |
| Hydro (70th%)—Other | 208 | 266 | 203 | 256 | 316 | 326 | 277 | 207 | 218 | 217 | 183 | 190 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 767 | 969 | 789 | 982 | 1,215 | 931 | 798 | 571 | 637 | 626 | 527 | 649 |
| **CSPP (PURPA)** | 263 | 339 | 372 | 455 | 472 | 486 | 454 | 400 | 393 | 343 | 281 | 259 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 377 | 156 | 0 | 0 | 64 | 12 | 0 | 335 | 343 | 0 |
| **Existing Resource Subtotal** | 2,356 | 2,251 | 1,691 | 1,653 | 2,109 | 2,730 | 2,667 | 2,302 | 1,942 | 1,652 | 1,688 | 2,225 |
| **Monthly Surplus/Deficit** | 413 | 406 | 0 | 0 | 270 | 531 | 0 | 0 | 32 | 0 | (0) | 170 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 413 | 406 | 0 | 0 | 270 | 531 | 0 | 0 | 32 | 0 | (0) | 170 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 75 | 73 | 69 | 72 | 84 | 95 | 102 | 95 | 77 | 66 | 67 | 73 |
| Load Forecast (70th% w/EE) | (2,046) | (1,925) | (1,783) | (1,747) | (1,947) | (2,322) | (2,803) | (2,427) | (2,013) | (1,741) | (1,778) | (2,159) |
| Total non-forecasted trended EE | 86 | 83 | 79 | 82 | 96 | 109 | 117 | 109 | 88 | 76 | 77 | 83 |
| **Net Load Forecast (70th% w/ EE)** | (1,960) | (1,842) | (1,703) | (1,665) | (1,851) | (2,213) | (2,687) | (2,318) | (1,925) | (1,665) | (1,702) | (2,075) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 753 | 732 | – | – | 283 | 756 | 797 | 753 | 726 | 294 | 402 | 753 |
| **Total Gas** | 503 | 145 | 87 | – | 87 | 510 | 503 | 503 | 135 | – | 90 | 503 |
| Hydro (70th%)—HCC | 556 | 696 | 585 | 724 | 897 | 602 | 519 | 362 | 412 | 409 | 343 | 450 |
| Hydro (70th%)—Other | 208 | 254 | 204 | 252 | 316 | 325 | 276 | 206 | 217 | 216 | 183 | 189 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 764 | 950 | 789 | 976 | 1,213 | 927 | 795 | 568 | 628 | 625 | 526 | 639 |
| **CSPP (PURPA)** | 263 | 339 | 372 | 455 | 472 | 486 | 454 | 400 | 393 | 343 | 281 | 259 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 389 | 173 | 0 | 0 | 86 | 41 | 0 | 348 | 341 | 0 |
| **Existing Resource Subtotal** | 2,353 | 2,232 | 1,703 | 1,665 | 2,107 | 2,735 | 2,687 | 2,318 | 1,934 | 1,665 | 1,702 | 2,224 |
| **Monthly Surplus/Deficit** | 392 | 389 | 0 | 0 | 256 | 522 | 0 | 0 | 9 | 0 | (0) | 149 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 392 | 389 | 0 | 0 | 256 | 522 | 0 | 0 | 9 | 0 | (0) | 149 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 80 | 78 | 74 | 77 | 88 | 99 | 107 | 100 | 81 | 71 | 72 | 78 |
| Load Forecast (70th% w/EE) | (2,071) | (1,964) | (1,803) | (1,767) | (1,969) | (2,349) | (2,837) | (2,457) | (2,037) | (1,761) | (1,799) | (2,186) |
| Total non-forecasted trended EE | 97 | 94 | 89 | 92 | 106 | 119 | 128 | 120 | 98 | 85 | 87 | 94 |
| **Net Load Forecast (70th% w/ EE)** | (1,974) | (1,870) | (1,714) | (1,675) | (1,864) | (2,230) | (2,709) | (2,337) | (1,940) | (1,676) | (1,713) | (2,092) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 753 | 732 | – | – | 283 | 756 | 797 | 753 | 726 | 294 | 419 | 753 |
| **Total Gas** | 494 | 145 | 87 | – | 87 | 510 | 512 | 503 | 135 | – | 90 | 503 |
| Hydro (70th%)—HCC | 554.8 | 693.9 | 583.8 | 722.3 | 895.1 | 598.3 | 518.1 | 361.0 | 407.5 | 401.0 | 344.3 | 446.8 |
| Hydro (70th%)—Other | 206.5 | 242.5 | 202.4 | 250.8 | 315.1 | 324.5 | 275.2 | 204.8 | 214.9 | 214.9 | 181.7 | 187.3 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 761 | 936 | 786 | 973 | 1,210 | 923 | 793 | 566 | 622 | 616 | 526 | 634 |
| **CSPP (PURPA)** | 263 | 339 | 372 | 455 | 472 | 486 | 454 | 400 | 393 | 341 | 278 | 257 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 402 | 187 | 0 | 0 | 101 | 62 | 12 | 371 | 338 | 0 |
| **Existing Resource Subtotal** | 2,342 | 2,219 | 1,714 | 1,675 | 2,104 | 2,730 | 2,709 | 2,337 | 1,940 | 1,676 | 1,713 | 2,217 |
| **Monthly Surplus/Deficit** | 367 | 349 | 0 | 0 | 241 | 500 | 0 | 0 | 0 | 0 | (0) | 124 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 567 | 549 | 200 | 500 | 741 | 1,000 | 500 | 500 | 500 | 200 | 200 | 324 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 86 | 83 | 79 | 81 | 92 | 103 | 111 | 104 | 85 | 75 | 77 | 83 |
| Load Forecast (70th% w/EE) | (2,095) | (1,985) | (1,823) | (1,787) | (1,991) | (2,376) | (2,871) | (2,486) | (2,062) | (1,781) | (1,820) | (2,213) |
| Total non-forecasted trended EE | 108 | 105 | 100 | 102 | 116 | 130 | 140 | 131 | 108 | 94 | 97 | 105 |
| **Net Load Forecast (70th% w/ EE)** | (1,988) | (1,880) | (1,724) | (1,685) | (1,876) | (2,246) | (2,731) | (2,355) | (1,954) | (1,687) | (1,723) | (2,108) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 651 | 651 | – | – | 210 | 651 | 651 | 651 | 651 | 294 | 304 | 651 |
| **Total Gas** | 494 | 145 | 87 | – | 87 | 510 | 494 | 512 | 135 | – | 90 | 512 |
| Hydro (70th%)—HCC | 553 | 689 | 583 | 720 | 893 | 597 | 517 | 359 | 403 | 401 | 344 | 446 |
| Hydro (70th%)—Other | 206 | 223 | 200 | 246 | 314 | 323 | 274 | 204 | 214 | 214 | 181 | 187 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 759 | 912 | 783 | 966 | 1,207 | 919 | 791 | 563 | 617 | 615 | 525 | 633 |
| **CSPP (PURPA)** | 260 | 336 | 365 | 448 | 467 | 484 | 452 | 398 | 390 | 338 | 274 | 254 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 422 | 210 | 0 | 0 | 257 | 177 | 111 | 386 | 336 | 0 |
| **Existing Resource Subtotal** | 2,234 | 2,110 | 1,724 | 1,685 | 2,024 | 2,618 | 2,697 | 2,355 | 1,954 | 1,687 | 1,591 | 2,119 |
| **Monthly Surplus/Deficit** | 246 | 230 | 0 | 0 | 148 | 372 | (34) | 0 | 0 | 0 | (132) | 11 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 446 | 430 | 200 | 500 | 648 | 872 | 466 | 500 | 500 | 200 | 68 | 211 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 91 | 88 | 84 | 85 | 95 | 107 | 116 | 108 | 89 | 79 | 81 | 88 |
| Load Forecast (70th% w/EE) | (2,120) | (2,006) | (1,843) | (1,806) | (2,013) | (2,403) | (2,904) | (2,515) | (2,086) | (1,801) | (1,840) | (2,241) |
| Total non-forecasted trended EE | 119 | 116 | 110 | 112 | 126 | 141 | 153 | 143 | 118 | 104 | 107 | 116 |
| **Net Load Forecast (70th% w/ EE)** | (2,001) | (1,890) | (1,733) | (1,694) | (1,887) | (2,262) | (2,751) | (2,372) | (1,968) | (1,698) | (1,733) | (2,124) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 651 | 651 | – | – | 210 | 651 | 651 | 651 | 651 | 294 | 304 | 651 |
| **Total Gas** | 503 | 145 | 87 | – | 87 | 510 | 494 | 512 | 135 | – | 90 | 494 |
| Hydro (70th%)—HCC | 551 | 679 | 582 | 719 | 892 | 595 | 515 | 358 | 398 | 401 | 344 | 445 |
| Hydro (70th%)—Other | 205 | 211 | 199 | 243 | 313 | 322 | 274 | 203 | 211 | 213 | 180 | 185 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 756 | 891 | 780 | 962 | 1,205 | 917 | 789 | 561 | 610 | 614 | 524 | 630 |
| **CSPP (PURPA)** | 257 | 333 | 365 | 448 | 467 | 484 | 452 | 398 | 390 | 338 | 274 | 254 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 36 | 33 | 36 | 33 | 30 | 32 | 34 | 33 | 27 | 30 | 33 | 35 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 71 | 67 | 67 | 60 | 52 | 54 | 52 | 54 | 51 | 55 | 63 | 70 |
| **Market Purchases** | 0 | 0 | 434 | 224 | 0 | 0 | 254 | 197 | 132 | 397 | 334 | 26 |
| **Existing Resource Subtotal** | 2,237 | 2,086 | 1,733 | 1,694 | 2,021 | 2,616 | 2,692 | 2,372 | 1,968 | 1,698 | 1,588 | 2,124 |
| **Monthly Surplus/Deficit** | 236 | 196 | 0 | 0 | 134 | 354 | (59) | 0 | 0 | 0 | (146) | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 436 | 396 | 200 | 500 | 634 | 854 | 441 | 500 | 500 | 200 | 54 | 200 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 92 | 88 | 89 | 99 | 111 | 120 | 112 | 93 | 82 | 85 | 92 | 92 |
| Load Forecast (70th% w/EE) | (2,010) | (1,864) | (1,826) | (2,035) | (2,429) | (2,937) | (2,544) | (2,111) | (1,822) | (1,861) | (2,268) | (2,010) |
| Total non-forecasted trended EE | 128 | 122 | 123 | 137 | 153 | 166 | 156 | 129 | 114 | 118 | 128 | 128 |
| **Net Load Forecast (70th% w/ EE)** | (1,881) | (1,742) | (1,703) | (1,898) | (2,276) | (2,771) | (2,388) | (1,982) | (1,707) | (1,743) | (2,140) | (1,881) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 651 | – | – | 210 | 651 | 651 | 651 | 651 | 294 | 304 | 651 | 651 |
| **Total Gas** | 145 | 87 | – | 87 | 501 | 503 | 512 | 135 | – | 90 | 494 | 145 |
| Hydro (70th%)—HCC | 675 | 581 | 717 | 890 | 593 | 514 | 357 | 393 | 402 | 344 | 442 | 675 |
| Hydro (70th%)—Other | 210 | 194 | 244 | 313 | 321 | 273 | 201 | 210 | 212 | 178 | 184 | 210 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 885 | 775 | 961 | 1,203 | 915 | 787 | 558 | 603 | 614 | 523 | 626 | 885 |
| **CSPP (PURPA)** | 333 | 365 | 448 | 467 | 484 | 452 | 398 | 390 | 338 | 274 | 254 | 333 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 | 24 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 | 33 |
| **Market Purchases** | 0 | 441 | 267 | 0 | 0 | 249 | 249 | 179 | 405 | 331 | 80 | 0 |
| **Existing Resource Subtotal** | 2,046 | 1,699 | 1,703 | 1,989 | 2,573 | 2,659 | 2,388 | 1,982 | 1,676 | 1,551 | 2,140 | 2,046 |
| **Monthly Surplus/Deficit** | 165 | (43) | 0 | 91 | 297 | (112) | 0 | 0 | (31) | (192) | 0 | 165 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 365 | 157 | 500 | 591 | 797 | 388 | 500 | 500 | 169 | 8 | 200 | 365 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 99 | 97 | 92 | 92 | 102 | 114 | 123 | 116 | 96 | 86 | 89 | 97 |
| Load Forecast (70th% w/EE) | (2,170) | (2,050) | (1,885) | (1,847) | (2,058) | (2,457) | (2,972) | (2,575) | (2,136) | (1,843) | (1,883) | (2,294) |
| Total non-forecasted trended EE | 144 | 140 | 133 | 134 | 148 | 165 | 179 | 168 | 140 | 124 | 129 | 140 |
| **Net Load Forecast (70th% w/ EE)** | (2,026) | (1,910) | (1,752) | (1,713) | (1,911) | (2,292) | (2,793) | (2,407) | (1,996) | (1,718) | (1,753) | (2,154) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 651 | 651 | – | – | 210 | 651 | 651 | 651 | 651 | 294 | 323 | 651 |
| **Total Gas** | 503 | 145 | 87 | – | 87 | 501 | 503 | 503 | 135 | – | 90 | 503 |
| Hydro (70th%)—HCC | 547 | 672 | 580 | 715 | 888 | 591 | 513 | 355 | 384 | 401 | 344 | 441 |
| Hydro (70th%)—Other | 204 | 208 | 193 | 240 | 312 | 320 | 272 | 200 | 209 | 211 | 178 | 182 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 751 | 880 | 773 | 955 | 1,201 | 911 | 785 | 556 | 593 | 612 | 522 | 623 |
| **CSPP (PURPA)** | 247 | 322 | 352 | 431 | 452 | 469 | 442 | 391 | 380 | 327 | 261 | 241 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 0 | 0 | 440 | 300 | 0 | 0 | 245 | 286 | 214 | 403 | 329 | 102 |
| **Existing Resource Subtotal** | 2,186 | 2,031 | 1,683 | 1,713 | 1,972 | 2,555 | 2,643 | 2,407 | 1,996 | 1,661 | 1,553 | 2,154 |
| **Monthly Surplus/Deficit** | 159 | 121 | (68) | 0 | 61 | 263 | (149) | 0 | 0 | (57) | (200) | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 359 | 321 | 132 | 500 | 561 | 763 | 351 | 500 | 500 | 143 | 0 | 200 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 104 | 102 | 97 | 97 | 106 | 118 | 129 | 121 | 101 | 90 | 94 | 102 |
| Load Forecast (70th% w/EE) | (2,194) | (2,070) | (1,904) | (1,866) | (2,080) | (2,483) | (3,004) | (2,603) | (2,160) | (1,862) | (1,902) | (2,320) |
| Total non-forecasted trended EE | 152 | 147 | 140 | 140 | 154 | 172 | 187 | 175 | 146 | 130 | 136 | 147 |
| **Net Load Forecast (70th% w/ EE)** | (2,043) | (1,922) | (1,764) | (1,725) | (1,926) | (2,312) | (2,817) | (2,428) | (2,014) | (1,732) | (1,767) | (2,172) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 651 | 488 | – | – | 210 | 651 | 651 | 651 | 651 | 210 | 439 | 651 |
| **Total Gas** | 503 | 145 | 87 | – | 87 | 510 | 503 | 503 | 90 | – | – | 503 |
| Hydro (70th%)—HCC | 546 | 670 | 579 | 713 | 887 | 590 | 511 | 355 | 379 | 401 | 345 | 438 |
| Hydro (70th%)—Other | 202 | 207 | 194 | 233 | 312 | 318 | 271 | 200 | 208 | 210 | 177 | 181 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 748 | 877 | 773 | 946 | 1,198 | 908 | 783 | 555 | 587 | 612 | 521 | 620 |
| **CSPP (PURPA)** | 244 | 319 | 349 | 431 | 452 | 459 | 435 | 386 | 373 | 320 | 251 | 233 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 0 | 60 | 438 | 321 | 0 | 0 | 242 | 305 | 289 | 402 | 327 | 131 |
| **Existing Resource Subtotal** | 2,180 | 1,922 | 1,677 | 1,725 | 1,969 | 2,551 | 2,631 | 2,421 | 2,014 | 1,569 | 1,567 | 2,172 |
| **Monthly Surplus/Deficit** | 137 | 0 | (87) | 0 | 43 | 240 | (186) | (7) | 0 | (163) | (200) | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 337 | 200 | 113 | 500 | 543 | 740 | 314 | 493 | 500 | 37 | 0 | 200 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 110 | 107 | 101 | 101 | 110 | 123 | 134 | 126 | 105 | 94 | 98 | 107 |
| Load Forecast (70th% w/EE) | (2,216) | (2,088) | (1,922) | (1,883) | (2,099) | (2,507) | (3,033) | (2,629) | (2,182) | (1,880) | (1,920) | (2,344) |
| Total non-forecasted trended EE | 159 | 154 | 147 | 146 | 160 | 178 | 194 | 182 | 152 | 136 | 142 | 154 |
| **Net Load Forecast (70th% w/ EE)** | (2,057) | (1,934) | (1,775) | (1,737) | (1,940) | (2,329) | (2,839) | (2,447) | (2,030) | (1,744) | (1,778) | (2,189) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 651 | 488 | – | – | 210 | 651 | 651 | 651 | 651 | 210 | 247 | 651 |
| **Total Gas** | 494 | 145 | 87 | – | 87 | 510 | 512 | 503 | 90 | – | – | 503 |
| Hydro (70th%)—HCC | 544 | 669 | 578 | 711 | 885 | 588 | 510 | 355 | 374 | 401 | 344 | 435 |
| Hydro (70th%)—Other | 202 | 205 | 193 | 226 | 311 | 317 | 271 | 199 | 206 | 209 | 176 | 181 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 746 | 874 | 770 | 937 | 1,196 | 905 | 781 | 553 | 580 | 610 | 521 | 616 |
| **CSPP (PURPA)** | 213 | 249 | 279 | 352 | 378 | 395 | 388 | 351 | 329 | 269 | 188 | 171 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 0 | 145 | 436 | 420 | 47 | 0 | 238 | 303 | 302 | 400 | 324 | 214 |
| **Existing Resource Subtotal** | 2,137 | 1,934 | 1,603 | 1,737 | 1,940 | 2,484 | 2,588 | 2,382 | 1,976 | 1,515 | 1,309 | 2,189 |
| **Monthly Surplus/Deficit** | 80 | 0 | (172) | 0 | 0 | 155 | (251) | (65) | (54) | (229) | (470) | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 |
| **New Resource Subtotal** | 470 | 470 | 470 | 770 | 770 | 770 | 770 | 770 | 770 | 470 | 470 | 470 |
| **Monthly Surplus/Deficit** | 550 | 470 | 298 | 770 | 770 | 925 | 519 | 705 | 716 | 241 | 0 | 470 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2032 | 2/2032 | 3/2032 | 4/2032 | 5/2032 | 6/2032 | 7/2032 | 8/2032 | 9/2032 | 10/2032 | 11/2032 | 12/2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 114 | 111 | 106 | 105 | 114 | 128 | 140 | 131 | 109 | 98 | 103 | 111 |
| Load Forecast (70th% w/EE) | (2,236) | (2,087) | (1,939) | (1,900) | (2,118) | (2,530) | (3,062) | (2,654) | (2,203) | (1,897) | (1,938) | (2,367) |
| Total non-forecasted trended EE | 166 | 161 | 153 | 152 | 166 | 185 | 202 | 189 | 158 | 142 | 148 | 161 |
| **Net Load Forecast (70th% w/ EE)** | (2,071) | (1,926) | (1,786) | (1,747) | (1,953) | (2,346) | (2,860) | (2,465) | (2,045) | (1,756) | (1,790) | (2,206) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 651 | 488 | – | – | 210 | 651 | 651 | 651 | 651 | 210 | 261 | 651 |
| **Total Gas** | 494 | 145 | 87 | – | 87 | 510 | 494 | 512 | 90 | – | – | 494 |
| Hydro (70th%)—HCC | 543 | 667 | 576 | 709 | 883 | 586 | 509 | 353 | 369 | 401 | 344 | 434 |
| Hydro (70th%)—Other | 201 | 204 | 191 | 222 | 310 | 316 | 270 | 198 | 205 | 208 | 175 | 179 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 743 | 871 | 767 | 931 | 1,193 | 902 | 779 | 551 | 574 | 610 | 520 | 613 |
| **CSPP (PURPA)** | 171 | 232 | 265 | 336 | 371 | 388 | 382 | 346 | 323 | 263 | 187 | 170 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 0 | 156 | 434 | 435 | 70 | 0 | 234 | 299 | 302 | 399 | 322 | 243 |
| **Existing Resource Subtotal** | 2,094 | 1,926 | 1,583 | 1,729 | 1,953 | 2,474 | 2,558 | 2,380 | 1,964 | 1,507 | 1,319 | 2,206 |
| **Monthly Surplus/Deficit** | 23 | 0 | (202) | (18) | 0 | 128 | (303) | (85) | (82) | (248) | (470) | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 |
| **New Resource Subtotal** | 470 | 470 | 470 | 770 | 770 | 770 | 770 | 770 | 770 | 470 | 470 | 470 |
| **Monthly Surplus/Deficit** | 493 | 470 | 268 | 752 | 770 | 898 | 467 | 685 | 688 | 222 | (0) | 470 |

# Monthly Average Energy Load and Resource Balance (continued)

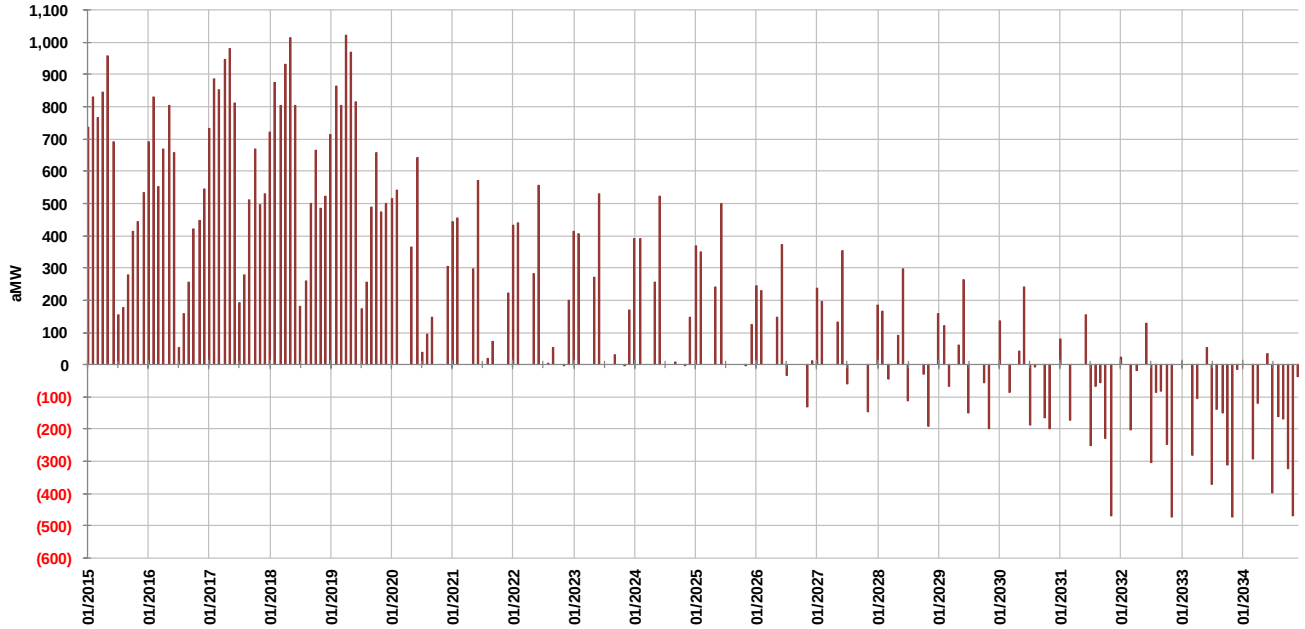
| | 1/2033 | 2/2033 | 3/2033 | 4/2033 | 5/2033 | 6/2033 | 7/2033 | 8/2033 | 9/2033 | 10/2033 | 11/2033 | 12/2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 119 | 116 | 110 | 109 | 118 | 132 | 145 | 136 | 113 | 102 | 107 | 116 |
| Load Forecast (70th% w/EE) | (2,259) | (2,124) | (1,957) | (1,918) | (2,139) | (2,556) | (3,093) | (2,682) | (2,227) | (1,916) | (1,957) | (2,392) |
| Total non-forecasted trended EE | 173 | 168 | 159 | 158 | 171 | 191 | 209 | 196 | 164 | 147 | 154 | 168 |
| **Net Load Forecast (70th% w/ EE)** | (2,086) | (1,956) | (1,798) | (1,759) | (1,968) | (2,364) | (2,884) | (2,485) | (2,062) | (1,769) | (1,802) | (2,224) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 651 | 488 | – | – | 210 | 651 | 651 | 651 | 651 | 210 | 313 | 651 |
| **Total Gas** | 503 | 145 | 87 | – | 87 | 510 | 494 | 512 | 90 | – | – | 494 |
| Hydro (70th%)—HCC | 542 | 665 | 571 | 707 | 882 | 584 | 507 | 352 | 364 | 401 | 345 | 432 |
| Hydro (70th%)—Other | 199 | 203 | 189 | 220 | 309 | 314 | 269 | 197 | 204 | 208 | 174 | 178 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 741 | 868 | 760 | 927 | 1,191 | 899 | 777 | 549 | 568 | 608 | 520 | 610 |
| **CSPP (PURPA)** | 130 | 175 | 208 | 268 | 319 | 335 | 343 | 319 | 280 | 220 | 151 | 134 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 28 | 247 | 433 | 433 | 139 | 0 | 230 | 296 | 302 | 396 | 319 | 285 |
| **Existing Resource Subtotal** | 2,086 | 1,956 | 1,519 | 1,656 | 1,968 | 2,418 | 2,512 | 2,347 | 1,915 | 1,460 | 1,332 | 2,209 |
| **Monthly Surplus/Deficit** | 0 | 0 | (279) | (104) | 0 | 54 | (371) | (138) | (148) | (309) | (470) | (16) |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 |
| **New Resource Subtotal** | 470 | 470 | 470 | 770 | 770 | 770 | 770 | 770 | 770 | 470 | 470 | 470 |
| **Monthly Surplus/Deficit** | 470 | 470 | 191 | 666 | 770 | 824 | 399 | 632 | 622 | 161 | (0) | 454 |

# Monthly Average Energy Load and Resource Balance (continued)

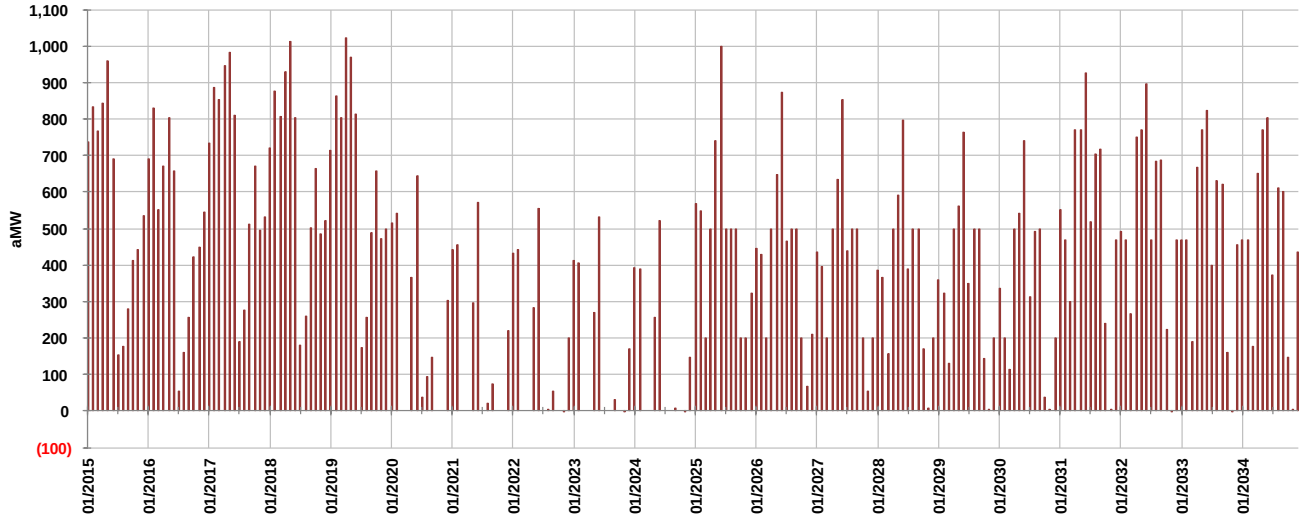
| | 1/2034 | 2/2034 | 3/2034 | 4/2034 | 5/2034 | 6/2034 | 7/2034 | 8/2034 | 9/2034 | 10/2034 | 11/2034 | 12/2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast EE | 124 | 120 | 114 | 113 | 122 | 136 | 149 | 140 | 117 | 105 | 111 | 120 |
| Load Forecast (70th% w/EE) | (2,280) | (2,142) | (1,974) | (1,935) | (2,159) | (2,579) | (3,123) | (2,708) | (2,249) | (1,934) | (1,974) | (2,416) |
| Total non-forecasted trended EE | 179 | 174 | 166 | 164 | 177 | 198 | 217 | 203 | 170 | 153 | 161 | 174 |
| **Net Load Forecast (70th% w/ EE)** | (2,101) | (1,968) | (1,808) | (1,771) | (1,981) | (2,382) | (2,906) | (2,505) | (2,079) | (1,781) | (1,814) | (2,242) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 651 | 488 | – | – | 210 | 651 | 651 | 651 | 651 | 210 | 327 | 651 |
| **Total Gas** | 503 | 145 | 87 | – | 87 | 510 | 494 | 512 | 90 | – | – | 494 |
| Hydro (70th%)—HCC | 542 | 664 | 569 | 706 | 881 | 582 | 506 | 350 | 359 | 401 | 345 | 432 |
| Hydro (70th%)—Other | 197 | 200 | 187 | 218 | 308 | 313 | 269 | 196 | 203 | 207 | 173 | 177 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (70th%)** | 739 | 864 | 756 | 924 | 1,189 | 896 | 775 | 546 | 562 | 607 | 518 | 609 |
| **CSPP (PURPA)** | 130 | 175 | 208 | 268 | 319 | 335 | 343 | 319 | 280 | 220 | 151 | 134 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 44 | 262 | 433 | 433 | 154 | 0 | 230 | 296 | 302 | 396 | 319 | 285 |
| **Existing Resource Subtotal** | 2,101 | 1,968 | 1,515 | 1,653 | 1,981 | 2,415 | 2,510 | 2,345 | 1,909 | 1,459 | 1,344 | 2,207 |
| **Monthly Surplus/Deficit** | 0 | 0 | (293) | (118) | 0 | 33 | (396) | (160) | (170) | (322) | (470) | (35) |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 | 270 |
| **New Resource Subtotal** | 470 | 470 | 470 | 770 | 770 | 770 | 770 | 770 | 770 | 470 | 470 | 470 |
| **Monthly Surplus/Deficit** | 470 | 470 | 177 | 652 | 770 | 803 | 374 | 610 | 600 | 148 | 0 | 435 |

# Monthly Average Energy Surplus/Deficit Charts

**Average energy monthly surpluses and deficits with existing DSM and existing resources**




**Average energy monthly surpluses and deficits with existing DSM, existing resources, IRP DSM, and IRP Resources**



# Peak-Hour Load and Resource Balance

| | 1/2015 | 2/2015 | 3/2015 | 4/2015 | 5/2015 | 6/2015 | 7/2015 | 8/2015 | 9/2015 | 10/2015 | 11/2015 | 12/2015 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,343) | (2,412) | (2,137) | (2,039) | (2,697) | (3,181) | (3,597) | (3,044) | (2,918) | (2,141) | (2,245) | (2,637) |
| Existing DSM (EE) | 12 | 12 | 10 | 12 | 15 | 18 | 21 | 15 | 17 | 8 | 12 | 12 |
| Load Forecast (95th% w/DSM and EE) | (2,330) | (2,400) | (2,128) | (2,027) | (2,682) | (3,163) | (3,576) | (3,029) | (2,901) | (2,133) | (2,233) | (2,625) |
| Non-forecasted trended EE | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,330) | (2,400) | (2,128) | (2,027) | (2,682) | (2,773) | (3,186) | (2,692) | (2,901) | (2,133) | (2,233) | (2,625) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 1,087 | 1,078 | 1,003 | 1,072 | 1,119 | 995 | 1,000 | 724 | 789 | 878 | 709 | 802 |
| Hydro (90th%)—Other | 207 | 209 | 187 | 204 | 303 | 313 | 281 | 208 | 215 | 214 | 200 | 207 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,294 | 1,287 | 1,190 | 1,276 | 1,422 | 1,307 | 1,281 | 932 | 1,004 | 1,092 | 909 | 1,009 |
| **CSPP (PURPA)** | 72 | 74 | 77 | 109 | 150 | 157 | 156 | 147 | 135 | 107 | 79 | 75 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange– Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| **Total PPAs** | 44 | 44 | 23 | 21 | 37 | 38 | 33 | 33 | 33 | 11 | 18 | 44 |
| **Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 3,147 | 3,141 | 3,027 | 3,143 | 3,345 | 3,240 | 3,207 | 2,849 | 2,909 | 2,947 | 2,743 | 2,865 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 817 | 742 | 899 | 1,116 | 663 | 467 | 21 | 157 | 8 | 814 | 510 | 239 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2016 | 2/2016 | 3/2016 | 4/2016 | 5/2016 | 6/2016 | 7/2016 | 8/2016 | 9/2016 | 10/2016 | 11/2016 | 12/2016 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,419) | (2,458) | (2,201) | (2,102) | (2,771) | (3,294) | (3,695) | (3,147) | (3,018) | (2,202) | (2,295) | (2,681) |
| Existing DSM (EE) | 19 | 21 | 20 | 20 | 24 | 28 | 26 | 25 | 25 | 20 | 14 | 18 |
| Load Forecast (95th% w/DSM and EE) | (2,400) | (2,437) | (2,181) | (2,082) | (2,748) | (3,266) | (3,669) | (3,122) | (2,992) | (2,183) | (2,281) | (2,663) |
| Non-forecasted trended EE | 7 | 8 | 8 | 8 | 9 | 11 | 10 | 10 | 10 | 8 | 5 | 7 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,393) | (2,429) | (2,173) | (2,075) | (2,738) | (2,865) | (3,270) | (2,775) | (2,982) | (2,175) | (2,276) | (2,656) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 1,086 | 1,094 | 1,003 | 1,073 | 1,133 | 993 | 1,000 | 722 | 785 | 880 | 710 | 801 |
| Hydro (90th%)—Other | 207 | 210 | 187 | 204 | 303 | 312 | 281 | 208 | 215 | 215 | 200 | 207 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,292 | 1,304 | 1,189 | 1,277 | 1,437 | 1,305 | 1,281 | 930 | 1,000 | 1,095 | 910 | 1,008 |
| **CSPP (PURPA)** | 72 | 74 | 88 | 120 | 170 | 221 | 220 | 211 | 192 | 139 | 111 | 77 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 |
| **Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 8 | 0 | 25 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 3,140 | 3,153 | 3,051 | 3,167 | 3,370 | 3,291 | 3,270 | 2,904 | 2,982 | 3,000 | 2,792 | 2,861 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 748 | 724 | 877 | 1,092 | 632 | 426 | 0 | 129 | 0 | 825 | 516 | 206 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,453) | (2,498) | (2,227) | (2,130) | (2,819) | (3,356) | (3,773) | (3,205) | (3,072) | (2,236) | (2,329) | (2,714) |
| Existing DSM (EE) | 27 | 26 | 23 | 27 | 31 | 36 | 36 | 33 | 30 | 27 | 24 | 28 |
| Load Forecast (95th% w/DSM and EE) | (2,426) | (2,472) | (2,204) | (2,103) | (2,788) | (3,320) | (3,736) | (3,172) | (3,042) | (2,209) | (2,305) | (2,686) |
| Non-forecasted trended EE | 21 | 20 | 18 | 21 | 25 | 28 | 28 | 26 | 23 | 21 | 19 | 22 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,405) | (2,452) | (2,185) | (2,083) | (2,763) | (2,902) | (3,318) | (2,809) | (3,018) | (2,189) | (2,286) | (2,665) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 1,083 | 1,098 | 995 | 1,089 | 1,143 | 994 | 1,000 | 722 | 780 | 880 | 712 | 794 |
| Hydro (90th%)—Other | 204 | 209 | 186 | 205 | 305 | 313 | 282 | 208 | 216 | 215 | 196 | 202 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,286 | 1,307 | 1,181 | 1,295 | 1,448 | 1,306 | 1,282 | 930 | 996 | 1,095 | 907 | 997 |
| **CSPP (PURPA)** | 74 | 76 | 203 | 235 | 375 | 406 | 405 | 396 | 359 | 232 | 204 | 77 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 |
| **Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 3,137 | 3,159 | 3,156 | 3,299 | 3,587 | 3,477 | 3,447 | 3,089 | 3,121 | 3,094 | 2,883 | 2,850 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 732 | 706 | 971 | 1,216 | 823 | 575 | 129 | 280 | 102 | 906 | 597 | 186 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,468) | (2,518) | (2,246) | (2,143) | (2,861) | (3,403) | (3,847) | (3,255) | (3,118) | (2,263) | (2,347) | (2,739) |
| Existing DSM (EE) | 35 | 35 | 33 | 34 | 42 | 47 | 54 | 50 | 41 | 35 | 34 | 36 |
| Load Forecast (95th% w/DSM and EE) | (2,433) | (2,483) | (2,213) | (2,109) | (2,820) | (3,356) | (3,793) | (3,205) | (3,076) | (2,228) | (2,313) | (2,703) |
| Non-forecasted trended EE | 32 | 32 | 31 | 31 | 38 | 44 | 50 | 46 | 38 | 32 | 31 | 33 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,401) | (2,451) | (2,182) | (2,078) | (2,781) | (2,922) | (3,353) | (2,822) | (3,038) | (2,196) | (2,282) | (2,670) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 1,077 | 1,108 | 991 | 1,090 | 1,147 | 992 | 1,000 | 720 | 774 | 878 | 711 | 791 |
| Hydro (90th%)—Other | 204 | 208 | 186 | 205 | 305 | 313 | 281 | 208 | 216 | 216 | 195 | 200 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,281 | 1,316 | 1,177 | 1,295 | 1,453 | 1,305 | 1,281 | 928 | 990 | 1,094 | 906 | 991 |
| **CSPP (PURPA)** | 74 | 76 | 203 | 235 | 375 | 406 | 405 | 396 | 359 | 232 | 204 | 77 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 |
| **Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 3,131 | 3,168 | 3,153 | 3,300 | 3,591 | 3,476 | 3,446 | 3,087 | 3,114 | 3,094 | 2,882 | 2,845 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 731 | 716 | 971 | 1,221 | 810 | 554 | 93 | 265 | 77 | 898 | 600 | 175 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,494) | (2,533) | (2,272) | (2,160) | (2,900) | (3,447) | (3,907) | (3,287) | (3,162) | (2,284) | (2,372) | (2,763) |
| Existing DSM (EE) | 38 | 33 | 42 | 34 | 51 | 60 | 61 | 53 | 55 | 38 | 41 | 40 |
| Load Forecast (95th% w/DSM and EE) | (2,456) | (2,500) | (2,231) | (2,127) | (2,849) | (3,387) | (3,847) | (3,234) | (3,108) | (2,246) | (2,332) | (2,723) |
| Non-forecasted trended EE | 41 | 36 | 45 | 36 | 54 | 65 | 65 | 57 | 59 | 41 | 44 | 43 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,415) | (2,464) | (2,186) | (2,090) | (2,795) | (2,932) | (3,391) | (2,841) | (3,049) | (2,205) | (2,288) | (2,681) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 1,077 | 1,123 | 977 | 1,088 | 1,155 | 996 | 1,000 | 720 | 769 | 880 | 712 | 772 |
| Hydro (90th%)—Other | 203 | 208 | 195 | 204 | 306 | 314 | 281 | 208 | 216 | 217 | 189 | 190 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,280 | 1,331 | 1,172 | 1,293 | 1,462 | 1,309 | 1,281 | 928 | 985 | 1,098 | 902 | 961 |
| **CSPP (PURPA)** | 74 | 76 | 203 | 235 | 375 | 406 | 405 | 396 | 359 | 232 | 204 | 77 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 |
| **Market Purchases** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 3,131 | 3,183 | 3,147 | 3,297 | 3,600 | 3,480 | 3,446 | 3,087 | 3,109 | 3,097 | 2,878 | 2,815 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 716 | 718 | 962 | 1,207 | 805 | 548 | 55 | 246 | 60 | 892 | 590 | 134 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,521) | (2,563) | (2,289) | (2,195) | (2,945) | (3,504) | (3,991) | (3,331) | (3,218) | (2,298) | (2,401) | (2,796) |
| Existing DSM (EE) | 42 | 47 | 40 | 50 | 63 | 78 | 86 | 61 | 75 | 34 | 50 | 50 |
| Load Forecast (95th% w/DSM and EE) | (2,479) | (2,515) | (2,249) | (2,145) | (2,882) | (3,426) | (3,905) | (3,270) | (3,143) | (2,264) | (2,351) | (2,747) |
| Non-forecasted trended EE | 40 | 46 | 38 | 48 | 61 | 76 | 83 | 59 | 73 | 33 | 48 | 48 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,439) | (2,470) | (2,210) | (2,097) | (2,821) | (2,961) | (3,432) | (2,874) | (3,071) | (2,231) | (2,303) | (2,699) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 1,021 | 1,021 | 55 | 55 | 1,021 | 1,021 | 1,021 | 1,021 | 1,021 | 758 | 758 | 1,021 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 716 | 716 |
| Hydro (90th%)—HCC | 1,073 | 1,098 | 977 | 1,084 | 1,152 | 992 | 1,000 | 716 | 760 | 880 | 710 | 771 |
| Hydro (90th%)—Other | 203 | 207 | 194 | 204 | 305 | 312 | 281 | 207 | 214 | 216 | 189 | 190 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,276 | 1,305 | 1,171 | 1,288 | 1,457 | 1,304 | 1,281 | 924 | 974 | 1,097 | 899 | 961 |
| **CSPP (PURPA)** | 74 | 76 | 203 | 235 | 375 | 406 | 405 | 396 | 359 | 232 | 204 | 77 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 |
| **Market Purchases** | 0 | 0 | 29 | 70 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 3,127 | 3,157 | 2,210 | 2,097 | 3,596 | 3,475 | 3,446 | 3,082 | 3,098 | 2,533 | 2,612 | 2,815 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 688 | 687 | 0 | 0 | 774 | 514 | 13 | 208 | 28 | 302 | 309 | 116 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,551) | (2,594) | (2,316) | (2,213) | (2,983) | (3,549) | (4,051) | (3,386) | (3,260) | (2,330) | (2,417) | (2,824) |
| Existing DSM (EE) | 57 | 63 | 53 | 55 | 67 | 79 | 85 | 76 | 78 | 46 | 52 | 57 |
| Load Forecast (95th% w/DSM and EE) | (2,495) | (2,531) | (2,263) | (2,158) | (2,916) | (3,469) | (3,965) | (3,310) | (3,182) | (2,284) | (2,365) | (2,766) |
| Non-forecasted trended EE | 56 | 62 | 52 | 54 | 66 | 78 | 84 | 75 | 77 | 46 | 51 | 56 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,439) | (2,469) | (2,211) | (2,104) | (2,850) | (3,001) | (3,491) | (2,897) | (3,105) | (2,238) | (2,314) | (2,710) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 966 | 966 | 0 | 0 | 966 | 966 | 966 | 966 | 966 | 703 | 703 | 966 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 716 | 716 |
| Hydro (90th%)—HCC | 1,070 | 1,072 | 968 | 1,083 | 1,149 | 988 | 1,000 | 713 | 748 | 879 | 710 | 770 |
| Hydro (90th%)—Other | 201 | 205 | 194 | 203 | 304 | 311 | 280 | 206 | 213 | 215 | 188 | 189 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,271 | 1,277 | 1,162 | 1,286 | 1,454 | 1,300 | 1,280 | 919 | 961 | 1,094 | 898 | 959 |
| **CSPP (PURPA)** | 74 | 76 | 203 | 235 | 375 | 406 | 405 | 396 | 359 | 232 | 204 | 77 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 |
| **Market Purchases** | 0 | 0 | 94 | 135 | 0 | 0 | 102 | 0 | 75 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 3,067 | 3,074 | 2,211 | 2,104 | 3,537 | 3,415 | 3,491 | 3,023 | 3,105 | 2,476 | 2,556 | 2,757 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 628 | 605 | 0 | 0 | 687 | 414 | 0 | 125 | 0 | 237 | 242 | 47 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,620) | (2,348) | (2,236) | (3,029) | (3,610) | (4,117) | (3,431) | (3,308) | (2,371) | (2,431) | (2,852) | (2,620) |
| Existing DSM (EE) | 70 | 67 | 64 | 77 | 100 | 91 | 83 | 87 | 64 | 48 | 60 | 70 |
| Load Forecast (95th% w/DSM and EE) | (2,550) | (2,281) | (2,173) | (2,952) | (3,510) | (4,026) | (3,348) | (3,221) | (2,307) | (2,383) | (2,792) | (2,550) |
| Non-forecasted trended EE | 73 | 70 | 66 | 81 | 103 | 94 | 86 | 91 | 67 | 50 | 62 | 73 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,477) | (2,211) | (2,107) | (2,871) | (3,017) | (3,541) | (2,925) | (3,130) | (2,240) | (2,333) | (2,729) | (2,477) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 966 | 0 | 0 | 966 | 966 | 966 | 966 | 966 | 703 | 703 | 966 | 966 |
| **Total Gas** | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 1,061 | 964 | 1,081 | 1,147 | 986 | 1,000 | 709 | 736 | 879 | 711 | 768 | 1,061 |
| Hydro (90th%)—Other | 204 | 192 | 203 | 304 | 310 | 279 | 205 | 211 | 214 | 187 | 188 | 204 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,265 | 1,156 | 1,283 | 1,450 | 1,296 | 1,279 | 914 | 947 | 1,093 | 898 | 956 | 1,265 |
| **CSPP (PURPA)** | 76 | 203 | 235 | 375 | 406 | 405 | 396 | 359 | 232 | 204 | 77 | 76 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 | 9 |
| Neal Hot Springs Geothermal | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 | 24 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 | 38 |
| **Market Purchases** | 0 | 100 | 140 | 0 | 0 | 152 | 0 | 113 | 0 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 3,062 | 2,211 | 2,107 | 3,534 | 3,412 | 3,541 | 3,018 | 3,130 | 2,474 | 2,556 | 2,755 | 3,062 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 585 | 0 | 0 | 663 | 395 | 0 | 93 | 0 | 234 | 222 | 25 | 585 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,617) | (2,647) | (2,374) | (2,271) | (3,080) | (3,664) | (4,201) | (3,485) | (3,346) | (2,405) | (2,477) | (2,903) |
| Existing DSM (EE) | 76 | 74 | 71 | 77 | 92 | 112 | 114 | 99 | 85 | 75 | 70 | 82 |
| Load Forecast (95th% w/DSM and EE) | (2,541) | (2,572) | (2,303) | (2,194) | (2,987) | (3,552) | (4,086) | (3,387) | (3,261) | (2,330) | (2,406) | (2,822) |
| Non-forecasted trended EE | 83 | 82 | 78 | 85 | 101 | 123 | 125 | 108 | 93 | 82 | 77 | 90 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,457) | (2,491) | (2,225) | (2,109) | (2,886) | (3,039) | (3,571) | (2,941) | (3,167) | (2,248) | (2,329) | (2,732) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 966 | 966 | 0 | 0 | 966 | 966 | 966 | 966 | 966 | 703 | 703 | 966 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 716 | 716 |
| Hydro (90th%)—HCC | 1,063 | 1,058 | 961 | 1,079 | 1,144 | 984 | 1,000 | 706 | 724 | 877 | 712 | 766 |
| Hydro (90th%)—Other | 199 | 202 | 191 | 202 | 303 | 309 | 278 | 204 | 210 | 211 | 186 | 187 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,262 | 1,260 | 1,152 | 1,281 | 1,447 | 1,293 | 1,278 | 910 | 934 | 1,088 | 898 | 952 |
| **CSPP (PURPA)** | 74 | 76 | 203 | 235 | 375 | 406 | 405 | 396 | 359 | 232 | 204 | 77 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 |
| **Market Purchases** | 0 | 0 | 119 | 144 | 0 | 0 | 183 | 0 | 163 | 0 | 0 | 0 |
| **Existing Resource Subtotal** | 3,058 | 3,057 | 2,225 | 2,109 | 3,531 | 3,408 | 3,571 | 3,014 | 3,167 | 2,469 | 2,556 | 2,751 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 601 | 566 | 0 | 0 | 645 | 369 | 0 | 72 | 0 | 221 | 226 | 19 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,658) | (2,679) | (2,413) | (2,283) | (3,120) | (3,721) | (4,268) | (3,534) | (3,412) | (2,428) | (2,514) | (2,931) |
| Existing DSM (EE) | 85 | 83 | 85 | 65 | 95 | 121 | 117 | 103 | 107 | 74 | 81 | 79 |
| Load Forecast (95th% w/DSM and EE) | (2,573) | (2,596) | (2,328) | (2,218) | (3,025) | (3,600) | (4,151) | (3,431) | (3,305) | (2,354) | (2,433) | (2,853) |
| Non-forecasted trended EE | 98 | 95 | 97 | 75 | 109 | 139 | 134 | 118 | 122 | 85 | 93 | 90 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,475) | (2,500) | (2,231) | (2,143) | (2,917) | (3,071) | (3,626) | (2,976) | (3,183) | (2,269) | (2,340) | (2,762) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 966 | 966 | 0 | 0 | 966 | 966 | 966 | 966 | 966 | 703 | 703 | 966 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 716 | 716 |
| Hydro (90th%)—HCC | 1,060 | 1,054 | 958 | 1,077 | 1,141 | 982 | 1,000 | 703 | 716 | 877 | 711 | 767 |
| Hydro (90th%)—Other | 198 | 202 | 191 | 202 | 302 | 308 | 277 | 203 | 208 | 209 | 185 | 186 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,258 | 1,256 | 1,149 | 1,279 | 1,443 | 1,290 | 1,277 | 905 | 924 | 1,086 | 896 | 953 |
| **CSPP (PURPA)** | 74 | 76 | 203 | 235 | 375 | 406 | 405 | 396 | 359 | 232 | 204 | 77 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 |
| **Market Purchases** | 0 | 0 | 127 | 181 | 0 | 0 | 239 | 0 | 189 | 0 | 0 | 11 |
| **Existing Resource Subtotal** | 3,054 | 3,053 | 2,231 | 2,143 | 3,527 | 3,405 | 3,626 | 3,009 | 3,183 | 2,467 | 2,554 | 2,762 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 579 | 552 | 0 | 0 | 610 | 335 | 0 | 33 | 0 | 198 | 214 | 0 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,673) | (2,698) | (2,438) | (2,308) | (3,164) | (3,773) | (4,350) | (3,571) | (3,454) | (2,453) | (2,533) | (2,970) |
| Existing DSM (EE) | 72 | 81 | 89 | 67 | 101 | 124 | 136 | 94 | 105 | 76 | 76 | 90 |
| Load Forecast (95th% w/DSM and EE) | (2,601) | (2,617) | (2,350) | (2,240) | (3,062) | (3,648) | (4,215) | (3,476) | (3,349) | (2,377) | (2,456) | (2,880) |
| Non-forecasted trended EE | 86 | 97 | 106 | 81 | 121 | 149 | 163 | 113 | 126 | 92 | 92 | 108 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,515) | (2,520) | (2,243) | (2,159) | (2,941) | (3,109) | (3,661) | (3,026) | (3,224) | (2,285) | (2,365) | (2,772) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 966 | 966 | 0 | 0 | 966 | 966 | 966 | 966 | 966 | 703 | 703 | 966 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 716 | 716 |
| Hydro (90th%)—HCC | 1,052 | 1,050 | 956 | 1,075 | 1,133 | 981 | 1,000 | 699 | 708 | 874 | 713 | 765 |
| Hydro (90th%)—Other | 197 | 202 | 190 | 201 | 296 | 302 | 277 | 202 | 207 | 209 | 184 | 185 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,250 | 1,252 | 1,146 | 1,276 | 1,430 | 1,283 | 1,277 | 901 | 914 | 1,082 | 897 | 950 |
| **CSPP (PURPA)** | 74 | 76 | 203 | 235 | 375 | 406 | 405 | 396 | 359 | 232 | 204 | 76 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 |
| **Market Purchases** | 0 | 0 | 142 | 200 | 0 | 0 | 261 | 21 | 240 | 0 | 0 | 24 |
| **Existing Resource Subtotal** | 3,045 | 3,048 | 2,243 | 2,159 | 3,513 | 3,398 | 3,648 | 3,026 | 3,224 | 2,463 | 2,555 | 2,772 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (14) | 0 | 0 | 0 | 0 | 0 |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 731 | 728 | 200 | 500 | 1,072 | 789 | 486 | 500 | 500 | 378 | 390 | 200 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,723) | (2,734) | (2,444) | (2,348) | (3,203) | (3,830) | (4,425) | (3,623) | (3,522) | (2,461) | (2,571) | (2,995) |
| Existing DSM (EE) | 96 | 97 | 73 | 87 | 103 | 133 | 147 | 103 | 129 | 61 | 93 | 89 |
| Load Forecast (95th% w/DSM and EE) | (2,627) | (2,637) | (2,370) | (2,261) | (3,099) | (3,697) | (4,278) | (3,521) | (3,393) | (2,399) | (2,479) | (2,906) |
| Non-forecasted trended EE | 121 | 122 | 92 | 109 | 130 | 168 | 185 | 129 | 162 | 77 | 117 | 112 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,506) | (2,515) | (2,278) | (2,152) | (2,969) | (3,139) | (3,703) | (3,054) | (3,231) | (2,322) | (2,362) | (2,794) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 703 | 703 | 0 | 0 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 716 | 716 |
| Hydro (90th%)—HCC | 1,047 | 1,047 | 954 | 1,073 | 1,131 | 979 | 1,000 | 696 | 697 | 874 | 713 | 762 |
| Hydro (90th%)—Other | 197 | 201 | 190 | 200 | 293 | 299 | 276 | 201 | 205 | 208 | 183 | 184 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,244 | 1,247 | 1,143 | 1,274 | 1,424 | 1,278 | 1,276 | 897 | 902 | 1,082 | 896 | 947 |
| **CSPP (PURPA)** | 74 | 76 | 202 | 234 | 374 | 405 | 404 | 395 | 358 | 231 | 203 | 76 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 |
| **Market Purchases** | 0 | 0 | 181 | 196 | 0 | 10 | 257 | 305 | 302 | 0 | 0 | 301 |
| **Existing Resource Subtotal** | 2,776 | 2,781 | 2,278 | 2,152 | 3,243 | 3,139 | 3,379 | 3,042 | 3,010 | 2,462 | 2,553 | 2,782 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (324) | (13) | (221) | 0 | 0 | (12) |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 470 | 466 | 200 | 500 | 774 | 500 | 176 | 487 | 279 | 340 | 391 | 188 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,748) | (2,762) | (2,480) | (2,368) | (3,239) | (3,863) | (4,476) | (3,681) | (3,558) | (2,498) | (2,588) | (3,026) |
| Existing DSM (EE) | 95 | 106 | 89 | 86 | 103 | 119 | 134 | 117 | 121 | 77 | 88 | 94 |
| Load Forecast (95th% w/DSM and EE) | (2,653) | (2,656) | (2,391) | (2,281) | (3,136) | (3,744) | (4,341) | (3,565) | (3,437) | (2,422) | (2,500) | (2,932) |
| Non-forecasted trended EE | 125 | 139 | 118 | 114 | 136 | 157 | 177 | 154 | 160 | 101 | 116 | 124 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,528) | (2,517) | (2,273) | (2,167) | (2,999) | (3,197) | (3,774) | (3,074) | (3,277) | (2,321) | (2,384) | (2,809) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 703 | 703 | 0 | 0 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 716 | 716 |
| Hydro (90th%)—HCC | 1,044 | 1,039 | 949 | 1,071 | 1,128 | 978 | 1,000 | 692 | 687 | 874 | 711 | 761 |
| Hydro (90th%)—Other | 196 | 198 | 190 | 200 | 292 | 298 | 275 | 200 | 204 | 207 | 183 | 183 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,240 | 1,237 | 1,139 | 1,271 | 1,421 | 1,276 | 1,275 | 892 | 890 | 1,080 | 894 | 944 |
| **CSPP (PURPA)** | 73 | 75 | 202 | 234 | 374 | 405 | 404 | 395 | 358 | 231 | 203 | 76 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 39 | 38 | 36 | 32 | 27 | 27 | 23 | 26 | 29 | 30 | 35 | 40 |
| **Market Purchases** | 0 | 0 | 181 | 214 | 0 | 70 | 254 | 305 | 302 | 0 | 0 | 298 |
| **Existing Resource Subtotal** | 2,771 | 2,770 | 2,273 | 2,167 | 3,240 | 3,197 | 3,375 | 3,037 | 2,998 | 2,461 | 2,551 | 2,777 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (399) | (37) | (279) | 0 | 0 | (32) |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 444 | 453 | 200 | 500 | 741 | 500 | 101 | 463 | 221 | 340 | 367 | 168 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,780) | (2,786) | (2,507) | (2,406) | (3,278) | (3,930) | (4,558) | (3,721) | (3,597) | (2,542) | (2,629) | (3,059) |
| Existing DSM (EE) | 100 | 111 | 95 | 103 | 106 | 138 | 153 | 112 | 116 | 98 | 106 | 100 |
| Load Forecast (95th% w/DSM and EE) | (2,680) | (2,675) | (2,412) | (2,303) | (3,172) | (3,792) | (4,404) | (3,609) | (3,481) | (2,444) | (2,523) | (2,960) |
| Non-forecasted trended EE | 139 | 154 | 132 | 142 | 148 | 192 | 212 | 155 | 161 | 136 | 147 | 138 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,541) | (2,521) | (2,281) | (2,161) | (3,025) | (3,210) | (3,802) | (3,117) | (3,320) | (2,308) | (2,377) | (2,821) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 703 | 703 | 0 | 0 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 716 | 716 |
| Hydro (90th%)—HCC | 1,040 | 1,041 | 945 | 1,070 | 1,126 | 976 | 1,000 | 689 | 673 | 872 | 713 | 756 |
| Hydro (90th%)—Other | 195 | 197 | 189 | 199 | 292 | 297 | 275 | 199 | 202 | 206 | 181 | 182 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,236 | 1,238 | 1,134 | 1,269 | 1,418 | 1,274 | 1,275 | 888 | 875 | 1,078 | 895 | 938 |
| **CSPP (PURPA)** | 73 | 75 | 202 | 234 | 374 | 405 | 404 | 395 | 358 | 231 | 203 | 76 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 0 | 0 | 198 | 214 | 0 | 90 | 249 | 305 | 302 | 0 | 0 | 295 |
| **Existing Resource Subtotal** | 2,762 | 2,766 | 2,281 | 2,161 | 3,233 | 3,210 | 3,364 | 3,028 | 2,977 | 2,453 | 2,547 | 2,762 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (438) | (88) | (343) | 0 | 0 | (59) |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 421 | 445 | 200 | 500 | 708 | 500 | 62 | 412 | 157 | 345 | 370 | 141 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,823) | (2,808) | (2,544) | (2,426) | (3,328) | (3,988) | (4,631) | (3,814) | (3,643) | (2,572) | (2,657) | (3,105) |
| Existing DSM (EE) | 115 | 111 | 110 | 102 | 118 | 146 | 162 | 159 | 117 | 104 | 111 | 120 |
| Load Forecast (95th% w/DSM and EE) | (2,708) | (2,697) | (2,434) | (2,325) | (3,210) | (3,842) | (4,469) | (3,655) | (3,527) | (2,468) | (2,546) | (2,985) |
| Non-forecasted trended EE | 167 | 161 | 160 | 148 | 171 | 212 | 235 | 230 | 169 | 151 | 160 | 174 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,541) | (2,535) | (2,274) | (2,177) | (3,039) | (3,240) | (3,844) | (3,088) | (3,357) | (2,316) | (2,386) | (2,811) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 703 | 703 | 0 | 0 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 716 | 716 |
| Hydro (90th%)—HCC | 1,037 | 1,037 | 941 | 1,068 | 1,124 | 975 | 1,000 | 686 | 663 | 872 | 712 | 752 |
| Hydro (90th%)—Other | 195 | 196 | 189 | 199 | 288 | 292 | 274 | 198 | 200 | 205 | 180 | 180 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,232 | 1,233 | 1,130 | 1,267 | 1,411 | 1,267 | 1,274 | 884 | 863 | 1,077 | 892 | 933 |
| **CSPP (PURPA)** | 71 | 73 | 200 | 231 | 371 | 402 | 401 | 392 | 355 | 229 | 201 | 73 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 0 | 0 | 197 | 235 | 0 | 130 | 245 | 305 | 302 | 0 | 0 | 293 |
| **Existing Resource Subtotal** | 2,757 | 2,759 | 2,274 | 2,177 | 3,223 | 3,240 | 3,357 | 3,021 | 2,962 | 2,450 | 2,542 | 2,753 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (487) | (66) | (395) | 0 | 0 | (58) |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 416 | 424 | 200 | 500 | 684 | 500 | 13 | 434 | 105 | 334 | 356 | 142 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,838) | (2,809) | (2,575) | (2,432) | (3,366) | (4,045) | (4,677) | (3,829) | (3,711) | (2,589) | (2,682) | (3,121) |
| Existing DSM (EE) | 106 | 94 | 122 | 88 | 120 | 157 | 146 | 131 | 142 | 99 | 115 | 112 |
| Load Forecast (95th% w/DSM and EE) | (2,732) | (2,715) | (2,453) | (2,344) | (3,246) | (3,888) | (4,531) | (3,698) | (3,569) | (2,489) | (2,567) | (3,009) |
| Non-forecasted trended EE | 154 | 136 | 177 | 128 | 174 | 228 | 211 | 190 | 206 | 144 | 167 | 162 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,578) | (2,579) | (2,276) | (2,216) | (3,071) | (3,270) | (3,930) | (3,171) | (3,363) | (2,346) | (2,400) | (2,847) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 703 | 703 | 0 | 0 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 416 | 716 |
| Hydro (90th%)—HCC | 1,035 | 1,034 | 938 | 1,066 | 1,121 | 973 | 1,000 | 682 | 652 | 873 | 712 | 752 |
| Hydro (90th%)—Other | 194 | 194 | 188 | 198 | 288 | 292 | 273 | 197 | 199 | 204 | 180 | 180 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,229 | 1,228 | 1,126 | 1,264 | 1,409 | 1,265 | 1,273 | 879 | 851 | 1,077 | 892 | 931 |
| **CSPP (PURPA)** | 71 | 73 | 200 | 231 | 371 | 401 | 400 | 390 | 353 | 227 | 199 | 72 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 0 | 0 | 204 | 277 | 0 | 163 | 242 | 305 | 302 | 0 | 161 | 291 |
| **Existing Resource Subtotal** | 2,754 | 2,753 | 2,276 | 2,216 | 3,221 | 3,270 | 3,352 | 3,015 | 2,949 | 2,448 | 2,400 | 2,748 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (579) | (156) | (414) | 0 | 0 | (99) |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 60 | 60 | 60 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 20 | 20 | 20 | 20 | 20 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 520 | 580 | 580 | 580 | 520 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 375 | 374 | 200 | 500 | 669 | 580 | 1 | 424 | 106 | 302 | 200 | 101 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,852) | (2,842) | (2,592) | (2,448) | (3,407) | (4,091) | (4,764) | (3,855) | (3,744) | (2,614) | (2,691) | (3,150) |
| Existing DSM (EE) | 101 | 112 | 123 | 89 | 127 | 160 | 172 | 118 | 135 | 104 | 108 | 119 |
| Load Forecast (95th% w/DSM and EE) | (2,751) | (2,730) | (2,469) | (2,359) | (3,280) | (3,931) | (4,592) | (3,737) | (3,608) | (2,509) | (2,584) | (3,031) |
| Non-forecasted trended EE | 145 | 162 | 178 | 129 | 184 | 232 | 250 | 170 | 196 | 151 | 156 | 172 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,606) | (2,569) | (2,292) | (2,230) | (3,095) | (3,309) | (3,952) | (3,230) | (3,412) | (2,358) | (2,428) | (2,859) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 703 | 703 | 0 | 0 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 416 | 716 |
| Hydro (90th%)—HCC | 1,034 | 1,029 | 935 | 1,064 | 1,119 | 972 | 1,000 | 679 | 641 | 869 | 714 | 749 |
| Hydro (90th%)—Other | 193 | 193 | 187 | 197 | 287 | 291 | 272 | 196 | 197 | 202 | 179 | 178 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,226 | 1,222 | 1,122 | 1,262 | 1,406 | 1,262 | 1,272 | 876 | 839 | 1,071 | 893 | 926 |
| **CSPP (PURPA)** | 66 | 63 | 190 | 221 | 360 | 391 | 390 | 381 | 344 | 218 | 189 | 61 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 0 | 0 | 233 | 304 | 0 | 214 | 238 | 303 | 302 | 0 | 198 | 289 |
| **Existing Resource Subtotal** | 2,746 | 2,737 | 2,292 | 2,230 | 3,207 | 3,309 | 3,338 | 3,000 | 2,927 | 2,433 | 2,428 | 2,730 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (615) | (230) | (485) | 0 | 0 | (129) |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 60 | 60 | 60 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 20 | 20 | 20 | 20 | 20 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| **New Resource Subtotal** | 500 | 500 | 500 | 800 | 820 | 880 | 880 | 880 | 820 | 500 | 500 | 500 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 640 | 668 | 500 | 800 | 932 | 880 | 265 | 650 | 335 | 575 | 500 | 371 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2032 | 2/2032 | 3/2032 | 4/2032 | 5/2032 | 6/2032 | 7/2032 | 8/2032 | 9/2032 | 10/2032 | 11/2032 | 12/2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,902) | (2,877) | (2,599) | (2,481) | (3,438) | (4,114) | (4,818) | (3,916) | (3,798) | (2,625) | (2,715) | (3,172) |
| Existing DSM (EE) | 130 | 132 | 113 | 106 | 125 | 141 | 167 | 140 | 151 | 97 | 114 | 119 |
| Load Forecast (95th% w/DSM and EE) | (2,772) | (2,745) | (2,486) | (2,375) | (3,313) | (3,972) | (4,651) | (3,776) | (3,647) | (2,529) | (2,601) | (3,054) |
| Non-forecasted trended EE | 188 | 191 | 164 | 153 | 181 | 205 | 241 | 203 | 218 | 140 | 165 | 171 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,584) | (2,554) | (2,322) | (2,223) | (3,132) | (3,377) | (4,020) | (3,236) | (3,429) | (2,389) | (2,437) | (2,882) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 703 | 703 | 0 | 0 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 416 | 716 |
| Hydro (90th%)—HCC | 1,032 | 1,025 | 932 | 1,063 | 1,118 | 971 | 1,000 | 676 | 630 | 869 | 714 | 746 |
| Hydro (90th%)—Other | 192 | 192 | 187 | 196 | 285 | 289 | 272 | 195 | 196 | 201 | 178 | 176 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,224 | 1,218 | 1,119 | 1,259 | 1,403 | 1,259 | 1,272 | 871 | 826 | 1,070 | 892 | 922 |
| **CSPP (PURPA)** | 59 | 60 | 187 | 219 | 359 | 390 | 389 | 380 | 343 | 216 | 188 | 61 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 0 | 0 | 269 | 301 | 0 | 287 | 234 | 299 | 302 | 0 | 208 | 287 |
| **Existing Resource Subtotal** | 2,736 | 2,730 | 2,322 | 2,223 | 3,203 | 3,377 | 3,331 | 2,990 | 2,914 | 2,431 | 2,437 | 2,724 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (689) | (245) | (515) | 0 | 0 | (158) |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 60 | 60 | 60 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 20 | 20 | 20 | 20 | 20 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| **New Resource Subtotal** | 500 | 500 | 500 | 800 | 820 | 880 | 880 | 880 | 820 | 500 | 500 | 500 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 652 | 677 | 500 | 800 | 890 | 880 | 191 | 635 | 305 | 542 | 500 | 342 |

# Peak-Hour Load and Resource Balance (continued)

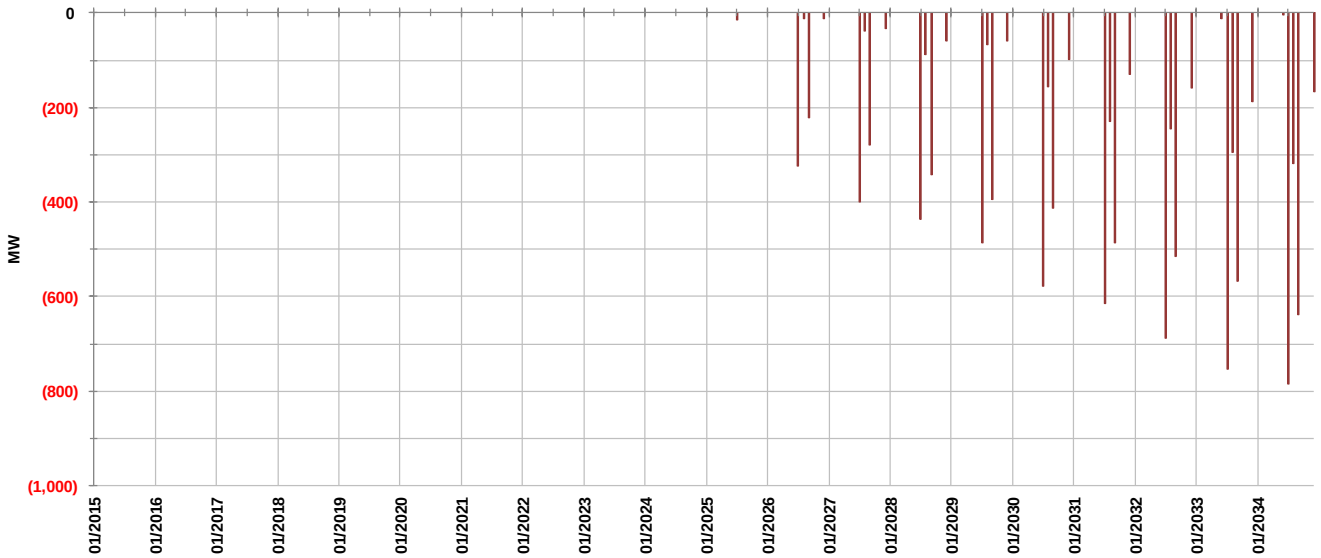
| | 1/2033 | 2/2033 | 3/2033 | 4/2033 | 5/2033 | 6/2033 | 7/2033 | 8/2033 | 9/2033 | 10/2033 | 11/2033 | 12/2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,920) | (2,903) | (2,622) | (2,502) | (3,478) | (4,163) | (4,886) | (3,962) | (3,845) | (2,650) | (2,739) | (3,200) |
| Existing DSM (EE) | 126 | 141 | 118 | 109 | 129 | 146 | 173 | 145 | 157 | 101 | 119 | 123 |
| Load Forecast (95th% w/DSM and EE) | (2,794) | (2,763) | (2,504) | (2,393) | (3,348) | (4,017) | (4,713) | (3,817) | (3,688) | (2,549) | (2,620) | (3,077) |
| Non-forecasted trended EE | 183 | 204 | 171 | 158 | 187 | 212 | 251 | 210 | 228 | 146 | 172 | 179 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,611) | (2,559) | (2,332) | (2,235) | (3,161) | (3,415) | (4,071) | (3,270) | (3,461) | (2,404) | (2,448) | (2,899) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 703 | 703 | 0 | 0 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 416 | 716 |
| Hydro (90th%)—HCC | 1,030 | 1,004 | 929 | 1,061 | 1,116 | 969 | 1,000 | 673 | 620 | 870 | 712 | 745 |
| Hydro (90th%)—Other | 191 | 191 | 186 | 196 | 282 | 285 | 271 | 194 | 195 | 200 | 177 | 175 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,221 | 1,195 | 1,115 | 1,257 | 1,398 | 1,254 | 1,271 | 867 | 814 | 1,070 | 889 | 921 |
| **CSPP (PURPA)** | 50 | 52 | 178 | 210 | 350 | 381 | 380 | 371 | 334 | 208 | 179 | 52 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 0 | 0 | 292 | 324 | 0 | 328 | 230 | 296 | 302 | 0 | 231 | 285 |
| **Existing Resource Subtotal** | 2,724 | 2,699 | 2,332 | 2,235 | 3,189 | 3,404 | 3,318 | 2,974 | 2,893 | 2,422 | 2,448 | 2,712 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (11) | (754) | (296) | (568) | 0 | 0 | (187) |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 60 | 60 | 60 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 20 | 20 | 20 | 20 | 20 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| **New Resource Subtotal** | 500 | 500 | 500 | 800 | 820 | 880 | 880 | 880 | 820 | 500 | 500 | 500 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 613 | 640 | 500 | 800 | 848 | 869 | 126 | 584 | 252 | 518 | 500 | 313 |

# Peak-Hour Load and Resource Balance (continued)

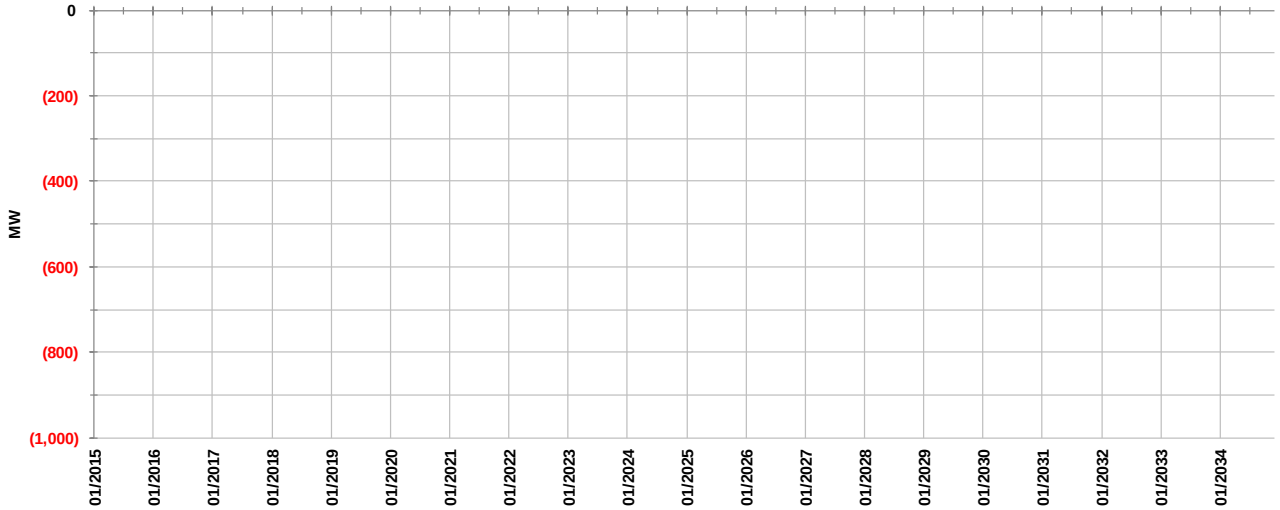
| | 1/2034 | 2/2034 | 3/2034 | 4/2034 | 5/2034 | 6/2034 | 7/2034 | 8/2034 | 9/2034 | 10/2034 | 11/2034 | 12/2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,955) | (2,917) | (2,652) | (2,539) | (3,531) | (4,241) | (4,966) | (4,017) | (3,870) | (2,698) | (2,768) | (3,256) |
| Existing DSM (EE) | 141 | 139 | 132 | 130 | 149 | 181 | 193 | 160 | 142 | 129 | 131 | 156 |
| Load Forecast (95th% w/DSM and EE) | (2,815) | (2,778) | (2,520) | (2,409) | (3,382) | (4,060) | (4,773) | (3,857) | (3,728) | (2,569) | (2,638) | (3,100) |
| Non-forecasted trended EE | 204 | 202 | 192 | 189 | 217 | 264 | 280 | 232 | 206 | 188 | 190 | 226 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM (EE)** | (2,610) | (2,576) | (2,328) | (2,220) | (3,166) | (3,406) | (4,103) | (3,287) | (3,522) | (2,381) | (2,448) | (2,873) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 703 | 703 | 0 | 0 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Total Gas** | 716 | 716 | 716 | 416 | 716 | 716 | 716 | 716 | 716 | 416 | 416 | 716 |
| Hydro (90th%)—HCC | 1,028 | 992 | 926 | 1,059 | 1,114 | 968 | 1,000 | 669 | 612 | 868 | 712 | 743 |
| Hydro (90th%)—Other | 190 | 190 | 186 | 195 | 278 | 283 | 270 | 193 | 194 | 200 | 176 | 174 |
| Sho-Ban Water Lease | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Hydro (90th%)** | 1,219 | 1,181 | 1,112 | 1,254 | 1,392 | 1,251 | 1,270 | 862 | 806 | 1,068 | 888 | 917 |
| **CSPP (PURPA)** | 50 | 52 | 178 | 210 | 350 | 381 | 380 | 371 | 334 | 208 | 179 | 52 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 9 | 9 | 9 | 8 | 7 | 7 | 8 | 8 | 8 | 10 | 9 | 9 |
| Neal Hot Springs Geothermal | 25 | 24 | 22 | 19 | 14 | 15 | 11 | 13 | 16 | 15 | 20 | 26 |
| Clatskanie Exchange–Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange– Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 34 | 33 | 31 | 27 | 22 | 22 | 18 | 21 | 24 | 25 | 30 | 35 |
| **Market Purchases** | 0 | 0 | 291 | 313 | 0 | 328 | 230 | 296 | 302 | 0 | 232 | 285 |
| **Existing Resource Subtotal** | 2,721 | 2,685 | 2,328 | 2,220 | 3,183 | 3,401 | 3,317 | 2,970 | 2,884 | 2,420 | 2,448 | 2,708 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | (5) | (786) | (318) | (638) | 0 | 0 | (165) |
| **2015 IRP Resources** | | | | | | | | | | | | |
| 2025 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2030 New DR | 0 | 0 | 0 | 0 | 0 | 60 | 60 | 60 | 0 | 0 | 0 | 0 |
| 2030 Ice TES | 0 | 0 | 0 | 0 | 20 | 20 | 20 | 20 | 20 | 0 | 0 | 0 |
| 2031 Combined Cycle Combustion Turbine | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| **New Resource Subtotal** | 500 | 500 | 500 | 800 | 820 | 880 | 880 | 880 | 820 | 500 | 500 | 500 |
| **Monthly Surplus/Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Remaining Monthly Surplus/Deficit** | 611 | 609 | 500 | 800 | 837 | 875 | 94 | 562 | 182 | 538 | 500 | 335 |

# Peak-Hour Surplus/Deficit Charts

**Peak-hour monthly deficits with existing DSM and existing resources**




**Peak-hour monthly deficits with existing DSM, existing resources, IRP DSM, and IRP resources**



# DEMAND-SIDE RESOURCE DATA

## Cost Effectiveness

Idaho Power considers cost-effectiveness to be the primary screening tool prior to demand-side management (DSM) program implementation. Idaho Power uses the total resource cost (TRC) test and the utility cost (UC) test to develop benefit cost (B/C) ratios to determine the cost-effectiveness of DSM programs for inclusion in resource planning. The two tests insure that the program benefits will exceed costs from both the perspective of Idaho Power (UC) and its customers (TRC). For ongoing programs, tests are also run to look at cost-effectiveness from the point of view of the program participant. Each energy efficiency and demand response program and individual program measures are reviewed annually as part of preparation of an annual report that is submitted to both the Idaho and Oregon public utility commissions. More information on Idaho Power's programs and cost-effectiveness are included in the *Demand-Side Management 2012 Annual Report* and its *Supplement 1: Cost-Effectiveness,* (idahopower.com/EnergyEfficiency/reports.cfm).

Incorporated into the cost-effectiveness analysis are inputs from various sources that represent the most current and reliable information available. Measure savings, measure life, and participant cost assumptions for prescriptive programs are usually sourced from the Regional Technical Forum (RTF), which is the regional advisory group and technical arm of the Northwest Power and Conservation Council (NPCC). For custom and non-prescriptive programs, annual energy savings can be derived from program evaluations, engineering estimates, or regionally deemed values. Participant costs for non-prescriptive programs are often actual costs from customer-submitted information. Other inputs used in the cost-effectiveness models are obtained from the IRP process, including the financial assumptions along with the forecasted value of DSM alternative costs.

Idaho Power determines cost-effectiveness on both a program basis and also on a measure-by-measure basis. In all cases, when cost-effectiveness is calculated for one measure or for an entire program, to be considered cost-effective, the B/C ratios must be greater than one for both the TRC and UC tests.

For the 2015 IRP, non-energy related benefits (NEB) were included in the cost-effectiveness analysis of the program forecasts. NEB include savings from the customer's perspective, including water savings, deferred maintenance and operational costs, health and safety benefits, avoided supplemental fuels, and other quantifiable benefits apart from avoided energy production. NEB were applied to the energy efficiency forecast at the sector level based on cost-effectiveness analysis of the 2014 portfolio of programs. For a complete list of NEB and sources that Idaho Power currently uses for its program cost-effectiveness, see *Demand-Side Management 2014 Annual Report* and its *Supplement 1: Cost-Effectiveness,* (idahopower.com/EnergyEfficiency/reports.cfm).

The cost-effective analysis methods used at Idaho Power are consistent with published methods and standard practices. Idaho Power relies on the *Electric Power Research Institute End Use Technical Assessment Guide* (TAG) *Understanding Cost-Effectiveness of Energy Efficiency Programs,* and the *California Standard Practice Manual* for the cost-effectiveness methodology. As defined in the TAG and *California Standard Practice Manual*, the TRC and UC tests are most similar to supply-side cost analysis and provide a useful basis to compare demand-side and supply-side resources.

## Resource Development and Evaluation

When developing energy efficiency programs, Idaho Power uses actual data and experiences from other companies in the region, or throughout the country, where applicable, to help identify specific program

parameters. The regional program review is typically accomplished through discussions with other utilities' program managers and research staff. Other program development resources include; E Source, Edison Electrical Institute (EEI), Consortium for Energy Efficiency (CEE), American Council for an Energy Efficient Economy (ACEEE), Advanced Load Control Alliance (ALCA). For other assumptions, including estimated cost, savings, Idaho Power relies on sources, such as the NPCC, the RTF, NEEA, the Database for Energy Efficiency Resources (DEER), third-party consultants, and other regional utilities.

Sometimes Idaho Power launches pilot programs or limited-scale programs; to evaluate estimates or assumptions in the cost-effectiveness model. Pilot programs are designed to measure actual program experiences, including program expenses, savings, and participation. Following implementation of a program, the cost-effectiveness models are reviewed as data from actual program activity becomes available. The program design may be re-examined after program implementation.

All programs are included in an ongoing evaluation schedule where a third-party consultant verifies the claimed savings from the program. Programs are also evaluated to review the program processes to review the effectiveness of the program delivery. If an evaluation determines that savings are less than claimed or that there is potential for improvement in delivery of the program then changes can be made based on the recommendations. Recent evaluations from the 2014 program year can be reviewed in the *Demand-Side Management 2014 Annual Report* and its *Supplement 2: Evaluations*, (idahopower.com/EnergyEfficiency/reports.cfm).

## Planning Assumptions and Alternate Costs

The financial assumptions used in the analysis for the 2015 IRP are consistent with the financial assumptions made for supply-side resources, including the discount rate and cost escalation rates. Table DSM-1 lists the financial assumptions The IRP is also the source of the DSM alternative costs, which is the basis for estimating the value of energy savings and demand reduction resulting from the DSM programs. The DSM alternative costs vary by season and time-of-day. The DSM alternative energy costs are based on either projected fuel costs of a natural gas peaking unit for peak summer hours or forward marginal prices as determined by the AURORAxmp® Electric Market Model. The avoided capacity resource for peak summer hours and for demand response programs is based on a 170 MW natural gas-fired, simple-cycle combustion turbine (SCCT).

The prices of avoided energy throughout the 20-year planning period were simulated using 2015 IRP Portfolio 6b. Portfolio 6b was run assuming 111d sensitivity #5 within the AURORA model. The AURORA model is a production cost tool that simulates hourly economic dispatch and commitment of supply-side, demand-side, and transmission resources. Idaho Power's setup of the AURORA model forecasts electric market prices throughout the Western Electricity Coordinating Council (WECC) region. AURORA also forecasts marginal electricity costs for Idaho Power. Marginal electricity costs are set by the highest variable cost resource that is dispatched in any given forecasted hour. Variable costs include variable O&M and variable fuel costs. Idaho Power modeled hourly, marginal electricity costs for the years 2015 through 2034 to estimate the potential system benefit of avoiding production of the next unit of energy. An initial run of marginal costs are run during the preliminary analysis phase of the IRP process. The preliminary runs will combine updated planning assumptions including load and natural gas price forecasts run against the current preferred resource portfolio from the previous IRP. After the selection of the preferred portfolio which for the 2015 IRP is portfolio 6b, a final run of marginal prices are run which become the avoided energy prices for DSM energy valuation until the next IRP cycle.

The forward prices are placed into five homogenous pricing categories for the convenience of cost-effectiveness calculation the categories follow the pattern of heavy and light load pricing throughout each year of the planning period. The resulting categories include the following:

- Summer On-Peak (SONP)—Average of Idaho Power variable energy and operating costs of a 170 MW SCCT, which is the marginal resource for peak hour load deficits during summertime heavy load hours
- Summer Mid-Peak (SMP)—Average of heavy load prices from June to August (excluding the SONP hours)
- Summer Off-Peak (SOFP)—Average of light load prices from June to August
- Non-Summer Mid-Peak (NSMP)—Average of heavy load prices in January through May and September through December
- Non-Summer Off-Peak (NSOFP)—Average of light load prices in January through May and September through December

The SONP is treated differently than the other four pricing periods when valuing energy efficiency. The estimated levelized capacity cost of a new SCCT is approximately $119 per kW over a 30-year period. The avoided capacity value is spread across the annual SONP hours to estimate the value of energy efficiency savings occurring during the hours. The total SONP hours vary between 512 to 528 hours depending on the year. When the levelized capacity cost of a new SCCT ($119/kW) is multiplied by the Effective Load Carry Capacity (ELCC) of 89 percent which is the estimated percent of top 100 peak load hours that demand response can cover, the annual avoided capacity cost is $106/kW. For demand response or direct load control DSM programs $106 per kW becomes the cost threshold for program cost-effectiveness on an annual per kW basis.

Annual benefits for demand response are also established as part of the IRP process once the value of the 170 MW SCCT is determined. The method for determining cost-effectiveness for demand response programs was updated in 2014 as part of a series of public workshop supporting IPUC Case No. IP-E-13-14 resulting in orders from both the IPUPC (No. 32980) and Oregon (No.13-482). The orders established that through the IRP process IPC will establish an annual operating cost ceiling tied to the levelized annual benefit of a 170-MW SCCT. The updated established annual value for the 2015 IRP is $18.5 million which is an increase from 16.7 million from the 2013 IRP. While the intent of the benefit calculation provides guidance for annual cost limit to operating demand response in years with no anticipated peak deficits, actual 2014 operating costs of demand response programs were considerable less at 10.6 million.

## Forecast and Cost-Effectiveness Data

Table DSM-1 lists the financial assumptions used for the cost-effectiveness analysis and new program screening.

Table DSM-2 shows the results of averaging forward marginal energy prices over the 20-year planning period that were determined as a result of the IRP planning process and selection of the preferred portfolio. The alternate cost prices for energy efficiency measures that have a life longer than the 20-year planning horizon, which is typical for weatherization and building shell measures, are escalated at 2.2 percent annually beyond the planning period.

Tables DSM-3 and DSM-4 show the distribution of the three summer and two non-summer pricing periods across the hours and days of the week and for holidays.

Tables DSM-5 and DSM-6 lists the 20-year cumulative forecasted impact of average energy (aMW) and on-peak reduction (MW) by customer class.

Table DSM-7 details the 20-year estimated utility or program administrator costs to support the achievable potential forecast by customer class.

Table DSM-8 details the 20-year estimated TRC that accounts for both program administration costs and incremental costs to acquire efficient measures and equipments by customers listed by customer class.

Table DSM-9 outlines the 20-year flow of total benefits attributed to energy efficiency programs including NEB associated with the forecast.

Table DSM-10 summarizes the cost-effectiveness analysis for energy efficiency programs through the 20-year IRP planning period.

**Table DSM-1. IRP financial assumptions**

| DSM Analysis Assumptions | |
|---|---|
| **Avoided 30-Year Levelized Capacity Costs** | |
| SCCT | $119/kW |
| **Financial Assumptions** | |
| Weighted average cost of capital (2014 year ending after tax) | 6.74% |
| Financial escalation factor | 2.20% |
| **Transmission Losses** | |
| Non-summer secondary losses | 9.60% |
| Summer peak loss | 9.70% |

**Table DSM-2. DSM alternate costs by pricing period**

| Year | Summer On-Peak* (SONP) | Summer Mid-Peak (SMP) | Summer Off-Peak (SOFP) | Non-Summer Mid-Peak (NSMP) | Non-Summer Off-Peak (NSOFP) |
|---|---|---|---|---|---|
| 2015 | $62.94 | $44.84 | $39.58 | $31.67 | $25.98 |
| 2016 | $59.05 | $40.44 | $31.86 | $33.75 | $27.20 |
| 2017 | $59.90 | $39.64 | $29.55 | $35.44 | $28.21 |
| 2018 | $65.19 | $43.78 | $31.37 | $38.82 | $30.39 |
| 2019 | $69.96 | $43.83 | $32.20 | $38.74 | $30.94 |
| 2020 | $72.48 | $42.68 | $36.40 | $38.06 | $30.90 |
| 2021 | $75.10 | $47.16 | $39.39 | $41.11 | $33.13 |
| 2022 | $77.01 | $49.12 | $41.30 | $43.02 | $34.72 |
| 2023 | $80.16 | $51.53 | $46.42 | $44.43 | $36.23 |
| 2024 | $82.91 | $53.18 | $46.25 | $46.27 | $38.89 |
| 2025 | $85.45 | $48.50 | $40.63 | $47.50 | $40.33 |
| 2026 | $85.22 | $51.66 | $42.84 | $48.75 | $42.18 |
| 2027 | $86.54 | $53.57 | $44.94 | $49.64 | $43.66 |
| 2028 | $89.52 | $55.95 | $46.56 | $51.45 | $45.72 |
| 2029 | $93.32 | $59.08 | $49.66 | $53.69 | $48.05 |
| 2030 | $98.68 | $64.01 | $53.60 | $56.72 | $51.40 |
| 2031 | $103.53 | $64.37 | $56.15 | $58.55 | $53.88 |
| 2032 | $106.22 | $66.04 | $58.74 | $61.52 | $56.57 |
| 2033 | $110.98 | $71.21 | $63.23 | $64.96 | $60.09 |
| 2034 | $119.66 | $78.44 | $67.91 | $68.39 | $62.98 |

* Estimated average annual variable operations and management costs of a 170 MW capacity SCCT.

**Table DSM-3. DSM alternate cost summer pricing periods (June 1–August 31)**

| Hour | Sunday | Monday | Tuesday | Wednesday | Thursday | Friday | Saturday | Holiday |
|---|---|---|---|---|---|---|---|---|
| 1 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 2 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 3 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 4 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 5 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 6 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 7 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 8 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 9 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 10 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 11 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 12 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 13 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 14 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 15 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 16 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 17 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 18 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 19 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 20 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 21 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 22 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 23 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 24 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |

**Table DSM-4. DSM alternate cost non-summer pricing periods (September 1–May 31)**

| Hour | Sunday | Monday | Tuesday | Wednesday | Thursday | Friday | Saturday | Holiday |
|---|---|---|---|---|---|---|---|---|
| 1 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 2 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 3 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 4 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 5 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 6 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 7 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 8 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 9 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 10 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 11 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 12 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 13 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 14 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 15 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 16 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 17 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 18 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 19 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 20 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 21 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 22 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 23 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 24 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |

**Table DSM-5. Cumulative existing energy efficiency forecast 2015–2034**
*(aMW w/transmission losses)*

| Year | Residential | Commercial/Industrial/ Special Contracts | Irrigation | Total |
|---|---|---|---|---|
| 2015 | 3 | 8 | 1 | 12 |
| 2016 | 8 | 17 | 3 | 27 |
| 2017 | 14 | 26 | 4 | 45 |
| 2018 | 21 | 35 | 9 | 65 |
| 2019 | 28 | 46 | 11 | 84 |
| 2020 | 33 | 55 | 13 | 101 |
| 2021 | 38 | 64 | 15 | 117 |
| 2022 | 43 | 74 | 17 | 134 |
| 2023 | 49 | 83 | 19 | 152 |
| 2024 | 55 | 93 | 22 | 169 |
| 2025 | 61 | 102 | 22 | 185 |
| 2026 | 67 | 111 | 22 | 200 |
| 2027 | 73 | 120 | 22 | 215 |
| 2028 | 79 | 129 | 22 | 231 |
| 2029 | 85 | 138 | 23 | 246 |
| 2030 | 91 | 144 | 23 | 257 |
| 2031 | 96 | 150 | 23 | 269 |
| 2032 | 101 | 156 | 23 | 280 |
| 2033 | 106 | 161 | 23 | 290 |
| 2034 | 111 | 167 | 23 | 301 |

**Table DSM-6. Cumulative Energy Efficiency On-Peak Forecast 2015–2034**

| Year | Residential | Commercial/Industrial/ Special Contracts | Irrigation | Total |
|---|---|---|---|---|
| 2015 | 3 | 13 | 4 | 21 |
| 2016 | 9 | 18 | 8 | 35 |
| 2017 | 16 | 36 | 13 | 65 |
| 2018 | 22 | 56 | 25 | 103 |
| 2019 | 17 | 75 | 34 | 126 |
| 2020 | 41 | 87 | 41 | 168 |
| 2021 | 54 | 66 | 49 | 169 |
| 2022 | 55 | 79 | 51 | 185 |
| 2023 | 66 | 114 | 60 | 240 |
| 2024 | 34 | 149 | 69 | 252 |
| 2025 | 67 | 160 | 71 | 299 |
| 2026 | 93 | 170 | 70 | 333 |
| 2027 | 118 | 121 | 73 | 311 |
| 2028 | 107 | 187 | 71 | 366 |
| 2029 | 120 | 209 | 68 | 397 |
| 2030 | 58 | 227 | 72 | 357 |
| 2031 | 114 | 233 | 75 | 422 |
| 2032 | 176 | 156 | 75 | 408 |
| 2033 | 187 | 162 | 76 | 425 |
| 2034 | 175 | 226 | 72 | 473 |

**Table DSM-7. Energy Efficiency Total Utility (Program Administrator) Costs 2015–2034 ($000s)**

| Year | Residential | Commercial/Industrial/ Special Contracts | Irrigation | Total |
|---|---|---|---|---|
| 2015 | $7,055 | $9,469 | $1,467 | $17,991 |
| 2016 | $9,976 | $10,289 | $1,509 | $21,773 |
| 2017 | $12,738 | $11,386 | $1,529 | $25,653 |
| 2018 | $13,667 | $11,539 | $4,878 | $30,085 |
| 2019 | $14,999 | $13,288 | $2,501 | $30,787 |
| 2020 | $13,339 | $12,356 | $2,527 | $28,221 |
| 2021 | $14,535 | $12,302 | $2,576 | $29,413 |
| 2022 | $16,012 | $12,806 | $2,700 | $31,518 |
| 2023 | $17,772 | $13,611 | $2,813 | $34,197 |
| 2024 | $18,220 | $13,886 | $2,902 | $35,009 |
| 2025 | $18,358 | $12,850 | $229 | $31,438 |
| 2026 | $18,771 | $13,405 | $232 | $32,408 |
| 2027 | $19,463 | $13,776 | $267 | $33,506 |
| 2028 | $20,865 | $14,197 | $260 | $35,322 |
| 2029 | $20,510 | $14,352 | $252 | $35,114 |
| 2030 | $18,994 | $9,813 | $228 | $29,035 |
| 2031 | $18,935 | $9,602 | $266 | $28,803 |
| 2032 | $18,928 | $9,742 | $264 | $28,934 |
| 2033 | $18,862 | $9,550 | $272 | $28,684 |
| 2034 | $18,719 | $10,081 | $197 | $28,998 |
| **20-Year NPV** | **$165,579** | **$128,817** | **$18,449** | **$312,845** |

**Table DSM-8. Energy Efficiency Total Resource Costs 2015–2034 ($000s)**

| Year | Residential | Commercial/Industrial/ Special Contracts | Irrigation | Total |
|---|---|---|---|---|
| 2015 | $16,326 | $18,669 | $11,067 | $46,061 |
| 2016 | $29,583 | $20,286 | $11,385 | $61,254 |
| 2017 | $38,737 | $22,450 | $11,533 | $72,720 |
| 2018 | $42,651 | $22,751 | $36,805 | $102,207 |
| 2019 | $42,679 | $26,199 | $18,868 | $87,746 |
| 2020 | $30,400 | $24,361 | $19,067 | $73,829 |
| 2021 | $34,094 | $24,255 | $19,435 | $77,784 |
| 2022 | $38,590 | $25,249 | $20,369 | $84,208 |
| 2023 | $42,024 | $26,837 | $21,228 | $90,089 |
| 2024 | $42,358 | $27,379 | $21,898 | $91,635 |
| 2025 | $47,611 | $25,336 | $1,731 | $74,678 |
| 2026 | $46,892 | $26,430 | $1,752 | $75,074 |
| 2027 | $48,215 | $27,161 | $2,016 | $77,391 |
| 2028 | $52,314 | $27,992 | $1,958 | $82,264 |
| 2029 | $50,857 | $28,297 | $1,900 | $81,054 |
| 2030 | $46,970 | $19,348 | $1,722 | $68,040 |
| 2031 | $47,774 | $18,931 | $2,009 | $68,714 |
| 2032 | $46,959 | $19,208 | $1,994 | $68,161 |
| 2033 | $47,981 | $18,830 | $2,051 | $68,862 |
| 2034 | $44,098 | $19,877 | $1,486 | $65,461 |
| **20-Year NPV** | **$425,360** | **$253,982** | **$139,206** | **$818,548** |

**Table DSM-9. Total Energy Efficiency Benefits 2015–2034 ($000s)**

| Year | Residential | Commercial/Industrial/ Special Contracts | Irrigation | Total |
|---|---|---|---|---|
| 2015 | $21,699 | $36,952 | $14,660 | $73,310 |
| 2016 | $38,766 | $38,720 | $14,574 | $92,061 |
| 2017 | $49,147 | $41,059 | $14,219 | $104,426 |
| 2018 | $52,146 | $52,256 | $43,698 | $148,101 |
| 2019 | $49,827 | $47,230 | $21,487 | $118,544 |
| 2020 | $33,160 | $42,650 | $20,917 | $96,727 |
| 2021 | $35,039 | $40,544 | $20,306 | $95,888 |
| 2022 | $37,416 | $40,278 | $20,249 | $97,943 |
| 2023 | $38,390 | $40,571 | $20,011 | $98,971 |
| 2024 | $36,462 | $39,329 | $19,573 | $95,364 |
| 2025 | $38,695 | $27,735 | $1,465 | $67,895 |
| 2026 | $35,732 | $27,415 | $1,403 | $64,550 |
| 2027 | $34,540 | $26,725 | $1,526 | $62,790 |
| 2028 | $35,273 | $26,015 | $1,401 | $62,690 |
| 2029 | $32,236 | $24,768 | $1,283 | $58,287 |
| 2030 | $27,963 | $15,185 | $1,097 | $44,244 |
| 2031 | $26,665 | $13,946 | $1,204 | $41,814 |
| 2032 | $24,523 | $13,256 | $1,121 | $38,901 |
| 2033 | $23,395 | $12,098 | $1,081 | $36,574 |
| 2034 | $20,077 | $11,902 | $734 | $32,712 |
| **20-Year NPV** | **$691,151** | **$618,633** | **$222,009** | **$1,531,793** |

**Table DSM-10. Total energy efficiency cost-effectiveness summary**

| | 2034 Load Reduction (aMW) | Utility Costs ($000s) (20-Year NPV) | Resource Costs ($000s) (20-Year NPV) | Total Benefits ($000s) (20-Year NPV) | TRC: Benefit/ Cost Ratio | TRC Levelized Costs (cents/kWh) |
|---|---|---|---|---|---|---|
| Residential | 111 | $165,579 | $425,360 | $691,151 | 1.6 | 9.8 |
| Industrial/Commercial/ Special Contract | 167 | $128,817 | $253,982 | $618,633 | 2.4 | 3.3 |
| Irrigation | 23 | $18,449 | $139,206 | $222,009 | 1.6 | 10.3 |
| **Total** | **301** | **$312,845** | **$818,548** | **$1,531,793** | **1.9** | **6.1** |

# SUPPLY-SIDE RESOURCE DATA

## Key Financial and Forecast Assumptions

| Financing Cap Structure and Cost | |
|---|---|
| **Composition** | |
| Debt | 50.04% |
| Preferred | 0.00% |
| Common | 49.96% |
| **Total** | **100.00%** |
| **Cost** | |
| Debt | 5.73% |
| Preferred | 0.00% |
| Common | 10.00% |
| Average Weighted Cost | 7.86% |

| Financial Assumptions and Factors | |
|---|---|
| Plant operating (book) life | Expected Life of the Asset |
| Discount rate (weighted average cost of capital[1]) | 6.74% |
| Composite tax rate | 39.10% |
| Deferred rate | 35.00% |
| General O&M escalation rate | 2.20% |
| Annual property tax rate (% of investment) | 0.29% |
| Property tax escalation rate | 3.00% |
| Annual insurance premiums (% of investment) | 0.31% |
| Insurance escalation rate | 2.00% |
| AFUDC rate (annual) | 7.75% |

[1] Incorporates tax effects.

| Emission Intensity Rate (lbs per MWh by technology) | |
|---|---|
| | $CO_2$ |
| Small aeroderivative SCCT | 1,115 |
| Large aeroderivative SCCT | 1,047 |
| Large frame SCCT | 1,413 |
| CCCT 1x1 | 809 |
| CCCT 2x1 | 809 |
| Combined heat and power (CHP) | 1,115 |
| Distributed generation–gas fired | 1,115 |
| Pulverized coal | 1,901 |
| IGCC | 2,279 |
| IGCC w/carbon sequestration | 421 |

| Fuel Forecast Base Case (Nominal, $ per MMBtu) | | | |
|---|---|---|---|
| **Year** | **Natural Gas** | **Generic Coal** | **Nuclear** |
| 2015 | $5.10 | $1.47 | $0.51 |
| 2016 | $4.70 | $1.52 | $0.52 |
| 2017 | $4.76 | $1.55 | $0.53 |
| 2018 | $5.25 | $1.58 | $0.54 |
| 2019 | $5.69 | $1.61 | $0.56 |
| 2020 | $5.91 | $1.64 | $0.57 |
| 2021 | $6.14 | $1.69 | $0.58 |
| 2022 | $6.30 | $1.74 | $0.59 |
| 2023 | $6.58 | $1.78 | $0.61 |
| 2024 | $6.82 | $1.83 | $0.62 |
| 2025 | $7.04 | $1.87 | $0.63 |
| 2026 | $6.99 | $1.91 | $0.65 |
| 2027 | $7.09 | $1.98 | $0.66 |
| 2028 | $7.35 | $2.00 | $0.68 |
| 2029 | $7.69 | $2.07 | $0.69 |
| 2030 | $8.18 | $2.12 | $0.71 |
| 2031 | $8.62 | $2.16 | $0.72 |
| 2032 | $8.85 | $2.21 | $0.74 |
| 2033 | $9.28 | $2.27 | $0.75 |
| 2034 | $10.09 | $2.32 | $0.77 |
| 2035 | $10.15 | $2.34 | $0.79 |
| 2036 | $10.21 | $2.35 | $0.81 |
| 2037 | $10.27 | $2.37 | $0.82 |
| 2038 | $10.33 | $2.38 | $0.83 |
| 2039 | $10.39 | $2.39 | $0.83 |
| 2040 | $10.46 | $2.41 | $0.84 |
| 2041 | $10.52 | $2.42 | $0.84 |
| 2042 | $10.58 | $2.44 | $0.85 |
| 2043 | $10.65 | $2.45 | $0.85 |
| 2044 | $10.71 | $2.47 | $0.86 |

# Cost Inputs and Operating Assumptions

(All costs in 2015 dollars)

| Supply-Side Resources | Plant Capacity (MW) | Plant Capital ($/kW)[1,3] | Transmission Capital $/kW | Total Capital $/kW | Total Investment $/kW[2] | Fixed O&M $/kW[3] | Variable O&M $/kW | Other $/MWh | Heat Rate Btu/kWh | Economic Life |
|---|---|---|---|---|---|---|---|---|---|---|
| Advanced Nuclear (250 MW) | 1,100 | 4,350 | 441 | $4,791 | $7,266 | 95 | 0 | 0 | 10,450 | 40 |
| Battery Storage (6 MW) | 6 | 3,000 | 0 | $3,000 | $3,059 | 28 | 0 | 0 | NA | 10 |
| Biomass Direct—Woody Residue (35 MW) | 35 | 2,622 | 357 | $2,979 | $3,189 | 95 | 15 | 0 | 14,500 | 30 |
| Biomass Indirect—Anaerobic Digester (3 MW) | 3 | 4,761 | 133 | $4,894 | $5,239 | 43 | 14 | 0 | 10,250 | 25 |
| Boardman to Hemingway (350 MW) | 350 | 0 | 703 | $703 | $703 | 0 | 0 | 0 | NA | 55 |
| Canal Drop Hydro (1.28 MW) | 1 | 3,600 | 70 | $3,670 | $4,371 | 20 | 0 | 0 | NA | 75 |
| CCCT (1x1) F Class with Duct Firing (270 MW) | 270 | 1,145 | 122 | $1,267 | $1,484 | 8 | 2 | 0 | 6,714 | 30 |
| CCCT (2x1) F Class (580 MW) | 580 | 899 | 101 | $1,000 | $1,172 | 6 | 4 | 0 | 6,700 | 30 |
| CHP (45 MW) | 45 | 2,123 | 57 | $2,180 | $2,334 | 47 | 5 | 0 | 6,060 | 40 |
| IGCC (580 MW) | 580 | 3,257 | 745 | $4,002 | $4,773 | 62 | 7 | 0 | 8,800 | 35 |
| IGCC with Carbon Capture (580 MW) | 580 | 6,390 | 744 | $7,134 | $8,510 | 73 | 9 | 0 | 10,520 | 35 |
| Geothermal (30 MW) | 30 | 4,021 | 850 | $4,871 | $5,402 | 0 | 30 | 0 | NA | 25 |
| ICE Thermal Storage (10 MW) | 10 | 1,500 | 0 | $1,500 | $1,529 | 30 | 0 | 0 | NA | 20 |
| Pumped Storage (150 MW) | 150 | 5,000 | 1,095 | $6,095 | $7,259 | 20 | 0 | 0 | NA | 50 |
| Reciprocating Gas Engine (18.8 MW) | 19 | 500 | 73 | $573 | $610 | 2 | 4 | 0 | 7,329 | 40 |
| SCCT—Aeroderivative (47 MW) | 47 | 1,000 | 46 | $1,046 | $1,114 | 25 | 8 | 0 | 9,000 | 35 |
| SCCT—Frame F Class (170 MW) | 170 | 800 | 194 | $994 | $1,059 | 5 | 5 | 0 | 10,300 | 35 |
| Shoshone Falls Upgrade (49.5 MW) | 50 | 2,255 | 269 | $2,524 | $2,825 | 2 | 0 | 0 | NA | 75 |
| Small Modular Nuclear (250 MW) | 600 | 5,000 | 520 | $5,520 | $8,371 | 0 | 23 | 0 | 11,493 | 40 |
| Solar Power Tower (110 MW) | 110 | 6,250 | 330 | $6,580 | $7,710 | 82 | 3 | 6 | NA | 20 |
| Solar PV—Distr Residential Fixed S (10 MW) | 10 | 3,500 | 0 | $3,500 | $3,639 | 25 | 0 | 6 | NA | 20 |
| Solar PV—Distr C&I Fixed S (10 MW) | 10 | 2,500 | 0 | $2,500 | $2,599 | 13 | 0 | 6 | NA | 20 |
| Solar PV—Distr C&I Fixed SW (10 MW) | 10 | 2,500 | 0 | $2,500 | $2,599 | 13 | 0 | 6 | NA | 20 |
| Solar PV—Utility Scale Fixed S (10 MW) | 10 | 1,500 | 305 | $1,805 | $1,877 | 13 | 0 | 6 | NA | 20 |
| Solar PV—Utility Scale Fixed SW (10 MW) | 10 | 1,500 | 305 | $1,805 | $1,877 | 13 | 0 | 6 | NA | 20 |
| Solar PV—Utility Scale 1-Axis Tracking (10 MW) | 10 | 1,750 | 305 | $2,055 | $2,136 | 20 | 0 | 6 | NA | 20 |
| Solar PV—Utility Scale 2-Axis Tracking (10 MW) | 10 | 1,860 | 305 | $2,165 | $2,251 | 24 | 0 | 6 | NA | 20 |
| TurboPhase (23.6 MW) | 24 | 400 | 0 | $400 | $403 | 0 | 4 | 0 | 7,824 | 35 |
| Wind (100 MW) | 100 | 1,800 | 330 | $2,130 | $2,276 | 40 | 0 | 15 | NA | 25 |

[1] Plant costs include engineering development costs, generating and ancillary equipment purchase, and installation costs, as well as balance of plant construction.

[2] Total Investment includes capital costs and AFUDC.

[3] Fixed O&M excludes property taxes and insurance (separately calculated within the levelized resource cost analysis)

# Transmission Cost Assumptions

## *Cost Assumptions by Supply-Side Resource Type*

| Capacity (MW Rating) | Overnight Transmission Capital Cost/kW[1] | Cost Assumptions Notes | Local Interconnection Assumptions | Backbone Transmission Assumptions |
|---|---|---|---|---|
| Battery Storage | | | | |
| 6 | $0 | Assume location in or near existing substation. | No transmission upgrades required. | No backbone upgrades required. |
| Biomass Direct—Woody Residue | | | | |
| 35 | $357 | Assume a 20-mile, 138-kV line to existing Idaho Power 138-kV substation. Add 3 new 138-kV terminals. Assume $250k in communications upgrades. | Assume a 20-mile, 138-kV line interconnection to existing Idaho Power 138-kV substation. Add 3 new 138-kV terminals. Assume $250k in communications upgrades. | No backbone upgrades required. |
| Biomass Indirect—Anaerobic Digester | | | | |
| 3 | $133 | Assume distribution feeder location with no backbone transmission upgrades required. | Assume $300k of distribution feeder upgrades and $100k in substation upgrades. | No backbone upgrades required. |
| Coal—Integrated Gasification Combined Cycle (IGCC) | | | | |
| 580 | $745 | Assume resource is located close to future 500-kV Aeolus substation. Pro-rated share of 3000 MW Gateway West project, with estimated toal cost of $2.19 billion. | Assume resource is located close to future 500-kV Aeolus substation. Assume 2 new terminals at 500-kV substation. | Pro-rata share of Gateway. |
| Coal—IGCC with Carbon Capture and Sequestration | | | | |
| 600 | $744 | Assume resource is located close to future 500-kV Aeolus substation. Pro-rated share of 3000 MW Gateway West project, with estimated toal cost of $2.19 billion . | Assume resource is located close to future 500-kV Aeolus substation. Assume 2 new terminals at 500-kV substation. | Pro-rata share of Gateway. |
| Geothermal (binary-cycle)—Idaho | | | | |
| 30 | $850 | Assume Raft River area. Requires 45-mile, 138-kV line to existing Minidoka substation. Assume capacity fits on existing backbone. | New 45-mile, 138-kV line to Minidoka substation with new 138-kV substation line terminal bay. | No backbone upgrades required. |
| Hydro—Canal Drop (Seasonal) | | | | |
| 10 | $70 | Assume 46-kV sub-transmission or local feeder interconnection. Feeder rebuild or 46-kV upgrade would likely be required. | Assume 4 miles of distribution rebuild at $150k per mile plus $100k in substation upgrades. | No backbone upgrades required. |
| Hydro—Shoshone Falls Expansion | | | | |
| 50 | $269 | Line and station modifications required. New substation above existing power plant. | Assume $2 million for transmission line modifications, $7 million for station upgrades, and $4.3 million for Cliff substation modifications. | Part of Generation Interconnect Cluster Study. No further backbone upgrades required. |
| Hydro—Hydrokinetic (In stream) | | | | |
| 1 | $100 | Assume minor upgrades required to distribution feeder or substation. | Assume $100k in substation upgrades. | No backbone upgrades required. |
| ICE Thermal Storage | | | | |
| 10 | $0 | No transmission upgrades required. | No transmission upgrades required. | No backbone upgrades required. |
| Natural Gas—Simple Cycle Combustion Turbine (SCCT) Aeroderivative | | | | |
| 47 | $46 | Assume plant located at or near existing Bennett Mountain plant. Capacity would fit within existing transmission system between Bennett Mountain and Boise. | New 230-kV substation terminal and station modifications. | No backbone upgrades required. |

| Capacity (MW Rating) | Overnight Transmission Capital Cost/kW[1] | Cost Assumptions Notes | Local Interconnection Assumptions | Backbone Transmission Assumptions |
|---|---|---|---|---|
| Natural Gas—SCCT Frame F Class (Idaho Power's peaker plants use this technology) | | | | |
| 170 | $194 | Build new facility south of Boise (assume Simco Road area) with new 230-kV switching station; 22-mile, 230-kV line to Boise Bench Substation, and 230-kV double circuit in/out of Danskin–Hubbard 230-kV line. | New 230-kV switching station with a 22-mile, 230-kV line to Boise Bench Substation and 1 mile, 23-kV double circuit in/out of Danksin–Hubbard 230-kV line. | No backbone upgrades required. |
| Natural Gas—Reciprocating Gas Engine Wartsila 34SG | | | | |
| 4.1 | $73 | Assume distribution feeder location with no backbone transmission upgrades required. | Assume $300k of distribution feeder upgrades. | No backbone upgrades required. |
| Natural Gas—CCCT (1x1) F Class with Duct Firing | | | | |
| 270 | $122 | Build new facility south of Boise (assume Simco Road area) with new 230-kV switching station; 22-mile, 230-kV line to Boise Bench Substation, and 230-kV double circuit in/out of Danskin–Hubbard 230-kV line. | New 230-kV switching station with a 22-mile, 230-kV line to Boise Bench Substation and 1 mile, 23-kV double circuit in/out of Danksin–Hubbard 230-kV line. | No backbone upgrades required. |
| Natural Gas—CCCT (2x1) F Class | | | | |
| 580 | $101 | Build new facility south of Boise (assume Simco Road area) with new 230-kV switching station; 22-mile, 230-kV line to Boise Bench Substation, and 230-kV double circuit in/out of Danskin–Hubbard 230-kV line. | New 230-kV switching station with a 22-mile; 230-kV line to Boise Bench Substation and 28-mile, 230-kV line to Hubbard Substation. | No backbone upgrades required. Entire project assumed as backbone upgrade. |
| Natural Gas—Combined Heat and Power (CHP) | | | | |
| 45 | $57 | Assume 0.5 mile tap to existing 138-kV line and new 138-kV source substation (or large upgrade to existing substation). | Assume 0.5 mile tap to existing 138-kV line and new 138-kV source substation. | No backbone upgrades required. |
| Nuclear—Small Modular Reactor (SMR) | | | | |
| 45 | $358 | Tie into nearby 230-kV transmission substation. Backbone transmission uprgrades required. | Assume 2 mile, 138-kV interconnection to existing Antelope substation and one new 138-kV terminal. | Pro rata share of Gateway West upgrade from Populus to Cedar Hill to Hemingway. Assume 2.5% ownership of the 280-mile Gateway West segments from Populus to Cedar Hill and Cedar Hill to Hemingway. |
| Nuclear—SMR | | | | |
| 250 | $520 | Tie into nearby 230-kV transmission substation. Build new 55 mile, 230-kV line. Backbone transmission uprgrades required. | Two 2-mile, 138-kV lines to interconnect to Antelope Substation. New 230-kV transformer terminal. New parallel 55-mile, 230-kV line from Antelope to Brady Substation. New 230-kV terminal at Brady Substation. | Pro rata share of Gateway West upgrade from Populus to Cedar hill to Hemingway. Assume 12.5% ownership of the 280-mile Gateway West segments from Populus to Cedar Hill and Cedar Hill to Hemingway. |
| Nuclear—Advanced Nuclear | | | | |
| 1,100 | $441 | Two new 345kV transmission lines required. One 55 mile line from site to Borah Substation. One 85 mile line from site to Kinport Substation via Goshen Substation. | New 345 kV station. New 55 mile 345kV transmission line to existing Borah substation and new 345kV line terminal. New 85 mile transmission line to existing Kinport Substation through existing Goshen Substation and three new 345 kV line terminals. | Pro rata share of Gateway West upgrade from Populus to Cedar hill to Hemingway. Assume 50% ownership of the 280 mile Gateway West segments from Populus to Cedar Hill and Cedar Hill to Hemingway. |
| Pumped Storage—new upper reservoir and new generation/pumping plant (pumping water from an existing lower reservoir to a new upper reservoir then running the water through a new power plant) | | | | |
| 100 | $1,095 | Tie into existing Oxbow 230-/ 138-kV switchyard. New 230-kV transmission line required from Oxbow to Treasure Valley (no existing backbone capacity). | Assume 0.5 mile tap off of Oxbow 138-kV line. | New 110 mile, 230-kV line from Oxbow to Treasure Valley. |

| Capacity (MW Rating) | Overnight Transmission Capital Cost/kW[1] | Cost Assumptions Notes | Local Interconnection Assumptions | Backbone Transmission Assumptions |
|---|---|---|---|---|
| Solar Thermal—Solar Power Tower with storage | | | | |
| 100 | $330 | Assume Mountain Home desert area with 20-mile, 138-kV line to new substation intersecting existing Danskin—Hubbard 230-kV line. | New 230-kV switching station with a 22-mile, 230-kV line to Boise Bench Substation and 1-mile, 230-kV double circuit in/out of Danskin–Hubbard 230-kV line. | No backbone upgrades required. |
| Solar PV—Distributed Residential Fixed-Tilt (S Orientation) | | | | |
| 10 | $0 | Assume that no upgrades are required for small residential installations. | Assume that no upgrades are required for small residential installations. | No backbone upgrades required. |
| Solar PV—Distributed C&I Fixed-Tilt (S Orientation) | | | | |
| 10 | $0 | Assume that no upgrades are required for small C&I installations. | Assume that no upgrades are required for small C&I installations. | No backbone upgrades required. |
| Solar PV—Distributed C&I Fixed-Tilt (SW Orientation) | | | | |
| 10 | $0 | Assume that no upgrades are required for small C&I installations. | Assume that no upgrades are required for small C&I installations. | No backbone upgrades required. |
| Solar PV—Utility Scale Fixed-Tilt (S Orientation) | | | | |
| 10 | $305 | Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250k communication infrastructure upgrades. | Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250 communication infrastructure upgrades. | Assume that no backbone upgrades are required for 10 MW (depending on point in time, assumption may not be valid if PURPA projects are constructed in the same geographic area). |
| Solar PV—Utility Scale Fixed-Tilt (SW Orientation) | | | | |
| 10 | $305 | Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250k communication infrastructure upgrades. | Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250 communication infrastructure upgrades. | Assume that no backbone upgrades are required for 10 MW (depending on point in time, assumption may not be valid if PURPA projects are constructed in the same geographic area). |
| Solar PV—Utility Scale 1-Axis Tracking | | | | |
| 10 | $305 | Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250k communication infrastructure upgrades. | Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250 communication infrastructure upgrades. | Assume that no backbone upgrades are required for 10 MW (depending on point in time, assumption may not be valid if PURPA projects are constructed in the same geographic area). |
| Solar PV—Utility Scale 2-Axis Tracking | | | | |
| 10 | $305 | Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250k communication infrastructure upgrades. | Assume 1 mile, 138-kV interconnection to existing 138-kV transmission line. One 138-kV line terminal. Assume $250 communication infrastructure upgrades. | Assume that no backbone upgrades are required for 10 MW (depending on point in time, assumption may not be valid if PURPA projects are constructed in the same geographic area). |
| Transmission—Boardman to Hemingway | | | | |
| Inbound<br>350—Average<br>500—Summer<br>350—Winter | $711 | Per the B2H Funding Agreement, Idaho Power's share of the project is roughly 21.2% of total project cost. Assume approximately $16 million in B2H 230-kV integration costs. | New 230-kV transmission circuit from Hemingway Substation to Bowmont Substation. New 230-kV line from Bowmont Substation to Hubbard Substation and 138-kV line re-configuration. | Pro-rata share of B2H project. |
| Wind—Idaho | | | | |
| 100 | $330 | Assume location near Midpoint Substation or Justice Substation. Estimated $1.5 million for upgrades at Midpoint or Justice Substation plus 100 MW pro-rata share of 2,000-MW Gateway West 500-kV project from Midpoint/Cedar Hill Substation to Hemingway Substation. | Assume 10 miles of 138-kV local transmission to project site with 138-kV substation and 138-/ 230-kV transformer. | Assume $1.5 million for upgrades at Midpoint Substation or Justice Substation. Assume 5% share of estimated $425 million Gateway West 500kV project from Midpoint/Cedar Hill Substation to Hemingway Substation. |

# Levelized Cost of Production

**30-Year Levelized Cost of Production (at stated capacity factors)**

| Supply-Side Resources | Cost of Capital | Non-Fuel O&M[1] | Fuel | Wholesale Energy | Net of Tax Credit/Steam sales/Integration | Total Cost per MWh | Capacity Factor |
|---|---|---|---|---|---|---|---|
| Advanced Nuclear (250 MW) | $88 | $25 | $7 | $0 | $0 | $119 | 90% |
| Battery Storage (6 MW) | $216 | $24 | $0 | $46 | $0 | $285 | 25% |
| Biomass Direct—Woody Residue (35 MW) | $44 | $40 | $19 | $0 | $0 | $102 | 85% |
| Biomass Indirect— Anaerobic Digester (3 MW) | $87 | $33 | $0 | $0 | $0 | $119 | 75% |
| Boardman to Hemingway (350 MW) | $21 | $2 | $0 | $54 | $0 | $78 | 33% |
| Canal Drop Hydro (1.28 MW) | $135 | $24 | $0 | $0 | $0 | $159 | 33% |
| CCCT (1x1) F Class with Duct Firing (270 MW) | $25 | $6 | $49 | $0 | $0 | $79 | 70% |
| CCCT (2x1) F Class (580 MW) | $20 | $7 | $48 | $0 | $0 | $75 | 70% |
| CHP (45 MW) | $32 | $19 | $46 | $0 | -$16 | $81 | 80% |
| IGCC (580 MW) | $71 | $28 | $17 | $0 | $0 | $116 | 75% |
| IGCC with Carbon Capture (580 MW) | $127 | $37 | $21 | $0 | $0 | $184 | 75% |
| Geothermal (30 MW) | $64 | $43 | $0 | $0 | -$6 | $101 | 90% |
| ICE Thermal Storage (10 MW) | $171 | $53 | $0 | $0 | $0 | $224 | 10% |
| Pumped Storage (150 MW) | $304 | $42 | $0 | $57 | $0 | $403 | 25% |
| Reciprocating Gas Engine (18.8 MW) | $66 | $14 | $55 | $0 | $0 | $136 | 10% |
| SCCT—Aeroderivative (47 MW) | $124 | $59 | $67 | $0 | $0 | $250 | 10% |
| SCCT—Frame F Class (170 MW) | $118 | $24 | $76 | $0 | $0 | $219 | 10% |
| Shoshone Falls Upgrade (49.5 MW) | $66 | $8 | $0 | $0 | $0 | $74 | 43% |
| Small Modular Nuclear (250 MW) | $96 | $39 | $208 | $0 | $0 | $343 | 95% |
| Solar Power Tower (110 MW) | $325 | $69 | $0 | $0 | -$21 | $372 | 28% |
| Solar PV—Distr Residential Fixed S (10 MW) | $212 | $33 | $0 | $0 | -$11 | $234 | 20% |
| Solar PV—Distr C&I Fixed S (10 MW) | $148 | $20 | $0 | $0 | -$6 | $162 | 21% |
| Solar PV—Distr C&I Fixed SW (10 MW) | $155 | $21 | $0 | $0 | -$6 | $170 | 20% |
| Solar PV—Utility Scale Fixed S (10 MW) | $103 | $16 | $0 | $0 | -$2 | $118 | 21% |
| Solar PV—Utility Scale Fixed SW (10 MW) | $109 | $17 | $0 | $0 | -$2 | $124 | 20% |
| Solar PV—Utility Scale 1-Axis Tracking (10 MW) | $92 | $17 | $0 | $0 | -$1 | $109 | 27% |
| Solar PV—Utility Scale 2-Axis Tracking (10 MW) | $88 | $18 | $0 | $0 | $0 | $105 | 30% |
| TurboPhase (23.6 MW) | $45 | $8 | $58 | $0 | $0 | $111 | 10% |
| Wind (100 MW) | $86 | $28 | $0 | $0 | $21 | $135 | 28% |

[1] Non Fuel O&M includes fixed and variable costs, property taxes.

| 30-Year Levelized Capacity (fixed) Cost per kW/Month | | | | | |
|---|---|---|---|---|---|
| **Supply-Side Resources** | **Cost of Capital** | **Non-Fuel O&M** | **Fuel** | **Net of Tax Credit/Steam sales/Integration** | **Total Cost per kW** |
| Advanced Nuclear (250 MW) | $57 | $16 | $0 | $0 | $73 |
| Battery Storage (6 MW) | $39 | $4 | $0 | $0 | $44 |
| Biomass Direct—Woody Residue (35 MW) | $27 | $12 | $0 | $0 | $40 |
| Biomass Indirect—Anaerobic Digester (3 MW) | $48 | $8 | $0 | $0 | $55 |
| Boardman to Hemingway (350 MW) | $5 | $1 | $0 | $0 | $6 |
| Canal Drop Hydro (1.28 MW) | $32 | $6 | $0 | $0 | $38 |
| CCCT (1x1) F Class with Duct Firing (270 MW) | $13 | $2 | $0 | $0 | $14 |
| CCCT (2x1) F Class (580 MW) | $10 | $1 | $0 | $0 | $11 |
| CHP (45 MW) | $18 | $7 | $0 | $0 | $26 |
| IGCC (580 MW) | $39 | $10 | $0 | $0 | $49 |
| IGCC with Carbon Capture (580 MW) | $69 | $14 | $0 | $0 | $83 |
| Geothermal (30 MW) | $42 | $0 | $0 | $0 | $42 |
| ICE Thermal Storage (10 MW) | $13 | $4 | $0 | $0 | $17 |
| Pumped Storage (150 MW) | $55 | $8 | $0 | $0 | $63 |
| Reciprocating Gas Engine (18.8 MW) | $5 | $1 | $0 | $0 | $5 |
| SCCT—Aeroderivative (47 MW) | $9 | $4 | $0 | $0 | $13 |
| SCCT—Frame F Class (170 MW) | $9 | $1 | $0 | $0 | $10 |
| Shoshone Falls Upgrade (49.5 MW) | $21 | $2 | $0 | $0 | $23 |
| Small Modular Nuclear (250 MW) | $66 | $6 | $0 | $0 | $72 |
| Solar Power Tower (110 MW) | $66 | $7 | $0 | $0 | $73 |
| Solar PV—Distr Residential Fixed S (10 MW) | $31 | $2 | $0 | $0 | $33 |
| Solar PV—Distr C&I Fixed S (10 MW) | $22 | $1 | $0 | $0 | $23 |
| Solar PV—Distr C&I Fixed SW (10 MW) | $22 | $1 | $0 | $0 | $23 |
| Solar PV—Utility Scale Fixed S (10 MW) | $16 | $1 | $0 | $0 | $17 |
| Solar PV—Utility Scale Fixed SW (10 MW) | $16 | $1 | $0 | $0 | $17 |
| Solar PV—Utility Scale 1-Axis Tracking (10 MW) | $18 | $2 | $0 | $0 | $20 |
| Solar PV—Utility Scale 2-Axis Tracking (10 MW) | $19 | $2 | $0 | $0 | $21 |
| TurboPhase (23.6 MW) | $3 | $0 | $0 | $0 | $4 |
| Wind (100 MW) | $18 | $6 | $0 | $0 | $23 |

## Peak-Hour Capacity Credit (Contribution to Peak)—Solar and Wind Resources

Peak hour capacity credit (contribution to peak) for new IRP intermittent generation resources:

| New IRP intermittent generation—Peak hour capacity credit | |
|---|---|
| **Resource** | **Peak Hour Capacity Credit** |
| PV solar south orientation | 28.4% |
| PV solar southwest orientation | 45.4% |
| PV solar single-axis tracking | 51.3% |
| Wind | 5.0% |

# Energy Shape—Solar

## *2015 IRP Assumed Solar Capacity Factors*

| Month | Utility Scale, Single Axis Tracking | Residential, Fixed Tilt |
|---|---|---|
| January | 12% | 7% |
| February | 19% | 11% |
| March | 26% | 16% |
| April | 32% | 20% |
| May | 37% | 23% |
| June | 41% | 25% |
| July | 42% | 26% |
| August | 39% | 24% |
| September | 33% | 20% |
| October | 25% | 16% |
| November | 14% | 9% |
| December | 11% | 7% |
| **Annual Capacity Factor** | **27.5%** | **17.0%** |

# Schedule 87—Integration Costs for Solar and Wind Resources

## *Solar*

| 0–100 MW Solar Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates* |
| 2014 | 0.54 | 2014 | 0.43 |
| 2015 | 0.56 | 2015 | 0.44 |
| 2016 | 0.58 | 2016 | 0.46 |
| 2017 | 0.59 | 2017 | 0.47 |
| 2018 | 0.61 | 2018 | 0.48 |
| 2019 | 0.63 | 2019 | 0.50 |
| | | 2020 | 0.51 |
| | | 2021 | 0.53 |
| | | 2022 | 0.54 |
| | | 2023 | 0.56 |
| | | 2024 | 0.58 |
| | | 2025 | 0.60 |
| | | 2026 | 0.61 |
| | | 2027 | 0.63 |
| | | 2028 | 0.65 |
| | | 2029 | 0.67 |
| | | 2030 | 0.69 |
| | | 2031 | 0.71 |
| | | 2032 | 0.73 |
| | | 2033 | 0.75 |
| | | 2034 | 0.78 |
| | | 2035 | 0.80 |
| | | 2036 | 0.82 |
| | | 2037 | 0.85 |
| | | 2038 | 0.87 |
| | | 2039 | 0.90 |

*$/MWh

| 101–200 MW Solar Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 1.49 | 2014 | 1.18 |
| 2015 | 1.53 | 2015 | 1.22 |
| 2016 | 1.58 | 2016 | 1.25 |
| 2017 | 1.63 | 2017 | 1.29 |
| 2018 | 1.68 | 2018 | 1.33 |
| 2019 | 1.73 | 2019 | 1.37 |
| | | 2020 | 1.41 |
| | | 2021 | 1.45 |
| | | 2022 | 1.50 |
| | | 2023 | 1.54 |
| | | 2024 | 1.59 |
| | | 2025 | 1.63 |
| | | 2026 | 1.68 |
| | | 2027 | 1.73 |
| | | 2028 | 1.79 |
| | | 2029 | 1.84 |
| | | 2030 | 1.89 |
| | | 2031 | 1.95 |
| | | 2032 | 2.01 |
| | | 2033 | 2.07 |
| | | 2034 | 2.13 |
| | | 2035 | 2.20 |
| | | 2036 | 2.26 |
| | | 2037 | 2.33 |
| | | 2038 | 2.40 |
| | | 2039 | 2.47 |

*$/MWh

| 201–300 MW Solar Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 2.32 | 2014 | 1.84 |
| 2015 | 2.39 | 2015 | 1.89 |
| 2016 | 2.46 | 2016 | 1.95 |
| 2017 | 2.54 | 2017 | 2.01 |
| 2018 | 2.61 | 2018 | 2.07 |
| 2019 | 2.69 | 2019 | 2.13 |
| | | 2020 | 2.20 |
| | | 2021 | 2.26 |
| | | 2022 | 2.33 |
| | | 2023 | 2.40 |
| | | 2024 | 2.47 |
| | | 2025 | 2.55 |
| | | 2026 | 2.62 |
| | | 2027 | 2.70 |
| | | 2028 | 2.78 |
| | | 2029 | 2.87 |
| | | 2030 | 2.95 |
| | | 2031 | 3.04 |
| | | 2032 | 3.13 |
| | | 2033 | 3.23 |
| | | 2034 | 3.32 |
| | | 2035 | 3.42 |
| | | 2036 | 3.52 |
| | | 2037 | 3.63 |
| | | 2038 | 3.74 |
| | | 2039 | 3.85 |

*$/MWh

| 301–400 MW Solar Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 3.12 | 2014 | 2.48 |
| 2015 | 3.22 | 2015 | 2.55 |
| 2016 | 3.32 | 2016 | 2.63 |
| 2017 | 3.41 | 2017 | 2.71 |
| 2018 | 3.52 | 2018 | 2.79 |
| 2019 | 3.62 | 2019 | 2.87 |
| | | 2020 | 2.96 |
| | | 2021 | 3.05 |
| | | 2022 | 3.14 |
| | | 2023 | 3.23 |
| | | 2024 | 3.33 |
| | | 2025 | 3.43 |
| | | 2026 | 3.53 |
| | | 2027 | 3.64 |
| | | 2028 | 3.75 |
| | | 2029 | 3.86 |
| | | 2030 | 3.97 |
| | | 2031 | 4.09 |
| | | 2032 | 4.22 |
| | | 2033 | 4.34 |
| | | 2034 | 4.47 |
| | | 2035 | 4.61 |
| | | 2036 | 4.75 |
| | | 2037 | 4.89 |
| | | 2038 | 5.03 |
| | | 2039 | 5.19 |

*$/MWh

| 401–500 MW Solar Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 3.94 | 2014 | 3.12 |
| 2015 | 4.06 | 2015 | 3.22 |
| 2016 | 4.18 | 2016 | 3.31 |
| 2017 | 4.31 | 2017 | 3.41 |
| 2018 | 4.44 | 2018 | 3.52 |
| 2019 | 4.57 | 2019 | 3.62 |
| | | 2020 | 3.73 |
| | | 2021 | 3.84 |
| | | 2022 | 3.96 |
| | | 2023 | 4.08 |
| | | 2024 | 4.20 |
| | | 2025 | 4.32 |
| | | 2026 | 4.45 |
| | | 2027 | 4.59 |
| | | 2028 | 4.72 |
| | | 2029 | 4.87 |
| | | 2030 | 5.01 |
| | | 2031 | 5.16 |
| | | 2032 | 5.32 |
| | | 2033 | 5.48 |
| | | 2034 | 5.64 |
| | | 2035 | 5.81 |
| | | 2036 | 5.98 |
| | | 2037 | 6.16 |
| | | 2038 | 6.35 |
| | | 2039 | 6.54 |

*$/MWh

**501–600 MW Solar Capacity Penetration Level**

| Levelized | | Non Levelized | |
|---|---|---|---|
| **On-line Year** | **20-Year Contract Term Levelized Rates*** | **Contract year** | **Non-Levelized Rates** |
| 2014 | 4.76 | 2014 | 3.78 |
| 2015 | 4.91 | 2015 | 3.89 |
| 2016 | 5.05 | 2016 | 4.01 |
| 2017 | 5.21 | 2017 | 4.13 |
| 2018 | 5.36 | 2018 | 4.25 |
| 2019 | 5.52 | 2019 | 4.38 |
| | | 2020 | 4.51 |
| | | 2021 | 4.64 |
| | | 2022 | 4.78 |
| | | 2023 | 4.93 |
| | | 2024 | 5.07 |
| | | 2025 | 5.23 |
| | | 2026 | 5.38 |
| | | 2027 | 5.55 |
| | | 2028 | 5.71 |
| | | 2029 | 5.88 |
| | | 2030 | 6.06 |
| | | 2031 | 6.24 |
| | | 2032 | 6.43 |
| | | 2033 | 6.62 |
| | | 2034 | 6.82 |
| | | 2035 | 7.02 |
| | | 2036 | 7.24 |
| | | 2037 | 7.45 |
| | | 2038 | 7.68 |
| | | 2039 | 7.91 |

*$/MWh

| 601–700 MW Solar Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 5.54 | 2014 | 4.39 |
| 2015 | 5.71 | 2015 | 4.53 |
| 2016 | 5.88 | 2016 | 4.66 |
| 2017 | 6.06 | 2017 | 4.80 |
| 2018 | 6.24 | 2018 | 4.95 |
| 2019 | 6.43 | 2019 | 5.09 |
| | | 2020 | 5.25 |
| | | 2021 | 5.40 |
| | | 2022 | 5.57 |
| | | 2023 | 5.73 |
| | | 2024 | 5.91 |
| | | 2025 | 6.08 |
| | | 2026 | 6.26 |
| | | 2027 | 6.45 |
| | | 2028 | 6.65 |
| | | 2029 | 6.85 |
| | | 2030 | 7.05 |
| | | 2031 | 7.26 |
| | | 2032 | 7.48 |
| | | 2033 | 7.70 |
| | | 2034 | 7.94 |
| | | 2035 | 8.17 |
| | | 2036 | 8.42 |
| | | 2037 | 8.67 |
| | | 2038 | 8.93 |
| | | 2039 | 9.20 |

*$/MWh

| 701–800 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 6.70 | 2014 | 5.31 |
| 2015 | 6.91 | 2015 | 5.47 |
| 2016 | 7.11 | 2016 | 5.64 |
| 2017 | 7.33 | 2017 | 5.81 |
| 2018 | 7.55 | 2018 | 5.98 |
| 2019 | 7.77 | 2019 | 6.16 |
| | | 2020 | 6.35 |
| | | 2021 | 6.54 |
| | | 2022 | 6.73 |
| | | 2023 | 6.93 |
| | | 2024 | 7.14 |
| | | 2025 | 7.36 |
| | | 2026 | 7.58 |
| | | 2027 | 7.80 |
| | | 2028 | 8.04 |
| | | 2029 | 8.28 |
| | | 2030 | 8.53 |
| | | 2031 | 8.78 |
| | | 2032 | 9.05 |
| | | 2033 | 9.32 |
| | | 2034 | 9.60 |
| | | 2035 | 9.89 |
| | | 2036 | 10.18 |
| | | 2037 | 10.49 |
| | | 2038 | 10.80 |
| | | 2039 | 11.13 |

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

| 801–900 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 7.98 | 2014 | 6.32 |
| 2015 | 8.21 | 2015 | 6.51 |
| 2016 | 8.46 | 2016 | 6.71 |
| 2017 | 8.71 | 2017 | 6.91 |
| 2018 | 8.98 | 2018 | 7.11 |
| 2019 | 9.25 | 2019 | 7.33 |
| | | 2020 | 7.55 |
| | | 2021 | 7.77 |
| | | 2022 | 8.01 |
| | | 2023 | 8.25 |
| | | 2024 | 8.50 |
| | | 2025 | 8.75 |
| | | 2026 | 9.01 |
| | | 2027 | 9.28 |
| | | 2028 | 9.56 |
| | | 2029 | 9.85 |
| | | 2030 | 10.14 |
| | | 2031 | 10.45 |
| | | 2032 | 10.76 |
| | | 2033 | 11.08 |
| | | 2034 | 11.42 |
| | | 2035 | 11.76 |
| | | 2036 | 12.11 |
| | | 2037 | 12.48 |
| | | 2038 | 12.85 |
| | | 2039 | 13.24 |

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

| 901–1,000 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 9.52 | 2014 | 7.54 |
| 2015 | 9.80 | 2015 | 7.77 |
| 2016 | 10.10 | 2016 | 8.00 |
| 2017 | 10.40 | 2017 | 8.24 |
| 2018 | 10.71 | 2018 | 8.49 |
| 2019 | 11.03 | 2019 | 8.74 |
| | | 2020 | 9.01 |
| | | 2021 | 9.28 |
| | | 2022 | 9.55 |
| | | 2023 | 9.84 |
| | | 2024 | 10.14 |
| | | 2025 | 10.44 |
| | | 2026 | 10.75 |
| | | 2027 | 11.08 |
| | | 2028 | 11.41 |
| | | 2029 | 11.75 |
| | | 2030 | 12.10 |
| | | 2031 | 12.47 |
| | | 2032 | 12.84 |
| | | 2033 | 13.23 |
| | | 2034 | 13.62 |
| | | 2035 | 14.03 |
| | | 2036 | 14.45 |
| | | 2037 | 14.89 |
| | | 2038 | 15.33 |
| | | 2039 | 15.79 |

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

| 1,001–1,100 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 11.38 | 2014 | 9.02 |
| 2015 | 11.72 | 2015 | 9.29 |
| 2016 | 12.07 | 2016 | 9.56 |
| 2017 | 12.43 | 2017 | 9.85 |
| 2018 | 12.80 | 2018 | 10.15 |
| 2019 | 13.19 | 2019 | 10.45 |
| | | 2020 | 10.77 |
| | | 2021 | 11.09 |
| | | 2022 | 11.42 |
| | | 2023 | 11.76 |
| | | 2024 | 12.12 |
| | | 2025 | 12.48 |
| | | 2026 | 12.85 |
| | | 2027 | 13.24 |
| | | 2028 | 13.64 |
| | | 2029 | 14.05 |
| | | 2030 | 14.47 |
| | | 2031 | 14.90 |
| | | 2032 | 15.35 |
| | | 2033 | 15.81 |
| | | 2034 | 16.28 |
| | | 2035 | 16.77 |
| | | 2036 | 17.28 |
| | | 2037 | 17.79 |
| | | 2038 | 18.33 |
| | | 2039 | 18.88 |

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

| 1,101–1,200 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 13.61 | 2014 | 10.78 |
| 2015 | 14.01 | 2015 | 11.11 |
| 2016 | 14.43 | 2016 | 11.44 |
| 2017 | 14.87 | 2017 | 11.78 |
| 2018 | 15.31 | 2018 | 12.14 |
| 2019 | 15.77 | 2019 | 12.50 |
| | | 2020 | 12.88 |
| | | 2021 | 13.26 |
| | | 2022 | 13.66 |
| | | 2023 | 14.07 |
| | | 2024 | 14.49 |
| | | 2025 | 14.93 |
| | | 2026 | 15.37 |
| | | 2027 | 15.84 |
| | | 2028 | 16.31 |
| | | 2029 | 16.80 |
| | | 2030 | 17.30 |
| | | 2031 | 17.82 |
| | | 2032 | 18.36 |
| | | 2033 | 18.91 |
| | | 2034 | 19.48 |
| | | 2035 | 20.06 |
| | | 2036 | 20.66 |
| | | 2037 | 21.28 |
| | | 2038 | 21.92 |
| | | 2039 | 22.58 |

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

| 1,201–1,300 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 16.26 | 2014 | 12.89 |
| 2015 | 16.75 | 2015 | 13.28 |
| 2016 | 17.25 | 2016 | 13.67 |
| 2017 | 17.77 | 2017 | 14.08 |
| 2018 | 18.30 | 2018 | 14.51 |
| 2019 | 18.85 | 2019 | 14.94 |
| | | 2020 | 15.39 |
| | | 2021 | 15.85 |
| | | 2022 | 16.33 |
| | | 2023 | 16.82 |
| | | 2024 | 17.32 |
| | | 2025 | 17.84 |
| | | 2026 | 18.38 |
| | | 2027 | 18.93 |
| | | 2028 | 19.50 |
| | | 2029 | 20.08 |
| | | 2030 | 20.68 |
| | | 2031 | 21.30 |
| | | 2032 | 21.94 |
| | | 2033 | 22.60 |
| | | 2034 | 23.28 |
| | | 2035 | 23.98 |
| | | 2036 | 24.70 |
| | | 2037 | 25.44 |
| | | 2038 | 26.20 |
| | | 2039 | 26.99 |

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

| 1,301–1,400 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 19.40 | 2014 | 15.38 |
| 2015 | 19.98 | 2015 | 15.84 |
| 2016 | 20.58 | 2016 | 16.31 |
| 2017 | 21.20 | 2017 | 16.80 |
| 2018 | 21.84 | 2018 | 17.31 |
| 2019 | 22.49 | 2019 | 17.83 |
| | | 2020 | 18.36 |
| | | 2021 | 18.91 |
| | | 2022 | 19.48 |
| | | 2023 | 20.06 |
| | | 2024 | 20.66 |
| | | 2025 | 21.28 |
| | | 2026 | 21.92 |
| | | 2027 | 22.58 |
| | | 2028 | 23.26 |
| | | 2029 | 23.96 |
| | | 2030 | 24.67 |
| | | 2031 | 25.41 |
| | | 2032 | 26.18 |
| | | 2033 | 26.96 |
| | | 2034 | 27.77 |
| | | 2035 | 28.60 |
| | | 2036 | 29.46 |
| | | 2037 | 30.35 |
| | | 2038 | 31.26 |
| | | 2039 | 32.19 |

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

| 1,301–1,400 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 23.07 | 2014 | 18.29 |
| 2015 | 23.77 | 2015 | 18.84 |
| 2016 | 24.48 | 2016 | 19.40 |
| 2017 | 25.21 | 2017 | 19.98 |
| 2018 | 25.97 | 2018 | 20.58 |
| 2019 | 26.75 | 2019 | 21.20 |
| | | 2020 | 21.84 |
| | | 2021 | 22.49 |
| | | 2022 | 23.17 |
| | | 2023 | 23.86 |
| | | 2024 | 24.58 |
| | | 2025 | 25.31 |
| | | 2026 | 26.07 |
| | | 2027 | 26.86 |
| | | 2028 | 27.66 |
| | | 2029 | 28.49 |
| | | 2030 | 29.35 |
| | | 2031 | 30.23 |
| | | 2032 | 31.13 |
| | | 2033 | 32.07 |
| | | 2034 | 33.03 |
| | | 2035 | 34.02 |
| | | 2036 | 35.04 |
| | | 2037 | 36.09 |
| | | 2038 | 37.18 |
| | | 2039 | 38.29 |

*$/MWh

**Integration costs for solar penetrations beyond 700 MW are not part of published Schedule 87 as of June 2015. These integration costs are based on an extrapolation of published integrated costs.

## Wind

| 0–100 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 0.27 | 2014 | 0.21 |
| 2015 | 0.27 | 2015 | 0.22 |
| 2016 | 0.28 | 2016 | 0.23 |
| 2017 | 0.29 | 2017 | 0.23 |
| 2018 | 0.30 | 2018 | 0.24 |
| 2019 | 0.31 | 2019 | 0.25 |
| | | 2020 | 0.25 |
| | | 2021 | 0.26 |
| | | 2022 | 0.27 |
| | | 2023 | 0.28 |
| | | 2024 | 0.29 |
| | | 2025 | 0.29 |
| | | 2026 | 0.30 |
| | | 2027 | 0.31 |
| | | 2028 | 0.32 |
| | | 2029 | 0.33 |
| | | 2030 | 0.34 |
| | | 2031 | 0.35 |
| | | 2032 | 0.36 |
| | | 2033 | 0.37 |
| | | 2034 | 0.38 |
| | | 2035 | 0.40 |
| | | 2036 | 0.41 |
| | | 2037 | 0.42 |
| | | 2038 | 0.43 |
| | | 2039 | 0.45 |

*$/MWh

| 101–200 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 1.22 | 2014 | 0.98 |
| 2015 | 1.25 | 2015 | 1.00 |
| 2016 | 1.29 | 2016 | 1.04 |
| 2017 | 1.33 | 2017 | 1.07 |
| 2018 | 1.37 | 2018 | 1.10 |
| 2019 | 1.41 | 2019 | 1.13 |
| | | 2020 | 1.16 |
| | | 2021 | 1.20 |
| | | 2022 | 1.24 |
| | | 2023 | 1.27 |
| | | 2024 | 1.31 |
| | | 2025 | 1.35 |
| | | 2026 | 1.39 |
| | | 2027 | 1.43 |
| | | 2028 | 1.48 |
| | | 2029 | 1.52 |
| | | 2030 | 1.57 |
| | | 2031 | 1.61 |
| | | 2032 | 1.66 |
| | | 2033 | 1.71 |
| | | 2034 | 1.76 |
| | | 2035 | 1.81 |
| | | 2036 | 1.87 |
| | | 2037 | 1.93 |
| | | 2038 | 1.98 |
| | | 2039 | 2.04 |

*$/MWh

| 201–300 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 2.78 | 2014 | 2.23 |
| 2015 | 2.87 | 2015 | 2.30 |
| 2016 | 2.95 | 2016 | 2.37 |
| 2017 | 3.04 | 2017 | 2.44 |
| 2018 | 3.13 | 2018 | 2.51 |
| 2019 | 3.23 | 2019 | 2.59 |
| | | 2020 | 2.67 |
| | | 2021 | 2.75 |
| | | 2022 | 2.83 |
| | | 2023 | 2.92 |
| | | 2024 | 3.00 |
| | | 2025 | 3.09 |
| | | 2026 | 3.19 |
| | | 2027 | 3.28 |
| | | 2028 | 3.38 |
| | | 2029 | 3.48 |
| | | 2030 | 3.59 |
| | | 2031 | 3.69 |
| | | 2032 | 3.80 |
| | | 2033 | 3.92 |
| | | 2034 | 4.04 |
| | | 2035 | 4.16 |
| | | 2036 | 4.28 |
| | | 2037 | 4.41 |
| | | 2038 | 4.54 |
| | | 2039 | 4.68 |

*$/MWh

| 301–400 MW Solar Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 4.95 | 2014 | 3.98 |
| 2015 | 5.10 | 2015 | 4.10 |
| 2016 | 5.26 | 2016 | 4.22 |
| 2017 | 5.41 | 2017 | 4.35 |
| 2018 | 5.58 | 2018 | 4.48 |
| 2019 | 5.74 | 2019 | 4.61 |
| | | 2020 | 4.75 |
| | | 2021 | 4.89 |
| | | 2022 | 5.04 |
| | | 2023 | 5.19 |
| | | 2024 | 5.34 |
| | | 2025 | 5.51 |
| | | 2026 | 5.67 |
| | | 2027 | 5.84 |
| | | 2028 | 6.02 |
| | | 2029 | 6.20 |
| | | 2030 | 6.38 |
| | | 2031 | 6.57 |
| | | 2032 | 6.77 |
| | | 2033 | 6.97 |
| | | 2034 | 7.18 |
| | | 2035 | 7.40 |
| | | 2036 | 7.62 |
| | | 2037 | 7.85 |
| | | 2038 | 8.08 |
| | | 2039 | 8.33 |

*$/MWh

| 401–500 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 7.71 | 2014 | 6.19 |
| 2015 | 7.95 | 2015 | 6.38 |
| 2016 | 8.18 | 2016 | 6.57 |
| 2017 | 8.43 | 2017 | 6.77 |
| 2018 | 8.68 | 2018 | 6.97 |
| 2019 | 8.94 | 2019 | 7.18 |
| | | 2020 | 7.39 |
| | | 2021 | 7.62 |
| | | 2022 | 7.84 |
| | | 2023 | 8.08 |
| | | 2024 | 8.32 |
| | | 2025 | 8.57 |
| | | 2026 | 8.83 |
| | | 2027 | 9.09 |
| | | 2028 | 9.37 |
| | | 2029 | 9.65 |
| | | 2030 | 9.94 |
| | | 2031 | 10.23 |
| | | 2032 | 10.54 |
| | | 2033 | 10.86 |
| | | 2034 | 11.18 |
| | | 2035 | 11.52 |
| | | 2036 | 11.86 |
| | | 2037 | 12.22 |
| | | 2038 | 12.59 |
| | | 2039 | 12.96 |

*$/MWh

| 501–600 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 11.05 | 2014 | 8.87 |
| 2015 | 11.38 | 2015 | 9.13 |
| 2016 | 11.72 | 2016 | 9.41 |
| 2017 | 12.07 | 2017 | 9.69 |
| 2018 | 12.43 | 2018 | 9.98 |
| 2019 | 12.81 | 2019 | 10.28 |
| | | 2020 | 10.59 |
| | | 2021 | 10.91 |
| | | 2022 | 11.23 |
| | | 2023 | 11.57 |
| | | 2024 | 11.92 |
| | | 2025 | 12.28 |
| | | 2026 | 12.64 |
| | | 2027 | 13.02 |
| | | 2028 | 13.41 |
| | | 2029 | 13.82 |
| | | 2030 | 14.23 |
| | | 2031 | 14.66 |
| | | 2032 | 15.10 |
| | | 2033 | 15.55 |
| | | 2034 | 16.02 |
| | | 2035 | 16.50 |
| | | 2036 | 16.99 |
| | | 2037 | 17.50 |
| | | 2038 | 18.03 |
| | | 2039 | 18.57 |

*$/MWh

| 601–700 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 14.94 | 2014 | 11.99 |
| 2015 | 15.39 | 2015 | 12.35 |
| 2016 | 15.85 | 2016 | 12.72 |
| 2017 | 16.33 | 2017 | 13.10 |
| 2018 | 16.82 | 2018 | 13.50 |
| 2019 | 17.32 | 2019 | 13.90 |
| | | 2020 | 14.32 |
| | | 2021 | 14.75 |
| | | 2022 | 15.19 |
| | | 2023 | 15.65 |
| | | 2024 | 16.12 |
| | | 2025 | 16.60 |
| | | 2026 | 17.10 |
| | | 2027 | 17.61 |
| | | 2028 | 18.14 |
| | | 2029 | 18.68 |
| | | 2030 | 19.24 |
| | | 2031 | 19.82 |
| | | 2032 | 20.42 |
| | | 2033 | 21.03 |
| | | 2034 | 21.66 |
| | | 2035 | 22.31 |
| | | 2036 | 22.98 |
| | | 2037 | 23.67 |
| | | 2038 | 24.38 |
| | | 2039 | 25.11 |

*$/MWh

| 701–800 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 19.38 | 2014 | 15.55 |
| 2015 | 19.96 | 2015 | 16.02 |
| 2016 | 20.56 | 2016 | 16.50 |
| 2017 | 21.17 | 2017 | 17.00 |
| 2018 | 21.81 | 2018 | 17.51 |
| 2019 | 22.46 | 2019 | 18.03 |
| | | 2020 | 18.57 |
| | | 2021 | 19.13 |
| | | 2022 | 19.70 |
| | | 2023 | 20.29 |
| | | 2024 | 20.90 |
| | | 2025 | 21.53 |
| | | 2026 | 22.18 |
| | | 2027 | 22.84 |
| | | 2028 | 23.53 |
| | | 2029 | 24.23 |
| | | 2030 | 24.96 |
| | | 2031 | 25.71 |
| | | 2032 | 26.48 |
| | | 2033 | 27.27 |
| | | 2034 | 28.09 |
| | | 2035 | 28.93 |
| | | 2036 | 29.80 |
| | | 2037 | 30.70 |
| | | 2038 | 31.62 |
| | | 2039 | 32.57 |

*$/MWh

| 801–900 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 24.34 | 2014 | 19.54 |
| 2015 | 25.07 | 2015 | 20.13 |
| 2016 | 25.83 | 2016 | 20.73 |
| 2017 | 26.60 | 2017 | 21.35 |
| 2018 | 27.40 | 2018 | 21.99 |
| 2019 | 28.22 | 2019 | 22.65 |
| | | 2020 | 23.33 |
| | | 2021 | 24.03 |
| | | 2022 | 24.75 |
| | | 2023 | 25.50 |
| | | 2024 | 26.26 |
| | | 2025 | 27.05 |
| | | 2026 | 27.86 |
| | | 2027 | 28.70 |
| | | 2028 | 29.56 |
| | | 2029 | 30.44 |
| | | 2030 | 31.36 |
| | | 2031 | 32.30 |
| | | 2032 | 33.27 |
| | | 2033 | 34.26 |
| | | 2034 | 35.29 |
| | | 2035 | 36.35 |
| | | 2036 | 37.44 |
| | | 2037 | 38.56 |
| | | 2038 | 39.72 |
| | | 2039 | 40.91 |

*$/MWh

| 901–1,000 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 29.82 | 2014 | 23.94 |
| 2015 | 30.72 | 2015 | 24.66 |
| 2016 | 31.64 | 2016 | 25.40 |
| 2017 | 32.59 | 2017 | 26.16 |
| 2018 | 33.57 | 2018 | 26.94 |
| 2019 | 34.57 | 2019 | 27.75 |
| | | 2020 | 28.59 |
| | | 2021 | 29.44 |
| | | 2022 | 30.33 |
| | | 2023 | 31.24 |
| | | 2024 | 32.17 |
| | | 2025 | 33.14 |
| | | 2026 | 34.13 |
| | | 2027 | 35.16 |
| | | 2028 | 36.21 |
| | | 2029 | 37.30 |
| | | 2030 | 38.42 |
| | | 2031 | 39.57 |
| | | 2032 | 40.76 |
| | | 2033 | 41.98 |
| | | 2034 | 43.24 |
| | | 2035 | 44.54 |
| | | 2036 | 45.87 |
| | | 2037 | 47.25 |
| | | 2038 | 48.66 |
| | | 2039 | 50.12 |

*$/MWh

| 1,001–1,100 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 35.81 | 2014 | 28.74 |
| 2015 | 36.88 | 2015 | 29.60 |
| 2016 | 37.99 | 2016 | 30.49 |
| 2017 | 39.13 | 2017 | 31.41 |
| 2018 | 40.30 | 2018 | 32.35 |
| 2019 | 41.51 | 2019 | 33.32 |
| | | 2020 | 34.32 |
| | | 2021 | 35.35 |
| | | 2022 | 36.41 |
| | | 2023 | 37.50 |
| | | 2024 | 38.63 |
| | | 2025 | 39.78 |
| | | 2026 | 40.98 |
| | | 2027 | 42.21 |
| | | 2028 | 43.47 |
| | | 2029 | 44.78 |
| | | 2030 | 46.12 |
| | | 2031 | 47.51 |
| | | 2032 | 48.93 |
| | | 2033 | 50.40 |
| | | 2034 | 51.91 |
| | | 2035 | 53.47 |
| | | 2036 | 55.07 |
| | | 2037 | 56.72 |
| | | 2038 | 58.43 |
| | | 2039 | 60.18 |

*$/MWh

| 1,101–1,200 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 42.27 | 2014 | 33.93 |
| 2015 | 43.54 | 2015 | 34.95 |
| 2016 | 44.85 | 2016 | 36.00 |
| 2017 | 46.19 | 2017 | 37.08 |
| 2018 | 47.58 | 2018 | 38.19 |
| 2019 | 49.01 | 2019 | 39.34 |
| | | 2020 | 40.52 |
| | | 2021 | 41.73 |
| | | 2022 | 42.98 |
| | | 2023 | 44.27 |
| | | 2024 | 45.60 |
| | | 2025 | 46.97 |
| | | 2026 | 48.38 |
| | | 2027 | 49.83 |
| | | 2028 | 51.33 |
| | | 2029 | 52.87 |
| | | 2030 | 54.45 |
| | | 2031 | 56.09 |
| | | 2032 | 57.77 |
| | | 2033 | 59.50 |
| | | 2034 | 61.29 |
| | | 2035 | 63.12 |
| | | 2036 | 65.02 |
| | | 2037 | 66.97 |
| | | 2038 | 68.98 |
| | | 2039 | 71.05 |

*$/MWh

# PURPA Reference Data

The following information is provided for PURPA reference purposes.

1. Preferred portfolio: Portfolio P6(b)

## *Resource portfolio P6(b)*

| Date | Resource | Installed Capacity | Peak-Hour Capacity |
|---|---|---|---|
| 2025 | B2H | 500 MW transfer capacity April–Sep<br>200 MW transfer capacity Oct–Mar | 500 MW |
| 2025 | Retire North Valmy (both units) | (262 MW) | (262 MW) |
| 2030 | Demand response | 60 MW | 60 MW |
| 2030 | Ice-based TES | 20 MW | 20 MW |
| 2031 | CCCT | 300 MW | 300 MW |
| | | Total retired capacity | (262 MW) |
| | | Total added capacity | 880 MW |
| | | Net peak-hour capacity | 618 MW |

2. Deficiency period under preferred portfolio

   1st capacity deficit = (14) MW July 2025
   1st energy deficit = (34) MW July 2026

   Note—Above deficits are based on 461 MW of installed PV solar capacity under contract at the time of portfolio design, and do not reflect the April 2015 cancellation of 141 MW of PV solar PURPA contracts. With removal of the 141 MW of PV solar PURPA contracts, the first deficits for capacity and energy are respectively (47) MW in July 2024 and (76) MW in July 2026.

3. Intermittent generation integration costs

   See integration cost schedule included in *Appendix C—Technical Appendix*, section *Schedule 87—Integration Costs for Solar and Wind Resources*.

# Renewable Energy Certificate Price Forecast

| Year | Nominal ($/MWh) |
|---|---|
| 2015 | $3.04 |
| 2016 | $3.06 |
| 2017 | $3.95 |
| 2018 | $3.95 |
| 2019 | $4.70 |
| 2020 | $5.23 |
| 2021 | $5.48 |
| 2022 | $5.73 |
| 2023 | $5.98 |
| 2024 | $6.33 |
| 2025 | $6.68 |
| 2026 | $7.05 |
| 2027 | $7.45 |
| 2028 | $7.83 |
| 2029 | $8.22 |
| 2030 | $8.64 |
| 2031 | $9.06 |
| 2032 | $9.49 |
| 2033 | $9.93 |
| 2034 | $10.38 |

# JIM BRIDGER UNITS 3 AND 4 SELECTIVE CATALYTIC REDUCTION ANALYSIS

The 2015 Jim Bridger Plant units 3 and 4 Selective Catalytic Reduction (SCR) Analysis (2015 SCR Analysis) is intended to satisfy the conditions set forth by the Idaho Public Utilities Commission (IPUC) in Order No. 32929 approving the Certificate of Public Convenience and Necessity (CPCN) for the investment in SCR controls on Jim Bridger units 3 and 4. Commission Order No. 32929 directs Idaho Power to be "continuously analyzing the impact of changing environmental regulations on its upgrade project." (Order No. 32929, p. 11). In addition to the above requirement, the company files quarterly reports in Docket No. IPC-E-13-16 providing updates as to the current status of environmental policies that are relevant to the construction of the SCR controls at Jim Bridger units 3 and 4, construction progress updates, and any other pertinent updates related to the SCRs.

The company's 2015 SCR Analysis evaluates the impacts of new environmental regulations proposed since the company filed its Coal Unit Environmental Analysis in 2013 (2013 Coal Study) as well as the cost-effectiveness of continuing the installation of the SCRs compared to shutting down units 3 and 4 and replacing that generation with an alternate generation resource.

## Background

The Jim Bridger coal-fired power plant (Jim Bridger Plant) consists of four units and is located near Rock Springs, Wyoming. Idaho Power owns one-third of the Jim Bridger Plant with the other two-thirds owned by PacifiCorp. The plant is maintained and operated by PacifiCorp. Units 3 and 4 have nominal net generation capacities of 523 and 530 megawatts (MW) respectively, and Idaho Power's share of the generation capacity is approximately 351 MW from both units.

Currently, the Jim Bridger Plant is required to meet SCR-based emission limits of 0.07 lb/MMBtu for nitrogen oxides (NOx) for all four units to comply with the U.S. Environmental Protection Agency (EPA) Regional Haze (RH) rules and the resulting Wyoming State Implementation Plan (SIP). SCRs are used to facilitate a chemical reaction between NOx (created during combustion) and ammonia to create nitrogen and water.

In 2013, as part of the 2011 IRP Update, the company filed its 2013 Coal Study which examined future investments required for environmental compliance in existing coal units and compared those investments to the costs of alternative replacement resources. The results of the 2013 Coal Study analysis for Jim Bridger identified additional investments in environmental controls on all four Jim Bridger units as prudent decisions that represented the lowest cost and least-risk option when compared to the other investment alternatives. The company used the results of the 2013 Coal Study to support its Application for approval of a CPCN for the investment in SCRs on units 3 and 4. Subsequently, the IPUC issued its approval of the CPCN in December 2013 and construction of the SCRs began shortly after.

## SCR Construction Progress Update

The major components of an SCR upgrade consist of: large particle ash collection, ammonia injection grid, the SCR reactor vessel (which contains the catalyst modules), and all added flue gas path ductwork. In addition to the SCR, Unit 4 will require larger induced draft fans to compensate for the flow restriction of the SCR reactor.

Construction of the SCRs is ongoing; as of May 2015, 99 percent of the 2,588 tons of the Unit 3 structural steel and 83 percent of the 7,570 linear feet of the SCR reactor piping has been completed. For Unit 4, 63 percent of the 3,031 tons of structural steel has been completed.

The Unit 3 SCR is scheduled to be completed by November 5, 2015, with a Wyoming SIP compliance deadline of December 31, 2015. Unit 4 is scheduled for completion by November 3, 2016, with a Wyoming SIP compliance date of December 31, 2016.

## 2015 Jim Bridger Units 3 and 4 SCR Analysis

The 2015 SCR Analysis re-examines the previous conclusion that installation of the SCRs on units 3 and 4 is the least-cost and least-risk means of ensuring that units 3 and 4 comply with state and federal emissions regulations. The 2015 SCR Analysis had two objectives:

1. Evaluate changes in environmental requirements since the 2013 Coal Study that may have an impact on the cost-effectiveness and/or viability of the SCRs on units 3 and 4, and

2. Determine the cost-effectiveness of installing the SCRs compared to the fixed costs of replacing the coal-fired generation from units 3 and 4 with a combined-cycle combustion turbine (CCCT) generation resource alternative.

### *Changes in Environmental Regulations*

On June 2, 2014, the EPA released its draft proposal to regulate carbon dioxide ($CO_2$) emissions from existing power plants. In the rule, the EPA proposes enforceable $CO_2$ performance goals that are based on a bottom-up, multi-factor analysis that reflects a system-wide approach of four building blocks, including increasing efficiency of the existing coal-fired generation, natural gas re-dispatch, renewable energy deployment, and demand-side energy efficiency. The goals take the form of state-wide carbon intensity rates for the state's electric power sector. Each state's goal reflects an emissions target (stated as lbs of $CO_2$/MWh of generation) that EPA has determined to be reasonable based upon the theoretical application of the "best system of emission reduction" for fossil-fueled power plants.

The proposal directs states to submit plans for meeting their goals. States may also work together to submit a single, coordinated multi-state plan. States and multi-state groups have a June 2016 deadline for submitting their plans, with the possibility of a 1- or 2-year extension depending on the plan type. Under the proposed rule, each state's plan must be approved by the EPA, based on modeling projections by the state that demonstrate, to the agency's satisfaction, that the plan will be adequate to meet EPA's determination of the state's interim and final goals. State plans do not need to rely upon the four building block measures EPA used to construct each state's goal. Rather, each state has relatively broad discretion to determine the policy measures on which it will rely to meet its goal.

There are several alternative approaches to 111(d) compliance. The individual states where the generators are physically located will determine the final impact to each of the affected units. Idaho Power has reviewed the Wyoming intensity targets and alternative approaches to compliance, and the company believes that there will be minimal impact on the normal operation of Jim Bridger units 3 and 4.

### *SCR Cost-Effectiveness*

To determine if the SCRs on units 3 and 4 continue to be the least-cost and least-risk option for compliance, the 2015 SCR Analysis compared the costs of two compliance options:

**Option 1**—Continue to install SCRs for compliance with state and federal environmental regulations

**Option 2**—Stop installation of SCRs and replace the coal-fired generation from units 3 and 4 with a CCCT.

## Overall Analysis Methodology

The study approach examined the costs and benefits of each option. The company's share of the nominal generation capacity at units 3 and 4 of 351 MW was assumed to be replaced with a CCCT with the same capacity. Incremental capital investment and fixed operations and maintenance (O&M) were included in the analysis. In addition, the fuel and variable O&M were forecasted for the duration of the study period to forecast the total cost of generation, both fixed and variable, for each compliance option.

The 2015 SCR Analysis utilized a 20-year study period over which the costs of both options are calculated. One difference between the 2015 SCR Analysis and the 2013 Coal Study is the inclusion of the return on investment in the net present value (NPV) calculations. In the 2013 Coal Study, the Science Applications International Corporation (SAIC) capital evaluation approach evaluated the capital costs of construction *without* the associated return on investment that is included in the company's regulatory revenue requirement determinations.

## Option 1 NPV Methodology

The company determined the cost of Option 1 by calculating the revenue requirement of the existing investment in units 3 and 4, incremental capital additions over the study period, the SCR capital costs (total SCR construction costs and fixed O&M) over the study period, and decommissioning costs. The additional costs of fuel and O&M related to operating the units over the study period were added to the revenue requirement of the capital investments.

The revenue requirement associated with the existing investment in units 3 and 4 includes the return on the existing investment for units 3 and 4, O&M, and fuel costs over the study period. The O&M information used in the analysis comes from the company's 10-year budget information from the Jim Bridger Plant forecast through the end of the study period. The company used data from its coal price forecast over the study period to determine the annual fuel expense including transportation costs. The company's coal price forecast is based on long-term contracts for supplying coal to the Jim Bridger Plant. The incremental capital additions include the cost of the SCRs as well as routine capital expenditures for maintenance and repairs throughout the study period. Also included as part of the costs of Option 1 are the decommissioning costs for units 3 and 4 that will be required when the units are retired. The company took the present value of the annual cost stream over the study period to determine the cost of Option 1. The cost of continuing to install the SCRs for compliance is $1.42 billion over the study period.

## Option 2 NPV Methodology

The costs of Option 2 is the combination of the costs to shutdown units 3 and 4 and build a CCCT to replace the generation from those shuttered units. The shutdown costs of units 3 and 4 include the accelerated recovery of the existing investment at units 3 and 4, accelerated recovery of the costs-to-date of the SCRs (dollars committed including cancelation penalties as of December 31, 2014), and decommissioning costs. By shutting down units 3 and 4 early, future ongoing capital costs on units 3 and 4 are avoided. The revenue requirement of the CCCT includes construction costs, fixed O&M, and return on investment over a 20-year period. The cost of the CCCT was based on the costs identified in the 2015 IRP for this type of resource. The assumption is that the CCCT would be sized to exactly replace the MW capacity of units 3 and 4. The CCCT in the analysis has an 85 percent capacity factor with an assumed heat rate of 6,714 Btu/kWh. The natural gas price forecast used in the analysis is an Idaho Citygate price forecast based on the 2015 IRP. The Idaho Citygate price is a Henry hub gas price with a Sumas hub differential applied plus transportation costs. It is assumed the CCCT would be sited in a region with access to the Sumas hub natural gas pricing, with additional gas transportation charges and capacity to a generic Idaho Citygate. The costs of shuttering units 3 and 4 and replacing that capacity with a CCCT are $2.496 billion over the study period.

## Analysis Results

Over the study period, the NPV of Option 1 is $1.420 billion and the NPV of Option 2 is $2.496 billion. Option 1, continuing to install the SCRs for compliance, is $1.076 billion less than compliance alternative Option 2.

The company performed additional analyses on the results to determine the main drivers of the $1.076 billion difference. As shown in the table below, $793 million was due to higher fuel costs in Option 2, $186 million was due to a higher return on capital investment in Option 2 due to the higher capital costs, O&M costs were $35 million less than Option 1 as a CCCT would be less O&M intensive than the Jim Bridger Plant, and capital costs for Option 2 were $132 million higher.

### *Option 2 Impact of Various Cost Drivers*

| | |
|---|---|
| Impact from fuel costs: | $793,308,007 |
| Impact from ROI: | 185,890,627 |
| Impact from difference in O&M: | (35,319,989) |
| Impact due to difference in capital costs: | 132,407,174 |
| **Total** | **$1,076,285,819** |

## Conclusions and Recommendations

Based on the 2015 SCR Analysis, continuing with the installation of the SCRs on units 3 and 4 represents a cost savings of $1.076 billion compared to shuttering units 3 and 4 and replacing that generation with a CCCT resource. The company evaluated the changes in environmental regulations proposed since the 2013 Coal Study and believes there will be little impact to the normal operation of units 3 and 4. The SCRs remain the least-cost and least risk option for compliance and the company will continue the installation of the SCRs on units 3 and 4.

# Revenue Requirement Comparison between Jim Bridger Units 3 and 4 SCR Completion and CCCT Replacement

## *Revenue Requirement on Existing Investments*

| Year | Existing Investments |
|---|---|
| 2015 | $101,017,077 |
| 2016 | $101,191,683 |
| 2017 | $102,260,140 |
| 2018 | $102,958,825 |
| 2019 | $103,167,948 |
| 2020 | $94,039,451 |
| 2021 | $91,247,597 |
| 2022 | $91,513,087 |
| 2023 | $94,069,370 |
| 2024 | $107,116,956 |
| 2025 | $108,120,849 |
| 2026 | $109,746,974 |
| 2027 | $111,413,380 |
| 2028 | $113,148,724 |
| 2029 | $114,824,751 |
| 2030 | $116,577,779 |
| 2031 | $118,486,952 |
| 2032 | $120,459,297 |
| 2033 | $122,496,977 |
| 2034 | $124,607,408 |
| **Total** | **$2,148,465,226** |

## Revenue Requirement on Incremental Investments

| | Bridger Capital Forecast | Life (years) | Assumed In-Service | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|---|---|
| 2015 | 90,802,222 | 20 | 12/31/2015 | $14,340,755 | — | — | — | — |
| 2016 | 44,787,706 | 19 | 12/31/2016 | $13,838,158 | $7,184,838 | — | — | — |
| 2017 | 13,508,618 | 18 | 12/31/2017 | $13,335,560 | $6,923,888 | $2,204,363 | — | — |
| 2018 | 18,268,574 | 17 | 12/31/2018 | $12,832,963 | $6,662,937 | $2,121,284 | $3,037,499 | — |
| 2019 | 14,439,932 | 16 | 12/31/2019 | $12,330,366 | $6,401,986 | $2,038,205 | $2,918,537 | $2,451,064 |
| 2020 | 9,596,002 | 15 | 12/31/2020 | $11,827,769 | $6,141,035 | $1,955,126 | $2,799,575 | $2,351,156 |
| 2021 | 7,181,971 | 14 | 12/31/2021 | $11,325,172 | $5,880,084 | $1,872,047 | $2,680,613 | $2,251,249 |
| 2022 | 5,935,721 | 13 | 12/31/2022 | $10,822,575 | $5,619,133 | $1,788,968 | $2,561,650 | $2,151,341 |
| 2023 | 7,897,482 | 12 | 12/31/2023 | $10,319,978 | $5,358,183 | $1,705,889 | $2,442,688 | $2,051,434 |
| 2024 | 7,633,488 | 11 | 12/31/2024 | $9,817,381 | $5,097,232 | $1,622,810 | $2,323,726 | $1,951,526 |
| 2025 | 7,648,933 | 10 | 12/31/2025 | $9,314,784 | $4,836,281 | $1,539,730 | $2,204,764 | $1,851,618 |
| 2026 | 7,259,519 | 9 | 12/31/2026 | $8,812,187 | $4,575,330 | $1,456,651 | $2,085,801 | $1,751,711 |
| 2027 | 7,275,029 | 8 | 12/31/2027 | $8,309,589 | $4,314,379 | $1,373,572 | $1,966,839 | $1,651,803 |
| 2028 | 7,542,890 | 7 | 12/31/2028 | $7,806,992 | $4,053,428 | $1,290,493 | $1,847,877 | $1,551,895 |
| 2029 | 7,471,972 | 6 | 12/31/2029 | $7,304,395 | $3,792,477 | $1,207,414 | $1,728,914 | $1,451,988 |
| 2030 | 7,439,668 | 5 | 12/31/2030 | $6,801,798 | $3,531,527 | $1,124,335 | $1,609,952 | $1,352,080 |
| 2031 | 7,397,816 | 4 | 12/31/2031 | $6,299,201 | $3,270,576 | $1,041,256 | $1,490,990 | $1,252,172 |
| 2032 | 7,425,475 | 3 | 12/31/2032 | $5,796,604 | $3,009,625 | $958,177 | $1,372,028 | $1,152,265 |
| 2033 | 7,455,564 | 2 | 12/31/2033 | $5,294,007 | $2,748,674 | $875,097 | $1,253,065 | $1,052,357 |
| 2034 | 7,438,099 | 1 | 12/31/2034 | $4,791,410 | $2,487,723 | $792,018 | $1,134,103 | $952,450 |
| **Total** | | | | **$191,321,644** | **$91,889,335** | **$26,967,437** | **$35,458,621** | **$27,228,109** |

| | Bridger Capital Forecast | Life (years) | Assumed In-Service | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|
| 2015 | 90,802,222 | 20 | 12/31/2015 | — | — | — | — | — |
| 2016 | 44,787,706 | 19 | 12/31/2016 | — | — | — | — | — |
| 2017 | 13,508,618 | 18 | 12/31/2017 | — | — | — | — | — |
| 2018 | 18,268,574 | 17 | 12/31/2018 | — | — | — | — | — |
| 2019 | 14,439,932 | 16 | 12/31/2019 | — | — | — | — | — |
| 2020 | 9,596,002 | 15 | 12/31/2020 | $1,666,615 | — | — | — | — |
| 2021 | 7,181,971 | 14 | 12/31/2021 | $1,595,796 | $1,279,658 | — | — | — |
| 2022 | 5,935,721 | 13 | 12/31/2022 | $1,524,977 | $1,222,868 | $1,088,414 | — | — |
| 2023 | 7,897,482 | 12 | 12/31/2023 | $1,454,157 | $1,166,079 | $1,037,869 | $1,495,959 | — |
| 2024 | 7,633,488 | 11 | 12/31/2024 | $1,383,338 | $1,109,289 | $987,323 | $1,423,104 | $1,500,581 |
| 2025 | 7,648,933 | 10 | 12/31/2025 | $1,312,518 | $1,052,500 | $936,777 | $1,350,249 | $1,423,759 |
| 2026 | 7,259,519 | 9 | 12/31/2026 | $1,241,699 | $995,710 | $886,232 | $1,277,393 | $1,346,938 |
| 2027 | 7,275,029 | 8 | 12/31/2027 | $1,170,879 | $938,920 | $835,686 | $1,204,538 | $1,270,116 |
| 2028 | 7,542,890 | 7 | 12/31/2028 | $1,100,060 | $882,131 | $785,141 | $1,131,683 | $1,193,294 |
| 2029 | 7,471,972 | 6 | 12/31/2029 | $1,029,240 | $825,341 | $734,595 | $1,058,827 | $1,116,473 |
| 2030 | 7,439,668 | 5 | 12/31/2030 | $958,421 | $768,551 | $684,049 | $985,972 | $1,039,651 |
| 2031 | 7,397,816 | 4 | 12/31/2031 | $887,602 | $711,762 | $633,504 | $913,117 | $962,829 |
| 2032 | 7,425,475 | 3 | 12/31/2032 | $816,782 | $654,972 | $582,958 | $840,262 | $886,008 |
| 2033 | 7,455,564 | 2 | 12/31/2033 | $745,963 | $598,182 | $532,412 | $767,406 | $809,186 |
| 2034 | 7,438,099 | 1 | 12/31/2034 | $675,143 | $541,393 | $481,867 | $694,551 | $732,364 |
| **Total** | | | | **$12,747,356** | **$10,206,828** | **$13,143,061** | **$12,281,200** | **$11,882,675** |

| | Bridger Capital Forecast | Life (years) | Assumed In-Service | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|
| 2015 | 90,802,222 | 20 | 12/31/2015 | — | — | — | — | — |
| 2016 | 44,787,706 | 19 | 12/31/2016 | — | — | — | — | — |
| 2017 | 13,508,618 | 18 | 12/31/2017 | — | — | — | — | — |
| 2018 | 18,268,574 | 17 | 12/31/2018 | — | — | — | — | — |
| 2019 | 14,439,932 | 16 | 12/31/2019 | — | — | — | — | — |
| 2020 | 9,596,002 | 15 | 12/31/2020 | — | — | — | — | — |
| 2021 | 7,181,971 | 14 | 12/31/2021 | — | — | — | — | — |
| 2022 | 5,935,721 | 13 | 12/31/2022 | — | — | — | — | — |
| 2023 | 7,897,482 | 12 | 12/31/2023 | — | — | — | — | — |
| 2024 | 7,633,488 | 11 | 12/31/2024 | — | — | — | — | — |
| 2025 | 7,648,933 | 10 | 12/31/2025 | $1,569,304 | — | — | — | — |
| 2026 | 7,259,519 | 9 | 12/31/2026 | $1,484,629 | $1,565,606 | — | — | — |
| 2027 | 7,275,029 | 8 | 12/31/2027 | $1,399,955 | $1,476,313 | $1,664,400 | — | — |
| 2028 | 7,542,890 | 7 | 12/31/2028 | $1,315,280 | $1,387,020 | $1,563,731 | $1,852,921 | — |
| 2029 | 7,471,972 | 6 | 12/31/2029 | $1,230,605 | $1,297,726 | $1,463,061 | $1,733,634 | $2,003,557 |
| 2030 | 7,439,668 | 5 | 12/31/2030 | $1,145,930 | $1,208,433 | $1,362,392 | $1,614,347 | $1,865,697 |
| 2031 | 7,397,816 | 4 | 12/31/2031 | $1,061,255 | $1,119,140 | $1,261,722 | $1,495,060 | $1,727,838 |
| 2032 | 7,425,475 | 3 | 12/31/2032 | $976,580 | $1,029,846 | $1,161,053 | $1,375,773 | $1,589,978 |
| 2033 | 7,455,564 | 2 | 12/31/2033 | $891,906 | $940,553 | $1,060,383 | $1,256,486 | $1,452,118 |
| 2034 | 7,438,099 | 1 | 12/31/2034 | $807,231 | $851,260 | $959,713 | $1,137,199 | $1,314,259 |
| **Total** | | | | **$11,882,675** | **$10,875,898** | **$10,496,455** | **$10,465,423** | **$9,953,447** |

| | Bridger Capital Forecast | Life (years) | Assumed In-Service | 2030 | 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|---|---|---|---|---|
| 2015 | 90,802,222 | 20 | 12/31/2015 | — | — | — | — | — |
| 2016 | 44,787,706 | 19 | 12/31/2016 | — | — | — | — | — |
| 2017 | 13,508,618 | 18 | 12/31/2017 | — | — | — | — | — |
| 2018 | 18,268,574 | 17 | 12/31/2018 | — | — | — | — | — |
| 2019 | 14,439,932 | 16 | 12/31/2019 | — | — | — | — | — |
| 2020 | 9,596,002 | 15 | 12/31/2020 | — | — | — | — | — |
| 2021 | 7,181,971 | 14 | 12/31/2021 | — | — | — | — | — |
| 2022 | 5,935,721 | 13 | 12/31/2022 | — | — | — | — | — |
| 2023 | 7,897,482 | 12 | 12/31/2023 | — | — | — | — | — |
| 2024 | 7,633,488 | 11 | 12/31/2024 | — | — | — | — | — |
| 2025 | 7,648,933 | 10 | 12/31/2025 | — | — | — | — | — |
| 2026 | 7,259,519 | 9 | 12/31/2026 | — | — | — | — | — |
| 2027 | 7,275,029 | 8 | 12/31/2027 | — | — | — | — | — |
| 2028 | 7,542,890 | 7 | 12/31/2028 | — | — | — | — | — |
| 2029 | 7,471,972 | 6 | 12/31/2029 | — | — | — | — | — |
| 2030 | 7,439,668 | 5 | 12/31/2030 | $2,229,158 | — | — | — | — |
| 2031 | 7,397,816 | 4 | 12/31/2031 | $2,064,441 | $2,566,035 | — | — | — |
| 2032 | 7,425,475 | 3 | 12/31/2032 | $1,899,725 | $2,361,297 | $3,160,168 | — | — |
| 2033 | 7,455,564 | 2 | 12/31/2033 | $1,735,008 | $2,156,560 | $2,886,164 | $4,346,789 | — |
| 2034 | 7,438,099 | 1 | 12/31/2034 | $1,570,292 | $1,951,823 | $2,612,160 | $3,934,118 | $7,849,803 |
| **Total** | | | | **$9,498,625** | **$9,035,714** | **$8,658,492** | **$8,280,906** | **$7,849,803** |

## Revenue Requirement on Decommissioning Costs

| | Decommissioning Costs (Estimated in 2034 dollars) |
|---|---|
| 2034 Costs | $52,244,513 |
| Present Value | $29,794,316 |
| Annual Payment | $1,241,717 |

## Total Payments—Comparison between Option 1 & 2

| | Option 1 | Option 2 | | | |
|---|---|---|---|---|---|
| Year | Continue w/SCR | Total Payments Accelerated Shutdown* | Costs of Replacement CCCT | Total Annual Costs | Difference between Option 1 & 2 |
| 2015 | $116,599,549 | $335,842,318 | $169,233,797 | $505,076,115 | $388,476,567 |
| 2016 | $123,456,396 | $351,737,422 | $159,080,882 | $510,818,304 | $387,361,908 |
| 2017 | $125,965,668 | | $158,051,633 | $158,051,633 | $32,085,964 |
| 2018 | $128,855,226 | | $164,658,910 | $164,658,910 | $35,803,683 |
| 2019 | $130,549,824 | | $170,473,692 | $170,473,692 | $39,923,868 |
| 2020 | $122,022,445 | | $172,507,122 | $172,507,122 | $50,484,678 |
| 2021 | $119,373,933 | | $174,789,729 | $174,789,729 | $55,415,797 |
| 2022 | $119,534,731 | | $175,912,781 | $175,912,781 | $56,378,050 |
| 2023 | $122,343,322 | | $179,087,087 | $179,087,087 | $56,743,766 |
| 2024 | $135,574,982 | | $181,551,652 | $181,551,652 | $45,976,670 |
| 2025 | $136,754,850 | | $183,671,759 | $183,671,759 | $46,916,909 |
| 2026 | $138,468,578 | | $181,060,725 | $181,060,725 | $42,592,147 |
| 2027 | $140,232,087 | | $181,088,595 | $181,088,595 | $40,856,508 |
| 2028 | $142,152,387 | | $183,931,004 | $183,931,004 | $41,778,617 |
| 2029 | $144,044,717 | | $188,184,330 | $188,184,330 | $44,139,613 |
| 2030 | $146,101,790 | | $195,077,058 | $195,077,058 | $48,975,268 |
| 2031 | $148,487,168 | | $201,099,893 | $201,099,893 | $52,612,724 |
| 2032 | $151,325,114 | | $203,445,436 | $203,445,436 | $52,120,322 |
| 2033 | $155,141,012 | | $209,308,283 | $209,308,283 | $54,167,271 |
| 2034 | $162,120,005 | | $58,279,478** | $58,279,478 | $(103,840,527) |
| **NPV** | **$1,419,569,231** | | | **$2,495,855,049** | **$1,076,285,818** |

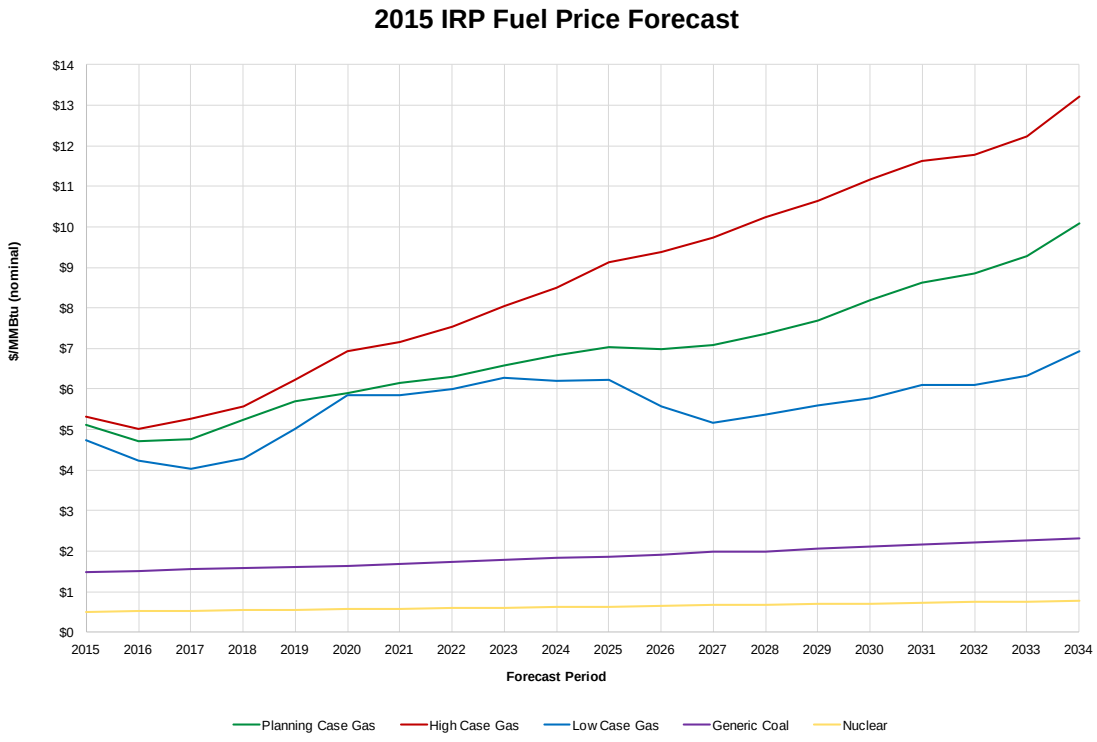
*Bridger SCR 3 and 4 Stacked PWorth—accelerated

**Residual value (Book value) included in the final year: (163,567,666)

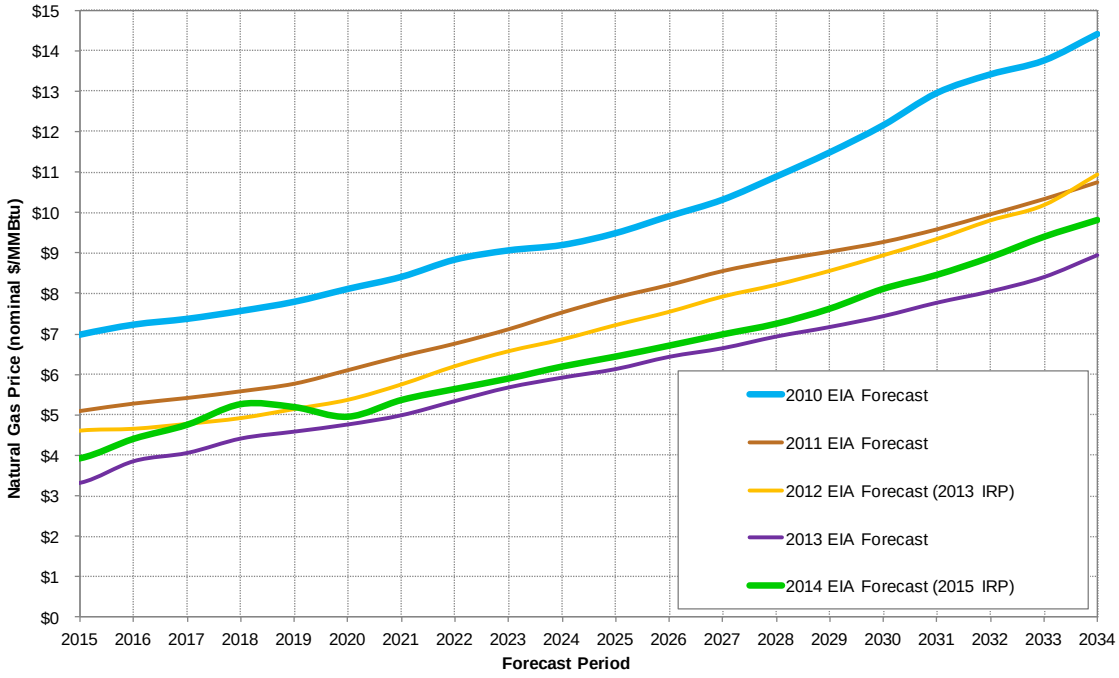
# FUEL PRICE FORECAST

## Natural Gas and Coal Price Forecast (nominal $/MMBtu)

| | Idaho Citygate Natural Gas | | | | |
|---|---|---|---|---|---|
| Year | Planning Case | High Case | Low Case | Generic Coal | Nuclear |
| 2015 | $5.10 | $5.32 | $4.74 | $1.47 | $0.51 |
| 2016 | $4.70 | $5.02 | $4.24 | $1.52 | $0.52 |
| 2017 | $4.76 | $5.26 | $4.02 | $1.55 | $0.53 |
| 2018 | $5.25 | $5.56 | $4.27 | $1.58 | $0.54 |
| 2019 | $5.69 | $6.22 | $5.02 | $1.61 | $0.56 |
| 2020 | $5.91 | $6.94 | $5.85 | $1.64 | $0.57 |
| 2021 | $6.14 | $7.17 | $5.85 | $1.69 | $0.58 |
| 2022 | $6.30 | $7.54 | $5.99 | $1.74 | $0.59 |
| 2023 | $6.58 | $8.04 | $6.27 | $1.78 | $0.61 |
| 2024 | $6.82 | $8.49 | $6.21 | $1.83 | $0.62 |
| 2025 | $7.04 | $9.13 | $6.24 | $1.87 | $0.63 |
| 2026 | $6.99 | $9.38 | $5.57 | $1.91 | $0.65 |
| 2027 | $7.09 | $9.73 | $5.17 | $1.98 | $0.66 |
| 2028 | $7.35 | $10.24 | $5.38 | $2.00 | $0.68 |
| 2029 | $7.69 | $10.64 | $5.60 | $2.07 | $0.69 |
| 2030 | $8.18 | $11.18 | $5.77 | $2.12 | $0.71 |
| 2031 | $8.62 | $11.62 | $6.10 | $2.16 | $0.72 |
| 2032 | $8.85 | $11.78 | $6.09 | $2.21 | $0.74 |
| 2033 | $9.28 | $12.24 | $6.33 | $2.27 | $0.75 |
| 2034 | $10.09 | $13.21 | $6.94 | $2.32 | $0.77 |



**Historical EIA Henry Hub Spot Price Forecasts**




*all values taken from EIA Annual Energy Outlook reports:
http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2013&subject=0-AEO2013&table=13-AEO2013&region=0-0&cases=ref2013-d102312a

# EXISTING RESOURCE DATA

## Hydroelectric and Thermal Plant Data

| Hydroelectric Power Plants | Nameplate kVA | Nameplate kW | Normal Rating kW[4] | Emergency Rating kW[5] |
|---|---|---|---|---|
| American Falls | 102,600 | 92,340 | 92,340 | 106,190 |
| Bliss | 86,250 | 75,000 | 75,000 | 84,860 |
| Brownlee | 650,444 | 585,400 | 585,400 | 678,040 |
| Cascade | 13,800 | 12,420 | 12,420 | 14,280 |
| C.J. Strike | 90,000 | 82,800 | 82,800 | 95,420 |
| Clear Lake | 3,125 | 2,500[1] | 2,420 | 2,430 |
| Hells Canyon | 435,000 | 391,500 | 391,500 | 449,580 |
| Lower Salmon | 70,000 | 60,000 | 60,000 | 69,140 |
| Malad–Lower | 15,500 | 13,500 | 13,500 | 13,500 |
| Malad–Upper | 9,650 | 8,270 | 8,270 | 8,400 |
| Milner | 62,890 | 59,448 | 59,448 | 61,880 |
| Oxbow | 211,112 | 190,000 | 190,000 | 218,520 |
| Shoshone Falls | 14,900 | 12,500[1] | 12,500 | 12,500 |
| Swan Falls | 28,600 | 27,170 | 24,170[3] | 24,170 |
| Thousand Springs | 11,000 | 8,800 | 6,380[2] | 6,380 |
| Twin Falls | 56,175 | 52,897 | 52,561 | 54,170 |
| Upper Salmon “A” | 18,000 | 18,000 | 18,000 | 18,000 |
| Upper Salmon “B” | 18,000 | 16,500 | 16,500 | 16,560 |
| **Total Hydro** | **1,897,046** | **1,709,045** | | |

| Thermal, Natural Gas, and Diesel Power Plants | Generator Nameplate Rating Gross kVA | Generator Nameplate Rating Gross kW | Net Dependable Capability (NDC)[6,7] kW | Net Dependable Capability (NDC)[6,7] Summer kW | Net Dependable Capability (NDC)[6,7] Winter kW |
|---|---|---|---|---|---|
| Bridger (Idaho Power share) | 811,053 | 770,501 | | 707,667 | 707,667 |
| Boardman (Idaho Power share) | 67,600 | 64,200 | | 57,550 | 58,050 |
| Valmy (Idaho Power share) | 315,000 | 283,500 | | 260,000 | 260,000 |
| **Total Thermal** | **1,193,653** | **1,118,201** | | | |
| Bennett Mountain | 192,000 | 172,800 | 164,159 | | |
| Evander Andrews Unit #1 | 199,000 | 179,100 | 170,955 | | |
| Evander Andrews Unit #2 | 51,000 | 45,900 | 45,405 | | |
| Evander Andrews Unit #3 | 51,000 | 45,900 | 45,066 | | |
| Langley Gulch CT | 220,000 | 187,000 | 176,880 | | |
| Langley Gulch ST | 154,650 | 131,452 | 122,765 | | |
| **Total Natural Gas** | **867,650** | **762,152** | | | |
| Salmon Diesel | 6,880 | 5,000 | 5,500 | | |
| **Total IPC Generation** | **3,965,229** | **3,594,398** | | | |

1 A power factor rating of 0.8 is assumed on four units (Clear Lake, Shoshone Falls unit 2, and Thousand Springs units 1 and 2) with a total kVA rating of 6,127 kVA where there is no nameplate kW rating.

2 The two smaller units, 1 and 2, have nameplate ratings of 1.25 MVA and 1 MW and are not in service due to reduced flows from the springs and penstock integrity.

3 The Swan Falls units have been limited to 24,170 kW as a result of vibration issues.

4 Normal Rating is the normal kW output of the facility with all units on-line. This rating includes all equipment limitations and may be lower than the nameplate rating. To operate at the Normal Rating, appropriate water conditions must exist and the FERC license requirements permit.

5 Emergency Rating is the maximum kW output of the facility with all units on-line. The Emergency Rating is based on manufacturer guidelines, ANSI standards, and limited by auxiliary equipment ratings. To operate at the Emergency Rating, appropriate water conditions must exist and the FERC license requirements permit.

6 Ratings for coal-fired generators are provided by Idaho Power's thermal partners who operate these plants.

7 NDC is defined in the NERC Generating Availability Data System (GADS) as Gross Dependable Capacity (GDC) less the unit capacity utilized for that unit's station service or auxiliaries. GDC is the Gross Maximum Capacity (GMC) modified for seasonal limitations over a specified period of time. The GDC and Maximum Dependable Capacity (MDC) used in previous GADS reports are the same in intent and purpose. GMC is the maximum capacity a unit can sustain over a specified period of time when not restricted by seasonal or other de-ratings.

# Qualifying Facility Data (PURPA)

**Cogeneration and Small Power Production Projects**

**Status as of May 26, 2015.**

| Project | MW | Contract On-line Date | Contract End Date | Project | MW | Contract On-line Date | Contract End Date |
|---|---|---|---|---|---|---|---|
| **Hydro Projects** | | | | | | | |
| Arena Drop | 0.45 | Sep-2010 | Sep-2030 | Little Wood Rvr Res | 2.85 | Feb-1985 | Feb-2020 |
| Barber Dam | 3.70 | Apr-1989 | Apr-2024 | Littlewood / Arkoosh | 0.87 | Aug-1986 | Aug-2021 |
| Birch Creek | 0.05 | Nov-1984 | Nov-2019 | Low Line Canal | 7.97 | May-1985 | May-2020 |
| Black Canyon #3 | 0.14 | Apr-1984 | Apr-2019 | Low Line Midway Hydro | 2.50 | Aug-2007 | Aug-2027 |
| Black Canyon Bliss Hydro | 0.03 | Nov-2014 | Estimated | Lowline #2 | 2.79 | Apr-1988 | Apr-2023 |
| Blind Canyon | 1.63 | Dec-2014 | Dec-2034 | Magic Reservoir | 9.07 | Jun-1989 | Jun-2024 |
| Box Canyon | 0.36 | Feb-1984 | Feb-2019 | Malad River | 0.62 | May-1984 | May-2019 |
| Briggs Creek | 0.60 | Oct-1985 | Oct-2020 | Marco Ranches | 1.20 | Aug-1985 | Aug-2020 |
| Bypass | 9.96 | Jun-1988 | Jun-2023 | Mile 28 | 1.50 | Jun-1994 | Jun-2029 |
| Canyon Springs | 0.13 | Oct-1984 | Oct-2040 | Mill Creek Hydroelectric | 0.80 | Oct-2011 | Jun-2017 |
| Cedar Draw | 1.55 | Jun-1984 | Jun-2019 | Mitchell Butte | 2.09 | May-1989 | Dec-2033 |
| Clark Canyon Hydroelectric | 7.55 | Jun-2017 | Estimated | Mora Drop Small Hydro Fac | 1.85 | Sep-2006 | Sep-2026 |
| Clear Springs Trout | 0.52 | Nov-1983 | Nov-2018 | Mud Creek/S&S | 0.52 | Feb-1982 | Jan-2017 |
| Crystal Springs | 2.44 | Apr-1986 | Apr-2021 | Mud Creek/White | 0.21 | Jan-1986 | Jan-2021 |
| Curry Cattle Company | 0.22 | Jun-1983 | Jun-2018 | Owyhee Dam Cspp | 5.00 | Aug-1985 | May-2033 |
| Dietrich Drop | 4.50 | Aug-1988 | Aug-2023 | Pigeon Cove | 1.89 | Oct-1984 | Oct-2019 |
| Eightmile Hydro Project | 0.36 | Oct-2014 | Oct-2034 | Pristine Springs #1 2005 | 0.13 | May-2005 | May-2015 |
| Elk Creek | 2.00 | May-1986 | May-2021 | Pristine Springs #3 2005 | 0.20 | May-2005 | May-2015 |
| Falls River | 9.10 | Aug-1993 | Aug-2028 | Reynolds Irrigation | 0.26 | May-1986 | May-2021 |
| Fargo Drop Hydroelectric | 1.27 | Apr-2013 | Apr-2033 | Rock Creek #1 | 2.05 | Sep-1983 | Sep-2018 |
| Faulkner Ranch | 0.87 | Aug-1987 | Aug-2022 | Rock Creek #2 | 1.90 | Apr-1989 | Apr-2024 |
| Fisheries Dev. | 0.26 | Jul-1990 | Jul-2040 | Sagebrush | 0.43 | Sep-1985 | Sep-2020 |
| Geo-Bon #2 | 0.93 | Nov-1986 | Nov-2021 | Sahko Hydro | 0.50 | Feb-2011 | Feb-2021 |
| Hailey Cspp | 0.06 | Jun-1985 | Jun-2020 | Schaffner | 0.53 | Aug-1986 | Aug-2021 |
| Hazelton A | 8.10 | Mar-2011 | Mar-2026 | Shingle Creek | 0.22 | Aug-1983 | Aug-2017 |
| Hazelton B | 7.60 | May-1993 | May-2028 | Shoshone #2 | 0.58 | May-1996 | May-2031 |
| Head of U Canal Project | 1.28 | May-2015 | Estimated | Shoshone Cspp | 0.37 | Jun-1982 | Feb-2017 |
| Horseshoe Bend Hydro | 9.50 | Sep-1995 | Sep-2030 | Snake River Pottery | 0.07 | Nov-1984 | Nov-2019 |
| Jim Knight | 0.34 | Jun-1985 | Jun-2020 | Snedigar | 0.54 | Jan-1985 | Jan-2020 |
| Kasel & Witherspoon | 0.90 | Mar-1984 | Mar-2019 | Tiber Dam | 7.50 | Jun-2004 | Jun-2024 |
| Koyle Small Hydro | 1.25 | Apr-1984 | Apr-2019 | Trout-Co | 0.24 | Dec-1986 | Dec-2021 |
| Lateral # 10 | 2.06 | May-1985 | May-2020 | Tunnel #1 | 7.00 | Jun-1993 | Feb-2035 |
| Lemoyne | 0.08 | Jun-1985 | Jun-2020 | White Water Ranch | 0.16 | Aug-1985 | Aug-2020 |
| Little Wood River Ranch II | 1.25 | Jun-2015 | Estimated | Wilson Lake Hydro | 8.40 | May-1993 | May-2028 |
| **Total Hydro Nameplate Rating 153.81 MW** | | | | | | | |
| **Thermal Projects** | | | | | | | |
| Magic Valley Natural Gas | 10.00 | Nov-1996 | Nov-2016 | TASCO—Nampa Natural Gas | 2.00 | Sep-2003 | Non firm |
| Simplot Pocatello Cogen | 15.90 | Mar-2013 | Feb-2016 | TASCO—Twin Falls Natural Gas | 3.00 | Aug-2001 | Non firm |
| **Total Thermal Nameplate Rating 30.90 MW** | | | | | | | |

| Project | MW | Contract On-line Date | Contract End Date | Project | MW | Contract On-line Date | Contract End Date |
|---|---|---|---|---|---|---|---|
| **Biomass Projects** | | | | | | | |
| B6 Anaerobic Digester | 2.28 | Aug-2010 | Aug-2020 | Fighting Creek Landfill | 3.06 | Apr-2014 | Apr-2029 |
| Bannock County Landfill | 3.20 | May-2014 | May-2034 | Hidden Hollow Landfill Gas | 3.20 | Jan-2007 | Jan-2027 |
| Bettencourt Dry Creek BioFactory | 2.25 | May-2010 | May-2020 | Pocatello Waste | 0.46 | Dec-1985 | Dec-2020 |
| Big Sky West Dairy Digester | 1.50 | Jan-2009 | Jan-2029 | Rock Creek Dairy | 4.00 | Aug-2012 | Aug-2027 |
| Double A Digester Project | 4.50 | Jan-2012 | Jan-2032 | Tamarack CSPP | 5.00 | Jun-1983 | Jun-2018 |
| **Total Biomass Nameplate Rating 29.45 MW** | | | | | | | |
| **Solar Projects** | | | | | | | |
| American Falls Solar II, LLC | 20.00 | Dec-2016 | Estimated | Open Range Solar Center, LLC | 10.00 | Dec-2016 | Estimated |
| American Falls Solar, LLC | 40.00 | Jan-2016 | Estimated | Orchard Ranch Solar, LLC | 20.00 | Dec-2016 | Estimated |
| Boise City Solar, LLC | 80.00 | Sep-2016 | Estimated | Pocatello Solar 1, LLC | 20.00 | Dec-2016 | Estimated |
| Grand View PV Solar Two | 10.00 | Dec-2016 | Estimated | Railroad Solar Center, LLC | 10.00 | Dec-2016 | Estimated |
| Grove Solar Center, LLC | 10.00 | Dec-2016 | Estimated | Simco Solar, LLC | 20.00 | Dec-2016 | Estimated |
| Hyline Solar Center, LLC | 20.00 | Dec-2016 | Estimated | Thunderegg Solar Center, LLC | 10.00 | Dec-2016 | Estimated |
| Mountain Home Solar, LLC | 20.00 | Dec-2016 | Estimated | Vale Air Solar Center, LLC | 10.00 | Dec-2016 | Estimated |
| Murphy Flat Power, LLC | 20.00 | Dec-2016 | Estimated | | | | |
| **Total Solar Nameplate Rating 320 MW** | | | | | | | |
| **Wind Projects** | | | | | | | |
| Bennett Creek Wind Farm | 21.00 | Dec-2008 | Dec-2028 | Mainline Windfarm | 23.00 | Dec-2012 | Dec-2032 |
| Benson Creek Windfarm | 10.00 | Dec-2016 | Estimated | Milner Dam Wind | 19.92 | Feb-2011 | Feb-2031 |
| Burley Butte Wind Park | 21.30 | Feb-2011 | Feb-2031 | Oregon Trail Wind Park | 13.50 | Jan-2011 | Jan-2031 |
| Camp Reed Wind Park | 22.50 | Dec-2010 | Dec-2030 | Payne's Ferry Wind Park | 21.00 | Dec-2010 | Dec-2030 |
| Cassia Wind Farm LLC | 10.50 | Mar-2009 | Mar-2029 | Pilgrim Stage Station Wind Park | 10.50 | Jan-2011 | Jan-2031 |
| Cold Springs Windfarm | 23.00 | Dec-2012 | Dec-2032 | Prospector Windfarm | 10.00 | Dec-2016 | Estimated |
| Desert Meadow Windfarm | 23.00 | Dec-2012 | Dec-2032 | Rockland Wind Farm | 80.00 | Dec-2011 | Dec-2036 |
| Durbin Creek Windfarm | 10.00 | Dec-2016 | Estimated | Ryegrass Windfarm | 23.00 | Dec-2012 | Dec-2032 |
| Fossil Gulch Wind | 10.50 | Sep-2005 | Sep-2025 | Salmon Falls Wind | 22.00 | Apr-2011 | Apr-2031 |
| Golden Valley Wind Park | 12.00 | Feb-2011 | Feb-2031 | Sawtooth Wind Project | 22.00 | Nov-2011 | Nov-2031 |
| Hammett Hill Windfarm | 23.00 | Dec-2012 | Dec-2032 | Thousand Springs Wind Park | 12.00 | Jan-2011 | Jan-2031 |
| High Mesa Wind Project | 40.00 | Dec-2012 | Dec-2032 | Tuana Gulch Wind Park | 10.50 | Jan-2011 | Jan-2031 |
| Horseshoe Bend Wind | 9.00 | Feb-2006 | Feb-2026 | Tuana Springs Expansion | 35.70 | May-2010 | May-2030 |
| Hot Springs Wind Farm | 21.00 | Dec-2008 | Dec-2028 | Two Ponds Windfarm | 23.00 | Dec-2012 | Dec-2032 |
| Jett Creek Windfarm | 10.00 | Dec-2016 | Estimated | Willow Spring Windfarm | 10.00 | Dec-2016 | Estimated |
| Lime Wind Energy | 3.00 | Dec-2011 | Dec-2031 | Yahoo Creek Wind Park | 21.00 | Dec-2010 | Dec-2030 |
| **Total Wind Nameplate Rating 626.92 MW** | | | | | | | |
| **Total Nameplate Rating 1,161.80 MW** | | | | | | | |

The above is a summary of the Nameplate rating for the CSPP projects under contract with Idaho Power as of May 26, 2015. In the case of CSPP projects, Nameplate rating of the actual generation units is not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy these projects will produce.

# Power Purchase Agreement Data

**Idaho Power Company Power Purchase Agreements Status as of April 1, 2015**

| Project | MW | Contract On-Line Date | Contract End Date |
|---|---|---|---|
| **Wind projects** | | | |
| Elkhorn Wind Project | 101 | December 2007 | December 2027 |
| **Total wind nameplate MW rating** | 101 | | |
| **Geothermal Projects** | | | |
| Raft River Unit 1 | 13 | April 2008 | April 2033 |
| Neal Hot Springs | 22 | November 2012 | November 2037 |
| **Total geothermal nameplate MW rating** | 35 | | |
| **Total nameplate MW rating** | 136 | | |

1. Above is a summary of the nameplate ratings for the Power Purchase Agreements under contract with Idaho Power. Nameplate ratings of the actual generation units are not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource-specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy the projects will produce.
2. Not included in the above table is the energy exchange agreement between Idaho Power and the Clatskanie PUD. Under the exchange, Idaho Power receives energy from the 18-MW power plant at Arrowrock Dam on the Boise River and returns to Clatskanie PUD energy of an equivalent value delivered seasonally. The agreement began in January 2010 and extends through 2015. Idaho Power retains the right to renew the agreement through 2025.

# Hydro Modeling Results (PDR580)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2015** | **2/2015** | **3/2015** | **4/2015** | **5/2015** | **6/2015** | **7/2015** | **8/2015** | **9/2015** | **10/2015** | **11/2015** | **12/2015** | **aMW** |
| Brownlee | HCC* | 319.5 | 359.7 | 341.3 | 433.4 | 409.9 | 397.5 | 247.5 | 164.8 | 212.9 | 193.7 | 152.6 | 253.6 | 290.5 |
| Oxbow | HCC | 131.7 | 155.5 | 155.1 | 188.7 | 168.0 | 161.7 | 105.0 | 75.3 | 97.5 | 89.0 | 69.3 | 106.8 | 125.3 |
| Hells Canyon | HCC | 259.2 | 308.6 | 313.1 | 386.6 | 346.5 | 326.9 | 208.1 | 148.1 | 191.3 | 175.5 | 138.1 | 211.7 | 251.1 |
| 1000 Springs | ROR** | 24.4 | 25.8 | 26.0 | 58.3 | 83.0 | 89.5 | 83.9 | 64.8 | 43.1 | 16.1 | - | 17.4 | 44.4 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 49.5 | 50.4 | 44.0 | 54.2 | 48.2 | 42.0 | 35.3 | 28.3 | 37.3 | 40.0 | 38.4 | 45.8 | 42.8 |
| C .J. Strike | ROR | 64.7 | 66.1 | 58.9 | 70.6 | 60.8 | 52.2 | 36.9 | 31.4 | 44.6 | 51.0 | 50.7 | 59.9 | 54.0 |
| Cascade | ROR | 1.5 | 1.5 | 2.8 | 5.9 | 5.5 | 11.7 | 10.3 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 34.9 | 35.5 | 29.3 | 38.4 | 34.2 | 28.3 | 23.0 | 16.1 | 23.6 | 26.0 | 24.3 | 31.5 | 28.8 |
| Milner | ROR | 41.5 | 42.1 | 26.3 | 42.5 | 34.3 | 15.4 | 6.2 | - | - | - | 4.9 | 30.8 | 20.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.9 | 21.3 | 19.0 | 22.6 | 19.9 | 17.1 | 12.9 | 11.0 | 15.0 | 16.9 | 16.8 | 19.4 | 17.7 |
| Twin Falls | ROR | 40.8 | 41.8 | 27.9 | 45.8 | 34.7 | 20.1 | 10.5 | - | - | 6.6 | 9.1 | 31.6 | 22.4 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 19.1 | 19.1 | 17.6 | 18.1 | 14.1 | 8.9 | 14.5 | 16.1 | 14.9 | 19.2 | 16.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.6 | 17.7 | 17.7 | 16.2 | 13.2 | 8.9 | 13.6 | 15.0 | 13.9 | 17.7 | 15.6 |
| **HCC Total** | | **710.4** | **823.8** | **809.5** | **1,008.7** | **924.3** | **886.1** | **560.6** | **388.2** | **501.7** | **458.2** | **360.0** | **572.1** | **667.0** |
| **ROR Total** | | **353.1** | **360.4** | **310.6** | **414.6** | **396.6** | **349.8** | **285.2** | **217.2** | **235.8** | **228.4** | **212.9** | **313.1** | **306.5** |
| **Total** | | **1,063.5** | **1,184.2** | **1,120.1** | **1,423.3** | **1,320.9** | **1,235.9** | **845.8** | **605.4** | **737.5** | **686.6** | **572.9** | **885.2** | **973.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2016** | **2/2016** | **3/2016** | **4/2016** | **5/2016** | **6/2016** | **7/2016** | **8/2016** | **9/2016** | **10/2016** | **11/2016** | **12/2016** | **aMW** |
| Brownlee | HCC* | 319.9 | 361.6 | 342.8 | 440.7 | 419.2 | 406.5 | 247.9 | 164.5 | 212.8 | 193.5 | 152.7 | 254.7 | 293.1 |
| Oxbow | HCC | 131.9 | 156.3 | 155.7 | 191.7 | 171.7 | 165.2 | 105.2 | 75.2 | 97.5 | 88.9 | 69.4 | 107.3 | 126.3 |
| Hells Canyon | HCC | 259.5 | 310.1 | 314.4 | 392.7 | 353.8 | 333.8 | 208.5 | 147.8 | 191.4 | 175.4 | 138.2 | 212.6 | 253.2 |
| 1000 Springs | ROR** | 24.8 | 26.5 | 26.8 | 60.7 | 84.5 | 90.9 | 83.9 | 64.9 | 42.8 | 16.1 | - | 19.3 | 45.1 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 49.4 | 50.5 | 44.2 | 55.0 | 49.1 | 42.3 | 35.2 | 28.2 | 37.2 | 40.0 | 38.0 | 47.3 | 43.0 |
| C .J. Strike | ROR | 64.6 | 66.1 | 59.6 | 70.7 | 63.4 | 53.4 | 36.7 | 31.3 | 44.5 | 51.0 | 50.6 | 60.7 | 54.4 |
| Cascade | ROR | 1.5 | 1.5 | 2.8 | 5.9 | 5.5 | 11.7 | 10.3 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 34.9 | 35.7 | 29.7 | 38.9 | 35.0 | 28.9 | 23.0 | 16.0 | 23.5 | 25.9 | 24.3 | 32.5 | 29.0 |
| Milner | ROR | 42.0 | 43.0 | 26.9 | 42.5 | 36.7 | 17.3 | 6.2 | - | - | - | 4.9 | 34.6 | 21.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.9 | 21.3 | 19.3 | 22.8 | 20.4 | 17.5 | 12.9 | 11.0 | 14.9 | 16.8 | 16.7 | 19.6 | 17.8 |
| Twin Falls | ROR | 41.7 | 42.1 | 28.0 | 45.8 | 36.7 | 21.3 | 10.5 | - | - | 6.6 | 9.1 | 35.4 | 23.1 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 19.2 | 19.1 | 17.6 | 18.6 | 14.0 | 8.9 | 14.4 | 16.1 | 14.8 | 19.2 | 16.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.7 | 17.7 | 17.7 | 16.2 | 13.2 | 8.8 | 13.5 | 15.0 | 13.9 | 17.7 | 15.6 |
| **HCC Total** | | **711.3** | **828.0** | **812.9** | **1,025.1** | **944.7** | **905.5** | **561.6** | **387.5** | **501.6** | **457.8** | **360.3** | **574.6** | **672.6** |
| **ROR Total** | | **354.7** | **362.6** | **313.9** | **418.6** | **407.3** | **357.3** | **284.8** | **216.9** | **235.0** | **228.2** | **212.2** | **326.1** | **309.8** |
| **Total** | | **1,066.0** | **1,190.6** | **1,126.8** | **1,443.7** | **1,351.9** | **1,262.8** | **846.4** | **604.4** | **736.6** | **686.0** | **572.5** | **900.7** | **982.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2017** | **2/2017** | **3/2017** | **4/2017** | **5/2017** | **6/2017** | **7/2017** | **8/2017** | **9/2017** | **10/2017** | **11/2017** | **12/2017** | **aMW** |
| Brownlee | HCC* | 319.1 | 365.2 | 343.4 | 446.8 | 429.4 | 418.8 | 248.5 | 164.6 | 210.7 | 194.5 | 152.6 | 253.7 | 295.6 |
| Oxbow | HCC | 131.6 | 157.8 | 156.0 | 194.3 | 175.8 | 170.1 | 105.4 | 75.2 | 96.3 | 89.1 | 69.2 | 106.9 | 127.3 |
| Hells Canyon | HCC | 258.9 | 313.1 | 314.9 | 397.8 | 361.8 | 343.3 | 209.0 | 148.0 | 189.1 | 175.7 | 138.0 | 211.8 | 255.1 |
| 1000 Springs | ROR** | 25.1 | 26.6 | 27.1 | 61.1 | 85.8 | 93.3 | 84.0 | 65.0 | 43.1 | 16.6 | - | 20.9 | 45.7 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 49.2 | 50.6 | 44.2 | 55.4 | 50.2 | 43.6 | 35.4 | 28.3 | 37.2 | 40.0 | 38.1 | 48.2 | 43.4 |
| C .J. Strike | ROR | 64.8 | 66.0 | 59.4 | 70.7 | 65.1 | 53.7 | 36.8 | 31.5 | 44.5 | 51.1 | 50.1 | 61.7 | 54.6 |
| Cascade | ROR | 1.5 | 1.5 | 2.8 | 5.9 | 5.5 | 11.7 | 10.3 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 35.0 | 35.4 | 29.6 | 38.9 | 35.9 | 29.3 | 23.0 | 16.1 | 23.4 | 26.0 | 23.9 | 33.0 | 29.1 |
| Milner | ROR | 41.5 | 42.3 | 27.8 | 42.9 | 39.0 | 20.9 | 6.2 | - | - | - | 3.8 | 34.8 | 21.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.9 | 21.3 | 19.3 | 22.7 | 21.1 | 17.5 | 12.9 | 11.0 | 14.9 | 16.8 | 16.4 | 19.9 | 17.9 |
| Twin Falls | ROR | 41.5 | 41.6 | 29.1 | 45.8 | 38.7 | 23.8 | 10.5 | - | - | 6.6 | 8.5 | 35.1 | 23.4 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 19.2 | 19.1 | 17.6 | 19.0 | 14.0 | 8.9 | 14.3 | 16.1 | 14.5 | 19.2 | 16.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.7 | 17.7 | 17.7 | 16.2 | 13.2 | 8.8 | 13.4 | 15.0 | 13.6 | 17.7 | 15.5 |
| **HCC Total** | | **709.6** | **836.1** | **814.3** | **1,038.9** | **967.0** | **932.2** | **562.9** | **387.8** | **496.1** | **459.3** | **359.8** | **572.4** | **678.0** |
| **ROR Total** | | **354.4** | **361.2** | **315.9** | **419.7** | **417.3** | **368.2** | **285.2** | **217.4** | **234.9** | **228.9** | **208.8** | **330.3** | **311.9** |
| **Total** | | **1,064.0** | **1,197.3** | **1,130.2** | **1,458.6** | **1,384.3** | **1,300.4** | **848.1** | **605.2** | **731.0** | **688.2** | **568.6** | **902.7** | **989.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2018** | **2/2018** | **3/2018** | **4/2018** | **5/2018** | **6/2018** | **7/2018** | **8/2018** | **9/2018** | **10/2018** | **11/2018** | **12/2018** | **aMW** |
| Brownlee | HCC* | 321.3 | 364.6 | 343.3 | 444.7 | 432.7 | 419.1 | 249.0 | 164.3 | 209.5 | 194.4 | 153.1 | 252.6 | 295.7 |
| Oxbow | HCC | 132.5 | 157.5 | 155.9 | 193.4 | 176.8 | 170.2 | 105.6 | 75.1 | 95.7 | 88.9 | 69.4 | 106.4 | 127.3 |
| Hells Canyon | HCC | 260.5 | 312.6 | 314.8 | 396.0 | 364.4 | 343.5 | 209.4 | 147.7 | 187.8 | 175.5 | 138.3 | 210.9 | 255.1 |
| 1000 Springs | ROR** | 25.7 | 28.4 | 27.0 | 61.3 | 86.8 | 95.1 | 84.0 | 65.1 | 43.1 | 17.8 | - | 20.9 | 46.3 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 49.5 | 51.1 | 43.7 | 55.4 | 50.9 | 44.7 | 35.3 | 28.2 | 37.0 | 40.0 | 38.0 | 47.3 | 43.4 |
| C .J. Strike | ROR | 65.4 | 66.4 | 58.9 | 70.7 | 66.1 | 54.6 | 36.7 | 31.4 | 44.3 | 51.0 | 50.1 | 61.3 | 54.7 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 35.1 | 36.2 | 29.2 | 38.9 | 36.6 | 30.2 | 22.9 | 16.0 | 23.3 | 25.9 | 23.8 | 32.7 | 29.2 |
| Milner | ROR | 41.5 | 45.0 | 26.7 | 44.9 | 40.9 | 24.5 | 6.2 | - | - | - | 3.6 | 34.3 | 22.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 12.0 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.9 | 21.4 | 19.1 | 22.7 | 21.3 | 17.8 | 12.8 | 11.0 | 14.9 | 16.8 | 16.4 | 19.8 | 17.9 |
| Twin Falls | ROR | 41.6 | 43.8 | 28.3 | 47.4 | 40.5 | 26.9 | 10.5 | - | - | 6.6 | 8.5 | 34.7 | 24.1 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 19.1 | 19.1 | 17.5 | 19.2 | 14.0 | 8.8 | 14.2 | 16.0 | 14.4 | 19.2 | 16.6 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 17.5 | 17.7 | 17.7 | 16.2 | 13.2 | 8.8 | 13.3 | 14.9 | 13.5 | 17.7 | 15.5 |
| **HCC Total** | | **714.3** | **834.7** | **814.0** | **1,034.1** | **973.9** | **932.8** | **564.0** | **387.1** | **493.0** | **458.8** | **360.8** | **569.9** | **678.1** |
| **ROR Total** | | **356.1** | **369.8** | **312.0** | **423.5** | **424.3** | **380.4** | **284.7** | **217.1** | **234.2** | **229.8** | **208.2** | **327.7** | **314.0** |
| **Total** | | **1,070.4** | **1,204.5** | **1,126.0** | **1,457.6** | **1,398.1** | **1,313.2** | **848.7** | **604.2** | **727.2** | **688.6** | **569.0** | **897.6** | **992.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2019** | **2/2019** | **3/2019** | **4/2019** | **5/2019** | **6/2019** | **7/2019** | **8/2019** | **9/2019** | **10/2019** | **11/2019** | **12/2019** | **aMW** |
| Brownlee | HCC* | 320.0 | 363.3 | 344.2 | 441.7 | 437.9 | 419.7 | 249.6 | 164.8 | 207.5 | 195.1 | 153.1 | 250.3 | 295.6 |
| Oxbow | HCC | 132.0 | 157.0 | 156.3 | 192.2 | 177.8 | 170.4 | 105.9 | 75.3 | 94.5 | 89.0 | 69.3 | 105.4 | 127.1 |
| Hells Canyon | HCC | 259.6 | 311.5 | 315.6 | 393.5 | 368.5 | 344.0 | 209.9 | 148.1 | 185.6 | 175.5 | 138.1 | 208.9 | 254.9 |
| 1000 Springs | ROR** | 25.9 | 28.4 | 27.2 | 61.0 | 87.9 | 95.5 | 84.1 | 65.1 | 43.1 | 18.2 | 5.2 | 18.1 | 46.6 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 49.7 | 51.4 | 42.4 | 54.5 | 51.5 | 45.5 | 35.5 | 28.4 | 37.1 | 40.1 | 37.2 | 46.1 | 43.3 |
| C .J. Strike | ROR | 65.8 | 67.4 | 57.6 | 70.1 | 67.0 | 55.2 | 36.8 | 31.5 | 44.3 | 51.1 | 48.8 | 58.4 | 54.5 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 35.3 | 36.6 | 28.2 | 38.9 | 37.4 | 31.7 | 23.0 | 16.1 | 23.3 | 25.9 | 23.4 | 30.5 | 29.2 |
| Milner | ROR | 41.7 | 44.9 | 22.6 | 43.7 | 42.7 | 27.2 | 6.2 | - | - | - | - | 27.8 | 21.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.7 | 12.0 | 10.8 |
| Swan Falls | ROR | 21.0 | 21.5 | 18.7 | 22.5 | 21.6 | 18.0 | 12.9 | 11.1 | 14.9 | 16.9 | 16.1 | 19.0 | 17.9 |
| Twin Falls | ROR | 41.8 | 43.7 | 24.7 | 46.7 | 41.9 | 28.9 | 10.5 | - | - | 6.6 | 6.0 | 28.9 | 23.3 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 18.3 | 19.1 | 17.5 | 19.2 | 14.1 | 8.9 | 14.2 | 16.1 | 14.1 | 19.2 | 16.6 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 16.9 | 17.7 | 17.7 | 16.2 | 13.2 | 8.8 | 13.3 | 15.0 | 13.3 | 17.7 | 15.4 |
| **HCC Total** | | **711.6** | **831.8** | **816.1** | **1,027.4** | **984.2** | **934.1** | **565.4** | **388.2** | **487.6** | **459.6** | **360.5** | **564.6** | **677.6** |
| **ROR Total** | | **357.6** | **371.4** | **299.1** | **419.6** | **431.2** | **388.6** | **285.4** | **217.7** | **234.3** | **230.7** | **201.7** | **305.5** | **311.9** |
| **Total** | | **1,069.2** | **1,203.2** | **1,115.2** | **1,447.0** | **1,415.4** | **1,322.7** | **850.8** | **605.9** | **721.9** | **690.3** | **562.2** | **870.1** | **989.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2020** | **2/2020** | **3/2020** | **4/2020** | **5/2020** | **6/2020** | **7/2020** | **8/2020** | **9/2020** | **10/2020** | **11/2020** | **12/2020** | **aMW** |
| Brownlee | HCC* | 318.8 | 360.6 | 343.8 | 440.8 | 436.3 | 418.9 | 249.0 | 164.1 | 205.9 | 195.3 | 153.5 | 249.2 | 294.7 |
| Oxbow | HCC | 131.5 | 155.8 | 156.2 | 191.8 | 177.4 | 170.1 | 105.6 | 75.0 | 93.7 | 89.0 | 69.4 | 104.9 | 126.7 |
| Hells Canyon | HCC | 258.6 | 309.3 | 315.3 | 392.8 | 367.2 | 343.3 | 209.4 | 147.5 | 184.0 | 175.5 | 138.3 | 208.0 | 254.1 |
| 1000 Springs | ROR** | 25.7 | 27.1 | 26.9 | 60.7 | 87.7 | 95.1 | 84.1 | 65.1 | 42.9 | 18.5 | 5.2 | 16.9 | 46.3 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 49.4 | 51.0 | 42.2 | 54.3 | 51.3 | 45.2 | 35.4 | 28.2 | 36.8 | 39.9 | 37.0 | 45.2 | 43.0 |
| C .J. Strike | ROR | 64.7 | 65.9 | 56.8 | 69.8 | 66.7 | 54.6 | 36.6 | 31.3 | 44.0 | 50.9 | 48.6 | 57.1 | 53.9 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 35.1 | 35.3 | 27.8 | 38.9 | 37.2 | 31.2 | 22.9 | 15.9 | 23.0 | 25.8 | 23.2 | 29.7 | 28.8 |
| Milner | ROR | 41.4 | 43.3 | 22.1 | 43.4 | 42.3 | 27.1 | 6.2 | - | - | - | - | 25.7 | 21.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 11.3 | 12.0 | 11.0 |
| Swan Falls | ROR | 20.9 | 21.3 | 18.5 | 22.4 | 21.5 | 17.8 | 12.9 | 11.0 | 14.8 | 16.8 | 16.0 | 18.6 | 17.7 |
| Twin Falls | ROR | 41.5 | 43.3 | 24.3 | 46.4 | 41.6 | 28.9 | 10.5 | - | - | 6.6 | 7.4 | 27.1 | 23.1 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 18.0 | 19.1 | 17.5 | 19.2 | 14.0 | 8.8 | 14.0 | 16.0 | 14.0 | 19.1 | 16.5 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 16.6 | 17.7 | 17.7 | 16.2 | 13.2 | 8.7 | 13.2 | 14.9 | 13.1 | 17.6 | 15.4 |
| **HCC Total** | | **708.9** | **825.7** | **815.3** | **1,025.4** | **980.9** | **932.3** | **564.0** | **386.6** | **483.5** | **459.8** | **361.2** | **562.1** | **675.5** |
| **ROR Total** | | **355.1** | **364.7** | **295.7** | **418.1** | **429.5** | **386.5** | **284.9** | **216.8** | **232.8** | **230.2** | **203.7** | **296.8** | **309.6** |
| **Total** | | **1,064.0** | **1,190.4** | **1,111.0** | **1,443.5** | **1,410.4** | **1,318.8** | **848.9** | **603.4** | **716.3** | **690.0** | **564.9** | **858.9** | **985.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2021** | **2/2021** | **3/2021** | **4/2021** | **5/2021** | **6/2021** | **7/2021** | **8/2021** | **9/2021** | **10/2021** | **11/2021** | **12/2021** | **aMW** |
| Brownlee | HCC* | 317.6 | 356.8 | 343.3 | 439.9 | 434.6 | 418.1 | 248.4 | 163.5 | 204.4 | 195.9 | 153.1 | 248.5 | 293.7 |
| Oxbow | HCC | 131.0 | 154.3 | 156.0 | 191.4 | 177.1 | 169.8 | 105.4 | 74.7 | 92.9 | 89.1 | 69.2 | 104.6 | 126.3 |
| Hells Canyon | HCC | 257.7 | 306.2 | 314.9 | 392.0 | 365.9 | 342.7 | 208.9 | 147.0 | 182.4 | 175.7 | 137.9 | 207.4 | 253.2 |
| 1000 Springs | ROR** | 25.5 | 26.9 | 26.4 | 60.5 | 87.5 | 95.1 | 84.1 | 65.0 | 42.4 | 18.0 | - | 15.6 | 45.6 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 49.2 | 50.7 | 41.9 | 54.0 | 51.1 | 44.8 | 35.2 | 28.0 | 36.6 | 39.7 | 36.8 | 44.3 | 42.7 |
| C .J. Strike | ROR | 64.4 | 65.0 | 56.4 | 69.4 | 66.4 | 54.3 | 36.4 | 31.1 | 43.6 | 50.6 | 48.4 | 55.7 | 53.5 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 34.7 | 34.9 | 27.6 | 38.5 | 37.0 | 30.8 | 22.8 | 15.7 | 22.8 | 25.6 | 23.0 | 29.5 | 28.6 |
| Milner | ROR | 41.1 | 42.9 | 21.4 | 43.0 | 42.0 | 26.9 | 6.2 | - | - | - | - | 24.9 | 20.7 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.7 | 12.0 | 10.8 |
| Swan Falls | ROR | 20.8 | 21.1 | 18.4 | 22.3 | 21.4 | 17.7 | 12.8 | 10.9 | 14.7 | 16.7 | 16.0 | 18.2 | 17.6 |
| Twin Falls | ROR | 41.3 | 43.0 | 23.4 | 45.9 | 41.3 | 28.5 | 10.5 | - | - | 6.6 | 6.0 | 26.9 | 22.8 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 17.8 | 19.1 | 17.5 | 19.2 | 13.9 | 8.6 | 13.8 | 15.8 | 13.8 | 19.0 | 16.4 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 16.4 | 17.7 | 17.7 | 16.2 | 13.1 | 8.6 | 13.0 | 14.7 | 13.0 | 17.5 | 15.3 |
| **HCC Total** | | **706.3** | **817.3** | **814.2** | **1,023.3** | **977.5** | **930.6** | **562.7** | **385.2** | **479.6** | **460.7** | **360.2** | **560.5** | **673.2** |
| **ROR Total** | | **353.4** | **362.0** | **292.2** | **415.8** | **427.9** | **384.7** | **284.1** | **215.7** | **231.0** | **228.5** | **194.6** | **291.4** | **306.8** |
| **Total** | | **1,059.7** | **1,179.3** | **1,106.4** | **1,439.1** | **1,405.4** | **1,315.3** | **846.8** | **600.9** | **710.6** | **689.2** | **554.8** | **851.9** | **980.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2022** | **2/2022** | **3/2022** | **4/2022** | **5/2022** | **6/2022** | **7/2022** | **8/2022** | **9/2022** | **10/2022** | **11/2022** | **12/2022** | **aMW** |
| Brownlee | HCC* | 316.4 | 353.8 | 342.8 | 438.9 | 433.0 | 417.3 | 247.7 | 162.8 | 201.2 | 196.4 | 153.6 | 247.3 | 292.6 |
| Oxbow | HCC | 130.5 | 153.0 | 155.7 | 191.0 | 176.8 | 169.5 | 105.1 | 74.4 | 91.1 | 89.0 | 69.4 | 104.1 | 125.8 |
| Hells Canyon | HCC | 256.8 | 303.7 | 314.4 | 391.2 | 364.6 | 342.1 | 208.3 | 146.4 | 178.9 | 175.5 | 138.2 | 206.4 | 252.2 |
| 1000 Springs | ROR** | 24.7 | 26.5 | 26.1 | 60.3 | 87.3 | 95.1 | 84.1 | 65.0 | 42.3 | 17.5 | - | 14.3 | 45.3 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 48.9 | 50.0 | 41.4 | 53.8 | 50.9 | 44.5 | 35.0 | 27.8 | 36.4 | 39.5 | 36.6 | 43.4 | 42.4 |
| C .J. Strike | ROR | 64.0 | 65.0 | 56.0 | 69.1 | 66.1 | 54.0 | 36.2 | 30.8 | 43.3 | 50.3 | 47.8 | 54.5 | 53.1 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 34.4 | 34.7 | 27.3 | 38.2 | 36.8 | 30.4 | 22.6 | 15.6 | 22.6 | 25.4 | 22.8 | 29.3 | 28.3 |
| Milner | ROR | 40.6 | 42.3 | 18.8 | 42.8 | 41.7 | 26.2 | 6.2 | - | - | - | - | 24.9 | 20.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.7 | 12.0 | 10.8 |
| Swan Falls | ROR | 20.4 | 21.0 | 18.3 | 22.2 | 21.3 | 17.6 | 12.8 | 10.8 | 14.6 | 16.4 | 15.8 | 17.9 | 17.4 |
| Twin Falls | ROR | 40.1 | 41.4 | 21.6 | 45.8 | 41.1 | 28.3 | 10.5 | - | - | 6.6 | 6.0 | 26.9 | 22.4 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 17.6 | 19.1 | 17.5 | 19.2 | 13.8 | 8.5 | 13.7 | 15.7 | 13.7 | 18.8 | 16.3 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 16.3 | 17.7 | 17.7 | 16.2 | 13.0 | 8.5 | 12.9 | 14.6 | 12.9 | 17.3 | 15.2 |
| **HCC Total** | | **703.7** | **810.5** | **812.9** | **1,021.1** | **974.4** | **928.9** | **561.1** | **383.6** | **471.2** | **460.9** | **361.2** | **557.8** | **670.6** |
| **ROR Total** | | **349.5** | **358.4** | **285.9** | **414.4** | **426.4** | **382.7** | **283.3** | **214.8** | **230.0** | **226.8** | **193.2** | **287.1** | **304.4** |
| **Total** | | **1,053.2** | **1,168.9** | **1,098.8** | **1,435.5** | **1,400.8** | **1,311.6** | **844.4** | **598.4** | **701.2** | **687.7** | **554.4** | **844.9** | **975.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2023** | **2/2023** | **3/2023** | **4/2023** | **5/2023** | **6/2023** | **7/2023** | **8/2023** | **9/2023** | **10/2023** | **11/2023** | **12/2023** | **aMW** |
| Brownlee | HCC* | 315.3 | 351.6 | 342.5 | 438.1 | 431.7 | 416.5 | 247.1 | 162.2 | 198.5 | 196.2 | 153.6 | 246.7 | 291.7 |
| Oxbow | HCC | 130.1 | 152.1 | 155.6 | 190.6 | 176.5 | 169.2 | 104.8 | 74.1 | 89.7 | 88.7 | 69.3 | 103.8 | 125.4 |
| Hells Canyon | HCC | 255.9 | 301.9 | 314.2 | 390.5 | 363.6 | 341.5 | 207.8 | 145.8 | 176.2 | 175.0 | 138.1 | 205.9 | 251.4 |
| 1000 Springs | ROR** | 24.5 | 25.6 | 25.9 | 60.0 | 87.1 | 95.1 | 84.1 | 64.9 | 42.3 | 17.4 | - | 13.8 | 45.1 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 48.7 | 48.8 | 41.3 | 53.6 | 50.7 | 44.2 | 34.9 | 27.6 | 36.2 | 39.3 | 36.4 | 42.5 | 42.0 |
| C .J. Strike | ROR | 63.6 | 64.6 | 55.9 | 68.8 | 65.8 | 53.8 | 36.0 | 30.6 | 43.0 | 50.1 | 47.6 | 53.3 | 52.8 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 34.2 | 34.0 | 27.1 | 37.8 | 36.6 | 30.0 | 22.5 | 15.4 | 22.4 | 25.3 | 22.6 | 28.5 | 28.0 |
| Milner | ROR | 40.3 | 40.7 | 18.5 | 42.5 | 41.4 | 25.4 | 6.2 | - | - | - | - | 23.9 | 19.9 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.7 | 12.0 | 10.8 |
| Swan Falls | ROR | 20.3 | 20.9 | 18.2 | 22.1 | 21.3 | 17.6 | 12.7 | 10.7 | 14.5 | 16.4 | 15.8 | 17.5 | 17.3 |
| Twin Falls | ROR | 39.9 | 40.8 | 21.3 | 45.6 | 40.9 | 27.8 | 10.5 | - | - | 6.6 | 6.0 | 25.4 | 22.1 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 17.4 | 19.1 | 17.5 | 19.2 | 13.7 | 8.4 | 13.5 | 15.6 | 13.5 | 18.2 | 16.2 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 16.1 | 17.7 | 17.7 | 16.2 | 12.9 | 8.4 | 12.7 | 14.5 | 12.8 | 16.8 | 15.1 |
| **HCC Total** | | **701.3** | **805.6** | **812.3** | **1,019.2** | **971.7** | **927.2** | **559.7** | **382.1** | **464.4** | **459.9** | **361.0** | **556.4** | **668.4** |
| **ROR Total** | | **347.9** | **352.9** | **284.2** | **412.6** | **425.0** | **380.5** | **282.6** | **213.8** | **228.7** | **226.0** | **192.3** | **279.7** | **302.2** |
| **Total** | | **1,049.2** | **1,158.5** | **1,096.5** | **1,431.8** | **1,396.7** | **1,307.7** | **842.3** | **595.9** | **693.1** | **685.9** | **553.3** | **836.1** | **970.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2024** | **2/2024** | **3/2024** | **4/2024** | **5/2024** | **6/2024** | **7/2024** | **8/2024** | **9/2024** | **10/2024** | **11/2024** | **12/2024** | **aMW** |
| Brownlee | HCC* | 314.2 | 350.3 | 345.8 | 437.2 | 430.1 | 415.7 | 246.5 | 161.5 | 196.3 | 196.1 | 153.6 | 245.6 | 291.1 |
| Oxbow | HCC | 129.6 | 151.5 | 157.0 | 190.3 | 176.3 | 168.9 | 104.6 | 73.8 | 88.6 | 88.6 | 69.3 | 103.3 | 125.1 |
| Hells Canyon | HCC | 255.0 | 300.9 | 317.0 | 389.8 | 362.4 | 340.9 | 207.3 | 145.2 | 174.0 | 174.8 | 138.0 | 205.0 | 250.9 |
| 1000 Springs | ROR** | 24.3 | 25.4 | 25.6 | 59.8 | 86.9 | 95.0 | 84.1 | 64.9 | 42.1 | 17.4 | - | 13.8 | 44.9 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 48.4 | 48.4 | 41.1 | 53.4 | 50.5 | 43.8 | 34.7 | 27.4 | 35.9 | 39.0 | 36.3 | 41.7 | 41.7 |
| C .J. Strike | ROR | 63.2 | 64.2 | 55.7 | 68.5 | 65.5 | 53.5 | 35.8 | 30.3 | 42.6 | 49.6 | 47.3 | 52.5 | 52.4 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 34.0 | 33.7 | 26.9 | 37.5 | 36.4 | 29.6 | 22.4 | 15.2 | 22.2 | 25.1 | 22.4 | 27.6 | 27.8 |
| Milner | ROR | 40.1 | 40.4 | 18.1 | 42.2 | 41.1 | 24.9 | 6.2 | - | - | - | - | 21.7 | 19.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.7 | 12.0 | 10.8 |
| Swan Falls | ROR | 20.2 | 20.2 | 18.1 | 22.0 | 21.2 | 17.5 | 12.6 | 10.6 | 14.4 | 16.3 | 15.7 | 17.3 | 17.2 |
| Twin Falls | ROR | 39.6 | 40.5 | 20.9 | 45.4 | 40.6 | 27.3 | 10.5 | - | - | 6.6 | 6.0 | 23.5 | 21.7 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 17.2 | 19.1 | 17.5 | 19.2 | 13.5 | 8.3 | 13.3 | 15.4 | 13.4 | 17.5 | 16.1 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.9 | 17.7 | 17.7 | 16.2 | 12.8 | 8.3 | 12.6 | 14.4 | 12.7 | 16.2 | 15.0 |
| **HCC Total** | | **698.8** | **802.7** | **819.8** | **1,017.3** | **968.7** | **925.5** | **558.4** | **380.5** | **458.8** | **459.5** | **360.9** | **553.9** | **667.1** |
| **ROR Total** | | **346.2** | **350.3** | **282.0** | **411.0** | **423.4** | **378.2** | **281.7** | **212.8** | **227.3** | **224.6** | **191.4** | **271.6** | **300.0** |
| **Total** | | **1,045.0** | **1,153.0** | **1,101.8** | **1,428.3** | **1,392.1** | **1,303.7** | **840.1** | **593.3** | **686.1** | **684.1** | **552.3** | **825.5** | **967.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2025** | **2/2025** | **3/2025** | **4/2025** | **5/2025** | **6/2025** | **7/2025** | **8/2025** | **9/2025** | **10/2025** | **11/2025** | **12/2025** | **aMW** |
| Brownlee | HCC* | 313.2 | 349.2 | 344.9 | 436.5 | 429.4 | 415.0 | 245.9 | 160.9 | 194.4 | 196.1 | 153.8 | 244.7 | 290.3 |
| Oxbow | HCC | 129.2 | 151.1 | 156.7 | 190.0 | 175.8 | 168.6 | 104.3 | 73.5 | 87.6 | 88.5 | 69.4 | 103.0 | 124.8 |
| Hells Canyon | HCC | 254.2 | 300.0 | 316.2 | 389.2 | 361.8 | 340.3 | 206.8 | 144.7 | 172.1 | 174.6 | 138.2 | 204.3 | 250.2 |
| 1000 Springs | ROR** | 23.9 | 25.2 | 25.4 | 59.5 | 86.7 | 94.7 | 84.1 | 64.9 | 42.0 | 17.3 | - | 13.4 | 44.8 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 48.1 | 48.1 | 40.9 | 53.2 | 50.3 | 43.5 | 34.5 | 27.2 | 35.7 | 38.9 | 36.0 | 41.0 | 41.5 |
| C .J. Strike | ROR | 62.9 | 63.8 | 55.3 | 68.2 | 65.3 | 53.3 | 35.6 | 30.1 | 42.3 | 49.4 | 47.1 | 51.4 | 52.1 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 33.6 | 33.5 | 26.7 | 37.2 | 36.2 | 29.3 | 22.2 | 15.1 | 21.9 | 24.9 | 22.3 | 26.9 | 27.5 |
| Milner | ROR | 39.5 | 40.3 | 17.8 | 42.0 | 40.8 | 24.6 | 6.2 | - | - | - | - | 20.0 | 19.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.7 | 12.0 | 10.8 |
| Swan Falls | ROR | 20.1 | 20.0 | 18.0 | 21.9 | 21.1 | 17.4 | 12.6 | 10.6 | 14.3 | 16.2 | 15.6 | 17.0 | 17.1 |
| Twin Falls | ROR | 39.1 | 40.3 | 20.6 | 45.2 | 40.4 | 27.0 | 10.5 | - | - | 6.6 | 6.0 | 22.0 | 21.5 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 17.1 | 19.1 | 17.5 | 18.9 | 13.4 | 8.1 | 13.1 | 15.3 | 13.3 | 16.9 | 15.9 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.8 | 17.7 | 17.7 | 16.2 | 12.7 | 8.2 | 12.4 | 14.3 | 12.6 | 15.7 | 14.9 |
| **HCC Total** | | **696.6** | **800.3** | **817.8** | **1,015.7** | **967.0** | **923.9** | **557.0** | **379.1** | **454.0** | **459.2** | **361.4** | **552.0** | **665.3** |
| **ROR Total** | | **343.6** | **348.7** | **280.1** | **409.4** | **422.0** | **376.1** | **280.9** | **212.0** | **225.9** | **223.7** | **190.5** | **264.1** | **298.1** |
| **Total** | | **1,040.2** | **1,149.0** | **1,097.9** | **1,425.1** | **1,389.0** | **1,300.0** | **837.9** | **591.1** | **679.9** | **682.9** | **551.9** | **816.1** | **963.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2026** | **2/2026** | **3/2026** | **4/2026** | **5/2026** | **6/2026** | **7/2026** | **8/2026** | **9/2026** | **10/2026** | **11/2026** | **12/2026** | **aMW** |
| Brownlee | HCC* | 312.2 | 348.2 | 343.9 | 435.7 | 429.4 | 414.2 | 245.3 | 160.3 | 192.5 | 196.0 | 153.8 | 244.5 | 289.7 |
| Oxbow | HCC | 128.8 | 150.6 | 156.2 | 189.6 | 175.8 | 168.2 | 104.0 | 73.2 | 86.6 | 88.3 | 69.3 | 102.9 | 124.5 |
| Hells Canyon | HCC | 253.4 | 299.1 | 315.4 | 388.5 | 361.8 | 339.7 | 206.3 | 144.1 | 170.2 | 174.2 | 138.1 | 204.1 | 249.6 |
| 1000 Springs | ROR** | 23.7 | 25.0 | 25.1 | 59.3 | 86.6 | 94.4 | 84.0 | 64.8 | 42.0 | 17.9 | - | 12.4 | 44.6 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 47.6 | 47.9 | 40.6 | 53.0 | 50.1 | 43.2 | 34.5 | 27.0 | 35.4 | 38.7 | 35.9 | 40.3 | 41.2 |
| C .J. Strike | ROR | 62.6 | 63.0 | 54.7 | 67.9 | 64.3 | 52.9 | 35.3 | 29.9 | 42.0 | 49.1 | 46.6 | 50.4 | 51.6 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 33.2 | 33.3 | 26.5 | 36.9 | 36.0 | 29.2 | 22.1 | 14.9 | 21.7 | 24.7 | 22.1 | 26.2 | 27.2 |
| Milner | ROR | 39.3 | 40.1 | 17.5 | 41.7 | 40.6 | 24.2 | 6.2 | - | - | - | - | 18.0 | 19.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.7 | 12.0 | 10.8 |
| Swan Falls | ROR | 20.0 | 19.9 | 17.9 | 21.8 | 20.9 | 17.3 | 12.5 | 10.5 | 14.2 | 16.2 | 15.5 | 16.7 | 17.0 |
| Twin Falls | ROR | 38.9 | 40.1 | 20.3 | 45.0 | 40.2 | 26.7 | 10.5 | - | - | 6.6 | 6.0 | 20.5 | 21.2 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.1 | 19.1 | 16.9 | 19.1 | 17.5 | 18.9 | 13.3 | 8.0 | 13.0 | 15.1 | 13.1 | 16.4 | 15.8 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.7 | 17.7 | 17.7 | 16.2 | 12.6 | 8.1 | 12.3 | 14.2 | 12.4 | 15.2 | 14.8 |
| **HCC Total** | | **694.4** | **797.9** | **815.5** | **1,013.8** | **967.0** | **922.1** | **555.6** | **377.6** | **449.3** | **458.5** | **361.2** | **551.5** | **663.7** |
| **ROR Total** | | **341.7** | **346.8** | **277.7** | **407.8** | **419.9** | **374.2** | **280.1** | **211.0** | **224.7** | **223.3** | **189.2** | **255.9** | **296.0** |
| **Total** | | **1,036.1** | **1,144.7** | **1,093.2** | **1,421.6** | **1,386.8** | **1,296.3** | **835.7** | **588.6** | **674.0** | **681.8** | **550.4** | **807.4** | **959.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2027** | **2/2027** | **3/2027** | **4/2027** | **5/2027** | **6/2027** | **7/2027** | **8/2027** | **9/2027** | **10/2027** | **11/2027** | **12/2027** | **aMW** |
| Brownlee | HCC* | 311.1 | 347.2 | 343.1 | 434.9 | 429.0 | 413.4 | 244.6 | 159.7 | 190.0 | 196.6 | 154.2 | 242.7 | 288.9 |
| Oxbow | HCC | 128.4 | 150.2 | 155.9 | 189.3 | 175.6 | 167.9 | 103.8 | 72.9 | 85.3 | 88.4 | 69.5 | 102.1 | 124.1 |
| Hells Canyon | HCC | 252.6 | 298.3 | 314.7 | 387.9 | 361.5 | 339.1 | 205.7 | 143.5 | 167.7 | 174.4 | 138.4 | 202.6 | 248.9 |
| 1000 Springs | ROR** | 23.6 | 24.8 | 24.9 | 59.1 | 86.4 | 94.2 | 84.0 | 64.8 | 41.9 | 17.3 | - | 11.4 | 44.4 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 47.4 | 47.6 | 40.4 | 52.1 | 49.9 | 42.9 | 34.4 | 26.8 | 35.2 | 38.4 | 35.9 | 39.6 | 40.9 |
| C .J. Strike | ROR | 62.0 | 61.5 | 54.0 | 67.6 | 63.9 | 52.5 | 35.1 | 29.6 | 41.7 | 48.9 | 46.3 | 49.2 | 51.0 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 33.0 | 33.0 | 26.0 | 36.6 | 35.8 | 29.1 | 22.0 | 14.8 | 21.5 | 24.5 | 21.9 | 25.4 | 27.0 |
| Milner | ROR | 39.1 | 39.8 | 17.2 | 40.9 | 40.3 | 23.9 | 6.2 | - | - | - | - | 16.0 | 18.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.7 | 12.0 | 10.8 |
| Swan Falls | ROR | 19.9 | 19.8 | 17.7 | 21.8 | 20.7 | 17.2 | 12.4 | 10.4 | 14.1 | 16.1 | 15.4 | 16.2 | 16.8 |
| Twin Falls | ROR | 38.7 | 39.8 | 20.0 | 43.8 | 40.0 | 26.4 | 10.5 | - | - | 6.6 | 6.0 | 18.9 | 20.9 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.1 | 16.6 | 19.1 | 17.6 | 18.7 | 13.2 | 7.9 | 12.8 | 15.0 | 13.0 | 15.8 | 15.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.4 | 17.7 | 17.7 | 16.2 | 12.5 | 8.0 | 12.2 | 14.0 | 12.3 | 14.7 | 14.7 |
| **HCC Total** | | **692.1** | **795.7** | **813.7** | **1,012.1** | **966.1** | **920.4** | **554.1** | **376.1** | **443.0** | **459.4** | **362.1** | **547.4** | **661.9** |
| **ROR Total** | | **340.2** | **343.8** | **274.7** | **404.1** | **418.3** | **372.3** | **279.4** | **210.1** | **223.6** | **221.6** | **188.4** | **247.0** | **293.6** |
| **Total** | | **1,032.3** | **1,139.5** | **1,088.4** | **1,416.2** | **1,384.4** | **1,292.7** | **833.5** | **586.2** | **666.6** | **681.0** | **550.5** | **794.4** | **955.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2028** | **2/2028** | **3/2028** | **4/2028** | **5/2028** | **6/2028** | **7/2028** | **8/2028** | **9/2028** | **10/2028** | **11/2028** | **12/2028** | **aMW** |
| Brownlee | HCC* | 310.1 | 346.1 | 340.1 | 434.1 | 427.8 | 412.6 | 244.0 | 159.0 | 188.1 | 196.7 | 153.9 | 242.1 | 287.9 |
| Oxbow | HCC | 128.0 | 149.8 | 154.6 | 189.0 | 175.1 | 167.6 | 103.5 | 72.6 | 84.3 | 88.4 | 69.3 | 101.8 | 123.7 |
| Hells Canyon | HCC | 251.8 | 297.4 | 312.2 | 387.2 | 360.6 | 338.5 | 205.3 | 143.0 | 165.8 | 174.3 | 138.0 | 202.1 | 248.0 |
| 1000 Springs | ROR** | 23.5 | 24.6 | 23.9 | 58.2 | 86.3 | 94.0 | 84.0 | 64.7 | 41.9 | 17.0 | - | 10.4 | 44.0 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 47.1 | 47.3 | 39.8 | 51.8 | 49.7 | 42.6 | 34.3 | 26.7 | 34.9 | 38.2 | 35.7 | 38.9 | 40.6 |
| C .J. Strike | ROR | 61.3 | 61.1 | 53.0 | 67.3 | 63.5 | 52.1 | 34.9 | 29.4 | 41.3 | 48.5 | 46.1 | 48.1 | 50.6 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 32.7 | 32.8 | 25.5 | 36.4 | 35.4 | 28.8 | 21.8 | 14.6 | 21.3 | 24.4 | 21.8 | 24.7 | 26.7 |
| Milner | ROR | 38.9 | 39.5 | 16.2 | 43.5 | 40.2 | 23.6 | 6.2 | - | - | - | - | 14.4 | 18.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.6 | 12.0 | 10.8 |
| Swan Falls | ROR | 19.7 | 19.7 | 17.5 | 21.7 | 20.4 | 17.1 | 12.4 | 10.3 | 14.2 | 16.0 | 15.3 | 15.9 | 16.7 |
| Twin Falls | ROR | 38.5 | 39.6 | 18.7 | 42.3 | 39.8 | 26.2 | 10.5 | - | - | 6.6 | 5.9 | 17.3 | 20.5 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.2 | 16.1 | 19.1 | 17.6 | 18.5 | 13.1 | 7.8 | 12.6 | 14.9 | 12.9 | 15.2 | 15.5 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.0 | 17.7 | 17.7 | 16.2 | 12.4 | 7.9 | 12.0 | 13.9 | 12.2 | 14.2 | 14.6 |
| **HCC Total** | | **689.9** | **793.3** | **806.9** | **1,010.3** | **963.5** | **918.7** | **552.8** | **374.6** | **438.1** | **459.4** | **361.2** | **546.0** | **659.6** |
| **ROR Total** | | **338.2** | **342.2** | **268.2** | **403.4** | **416.6** | **370.3** | **278.7** | **209.2** | **222.3** | **220.3** | **187.4** | **238.9** | **291.3** |
| **Total** | | **1,028.1** | **1,135.5** | **1,075.1** | **1,413.7** | **1,380.0** | **1,289.0** | **831.5** | **583.8** | **660.4** | **679.7** | **548.6** | **784.9** | **950.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2029** | **2/2029** | **3/2029** | **4/2029** | **5/2029** | **6/2029** | **7/2029** | **8/2029** | **9/2029** | **10/2029** | **11/2029** | **12/2029** | **aMW** |
| Brownlee | HCC* | 309.1 | 345.1 | 339.7 | 433.4 | 427.0 | 411.9 | 243.5 | 158.4 | 185.8 | 197.0 | 154.2 | 241.1 | 287.2 |
| Oxbow | HCC | 127.6 | 149.3 | 154.4 | 188.7 | 174.8 | 167.3 | 103.3 | 72.3 | 83.2 | 88.3 | 69.4 | 101.4 | 123.3 |
| Hells Canyon | HCC | 251.0 | 296.6 | 311.8 | 386.6 | 359.9 | 337.9 | 204.8 | 142.5 | 163.6 | 174.3 | 138.2 | 201.2 | 247.4 |
| 1000 Springs | ROR** | 23.3 | 24.5 | 23.7 | 58.0 | 85.8 | 93.8 | 84.0 | 64.7 | 41.8 | 17.3 | - | 9.4 | 43.9 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 46.9 | 47.1 | 39.5 | 51.6 | 49.5 | 42.3 | 34.1 | 26.5 | 34.7 | 38.1 | 35.4 | 38.2 | 40.3 |
| C .J. Strike | ROR | 61.0 | 60.8 | 52.6 | 66.5 | 63.2 | 51.7 | 34.7 | 29.2 | 41.0 | 48.2 | 45.8 | 47.1 | 50.2 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 32.5 | 32.5 | 25.0 | 36.1 | 34.2 | 28.5 | 21.7 | 14.4 | 21.1 | 24.2 | 21.5 | 24.0 | 26.3 |
| Milner | ROR | 38.6 | 39.3 | 14.5 | 42.9 | 36.4 | 23.3 | 6.2 | - | - | - | - | 12.5 | 17.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.6 | 12.0 | 10.8 |
| Swan Falls | ROR | 19.6 | 19.6 | 17.3 | 21.4 | 20.3 | 17.0 | 12.3 | 10.3 | 14.1 | 15.9 | 15.2 | 15.6 | 16.6 |
| Twin Falls | ROR | 38.3 | 39.4 | 18.4 | 41.8 | 36.5 | 25.9 | 10.5 | - | - | 6.6 | 5.9 | 15.8 | 19.9 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.2 | 15.7 | 19.1 | 17.6 | 18.3 | 13.0 | 7.7 | 12.5 | 14.8 | 12.7 | 14.7 | 15.4 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.7 | 17.7 | 17.7 | 16.2 | 12.3 | 7.8 | 11.9 | 13.8 | 12.1 | 13.8 | 14.5 |
| **HCC Total** | | **687.7** | **791.0** | **805.9** | **1,008.7** | **961.7** | **917.1** | **551.6** | **373.2** | **432.6** | **459.6** | **361.8** | **543.7** | **657.9** |
| **ROR Total** | | **336.7** | **340.8** | **263.9** | **400.5** | **407.2** | **368.2** | **277.9** | **208.4** | **221.2** | **219.7** | **186.1** | **230.9** | **288.5** |
| **Total** | | **1,024.4** | **1,131.8** | **1,069.8** | **1,409.2** | **1,368.9** | **1,285.3** | **829.5** | **581.6** | **653.8** | **679.3** | **547.9** | **774.6** | **946.3** |

*HCC=HellsCanyonComplex,**ROR=RunofRiver

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2030** | **2/2030** | **3/2030** | **4/2030** | **5/2030** | **6/2030** | **7/2030** | **8/2030** | **9/2030** | **10/2030** | **11/2030** | **12/2030** | **aMW** |
| Brownlee | HCC* | 308.1 | 344.0 | 339.3 | 432.6 | 426.2 | 411.0 | 242.8 | 157.8 | 184.7 | 197.1 | 153.9 | 240.3 | 286.5 |
| Oxbow | HCC | 127.1 | 148.9 | 154.2 | 188.3 | 174.5 | 167.0 | 103.0 | 72.0 | 82.6 | 88.3 | 69.2 | 101.0 | 123.0 |
| Hells Canyon | HCC | 250.2 | 295.7 | 311.5 | 385.9 | 359.3 | 337.3 | 204.3 | 141.9 | 162.4 | 174.2 | 137.9 | 200.5 | 246.8 |
| 1000 Springs | ROR** | 23.1 | 24.3 | 23.4 | 57.8 | 85.8 | 93.7 | 84.0 | 64.7 | 41.7 | 17.2 | - | 8.4 | 43.7 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 46.7 | 46.8 | 38.9 | 51.4 | 49.3 | 42.0 | 34.0 | 26.3 | 34.4 | 38.0 | 35.4 | 37.5 | 40.1 |
| C .J. Strike | ROR | 60.7 | 60.4 | 52.3 | 66.1 | 62.9 | 51.3 | 34.5 | 28.9 | 40.7 | 48.0 | 45.5 | 46.7 | 49.8 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 32.3 | 32.1 | 25.0 | 35.8 | 34.0 | 28.3 | 21.6 | 14.3 | 20.8 | 24.1 | 21.3 | 23.7 | 26.1 |
| Milner | ROR | 38.4 | 39.0 | 13.5 | 42.6 | 36.2 | 23.0 | 6.2 | - | - | - | - | 11.4 | 17.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.6 | 12.0 | 10.8 |
| Swan Falls | ROR | 19.5 | 19.5 | 17.2 | 21.3 | 20.2 | 16.9 | 12.2 | 10.2 | 14.0 | 15.9 | 15.4 | 15.6 | 16.5 |
| Twin Falls | ROR | 38.1 | 39.1 | 17.2 | 41.4 | 36.2 | 25.6 | 10.5 | - | - | 6.6 | 5.9 | 14.2 | 19.6 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.2 | 15.7 | 19.1 | 17.6 | 18.1 | 12.9 | 7.5 | 12.3 | 14.6 | 12.5 | 14.5 | 15.3 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.7 | 17.7 | 17.7 | 16.2 | 12.3 | 7.7 | 11.7 | 13.7 | 11.9 | 13.6 | 14.4 |
| **HCC Total** | | **685.4** | **788.6** | **805.0** | **1,006.8** | **959.9** | **915.3** | **550.1** | **371.7** | **429.7** | **459.6** | **361.0** | **541.8** | **656.2** |
| **ROR Total** | | **335.3** | **338.8** | **260.4** | **398.6** | **405.9** | **366.3** | **277.3** | **207.4** | **219.7** | **218.9** | **185.4** | **225.4** | **286.6** |
| **Total** | | **1,020.7** | **1,127.4** | **1,065.4** | **1,405.4** | **1,365.8** | **1,281.6** | **827.4** | **579.1** | **649.4** | **678.5** | **546.4** | **767.2** | **942.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2031** | **2/2031** | **3/2031** | **4/2031** | **5/2031** | **6/2031** | **7/2031** | **8/2031** | **9/2031** | **10/2031** | **11/2031** | **12/2031** | **aMW** |
| Brownlee | HCC* | 307.1 | 343.0 | 338.8 | 431.9 | 425.3 | 410.3 | 242.3 | 157.2 | 179.2 | 197.0 | 154.4 | 239.4 | 285.5 |
| Oxbow | HCC | 126.7 | 148.5 | 154.0 | 188.0 | 174.2 | 166.7 | 102.8 | 71.7 | 81.7 | 88.1 | 69.4 | 100.7 | 122.7 |
| Hells Canyon | HCC | 249.4 | 294.8 | 311.0 | 385.3 | 358.6 | 336.8 | 203.8 | 141.3 | 160.4 | 173.8 | 138.3 | 199.8 | 246.1 |
| 1000 Springs | ROR** | 23.0 | 23.8 | 22.6 | 57.0 | 85.8 | 93.5 | 84.0 | 64.6 | 41.7 | 17.3 | - | 7.4 | 43.4 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 46.4 | 46.5 | 38.6 | 51.2 | 49.1 | 42.0 | 33.8 | 26.1 | 34.2 | 37.8 | 35.3 | 36.8 | 39.8 |
| C .J. Strike | ROR | 60.3 | 60.0 | 52.0 | 65.2 | 62.7 | 50.9 | 34.3 | 28.7 | 40.5 | 47.7 | 45.3 | 46.5 | 49.5 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 32.1 | 31.9 | 24.9 | 35.5 | 33.8 | 28.0 | 21.4 | 14.1 | 20.6 | 23.9 | 21.2 | 23.7 | 25.9 |
| Milner | ROR | 38.2 | 38.5 | 13.5 | 42.0 | 35.9 | 22.6 | 6.2 | - | - | - | - | 9.8 | 17.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.6 | 12.0 | 10.8 |
| Swan Falls | ROR | 19.4 | 19.4 | 17.1 | 21.1 | 20.1 | 16.7 | 12.2 | 10.1 | 13.9 | 15.8 | 15.3 | 15.6 | 16.4 |
| Twin Falls | ROR | 38.0 | 38.2 | 16.8 | 40.9 | 36.0 | 25.3 | 10.5 | - | - | 6.6 | 5.9 | 12.6 | 19.2 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.2 | 15.6 | 19.1 | 17.6 | 17.9 | 12.8 | 7.4 | 12.1 | 14.5 | 12.4 | 14.5 | 15.2 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.6 | 17.7 | 17.7 | 16.2 | 12.2 | 7.6 | 11.6 | 13.6 | 11.8 | 13.6 | 14.3 |
| **HCC Total** | | **683.2** | **786.3** | **803.8** | **1,005.2** | **958.1** | **913.8** | **548.9** | **370.2** | **421.2** | **458.9** | **362.1** | **539.9** | **654.3** |
| **ROR Total** | | **333.9** | **335.9** | **258.2** | **395.1** | **404.7** | **364.3** | **276.5** | **206.4** | **218.7** | **218.0** | **184.7** | **220.3** | **284.7** |
| **Total** | | **1,017.1** | **1,122.2** | **1,062.0** | **1,400.3** | **1,362.7** | **1,278.1** | **825.4** | **576.6** | **639.9** | **676.9** | **546.8** | **760.2** | **939.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2032** | **2/2032** | **3/2032** | **4/2032** | **5/2032** | **6/2032** | **7/2032** | **8/2032** | **9/2032** | **10/2032** | **11/2032** | **12/2032** | **aMW** |
| Brownlee | HCC* | 306.1 | 342.0 | 338.4 | 431.1 | 424.6 | 409.3 | 241.7 | 156.5 | 177.0 | 197.3 | 154.3 | 238.7 | 284.7 |
| Oxbow | HCC | 126.3 | 148.0 | 153.8 | 187.7 | 173.9 | 166.3 | 102.5 | 71.4 | 80.5 | 88.1 | 69.3 | 100.4 | 122.3 |
| Hells Canyon | HCC | 248.6 | 294.0 | 310.7 | 384.7 | 358.0 | 335.9 | 203.4 | 140.8 | 158.1 | 173.8 | 138.1 | 199.2 | 245.4 |
| 1000 Springs | ROR** | 22.9 | 23.7 | 21.7 | 56.8 | 85.6 | 93.3 | 84.0 | 64.6 | 41.6 | 17.2 | - | 6.4 | 43.1 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 46.2 | 46.3 | 38.5 | 51.1 | 48.9 | 42.0 | 33.7 | 25.9 | 33.9 | 37.7 | 35.1 | 36.5 | 39.7 |
| C .J. Strike | ROR | 60.0 | 59.7 | 51.7 | 64.9 | 62.4 | 50.5 | 34.1 | 28.4 | 40.2 | 47.6 | 45.1 | 46.2 | 49.2 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 31.9 | 31.7 | 24.7 | 35.0 | 33.7 | 27.7 | 21.3 | 14.0 | 20.4 | 23.8 | 21.0 | 23.7 | 25.7 |
| Milner | ROR | 38.0 | 38.2 | 12.5 | 40.8 | 35.7 | 22.3 | 6.2 | - | - | - | - | 8.2 | 16.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.6 | 12.0 | 10.8 |
| Swan Falls | ROR | 19.4 | 19.3 | 17.0 | 21.0 | 20.1 | 16.5 | 12.1 | 10.0 | 13.8 | 15.7 | 15.3 | 15.6 | 16.3 |
| Twin Falls | ROR | 37.8 | 38.0 | 16.0 | 39.9 | 35.8 | 25.0 | 10.5 | - | - | 6.6 | 5.9 | 11.0 | 18.9 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.2 | 15.5 | 19.1 | 17.6 | 17.7 | 12.7 | 7.3 | 12.0 | 14.4 | 12.3 | 14.5 | 15.1 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.5 | 17.7 | 17.7 | 16.2 | 12.1 | 7.5 | 11.4 | 13.5 | 11.7 | 13.6 | 14.3 |
| **HCC Total** | | **681.0** | **784.0** | **802.9** | **1,003.5** | **956.4** | **911.5** | **547.6** | **368.7** | **415.6** | **459.2** | **361.7** | **538.3** | **652.5** |
| **ROR Total** | | **332.7** | **334.5** | **254.6** | **391.7** | **403.5** | **362.4** | **275.8** | **205.5** | **217.4** | **217.3** | **183.9** | **215.5** | **282.9** |
| **Total** | | **1,013.7** | **1,118.5** | **1,057.5** | **1,395.2** | **1,359.9** | **1,273.9** | **823.4** | **574.2** | **633.0** | **676.5** | **545.6** | **753.8** | **935.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2033** | **2/2033** | **3/2033** | **4/2033** | **5/2033** | **6/2033** | **7/2033** | **8/2033** | **9/2033** | **10/2033** | **11/2033** | **12/2033** | **aMW** |
| Brownlee | HCC* | 305.2 | 340.9 | 337.8 | 430.3 | 423.7 | 408.0 | 241.1 | 155.9 | 174.7 | 197.8 | 154.3 | 237.6 | 283.9 |
| Oxbow | HCC | 126.0 | 147.6 | 153.5 | 187.4 | 173.5 | 165.8 | 102.3 | 71.1 | 79.4 | 88.2 | 69.3 | 99.9 | 122.0 |
| Hells Canyon | HCC | 247.9 | 293.2 | 310.2 | 384.0 | 357.3 | 334.9 | 202.9 | 140.2 | 155.9 | 174.0 | 138.0 | 198.3 | 244.7 |
| 1000 Springs | ROR** | 22.7 | 23.5 | 20.8 | 56.6 | 85.4 | 93.1 | 83.9 | 64.5 | 41.5 | 16.9 | - | 5.4 | 42.9 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 46.0 | 46.0 | 38.2 | 50.9 | 48.7 | 42.0 | 33.5 | 25.7 | 33.7 | 37.4 | 34.9 | 36.5 | 39.5 |
| C .J. Strike | ROR | 59.7 | 59.3 | 51.3 | 64.6 | 62.1 | 50.2 | 33.9 | 28.2 | 39.9 | 47.4 | 44.8 | 46.0 | 49.0 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 31.7 | 31.5 | 23.7 | 34.5 | 33.5 | 27.5 | 21.2 | 13.8 | 20.2 | 23.6 | 20.9 | 23.7 | 25.5 |
| Milner | ROR | 37.7 | 37.9 | 11.9 | 38.0 | 35.4 | 22.0 | 6.2 | - | - | - | - | 6.4 | 16.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.6 | 12.0 | 10.8 |
| Swan Falls | ROR | 19.3 | 19.2 | 16.9 | 21.0 | 20.0 | 16.4 | 12.0 | 9.9 | 13.7 | 15.6 | 15.2 | 15.6 | 16.2 |
| Twin Falls | ROR | 37.6 | 37.8 | 14.6 | 37.4 | 35.6 | 24.8 | 10.5 | - | - | 6.6 | 5.9 | 9.6 | 18.4 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.2 | 14.7 | 19.1 | 17.6 | 17.5 | 12.6 | 7.2 | 11.8 | 14.3 | 12.2 | 14.5 | 15.0 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 13.8 | 17.7 | 17.7 | 16.2 | 12.0 | 7.4 | 11.3 | 13.4 | 11.7 | 13.6 | 14.2 |
| **HCC Total** | | **679.1** | **781.7** | **801.5** | **1,001.7** | **954.4** | **908.7** | **546.3** | **367.2** | **410.0** | **460.0** | **361.6** | **535.8** | **650.7** |
| **ROR Total** | | **331.2** | **332.8** | **248.4** | **385.2** | **402.0** | **360.9** | **274.9** | **204.5** | **216.2** | **216.0** | **183.1** | **211.1** | **280.5** |
| **Total** | | **1,010.3** | **1,114.5** | **1,049.9** | **1,386.9** | **1,356.4** | **1,269.6** | **821.2** | **571.7** | **626.2** | **676.0** | **544.7** | **746.9** | **931.2** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2034** | **2/2034** | **3/2034** | **4/2034** | **5/2034** | **6/2034** | **7/2034** | **8/2034** | **9/2034** | **10/2034** | **11/2034** | **12/2034** | **aMW** |
| Brownlee | HCC* | 304.1 | 339.2 | 337.0 | 429.6 | 422.9 | 406.7 | 240.5 | 155.3 | 172.7 | 197.7 | 154.7 | 236.6 | 283.1 |
| Oxbow | HCC | 125.5 | 146.9 | 153.2 | 187.1 | 173.2 | 165.3 | 102.0 | 70.8 | 78.4 | 88.0 | 69.4 | 99.5 | 121.6 |
| Hells Canyon | HCC | 247.1 | 291.7 | 309.4 | 383.4 | 356.7 | 333.9 | 202.4 | 139.6 | 154.0 | 173.7 | 138.3 | 197.5 | 244.0 |
| 1000 Springs | ROR** | 22.4 | 23.3 | 19.9 | 56.4 | 85.3 | 92.9 | 83.9 | 64.5 | 41.5 | 16.5 | - | - | 42.2 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 45.7 | 45.7 | 38.0 | 50.7 | 48.5 | 41.8 | 33.3 | 25.5 | 33.4 | 37.2 | 34.7 | 36.5 | 39.3 |
| C .J. Strike | ROR | 59.4 | 58.9 | 51.0 | 64.3 | 61.8 | 50.0 | 33.7 | 28.0 | 39.5 | 47.1 | 44.7 | 45.8 | 48.7 |
| Cascade | ROR | 1.5 | 1.6 | 2.8 | 5.9 | 5.3 | 12.0 | 10.2 | 13.3 | 8.8 | 2.0 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 31.5 | 31.2 | 23.5 | 34.3 | 33.3 | 27.2 | 21.0 | 13.6 | 20.0 | 23.4 | 20.7 | 23.7 | 25.3 |
| Milner | ROR | 37.3 | 37.6 | 11.6 | 36.7 | 35.2 | 21.7 | 6.2 | - | - | - | - | 6.2 | 16.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.6 | 12.0 | 10.8 |
| Swan Falls | ROR | 19.1 | 19.1 | 16.8 | 20.9 | 19.9 | 16.3 | 12.0 | 9.9 | 13.6 | 15.6 | 15.2 | 15.6 | 16.2 |
| Twin Falls | ROR | 37.2 | 37.5 | 14.3 | 36.3 | 35.4 | 24.5 | 10.5 | - | - | 6.6 | 5.9 | 9.5 | 18.1 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.2 | 14.6 | 19.1 | 17.6 | 17.3 | 12.5 | 7.0 | 11.6 | 14.1 | 12.0 | 14.5 | 14.9 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 13.7 | 17.7 | 17.7 | 16.0 | 11.9 | 7.3 | 11.2 | 13.3 | 11.5 | 13.6 | 14.1 |
| **HCC Total** | | **676.7** | **777.8** | **799.6** | **1,000.1** | **952.7** | **905.9** | **544.9** | **365.7** | **405.0** | **459.4** | **362.4** | **533.6** | **648.6** |
| **ROR Total** | | **329.1** | **330.9** | **245.9** | **381.8** | **400.7** | **358.9** | **274.1** | **203.6** | **214.9** | **214.6** | **182.2** | **205.2** | **278.5** |
| **Total** | | **1,005.8** | **1,108.7** | **1,045.5** | **1,381.9** | **1,353.3** | **1,264.8** | **819.0** | **569.3** | **619.9** | **674.0** | **544.6** | **738.8** | **927.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2015** | **2/2015** | **3/2015** | **4/2015** | **5/2015** | **6/2015** | **7/2015** | **8/2015** | **9/2015** | **10/2015** | **11/2015** | **12/2015** | **aMW** |
| Brownlee | HCC* | 252.2 | 312.3 | 252.5 | 317.5 | 387.2 | 263.4 | 232.9 | 157.0 | 191.8 | 173.5 | 146.5 | 214.8 | 241.8 |
| Oxbow | HCC | 106.2 | 131.2 | 111.4 | 133.2 | 160.2 | 110.8 | 98.5 | 71.6 | 88.8 | 78.5 | 65.6 | 90.0 | 103.8 |
| Hells Canyon | HCC | 210.3 | 258.9 | 227.3 | 269.4 | 325.3 | 226.7 | 194.3 | 140.7 | 174.0 | 154.8 | 130.6 | 178.3 | 207.5 |
| 1000 Springs | ROR** | - | 15.4 | 14.2 | 36.1 | 71.6 | 88.4 | 84.3 | 62.0 | 36.3 | 12.7 | - | - | 35.1 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 38.1 | 42.4 | 38.5 | 38.9 | 41.0 | 39.2 | 34.7 | 27.7 | 36.5 | 38.9 | 36.9 | 37.0 | 37.5 |
| C .J. Strike | ROR | 49.7 | 55.1 | 50.5 | 51.0 | 48.1 | 45.2 | 35.4 | 30.5 | 43.5 | 49.3 | 47.9 | 48.1 | 46.2 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 24.1 | 29.1 | 24.2 | 25.3 | 27.3 | 27.1 | 22.5 | 15.7 | 23.1 | 25.2 | 23.6 | 23.5 | 24.2 |
| Milner | ROR | 8.9 | 26.6 | 10.1 | 10.4 | 15.4 | 15.4 | 6.2 | - | - | - | 3.0 | 6.2 | 8.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 11.8 | 12.0 | 11.0 |
| Swan Falls | ROR | 16.2 | 17.9 | 16.5 | 17.3 | 16.1 | 15.2 | 12.6 | 10.7 | 14.7 | 16.2 | 15.8 | 15.8 | 15.4 |
| Twin Falls | ROR | 11.9 | 27.8 | 12.5 | 12.5 | 18.2 | 18.4 | 10.5 | - | - | 6.6 | 7.8 | 9.5 | 11.3 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 14.8 | 18.9 | 15.1 | 16.0 | 17.6 | 17.2 | 13.6 | 8.6 | 14.1 | 15.5 | 14.3 | 14.3 | 15.0 |
| Upper Salmon 3&4 | ROR | 13.9 | 17.4 | 14.1 | 14.9 | 16.2 | 15.9 | 12.9 | 8.6 | 13.2 | 14.5 | 13.4 | 13.5 | 14.0 |
| **HCC Total** | | **568.7** | **702.4** | **591.2** | **720.1** | **872.6** | **600.9** | **525.7** | **369.3** | **454.5** | **406.8** | **342.7** | **483.1** | **553.2** |
| **ROR Total** | | **217.2** | **291.1** | **236.7** | **263.1** | **314.2** | **328.2** | **279.0** | **210.4** | **224.0** | **219.2** | **202.3** | **207.7** | **249.4** |
| **Total** | | **785.9** | **993.5** | **827.9** | **983.2** | **1,186.8** | **929.1** | **804.7** | **579.7** | **678.5** | **626.0** | **545.0** | **690.8** | **802.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2016** | **2/2016** | **3/2016** | **4/2016** | **5/2016** | **6/2016** | **7/2016** | **8/2016** | **9/2016** | **10/2016** | **11/2016** | **12/2016** | **aMW** |
| Brownlee | HCC* | 252.7 | 316.9 | 254.5 | 321.2 | 391.9 | 265.6 | 232.6 | 156.8 | 190.9 | 173.3 | 146.8 | 214.6 | 243.1 |
| Oxbow | HCC | 106.4 | 133.1 | 112.3 | 134.7 | 162.1 | 111.8 | 98.4 | 71.5 | 88.4 | 78.4 | 65.8 | 89.9 | 104.4 |
| Hells Canyon | HCC | 210.6 | 262.6 | 229.0 | 272.3 | 329.0 | 228.6 | 194.1 | 140.6 | 173.3 | 154.7 | 130.9 | 178.1 | 208.6 |
| 1000 Springs | ROR** | - | 18.0 | 14.1 | 36.7 | 71.6 | 88.5 | 84.5 | 62.4 | 37.1 | 12.9 | - | - | 35.5 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 38.0 | 43.1 | 38.8 | 39.0 | 41.4 | 39.2 | 34.6 | 27.6 | 36.4 | 38.8 | 36.7 | 36.9 | 37.5 |
| C .J. Strike | ROR | 49.8 | 57.3 | 50.8 | 51.2 | 48.8 | 45.1 | 35.4 | 30.4 | 43.3 | 49.2 | 47.8 | 48.1 | 46.4 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 24.2 | 30.9 | 24.8 | 25.3 | 27.4 | 26.9 | 22.4 | 15.6 | 23.0 | 25.1 | 23.5 | 23.5 | 24.4 |
| Milner | ROR | 8.9 | 30.6 | 11.9 | 10.8 | 15.4 | 15.4 | 6.2 | - | - | - | 3.0 | 6.2 | 9.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 11.8 | 12.0 | 11.0 |
| Swan Falls | ROR | 16.2 | 18.1 | 16.8 | 17.5 | 16.1 | 15.3 | 12.6 | 10.7 | 14.6 | 16.2 | 15.8 | 15.8 | 15.5 |
| Twin Falls | ROR | 12.2 | 31.2 | 14.6 | 13.2 | 18.2 | 18.8 | 10.5 | - | - | 6.6 | 7.8 | 9.5 | 11.9 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 14.9 | 19.2 | 15.6 | 16.1 | 17.6 | 17.1 | 13.6 | 8.6 | 13.9 | 15.4 | 14.2 | 14.3 | 15.0 |
| Upper Salmon 3&4 | ROR | 13.9 | 17.7 | 14.5 | 14.9 | 16.3 | 15.8 | 12.8 | 8.5 | 13.1 | 14.4 | 13.4 | 13.4 | 14.1 |
| **HCC Total** | | **569.7** | **712.6** | **595.8** | **728.2** | **882.9** | **606.0** | **525.1** | **368.9** | **452.5** | **406.4** | **343.5** | **482.6** | **556.2** |
| **ROR Total** | | **217.7** | **306.6** | **242.9** | **265.4** | **315.6** | **328.3** | **278.9** | **210.4** | **224.0** | **218.9** | **201.8** | **207.5** | **251.5** |
| **Total** | | **787.4** | **1,019.2** | **838.7** | **993.6** | **1,198.5** | **934.3** | **804.0** | **579.3** | **676.5** | **625.3** | **545.3** | **690.1** | **807.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2017** | **2/2017** | **3/2017** | **4/2017** | **5/2017** | **6/2017** | **7/2017** | **8/2017** | **9/2017** | **10/2017** | **11/2017** | **12/2017** | **aMW** |
| Brownlee | HCC* | 251.4 | 315.8 | 256.8 | 322.5 | 397.3 | 269.0 | 232.8 | 157.2 | 189.6 | 174.0 | 146.8 | 216.3 | 244.1 |
| Oxbow | HCC | 105.9 | 132.6 | 113.3 | 135.2 | 164.3 | 113.2 | 98.5 | 71.7 | 87.6 | 78.5 | 65.7 | 90.6 | 104.8 |
| Hells Canyon | HCC | 209.6 | 261.7 | 230.9 | 273.4 | 333.3 | 231.3 | 194.2 | 140.9 | 171.8 | 154.9 | 130.7 | 179.5 | 209.3 |
| 1000 Springs | ROR** | - | 19.2 | 14.2 | 38.7 | 71.6 | 88.5 | 84.5 | 62.9 | 37.5 | 13.0 | - | - | 35.8 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 37.7 | 44.0 | 38.5 | 38.9 | 41.9 | 39.4 | 34.6 | 27.6 | 36.3 | 38.8 | 36.1 | 36.4 | 37.5 |
| C .J. Strike | ROR | 49.9 | 57.3 | 50.2 | 52.3 | 49.9 | 45.5 | 35.5 | 30.4 | 43.2 | 49.2 | 47.0 | 47.6 | 46.5 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 24.0 | 31.3 | 24.8 | 25.3 | 27.6 | 27.0 | 22.5 | 15.7 | 22.9 | 25.1 | 23.2 | 23.1 | 24.4 |
| Milner | ROR | 8.2 | 31.5 | 11.1 | 10.6 | 15.4 | 15.4 | 6.2 | - | - | - | - | 4.5 | 8.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.9 | 12.0 | 10.8 |
| Swan Falls | ROR | 16.2 | 18.5 | 16.4 | 17.6 | 16.5 | 15.4 | 12.6 | 10.7 | 14.6 | 16.2 | 15.5 | 15.7 | 15.5 |
| Twin Falls | ROR | 11.2 | 32.1 | 13.7 | 13.0 | 18.2 | 19.2 | 10.5 | - | - | 6.6 | 6.2 | 8.5 | 11.6 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 14.7 | 19.2 | 15.6 | 16.1 | 17.7 | 17.1 | 13.6 | 8.6 | 13.9 | 15.4 | 13.9 | 14.0 | 15.0 |
| Upper Salmon 3&4 | ROR | 13.8 | 17.7 | 14.5 | 14.9 | 16.4 | 15.8 | 12.9 | 8.6 | 13.1 | 14.4 | 13.1 | 13.1 | 14.0 |
| **HCC Total** | | **566.9** | **710.1** | **601.0** | **731.1** | **894.8** | **613.5** | **525.5** | **369.8** | **448.9** | **407.4** | **343.2** | **486.4** | **558.2** |
| **ROR Total** | | **215.3** | **311.3** | **240.0** | **268.1** | **318.0** | **329.5** | **279.2** | **211.1** | **224.2** | **219.0** | **192.7** | **202.7** | **250.9** |
| **Total** | | **782.2** | **1,021.4** | **841.0** | **999.2** | **1,212.8** | **943.0** | **804.7** | **580.9** | **673.1** | **626.4** | **535.9** | **689.1** | **809.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2018** | **2/2018** | **3/2018** | **4/2018** | **5/2018** | **6/2018** | **7/2018** | **8/2018** | **9/2018** | **10/2018** | **11/2018** | **12/2018** | **aMW** |
| Brownlee | HCC* | 251.4 | 315.7 | 256.4 | 323.3 | 399.7 | 268.5 | 232.5 | 156.9 | 189.0 | 174.4 | 146.6 | 215.6 | 244.2 |
| Oxbow | HCC | 105.9 | 132.6 | 113.1 | 135.5 | 165.2 | 113.0 | 98.3 | 71.6 | 87.3 | 78.7 | 65.6 | 90.3 | 104.8 |
| Hells Canyon | HCC | 209.6 | 261.7 | 230.6 | 274.0 | 335.1 | 230.9 | 194.0 | 140.6 | 171.1 | 155.2 | 130.5 | 178.9 | 209.3 |
| 1000 Springs | ROR** | - | 19.1 | 14.0 | 39.4 | 72.1 | 88.6 | 84.6 | 63.1 | 37.8 | 14.2 | - | - | 36.1 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 37.6 | 43.0 | 38.4 | 39.5 | 42.4 | 39.4 | 34.5 | 27.5 | 36.2 | 38.7 | 36.1 | 36.1 | 37.5 |
| C .J. Strike | ROR | 49.9 | 57.0 | 49.5 | 52.4 | 49.9 | 45.4 | 35.4 | 30.3 | 43.0 | 49.1 | 46.9 | 47.2 | 46.3 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 24.0 | 31.2 | 24.1 | 25.4 | 27.5 | 26.9 | 22.4 | 15.6 | 22.8 | 25.0 | 23.1 | 22.8 | 24.2 |
| Milner | ROR | 8.2 | 31.3 | 9.6 | 10.7 | 15.4 | 15.4 | 6.2 | - | - | - | - | 3.8 | 8.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 9.9 | 12.0 | 10.8 |
| Swan Falls | ROR | 16.2 | 18.2 | 16.2 | 17.7 | 16.5 | 15.2 | 12.6 | 10.6 | 14.5 | 16.1 | 15.5 | 15.6 | 15.4 |
| Twin Falls | ROR | 11.6 | 31.8 | 12.2 | 13.5 | 18.2 | 19.2 | 10.5 | - | - | 6.6 | 6.2 | 8.1 | 11.5 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 14.8 | 19.2 | 15.1 | 16.1 | 17.7 | 17.0 | 13.6 | 8.5 | 13.8 | 15.4 | 13.9 | 13.8 | 14.9 |
| Upper Salmon 3&4 | ROR | 13.8 | 17.7 | 14.1 | 15.0 | 16.4 | 15.8 | 12.8 | 8.5 | 13.0 | 14.3 | 13.1 | 13.0 | 14.0 |
| **HCC Total** | | **566.9** | **710.0** | **600.1** | **732.8** | **900.0** | **612.4** | **524.8** | **369.1** | **447.4** | **408.3** | **342.7** | **484.8** | **558.3** |
| **ROR Total** | | **215.7** | **309.0** | **234.2** | **270.4** | **318.9** | **329.1** | **278.9** | **210.7** | **223.8** | **219.7** | **192.5** | **200.2** | **250.3** |
| **Total** | | **782.6** | **1,019.0** | **834.3** | **1,003.2** | **1,218.8** | **941.5** | **803.7** | **579.8** | **671.1** | **628.0** | **535.2** | **685.0** | **808.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2019** | **2/2019** | **3/2019** | **4/2019** | **5/2019** | **6/2019** | **7/2019** | **8/2019** | **9/2019** | **10/2019** | **11/2019** | **12/2019** | **aMW** |
| Brownlee | HCC* | 252.1 | 316.1 | 256.3 | 324.2 | 402.8 | 270.3 | 233.2 | 157.3 | 187.0 | 174.9 | 147.1 | 212.8 | 244.5 |
| Oxbow | HCC | 106.2 | 132.7 | 113.1 | 135.9 | 166.4 | 113.7 | 98.6 | 71.8 | 86.2 | 78.6 | 65.7 | 89.2 | 104.8 |
| Hells Canyon | HCC | 210.2 | 262.0 | 230.5 | 274.7 | 337.5 | 232.3 | 194.6 | 141.0 | 169.0 | 155.2 | 130.8 | 176.6 | 209.5 |
| 1000 Springs | ROR** | - | 17.6 | 14.1 | 39.7 | 72.8 | 88.6 | 84.6 | 63.3 | 37.7 | 15.0 | - | - | 36.1 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 37.9 | 42.8 | 36.9 | 39.3 | 42.7 | 39.5 | 34.7 | 27.7 | 36.1 | 38.8 | 35.8 | 35.6 | 37.3 |
| C .J. Strike | ROR | 49.9 | 56.8 | 47.8 | 52.3 | 50.3 | 45.7 | 35.7 | 30.3 | 42.9 | 49.1 | 46.0 | 46.4 | 46.1 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 23.9 | 30.3 | 22.9 | 24.6 | 27.7 | 27.0 | 22.5 | 15.6 | 22.8 | 25.1 | 22.5 | 22.3 | 23.9 |
| Milner | ROR | 8.0 | 29.0 | 5.8 | 8.1 | 15.4 | 15.4 | 6.2 | - | - | - | - | 1.7 | 7.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 10.7 | 10.6 |
| Swan Falls | ROR | 16.1 | 17.8 | 15.8 | 17.7 | 16.7 | 15.4 | 12.6 | 10.6 | 14.5 | 16.1 | 15.4 | 15.4 | 15.3 |
| Twin Falls | ROR | 11.3 | 29.8 | 9.1 | 10.9 | 18.2 | 19.2 | 10.5 | - | - | 6.6 | 4.5 | 6.8 | 10.6 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 14.7 | 19.2 | 14.1 | 15.5 | 17.7 | 17.1 | 13.7 | 8.6 | 13.8 | 15.4 | 13.4 | 13.4 | 14.7 |
| Upper Salmon 3&4 | ROR | 13.8 | 17.7 | 13.3 | 14.4 | 16.5 | 15.9 | 12.9 | 8.6 | 13.0 | 14.4 | 12.7 | 12.6 | 13.8 |
| **HCC Total** | | **568.5** | **710.8** | **599.9** | **734.8** | **906.6** | **616.3** | **526.4** | **370.1** | **442.1** | **408.7** | **343.6** | **478.6** | **558.9** |
| **ROR Total** | | **215.2** | **301.5** | **220.8** | **263.2** | **320.8** | **330.0** | **279.7** | **211.3** | **223.5** | **220.8** | **186.3** | **192.7** | **247.2** |
| **Total** | | **783.7** | **1,012.3** | **820.7** | **998.0** | **1,227.4** | **946.3** | **806.1** | **581.4** | **665.6** | **629.5** | **529.9** | **671.3** | **806.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2020** | **2/2020** | **3/2020** | **4/2020** | **5/2020** | **6/2020** | **7/2020** | **8/2020** | **9/2020** | **10/2020** | **11/2020** | **12/2020** | **aMW** |
| Brownlee | HCC* | 251.1 | 315.3 | 256.2 | 323.3 | 401.8 | 269.0 | 232.6 | 156.7 | 184.5 | 175.0 | 147.2 | 210.1 | 243.6 |
| Oxbow | HCC | 105.7 | 132.4 | 113.0 | 135.5 | 166.1 | 113.2 | 98.4 | 71.4 | 84.9 | 78.5 | 65.7 | 88.0 | 104.4 |
| Hells Canyon | HCC | 209.3 | 261.3 | 230.4 | 274.0 | 336.8 | 231.3 | 194.1 | 140.4 | 166.6 | 155.0 | 130.7 | 174.3 | 208.7 |
| 1000 Springs | ROR** | - | 15.6 | 14.0 | 39.5 | 72.7 | 88.6 | 84.6 | 63.2 | 37.7 | 15.0 | - | - | 35.9 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 37.5 | 42.1 | 36.7 | 39.1 | 42.5 | 39.3 | 34.6 | 27.5 | 35.9 | 38.6 | 35.5 | 35.5 | 37.1 |
| C .J. Strike | ROR | 49.1 | 54.6 | 47.5 | 52.1 | 50.1 | 45.4 | 35.4 | 30.1 | 42.6 | 48.8 | 45.7 | 46.2 | 45.6 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 23.5 | 29.3 | 22.6 | 24.4 | 27.6 | 26.9 | 22.4 | 15.5 | 22.5 | 24.9 | 22.5 | 22.2 | 23.7 |
| Milner | ROR | 7.7 | 26.8 | 5.2 | 7.8 | 15.4 | 15.4 | 6.2 | - | - | - | - | 1.9 | 7.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 10.9 | 10.6 |
| Swan Falls | ROR | 16.1 | 17.5 | 15.7 | 17.6 | 16.5 | 15.3 | 12.6 | 10.6 | 14.4 | 16.0 | 15.3 | 15.3 | 15.2 |
| Twin Falls | ROR | 11.1 | 27.9 | 8.6 | 10.6 | 18.2 | 19.2 | 10.5 | - | - | 6.6 | 4.5 | 7.0 | 10.4 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 14.4 | 19.0 | 13.9 | 15.3 | 17.7 | 17.0 | 13.6 | 8.4 | 13.6 | 15.3 | 13.4 | 13.3 | 14.6 |
| Upper Salmon 3&4 | ROR | 13.5 | 17.5 | 13.1 | 14.3 | 16.4 | 15.8 | 12.8 | 8.4 | 12.8 | 14.3 | 12.7 | 12.6 | 13.7 |
| **HCC Total** | | **566.1** | **709.0** | **599.6** | **732.8** | **904.6** | **613.5** | **525.1** | **368.5** | **436.0** | **408.5** | **343.6** | **472.4** | **556.6** |
| **ROR Total** | | **212.5** | **290.8** | **218.3** | **261.4** | **319.8** | **329.1** | **279.0** | **210.3** | **222.2** | **219.8** | **185.6** | **192.7** | **245.1** |
| **Total** | | **778.6** | **999.8** | **817.9** | **994.2** | **1,224.4** | **942.6** | **804.1** | **578.8** | **658.1** | **628.3** | **529.2** | **665.1** | **801.8** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2021** | **2/2021** | **3/2021** | **4/2021** | **5/2021** | **6/2021** | **7/2021** | **8/2021** | **9/2021** | **10/2021** | **11/2021** | **12/2021** | **aMW** |
| Brownlee | HCC* | 250.0 | 314.4 | 251.5 | 322.3 | 400.9 | 267.8 | 232.0 | 156.0 | 182.3 | 175.2 | 147.5 | 208.5 | 242.4 |
| Oxbow | HCC | 105.3 | 132.0 | 110.9 | 135.1 | 165.7 | 112.7 | 98.1 | 71.1 | 83.8 | 78.5 | 65.8 | 87.3 | 103.9 |
| Hells Canyon | HCC | 208.5 | 260.6 | 226.4 | 273.1 | 336.1 | 230.3 | 193.6 | 139.9 | 164.4 | 154.8 | 130.9 | 173.1 | 207.6 |
| 1000 Springs | ROR** | - | 15.2 | 14.0 | 39.3 | 72.5 | 88.6 | 84.7 | 63.0 | 37.6 | 15.0 | - | - | 35.8 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 37.2 | 40.6 | 35.7 | 38.8 | 42.4 | 39.1 | 34.4 | 27.3 | 35.6 | 38.4 | 35.3 | 35.4 | 36.7 |
| C .J. Strike | ROR | 48.9 | 53.2 | 47.3 | 51.9 | 49.9 | 45.1 | 35.2 | 29.8 | 42.2 | 48.5 | 45.5 | 45.9 | 45.3 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 23.4 | 29.0 | 21.6 | 24.1 | 27.5 | 26.7 | 22.3 | 15.3 | 22.3 | 24.7 | 22.3 | 22.1 | 23.4 |
| Milner | ROR | 7.7 | 26.0 | 2.4 | 7.4 | 15.4 | 15.4 | 6.2 | - | - | - | - | 1.9 | 6.9 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.2 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 10.9 | 10.5 |
| Swan Falls | ROR | 16.0 | 17.4 | 15.7 | 17.5 | 16.4 | 15.2 | 12.5 | 10.5 | 14.3 | 16.0 | 15.2 | 15.3 | 15.2 |
| Twin Falls | ROR | 10.4 | 27.3 | 6.4 | 10.2 | 18.2 | 19.2 | 10.5 | - | - | 6.6 | 4.5 | 7.0 | 10.0 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 14.3 | 18.8 | 13.1 | 15.1 | 17.7 | 16.9 | 13.5 | 8.3 | 13.4 | 15.1 | 13.3 | 13.2 | 14.4 |
| Upper Salmon 3&4 | ROR | 13.4 | 17.3 | 12.4 | 14.2 | 16.4 | 15.6 | 12.7 | 8.3 | 12.7 | 14.1 | 12.6 | 12.5 | 13.5 |
| **HCC Total** | | **563.8** | **707.0** | **588.8** | **730.5** | **902.6** | **610.8** | **523.7** | **367.0** | **430.4** | **408.5** | **344.2** | **468.9** | **553.9** |
| **ROR Total** | | **210.9** | **285.3** | **207.8** | **259.2** | **319.1** | **328.0** | **278.3** | **209.1** | **220.8** | **218.7** | **184.7** | **192.0** | **242.8** |
| **Total** | | **774.7** | **992.3** | **796.6** | **989.7** | **1,221.7** | **938.8** | **802.0** | **576.1** | **651.2** | **627.2** | **528.9** | **660.9** | **796.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2022** | **2/2022** | **3/2022** | **4/2022** | **5/2022** | **6/2022** | **7/2022** | **8/2022** | **9/2022** | **10/2022** | **11/2022** | **12/2022** | **aMW** |
| Brownlee | HCC* | 249.1 | 313.6 | 250.6 | 321.3 | 400.0 | 266.6 | 231.3 | 155.4 | 180.2 | 175.6 | 147.2 | 207.6 | 241.5 |
| Oxbow | HCC | 104.9 | 131.7 | 110.5 | 134.7 | 165.3 | 112.2 | 97.8 | 70.8 | 82.6 | 78.5 | 65.6 | 86.9 | 103.5 |
| Hells Canyon | HCC | 207.7 | 260.0 | 225.6 | 272.3 | 335.3 | 229.3 | 193.0 | 139.3 | 162.2 | 155.0 | 130.5 | 172.2 | 206.9 |
| 1000 Springs | ROR** | - | 15.4 | 13.6 | 39.0 | 72.3 | 88.6 | 84.6 | 62.8 | 37.5 | 15.0 | - | - | 35.7 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 37.1 | 40.7 | 35.7 | 38.6 | 41.9 | 38.9 | 34.4 | 27.1 | 35.4 | 38.2 | 35.3 | 35.2 | 36.5 |
| C .J. Strike | ROR | 48.6 | 53.3 | 47.1 | 51.7 | 49.7 | 44.9 | 35.0 | 29.6 | 41.9 | 48.3 | 45.5 | 45.7 | 45.1 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 23.1 | 29.1 | 21.5 | 23.9 | 27.4 | 26.5 | 22.1 | 15.2 | 22.1 | 24.5 | 22.1 | 21.9 | 23.3 |
| Milner | ROR | 7.7 | 25.8 | - | 7.0 | 15.4 | 15.4 | 6.2 | - | - | - | - | 1.9 | 6.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 9.5 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 10.9 | 10.4 |
| Swan Falls | ROR | 15.9 | 17.5 | 15.6 | 17.4 | 16.4 | 15.2 | 12.4 | 10.4 | 14.2 | 15.9 | 15.4 | 15.4 | 15.1 |
| Twin Falls | ROR | 10.4 | 27.4 | 5.8 | 9.9 | 18.2 | 19.2 | 10.5 | - | - | 6.6 | 4.5 | 7.0 | 10.0 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 14.0 | 18.8 | 13.1 | 15.0 | 17.6 | 16.7 | 13.4 | 8.2 | 13.3 | 15.0 | 13.1 | 13.1 | 14.3 |
| Upper Salmon 3&4 | ROR | 13.2 | 17.3 | 12.4 | 14.0 | 16.3 | 15.5 | 12.6 | 8.2 | 12.6 | 14.0 | 12.4 | 12.4 | 13.4 |
| **HCC Total** | | **561.7** | **705.3** | **586.7** | **728.3** | **900.6** | **608.1** | **522.1** | **365.5** | **424.9** | **409.1** | **343.3** | **466.7** | **551.9** |
| **ROR Total** | | **209.6** | **285.8** | **203.3** | **257.2** | **318.0** | **327.1** | **277.5** | **208.1** | **219.7** | **217.8** | **184.3** | **191.3** | **241.6** |
| **Total** | | **771.3** | **991.1** | **790.0** | **985.5** | **1,218.5** | **935.2** | **799.6** | **573.6** | **644.6** | **626.9** | **527.6** | **658.0** | **793.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2023** | **2/2023** | **3/2023** | **4/2023** | **5/2023** | **6/2023** | **7/2023** | **8/2023** | **9/2023** | **10/2023** | **11/2023** | **12/2023** | **aMW** |
| Brownlee | HCC* | 247.9 | 312.3 | 250.1 | 320.3 | 399.2 | 265.3 | 230.7 | 154.8 | 177.7 | 175.8 | 147.5 | 204.3 | 240.5 |
| Oxbow | HCC | 104.4 | 131.2 | 110.4 | 134.3 | 165.0 | 111.6 | 97.6 | 70.5 | 81.4 | 78.5 | 65.7 | 85.5 | 103.0 |
| Hells Canyon | HCC | 206.8 | 259.0 | 225.3 | 271.6 | 334.7 | 228.3 | 192.5 | 138.7 | 159.7 | 154.9 | 130.7 | 169.5 | 206.0 |
| 1000 Springs | ROR** | - | 12.7 | 13.5 | 38.8 | 72.0 | 88.6 | 84.7 | 62.7 | 36.9 | 14.8 | - | - | 35.4 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.9 | 37.9 | 35.7 | 38.3 | 41.8 | 38.7 | 34.2 | 26.9 | 35.1 | 38.0 | 35.2 | 35.0 | 36.1 |
| C .J. Strike | ROR | 48.3 | 52.6 | 46.9 | 51.6 | 49.1 | 44.6 | 34.8 | 29.4 | 41.6 | 48.0 | 45.3 | 45.1 | 44.8 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.7 | 27.4 | 21.4 | 23.7 | 27.2 | 26.4 | 22.0 | 15.0 | 21.9 | 24.4 | 21.9 | 21.7 | 23.0 |
| Milner | ROR | 7.7 | 21.2 | - | 6.7 | 15.4 | 15.4 | 6.2 | - | - | - | - | 1.9 | 6.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 9.5 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 10.9 | 10.4 |
| Swan Falls | ROR | 15.8 | 17.0 | 15.6 | 17.4 | 16.3 | 15.2 | 12.4 | 10.3 | 14.1 | 15.8 | 15.3 | 15.3 | 15.0 |
| Twin Falls | ROR | 10.4 | 23.3 | 5.8 | 9.8 | 18.2 | 19.2 | 10.5 | - | - | 6.6 | 4.5 | 7.0 | 9.6 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.8 | 17.5 | 13.0 | 14.8 | 17.5 | 16.6 | 13.3 | 8.1 | 13.1 | 14.9 | 13.0 | 12.9 | 14.0 |
| Upper Salmon 3&4 | ROR | 13.0 | 16.2 | 12.3 | 13.9 | 16.2 | 15.4 | 12.5 | 8.1 | 12.4 | 13.9 | 12.3 | 12.3 | 13.2 |
| **HCC Total** | | **559.1** | **702.5** | **585.8** | **726.2** | **898.8** | **605.2** | **520.8** | **364.0** | **418.7** | **409.2** | **343.9** | **459.3** | **549.5** |
| **ROR Total** | | **208.2** | **266.3** | **202.7** | **255.7** | **316.4** | **326.3** | **276.9** | **207.1** | **217.8** | **216.7** | **183.5** | **189.9** | **239.0** |
| **Total** | | **767.3** | **968.8** | **788.5** | **981.9** | **1,215.2** | **931.5** | **797.7** | **571.1** | **636.5** | **625.9** | **527.4** | **649.2** | **788.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2024** | **2/2024** | **3/2024** | **4/2024** | **5/2024** | **6/2024** | **7/2024** | **8/2024** | **9/2024** | **10/2024** | **11/2024** | **12/2024** | **aMW** |
| Brownlee | HCC* | 246.6 | 309.4 | 249.7 | 319.4 | 398.3 | 263.9 | 230.1 | 154.1 | 174.9 | 176.2 | 147.5 | 200.3 | 239.2 |
| Oxbow | HCC | 103.8 | 130.0 | 110.2 | 133.9 | 164.6 | 111.0 | 97.3 | 70.2 | 79.9 | 78.4 | 65.5 | 83.8 | 102.4 |
| Hells Canyon | HCC | 205.7 | 256.6 | 224.9 | 270.8 | 334.0 | 227.2 | 192.0 | 138.1 | 156.9 | 154.8 | 130.4 | 166.2 | 204.8 |
| 1000 Springs | ROR** | - | 10.3 | 13.0 | 37.1 | 71.9 | 88.6 | 84.7 | 62.5 | 36.9 | 14.7 | - | - | 35.0 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.7 | 37.7 | 35.7 | 38.1 | 41.6 | 38.5 | 34.0 | 26.7 | 34.9 | 37.8 | 35.0 | 34.8 | 36.0 |
| C .J. Strike | ROR | 48.0 | 52.7 | 46.7 | 51.3 | 48.9 | 44.3 | 34.6 | 29.1 | 41.2 | 47.8 | 45.1 | 44.9 | 44.6 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.7 | 26.0 | 21.3 | 23.5 | 27.2 | 26.2 | 21.8 | 14.8 | 21.7 | 24.2 | 21.8 | 21.6 | 22.7 |
| Milner | ROR | 7.7 | 17.2 | 2.0 | 6.2 | 15.4 | 15.4 | 6.2 | - | - | - | - | 1.9 | 6.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 9.7 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 10.7 | 10.4 |
| Swan Falls | ROR | 15.7 | 17.1 | 15.5 | 17.2 | 16.3 | 15.2 | 12.3 | 10.2 | 14.1 | 15.8 | 15.2 | 15.2 | 15.0 |
| Twin Falls | ROR | 10.4 | 20.2 | 6.0 | 9.5 | 18.2 | 19.2 | 10.5 | - | - | 6.6 | 4.5 | 6.8 | 9.3 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.7 | 16.5 | 12.9 | 14.7 | 17.5 | 16.5 | 13.1 | 8.0 | 12.9 | 14.8 | 12.9 | 12.8 | 13.9 |
| Upper Salmon 3&4 | ROR | 13.0 | 15.3 | 12.2 | 13.8 | 16.1 | 15.3 | 12.4 | 8.0 | 12.3 | 13.8 | 12.2 | 12.2 | 13.1 |
| **HCC Total** | | **556.1** | **696.0** | **584.8** | **724.1** | **896.8** | **602.1** | **519.4** | **362.4** | **411.7** | **409.4** | **343.4** | **450.3** | **546.4** |
| **ROR Total** | | **207.5** | **253.5** | **204.0** | **252.1** | **315.9** | **325.4** | **275.9** | **205.9** | **216.7** | **215.8** | **182.7** | **188.7** | **237.0** |
| **Total** | | **763.6** | **949.5** | **788.8** | **976.2** | **1,212.7** | **927.5** | **795.3** | **568.3** | **628.3** | **625.2** | **526.1** | **639.0** | **783.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2025** | **2/2025** | **3/2025** | **4/2025** | **5/2025** | **6/2025** | **7/2025** | **8/2025** | **9/2025** | **10/2025** | **11/2025** | **12/2025** | **aMW** |
| Brownlee | HCC* | 246.0 | 308.4 | 249.3 | 318.5 | 397.5 | 262.2 | 229.5 | 153.5 | 173.2 | 168.8 | 147.9 | 198.8 | 237.8 |
| Oxbow | HCC | 103.6 | 129.6 | 110.0 | 133.6 | 164.3 | 110.3 | 97.1 | 69.9 | 79.1 | 78.2 | 65.7 | 83.1 | 102.0 |
| Hells Canyon | HCC | 205.2 | 255.9 | 224.5 | 270.2 | 333.4 | 225.8 | 191.5 | 137.6 | 155.3 | 154.0 | 130.7 | 164.9 | 204.1 |
| 1000 Springs | ROR** | - | 9.0 | 11.9 | 37.0 | 71.8 | 88.6 | 84.6 | 62.2 | 36.3 | 14.6 | - | - | 34.7 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.6 | 37.6 | 35.2 | 37.9 | 41.5 | 38.3 | 33.9 | 26.5 | 34.6 | 37.7 | 34.8 | 34.5 | 35.8 |
| C .J. Strike | ROR | 47.4 | 50.7 | 46.5 | 51.1 | 48.7 | 44.1 | 34.4 | 28.9 | 40.9 | 47.6 | 44.7 | 44.9 | 44.2 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.6 | 25.1 | 21.3 | 23.4 | 27.1 | 26.0 | 21.7 | 14.7 | 21.4 | 24.1 | 21.6 | 21.4 | 22.5 |
| Milner | ROR | 7.7 | 14.8 | 2.1 | 5.9 | 15.4 | 15.4 | 6.2 | - | - | - | - | 1.7 | 5.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 9.8 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 10.5 | 10.4 |
| Swan Falls | ROR | 15.6 | 16.1 | 15.4 | 17.2 | 16.2 | 15.1 | 12.2 | 10.2 | 14.1 | 15.7 | 15.2 | 15.2 | 14.9 |
| Twin Falls | ROR | 10.4 | 18.2 | 6.1 | 9.3 | 18.2 | 19.2 | 10.5 | - | - | 6.6 | 4.5 | 6.6 | 9.1 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.7 | 15.8 | 12.9 | 14.6 | 17.4 | 16.4 | 13.0 | 7.8 | 12.8 | 14.6 | 12.8 | 12.7 | 13.7 |
| Upper Salmon 3&4 | ROR | 12.9 | 14.7 | 12.2 | 13.7 | 16.1 | 15.2 | 12.4 | 7.9 | 12.1 | 13.7 | 12.1 | 12.0 | 12.9 |
| **HCC Total** | | **554.8** | **693.9** | **583.8** | **722.3** | **895.1** | **598.3** | **518.1** | **361.0** | **407.5** | **401.0** | **344.3** | **446.8** | **543.9** |
| **ROR Total** | | **206.5** | **242.5** | **202.4** | **250.8** | **315.1** | **324.5** | **275.2** | **204.8** | **214.9** | **214.9** | **181.7** | **187.3** | **235.1** |
| **Total** | | **761.3** | **936.4** | **786.2** | **973.1** | **1,210.2** | **922.8** | **793.3** | **565.8** | **622.4** | **615.9** | **526.0** | **634.1** | **779.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2026** | **2/2026** | **3/2026** | **4/2026** | **5/2026** | **6/2026** | **7/2026** | **8/2026** | **9/2026** | **10/2026** | **11/2026** | **12/2026** | **aMW** |
| Brownlee | HCC* | 245.3 | 306.0 | 248.8 | 317.7 | 396.7 | 261.4 | 228.9 | 152.8 | 171.5 | 168.8 | 147.9 | 198.4 | 237.0 |
| Oxbow | HCC | 103.3 | 128.6 | 109.8 | 133.2 | 164.0 | 110.0 | 96.8 | 69.6 | 78.2 | 78.2 | 65.6 | 83.0 | 101.7 |
| Hells Canyon | HCC | 204.6 | 253.9 | 224.1 | 269.5 | 332.8 | 225.1 | 191.0 | 137.0 | 153.6 | 153.9 | 130.6 | 164.6 | 203.4 |
| 1000 Springs | ROR** | - | 7.4 | 11.2 | 35.9 | 71.7 | 88.6 | 84.6 | 62.0 | 35.9 | 14.5 | - | - | 34.3 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.4 | 37.2 | 34.6 | 37.7 | 41.4 | 38.1 | 33.7 | 26.3 | 34.4 | 37.5 | 34.6 | 34.2 | 35.5 |
| C .J. Strike | ROR | 47.2 | 49.3 | 46.3 | 50.9 | 48.2 | 43.7 | 34.2 | 28.6 | 40.7 | 47.4 | 44.6 | 44.6 | 43.8 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.5 | 22.7 | 21.1 | 22.5 | 27.0 | 25.8 | 21.6 | 14.5 | 21.2 | 23.9 | 21.5 | 21.3 | 22.1 |
| Milner | ROR | 7.7 | 10.7 | 2.0 | 5.2 | 15.4 | 15.4 | 6.2 | - | - | - | - | 1.8 | 5.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 9.7 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 10.5 | 10.4 |
| Swan Falls | ROR | 15.6 | 16.0 | 15.3 | 17.1 | 16.0 | 14.9 | 12.1 | 10.1 | 14.0 | 15.6 | 15.1 | 15.1 | 14.7 |
| Twin Falls | ROR | 10.4 | 12.6 | 6.0 | 8.5 | 18.2 | 18.8 | 10.5 | - | - | 6.6 | 4.5 | 6.7 | 8.6 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.6 | 13.9 | 12.7 | 13.9 | 17.3 | 16.2 | 12.9 | 7.7 | 12.6 | 14.5 | 12.6 | 12.6 | 13.4 |
| Upper Salmon 3&4 | ROR | 12.8 | 13.1 | 12.1 | 13.1 | 16.0 | 15.1 | 12.3 | 7.8 | 12.0 | 13.6 | 12.0 | 11.9 | 12.7 |
| **HCC Total** | | **553.2** | **688.5** | **582.7** | **720.4** | **893.5** | **596.5** | **516.7** | **359.4** | **403.2** | **400.9** | **344.1** | **446.0** | **542.1** |
| **ROR Total** | | **205.8** | **223.4** | **200.0** | **245.5** | **313.9** | **322.8** | **274.4** | **203.6** | **213.5** | **213.9** | **180.9** | **186.5** | **232.0** |
| **Total** | | **759.0** | **911.9** | **782.7** | **965.9** | **1,207.4** | **919.3** | **791.1** | **563.0** | **616.7** | **614.8** | **525.0** | **632.5** | **774.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2027** | **2/2027** | **3/2027** | **4/2027** | **5/2027** | **6/2027** | **7/2027** | **8/2027** | **9/2027** | **10/2027** | **11/2027** | **12/2027** | **aMW** |
| Brownlee | HCC* | 244.3 | 301.9 | 248.3 | 316.9 | 395.9 | 260.6 | 228.3 | 152.2 | 169.6 | 169.1 | 147.9 | 197.8 | 236.1 |
| Oxbow | HCC | 102.9 | 126.9 | 109.5 | 132.9 | 163.7 | 109.7 | 96.6 | 69.3 | 77.2 | 78.2 | 65.6 | 82.7 | 101.3 |
| Hells Canyon | HCC | 203.8 | 250.6 | 223.7 | 268.9 | 332.2 | 224.5 | 190.5 | 136.4 | 151.7 | 153.9 | 130.6 | 164.1 | 202.6 |
| 1000 Springs | ROR** | - | - | 11.1 | 34.8 | 71.7 | 88.6 | 84.7 | 61.8 | 35.2 | 14.3 | - | - | 33.5 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.3 | 37.0 | 34.5 | 37.5 | 41.2 | 37.9 | 33.6 | 26.1 | 34.1 | 37.4 | 34.2 | 34.0 | 35.3 |
| C .J. Strike | ROR | 47.0 | 48.6 | 45.8 | 50.7 | 48.1 | 43.6 | 34.0 | 28.4 | 40.3 | 47.1 | 44.4 | 44.5 | 43.5 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.4 | 22.7 | 20.9 | 22.5 | 26.9 | 25.7 | 21.4 | 14.4 | 21.0 | 23.8 | 21.3 | 21.1 | 22.0 |
| Milner | ROR | 7.7 | 8.2 | 1.7 | 4.9 | 15.4 | 15.4 | 6.2 | - | - | - | - | 1.7 | 5.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 9.7 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 10.4 | 10.4 |
| Swan Falls | ROR | 15.5 | 15.8 | 15.4 | 17.0 | 16.0 | 14.8 | 12.1 | 10.0 | 13.9 | 15.5 | 15.0 | 15.0 | 14.7 |
| Twin Falls | ROR | 10.4 | 11.6 | 6.0 | 8.5 | 18.2 | 18.8 | 10.5 | - | - | 6.6 | 4.5 | 6.6 | 8.5 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.5 | 13.9 | 12.6 | 13.8 | 17.2 | 16.1 | 12.8 | 7.6 | 12.4 | 14.4 | 12.5 | 12.4 | 13.3 |
| Upper Salmon 3&4 | ROR | 12.7 | 13.1 | 12.0 | 13.0 | 16.0 | 15.0 | 12.2 | 7.7 | 11.8 | 13.6 | 11.9 | 11.8 | 12.6 |
| **HCC Total** | | **551.0** | **679.4** | **581.5** | **718.7** | **891.8** | **594.8** | **515.4** | **357.9** | **398.4** | **401.2** | **344.1** | **444.6** | **539.9** |
| **ROR Total** | | **205.1** | **211.4** | **198.7** | **243.4** | **313.4** | **322.1** | **273.8** | **202.6** | **211.4** | **213.0** | **179.8** | **185.3** | **230.0** |
| **Total** | | **756.1** | **890.8** | **780.2** | **962.1** | **1,205.2** | **916.9** | **789.2** | **560.5** | **609.8** | **614.2** | **523.9** | **629.9** | **769.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2028** | **2/2028** | **3/2028** | **4/2028** | **5/2028** | **6/2028** | **7/2028** | **8/2028** | **9/2028** | **10/2028** | **11/2028** | **12/2028** | **aMW** |
| Brownlee | HCC* | 243.3 | 299.7 | 247.9 | 316.0 | 395.2 | 259.9 | 227.7 | 151.6 | 167.3 | 169.6 | 148.0 | 196.7 | 235.2 |
| Oxbow | HCC | 102.4 | 126.0 | 109.4 | 132.5 | 163.4 | 109.4 | 96.3 | 69.0 | 76.1 | 78.3 | 65.6 | 82.3 | 100.9 |
| Hells Canyon | HCC | 202.9 | 248.8 | 223.3 | 268.2 | 331.6 | 223.9 | 190.0 | 135.9 | 149.4 | 154.1 | 130.6 | 163.2 | 201.8 |
| 1000 Springs | ROR** | - | - | 11.0 | 36.0 | 71.7 | 88.6 | 84.7 | 61.5 | 34.9 | 14.2 | - | - | 33.5 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.2 | 36.7 | 34.3 | 37.3 | 41.0 | 37.7 | 33.4 | 26.0 | 33.9 | 37.2 | 34.0 | 34.0 | 35.1 |
| C .J. Strike | ROR | 46.8 | 48.4 | 45.4 | 50.6 | 47.9 | 43.5 | 33.8 | 28.1 | 40.0 | 46.9 | 44.2 | 44.3 | 43.3 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.3 | 22.5 | 20.8 | 22.4 | 26.8 | 25.5 | 21.3 | 14.2 | 20.8 | 23.7 | 20.9 | 20.9 | 21.8 |
| Milner | ROR | 7.6 | 8.2 | - | 4.7 | 15.4 | 15.4 | 6.2 | - | - | - | - | 1.7 | 4.9 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.8 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 10.1 | 10.3 |
| Swan Falls | ROR | 15.4 | 15.7 | 15.4 | 16.9 | 16.0 | 14.8 | 12.0 | 9.9 | 13.8 | 15.5 | 15.0 | 15.0 | 14.6 |
| Twin Falls | ROR | 10.4 | 11.6 | 5.2 | 8.4 | 18.2 | 18.8 | 10.5 | - | - | 6.6 | 4.5 | 6.3 | 8.4 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.4 | 13.7 | 12.5 | 13.8 | 17.2 | 16.0 | 12.7 | 7.5 | 12.3 | 14.3 | 12.2 | 12.3 | 13.2 |
| Upper Salmon 3&4 | ROR | 12.7 | 12.9 | 11.9 | 13.0 | 15.9 | 14.9 | 12.1 | 7.6 | 11.7 | 13.4 | 11.7 | 11.7 | 12.5 |
| **HCC Total** | | **548.6** | **674.5** | **580.6** | **716.7** | **890.1** | **593.2** | **514.0** | **356.5** | **392.7** | **402.0** | **344.2** | **442.2** | **537.9** |
| **ROR Total** | | **204.4** | **210.2** | **194.3** | **243.8** | **312.8** | **321.4** | **273.0** | **201.4** | **210.1** | **212.1** | **178.5** | **184.1** | **228.8** |
| **Total** | | **753.0** | **884.7** | **774.9** | **960.5** | **1,202.9** | **914.6** | **787.0** | **557.9** | **602.8** | **614.1** | **522.7** | **626.3** | **766.8** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2029** | **2/2029** | **3/2029** | **4/2029** | **5/2029** | **6/2029** | **7/2029** | **8/2029** | **9/2029** | **10/2029** | **11/2029** | **12/2029** | **aMW** |
| Brownlee | HCC* | 242.7 | 298.5 | 247.5 | 315.1 | 394.4 | 259.1 | 227.1 | 151.1 | 161.7 | 169.4 | 148.1 | 196.1 | 234.2 |
| Oxbow | HCC | 102.2 | 125.5 | 109.2 | 132.2 | 163.1 | 109.0 | 96.1 | 68.8 | 75.1 | 78.1 | 65.6 | 82.0 | 100.6 |
| Hells Canyon | HCC | 202.5 | 247.9 | 223.0 | 267.5 | 331.0 | 223.3 | 189.6 | 135.5 | 147.4 | 153.7 | 130.6 | 162.7 | 201.2 |
| 1000 Springs | ROR** | - | - | 10.7 | 34.9 | 71.7 | 88.6 | 84.7 | 61.4 | 34.8 | 14.1 | - | - | 33.4 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.1 | 36.1 | 34.2 | 36.6 | 40.9 | 37.5 | 33.3 | 25.8 | 33.6 | 37.0 | 33.8 | 33.8 | 34.9 |
| C .J. Strike | ROR | 46.6 | 48.2 | 45.3 | 50.4 | 47.8 | 43.2 | 33.6 | 27.8 | 39.7 | 46.6 | 44.0 | 44.0 | 43.1 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.1 | 22.0 | 20.7 | 21.7 | 26.7 | 25.3 | 21.2 | 14.0 | 20.6 | 23.5 | 20.8 | 20.7 | 21.6 |
| Milner | ROR | 7.6 | 8.0 | - | 4.5 | 15.4 | 15.3 | 6.2 | - | - | - | - | 1.6 | 4.9 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.8 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 9.7 | 10.2 |
| Swan Falls | ROR | 15.3 | 15.6 | 15.3 | 16.8 | 16.0 | 14.7 | 11.9 | 9.8 | 13.7 | 15.5 | 14.9 | 14.9 | 14.5 |
| Twin Falls | ROR | 10.4 | 11.3 | 5.2 | 8.4 | 18.2 | 18.8 | 10.5 | - | - | 6.6 | 4.5 | 6.0 | 8.3 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.3 | 13.4 | 12.4 | 13.2 | 17.1 | 15.8 | 12.6 | 7.3 | 12.1 | 14.2 | 12.1 | 12.1 | 13.0 |
| Upper Salmon 3&4 | ROR | 12.6 | 12.6 | 11.8 | 12.5 | 15.8 | 14.7 | 12.0 | 7.5 | 11.6 | 13.3 | 11.5 | 11.6 | 12.3 |
| **HCC Total** | | **547.4** | **671.9** | **579.7** | **714.8** | **888.4** | **591.4** | **512.8** | **355.4** | **384.1** | **401.2** | **344.3** | **440.8** | **536.0** |
| **ROR Total** | | **203.6** | **207.7** | **193.4** | **239.7** | **312.3** | **320.1** | **272.3** | **200.2** | **208.8** | **211.1** | **177.6** | **182.2** | **227.4** |
| **Total** | | **751.0** | **879.6** | **773.1** | **954.5** | **1,200.7** | **911.5** | **785.1** | **555.6** | **592.9** | **612.3** | **521.9** | **623.0** | **763.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2030** | **2/2030** | **3/2030** | **4/2030** | **5/2030** | **6/2030** | **7/2030** | **8/2030** | **9/2030** | **10/2030** | **11/2030** | **12/2030** | **aMW** |
| Brownlee | HCC* | 242.1 | 297.7 | 247.0 | 314.3 | 393.6 | 258.4 | 226.5 | 151.0 | 159.8 | 169.5 | 148.2 | 195.0 | 233.6 |
| Oxbow | HCC | 101.9 | 125.2 | 109.0 | 131.9 | 162.8 | 108.7 | 95.8 | 68.8 | 74.1 | 78.1 | 65.6 | 81.5 | 100.3 |
| Hells Canyon | HCC | 202.0 | 247.2 | 222.6 | 266.8 | 330.4 | 222.7 | 189.0 | 135.4 | 145.5 | 153.7 | 130.7 | 161.8 | 200.6 |
| 1000 Springs | ROR** | - | - | 10.4 | 34.7 | 71.6 | 88.5 | 84.7 | 61.4 | 34.8 | 14.2 | - | - | 33.4 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 35.8 | 35.9 | 34.1 | 35.7 | 40.8 | 37.3 | 33.1 | 25.6 | 33.4 | 36.8 | 33.6 | 33.5 | 34.6 |
| C .J. Strike | ROR | 46.2 | 47.9 | 45.1 | 49.0 | 47.6 | 42.9 | 33.3 | 27.6 | 39.4 | 46.4 | 43.7 | 43.9 | 42.8 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.0 | 21.9 | 20.6 | 21.3 | 26.6 | 25.1 | 21.0 | 13.9 | 20.4 | 23.3 | 20.7 | 20.6 | 21.5 |
| Milner | ROR | 7.3 | 8.0 | - | 3.1 | 15.4 | 15.0 | 6.2 | - | - | - | - | 1.6 | 4.7 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 9.5 | 11.3 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 9.7 | 10.2 |
| Swan Falls | ROR | 15.2 | 15.6 | 15.3 | 16.5 | 15.9 | 14.6 | 11.9 | 9.8 | 13.6 | 15.4 | 14.9 | 14.8 | 14.5 |
| Twin Falls | ROR | 10.3 | 11.3 | 5.8 | 7.3 | 18.1 | 18.6 | 10.5 | - | - | 6.6 | 4.5 | 6.0 | 8.3 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.2 | 13.3 | 12.4 | 12.9 | 17.0 | 15.7 | 12.5 | 7.2 | 11.9 | 14.1 | 12.0 | 12.0 | 12.9 |
| Upper Salmon 3&4 | ROR | 12.5 | 12.5 | 11.8 | 12.3 | 15.8 | 14.6 | 11.9 | 7.4 | 11.4 | 13.2 | 11.5 | 11.5 | 12.2 |
| **HCC Total** | | **546.0** | **670.1** | **578.6** | **713.0** | **886.8** | **589.8** | **511.3** | **355.2** | **379.3** | **401.3** | **344.5** | **438.3** | **534.5** |
| **ROR Total** | | **202.1** | **206.9** | **194.0** | **232.8** | **311.6** | **318.5** | **271.4** | **199.5** | **207.6** | **210.3** | **176.9** | **181.4** | **226.1** |
| **Total** | | **748.1** | **877.0** | **772.6** | **945.8** | **1,198.3** | **908.3** | **782.7** | **554.7** | **586.9** | **611.6** | **521.4** | **619.7** | **760.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2031** | **2/2031** | **3/2031** | **4/2031** | **5/2031** | **6/2031** | **7/2031** | **8/2031** | **9/2031** | **10/2031** | **11/2031** | **12/2031** | **aMW** |
| Brownlee | HCC* | 241.3 | 297.0 | 246.6 | 313.4 | 392.9 | 257.7 | 225.9 | 150.7 | 157.7 | 169.7 | 148.2 | 193.7 | 232.9 |
| Oxbow | HCC | 101.6 | 124.9 | 108.8 | 131.5 | 162.5 | 108.4 | 95.5 | 68.7 | 72.9 | 78.0 | 65.6 | 81.0 | 99.9 |
| Hells Canyon | HCC | 201.3 | 246.7 | 222.3 | 266.1 | 329.7 | 222.1 | 188.5 | 135.2 | 143.3 | 153.6 | 130.6 | 160.7 | 200.0 |
| 1000 Springs | ROR** | - | - | 10.2 | 33.2 | 71.6 | 88.5 | 84.7 | 61.4 | 34.6 | 14.1 | - | - | 33.2 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 35.6 | 35.6 | 34.0 | 35.6 | 40.7 | 37.1 | 33.0 | 25.4 | 33.1 | 36.6 | 33.6 | 33.4 | 34.5 |
| C .J. Strike | ROR | 46.0 | 47.6 | 44.9 | 47.8 | 47.5 | 42.5 | 33.2 | 27.4 | 39.1 | 46.1 | 43.5 | 43.6 | 42.4 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 21.8 | 21.7 | 20.5 | 21.1 | 26.5 | 24.9 | 20.9 | 13.7 | 20.2 | 23.2 | 20.5 | 20.4 | 21.3 |
| Milner | ROR | 7.3 | 8.0 | - | 2.0 | 15.3 | 14.8 | 6.2 | - | - | - | - | 1.6 | 4.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 9.2 | 10.2 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 9.7 | 10.1 |
| Swan Falls | ROR | 15.4 | 15.5 | 15.2 | 16.4 | 15.9 | 14.5 | 11.8 | 9.7 | 13.5 | 15.3 | 14.8 | 14.8 | 14.4 |
| Twin Falls | ROR | 10.3 | 10.7 | 5.5 | 6.4 | 17.9 | 18.6 | 10.5 | - | - | 6.6 | 4.5 | 6.0 | 8.1 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.1 | 13.1 | 12.3 | 12.8 | 16.9 | 15.5 | 12.4 | 7.1 | 11.8 | 13.9 | 11.9 | 11.9 | 12.7 |
| Upper Salmon 3&4 | ROR | 12.4 | 12.4 | 11.7 | 12.1 | 15.7 | 14.4 | 11.8 | 7.3 | 11.3 | 13.1 | 11.4 | 11.4 | 12.1 |
| **HCC Total** | | **544.2** | **668.6** | **577.7** | **711.0** | **885.0** | **588.2** | **509.9** | **354.6** | **373.9** | **401.3** | **344.4** | **435.4** | **532.8** |
| **ROR Total** | | **201.5** | **205.1** | **192.5** | **226.3** | **310.8** | **317.0** | **270.8** | **198.6** | **206.3** | **209.2** | **176.2** | **180.6** | **224.6** |
| **Total** | | **745.7** | **873.7** | **770.2** | **937.3** | **1,195.8** | **905.2** | **780.7** | **553.2** | **580.1** | **610.5** | **520.6** | **616.0** | **757.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2032** | **2/2032** | **3/2032** | **4/2032** | **5/2032** | **6/2032** | **7/2032** | **8/2032** | **9/2032** | **10/2032** | **11/2032** | **12/2032** | **aMW** |
| Brownlee | HCC* | 240.7 | 296.2 | 245.9 | 312.6 | 392.1 | 256.8 | 225.3 | 150.1 | 155.7 | 169.9 | 148.2 | 193.1 | 232.2 |
| Oxbow | HCC | 101.3 | 124.6 | 108.5 | 131.2 | 162.2 | 108.1 | 95.3 | 68.4 | 71.9 | 78.0 | 65.6 | 80.7 | 99.6 |
| Hells Canyon | HCC | 200.8 | 246.1 | 221.6 | 265.5 | 329.2 | 221.4 | 188.0 | 134.6 | 141.4 | 153.5 | 130.5 | 160.2 | 199.4 |
| 1000 Springs | ROR** | - | - | 9.9 | 33.1 | 71.6 | 88.5 | 84.6 | 61.4 | 34.5 | 14.1 | - | - | 33.1 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 35.4 | 35.4 | 33.9 | 35.5 | 40.6 | 36.9 | 32.9 | 25.2 | 32.9 | 36.4 | 33.4 | 33.2 | 34.3 |
| C .J. Strike | ROR | 45.7 | 47.1 | 44.6 | 47.6 | 47.4 | 42.4 | 33.0 | 27.1 | 38.8 | 45.9 | 43.3 | 43.2 | 42.2 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 21.7 | 21.6 | 20.4 | 20.9 | 26.4 | 24.7 | 20.8 | 13.6 | 19.9 | 23.0 | 20.3 | 20.3 | 21.1 |
| Milner | ROR | 7.3 | 7.8 | - | - | 15.0 | 14.5 | 6.2 | - | - | - | - | 1.6 | 4.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.9 | 9.4 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 9.6 | 10.0 |
| Swan Falls | ROR | 15.3 | 15.4 | 15.2 | 16.3 | 15.9 | 14.5 | 11.8 | 9.7 | 13.4 | 15.2 | 14.7 | 14.7 | 14.3 |
| Twin Falls | ROR | 10.3 | 10.6 | 5.3 | 5.7 | 17.9 | 18.3 | 10.5 | - | - | 6.6 | 4.5 | 5.9 | 8.0 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.9 | 13.0 | 12.2 | 12.6 | 16.8 | 15.3 | 12.3 | 7.0 | 11.6 | 13.8 | 11.8 | 11.8 | 12.6 |
| Upper Salmon 3&4 | ROR | 12.3 | 12.3 | 11.6 | 12.0 | 15.6 | 14.3 | 11.7 | 7.2 | 11.1 | 13.0 | 11.3 | 11.3 | 12.0 |
| **HCC Total** | | **542.8** | **666.9** | **576.0** | **709.3** | **883.4** | **586.3** | **508.6** | **353.1** | **369.0** | **401.4** | **344.3** | **434.0** | **531.3** |
| **ROR Total** | | **200.5** | **203.7** | **191.0** | **221.8** | **309.9** | **315.6** | **270.1** | **197.8** | **204.9** | **208.3** | **175.3** | **179.4** | **223.2** |
| **Total** | | **743.3** | **870.6** | **767.0** | **931.1** | **1,193.3** | **901.9** | **778.7** | **550.9** | **573.8** | **609.7** | **519.6** | **613.4** | **754.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2033** | **2/2033** | **3/2033** | **4/2033** | **5/2033** | **6/2033** | **7/2033** | **8/2033** | **9/2033** | **10/2033** | **11/2033** | **12/2033** | **aMW** |
| Brownlee | HCC* | 240.1 | 295.5 | 243.7 | 311.7 | 391.6 | 256.0 | 224.7 | 149.5 | 153.8 | 169.7 | 148.7 | 192.4 | 231.4 |
| Oxbow | HCC | 101.1 | 124.3 | 107.6 | 130.8 | 162.0 | 107.7 | 95.0 | 68.1 | 70.9 | 77.8 | 65.7 | 80.4 | 99.3 |
| Hells Canyon | HCC | 200.3 | 245.5 | 219.8 | 264.8 | 328.7 | 220.7 | 187.5 | 134.1 | 139.5 | 153.2 | 130.8 | 159.6 | 198.7 |
| 1000 Springs | ROR** | - | - | 9.0 | 33.1 | 71.6 | 88.5 | 84.7 | 61.4 | 34.5 | 14.0 | - | - | 33.1 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 35.3 | 35.2 | 33.8 | 35.3 | 40.5 | 36.7 | 32.8 | 25.0 | 32.6 | 36.2 | 33.2 | 33.0 | 34.1 |
| C .J. Strike | ROR | 45.0 | 46.6 | 44.4 | 47.4 | 47.2 | 42.3 | 32.8 | 26.9 | 38.5 | 45.7 | 43.2 | 42.6 | 41.9 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 21.6 | 21.5 | 20.3 | 20.7 | 26.3 | 24.5 | 20.6 | 13.4 | 19.7 | 22.8 | 20.2 | 20.1 | 21.0 |
| Milner | ROR | 7.3 | 7.8 | - | - | 14.3 | 14.2 | 6.2 | - | - | - | - | 1.6 | 4.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.6 | 8.8 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 9.6 | 9.9 |
| Swan Falls | ROR | 15.2 | 15.3 | 15.1 | 16.3 | 15.8 | 14.4 | 11.7 | 9.6 | 13.3 | 15.4 | 14.6 | 14.5 | 14.3 |
| Twin Falls | ROR | 10.3 | 10.6 | 4.8 | 5.2 | 17.7 | 18.2 | 10.5 | - | - | 6.6 | 4.5 | 5.9 | 7.9 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.8 | 12.9 | 12.1 | 12.5 | 16.8 | 15.2 | 12.2 | 6.9 | 11.4 | 13.7 | 11.6 | 11.7 | 12.5 |
| Upper Salmon 3&4 | ROR | 12.2 | 12.2 | 11.6 | 11.9 | 15.6 | 14.2 | 11.6 | 7.1 | 11.0 | 12.9 | 11.2 | 11.2 | 11.9 |
| **HCC Total** | | **541.5** | **665.3** | **571.1** | **707.3** | **882.2** | **584.4** | **507.2** | **351.7** | **364.2** | **400.7** | **345.2** | **432.4** | **529.4** |
| **ROR Total** | | **199.3** | **202.6** | **188.7** | **219.9** | **308.5** | **314.4** | **269.4** | **196.9** | **203.7** | **207.6** | **174.5** | **178.0** | **222.0** |
| **Total** | | **740.8** | **867.9** | **759.8** | **927.2** | **1,190.7** | **898.8** | **776.6** | **548.6** | **567.8** | **608.3** | **519.7** | **610.4** | **751.4** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2034** | **2/2034** | **3/2034** | **4/2034** | **5/2034** | **6/2034** | **7/2034** | **8/2034** | **9/2034** | **10/2034** | **11/2034** | **12/2034** | **aMW** |
| Brownlee | HCC* | 240.1 | 294.7 | 242.8 | 310.9 | 391.1 | 255.1 | 224.1 | 148.9 | 151.9 | 169.8 | 148.4 | 192.2 | 230.8 |
| Oxbow | HCC | 101.1 | 123.9 | 107.1 | 130.5 | 161.8 | 107.3 | 94.8 | 67.8 | 69.9 | 77.8 | 65.6 | 80.3 | 99.0 |
| Hells Canyon | HCC | 200.3 | 244.9 | 219.0 | 264.1 | 328.3 | 220.0 | 187.1 | 133.5 | 137.6 | 153.1 | 130.5 | 159.4 | 198.1 |
| 1000 Springs | ROR** | - | - | 8.6 | 33.1 | 71.6 | 88.3 | 84.6 | 61.3 | 34.5 | 14.0 | - | - | 33.0 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 34.9 | 35.0 | 33.6 | 35.2 | 40.4 | 36.5 | 32.6 | 24.8 | 32.4 | 36.0 | 32.8 | 32.8 | 33.9 |
| C .J. Strike | ROR | 44.1 | 45.2 | 44.2 | 47.2 | 47.1 | 42.0 | 32.6 | 26.7 | 38.2 | 45.5 | 43.0 | 42.2 | 41.5 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.0 | 7.4 | 12.1 | 7.4 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 21.4 | 21.3 | 20.1 | 20.5 | 26.2 | 24.3 | 20.5 | 13.2 | 19.5 | 22.7 | 19.9 | 19.9 | 20.8 |
| Milner | ROR | 7.3 | 7.5 | - | - | 14.3 | 14.2 | 6.2 | - | - | - | - | 1.6 | 4.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.5 | 8.6 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 10.5 | 8.2 | 9.6 | 9.9 |
| Swan Falls | ROR | 15.0 | 15.3 | 15.0 | 16.2 | 15.7 | 14.4 | 11.6 | 9.5 | 13.2 | 15.3 | 14.6 | 14.4 | 14.2 |
| Twin Falls | ROR | 10.3 | 10.5 | 4.7 | 4.8 | 17.7 | 18.2 | 10.5 | - | - | 6.6 | 4.5 | 5.9 | 7.8 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.7 | 12.8 | 12.0 | 12.3 | 16.7 | 15.0 | 12.1 | 6.7 | 11.3 | 13.5 | 11.4 | 11.5 | 12.3 |
| Upper Salmon 3&4 | ROR | 12.1 | 12.1 | 11.5 | 11.8 | 15.5 | 14.1 | 11.5 | 7.0 | 10.8 | 12.8 | 11.0 | 11.0 | 11.8 |
| **HCC Total** | | **541.5** | **663.5** | **568.9** | **705.5** | **881.1** | **582.4** | **506.0** | **350.2** | **359.4** | **400.7** | **344.5** | **431.9** | **528.0** |
| **ROR Total** | | **197.4** | **200.2** | **187.2** | **218.4** | **307.9** | **313.2** | **268.5** | **195.8** | **202.6** | **206.7** | **173.2** | **176.7** | **220.7** |
| **Total** | | **738.9** | **863.7** | **756.1** | **923.9** | **1,189.0** | **895.6** | **774.5** | **546.0** | **561.9** | **607.4** | **517.7** | **608.6** | **748.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2015** | **2/2015** | **3/2015** | **4/2015** | **5/2015** | **6/2015** | **7/2015** | **8/2015** | **9/2015** | **10/2015** | **11/2015** | **12/2015** | **aMW** |
| Brownlee | HCC* | 211.6 | 197.2 | 238.9 | 253.6 | 272.2 | 204.3 | 218.2 | 144.1 | 157.4 | 153.8 | 149.0 | 191.1 | 199.3 |
| Oxbow | HCC | 88.6 | 82.8 | 99.9 | 105.6 | 112.7 | 84.2 | 91.9 | 65.5 | 73.1 | 70.5 | 65.7 | 79.6 | 85.0 |
| Hells Canyon | HCC | 175.1 | 164.8 | 202.4 | 214.2 | 231.3 | 169.8 | 180.6 | 128.8 | 143.1 | 139.2 | 130.4 | 157.4 | 169.8 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 0.0 | 29.8 | 70.5 | 86.4 | 85.4 | 56.2 | 28.0 | 9.4 | 0.0 | 0.0 | 30.5 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 34.7 | 35.0 | 33.4 | 32.5 | 38.0 | 36.7 | 33.5 | 26.6 | 35.2 | 37.7 | 35.6 | 35.4 | 34.5 |
| C .J. Strike | ROR | 44.1 | 43.7 | 43.5 | 41.2 | 42.5 | 39.4 | 31.3 | 29.0 | 39.0 | 44.9 | 44.5 | 44.0 | 40.6 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.3 | 22.6 | 20.6 | 20.0 | 25.5 | 24.4 | 21.8 | 15.0 | 22.0 | 24.1 | 22.9 | 22.7 | 22.0 |
| Milner | ROR | 6.0 | 6.1 | 0.0 | 0.0 | 12.8 | 12.7 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 4.9 | 4.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.6 | 4.5 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 9.2 | 10.7 | 12.0 | 9.8 |
| Swan Falls | ROR | 14.9 | 14.8 | 14.8 | 14.2 | 14.7 | 14.0 | 11.4 | 10.2 | 13.8 | 15.2 | 15.2 | 15.0 | 14.0 |
| Twin Falls | ROR | 9.3 | 9.3 | 4.0 | 0.0 | 15.9 | 16.4 | 10.1 | 0.0 | 0.0 | 5.5 | 6.8 | 8.9 | 7.2 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.4 | 13.8 | 12.3 | 11.9 | 16.1 | 15.1 | 13.1 | 8.1 | 13.2 | 14.7 | 13.8 | 13.7 | 13.3 |
| Upper Salmon 3&4 | ROR | 12.7 | 13.0 | 11.7 | 11.4 | 15.0 | 14.1 | 12.4 | 8.1 | 12.5 | 13.7 | 13.0 | 12.9 | 12.5 |
| **HCC Total** | | **475.3** | **444.8** | **541.2** | **573.4** | **616.1** | **458.3** | **490.7** | **338.4** | **373.6** | **363.5** | **345.1** | **428.1** | **454.0** |
| **ROR Total** | | **196.9** | **198.8** | **176.9** | **194.3** | **293.2** | **302.6** | **271.1** | **197.6** | **205.2** | **204.1** | **190.3** | **197.2** | **219.0** |
| **Total** | | **672.2** | **643.6** | **718.1** | **767.7** | **909.3** | **760.9** | **761.8** | **536.0** | **578.8** | **567.6** | **535.4** | **625.3** | **673.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2016** | **2/2016** | **3/2016** | **4/2016** | **5/2016** | **6/2016** | **7/2016** | **8/2016** | **9/2016** | **10/2016** | **11/2016** | **12/2016** | **aMW** |
| Brownlee | HCC* | 211.3 | 200.1 | 238.7 | 253.8 | 275.8 | 203.8 | 218.0 | 143.7 | 156.5 | 154.1 | 149.1 | 190.8 | 199.6 |
| Oxbow | HCC | 88.4 | 84.1 | 99.8 | 105.7 | 114.2 | 84.0 | 91.8 | 65.3 | 72.7 | 70.7 | 65.7 | 79.5 | 85.2 |
| Hells Canyon | HCC | 174.8 | 167.2 | 202.3 | 214.4 | 234.2 | 169.5 | 180.4 | 128.4 | 142.3 | 139.4 | 130.5 | 157.1 | 170.0 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 0.0 | 29.7 | 70.5 | 86.7 | 85.6 | 56.9 | 28.9 | 9.3 | 0.0 | 0.0 | 30.6 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 34.7 | 35.0 | 33.4 | 32.8 | 38.0 | 36.6 | 33.4 | 26.5 | 35.0 | 37.7 | 35.4 | 35.3 | 34.5 |
| C .J. Strike | ROR | 44.0 | 43.5 | 43.5 | 41.1 | 42.5 | 39.3 | 31.2 | 28.9 | 38.8 | 44.9 | 44.4 | 43.9 | 40.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.2 | 22.5 | 20.5 | 19.9 | 25.4 | 24.3 | 21.8 | 14.9 | 21.9 | 24.1 | 22.8 | 22.6 | 21.9 |
| Milner | ROR | 6.1 | 7.1 | 0.0 | 0.0 | 12.8 | 12.7 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 4.9 | 4.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.6 | 4.5 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 9.8 | 11.1 | 12.0 | 9.8 |
| Swan Falls | ROR | 14.9 | 14.8 | 14.8 | 14.2 | 14.8 | 14.0 | 11.4 | 10.2 | 13.8 | 15.2 | 15.2 | 15.0 | 14.0 |
| Twin Falls | ROR | 9.3 | 9.9 | 4.0 | 0.0 | 15.9 | 16.4 | 10.1 | 0.0 | 0.0 | 6.0 | 7.2 | 8.9 | 7.3 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.3 | 13.7 | 12.3 | 11.9 | 16.1 | 15.0 | 13.1 | 8.0 | 13.1 | 14.6 | 13.7 | 13.6 | 13.2 |
| Upper Salmon 3&4 | ROR | 12.6 | 13.0 | 11.7 | 11.4 | 15.0 | 14.1 | 12.4 | 8.1 | 12.4 | 13.7 | 12.9 | 12.9 | 12.5 |
| **HCC Total** | | **474.5** | **451.4** | **540.8** | **573.9** | **624.1** | **457.3** | **490.2** | **337.4** | **371.4** | **364.2** | **345.3** | **427.4** | **454.8** |
| **ROR Total** | | **196.6** | **200.0** | **176.8** | **194.3** | **293.2** | **302.5** | **271.1** | **197.9** | **205.4** | **205.0** | **190.5** | **196.8** | **219.2** |
| **Total** | | **671.1** | **651.4** | **717.6** | **768.2** | **917.3** | **759.8** | **761.3** | **535.3** | **576.7** | **569.2** | **535.8** | **624.2** | **674.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2017** | **2/2017** | **3/2017** | **4/2017** | **5/2017** | **6/2017** | **7/2017** | **8/2017** | **9/2017** | **10/2017** | **11/2017** | **12/2017** | **aMW** |
| Brownlee | HCC* | 210.7 | 201.0 | 236.8 | 257.8 | 280.9 | 204.0 | 218.4 | 143.7 | 155.6 | 154.3 | 149.6 | 189.2 | 200.2 |
| Oxbow | HCC | 88.2 | 84.4 | 99.0 | 107.3 | 114.6 | 84.1 | 92.0 | 65.3 | 72.2 | 70.6 | 65.9 | 78.8 | 85.2 |
| Hells Canyon | HCC | 174.3 | 167.9 | 200.7 | 217.6 | 234.1 | 169.6 | 180.7 | 128.4 | 141.3 | 139.3 | 130.8 | 155.9 | 170.0 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 0.0 | 29.9 | 70.7 | 86.7 | 85.7 | 57.1 | 30.1 | 9.4 | 0.0 | 0.0 | 30.8 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 34.3 | 34.7 | 33.2 | 33.2 | 38.3 | 36.6 | 33.4 | 26.5 | 34.9 | 37.6 | 34.8 | 34.7 | 34.4 |
| C .J. Strike | ROR | 43.7 | 43.3 | 43.5 | 41.4 | 43.5 | 39.6 | 31.4 | 29.0 | 38.8 | 44.9 | 44.1 | 43.2 | 40.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.1 | 22.3 | 20.4 | 20.0 | 25.5 | 24.3 | 21.8 | 14.9 | 21.9 | 24.1 | 22.3 | 22.1 | 21.8 |
| Milner | ROR | 5.0 | 7.0 | 0.0 | 0.0 | 12.8 | 12.7 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 3.8 | 4.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 4.5 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 10.0 | 9.8 | 12.0 | 9.7 |
| Swan Falls | ROR | 14.8 | 14.7 | 14.8 | 14.2 | 15.1 | 14.1 | 11.5 | 10.2 | 13.8 | 15.2 | 15.0 | 14.8 | 14.0 |
| Twin Falls | ROR | 8.7 | 9.8 | 3.8 | 0.0 | 15.9 | 16.4 | 10.1 | 0.0 | 0.0 | 6.2 | 6.1 | 8.3 | 7.1 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.2 | 13.5 | 12.2 | 11.9 | 16.2 | 15.0 | 13.1 | 8.0 | 13.1 | 14.6 | 13.3 | 13.2 | 13.1 |
| Upper Salmon 3&4 | ROR | 12.5 | 12.8 | 11.6 | 11.4 | 15.0 | 14.1 | 12.4 | 8.1 | 12.4 | 13.7 | 12.5 | 12.5 | 12.4 |
| **HCC Total** | | **473.2** | **453.3** | **536.5** | **582.7** | **629.5** | **457.7** | **491.1** | **337.4** | **369.0** | **364.2** | **346.3** | **423.9** | **455.4** |
| **ROR Total** | | **193.8** | **198.6** | **175.8** | **195.3** | **295.2** | **302.9** | **271.5** | **198.2** | **206.5** | **205.4** | **185.7** | **192.3** | **218.4** |
| **Total** | | **667.0** | **651.9** | **712.3** | **778.0** | **924.7** | **760.6** | **762.6** | **535.6** | **575.5** | **569.6** | **532.0** | **616.2** | **673.8** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2018** | **2/2018** | **3/2018** | **4/2018** | **5/2018** | **6/2018** | **7/2018** | **8/2018** | **9/2018** | **10/2018** | **11/2018** | **12/2018** | **aMW** |
| Brownlee | HCC* | 209.6 | 202.7 | 236.0 | 258.1 | 281.9 | 203.7 | 218.1 | 143.4 | 154.5 | 154.1 | 149.5 | 188.5 | 200.0 |
| Oxbow | HCC | 87.7 | 85.2 | 98.7 | 107.4 | 115.0 | 84.0 | 91.9 | 65.1 | 71.6 | 70.5 | 65.8 | 78.5 | 85.1 |
| Hells Canyon | HCC | 173.4 | 169.3 | 200.0 | 217.8 | 234.9 | 169.4 | 180.5 | 128.1 | 140.3 | 139.1 | 130.7 | 155.3 | 169.9 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 0.0 | 29.8 | 70.8 | 86.8 | 85.7 | 57.2 | 30.4 | 10.3 | 0.0 | 0.0 | 30.9 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 34.2 | 34.6 | 33.3 | 33.0 | 38.3 | 36.5 | 33.4 | 26.4 | 34.8 | 37.6 | 34.8 | 34.5 | 34.3 |
| C .J. Strike | ROR | 43.6 | 43.2 | 43.5 | 41.1 | 43.6 | 39.6 | 31.3 | 28.9 | 38.6 | 44.8 | 44.0 | 42.8 | 40.4 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.1 | 22.2 | 20.4 | 20.0 | 25.5 | 24.3 | 21.7 | 14.8 | 21.7 | 24.0 | 22.2 | 21.8 | 21.7 |
| Milner | ROR | 5.0 | 7.0 | 0.0 | 0.0 | 12.8 | 12.7 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 3.2 | 3.9 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 4.5 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 10.0 | 9.8 | 11.8 | 9.7 |
| Swan Falls | ROR | 14.8 | 14.7 | 14.8 | 14.4 | 15.1 | 14.0 | 11.4 | 10.1 | 13.7 | 15.1 | 15.0 | 14.7 | 14.0 |
| Twin Falls | ROR | 8.7 | 9.8 | 3.8 | 0.0 | 16.0 | 16.8 | 10.1 | 0.0 | 0.0 | 6.2 | 6.1 | 7.8 | 7.1 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.3 | 13.5 | 12.2 | 11.9 | 16.2 | 15.0 | 13.0 | 8.0 | 13.0 | 14.6 | 13.2 | 13.0 | 13.1 |
| Upper Salmon 3&4 | ROR | 12.5 | 12.7 | 11.6 | 11.4 | 15.0 | 14.0 | 12.4 | 8.0 | 12.3 | 13.7 | 12.5 | 12.3 | 12.4 |
| **HCC Total** | | **470.7** | **457.2** | **534.7** | **583.3** | **631.8** | **457.1** | **490.5** | **336.6** | **366.3** | **363.7** | **346.0** | **422.3** | **455.0** |
| **ROR Total** | | **193.7** | **198.2** | **175.9** | **194.9** | **295.5** | **303.1** | **271.1** | **197.8** | **206.0** | **206.0** | **185.4** | **189.6** | **218.1** |
| **Total** | | **664.4** | **655.4** | **710.6** | **778.2** | **927.2** | **760.2** | **761.6** | **534.4** | **572.3** | **569.7** | **531.4** | **611.9** | **673.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2019** | **2/2019** | **3/2019** | **4/2019** | **5/2019** | **6/2019** | **7/2019** | **8/2019** | **9/2019** | **10/2019** | **11/2019** | **12/2019** | **aMW** |
| Brownlee | HCC* | 209.6 | 205.5 | 232.5 | 257.6 | 283.9 | 204.5 | 218.9 | 143.3 | 153.6 | 154.6 | 149.9 | 180.0 | 199.5 |
| Oxbow | HCC | 87.7 | 86.4 | 97.2 | 107.2 | 115.8 | 84.2 | 92.2 | 65.1 | 71.1 | 70.6 | 65.9 | 78.0 | 85.1 |
| Hells Canyon | HCC | 173.4 | 171.6 | 197.2 | 217.4 | 236.5 | 170.0 | 181.1 | 128.0 | 139.3 | 139.3 | 130.9 | 153.8 | 169.9 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 8.0 | 29.6 | 70.6 | 86.9 | 85.6 | 57.3 | 30.6 | 11.2 | 0.0 | 0.0 | 31.7 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 34.1 | 34.6 | 33.4 | 32.8 | 38.6 | 36.7 | 33.3 | 26.5 | 34.7 | 37.6 | 34.4 | 33.9 | 34.2 |
| C .J. Strike | ROR | 43.4 | 43.2 | 43.8 | 41.2 | 43.9 | 39.8 | 31.6 | 28.9 | 38.6 | 44.9 | 43.6 | 42.2 | 40.4 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.1 | 22.2 | 20.5 | 20.1 | 25.7 | 24.4 | 21.7 | 14.9 | 21.5 | 24.1 | 21.5 | 21.3 | 21.7 |
| Milner | ROR | 5.0 | 6.8 | 0.0 | 0.0 | 12.8 | 12.7 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 4.0 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 10.0 | 8.2 | 9.6 | 9.3 |
| Swan Falls | ROR | 14.8 | 14.7 | 14.9 | 14.3 | 15.2 | 14.1 | 11.5 | 10.2 | 13.7 | 15.2 | 14.8 | 14.4 | 14.0 |
| Twin Falls | ROR | 8.6 | 9.6 | 3.8 | 0.0 | 15.9 | 16.4 | 10.1 | 0.0 | 0.0 | 6.2 | 4.5 | 5.9 | 6.8 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.2 | 13.5 | 12.3 | 12.0 | 16.3 | 15.1 | 13.0 | 8.0 | 12.8 | 14.6 | 12.7 | 12.6 | 13.0 |
| Upper Salmon 3&4 | ROR | 12.5 | 12.7 | 11.7 | 11.5 | 15.2 | 14.1 | 12.4 | 8.1 | 12.2 | 13.7 | 12.0 | 12.0 | 12.3 |
| **HCC Total** | | **470.7** | **463.5** | **526.9** | **582.2** | **636.2** | **458.7** | **492.2** | **336.4** | **364.0** | **364.5** | **346.7** | **411.8** | **454.5** |
| **ROR Total** | | **193.2** | **197.8** | **184.7** | **194.3** | **296.4** | **303.6** | **271.3** | **198.3** | **205.6** | **207.2** | **179.5** | **179.6** | **217.6** |
| **Total** | | **663.9** | **661.3** | **711.6** | **776.5** | **932.6** | **762.3** | **763.5** | **534.7** | **569.6** | **571.7** | **526.2** | **591.4** | **672.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2020** | **2/2020** | **3/2020** | **4/2020** | **5/2020** | **6/2020** | **7/2020** | **8/2020** | **9/2020** | **10/2020** | **11/2020** | **12/2020** | **aMW** |
| Brownlee | HCC* | 208.9 | 200.8 | 232.5 | 256.6 | 283.2 | 203.7 | 218.3 | 142.6 | 151.9 | 154.7 | 149.4 | 180.0 | 198.6 |
| Oxbow | HCC | 87.4 | 84.4 | 97.2 | 106.8 | 115.6 | 83.9 | 92.0 | 64.8 | 70.2 | 70.6 | 65.7 | 77.9 | 84.7 |
| Hells Canyon | HCC | 172.8 | 167.8 | 197.2 | 216.7 | 235.9 | 169.4 | 180.6 | 127.4 | 137.6 | 139.2 | 130.4 | 153.8 | 169.1 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 8.0 | 29.6 | 70.6 | 86.8 | 85.6 | 57.0 | 30.2 | 11.0 | 0.0 | 0.0 | 31.6 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 33.9 | 34.4 | 33.4 | 32.6 | 38.4 | 36.5 | 33.1 | 26.3 | 34.4 | 37.4 | 34.3 | 33.8 | 34.0 |
| C .J. Strike | ROR | 43.2 | 43.2 | 43.6 | 41.1 | 43.2 | 39.5 | 31.4 | 28.7 | 38.4 | 44.8 | 43.4 | 42.3 | 40.2 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 22.0 | 22.1 | 20.4 | 20.0 | 25.6 | 24.2 | 21.6 | 14.8 | 21.2 | 23.9 | 21.4 | 21.3 | 21.5 |
| Milner | ROR | 5.0 | 6.8 | 0.0 | 0.0 | 12.8 | 12.7 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 4.0 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 10.0 | 8.2 | 9.6 | 9.3 |
| Swan Falls | ROR | 14.7 | 14.7 | 14.8 | 14.3 | 14.9 | 14.0 | 11.5 | 10.1 | 13.7 | 15.1 | 14.8 | 14.5 | 13.9 |
| Twin Falls | ROR | 8.6 | 9.6 | 3.8 | 0.0 | 15.9 | 16.4 | 10.1 | 0.0 | 0.0 | 6.2 | 4.5 | 5.9 | 6.8 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 13.2 | 13.4 | 12.2 | 11.9 | 16.2 | 14.9 | 12.9 | 7.9 | 12.6 | 14.5 | 12.6 | 12.6 | 12.9 |
| Upper Salmon 3&4 | ROR | 12.5 | 12.7 | 11.7 | 11.4 | 15.1 | 14.0 | 12.3 | 8.0 | 12.0 | 13.6 | 12.0 | 11.9 | 12.3 |
| **HCC Total** | | **469.1** | **453.0** | **526.9** | **580.1** | **634.6** | **457.0** | **490.9** | **334.8** | **359.7** | **364.5** | **345.5** | **411.7** | **452.3** |
| **ROR Total** | | **192.6** | **197.4** | **184.2** | **193.7** | **294.9** | **302.4** | **270.6** | **197.2** | **204.0** | **206.2** | **179.0** | **179.6** | **216.8** |
| **Total** | | **661.7** | **650.4** | **711.1** | **773.8** | **929.5** | **759.4** | **761.5** | **532.0** | **563.6** | **570.7** | **524.5** | **591.3** | **669.1** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2021** | **2/2021** | **3/2021** | **4/2021** | **5/2021** | **6/2021** | **7/2021** | **8/2021** | **9/2021** | **10/2021** | **11/2021** | **12/2021** | **aMW** |
| Brownlee | HCC* | 208.3 | 196.1 | 230.3 | 256.2 | 282.5 | 202.9 | 217.6 | 141.9 | 149.7 | 154.7 | 149.5 | 179.7 | 197.4 |
| Oxbow | HCC | 87.1 | 82.4 | 96.3 | 106.6 | 115.3 | 83.6 | 91.7 | 64.4 | 69.0 | 70.4 | 65.7 | 77.8 | 84.2 |
| Hells Canyon | HCC | 172.3 | 163.9 | 195.5 | 216.3 | 235.3 | 168.8 | 180.1 | 126.8 | 135.4 | 139.0 | 130.4 | 153.5 | 168.1 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 8.0 | 29.6 | 70.6 | 86.6 | 85.5 | 56.9 | 29.8 | 10.9 | 0.0 | 0.0 | 31.5 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 33.8 | 34.3 | 33.2 | 32.5 | 38.3 | 36.3 | 33.0 | 26.1 | 34.2 | 37.2 | 34.2 | 33.6 | 33.9 |
| C .J. Strike | ROR | 42.8 | 42.8 | 43.5 | 41.0 | 43.0 | 39.2 | 31.1 | 28.5 | 38.3 | 44.6 | 43.3 | 42.0 | 40.0 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 21.6 | 21.9 | 20.3 | 19.9 | 25.5 | 24.0 | 21.5 | 14.6 | 21.0 | 23.8 | 21.2 | 21.1 | 21.4 |
| Milner | ROR | 5.0 | 6.1 | 0.0 | 0.0 | 12.8 | 12.7 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 4.0 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 9.8 | 8.2 | 9.6 | 9.3 |
| Swan Falls | ROR | 14.7 | 14.6 | 14.8 | 14.2 | 14.9 | 13.9 | 11.4 | 10.0 | 13.6 | 15.1 | 14.7 | 14.4 | 13.9 |
| Twin Falls | ROR | 8.6 | 9.4 | 3.8 | 0.0 | 15.9 | 16.4 | 10.1 | 0.0 | 0.0 | 6.0 | 4.5 | 5.9 | 6.7 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.9 | 13.2 | 12.1 | 11.9 | 16.2 | 14.8 | 12.9 | 7.8 | 12.4 | 14.4 | 12.5 | 12.4 | 12.8 |
| Upper Salmon 3&4 | ROR | 12.2 | 12.5 | 11.6 | 11.3 | 15.0 | 13.9 | 12.2 | 7.9 | 11.8 | 13.5 | 11.9 | 11.8 | 12.1 |
| **HCC Total** | | **467.7** | **442.4** | **522.1** | **579.1** | **633.0** | **455.3** | **489.4** | **333.1** | **354.0** | **364.1** | **345.6** | **411.0** | **449.7** |
| **ROR Total** | | **191.1** | **195.3** | **183.6** | **193.2** | **294.4** | **301.2** | **269.8** | **196.2** | **202.6** | **205.0** | **178.3** | **178.5** | **215.8** |
| **Total** | | **658.8** | **637.7** | **705.7** | **772.3** | **927.4** | **756.5** | **759.2** | **529.3** | **556.6** | **569.1** | **523.9** | **589.5** | **665.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2022** | **2/2022** | **3/2022** | **4/2022** | **5/2022** | **6/2022** | **7/2022** | **8/2022** | **9/2022** | **10/2022** | **11/2022** | **12/2022** | **aMW** |
| Brownlee | HCC* | 207.6 | 194.1 | 229.4 | 255.7 | 281.8 | 202.5 | 217.0 | 141.2 | 147.4 | 154.8 | 149.6 | 179.3 | 196.7 |
| Oxbow | HCC | 86.9 | 81.5 | 95.9 | 106.4 | 115.0 | 83.4 | 91.4 | 64.1 | 67.9 | 70.4 | 65.7 | 77.6 | 83.8 |
| Hells Canyon | HCC | 171.8 | 162.3 | 194.7 | 215.9 | 234.8 | 168.4 | 179.5 | 126.2 | 133.2 | 138.8 | 130.5 | 153.2 | 167.4 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 8.0 | 29.5 | 70.6 | 86.5 | 85.5 | 56.5 | 29.6 | 10.9 | 0.0 | 0.0 | 31.4 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 33.6 | 34.1 | 33.0 | 32.5 | 38.2 | 36.1 | 32.9 | 25.9 | 33.9 | 37.0 | 34.0 | 33.4 | 33.7 |
| C .J. Strike | ROR | 42.5 | 42.5 | 42.5 | 40.9 | 42.8 | 38.9 | 30.9 | 28.2 | 38.1 | 44.3 | 43.1 | 41.8 | 39.7 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 21.4 | 21.7 | 20.2 | 19.8 | 25.4 | 23.9 | 21.4 | 14.4 | 20.8 | 23.7 | 21.1 | 20.9 | 21.2 |
| Milner | ROR | 5.0 | 5.9 | 0.0 | 0.0 | 12.8 | 12.7 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 9.6 | 8.2 | 9.6 | 9.3 |
| Swan Falls | ROR | 14.6 | 14.5 | 14.5 | 14.1 | 14.8 | 13.8 | 11.2 | 9.9 | 13.6 | 15.0 | 14.6 | 14.3 | 13.7 |
| Twin Falls | ROR | 8.6 | 9.3 | 3.8 | 0.0 | 15.9 | 16.4 | 10.1 | 0.0 | 0.0 | 5.8 | 4.5 | 5.9 | 6.7 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.7 | 13.1 | 12.1 | 11.8 | 16.1 | 14.7 | 12.8 | 7.6 | 12.2 | 14.3 | 12.3 | 12.3 | 12.7 |
| Upper Salmon 3&4 | ROR | 12.1 | 12.4 | 11.5 | 11.3 | 15.0 | 13.8 | 12.1 | 7.8 | 11.7 | 13.4 | 11.8 | 11.7 | 12.1 |
| **HCC Total** | | **466.3** | **437.9** | **520.0** | **578.0** | **631.5** | **454.3** | **487.9** | **331.5** | **348.4** | **364.0** | **345.8** | **410.1** | **448.0** |
| **ROR Total** | | **190.0** | **194.0** | **181.9** | **192.6** | **293.8** | **300.2** | **269.0** | **194.7** | **201.4** | **203.7** | **177.4** | **177.6** | **214.7** |
| **Total** | | **656.3** | **631.9** | **701.9** | **770.6** | **925.3** | **754.5** | **756.9** | **526.2** | **549.8** | **567.7** | **523.2** | **587.7** | **662.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2023** | **2/2023** | **3/2023** | **4/2023** | **5/2023** | **6/2023** | **7/2023** | **8/2023** | **9/2023** | **10/2023** | **11/2023** | **12/2023** | **aMW** |
| Brownlee | HCC* | 206.9 | 193.5 | 228.5 | 255.3 | 281.2 | 202.0 | 216.4 | 140.6 | 145.3 | 154.5 | 149.9 | 178.7 | 196.1 |
| Oxbow | HCC | 86.6 | 81.3 | 95.6 | 106.3 | 114.7 | 83.2 | 91.1 | 63.8 | 66.7 | 70.1 | 65.8 | 77.3 | 83.5 |
| Hells Canyon | HCC | 171.2 | 161.8 | 194.0 | 215.6 | 234.3 | 168.0 | 179.0 | 125.6 | 131.0 | 138.4 | 130.7 | 152.6 | 166.8 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 8.0 | 29.6 | 70.5 | 86.5 | 85.5 | 56.2 | 29.0 | 10.6 | 0.0 | 0.0 | 31.3 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 33.4 | 33.9 | 32.9 | 32.4 | 38.1 | 35.9 | 32.8 | 25.7 | 33.7 | 36.8 | 33.8 | 33.2 | 33.6 |
| C .J. Strike | ROR | 42.3 | 42.3 | 42.2 | 40.9 | 42.7 | 38.5 | 30.7 | 28.0 | 38.0 | 44.1 | 42.8 | 41.5 | 39.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 21.3 | 21.5 | 20.1 | 19.7 | 25.3 | 23.7 | 21.2 | 14.3 | 20.6 | 23.4 | 20.9 | 20.8 | 21.1 |
| Milner | ROR | 5.0 | 5.4 | 0.0 | 0.0 | 12.8 | 12.7 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.5 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.8 | 8.2 | 9.6 | 9.2 |
| Swan Falls | ROR | 14.5 | 14.4 | 14.4 | 14.1 | 14.8 | 13.7 | 11.2 | 9.9 | 13.5 | 14.9 | 14.5 | 14.2 | 13.7 |
| Twin Falls | ROR | 8.6 | 8.9 | 3.8 | 0.0 | 15.9 | 16.4 | 10.1 | 0.0 | 0.0 | 5.2 | 4.5 | 5.9 | 6.6 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.6 | 13.0 | 12.0 | 11.7 | 16.0 | 14.6 | 12.6 | 7.5 | 12.1 | 14.1 | 12.2 | 12.2 | 12.6 |
| Upper Salmon 3&4 | ROR | 12.0 | 12.3 | 11.5 | 11.2 | 14.9 | 13.7 | 12.0 | 7.7 | 11.5 | 13.3 | 11.6 | 11.6 | 11.9 |
| **HCC Total** | | **464.7** | **436.6** | **518.1** | **577.2** | **630.1** | **453.2** | **486.5** | **330.0** | **342.9** | **363.0** | **346.4** | **408.6** | **446.4** |
| **ROR Total** | | **189.2** | **192.2** | **181.2** | **192.3** | **293.2** | **299.1** | **268.2** | **193.7** | **199.9** | **200.9** | **176.3** | **176.7** | **213.6** |
| **Total** | | **653.9** | **628.8** | **699.3** | **769.5** | **923.3** | **752.3** | **754.7** | **523.7** | **542.8** | **563.9** | **522.7** | **585.3** | **660.0** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2024** | **2/2024** | **3/2024** | **4/2024** | **5/2024** | **6/2024** | **7/2024** | **8/2024** | **9/2024** | **10/2024** | **11/2024** | **12/2024** | **aMW** |
| Brownlee | HCC* | 206.3 | 192.8 | 227.9 | 254.8 | 280.4 | 201.6 | 215.5 | 139.9 | 143.7 | 154.5 | 149.7 | 179.1 | 195.5 |
| Oxbow | HCC | 86.3 | 81.0 | 95.3 | 106.1 | 114.4 | 83.1 | 90.8 | 63.5 | 65.9 | 70.1 | 65.7 | 77.5 | 83.3 |
| Hells Canyon | HCC | 170.7 | 161.2 | 193.5 | 215.2 | 233.7 | 167.7 | 178.4 | 125.0 | 129.5 | 138.4 | 130.5 | 153.0 | 166.4 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 8.0 | 29.6 | 70.2 | 86.5 | 85.6 | 56.2 | 28.5 | 10.3 | 0.0 | 0.0 | 31.2 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 33.3 | 33.8 | 32.8 | 32.4 | 37.9 | 35.7 | 32.6 | 25.5 | 33.4 | 36.5 | 33.6 | 33.0 | 33.4 |
| C .J. Strike | ROR | 42.0 | 41.9 | 42.0 | 40.7 | 42.5 | 38.3 | 30.5 | 27.7 | 37.7 | 43.8 | 42.5 | 41.2 | 39.2 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 21.1 | 21.3 | 20.1 | 19.6 | 25.1 | 23.5 | 21.0 | 14.1 | 20.3 | 23.2 | 20.7 | 20.5 | 20.9 |
| Milner | ROR | 4.9 | 6.0 | 0.0 | 0.0 | 12.8 | 12.7 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.8 | 8.2 | 9.6 | 9.2 |
| Swan Falls | ROR | 14.4 | 14.4 | 14.3 | 14.0 | 14.8 | 13.6 | 11.1 | 9.8 | 13.4 | 14.8 | 14.4 | 14.1 | 13.6 |
| Twin Falls | ROR | 8.6 | 9.2 | 3.8 | 0.0 | 15.9 | 16.4 | 10.1 | 0.0 | 0.0 | 5.2 | 4.5 | 5.9 | 6.6 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.5 | 12.8 | 12.0 | 11.6 | 15.9 | 14.4 | 12.5 | 7.4 | 11.9 | 13.9 | 12.1 | 12.0 | 12.4 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.2 | 11.4 | 11.1 | 14.8 | 13.5 | 11.9 | 7.6 | 11.4 | 13.1 | 11.5 | 11.5 | 11.8 |
| **HCC Total** | | **463.3** | **435.0** | **516.7** | **576.1** | **628.5** | **452.4** | **484.7** | **328.4** | **339.0** | **363.0** | **345.9** | **409.6** | **445.2** |
| **ROR Total** | | **188.2** | **192.1** | **180.7** | **191.7** | **292.1** | **298.0** | **267.4** | **192.7** | **198.1** | **199.3** | **175.3** | **175.5** | **212.6** |
| **Total** | | **651.5** | **627.1** | **697.4** | **767.8** | **920.6** | **750.4** | **752.1** | **521.1** | **537.1** | **562.3** | **521.2** | **585.1** | **657.8** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2025** | **2/2025** | **3/2025** | **4/2025** | **5/2025** | **6/2025** | **7/2025** | **8/2025** | **9/2025** | **10/2025** | **11/2025** | **12/2025** | **aMW** |
| Brownlee | HCC* | 204.8 | 192.1 | 227.4 | 254.4 | 275.8 | 201.3 | 215.0 | 139.3 | 142.1 | 154.1 | 150.2 | 178.5 | 194.6 |
| Oxbow | HCC | 85.7 | 80.7 | 95.1 | 105.9 | 114.2 | 82.9 | 90.6 | 63.2 | 65.1 | 69.8 | 65.9 | 77.3 | 83.0 |
| Hells Canyon | HCC | 169.5 | 160.6 | 193.1 | 214.8 | 234.2 | 167.5 | 177.9 | 124.4 | 127.9 | 137.8 | 130.9 | 152.5 | 165.9 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 8.0 | 29.5 | 69.8 | 85.9 | 85.6 | 56.2 | 28.3 | 10.5 | 0.0 | 0.0 | 31.1 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 33.2 | 33.7 | 32.7 | 32.3 | 37.3 | 35.4 | 32.4 | 25.3 | 33.1 | 36.4 | 33.4 | 32.8 | 33.2 |
| C .J. Strike | ROR | 41.7 | 41.8 | 42.0 | 40.6 | 42.0 | 37.3 | 30.4 | 27.5 | 37.4 | 43.5 | 42.3 | 41.0 | 39.0 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 21.0 | 21.2 | 20.0 | 19.5 | 24.9 | 23.3 | 20.9 | 13.9 | 20.1 | 23.0 | 20.5 | 20.4 | 20.7 |
| Milner | ROR | 4.8 | 6.0 | 0.0 | 0.0 | 11.3 | 11.2 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.8 | 8.2 | 9.6 | 9.2 |
| Swan Falls | ROR | 14.4 | 14.3 | 14.3 | 14.0 | 14.7 | 13.3 | 11.0 | 9.7 | 13.3 | 14.8 | 14.4 | 14.1 | 13.5 |
| Twin Falls | ROR | 8.5 | 9.2 | 3.8 | 0.0 | 14.0 | 15.0 | 10.1 | 0.0 | 0.0 | 5.2 | 4.5 | 5.9 | 6.4 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.4 | 12.7 | 11.9 | 11.5 | 15.7 | 14.2 | 12.4 | 7.3 | 11.7 | 13.8 | 11.9 | 11.9 | 12.3 |
| Upper Salmon 3&4 | ROR | 11.8 | 12.1 | 11.4 | 11.1 | 14.6 | 13.4 | 11.8 | 7.5 | 11.2 | 13.0 | 11.4 | 11.4 | 11.7 |
| **HCC Total** | | **460.0** | **433.4** | **515.6** | **575.1** | **624.1** | **451.7** | **483.5** | **326.9** | **335.0** | **361.7** | **347.0** | **408.3** | **443.5** |
| **ROR Total** | | **187.3** | **191.5** | **180.4** | **191.2** | **286.5** | **292.4** | **266.7** | **191.8** | **196.6** | **198.7** | **174.4** | **174.8** | **211.0** |
| **Total** | | **647.3** | **624.9** | **696.0** | **766.3** | **910.5** | **744.1** | **750.2** | **518.7** | **531.6** | **560.4** | **521.4** | **583.1** | **654.5** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2026** | **2/2026** | **3/2026** | **4/2026** | **5/2026** | **6/2026** | **7/2026** | **8/2026** | **9/2026** | **10/2026** | **11/2026** | **12/2026** | **aMW** |
| Brownlee | HCC* | 203.8 | 191.5 | 226.9 | 254.0 | 275.2 | 201.0 | 214.3 | 138.5 | 140.0 | 154.2 | 150.2 | 177.9 | 194.0 |
| Oxbow | HCC | 85.3 | 80.4 | 94.9 | 105.7 | 113.9 | 82.8 | 90.3 | 62.9 | 64.1 | 69.8 | 65.9 | 77.0 | 82.7 |
| Hells Canyon | HCC | 168.7 | 160.1 | 192.6 | 214.5 | 233.7 | 167.2 | 177.4 | 123.8 | 125.9 | 137.8 | 130.8 | 152.0 | 165.4 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 7.9 | 29.4 | 69.6 | 85.5 | 85.5 | 56.2 | 28.2 | 10.4 | 0.0 | 0.0 | 31.1 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 33.1 | 33.5 | 32.6 | 32.3 | 37.1 | 35.1 | 32.3 | 25.1 | 32.8 | 36.2 | 33.2 | 32.8 | 33.0 |
| C .J. Strike | ROR | 41.5 | 41.7 | 41.8 | 40.4 | 41.8 | 36.5 | 30.4 | 27.3 | 37.1 | 43.3 | 42.0 | 40.8 | 38.7 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 20.8 | 21.0 | 19.9 | 19.3 | 24.3 | 23.1 | 20.7 | 13.8 | 19.9 | 22.9 | 20.4 | 20.2 | 20.5 |
| Milner | ROR | 5.0 | 6.0 | 0.0 | 0.0 | 10.5 | 10.4 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.8 | 8.2 | 9.6 | 9.2 |
| Swan Falls | ROR | 14.2 | 14.3 | 14.3 | 13.9 | 14.7 | 13.1 | 11.0 | 9.7 | 13.2 | 14.8 | 14.3 | 14.1 | 13.5 |
| Twin Falls | ROR | 8.6 | 9.2 | 3.8 | 0.0 | 13.3 | 14.3 | 10.1 | 0.0 | 0.0 | 5.2 | 4.5 | 5.9 | 6.2 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.3 | 12.6 | 11.8 | 11.4 | 15.3 | 14.1 | 12.3 | 7.2 | 11.5 | 13.7 | 11.8 | 11.8 | 12.2 |
| Upper Salmon 3&4 | ROR | 11.7 | 12.0 | 11.3 | 11.0 | 14.3 | 13.3 | 11.7 | 7.4 | 11.1 | 12.9 | 11.3 | 11.3 | 11.6 |
| **HCC Total** | | **457.8** | **432.0** | **514.4** | **574.2** | **622.7** | **451.0** | **482.0** | **325.2** | **330.0** | **361.8** | **346.9** | **406.9** | **442.1** |
| **ROR Total** | | **186.7** | **190.8** | **179.7** | **190.4** | **283.1** | **288.8** | **266.1** | **191.1** | **195.3** | **197.9** | **173.5** | **174.2** | **209.8** |
| **Total** | | **644.5** | **622.8** | **694.1** | **764.6** | **905.8** | **739.8** | **748.1** | **516.3** | **525.2** | **559.7** | **520.4** | **581.1** | **651.9** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

**Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 203.1 | 190.1 | 225.7 | 253.5 | 274.6 | 200.7 | 213.7 | 137.8 | 138.1 | 154.3 | 149.9 | 177.6 | 193.3 |
| Oxbow | HCC | 85.0 | 79.9 | 94.4 | 105.5 | 113.7 | 82.7 | 90.0 | 62.5 | 63.0 | 69.7 | 65.7 | 76.8 | 82.4 |
| Hells Canyon | HCC | 168.1 | 159.0 | 191.7 | 214.1 | 233.2 | 167.0 | 176.9 | 123.1 | 124.0 | 137.7 | 130.5 | 151.7 | 164.7 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 7.9 | 29.4 | 69.4 | 85.6 | 85.5 | 56.2 | 27.8 | 10.2 | 0.0 | 0.0 | 31.0 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 33.0 | 33.3 | 32.5 | 32.2 | 37.0 | 34.8 | 32.0 | 24.9 | 32.5 | 36.0 | 33.1 | 32.6 | 32.8 |
| C .J. Strike | ROR | 41.2 | 41.3 | 42.0 | 40.2 | 41.7 | 36.2 | 30.3 | 27.0 | 36.8 | 43.1 | 41.7 | 40.4 | 38.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 20.7 | 20.8 | 19.9 | 19.2 | 24.2 | 23.1 | 20.5 | 13.6 | 19.6 | 22.7 | 20.2 | 20.1 | 20.4 |
| Milner | ROR | 5.0 | 5.1 | 0.0 | 0.0 | 10.5 | 10.4 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.8 | 8.2 | 9.6 | 9.2 |
| Swan Falls | ROR | 14.2 | 14.1 | 14.3 | 13.8 | 14.7 | 13.0 | 10.9 | 9.6 | 13.1 | 14.8 | 14.2 | 14.0 | 13.4 |
| Twin Falls | ROR | 8.6 | 8.5 | 3.8 | 0.0 | 13.3 | 14.3 | 10.1 | 0.0 | 0.0 | 5.2 | 4.5 | 5.9 | 6.2 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.2 | 12.4 | 11.8 | 11.3 | 15.2 | 14.1 | 12.1 | 7.0 | 11.4 | 13.6 | 11.7 | 11.7 | 12.0 |
| Upper Salmon 3&4 | ROR | 11.6 | 11.8 | 11.3 | 10.9 | 14.2 | 13.2 | 11.6 | 7.2 | 10.9 | 12.8 | 11.2 | 11.2 | 11.5 |
| **HCC Total** | | **456.2** | **429.0** | **511.8** | **573.1** | **621.5** | **450.4** | **480.6** | **323.4** | **325.0** | **361.7** | **346.1** | **406.1** | **440.4** |
| **ROR Total** | | **186.0** | **187.8** | **179.8** | **189.7** | **282.4** | **288.1** | **265.1** | **189.9** | **193.6** | **196.9** | **172.6** | **173.2** | **208.8** |
| **Total** | | **642.2** | **616.8** | **691.6** | **762.8** | **903.9** | **738.5** | **745.7** | **513.3** | **518.6** | **558.6** | **518.7** | **579.3** | **649.2** |

*HCC=Hells Canyon Complex,**ROR= Run of River

**Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 202.5 | 190.4 | 224.7 | 253.1 | 274.0 | 200.4 | 213.3 | 137.2 | 135.5 | 154.2 | 150.4 | 176.4 | 192.7 |
| Oxbow | HCC | 84.7 | 80.0 | 94.0 | 105.3 | 113.4 | 82.6 | 89.8 | 62.2 | 61.7 | 69.6 | 65.9 | 76.3 | 82.1 |
| Hells Canyon | HCC | 167.6 | 159.3 | 190.9 | 213.8 | 232.7 | 166.7 | 176.5 | 122.6 | 121.5 | 137.3 | 130.9 | 150.7 | 164.2 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 7.9 | 29.4 | 69.5 | 85.6 | 85.6 | 56.2 | 27.3 | 10.4 | 0.0 | 0.0 | 31.0 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.9 | 33.0 | 32.4 | 32.1 | 37.0 | 34.6 | 31.8 | 24.8 | 32.2 | 35.8 | 32.6 | 32.4 | 32.6 |
| C .J. Strike | ROR | 40.9 | 41.1 | 41.8 | 40.0 | 41.6 | 36.0 | 30.2 | 26.8 | 36.4 | 43.0 | 41.5 | 40.2 | 38.3 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 20.5 | 20.7 | 19.7 | 19.1 | 24.1 | 23.0 | 20.4 | 13.5 | 19.4 | 22.5 | 20.0 | 20.0 | 20.2 |
| Milner | ROR | 5.0 | 5.2 | 0.0 | 0.0 | 10.5 | 10.4 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.7 | 8.2 | 9.2 | 9.2 |
| Swan Falls | ROR | 14.2 | 14.1 | 14.3 | 13.8 | 14.7 | 12.9 | 10.8 | 9.5 | 13.0 | 14.7 | 14.1 | 14.0 | 13.3 |
| Twin Falls | ROR | 8.5 | 8.5 | 3.8 | 0.0 | 13.3 | 14.3 | 10.1 | 0.0 | 0.0 | 4.8 | 4.5 | 5.5 | 6.1 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.1 | 12.3 | 11.6 | 11.2 | 15.1 | 14.0 | 12.0 | 6.9 | 11.2 | 13.4 | 11.5 | 11.6 | 11.9 |
| Upper Salmon 3&4 | ROR | 11.5 | 11.8 | 11.2 | 10.8 | 14.1 | 13.2 | 11.5 | 7.1 | 10.8 | 12.7 | 11.1 | 11.1 | 11.4 |
| **HCC Total** | | **454.8** | **429.7** | **509.6** | **572.2** | **620.1** | **449.7** | **479.6** | **322.0** | **318.7** | **361.1** | **347.2** | **403.4** | **439.0** |
| **ROR Total** | | **185.1** | **187.2** | **179.0** | **189.1** | **282.1** | **287.4** | **264.5** | **189.2** | **191.8** | **195.7** | **171.3** | **171.7** | **207.8** |
| **Total** | | **639.9** | **616.9** | **688.6** | **761.3** | **902.2** | **737.1** | **744.1** | **511.2** | **510.4** | **556.8** | **518.5** | **575.1** | **646.8** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2029** | **2/2029** | **3/2029** | **4/2029** | **5/2029** | **6/2029** | **7/2029** | **8/2029** | **9/2029** | **10/2029** | **11/2029** | **12/2029** | **aMW** |
| Brownlee | HCC* | 201.9 | 189.8 | 223.8 | 252.7 | 273.4 | 200.1 | 212.7 | 136.6 | 133.5 | 154.3 | 150.2 | 175.6 | 192.0 |
| Oxbow | HCC | 84.5 | 79.7 | 93.6 | 105.2 | 113.2 | 82.4 | 89.6 | 62.0 | 60.7 | 69.5 | 65.7 | 75.9 | 81.8 |
| Hells Canyon | HCC | 167.1 | 158.7 | 190.2 | 213.5 | 232.3 | 166.5 | 176.0 | 122.0 | 119.5 | 137.3 | 130.6 | 150.0 | 163.6 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 7.8 | 29.4 | 69.1 | 84.8 | 85.5 | 56.1 | 26.6 | 10.3 | 0.0 | 0.0 | 30.8 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.9 | 32.7 | 32.3 | 32.0 | 36.2 | 34.0 | 31.7 | 24.6 | 32.0 | 35.6 | 32.5 | 32.1 | 32.4 |
| C .J. Strike | ROR | 40.9 | 40.9 | 41.8 | 39.8 | 41.4 | 35.5 | 30.1 | 26.5 | 36.1 | 42.9 | 41.2 | 40.0 | 38.1 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 20.4 | 20.6 | 19.6 | 19.0 | 23.6 | 22.6 | 20.3 | 13.3 | 19.2 | 22.3 | 19.9 | 19.7 | 20.0 |
| Milner | ROR | 5.0 | 5.0 | 0.0 | 0.0 | 9.7 | 9.6 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.7 | 8.2 | 9.2 | 9.2 |
| Swan Falls | ROR | 14.1 | 14.1 | 14.3 | 13.7 | 14.6 | 12.5 | 10.8 | 9.4 | 12.9 | 14.7 | 14.1 | 13.9 | 13.3 |
| Twin Falls | ROR | 8.5 | 8.1 | 3.8 | 0.0 | 12.4 | 13.1 | 10.1 | 0.0 | 0.0 | 4.8 | 4.5 | 5.5 | 5.9 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 12.0 | 12.2 | 11.6 | 11.2 | 14.7 | 13.7 | 11.9 | 6.8 | 11.0 | 13.3 | 11.4 | 11.3 | 11.8 |
| Upper Salmon 3&4 | ROR | 11.4 | 11.7 | 11.1 | 10.8 | 13.8 | 12.9 | 11.4 | 7.0 | 10.6 | 12.6 | 10.9 | 10.9 | 11.3 |
| **HCC Total** | | **453.5** | **428.2** | **507.6** | **571.4** | **618.8** | **449.0** | **478.3** | **320.6** | **313.7** | **361.1** | **346.5** | **401.5** | **437.5** |
| **ROR Total** | | **184.7** | **185.8** | **178.6** | **188.6** | **277.7** | **282.1** | **263.9** | **188.1** | **189.9** | **194.9** | **170.5** | **170.3** | **206.3** |
| **Total** | | **638.2** | **614.0** | **686.2** | **760.0** | **896.5** | **731.1** | **742.2** | **508.7** | **503.5** | **556.0** | **517.0** | **571.8** | **643.8** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2030** | **2/2030** | **3/2030** | **4/2030** | **5/2030** | **6/2030** | **7/2030** | **8/2030** | **9/2030** | **10/2030** | **11/2030** | **12/2030** | **aMW** |
| Brownlee | HCC* | 201.5 | 189.1 | 223.1 | 252.2 | 272.8 | 199.8 | 212.1 | 135.8 | 131.5 | 154.5 | 150.2 | 175.4 | 191.5 |
| Oxbow | HCC | 84.3 | 79.4 | 93.3 | 105.0 | 112.9 | 82.3 | 89.3 | 61.6 | 59.7 | 69.5 | 65.7 | 75.9 | 81.6 |
| Hells Canyon | HCC | 166.8 | 158.2 | 189.5 | 213.1 | 231.8 | 166.3 | 175.5 | 121.4 | 117.6 | 137.3 | 130.5 | 149.8 | 163.1 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 7.9 | 29.4 | 69.4 | 85.0 | 85.5 | 56.1 | 26.5 | 10.2 | 0.0 | 0.0 | 30.8 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.7 | 32.5 | 32.2 | 31.9 | 36.4 | 34.2 | 31.5 | 24.4 | 31.7 | 35.4 | 32.4 | 32.0 | 32.3 |
| C .J. Strike | ROR | 40.6 | 40.6 | 41.5 | 39.5 | 41.3 | 35.2 | 29.9 | 26.3 | 35.8 | 42.8 | 41.0 | 39.7 | 37.9 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 20.3 | 20.3 | 19.5 | 18.9 | 23.6 | 22.5 | 20.1 | 13.1 | 19.0 | 22.2 | 19.7 | 19.7 | 19.9 |
| Milner | ROR | 5.0 | 4.7 | 0.0 | 0.0 | 9.6 | 9.5 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.9 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.7 | 8.2 | 9.2 | 9.2 |
| Swan Falls | ROR | 14.2 | 14.0 | 14.2 | 13.6 | 14.5 | 12.8 | 10.7 | 9.3 | 12.8 | 14.6 | 14.1 | 13.8 | 13.2 |
| Twin Falls | ROR | 8.5 | 8.0 | 3.8 | 0.0 | 12.3 | 13.0 | 10.1 | 0.0 | 0.0 | 4.8 | 4.5 | 5.5 | 5.9 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 11.8 | 12.0 | 11.5 | 11.1 | 14.7 | 13.6 | 11.8 | 6.7 | 10.8 | 13.2 | 11.3 | 11.3 | 11.7 |
| Upper Salmon 3&4 | ROR | 11.3 | 11.5 | 11.0 | 10.7 | 13.8 | 12.8 | 11.3 | 6.9 | 10.5 | 12.5 | 10.9 | 10.9 | 11.2 |
| **HCC Total** | | **452.6** | **426.7** | **505.9** | **570.3** | **617.4** | **448.4** | **476.9** | **318.8** | **308.7** | **361.3** | **346.4** | **401.1** | **436.2** |
| **ROR Total** | | **183.9** | **184.1** | **177.9** | **187.8** | **277.8** | **282.0** | **263.0** | **187.2** | **188.6** | **194.1** | **169.9** | **169.8** | **205.5** |
| **Total** | | **636.5** | **610.8** | **683.8** | **758.1** | **895.2** | **730.4** | **739.9** | **506.0** | **497.3** | **555.4** | **516.3** | **570.9** | **641.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2031** | **2/2031** | **3/2031** | **4/2031** | **5/2031** | **6/2031** | **7/2031** | **8/2031** | **9/2031** | **10/2031** | **11/2031** | **12/2031** | **aMW** |
| Brownlee | HCC* | 201.2 | 188.2 | 222.3 | 251.8 | 272.4 | 199.5 | 211.4 | 135.3 | 129.4 | 154.1 | 150.6 | 174.8 | 190.9 |
| Oxbow | HCC | 84.2 | 79.0 | 93.0 | 104.8 | 112.8 | 82.2 | 89.1 | 61.4 | 58.6 | 69.2 | 65.9 | 75.6 | 81.3 |
| Hells Canyon | HCC | 166.5 | 157.4 | 188.9 | 212.8 | 231.4 | 166.0 | 175.0 | 120.9 | 115.6 | 136.7 | 130.8 | 149.3 | 162.6 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 7.9 | 29.4 | 69.2 | 85.0 | 85.6 | 56.1 | 26.4 | 9.4 | 0.0 | 0.0 | 30.7 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.5 | 32.4 | 32.1 | 31.8 | 36.1 | 33.7 | 31.3 | 24.2 | 31.4 | 35.2 | 32.2 | 31.7 | 32.1 |
| C .J. Strike | ROR | 40.4 | 40.3 | 41.3 | 39.2 | 41.1 | 34.9 | 29.7 | 26.1 | 35.4 | 42.7 | 40.7 | 39.2 | 37.6 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 20.1 | 20.1 | 19.4 | 18.8 | 23.5 | 22.3 | 19.9 | 13.0 | 18.7 | 22.0 | 19.6 | 19.3 | 19.7 |
| Milner | ROR | 4.7 | 4.7 | 0.0 | 0.0 | 9.6 | 9.5 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.9 |
| Shoshone Falls | ROR | 12.0 | 11.9 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.4 | 8.2 | 8.9 | 9.1 |
| Swan Falls | ROR | 14.1 | 14.0 | 14.2 | 13.6 | 14.5 | 12.6 | 10.7 | 9.3 | 12.8 | 14.5 | 14.0 | 13.7 | 13.2 |
| Twin Falls | ROR | 8.4 | 7.9 | 3.8 | 0.0 | 12.3 | 13.0 | 10.1 | 0.0 | 0.0 | 4.6 | 4.5 | 5.3 | 5.8 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 11.7 | 11.9 | 11.4 | 11.0 | 14.6 | 13.5 | 11.7 | 6.5 | 10.7 | 13.0 | 11.2 | 11.1 | 11.5 |
| Upper Salmon 3&4 | ROR | 11.2 | 11.4 | 11.0 | 10.6 | 13.7 | 12.7 | 11.2 | 6.8 | 10.3 | 12.3 | 10.8 | 10.7 | 11.1 |
| **HCC Total** | | **451.9** | **424.6** | **504.2** | **569.4** | **616.5** | **447.7** | **475.5** | **317.6** | **303.6** | **360.0** | **347.3** | **399.7** | **434.8** |
| **ROR Total** | | **182.6** | **183.1** | **177.4** | **187.1** | **276.8** | **280.6** | **262.3** | **186.4** | **187.2** | **191.8** | **169.0** | **167.6** | **204.3** |
| **Total** | | **634.5** | **607.7** | **681.6** | **756.5** | **893.3** | **728.3** | **737.8** | **504.0** | **490.8** | **551.8** | **516.3** | **567.3** | **639.2** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2032** | **2/2032** | **3/2032** | **4/2032** | **5/2032** | **6/2032** | **7/2032** | **8/2032** | **9/2032** | **10/2032** | **11/2032** | **12/2032** | **aMW** |
| Brownlee | HCC* | 200.9 | 187.5 | 221.6 | 251.4 | 272.0 | 199.2 | 210.9 | 134.7 | 127.3 | 154.2 | 150.7 | 174.1 | 190.4 |
| Oxbow | HCC | 84.0 | 78.8 | 92.7 | 104.6 | 112.6 | 82.1 | 88.8 | 61.1 | 57.6 | 69.2 | 65.9 | 75.3 | 81.1 |
| Hells Canyon | HCC | 166.2 | 156.9 | 188.3 | 212.4 | 231.1 | 165.8 | 174.5 | 120.3 | 113.6 | 136.6 | 130.8 | 148.8 | 162.1 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 7.7 | 29.6 | 68.6 | 84.8 | 85.6 | 55.7 | 26.3 | 9.4 | 0.0 | 0.0 | 30.6 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.4 | 32.2 | 32.0 | 31.7 | 35.7 | 33.3 | 31.2 | 24.0 | 31.1 | 35.0 | 32.0 | 31.5 | 31.8 |
| C .J. Strike | ROR | 40.2 | 40.1 | 41.2 | 38.9 | 41.0 | 34.6 | 29.5 | 25.8 | 35.1 | 42.6 | 40.4 | 38.8 | 37.4 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 20.0 | 20.0 | 19.3 | 18.6 | 23.3 | 22.1 | 19.8 | 12.8 | 18.5 | 21.8 | 19.4 | 19.0 | 19.6 |
| Milner | ROR | 4.7 | 4.7 | 0.0 | 0.0 | 9.5 | 9.4 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.9 |
| Shoshone Falls | ROR | 12.0 | 11.9 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.4 | 8.1 | 8.9 | 9.1 |
| Swan Falls | ROR | 14.0 | 13.9 | 14.1 | 13.5 | 14.5 | 12.4 | 10.6 | 9.2 | 12.6 | 14.4 | 14.0 | 13.6 | 13.1 |
| Twin Falls | ROR | 8.4 | 7.9 | 3.8 | 0.0 | 12.2 | 12.9 | 10.1 | 0.0 | 0.0 | 4.6 | 4.4 | 5.3 | 5.8 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 11.6 | 11.8 | 11.4 | 10.9 | 14.5 | 13.3 | 11.5 | 6.4 | 10.5 | 12.9 | 11.0 | 10.8 | 11.4 |
| Upper Salmon 3&4 | ROR | 11.2 | 11.3 | 10.9 | 10.5 | 13.6 | 12.6 | 11.1 | 6.7 | 10.2 | 12.2 | 10.6 | 10.5 | 11.0 |
| **HCC Total** | | **451.1** | **423.2** | **502.6** | **568.4** | **615.6** | **447.1** | **474.2** | **316.1** | **298.4** | **360.0** | **347.4** | **398.2** | **433.5** |
| **ROR Total** | | **182.0** | **182.3** | **176.7** | **186.4** | **275.1** | **278.8** | **261.5** | **185.0** | **185.8** | **191.0** | **167.7** | **166.1** | **203.2** |
| **Total** | | **633.1** | **605.5** | **679.3** | **754.8** | **890.7** | **725.9** | **735.7** | **501.1** | **484.2** | **551.0** | **515.1** | **564.3** | **636.7** |

*HCC=Hells Canyon Complex,**ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2033** | **2/2033** | **3/2033** | **4/2033** | **5/2033** | **6/2033** | **7/2033** | **8/2033** | **9/2033** | **10/2033** | **11/2033** | **12/2033** | **aMW** |
| Brownlee | HCC* | 200.5 | 179.7 | 220.9 | 250.9 | 271.5 | 198.9 | 210.2 | 134.0 | 125.2 | 154.3 | 150.4 | 174.0 | 189.2 |
| Oxbow | HCC | 83.9 | 78.5 | 92.4 | 104.5 | 112.4 | 81.9 | 88.5 | 60.8 | 56.5 | 69.2 | 65.7 | 75.2 | 80.8 |
| Hells Canyon | HCC | 165.9 | 156.0 | 187.8 | 212.1 | 230.7 | 165.5 | 174.0 | 119.7 | 111.6 | 136.6 | 130.5 | 148.6 | 161.6 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 7.7 | 29.6 | 68.5 | 84.4 | 85.7 | 55.6 | 26.2 | 9.4 | 0.0 | 0.0 | 30.6 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.2 | 32.0 | 31.9 | 31.6 | 35.5 | 33.1 | 31.0 | 23.8 | 30.9 | 34.8 | 31.8 | 31.3 | 31.7 |
| C .J. Strike | ROR | 40.0 | 40.0 | 41.1 | 38.7 | 40.6 | 34.4 | 29.2 | 25.6 | 34.8 | 42.4 | 40.1 | 38.5 | 37.1 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Lower Salmon | ROR | 19.9 | 19.8 | 19.2 | 18.5 | 23.2 | 21.7 | 19.6 | 12.7 | 18.3 | 21.7 | 19.2 | 18.9 | 19.4 |
| Milner | ROR | 4.7 | 4.7 | 0.0 | 0.0 | 8.7 | 8.6 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.7 |
| Shoshone Falls | ROR | 12.0 | 11.9 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.4 | 8.1 | 8.9 | 9.1 |
| Swan Falls | ROR | 14.0 | 13.8 | 14.1 | 13.4 | 14.4 | 12.0 | 10.5 | 9.1 | 12.5 | 14.3 | 13.9 | 13.6 | 13.0 |
| Twin Falls | ROR | 8.4 | 7.9 | 3.8 | 0.0 | 11.4 | 12.3 | 10.1 | 0.0 | 0.0 | 4.6 | 4.4 | 5.3 | 5.7 |
| Upper Malad | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Upper Salmon 1&2 | ROR | 11.5 | 11.6 | 11.3 | 10.8 | 14.4 | 13.0 | 11.4 | 6.3 | 10.3 | 12.8 | 10.9 | 10.7 | 11.3 |
| Upper Salmon 3&4 | ROR | 11.1 | 11.2 | 10.9 | 10.5 | 13.5 | 12.3 | 11.0 | 6.6 | 10.0 | 12.1 | 10.5 | 10.4 | 10.8 |
| **HCC Total** | | **450.3** | **414.2** | **501.1** | **567.5** | **614.6** | **446.3** | **472.7** | **314.5** | **293.3** | **360.1** | **346.6** | **397.8** | **431.6** |
| **ROR Total** | | **181.3** | **181.4** | **176.3** | **185.8** | **272.4** | **275.2** | **260.6** | **184.1** | **184.5** | **190.2** | **166.7** | **165.3** | **202.0** |
| **Total** | | **631.6** | **595.6** | **677.4** | **753.3** | **887.0** | **721.5** | **733.3** | **498.6** | **477.8** | **550.3** | **513.3** | **563.1** | **633.6** |

*HCC=Hells Canyon Complex,**ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2034** | **2/2034** | **3/2034** | **4/2034** | **5/2034** | **6/2034** | **7/2034** | **8/2034** | **9/2034** | **10/2034** | **11/2034** | **12/2034** | **aMW** |
| Brownlee | HCC* | 200.1 | 177.6 | 220.2 | 250.5 | 271.1 | 198.6 | 209.7 | 133.3 | 123.7 | 154.2 | 150.5 | 173.4 | 188.6 |
| Oxbow | HCC | 83.7 | 77.5 | 92.1 | 104.3 | 112.2 | 81.8 | 88.3 | 60.4 | 55.8 | 69.0 | 65.7 | 74.9 | 80.5 |
| Hells Canyon | HCC | 165.6 | 154.2 | 187.2 | 211.7 | 230.4 | 165.3 | 173.5 | 119.1 | 110.2 | 136.3 | 130.5 | 148.1 | 161.0 |
| 1000 Springs | ROR** | 0.0 | 0.0 | 7.7 | 29.4 | 66.9 | 84.1 | 85.7 | 55.6 | 26.2 | 9.8 | 0.0 | 0.0 | 30.5 |
| American Falls | ROR | 6.2 | 6.3 | 6.2 | 5.9 | 6.0 | 6.0 | 5.9 | 6.1 | 6.2 | 6.2 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.7 | 1.7 | 1.7 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| C .J. Strike | ROR | 6.5 | 7.0 | 7.0 | 7.2 | 7.5 | 7.2 | 7.1 | 7.2 | 7.4 | 7.1 | 6.5 | 6.6 | 7.0 |
| Cascade | ROR | 11.5 | 12.0 | 12.7 | 12.8 | 13.5 | 12.3 | 12.2 | 12.6 | 13.3 | 13.0 | 11.9 | 11.8 | 12.5 |
| Clear Lake | ROR | 8.4 | 7.8 | 3.8 | 0.0 | 11.1 | 12.1 | 10.1 | 0.0 | 0.0 | 4.6 | 4.4 | 5.3 | 5.6 |
| Lower Malad | ROR | 12.0 | 11.8 | 7.3 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 8.4 | 8.1 | 8.9 | 9.1 |
| Lower Salmon | ROR | 11.0 | 10.9 | 10.8 | 10.4 | 13.4 | 12.1 | 10.9 | 6.5 | 9.9 | 12.0 | 10.4 | 10.3 | 10.7 |
| Milner | ROR | 11.4 | 11.4 | 11.2 | 10.8 | 14.2 | 12.8 | 11.3 | 6.2 | 10.2 | 12.6 | 10.7 | 10.6 | 11.1 |
| Shoshone Falls | ROR | 19.7 | 19.4 | 19.1 | 18.5 | 23.0 | 21.4 | 19.5 | 12.5 | 18.1 | 21.5 | 19.0 | 18.7 | 19.2 |
| Swan Falls | ROR | 32.1 | 31.9 | 31.8 | 31.5 | 35.1 | 33.0 | 30.9 | 23.6 | 30.7 | 34.6 | 31.6 | 31.2 | 31.5 |
| Twin Falls | ROR | 39.8 | 39.9 | 40.9 | 38.4 | 39.5 | 34.1 | 29.0 | 25.4 | 34.5 | 42.2 | 39.9 | 38.3 | 36.8 |
| Upper Malad | ROR | 13.9 | 13.8 | 14.1 | 13.3 | 13.9 | 11.9 | 10.5 | 9.0 | 12.4 | 14.3 | 13.7 | 13.4 | 12.9 |
| Upper Salmon 1&2 | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.4 | 1.4 | 1.3 | 1.3 | 3.2 |
| Upper Salmon 3&4 | ROR | 4.6 | 4.1 | 0.0 | 0.0 | 8.3 | 8.2 | 6.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.6 |
| **HCC Total** | | **449.4** | **409.3** | **499.5** | **566.5** | **613.6** | **445.7** | **471.5** | **312.8** | **289.7** | **359.5** | **346.7** | **396.4** | **430.1** |
| **ROR Total** | | **180.4** | **179.5** | **175.7** | **185.0** | **267.6** | **273.1** | **260.0** | **183.2** | **183.5** | **189.7** | **165.6** | **164.4** | **200.7** |
| **Total** | | **629.8** | **588.8** | **675.2** | **751.5** | **881.2** | **718.8** | **731.5** | **496.0** | **473.2** | **549.2** | **512.3** | **560.8** | **630.7** |

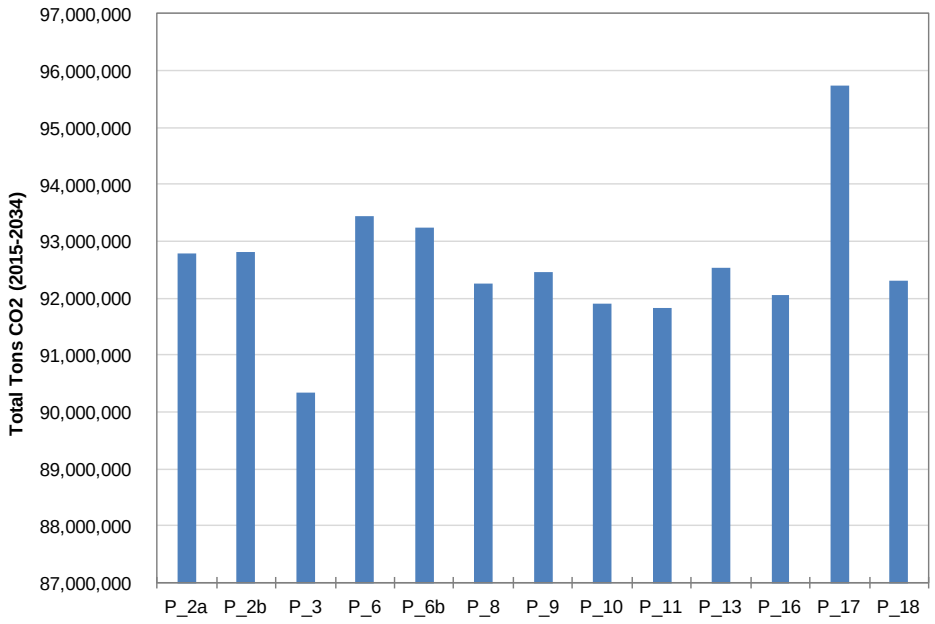
*HCC=Hells Canyon Complex,**ROR= Run of River

# PORTFOLIO ANALYSIS, RESULTS, AND SUPPORTING DOCUMENTATION

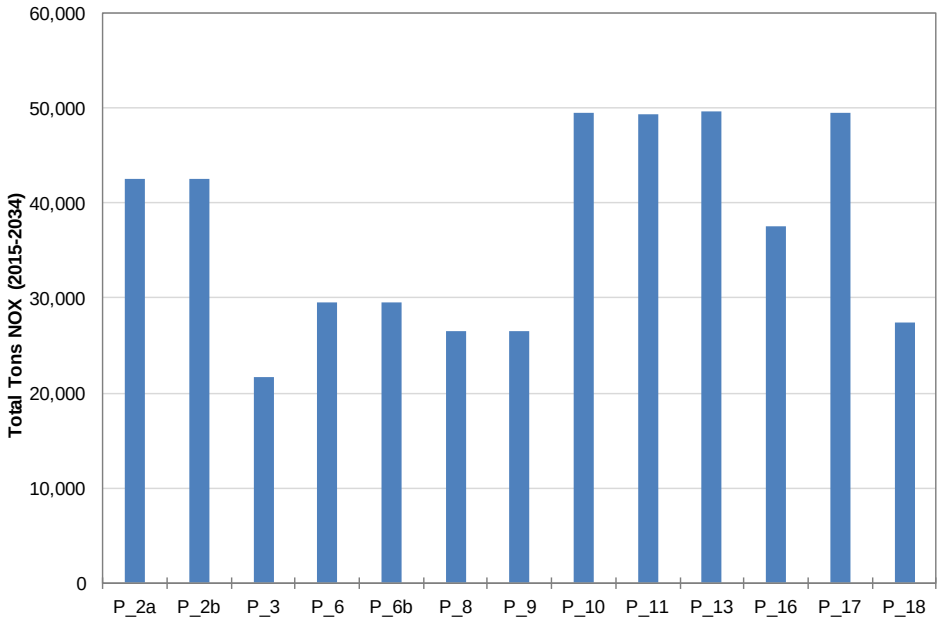
## Portfolio Emissions

### *IPC Systems*

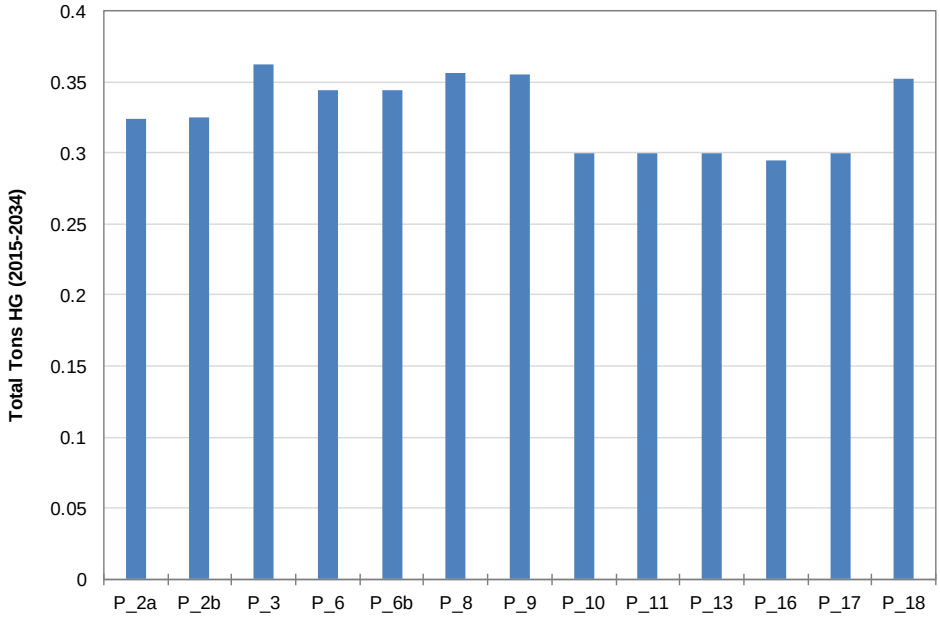
#### $CO_2$ Emission



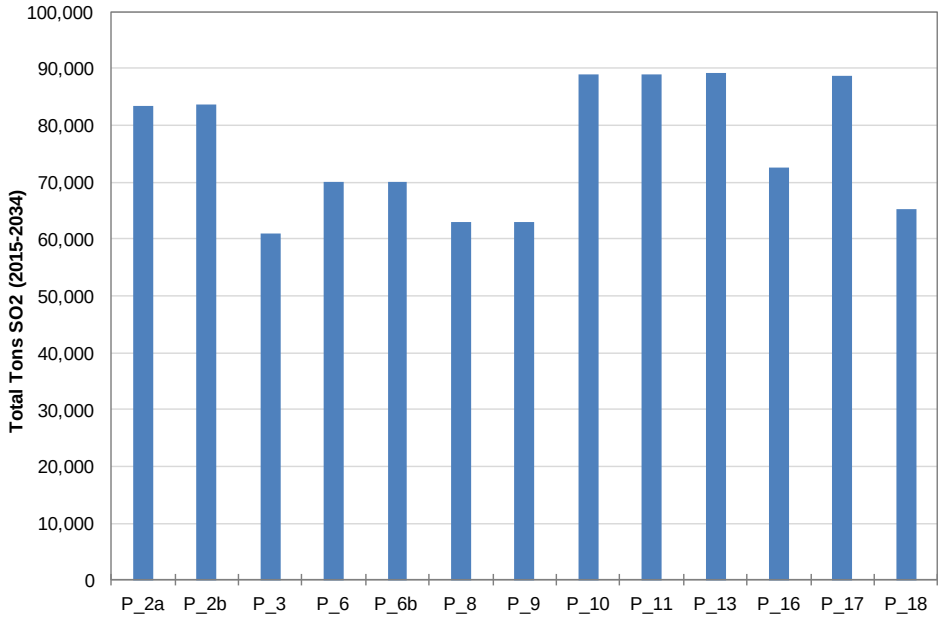

#### NOx Emission



## HG Emission




## $SO_2$ Emission



# Loss of Load Expectation Analysis

**Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 2a**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 0.52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 1.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.07 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.07 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.15 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.15 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 0.27 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.27 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 0.49 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.49 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 0.87 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.87 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 1.54 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.54 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 1.86 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.85 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 3**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.95 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.93 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 1.46 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.43 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 1.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.32 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 1.51 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 1.47 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 2.55 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 2.48 | 0.02 | 0.01 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.07 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.07 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.12 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.12 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.23 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 0.61 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.61 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 0.96 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.95 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 1.56 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.55 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 2.16 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 2.14 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 3.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 3.08 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 6b**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 0.52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 1.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.44 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.43 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.85 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.84 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 1.44 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 1.95 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 1.93 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 0.28 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.28 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 0.54 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.54 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 0.87 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.86 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 1.49 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.48 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 8**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.29 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.28 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.83 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.81 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.81 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.80 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 1.21 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.19 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 1.49 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 1.47 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.21 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.21 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.38 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.38 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.71 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.71 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 1.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.19 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 1.36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 1.23 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.23 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 1.28 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.27 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 1.96 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.96 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 9**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.94 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.92 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.91 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.90 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 1.45 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.42 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 1.47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 1.44 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.69 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.68 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 1.33 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 1.85 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.84 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 0.72 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.71 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 1.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 2.08 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 2.07 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 10**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 0.52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 0.89 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.88 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.12 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.12 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 0.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 0.75 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.75 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 0.47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 11**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.08 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.08 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.29 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.29 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.28 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.28 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 0.47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 1.55 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 1.52 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.21 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.21 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 0.36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 0.62 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.61 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 0.37 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.37 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 1.15 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.14 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 1.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.29 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 13**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 0.52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 0.89 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.88 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.19 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.18 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.37 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.37 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.70 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.70 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 0.19 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.19 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 0.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 0.62 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.62 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 0.38 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.37 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 0.60 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.60 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 16**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.94 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.92 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.91 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.90 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 1.45 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.42 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 1.47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 1.44 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 1.77 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.75 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.90 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.89 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 1.55 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.52 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 2.79 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 2.76 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 1.14 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 1.12 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 1.99 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 | 1.95 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 2.69 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 2.66 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 1.12 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.12 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 2.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 2.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 2.95 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 2.92 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 17**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 0.52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 1.61 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 1.58 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 1.81 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.79 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 1.86 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.84 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 2.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 2.06 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 2.16 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 2.14 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 2.26 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 2.23 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 0.34 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.34 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 0.59 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.59 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 0.97 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.97 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 1.36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 2.07 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 2.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

**Loss of Load Expectation Summary Data* (Hours per month)–Portfolio 18**

| Year | Annual | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2016 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2017 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2018 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 0.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2019 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.04 | 0.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2020 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2021 | 0.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2022 | 0.91 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.90 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2023 | 1.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.39 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2024 | 1.59 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.02 | 1.56 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2025 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2026 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2027 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2028 | 0.44 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.43 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2029 | 0.73 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 0.72 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2030 | 1.34 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.33 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2031 | 1.48 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2032 | 1.78 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.77 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2033 | 1.85 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 1.84 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2034 | 2.37 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 | 2.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

* With CBM@330 MW

# STATE OF OREGON IRP GUIDELINES

ORDER NO. 07-047

ENTERED 02/09/07

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

UM 1056

| | | |
|---|---|---|
| In the Matter of<br><br>PUBLIC UTILITY COMMISSION OF OREGON<br><br>Investigation Into Integrated Resource Planning. | )<br>)<br>)<br>)<br>)<br>)<br>) | ERRATA ORDER |

DISPOSITION: APPENDIX TO ORDER NO. 07-002 CORRECTED

In Order No. 07-002, we adopted guidelines to govern the Integrated Resource Planning (IRP) process. In setting forth those guidelines in an appendix, we inadvertently omitted Guideline 1(d), which we discussed and adopted in the body of the order on pages 7 and 8. Accordingly, Appendix A to Order No. 07-002 is replaced with the attached appendix to this order, which includes all the adopted guidelines. The remainder of the order is unchanged.

IT IS SO ORDERED.

Made, entered, and effective FEB 0 9 2007.

**Lee Beyer**
Chairman

**John Savage**
Commissioner

**Ray Baum**
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

**Adopted IRP Guidelines**

**Guideline 1: Substantive Requirements**

*a. All resources must be evaluated on a consistent and comparable basis.*

- *All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.*
- *Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.*
- *Consistent assumptions and methods should be used for evaluation of all resources.*
- *The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.*

*b. Risk and uncertainty must be considered.*

- *At a minimum, utilities should address the following sources of risk and uncertainty:*
  1. *Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.*
  2. *Natural gas utilities: demand (peak, swing and base-load), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.*
- *Utilities should identify in their plans any additional sources of risk and uncertainty.*

*c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and*

*associated risks and uncertainties for the utility and its customers.*[1]

- *The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.*

- *Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.*

- *To address risk, the plan should include, at a minimum:*

  1. *Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.*

  2. *Discussion of the proposed use and impact on costs and risks of physical and financial hedging.*

- *The utility should explain in its plan how its resource choices appropriately balance cost and risk.*

d. *The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.*

**Guideline 2: Procedural Requirements.**

a. *The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.*

[1] We sometimes refer to this portfolio as the "best cost/risk portfolio."

*b. While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.*

*c. The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.*

**Guideline 3: Plan Filing, Review, and Updates.**

*a. A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.*

*b. The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.*

*c. Commission staff and parties should complete their comments and recommendations within six months of IRP filing.*

*d. The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.*

*e. The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.*

*f. Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.*

g. *Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:*

- *Describes what actions the utility has taken to implement the plan;*
- *Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and*
- *Justifies any deviations from the acknowledged action plan.*

**Guideline 4: Plan Components.**

*At a minimum, the plan must include the following elements:*

a. *An explanation of how the utility met each of the substantive and procedural requirements;*

b. *Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;*

c. *For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;*

d. *For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;*

e. *Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;*

*f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;*

*g. Identification of key assumptions about the future( e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;*

*h. Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;*

*i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;*

*j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;*

*k. Analysis of the uncertainties associated with each portfolio evaluated;*

*l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;*

*m. Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and*

*n. An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.*

**Guideline 5: Transmission.**

*Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote*

*locations, acquiring alternative fuel supplies, and improving reliability.*

**Guideline 6: Conservation.**

a. *Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.*

b. *To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.*

c. *To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:*

   - *Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and*

   - *Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.*

**Guideline 7: Demand Response.**

*Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).*

**Guideline 8: Environmental Costs.**

*Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide ($CO_2$), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential $CO_2$ regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.*

**Guideline 9: Direct Access Loads.**

*An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.*

**Guideline 10: Multi-state Utilities.**

*Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.*

**Guideline 11: Reliability.**

*Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.*

**Guideline 12: Distributed Generation.**

*Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.*

**Guideline 13: Resource Acquisition.**

a. *An electric utility should, in its IRP:*

   - *Identify its proposed acquisition strategy for each resource in its action plan.*
   - *Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.*
   - *Identify any Benchmark Resources it plans to consider in competitive bidding.*

b. *Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.*

# Compliance with State of Oregon IRP Guidelines

| Oregon Order 07-047 Action Items | 2015 IRP |
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| **Guideline 1: Substantive Requirements**<br>a. All resources must be evaluated on a consistent and comparable basis.<br>• All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand side options which focus on conservation and demand response.<br>• Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.<br>• Consistent assumptions and methods should be used for evaluation of all resources.<br>• The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.<br>b. Risk and uncertainty must be considered.<br>• At a minimum, utilities should address the following sources of risk and uncertainty:<br>1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.<br>2. Natural gas utilities: demand (peak, swing and baseload), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.<br>• Utilities should identify in their plans any additional sources of risk and uncertainty.<br>c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.<br>• The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.<br>• Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all longlived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.<br>• To address risk, the plan should include, at a minimum:<br>1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.<br>2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.<br>• The utility should explain in its plan how its resource choices appropriately balance cost and risk.<br>d. The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies. | a-1) Supply-side and purchased resources for meeting the utility's load are discussed in Chapter 3 (Idaho Power Today), section *Existing Supply-Side Resources*, pages 27–38. Demand-side options for meeting the utility's load are discussed in Chapter 4 (Demand-Side Resources). Chapter 6 (Transmission Planning) discusses transmission resources for meeting the utility's load.<br>a-2) New resource options are described in Chapters 4 through 7. Chapter 4 (Demand-Side Resources) describes demand-side resource options for IRP resource portfolios. Chapter 5 (Supply-Side Generation and Storage Resources) describes generating resources and energy storage resources to be considered for IRP resource portfolios. Chapter 6 (Transmission Planning) describes transmission resources considered for IRP resource portfolios. Chapter 7 (Planning Period Forecasts) provides resource cost information.<br>a-3) The consistent modeling method for evaluating new resource options is described in Chapter 7 (Planning Period Forecasts), sections *Resource Cost Analysis*, *Resource Cost Analysis II—Resource Stack*, and *Supply-Side Resource Costs*. The consistent modeling method for evaluating all resource portfolios is explained in Chapter 9 (Modeling Analysis and Results), pages 113–114.<br>a-4) The WACC rate used to discount all future resource costs is stated in Chapter 9 (Modeling Analysis and Results), in Table 9.1 Financial Assumptions, on page 114.<br>b-1) Electric utility risk and uncertainty factors (load, NG and water conditions) for resource portfolios are considered in Chapter 9 (Modeling Analysis and Results), section *Stochastic Risk Analysis*, pages 121–124. (For electricity prices, AURORA forecasts electric market prices; therefore AURORA variables are changed to create different electric market price scenarios). Sensitivity analysis for CAA Section 111(d) performed to address costs to comply with greenhouse gas regulations is discussed in Chapter 9 (Modeling Analysis and Results), section *CAA Section 111(d) Sensitivity Analysis*, beginning on page 114.<br>Note: Plant forced outages for resource options and resource portfolios are not discussed in the IRP document or *2015 IRP Technical Appendix*. Plant forced outages are modeled in AURORA on a unit basis.<br>b-1-other) Additional sources of risk and uncertainty are identified in Chapter 2 (Political, Regulatory, and Operational Issues) in the following sections: *FERC Relicensing*, page 14; *Idaho Water Issues*, page 15; *Northwest Power Pool Energy Imbalance Market*, page 19; and *Federal Energy Legislation CAA Section 111(d)*, page 21.<br>Further discussion of risks is included in Chapter 9 (Modeling Analysis and Results), in section *Qualitative Risk Analysis*, beginning on page 125. Uncertainty factoring into the selection of the preferred portfolio is expressed in Chapter 1 (Summary) on pages 8-10.<br>c-1) The IRP methodology and the planning horizon of 20 years are discussed in Chapter 1 (Summary), section *IRP Methodology,* page 3.<br>c-2) Idaho Power uses the company's internal P-Worth model to calculate the PVRR for the capital component of the various portfolios. AURORA is used to model the variable (operating) component of the various portfolios. All costs are then discounted using the company's WACC. The summary of the NPV accounting for total portfolio costs is provided in Chapter 9 (Modeling Analysis and Results), pages 113-114. |

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| | c-1.) Measures of the variability of costs and the severity of bad outcomes are considered in Chapter 9 (Modeling Analysis and Results), section *Stochastic Risk Analysis,* pages 121–124. A discussion of extreme outcomes, including extreme bad outcomes, is provided in the *Stochastic Risk Analysis* section in the third paragraph of page 123.<br>c-2.) The risks of physical and financial hedging are referenced to Idaho Power's *Energy Risk Management Policy* discussed in Chapter 1 (Summary), in the last paragraph of section *Introduction*, on page 2. Idaho Power explains how its preferred portfolio appropriately balances cost and risk in Chapter 9 (Modeling Analysis and Results), section *Preferred Portfolio*, page 130. The accounting for qualitative risks and uncertainty in the preferred portfolio selection is discussed in Chapter 1 (Summary), section *Portfolio Analysis Summary*, beginning on page 8. Further discussion of the preferred portfolio's appropriate balancing of cost and risk is included in Chapter 10 (Preferred Portfolio and Action Plan), section *Preferred Portfolio (2015-2034)*, page 141.<br>d-1) The plan is consistent with long-run public interests and is discussed in Chapter 2 (Political, Regulatory, and Operational Issues). Additional discussion relevant to this requirement is in Chapter 1 (Summary), section *Public Advisory Process*, pages 2–3. |
| **Guideline 2: Procedural Requirements.**<br>a. The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.<br>b. While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.<br>c. The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission. | As set forth in Guideline 2, part a., Idaho Power solicits public involvement in the planning process. The company convenes a public forum as part of the resource planning process. For the 2004, 2006, 2009, 2011, 2013, and 2015 plans, Idaho Power assembled an IRP Advisory Council composed of customer representatives, representatives from both the Idaho and Oregon public utility commission staffs, and representatives from special interest groups. A roster of the IRP Advisory Council members is provided in the technical appendices of the IRPs. The IRP Advisory Council meetings are open to the public. IRP Advisory Council meetings are attended by members of the public and Idaho Power has involved the public participants in the IRP Advisory Council's discussions. These meetings allow parties to make relevant inquiries of Idaho Power formulating the plan.<br>As set forth in Guideline 2, part b., Idaho Power makes public extensive information relevant to its resource evaluation and action plan in its plan. This information is found throughout the 2015 IRP, the 2015 Load and Sales Forecast and in the 2015 Technical Appendix.<br>As set forth in Guideline 2, part c., Idaho Power posted online a draft 2015 IRP for public review on Thursday, June 4, 2015. The company requested for comments to be provided no later than Friday, June 12, 2015. |

| Oregon Order 07-047 Action Items | 2015 IRP |
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| **Guideline 3: Plan Filing, Review, and Updates.**<br>a. A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.<br>b. The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.<br>c. Commission staff and parties should complete their comments and recommendations within six months of IRP filing.<br>d. The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.<br>e. The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.<br>f. Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.<br>g. Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:<br>• Describes what actions the utility has taken to implement the plan;<br>• Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and<br>• Justifies any deviations from the acknowledged action plan. | a. The OPUC acknowledged Idaho Power's 2013 IRP on July 8, 2014 in Order 14-253. Idaho Power plans to file the 2015 IRP by June 30, 2015.<br>b. Idaho Power will schedule a public meeting at the OPUC after the 2015 IRP has been filed.<br>c. No action needed.<br>d. No action needed unless the OPUC provides Idaho Power an opportunity to revise the plan.<br>e. In Order No. 12-013, the OPUC provided direction on IRP flexible resource guidelines. In Order No. 14-253, the OPUC provided its resolution of fourteen components of the 2013 IRP. Idaho Power has addressed these action items in the 2015 IRP.<br>f. In Order No. 14-253, the OPUC waived for Idaho Power the requirement to file an annual update to the 2013 IRP, the most recently acknowledged IRP.<br>g. No action needed. |

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| **Guideline 4: Plan Components.**<br>At a minimum, the plan must include the following elements:<br>a. An explanation of how the utility met each of the substantive and procedural requirements;<br>b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;<br>c. For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;<br>d. For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;<br>e. Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;<br>f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;<br>g. Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;<br>h. Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;<br>i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;<br>j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;<br>k. Analysis of the uncertainties associated with each portfolio evaluated;<br>l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;<br>m. Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and<br>n. An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing. | a. Idaho Power anticipates delivering this table in an informal letter to the OPUC staff.<br>b. Idaho Power revises the sales and load forecast each year and Idaho Power included the most recent sales and load forecast assumptions in Chapter 7 (Planning Period Forecasts), section *Load Forecast,* beginning on page 73.. High-growth scenarios at the 90th and 95th percentile levels for peak hour, and at the 70th and 90th percentile levels for energy are provided in Chapter 7, Figures 7.1 and 7.2 and Tables 7.1 and 7.2. High- and low-growth scenarios analyzed for the stochastic load risk analysis are discussed in Chapter 9 (Modeling Analysis and Results), section *Stochastic Risk Analysis,* pages 121-124.<br>c. Peaking capacity and energy capability for each year of the plan for existing resources are discussed in Chapter 7 (Planning Period Forecasts), section *Generation Forecast for Existing Resources,* beginning on page 80. Idaho Power uses AURORA in the modeling of all existing transmission. Future transmission additions associated with the resource portfolios tested are discussed in Chapter 6 (Transmission Planning), section *Transmission Assumptions in the IRP Portfolios,* beginning on page 71.<br>d. Not applicable.<br>e. Supply-side resources considered are identified and described in Chapter 5 (Supply-Side Generation and Storage Resources). Resource costs are discussed and provided in Chapter 7 (Planning Period Forecasts), sections *Resource Cost Analysis*, *Resource Cost Analysis II—Resource Stack*, and *Supply-Side Resource Costs*. Demand-side resources and their levelized costs and technologies are covered in Chapter 4 (Demand-Side Resources).<br>f. Resource reliability is covered in Chapter 9 (Modeling Analysis and Results), section *Loss of Load Expectation (LOLE),* beginning on page 139.<br>g. Natural gas price forecasts are discussed in Chapter 7 (Planning Period Forecasts), section *Natural Gas Price Forecast*, page 84-85. Chapter 7 also includes key assumptions about future load in section *Load Forecast* and generation in section *Generation Forecast for Existing Resources*. Costs for environmental compliance with proposed $CO_2$ regulations are addressed in Chapter 9 (Modeling Analysis and Results), section *CAA Section 111(d) Sensitivity Analysis*, beginning on page 114. Compliance alternatives to SCR installation at Jim Bridger Units 1 and 2 are addressed by portfolios considering early retirement of Jim Bridger Units 1 and 2. Environmental compliance costs for SCR installation at Jim Bridger units 3 and 4 are addressed in the *Appendix C—Technical Appendix* in the section *Jim Bridger Units 3 and 4 Selective Catalytic Reduction Analysis*.<br>h. Resource portfolios considered for the 2015 IRP are described in Chapter 8 (Portfolio Selection). Resource portfolios were developed using resources from the resource stack provided in Chapter 7 (Planning Period Forecasts), sections *Resource Cost Analysis*, *Resource Cost Analysis II—Resource Stack*, and *Supply-Side Resource Costs*. Resource portfolios were developed with consult from the IRP Advisory Council and public participants.<br>i. The resource portfolios are evaluated against various risks in Chapter 9, Modeling Analysis and Results, section *Stochastic Risk Analysis,* pages 121–124.<br>j. Portfolio cost and risk results, with interpretations, are provided in Chapter 9 (Modeling Analysis and Results).<br>k. The uncertainties associated with each portfolio are evaluated in Chapter 9 (Modeling Analysis and Results), sections *Stochastic Risk Analysis* and *Qualitative Risk Analysis*.<br>l. The selection reasoning for the preferred resource portfolio is identified in Chapter 9 (Modeling Analysis and Results), section *Preferred Portfolio*, page 130.<br>m. No inconsistencies were identified.<br>n. An action plan is provided in Chapter 1 (Summary), section *Action Plan*, page 10. |

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| **Guideline 5: Transmission.**<br>Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability. | The transmission required for each resource being considered is described in the 2015 IRP *Technical Appendix*, section *Transmission Cost Assumptions*. Transmission assumptions for supply-side resources considered are included in Chapter 6 (Transmission Planning), section *Transmission Assumptions in the IRP Portfolios*, pages 71–72. AURORA accounts for the cost of wheeling when selling and purchasing power from the market. For natural gas-fired resources, the Idaho Citygate price reflects the cost of transport to a power plant. The Idaho Citygate price is described in Chapter 7 (Planning Period Forecasts), section Natural Gas Price Forecast, pages 84-85. Forecasts for Idaho Citygate price are provided in the 2015 IRP *Technical Appendix*, section *Fuel Price Forecasts*. |
| **Guideline 6: Conservation.**<br>a. Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.<br>b. To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.<br>c. To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:<br>• Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and<br>• Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition. | a. The potential study conducted by Applied Energy Group (AEG) for the 2015 IRP is described in Chapter 4 (Demand-Side Resources), section *Committed Energy Efficiency Forecast*, beginning on page 43.<br>b. The 2015 IRP action plan expresses Idaho Power's intent to continue pursuit of cost-effective energy efficiency. A forecast for energy efficiency effects in five-year blocks is provided in Chapter 4 (Demand-Side Resources), section *Committed Energy Efficiency Forecast*, Table 4.2. Detailed year-by-year forecast values are included in the 2015 IRP *Technical Appendix,* section *Monthly average energy load and resource balance*.<br>c. Treatment of third party market transformation savings provided by the Northwest Energy Efficiency Alliance (NEEA) in the 2015 IRP is discussed in Chapter 4 (Demand-Side Resource), pages 40-41. Idaho Power has changed how market transformation savings provided by NEEA are treated in the IRP. NEEA savings are now included as savings to meet targets because of the overlap of NEEA initiatives and IPC's most recent potential study. |
| **Guideline 7: Demand Response.**<br>Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities). | Demand response resources are detailed in Chapter 4 (Demand-Side Resources), section *Demand Response Performance,* page 42. Additional demand response above baseline levels is considered in select portfolios, including the preferred portfolio. The additional demand response is discussed in Chapter 4 (Demand-Side Resources), section *Additional Demand Response*, page 47. |
| **Guideline 8: Environmental Costs.**<br>Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide ($CO_2$), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential $CO^2$ regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable. | It is noted in Chapter 9 (Modeling Analysis and Results), section *Portfolio Emissions*, page 125, that with the exception of portfolios retiring Jim Bridger Units 1 and 2 without installation of NOx-controlling retrofits, all portfolios are designed to comply with environmental regulations. CAA Section 111(d) is modeled to reflect future carbon dioxide regulations. Portfolio costs provided for the considered CAA Section 111(d) sensitivities as provided in Chapter 9 (Modeling Analysis and Results), section *CAA Section 111(d) sensitivity analysis – results*, Table 9.4, page 119. |
| **Guideline 9: Direct Access Loads.**<br>An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier. | At present, Idaho Power does not have any customers served by alternative electricity suppliers and Idaho Power has no direct access loads. Guideline 9 is not expected to apply to Idaho Power during the 2015 IRP 20-year planning period. |
| **Guideline 10: Multi-state Utilities.**<br>Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers. | Idaho Power intends to file the 2015 IRP in both the Idaho and Oregon jurisdictions. |
| **Guideline 11: Reliability.**<br>Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demandside resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives. | Idaho Power discussed the capacity planning margin in Chapter 9 (Modeling Analysis and Results), section *Capacity Planning Margin*, beginning on page 131, and the loss of load probability in Chapter 9 (Modeling Analysis and Results), section *Loss of Load Expectation,* beginning on page 139. |

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| **Guideline 12: Distributed Generation.**<br>Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation. | Idaho Power evaluated distributed solar PV as a resource option in portfolio 18. Portfolio 18 is described in Chapter 8 (Portfolio Selection), page 110. Distributed storage (ice-based thermal and V redox flow battery) resources were evaluated in multiple portfolios. Portfolios are described in Chapter 8 (Portfolio Selection), beginning on page 97. Distributed resources, generating and storage, were credited to account for avoided transmission line losses. |
| **Guideline 13: Resource Acquisition.**<br>a. An electric utility should, in its IRP:<br>• Identify its proposed acquisition strategy for each resource in its action plan.<br>• Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.<br>• Identify any Benchmark Resources it plans to consider in competitive bidding.<br>b. Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment. | Idaho Power continues to evaluate resource ownership along with other supply options. Idaho Power conducts its resource acquisition and competitive bidding processes consistent with the guidelines established by Oregon in Order No. 14-149 issued on April 30, 2014.<br>Idaho Power discusses asset ownership in Chapter 10 (Action Plan), section *Action Plan (2015–2018)*, page 143.<br>Idaho Power's action plan includes ongoing permitting, planning studies, and regulatory filings associated with the Boardman to Hemingway transmission line. Construction of the Boardman to Hemingway transmission line will be managed to be consistent with resource acquisition and competitive bidding processes provided in guidelines established by Oregon in Order No. 14-149. |

# STATE OF OREGON IRP ELECTRIC VEHICLES (EV) GUIDELINES

ORDER NO. 12 013

ENTERED JAN 19 2012

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

UM 1461

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| In the Matter of<br><br>PUBLIC UTILITY COMMISSION OF OREGON<br><br>Investigation of matters related to Electric Vehicle Charging. | ORDER |

DISPOSITION: GUIDELINES ADOPTED; UTILITIES ORDERED TO MAKE REVISED TARIFF FILINGS

## I. PROCEDURAL HISTORY

At our December 8, 2009, Public Meeting, we opened this docket at our Staff's request to investigate matters related to the charging infrastructure for plug-in hybrid vehicles and electric vehicles (collectively referred to as EVs).[1] Specifically, we intended this docket to address general matters related to the emergence and development of the EV charging market and industry, including the role of electric utilities with regard to owning and operating EV service equipment (EVSE) and acting as EV service providers (EVSP). The Citizens' Utility Board of Oregon (CUB) noticed its intervention in the investigation, and the following parties were authorized over the course of the docket to intervene as parties: the Oregon Department of Energy (ODOE); ECOtality, Inc.; Smart Grid of Oregon (SGO); Grid Mobility LLC; Mitsubishi Motors R&D of America; the Oregon Department of Environmental Quality (DEQ); Nissan North America, Inc.; CleanFuture; the Northwest Energy Coalition (NWEC); Portland General Electric Company (PGE); PacifiCorp, dba Pacific Power (Pacific Power); and Idaho Power Company (Idaho Power).

On June 22, 2010, Staff and interested parties participated in a public workshop to discuss the scope of the investigation. Staff subsequently prepared a "straw proposal," published on July 22, 2010, that was intended to facilitate and focus further discussion in the docket. On August 6, 2010, a second public workshop was held. Staff and parties submitted opening comments on August 27, 2010.

[1] *See* Staff Report for December 8, 2009 Public Meeting, Item No. 4.

*2. Resolution*

We agree with Staff and all of the other parties in this docket that there is no discernible reason, at least at this time, to treat EV charging load differently than any other load with regard to distribution system upgrades. Moreover, we acknowledge that EV charging load may not necessitate system upgrades at any time should the load be effectively managed. Consequently, we adopt Staff's recommendation that utilities' existing line extension policies continue to apply, without modification, to all loads, including plug-in EV load.

**D. Integrated Resource Planning Flexible Resources Guidelines**

The current Integrated Resource Planning (IRP) guidelines are silent regarding flexible capacity. In opening comments, Staff proposed an IRP guideline to fill this need.

*1. Parties' Positions*

Staff's proposed IRP guideline has three parts, as follows:

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; and

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.

Staff asserts that the proposed IRP guideline is consistent with the language and content of the existing IRP guidelines, and addresses an issue that is relevant for resource and planning both now and in the future. Staff states, "[f]lexibility is an increasingly important consideration in the integration of higher percentages of variable renewable generation resources."[31] Staff further comments that "EVs, as the first 'smart appliance', represent an opportunity to capture the power of demand response flexibility as a compliment to other flexibility strategies coming from generation and storage technologies."[32] Although Staff realizes that EVs will not be ready to provide flexible

[31] Staff Response to Bench Request, p. 25.
[32] *Id.*

capacity any time soon due to measured market penetration and technical challenges, Staff argues that it appropriate to begin planning for the future and that a 20-year planning horizon is consistent with current IRP practice.

ECOtality, Inc., agrees, observing that as IRPs involve long-range planning, they should include developing technologies, or events may eclipse planning. ODOE recommends supports Staff's proposed IRP guideline. Neither NWEC nor CUB object to Staff's proposed IRP guideline, although CUB notes a possible practical limitation to EVs functioning as a flexible capacity resource should the manufacturers of EVs or EV batteries be reluctant to allow third parties access to EV battery storage capacity, thereby limiting flexible capacity availability from EVs.

All three utilities oppose adoption of Staff's proposed IRP guideline, arguing that the guideline is prematurely too prescriptive about planning for a resource that is still unknown and uncertain. Pacific Power complains about the administrative burden on a utility versus the analytical value of studies that would be undertaken pursuant to Staff's proposed guideline. Similarly, Idaho Power argues that given the significant uncertainties about whether and when EVs might provide flexible capacity, the Commission should direct utilities to consider, but not model such resources. PGE takes the position that adoption of Staff's proposed guideline is premature, and would impose long range speculative assumptions and create significant administrative burden.

All three utilities recommend further discussion and study in some other forum before adopting an IRP guideline related to flexible resource planning. Pacific Power urges the Commission to further study flexible capacity resources in a manner that accounts for each utility's planning and modeling framework, whether as part of an evolving investigation or through the public IRP processes. Pacific Power also notes that to the extent that these new guidelines are intended to inform the development of demand response programs more generally, the Commission should open an investigation to reevaluate all IRP guidelines related to demand response programs, rather than adopting certain new guidelines in an EV-specific proceeding. As already discussed, PGE suggests the Commission develop a pilot program to collect information to be used to late guide policy. PGE observes, however, that the company is increasing non-controllable variable generation in the form of wind and losing access to controllable flexible generation in the form of hydro. PGE acknowledges, therefore, that this situation makes the assessment of flexible generation an important component of PGE's IRP planning on a going forward basis. Consequently, PGE indicates that the first two parts of Staff's proposed guideline may have value. PGE argues, however, that it is unreasonable to link flexible capacity to EVs at this time, since EVs may be at least a decade away from commercial viability.

### 2. *Resolution*

At the outset, we conclude there is no need for further discussion on this issue. All three utilities submitted several rounds of comments regarding Staff's proposed guideline, including responses to our bench request. Although all three

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2. We direct each electric utility to fully address the new Integrated Resource Planning guideline adopted herein in the utility's next Integrated Resource Planning proceeding.

Made, entered, and effective JAN 19 2012.

**John Savage**
Commissioner

**Susan K. Ackerman**
Commissioner

**Stephen M. Bloom**
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

# Compliance with EV Guidelines

| Oregon Order 12-013 Guideline | 2015 IRP |
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| **Guideline 1: Forecast the Demand for Flexible Capacity.**<br>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;<br>**Guideline 2: Forecast the Supply for Flexible Capacity.**<br>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;<br>**Guideline 3: Evaluate Flexible Resources on a Consistent and Comparable Basis**<br>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. | A discussion of the 2015 IRP's analysis for the flexibility guideline is provided in Chapter 9 (Modeling Analysis and Results), section Flexible Resource Needs Assessment, pages 135–139. Figure 9.4 on page 135 presents a projection for flexibility need across multiple timescales. Simulations of the system capability to provide flexibility are illustrated in Figures 9.5 through 9.9 on pages 136–138. |

# STATE OF OREGON ACTION ITEMS REGARDING IDAHO POWER'S 2013 IRP

ORDER NO. 12 253

ENTERED JUL 0 8 2014

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

LC 58

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| In the Matter of<br>IDAHO POWER COMPANY,<br>2013 Integrated Resource Plan | ORDER |

DISPOSITION: PLAN ACKNOWLEDGED IN PART AND AS REVISED

## I. INTRODUCTION

Idaho Power Company is a public utility operating in Oregon and is subject to the Commission's jurisdiction and requirements regarding integrated resource planning. Idaho Power's 2011 Integrated Resource Plan (IRP) was acknowledged with exceptions and guidance for its next IRP in Order No. 12-177. Idaho Power now seeks acknowledgment of its 2013 IRP.

We require each regulated energy utility to prepare and file an IRP within two years of acknowledgment of the utility's last plan. In the IRP, an energy utility must: (1) evaluate resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) aim to select a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers; and (4) create a plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.[1]

Once a utility completes a plan, we review for adherence to the procedural and substantive requirements outlined in Order No. 89-507. We generally acknowledge the plan—that is, find it reasonable based on the information available at that time—or return it to the utility with comments.[2] We may also decline to acknowledge specific action items if we question whether the utility's proposed resource decision presents the least cost and risk option for its customers.

We reaffirm our long-standing view that decisions made in IRP proceedings do not constitute ratemaking. Decisions whether to allow a utility to recover from its customers the costs associated with new resources may only be made in a rate proceeding. Acknowledgment of an IRP, however, is relevant to subsequent examination of whether a

[1] Order No. 07-002.
[2] *Id.* at 2.

utility's resource investment is prudent and should be recovered from ratepayers. As we have previously stated:

> Consistency of resource investments with least-cost planning principles will be an additional factor that the Commission will consider in judging prudence. When a plan is acknowledged by the Commission, it will become a working document for use by the utility, the Commission, and any other interested party in a rate case or other proceeding before the Commission[.] Consistency with the plan may be evidence in support of favorable rate-making treatment of the action, although it is not a guarantee of favorable treatment.[3]

Just as acknowledgment does not guarantee favorable ratemaking, a decision to not acknowledge an action item does not constitute a preliminary determination of imprudence. The purpose of the IRP process is to provide the utility with the information and opinion of stakeholders and the Commission based on information presented by the utility. The question of whether a specific investment made by a utility in its planning process was prudent will be fairly examined in a subsequent rate case proceeding.

## II. DISCUSSION

We conclude Idaho Power satisfies all the procedural guidelines and all but one of the substantive guidelines for IRP planning. Idaho Power did not comply with the IRP Guideline regarding flexible capacity adopted in Order No 12-013.

We acknowledge the short-term action items in Idaho Power's Action Plan, except for the investment in selective catalytic reduction emissions technology at Jim Bridger Units 3 and 4.[4] In addition, we acknowledge two additional action items recommended by Staff that relate to energy efficiency. We do not acknowledge the remaining action items, which are for the most part outside the two-to-four year action plan period.[5]

## III. IDAHO POWER'S IRP

During the 20-year planning period, Idaho Power expects that the number of its customers will increase by about 8,400 each year, from approximately 500,000 in 2012 to 670,000 in 2032. Idaho Power's expected-case load forecast predicts that summer-peaking hour load requirements will grow at about 55 MW per year, and that the average-energy requirements will grow at 21 aMW per year. Idaho Power's load and resource balance analysis, which accounts for forecast load growth and generation from all of the company's existing resources and planned purchases, shows no energy deficits through the planning period. Idaho Power's analysis shows a capacity deficit starting in 2016 and monthly peak-hour deficit positions growing steadily in magnitude and the number of months affected. By July 2032, the capacity deficits are approximately 870 MW.

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[3] *Id.* at 24, *quoting* Order No. 89-507 at 7.
[4] *See* Appendix A.
[5] *See* Guideline 4(n).

Idaho Power identifies as its major resource addition the Boardman to Hemingway transmission line (B2H) with market purchases. The company's preferred portfolio also includes demand response, continued operations at the Jim Bridger and North Valmy coal facilities after investment in emission-control technology, and the continued operation of Idaho Power's other existing supply-side resources.

Guideline 4(n) requires the utility to include an action plan with resource activities the utility intends to undertake over the next two to four years. Idaho Power includes the following activities in its 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&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 – 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 |

## IV. DISCUSSION

In this order, we first address Idaho Power's Action Plan, discussing the comments filed by participants[6] and specific IRP Guidelines as appropriate. We then address issues raised by the participants or that we identify related to Idaho Power's compliance with the IRP Guidelines and our order regarding Idaho Power's 2011 IRP that are not discussed in connection with our review of the Action Plan.

[6] Renewable Northwest (RNW), the Citizens' Utility Board of Oregon (CUB), the Oregon Department of Energy (ODOE), and Staff of the Public Utility Commission (Staff) filed opening and reply comments regarding Idaho Power's IRP, and Idaho Power filed two rounds of comments in response. In addition, a resident of Idaho, John Weber, forwarded comments to Staff, which Staff forwarded to the Administrative Hearings Division for inclusion in the record.

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## A. Transmission

### *1. Boardman to Hemingway*

Currently, the Boardman to Hemingway transmission project (B2H) is envisioned as a single-circuit 500 kV transmission line approximately 300 miles long between northeast Oregon and southwest Idaho. Idaho Power states that it has entered into a joint funding agreement with PacifiCorp and the Bonneville Power Administration to pursue permitting the project, under which Idaho Power is the permitting project manager.

Idaho Power proposes the following actions for the Boardman to Hemingway transmission project:

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|---|---|
| *2013-2018* | *Boardman to Hemingway – Ongoing permitting, planning studies, and regulatory filings* |
| *2018* | *Boardman to Hemingway – Transmission line complete and in service* |

#### *a. Participants' Comments*

RNW supports investment in B2H because it would provide Idaho Power not only with transmission to a liquid market, enabling the company to access low-cost resources to meet capacity and energy needs, but to also generate revenue by selling energy to other regional utilities. RNW also contends B2H will provide environmental benefits by enabling Idaho Power to reach renewable energy resource zones, thereby facilitating renewable energy resources.

Staff recommends acknowledgement of ongoing permitting, planning studies, and regulatory filings for B2H. Staff notes that B2H is included in five of the nine portfolios modeled in the 2013 IRP. The preferred portfolio and the next lowest "total costs portfolios" include B2H. Staff finds that the IRP analysis regarding B2H supports acknowledgment of ongoing permitting, planning studies, and regulatory filings.

Staff recommends, however, that we decline to acknowledge B2H "Transmission line complete and in-service" in 2018. Staff reports that the estimated in-service date for B2H has moved from 2018 (the year noted in Idaho Power's IRP) to 2020 (the year reported in the company's reply comments). Staff concludes this action item is now well beyond the two-to-four year period prescribed in the IRP Guidelines.

With respect to Idaho Power's activities that occur between the our order in this docket and Idaho Power's 2015 IRP, Staff asks to be apprised of any (1) updated project plan incorporating changes related to Bureau of Land Management delays and Energy Facilities Siting Council developments; (2) final agreement regarding allocation of construction costs between project participants; and (3) significant regulatory decisions that impact the project schedule or costs. Staff also asks that the company to further explore whether B2H would significantly impact wind generation curtailment during

periods of low demand as well as the impact of B2H on resource integration costs in general.

In its first round of comments, Idaho Power asserts that Staff's recommendation to acknowledge only the permitting activities of B2H and not the construction phase of the project is inconsistent with the our past acknowledgment of B2H and is unnecessary to ensure continued analysis of this project. In its final comments, Idaho Power states that it is only requesting acknowledgment of specific action items scheduled to occur within the next four years (which excludes the construction of B2H), but does ask that we acknowledge the 2013 IRP in its entirety, which includes B2H in its preferred portfolio.

*b. Commission Resolution*

We acknowledge ongoing permitting, planning studies, and regulatory filings for B2H. As Staff notes, the analysis in the IRP supports these planned near-term activities. We anticipate additional analysis regarding B2H in Idaho Power's 2015 IRP before acknowledging other actions related to B2H.

We decline to acknowledge completion of B2H because it is well beyond the two-to-four year period for action items specified by the IRP Guidelines. Further, we disagree with any suggestion that declining to acknowledge the construction of B2H is inconsistent with our previous acknowledgment of certain activities (*e.g.*, permitting) related to this resource or inconsistent with previous orders acknowledging IRPs based on a preferred portfolio that includes B2H. Our acknowledgment of an IRP is based on our conclusion that it complies with our guidelines and that the plan seems reasonable based on information known at the time.

***2. Gateway West***

Gateway West is a multi-segment, multi-year, joint transmission project of Idaho Power and PacifiCorp/Rocky Mountain Power to build and operate approximately 1000 miles of new transmission lines from Wyoming to the Hemingway Substation near Melba, Idaho. The project timeline indicates line segments in service between 2019 and 2023. Idaho Power has a one-third interest in some, but not all, of the segments to be located in Idaho and sole interest in one segment.

Idaho Power asks for acknowledgment of the following action item related to Gateway West:

*2013* *Gateway West – Ongoing permitting, planning studies, and regulatory filings*

Idaho Power reports that the Gateway West and B2H projects 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 a population center in Utah. Idaho Power states that Gateway West will benefit customers by (1) relieving transmission constraints on certain transmission paths allowing Idaho Power to move additional energy between the east and west sides of the system; (2) providing the option

to locate future generation resources east of the Treasure Valley load center; and (3) providing future load service to the Magic Valley from the Cedar Hill Substation. Idaho Power does not request acknowledgment of Gateway West as a supply side resource. Instead, the company asserts that Gateway West is reasonable to address transmission system constraints and provide for future least cost resource development.

*a. Participants' Comments*

RNW supports investment in Gateway West because it will provide the same benefits that B2H will provide—that is, access to low-cost resources, access to regions where renewable resources could be sited, and reliability.

CUB recommends that we not acknowledge Gateway West as presented. CUB notes that Gateway West is a large project composed of a number of segments that can be analyzed individually. CUB asserts that Idaho Power should narrow its request and seek acknowledgment only of the segments of Gateway West that it can demonstrate are cost effective for Idaho Power's customers.

Staff concludes that, although there is insufficient information to support acknowledgment of the construction of Gateway West, we should acknowledge the permitting-related activities that must occur prior to construction. For purposes of Idaho Power's next IRP, however, Staff recommends that the company include an analysis of the historical and projected power flows for the portions of the Gateway West project in which Idaho Power has an interest in order to demonstrate the need and specific constraint-related benefits.

*b. Commission Resolution*

We acknowledge ongoing permitting, planning studies, and regulatory filings for Gateway West. However, as CUB notes, the project is composed of multiple segments that can and should be analyzed individually. Moreover, Idaho Power has an ownership interest in relatively few of the segments and must demonstrate the need and specific constraint-related benefits for each segment in which it holds an interest before we will consider acknowledgment of the project's construction.

**B. Pollution Control Investments in Coal Resources**

***1. Idaho Power's Analysis***

IRP Guideline 8, as modified by Order No. 08-339, contains four requirements related to environmental costs. Under this guideline, the utility must model a base case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide ($CO_2$), nitrogen oxides, sulfur oxides, and mercury emissions. The utility must also develop several compliance scenarios ranging from the present $CO_2$ level to the upper reaches of credible proposals by governing entities. Then, the utility must estimate, under each of the compliance scenarios, the present value of revenue requirement (PVRR) cost and risk measures in its preferred portfolio and alternate portfolios. Guideline 8 directs the utility to identify the $CO_2$ emission cost adder level

that triggers the selection of a portfolio that is substantially different from the preferred portfolio. In addition, Guideline 8 requires utilities develop a portfolio to achieve voluntary carbon emission reduction targets set forth in Oregon law.

*a. Participants' Comments*

RNW asserts that Idaho Power's analysis of its coal resources failed to meet IRP Guideline 8 because the company did not (1) model natural gas conversions of the Jim Bridger Units 3 and 4 boilers; (2) model a range of pollution control costs; and (3) account for recent direction from President Obama's Administration that may reduce the cost competitiveness of existing coal resources. RNW asserts that investing in coal units is generally not reasonable under scenarios with low natural gas costs or stringent $CO_2$ regulation or both.

CUB also criticizes Idaho Power's analysis, and contends the company failed to consider all possible scenarios. CUB proposes a four-part, Boardman-style analysis that (1) allows potential pollution controls under different scenarios; (2) compares the broader range of pollution control scenarios to alternative investments, such as repowering with natural gas, building a CCCT, or relying on front office transactions; (3) investigates whether there is a plausible scenario for a phase-out that is at a lower cost than either of the two options; and (4) analyzes whether committing to close a plant at the end of its depreciable life would reduce pollution control costs.

Staff voices a concern similar to CUB's regarding Idaho Power's failure to consider a range of early shutdown scenarios. Staff notes that Idaho Power compared the cost of early shutdown and no controls against other alternatives, but did not model a range of early shut-down scenarios, *e.g.*, smaller pollution control investment in exchange for shutdowns at different points in time, which Staff expected would be done. Like CUB, Staff recommends that future coal analysis consider alternative dates for pollution control equipment, shut down, or other alternatives such as gas conversion.

Staff concludes that Idaho Power's analysis is sufficient to comply with the IRP Guidelines, as well as our direction, provided in 2012, to evaluate whether there is flexibility in the emerging environmental regulations that would allow the company to avoid early compliance costs by offering to shut down individual units prior to the end of their useful lives.

Idaho Power responds that its modeling complies with Guideline 8. Idaho Power notes that it modeled three levels of carbon adders to evaluate the potential impact of carbon emissions regulations in its coal study and in the IRP. In addition, Idaho Power explains it created an alternate portfolio in which the North Valmy units are converted to a gas-fired plant and Jim Bridger Units 3 and 4 are replaced with combined cycle combustion turbines (CCCTs). Idaho Power points out that President Obama's announcement regarding $CO_2$ regulation was issued the same month Idaho Power filed its IRP and that Idaho Power could not account for the announcement without delaying the filing of the 2013 IRP. And, Idaho Power asserts the June 2013 Presidential Memorandum concerned regulations for new power plants and none are included in the company's IRP.

*b. Commission Resolution*

We conclude that Idaho Power's IRP complies with IRP Guideline 8, but as discussed below, is not sufficient to provide a basis to support acknowledgment of selective catalytic reduction emission-control technology (SCR) at Jim Bridger Units 3 and 4. Guideline 8 does not require Idaho Power to model every feasible alternative scenario, but requires the company to determine the PVRR costs and risk measures of a "set of reasonable alternative portfolios" assuming a range of different compliance scenarios. Although Idaho Power did not model a scenario in which both North Valmy units and Bridger Units 3 and 4 were converted to natural gas facilities, as RNW believes should have been done, Idaho Power did model a scenario in which North Valmy is converted to natural gas and Bridger Units 3 and 4 are replaced with CCCTs (portfolio 6). In addition, although Idaho Power did not build a compliance scenario that specifically accounts for the June 2013 Presidential Memorandum, Idaho Power did test its portfolios against a range of carbon compliance futures including a carbon adder in the planning case of $14.64 per ton beginning in 2018 and escalating three percent annually, and a carbon adder in the high case of $35 per ton beginning in 2018 and escalating nine percent annually.

The carbon adder was modeled at three levels: low ($0), planning, and high. Idaho Power did not model a distribution of values, as was done with gas prices, load, and hydro in the stochastic analysis. Instead, one-third of the simulations were drawn from each carbon adder level. The company's analysis showed the preferred portfolio 2 and the non-coal portfolio 6 would switch places at a carbon adder of $45 in 2018. We find the alternative portfolios selected by Idaho Power and the range of compliance futures sufficient to satisfy the requirements of Guideline 8.

We share CUB's and Staff's concern regarding the limited nature of Idaho Power's early retirement scenarios analysis. Even though Idaho Power may have technically complied with the action item from Order No. 12-177, we expected that Idaho Power would model a broader range of early shutdown scenarios. We expect Idaho Power to engage fully with Staff and stakeholders in a timely manner to design coal investment analyses for future IRPs to ensure more robust consideration of early shutdown as a compliance option.

Also, we direct Idaho Power to work with stakeholders to explore options for how it plans to model and perform analysis in the 2015 IRP in order to comply with the applicable emissions requirements of §111(d) of the Clean Air Act.

***2. North Valmy Unit 1***

North Valmy is a coal-fired plant consisting of two generating units located in Nevada. Idaho Power is a 50 percent owner of North Valmy. After adjusting for routine scheduled maintenance and estimated forced outages, the annual energy generating capability of Idaho Power's share of the plant is approximately 220 aMW. Idaho Power plans on the continued operation of North Valmy Unit 1 throughout the 20-year planning period of the 2013 IRP and both units of North Valmy are included in Idaho Power's preferred portfolio.

Idaho Power proposes the following action for North Valmy Unit 1 to comply with federal Mercury Air Toxics Standards (MATS):

*2013* *North Valmy Unit 1 – Commit to the installation of dry sorbent injection emission-control technology*

*a. Participants' Comments*

CUB is concerned because Idaho Power's preferred portfolio includes North Valmy with an end-of-life date that CUB fears is too far in the future. CUB notes that the end-of-life date for North Valmy is at or beyond the end of the 20-year planning period in Idaho Power's preferred portfolio but that the co-owner of North Valmy, Nevada Energy, has announced plans to close the plant in 2025.

Idaho Power responds that it modeled North Valmy consistently with its current expectation of the end-of-life date. Idaho Power asserts that Nevada Energy cannot close the plant early without Idaho Power's consent, which it has not given. Also, Idaho Power modeled two portfolios that included a shortened end-of-life date for North Valmy and replacement of lost energy with other resources. These portfolios were higher cost than the preferred portfolio.

Staff recommends acknowledgment of DSI installation. Staff finds that because the cost of the investment is so small, there is no tipping point in the modeled scenarios at which it is more cost-effective to shut down North Valmy rather than invest in DSI.

*b. Commission Resolution*

We acknowledge installation of DSI at North Valmy Unit 1. We find as Staff did that the relatively low cost of the investment leads to the conclusion that the DSI investment and continued operation of North Valmy is the least cost/least risk alternative given the information that is currently available.

We do not share CUB's concern regarding how Idaho Power included North Valmy in its preferred portfolio. First, shortening the life of North Valmy would not change the result of Idaho Power's analysis; installing DSI would still be the least cost/least risk alternative. Second, future events may lead to a shortened operating life for North Valmy, but whether they will is not certain. Idaho Power reasonably relied on the results of modeling based on the assumption North Valmy will operate as Idaho Power currently expects, rather than an assumption based on events that may, or may not, transpire.

***3. Jim Bridger Units 3 and 4***

Jim Bridger is a coal-fired plant consisting of four generating units located in Wyoming. Idaho Power owns one-third of the plant, or 771 MW. The Environmental Protection Agency (EPA) submitted a final rule on January 10, 2014, requiring the installation of selective catalytic reduction emission-control technology (SCR) at Bridger Units 3 and 4 by December 31, 2015 and December 31, 2016, respectively. Idaho Power's application to the Idaho Public Utilities Commission (IPUC) for a Certificate of Public Convenience

and Necessity states that Idaho Power's cost before AFUDC is estimated to be approximately $118 million.

Idaho Power proposes the following action for Jim Bridger Units 3 and 4:

*2013* *Jim Bridger Units 3 and 4 – Commit to the installation of selective catalytic reduction emission-control technology*

*a. Participants' Comments*

CUB and RNW recommend that we not acknowledge pollution control investments at Jim Bridger Units 3 and 4, contending additional analysis is needed. Specifically, CUB asserts that Idaho Power should analyze the effect that different early retirement dates would have on the need for pollution controls at Bridger Units 3 and 4 to inform whether the currently planned investment is cost-effective. CUB notes that a shorter life may reduce the controls needed (and therefore costs), making early retirement of coal plants more cost-effective than other options. RNW adds that Idaho Power did not adequately analyze conversion to natural gas or a sufficient range of future $CO_2$ compliance costs. Also, RNW believes that investing in coal units is generally not reasonable under scenarios with low natural gas costs or stringent $CO_2$ regulation or both.

Idaho Power disagrees with RNW's and CUB's conclusions regarding its analysis for Bridger Units 3 and 4, noting that it examined a range of options including early shutdown and conversion to natural gas, and that its analysis shows that installation of SCR at Bridger Units 3 and 4 is the least cost option for the majority of the alternate carbon and natural gas scenarios it modeled.

Staff recommends we acknowledge installation of SCR at Bridger Units 3 and 4. Staff concludes that Idaho Power's coal study demonstrates that the SCR investments are the lowest cost compared to the alternatives analyzed under planning case assumptions and in the majority of the carbon and gas sensitivities. In addition to reviewing the coal study, Staff constructed an independent spreadsheet analysis of the impact of a range of gas and carbon prices on the economics of the SCR investments, which confirmed the coal study results.

*b. Commission Resolution*

Based on the information we have at this time, we decline to acknowledge Idaho Power's action item related to Bridger Units 3 and 4. Our decision regarding these investments is inextricably tied to our decision regarding the same investments in the docket opened to address PacifiCorp's IRP, docket LC 57. In that docket, we did not acknowledge the investments for Bridger Units 3 and 4 for four interrelated reasons.

First, some of the alternatives modeled by PacifiCorp suggest that the installation of SCR at Bridger Units 3 and 4 is not the lowest cost resource option. Second, there were gaps in the analyses conducted by PacifiCorp. Third, some of the questions raised by Staff and other participants on the merit of retaining or retiring the units were not fully fleshed out, while others are more appropriately addressed in a rate proceeding. Finally, PacifiCorp,

the managing utility, is proceeding with the investments, which calls into question the appropriateness of addressing the investments in a planning docket.

We recognize that Idaho Power conducted its own analysis of whether installing SCR at Bridger Units 3 and 4 is the least cost and least risk option. However, Idaho Power's analysis does not persuade us to reach a resolution in this docket that differs from that in docket LC 57, at least in part because of deficiencies in Idaho Power's analysis. More specifically, Idaho Power did not (1) analyze a full range of reasonable scenarios; (2) consider a wider range of resource replacement options as PacifiCorp; or (3) evaluate an adequate range of natural gas price sensitivities.

Idaho Power is proceeding with the investments. We will undertake a fair and thorough investigation of the prudence of the SCR investments when Idaho Power seeks rate recovery. Our decision to not acknowledge them in this docket does not prejudge the prudence of the investments for purposes of rate recovery.

**C. Demand Response**

Idaho Power proposes the following near-term action related to demand response:

*2016-2017* *Have demand response capacity available to satisfy deficiencies up to approximately 150 MW*

*a. Participants' Comments*

Staff notes that both the Oregon and Idaho commissions recently issued orders approving stipulations regarding the redesign of Idaho Power's demand response programs for 2014 and beyond. Those stipulations provide that the annual value of demand response is equal to the levelized annual cost of the minimum size deferred resource, or 170 MW. Therefore, Staff recommends changing this action item to read: "Have demand response capacity available to satisfy deficiencies up to approximately ~~150 MW~~ 170 MW beginning in 2014, and increasing as needed through 2017."

Staff also recommends that the company update its assessment of demand response availability based on summer 2014 program participation and other relevant factors by the end of 2014. In addition, Staff recommends that the Energy Efficiency Advisory Group review any revisions to the resource assessment, along with other relevant factors.

RNW supports Idaho Power's continuation of its demand response program to meet the company's capacity needs.

*b. Commission Resolution*

We agree that revising the near-term demand response action item as recommended by Staff is appropriate in light of recently concluded dockets in Oregon and Idaho regarding demand response. We acknowledge the action item as revised by Staff. We also expect that Idaho Power will follow Staff's recommendation regarding updating its assessment of demand response availability in 2014.

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**D. Long-term Action Items**

Idaho Power's Action Plan includes the following long-term activities:

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| *2019* | *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* |
| *2024-2032* | *Demand Response – Have demand response capacity available to satisfy deficiencies in 50 MW increments up to approximately 370 MW* |

*a. Participants' Comments*

Both Staff and CUB note, and Idaho Power acknowledges, that Idaho Power's Action Plan includes long-term action items in addition to the short-term action items typically presented in an IRP action plan. Staff and CUB recommend that we not acknowledge action items occurring beyond a two-to-four year period. In response, Idaho Power states that it does not seek acknowledgment of the long-term items.

*b. Commission Resolution*

Although Idaho Power states it does not seek acknowledgment of these long-term action items, they remain part of the company's IRP. For this reason, we believe it is necessary to address them. We do not acknowledge these action items because, as Staff and CUB note, the purpose of an action plan is to identify specific near-term actions that the company plans to take to meet its resource needs.[7] We generally do not acknowledge action items planned to occur more than four years in the future.[8]

**D. Analysis of IRP**

***1. Wind Resources***

*a. Participants' Comments*

Several participants raise concerns related to wind resources. RNW asserts that Idaho Power's IRP underestimates the capacity factor of modern wind turbines and includes an unsupported and unreasonably high wind integration rate.

Staff and RNW raise concerns about Idaho Power's wind integration study (WIS), and the company's use of the technical review committee (TRC) we recommended the

[7] *See* Order No. 12-177.
[8] *Id.*

company form to improve such studies.[9] Staff notes that it anticipated more involvement of the TRC and recommends that Idaho Power engage with the TRC for future IRPs. RNW adds that Idaho Power's WIS based the size of the required balancing reserve on the difference between the day-ahead forecast and actual generation, which increased the assumed balancing reserves and costs. RNW notes that the TRC we required in Order No. 12-177 flagged this methodological assumption as a significant concern. Staff shares RNW's concern, and has reservations about using the study results in future filings.

In response to RNW's concern regarding overstated costs, Idaho Power notes the cost difference between the National Renewable Energy Laboratory (NREL) report and its costs comes from the conversion of 2009 dollars to 2013 dollars, the common base for the IRP's comparison of resource costs. In response to RNW's concern regarding the size of the balancing reserves, Idaho Power states that it chose to base the assumption on the day-ahead forecast because balancing reserves based on the hour-ahead forecast "would too often translate to a risky reliance on the wholesale energy market."

In response to RNW's concern regarding the average capacity factor, Idaho Power asserts that the NREL reports that Class 3 resources have an average capacity factor of 33 percent—a percentage Idaho Power adjusted downward to account for lower capacity factors of Class 2 resources. Idaho Power also asserts that its actual observations support the 26 percent average capacity factor used in the WIS and IRP.

In response to Staff's and RNW's concern regarding the role of the TRC, Idaho Power notes that we directed the company to form the committee in February 2012, nearly a year after the company had begun work on the WIS. Idaho Power announced the formation of the committee at an April 2012 workshop, but by this time the study was complete and the company was presenting preliminary study results.

*b. Commission Resolution*

We appreciate that Idaho Power responded quickly to our recommendation but are disappointed the TRC did not prove to be an effective mechanism for stakeholders to engage with Idaho Power regarding the analytical methodology of the WIS. Using the TRC to review and provide comments on the analytical methodology and results is not what we envisioned when making our 2012 recommendation. But, we recognize that our recommendation came late in Idaho Power's process, limiting the opportunity for TRC input.

We continue to recommend use of a TRC in connection with wind integration studies. The TRC could be an effective mechanism for stakeholders to engage with the company regarding the analytical methodology underlying the study and expect Idaho Power to engage with the TRC at the outset of any future study.

Regarding RNW's specific complaints regarding the WIS, we note that RNW does not urge us to disregard the WIS for the purpose of judging the reasonableness of Idaho Power's IRP, but cautions against using the WIS to determine avoided cost prices in a

[9] *Id.* at Appendix A at 3.

future proceeding. Our acknowledgment of Idaho Power's IRP has no effect on the validity of the WIS during any proceeding to establish avoided cost prices for variable wind resources. We do note, however, that effective engagement between stakeholders and utilities regarding the study methodology and inputs would likely lessen disagreements in any proceeding in which the accuracy of the study is at issue.

***2. Capacity Contribution of Solar and Other Resources***

*a. Participants' Comments*

ODOE recommends certain changes to how Idaho Power examines capacity credits for solar, wind, and hydro resources, and how the company models orientation of flat-plate solar PV systems.

Idaho Power disagrees with ODOE's specific recommendation regarding the capacity contribution, but recognizes that solar resources are unique and that its analysis must address numerous considerations such as tracking systems, resource orientation, and materials. Idaho Power states it seeks to attribute the proper capacity credit to distributed solar PV and has initiated an IRP Advisory Council distributed solar PV workgroup to address the cost and capacity credit of distributed solar PV in the 2015 IRP. Idaho Power states that it anticipates the workgroup will address topics such as panel orientation and tracking systems. Idaho Power also states that it is analyzing integration of large-scale solar PV projects and working on this topic with members of its Solar Integration Study Technical Review Committee.

*b. Commission Resolution*

We appreciate Idaho Power's willingness to work on the issues identified by ODOE for its next IRP. We hope Idaho Power will work directly with ODOE. In any event, we expect to see results of Idaho Power's work in its 2015 IRP.

***3. Gas Price Forecasts***

*a. Participants' Comments*

Staff comments on three aspects of Idaho Power's natural gas price forecasts used in the IRP. Staff expresses concerns regarding the symmetric adjustments to the base case forecast, the escalation of the Energy Information Administration (EIA) reference case gas price forecast, and the high correlation between natural gas prices and wholesale electricity prices in the company's modeling. Staff identifies gas price forecasts as an issue to be analyzed during the development of the 2015 IRP. The company responds that its stochastic inputs are reasonable and that it will consider alternatives to deriving high and low gas price scenarios for future IRPs.

*b. Commission Resolution*

We anticipate that these analytical issues will be raised by Staff and addressed during the planning process for the 2015 IRP.

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### 4. *Flexibility Guideline*

In our investigation of matters related to electric vehicle charging, we adopted our Staff's recommendation to add an IRP guideline to require utilities to incorporate planning for flexible capacity in IRPs.[10] Utilities must forecast the balancing reserves needed at different time intervals to respond to variation in load and intermittent renewable generation over the 20-year planning period and to forecast the availability of balancing reserves at different time intervals. In planning to fill any gap between the demand and supply of flexible capacity, utilities must also evaluate all resource options on a consistent and comparable basis.

#### *a. Participants' Comments*

RNP asserts that Idaho Power's IRP does not comply with the IRP Guidelines because it does not forecast the demand for and supply of flexible capacity, or evaluate flexible resources on a consistent and comparable basis. RNW suggests that future IRPs should quantify the existing supply of flexible resources across multiple time scales, quantify the amount of reserves associated with each supply-side resource, and expand types of demand for flexible resources, *e.g.*, need to meet hourly ramps of load and other variable resources.

Idaho Power responds that its 2013 IRP did, in fact, include much of the flexibility analysis that RNW asserts is lacking. Idaho Power notes that a pumped storage hydro project was modeled as a resource alternative and as a tool to assist in the integration of wind resources. Idaho Power asserts that this modeling captured the flexibility and peaking capacity of the pumped storage hydro project and helped to integrate the variable wind generation into the system, and captured market arbitrage opportunities.

Staff recognizes that the company provided qualitative analysis that shows it is unlikely Idaho Power will need additional flexible capacity over the 20-year planning horizon, but agrees with RNW that the guideline asks for quantitative analysis of the size and timing of the flexible capacity resource balance. Staff recommends that Idaho Power substantially expand its analysis in the 2015 IRP. Staff is willing to work with Idaho Power and other stakeholders to help develop the quantitative analysis.

#### *b. Commission Resolution*

We find that Idaho Power's IRP does not comply with the Flexible Resources Guideline. Idaho Power did not submit the required analysis of demand and supply of balancing reserves disaggregated across multiple timescales. We expect the company to use the recommendations of both RNW and Staff to provide a compliant and more robust analysis regarding flexible resources in its 2015 IRP.

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[10] Order No. 12-013 at16-18.

ORDER NO. 14 255

### 5. *Conservation Voltage Reduction*

Staff states that Idaho Power failed to include the required assessment of the available cost effective conservation voltage reduction (CVR) in its service area. Staff explains that we directed the assessment in our review of Idaho Power's 2012 IRP:

> The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The company will propose an action item in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's load-resource balance forecasts.[11]

We agree that Idaho Power's 2013 IRP failed to include this assessment, and direct the company to provide this assessment in its 2015 IRP.

In the interim, we direct our Staff to conduct the independent CVR and Volt/Var Ampere Reactive control programs we ordered in Idaho Power's 2013 Annual Smart Grid Report.[12] Staff should conduct the analysis within the next six months and report the results of the analysis to us at a public meeting.

### 6. *Energy Efficiency*

Although Idaho Power's IRP contains specific energy efficiency targets as part of its plan, the company does not include those amounts in the Action Plan. Staff proposes two action items to address energy efficiency:

| | | |
|---|---|---|
| *2013-2017* | *Energy Efficiency* | *The forecast reduction for 2013 to 2017 programs will be 69 aMW* |
| *2013-2017* | *Energy Efficiency* | *The incremental energy efficiency savings for 2013 to 2017 will reduce energy loads by 38 aMW* |

We adopt Staff's proposed additions to the Action Plan.

### 7. *NEEA*

Idaho Power plans to curtail funding to the Northwest Energy Efficiency Alliance (NEEA) in the next five-year funding cycle. Idaho Power explains that it has asked NEEA to operate under an alternative funding model that would allow Idaho Power's funds to be directed toward the costs of activities that Idaho Power believes are most valuable to its customers. Idaho Power supports the concept of optional programs in NEEA's 2015-2019 Business Plan in which funders could choose to participate and fund certain programs or opt out of them altogether.

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[11] Order No. 12-177 at 5.
[12] Order No. 13-481 at 1-2.

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*a. Participants' Comments*

CUB and Staff are concerned with Idaho Power's proposal to curtail funding to NEAA. Staff believes that NEAA is one of Idaho Power's most cost effective energy investments. Staff notes that NEEA is a compact between over 100 Northwest utilities and efficiency organizations that creates value for its supporters by broad market intervention and energy efficiency market development. NEEA's activities have resulted in the development of an energy efficiency products and practices pipeline to the region that benefits Idaho Power's and the region's ratepayers.

*b. Commission Resolution:*

We do not know Idaho Power's final decision about continued participation in NEEA. However, we are dismayed by the possibility that Idaho Power's approach could undermine support for regional market transformation. We agree with Staff's observations of the importance of NEEA. We believe that market transformation is an integral part of an effective energy efficiency strategy to lower cost and risk to ratepayers. Based on our analysis and our continued oversight of funding to NEEA from Oregon ratepayers, we believe that NEEA is capturing cost-effective energy efficiency over the long run and expanding opportunities for cost-effective energy efficiency in the future. For those programs Idaho Power opts out of, we expect Idaho Power will acquire commensurate savings from equivalent services at a cost equal to or less than what NEEA could provide.

**D. Recommendations For Idaho Power's 2015 IRP**

In Order No. 12-177, we reminded Idaho Power that IRP Guideline 4(n) requires utilities to include in an IRP action plan the resource activities the utility plans to undertake over the next two to four years to acquire the identified resources. We also recommended that Idaho Power's future IRPs include a "concise listing of action items for all resources and resource related activities, with each action item numbered."[13]

Idaho Power did include an action plan with resource activities it plans to take in the next two to four years, but the plan also includes longer-term actions. We clarify that, in future IRPs, Idaho Power should limit its Action Plan to activities it plans to undertake in the next two to four years. Idaho Power may compile other lists of activities planned for an extended period, as it has done in this IRP, but we recommend the company create and identify the action plan activities for which it requests specific acknowledgment. Again, we recommend that the company number each of these action items to facilitate our review.

**E. IRP Update**

Staff sought delays in these proceedings to facilitate our review of resource action items presented for acknowledgment in both PacifiCorp's IRP and Idaho Power's IRP.

[13] Order No. 12-177 at 8.

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As a result of this delay, Idaho Power's annual update to its 2013 IRP, which is due no later than 12 months after acknowledgment. However, Idaho Power must file its 2015 IRP with the Idaho Public Utilities Commission no later than June 2015. Idaho Power intends to file an IRP in Oregon at the same time it files in Idaho.

Given that Idaho Power will file its next IRP with the Idaho commission by June 2015, we waive the requirement that Idaho Power file an annual update to this IRP. This waiver addresses only a routine IRP update, and we expect Idaho Power to file an IRP update if it anticipates a significant deviation from its acknowledged 2013 IRP in the manner required by IRP Guideline 3(f).

## V. ORDER

IT IS ORDERED that the 2013 Integrated Resource Plan filed by Idaho Power Company is acknowledged in part consistent with the terms of this order.

Made, entered, and effective JUL 08 2014.

**Susan K. Ackerman**
Chair

**John Savage**
Commissioner

**Stephen M. Bloom**
Commissioner

ORDER NO. 14 253

# Appendix A

**Acknowledged Action Plan Items**

| 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 |
| 2016-2017 | Have demand response capacity available to satisfy deficiencies up to approximately 170 MW beginning in 2014, and increasing as needed through 2017 |
| 2013-2017 | Energy efficiency – The forecast reduction for 2013 to 2017 programs will be 69 aMW |
| 2013-2017 | The incremental energy efficiency savings for 2013-2017 will reduce energy loads by 38 aMW |
| 2013-2015 | CVR – Include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in service area and an action item related to this resource in the next IRP. Incorporate the planned energy savings and reduced peak demand into load-resource balance forecasts. |

APPENDIX A
Page 1 of 1

# Compliance with State of Oregon IRP Guidelines

## A. Transmission

### 1. Boardman to Hemingway

***Commission Resolution (Order No. 14-253):***

We acknowledge ongoing permitting, planning studies, and regulatory filings for B2H. As Staff notes, the analysis in the IRP supports these planned near-term activities. We anticipate additional analysis regarding B2H in Idaho Power's 2015 IRP before acknowledging other actions related to B2H. We decline to acknowledge completion of B2H because it is well beyond the two-to-four year period for action items specified by the IRP Guidelines. Further, we disagree with any suggestion that declining to acknowledge the construction of B2H is inconsistent with our previous acknowledgment of certain activities (e.g., permitting) related to this resource or inconsistent with previous orders acknowledging IRPs based on a preferred portfolio that includes B2H. Our acknowledgment of an IRP is based on our conclusion that it complies with our guidelines and that the plan seems reasonable based on information known at the time.

***Idaho Power Response (2015 IRP):***

Discussion specific to B2H is found in Chapter 6 (Transmission Planning), section Boardman to Hemingway, pages 71-72. Portfolio design for the 2015 IRP provides a comparison of portfolios having B2H as a resource to portfolios not having B2H. A tabulation of resource portfolios with respect to B2H inclusion is provided in Chapter 8 (Portfolio Selection), section *Portfolio Design Summary*, page 111.

### 2. Gateway West

***Commission Resolution (Order No. 14-253):***

We acknowledge ongoing permitting, planning studies, and regulatory filings for Gateway West. However, as CUB notes, the project is composed of multiple segments that can and should be analyzed individually. Moreover, Idaho Power has an ownership interest in relatively few of the segments and must demonstrate the need and specific constraint-related benefits for each segment in which it holds an interest before we will consider acknowledgment of the project's construction.

***Idaho Power Response (2015 IRP):***

Discussion specific to Gateway West is found in Chapter 6 (Transmission Planning), pages 69–71. The results of a "need" analysis are provided in the section Gateway West Need Analysis, pages 70–71.

## B. Pollution Control Investments in Coal Resources

### 1. Idaho Power's Analysis

Commission Resolution (Order No. 14-253):

We conclude that Idaho Power's IRP complies with IRP Guideline 8, but as discussed below, is not sufficient to provide a basis to support acknowledgment of selective catalytic reduction emission-control technology (SCR) at Jim Bridger units 3 and 4. Guideline 8 does not require Idaho Power to model every feasible alternative scenario, but requires the company to determine the PVRR costs and risk measures of a "set of reasonable alternative portfolios" assuming a range of different compliance scenarios. Although Idaho Power did not model a scenario in which both North Valmy units and Bridger units 3 and 4 were converted to natural gas facilities, as RNW believes should have been done, Idaho Power did model a scenario in which North Valmy is converted to natural gas and Bridger units 3 and 4

are replaced with CCCTs (portfolio 6). In addition, although Idaho Power did not build a compliance scenario that specifically accounts for the June 2013 Presidential Memorandum, Idaho Power did test its portfolios against a range of carbon compliance futures including a carbon adder in the planning case of $14.64 per ton beginning in 2018 and escalating three percent annually, and a carbon adder in the high case of $35 per ton beginning in 2018 and escalating nine percent annually.

The carbon adder was modeled at three levels: low ($0), planning, and high. Idaho Power did not model a distribution of values, as was done with gas prices, load, and hydro in the stochastic analysis. Instead, one-third of the simulations were drawn from each carbon adder level. The company's analysis showed the preferred portfolio 2 and the non-coal portfolio 6 would switch places at a carbon adder of $45 in 2018. We find the alternative portfolios selected by Idaho Power and the range of compliance futures sufficient to satisfy the requirements of Guideline 8.

We share CUB's and Staff's concern regarding the limited nature of Idaho Power's early retirement scenario analysis. Even though Idaho Power may have technically complied with the action item from Order No. 12-177, we expected that Idaho Power would model a broader range of early shutdown scenarios. We expect Idaho Power to engage fully with Staff and stakeholders in a timely manner to design coal investment analyses for future IRPs to ensure more robust consideration of early shutdown as a compliance option.

Also, we direct Idaho Power to work with stakeholders to explore options for how it plans to model and perform analysis in the 2015 IRP in order to comply with the applicable emissions requirements of Section 111(d) of the Clean Air Act.

***Idaho Power Response (2015 IRP):***

The 2015 IRP considers multiple early retirement scenarios as described in Chapter 8 (Portfolio Selection), pages 97–111. These early retirement scenarios were developed with input from the IRP Advisory Council and public participants of the IRP process, including input received at a portfolio design workshop held on January 28, 2015.

CAA Section 111(d) was discussed frequently during IRP Advisory Council meetings. A discussion led by IRP Advisory Council member John Chatburn (Idaho Office of Energy Resources) was held as part of the December 4, 2014 IRP Advisory Council meeting. Multiple sensitivities for CAA Section 111(d) were analyzed for the IRP. These sensitivities are described in Chapter 9 (Modeling Analysis and Results), section *CAA Section 111(d) Sensitivity Analysis*, pages 114–120.

## 2. North Valmy Unit 1

***Commission Resolution (Order No. 14-253):***

We acknowledge installation of DSI at North Valmy Unit 1. We find as Staff did that the relatively low cost of the investment leads to the conclusion that the DSI investment and continued operation of North Valmy is the least cost/least risk alternative given the information that is currently available.

We do not share CUB's concern regarding how Idaho Power included North Valmy in its preferred portfolio. First, shortening the life of North Valmy would not change the result of Idaho Power's analysis; installing DSI would still be the least cost/least risk alternative. Second, future events may lead to a shortened operating life for North Valmy, but whether they will is not certain. Idaho Power reasonably relied on the results of modeling based on the assumption North Valmy will operate as Idaho Power currently expects, rather than an assumption based on events that may, or may not, transpire.

***Idaho Power Response (2015 IRP):***

No action required.

### 3. Jim Bridger Units 3 and 4

***Commission Resolution (Order No. 14-253):***

Based on the information we have at this time, we decline to acknowledge Idaho Power's action item related to Bridger units 3 and 4. Our decision regarding these investments is inextricably tied to our decision regarding the same investments in the docket opened to address PacifiCorp's IRP, docket LC 57. In that docket, we did not acknowledge the investments for Bridger units 3 and 4 for four interrelated reasons.

First, some of the alternatives modeled by PacifiCorp suggest that the installation of SCR at Bridger units 3 and 4 is not the lowest cost resource option. Second, there were gaps in the analyses conducted by PacifiCorp. Third, some of the questions raised by Staff and other participants on the merit of retaining or retiring the units were not fully fleshed out, while others are more appropriately addressed in a rate proceeding. Finally, PacifiCorp, the managing utility, is proceeding with the investments, which calls into question the appropriateness of addressing the investments in a planning docket.

We recognize that Idaho Power conducted its own analysis of whether installing SCR at Bridger units 3 and 4 is the least cost and least risk option. However, Idaho Power's analysis does not persuade us to reach a resolution in this docket that differs from that in docket LC 57, at least in part because of deficiencies in Idaho Power's analysis. More specifically, Idaho Power did not (1) analyze a full range of reasonable scenarios; (2) consider a wider range of resource replacement options as PacifiCorp; or (3) evaluate an adequate range of natural gas price sensitivities.

Idaho Power is proceeding with the investments. We will undertake a fair and thorough investigation of the prudence of the SCR investments when Idaho Power seeks rate recovery. Our decision to not acknowledge them in this docket does not prejudge the prudence of the investments for purposes of rate recovery.

***Idaho Power Response (2015 IRP):***

A section titled Jim Bridger units 3 and 4 SCR Analysis is included in *Appendix C—Technical Appendix*.

## *C. Demand Response*

### Commission Resolution (Order No. 14-253):

We agree that revising the near-term demand response action item as recommended by Staff is appropriate in light of recently concluded dockets in Oregon and Idaho regarding demand response. We acknowledge the action item as revised by Staff. We also expect that Idaho Power will follow Staff's recommendation regarding updating its assessment of demand response availability in 2014.

### Idaho Power Response (2015 IRP):

The performance of demand response programs in 2014 is provided in Chapter 4 (Demand-Side Resources), section *Demand Response Performance*, pages 42–43. Chapter 4 also notes that demand response is forecast to provide 390 MW of peak reduction during July throughout the planning period (section *Committed Demand Response*, page 46).

## D. Long-Term Action Items

### Commission Resolution (Order No. 14-253):

Although Idaho Power states it does not seek acknowledgment of these long-term action items, they remain part of the company's IRP. For this reason, we believe it is necessary to address them. We do not acknowledge these action items because, as Staff and CUB note, the purpose of an action plan is to identify specific near-term actions that the company plans to take to meet its resource needs. We generally do not acknowledge action items planned to occur more than four years in the future.

### Idaho Power Response (2015 IRP):

The action plan provided in the 2015 IRP is focused on resource actions for the four-year period 2015-2018. The action plan is provided in Chapter 1 (Summary), section *Action Plan*, page 10–11. The action plan is also provided in Chapter 10 (Action Plan), section *Action Plan (2015–2018)*, pages 141–143.

## E. Analysis of IRP

### 1. Wind Resources

#### *Commission Resolution (Order No. 14-253):*

We appreciate that Idaho Power responded quickly to our recommendation but are disappointed the TRC did not prove to be an effective mechanism for stakeholders to engage with Idaho Power regarding the analytical methodology of the WIS. Using the TRC to review and provide comments on the analytical methodology and results is not what we envisioned when making our 2012 recommendation. But, we recognize that our recommendation came late in Idaho Power's process, limiting the opportunity for TRC input.

We continue to recommend use of a TRC in connection with wind integration studies. The TRC could be an effective mechanism for stakeholders to engage with the company regarding the analytical methodology underlying the study and expect Idaho Power to engage with the TRC at the outset of any future study.

Regarding RNW's specific complaints regarding the WIS, we note that RNW does not urge us to disregard the WIS for the purpose of judging the reasonableness of Idaho Power's IRP, but cautions against using the WIS to determine avoided cost prices in a future proceeding. Our acknowledgment of Idaho Power's IRP has no effect on the validity of the WIS during any proceeding to establish avoided cost prices for variable wind resources. We do note, however, that effective engagement between stakeholders and utilities regarding the study methodology and inputs would likely lessen disagreements in any proceeding in which the accuracy of the study is at issue.

#### *Idaho Power Response (2015 IRP):*

No action required.While no IRP-related action is required, Idaho Power notes the use of a technical review committee from the outset of its first solar integration study, completed in June 2014. A technical review committee has also been in place since the January 2015 start of Idaho Power's second solar integration study.

## 2. Capacity Contribution of Solar and Other Resources

***Commission Resolution (Order No. 14-253):***

We appreciate Idaho Power's willingness to work on the issues identified by ODOE for its next IRP. We hope Idaho Power will work directly with ODOE. In any event, we expect to see results of Idaho Power's work in its 2015 IRP.

***Idaho Power Response (2015 IRP):***

Idaho Power convened public working group meetings to address solar-related issues, including capacity contribution, on August 6, 2014 and September 3, 2014. The results of the solar capacity contribution analysis conducted as part of the working group meetings are provided in Chapter 5 (Supply-Side Generation and Storage Resources), section *Solar Capacity Credit*, pages 50–51.

## 3. Gas Price Forecasts

***Commission Resolution (Order No. 14-253):***

We anticipate these analytical issues will be raised by Staff and addressed during the planning process for the 2015 IRP.

***Idaho Power Response (2015 IRP):***

The natural gas price forecast is provided in Chapter 7 (Planning Period Forecasts), section *Natural Gas Price Forecast*, pages 84–85. As noted in this section, Idaho Power uses EIA published nominal forecast prices. Also noted is the use of the EIA high resource case for the low case natural gas price forecast, and similarly use of the EIA low resource case for the high case natural gas price forecast. Finally, part of AURORA model calibration conducted for the IRP is verification that future power market (i.e., Mid-C) prices derived by the AURORA model maintain their historic relationship to natural gas market prices. The ratio of these prices, power market and natural gas market, is called the implied market heat rate. Idaho Power verified that future implied market heat rate values (ratio of AURORA-derived power market price to input natural gas market price) reasonably approximate historic values for this ratio. The implied market heat rate analysis was presented to the IRP Advisory Council and public participants at the February 5, 2015 IRP Advisory Council meeting.

## 4. Flexibility Guideline

***Commission Resolution (Order No. 14-253):***

We find that Idaho Power's IRP does not comply with the Flexible Resources Guideline. Idaho Power did not submit the required analysis of demand and supply of balancing reserves disaggregated across multiple timescales. We expect the company to use the recommendations of both RNW and Staff to provide a compliant and more robust analysis regarding flexible resources in its 2015 IRP.

***Idaho Power Response (2015 IRP):***

A discussion of the 2015 IRP's analysis for the flexibility guideline is provided in Chapter 9 (Modeling Analysis and Results), section *Flexible Resource Needs Assessment*, pages 135–139. Figure 9.4 on page 143 presents a projection for flexibility need across multiple timescales. Simulations of the system capability to provide flexibility are illustrated in Figures 9.5 through 9.9 on pages 136-138.

## 5. Conservation Voltage Reduction

***Commission Resolution (Order No. 14-253):***

Staff states that Idaho Power failed to include the required assessment of the available cost effective conservation voltage reduction (CVR) in its service area. Staff explains that we directed the assessment in our review of Idaho Power's 2012 IRP:

> The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The company will propose an action item in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's load-resource balance forecasts.

We agree that Idaho Power's 2013 IRP failed to include this assessment, and direct the company to provide this assessment in its 2015 IRP. In the interim, we direct our Staff to conduct the independent CVR and Volt/Var Ampere Reactive control programs we ordered in Idaho Power's 2013 Annual Smart Grid Report. Staff should conduct the analysis within the next six months and report the results of the analysis to us at a public meeting.

***Idaho Power Response (2015 IRP):***

CVR is discussed in Chapter 4 (Demand-Side Resources), section *Conservation Voltage Reduction*, page 48. The 2015 IRP's treatment of CVR was communicated to OPUC staff in a conference call on August 22, 2014.

## 6. Energy Efficiency

***Commission Resolution (Order No. 14-253):***

We adopt Staff's proposed additions to the Action Plan. [Staff proposed the addition of action plan items specifying IRP energy efficiency targets.]

***Idaho Power Response (2015 IRP):***

The action plan provided in the 2015 IRP includes an action item related to the pursuit of cost-effective energy efficiency, and expresses energy efficiency targets in a manner similar to that proposed by Staff. The action plan is provided in Chapter 1 (Summary), section *Action Plan*, pages 10–11. The action plan is also provided in Chapter 10 (Action Plan), section *Action Plan (2015–2018)*, pages 141–143.

## 7. NEEA

***Commission Resolution (Order No. 14-253):***

We do not know Idaho Power's final decision about continued participation in NEEA. However, we are dismayed by the possibility that Idaho Power's approach could undermine support for regional market transformation. We agree with Staff's observations of the importance of NEEA. We believe that market transformation is an integral part of an effective energy efficiency strategy to lower cost and risk to ratepayers. Based on our analysis and our continued oversight of funding to NEEA from Oregon ratepayers, we believe that NEEA is capturing cost-effective energy efficiency over the long run and expanding opportunities for cost-effective energy efficiency in the future. For those programs Idaho Power opts out of, we expect Idaho Power will acquire commensurate savings from equivalent services at a cost equal to or less than what NEEA could provide.

***Idaho Power Response (2015 IRP):***

Idaho Power continues its commitment to NEEA as a participant in NEEA's 2015-2019 funding cycle. On September 30, 2014 Idaho Power and NEEA executed a contract to participate in the 2015-2019 funding cycle. For complete details on Idaho Power's involvement in NEEA activities please see pages 9, 141-145 of the Company's Demand-Side Management 2014 Annual Report – Appendix B.

# ATTACHMENT N-5
# IDAHO POWER COMPANY'S 2017 INTEGRATED RESOURCE PLAN (DOCKET LC 68)

INTEGRATED RESOURCE PLAN

IDAHO POWER®
An IDACORP Company

# 2017 IRP

## LOOKING AHEAD




JUNE • 2017

## SAFE HARBOR STATEMENT

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

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# 2017 IRP

LOOKING FORWARD

## ACKNOWLEDGEMENT

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

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

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

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

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*Appendix A—Sales and Load Forecast*

*Appendix B—Demand-Side Management 2016 Annual Report*

*Appendix C—Technical Appendix*

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# GLOSSARY OF ACRONYMS

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

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

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

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

# 1. SUMMARY

## Introduction

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

1. Identify sufficient resources to reliably serve the growing demand for energy within Idaho Power's service area throughout the 20-year planning period.

2. Ensure the selected resource portfolio balances cost, risk, and environmental concerns.

3. Give equal and balanced treatment to supply-side resources, demand-side measures, and transmission resources.

4. Involve the public in the planning process in a meaningful way.

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

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

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

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

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

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

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

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

## Public Advisory Process



IRPAC meeting, May 2017

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

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

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

## IRP Methodology

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

Resource sufficiency is assessed for energy and capacity. Existing supply-side resources include generation resources and transmission import capacity from regional wholesale electric markets. Existing demand response resources are included in the capacity resource sufficiency assessment

as well. Idaho Power then includes the IRP target amount of cost-effective and achievable energy efficiency, which reflects expansion of existing energy-savings potential.

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

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

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

## Greenhouse Gas Emissions

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

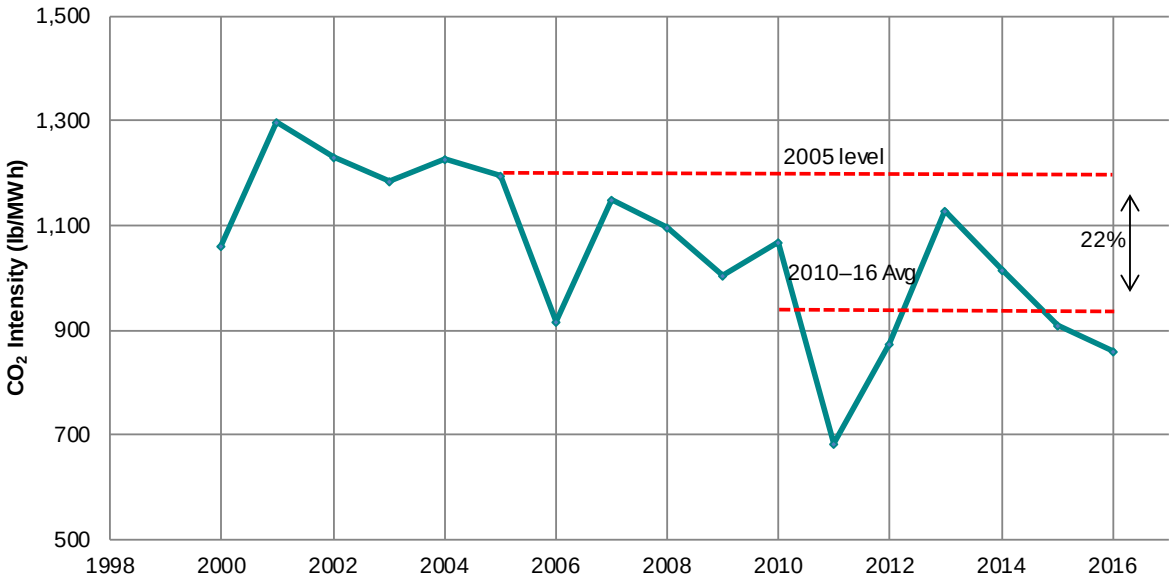



**Figure 1.1 Estimated Idaho Power $CO_2$ emissions intensity**

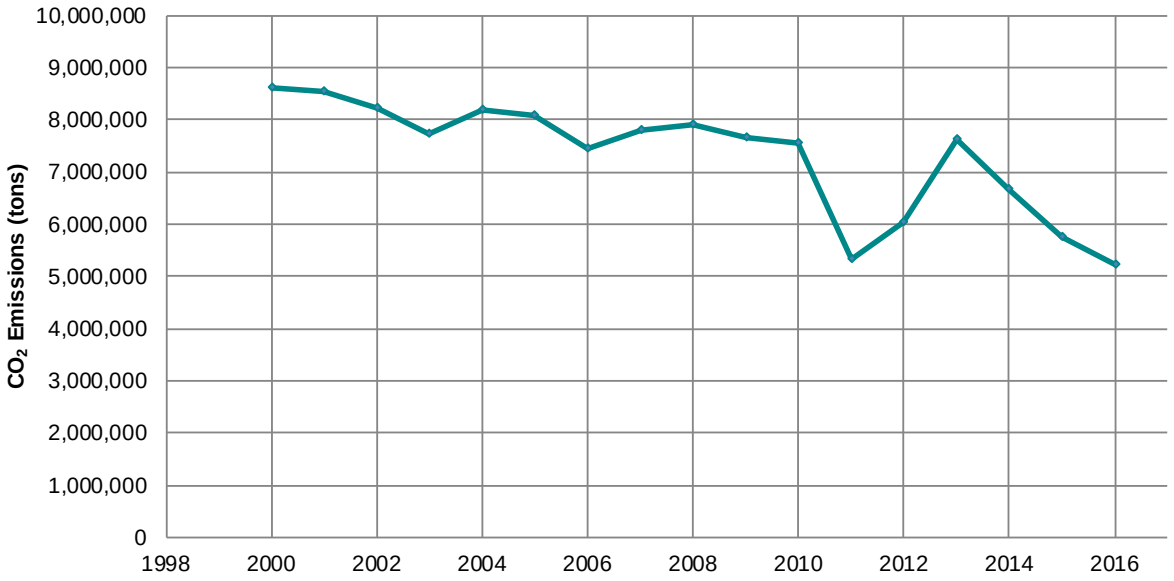



**Figure 1.2 Estimated Idaho Power $CO_2$ emissions**

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

Generation and emissions from company-owned resources are included in the $CO_2$ emissions intensity calculation. The company's progress toward achieving this intensity reduction goal and additional information on Idaho Power's $CO_2$ emissions are reported on the company's website.[4] Information related to Idaho Power's $CO_2$ emissions, voluntarily reported annually, is also available through the Carbon Disclosure Project at cdp.net.

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

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

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

## Portfolio Analysis Summary

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

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

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

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

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

**Table 1.1 Factorial design applied to portfolios**

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

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

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

**Table 1.2 P7 resource additions**

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

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

## Action Plan

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

**Table 1.3 Action plan[5]**

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

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

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

# 2. POLITICAL, REGULATORY, AND OPERATIONAL ISSUES

## Idaho Strategic Energy Alliance

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

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

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

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

## Idaho Energy Primer

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

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

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

## State of Oregon Biennial Energy Plan: 2015–2017

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

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

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

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

## FERC Relicensing

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.



Bayha Island

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

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

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

Relicensing activities include the following:

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

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

4. Analyzing data and reporting study results

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

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

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

## Idaho Water Issues

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

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

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

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

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

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

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

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

Water management activities for the ESPA are currently being driven by the recent agreement between the Surface Water Coalition and the Idaho Ground Water Appropriators. This agreement settled a call by the Surface Water Coalition against groundwater appropriators for delivery of water to its members at Minidoka Dam and Milner Dam. The agreement provides a plan for the management of groundwater resources on the ESPA with the goal of improving

aquifer levels and spring discharge upstream of Milner Dam. The plan provides short-term and long-term aquifer level goals that must be met to ensure a sufficient water supply for the Surface Water Coalition. The plan also references ongoing management activities, such as aquifer recharge. The plan provided the framework for modeling future management activities on the ESPA. These management activities were included in the modeling to develop the flow file for assessing hydropower production through the IRP planning horizon.

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

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

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

## Renewable Integration Costs

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

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

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

## Community Solar Pilot Program

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

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

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

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

## Energy Imbalance Market

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

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

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

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

## Renewable Energy Certificates

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

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

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

REC prices depend on many factors, including the following:

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

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

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

## Renewable Portfolio Standard

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

The State of Idaho does not currently have an RPS.

# Clean Power Plan

## Rule History

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

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

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

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

## Clean Power Plan Final Rule

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

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

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

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

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

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

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

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

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

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

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

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

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# 3. IDAHO POWER TODAY

## Customer Load and Growth

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



Construction in downtown Boise.

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

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

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

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

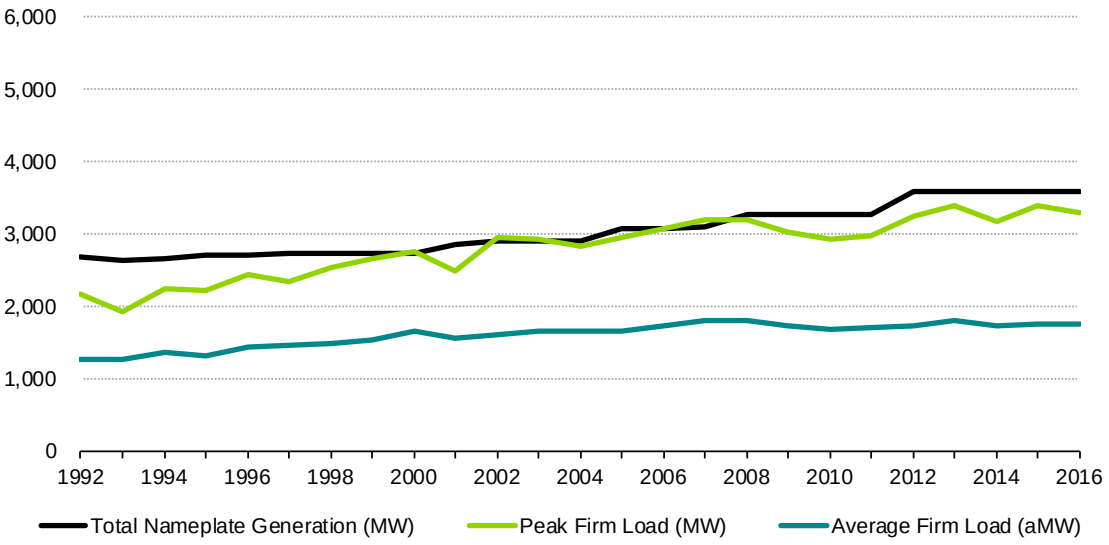



**Figure 3.1 Historical capacity, load, and customer data**

**Table 3.1 Historical capacity, load, and customer data**

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

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

## 2016 Energy Sources

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

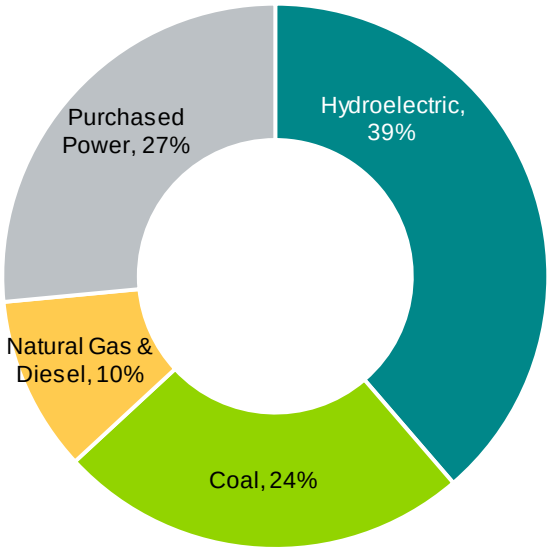



**Figure 3.2 2016 energy sources**

## Existing Supply-Side Resources

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

**Table 3.2 Existing resources**

| Resource | Type | Generator Nameplate Capacity (MW) | Location |
|---|---|---|---|
| American Falls | Hydroelectric | 92.3 | Upper Snake |
| Bliss | Hydroelectric | 75.0 | Mid-Snake |
| Brownlee | Hydroelectric | 585.4 | Hells Canyon |
| C. J. Strike | Hydroelectric | 82.8 | Mid-Snake |
| Cascade | Hydroelectric | 12.4 | North Fork Payette |
| Clear Lake | Hydroelectric | 2.5 | South Central Idaho |
| Hells Canyon | Hydroelectric | 391.5 | Hells Canyon |
| Lower Malad | Hydroelectric | 13.5 | South Central Idaho |
| Lower Salmon | Hydroelectric | 60.0 | Mid-Snake |
| Milner | Hydroelectric | 59.4 | Upper Snake |
| Oxbow | Hydroelectric | 190.0 | Hells Canyon |
| Shoshone Falls | Hydroelectric | 12.5 | Upper Snake |
| Swan Falls | Hydroelectric | 27.2 | Mid-Snake |
| Thousand Springs | Hydroelectric | 8.8 | South Central Idaho |
| Twin Falls | Hydroelectric | 52.9 | Mid-Snake |
| Upper Malad | Hydroelectric | 8.3 | South Central Idaho |
| Upper Salmon A | Hydroelectric | 18.0 | Mid-Snake |
| Upper Salmon B | Hydroelectric | 16.5 | Mid-Snake |
| Boardman | Coal | 64.2 | North Central Oregon |
| Jim Bridger | Coal | 770.5 | Southwest Wyoming |
| North Valmy | Coal | 283.5 | North Central Nevada |
| Langley Gulch | Natural Gas—CCCT* | 318.5 | Southwest Idaho |
| Bennett Mountain | Natural Gas—SCCT** | 172.8 | Southwest Idaho |
| Danskin | Natural Gas—SCCT** | 270.9 | Southwest Idaho |
| Salmon Diesel | Diesel | 5.0 | Eastern Idaho |
| **Total existing nameplate capacity** | | **3,594.4** | |

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

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

## Hydroelectric Facilities

Idaho Power operates 17 hydroelectric projects on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,709 MW and an annual generation equal to approximately 960 aMW, or 8.4 million MWh under median water conditions.

## Hells Canyon Complex

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

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

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

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

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

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

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

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

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

### Upper Snake and Mid-Snake Projects

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

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

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

### Water Lease Agreements

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

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

## Cloud Seeding

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

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

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

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

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

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

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

## Coal Facilities

### Jim Bridger

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

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

### North Valmy

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

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

### Boardman

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

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

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

## Natural Gas Facilities

### Langley Gulch

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



Langley Gulch Power Plant

### Danskin

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

### Bennett Mountain

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

### Salmon Diesel

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

## Solar Facilities

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

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

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

## Net Metering Service

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

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

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

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

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

## Oregon Solar PV Pilot Program and Oregon Solar PV Capacity Standard

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

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

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

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

## *PURPA*

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

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

As of April 1, 2017, Idaho Power had 133 PURPA contracts with independent developers for approximately 1,135 MW of nameplate capacity. These PURPA contracts are for hydroelectric projects, cogeneration projects, wind projects, solar projects, anaerobic digesters, landfill gas, wood-burning facilities, and various other small, renewable-power generation facilities. Of the 133 contracts, 128 were on-line as of April 1, 2017, with a cumulative nameplate rating of approximately 1,115 MW. Figure 3.3 shows the percentage of the total PURPA nameplate capacity of each resource type under contract.

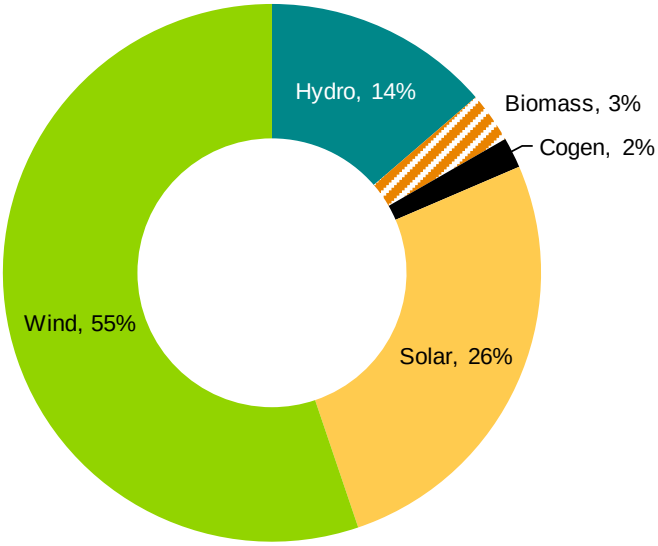



**Figure 3.3 PURPA contracts by resource type**

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

## *Power Purchase Agreements*

### Elkhorn Valley Wind Project

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



Elkhorn Valley Wind Project, Union County, Oregon

### Raft River Geothermal Project

In January 2008, the IPUC approved a PPA for 13 MW of nameplate generation from the Raft River Geothermal Power Plant (Unit 1) located in southern Idaho. The Raft River project began commercial operations in October 2007 under a PURPA contract with Idaho Power that was canceled when the new PPA was approved by the IPUC. For the first 10 years (2008–2017)

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

### Neal Hot Springs Geothermal Project

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

### Clatskanie Energy Exchange

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

## *Wholesale Contracts*

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

## *Power Market Purchases and Sales*

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

### Transmission MW Import Rights

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

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

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

# 4. FUTURE SUPPLY-SIDE GENERATION AND STORAGE RESOURCES

## Generation Resources

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

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

## Renewable Resources

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

### *Solar*

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

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

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

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

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

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

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

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

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

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

### Solar Capacity Credit

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

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

**Table 4.1 Solar capacity credit values**

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

## *Geothermal*

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

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

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

## Hydroelectric

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

### Small Hydroelectric

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

## Wind

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

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

### Biomass

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

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

## Conventional Resources

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

### Natural Gas-Fired Resources

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

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

#### Combined-Cycle Combustion Turbines

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

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

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

### Simple-Cycle Combustion Turbines

Simple cycle, natural gas-turbine technology involves pressurizing air that is then heated by burning gas in fuel combustors. The hot, pressurized air expands through the blades of the turbine that connects by a shaft to the electric generator. Designs range from larger, industrial machines at 80 to 200 MW to smaller machines derived from aircraft technology. SCCTs have a lower thermal efficiency than CCCT resources and are not typically economical to operate other than to meet peak-hour load requirements.

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

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

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

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

## Reciprocating Engines

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

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

## Combined Heat and Power

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

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

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

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

## Nuclear Resources

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

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

## Coal Resources

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

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

Coal gasification is a relatively mature technology, but it has not been widely adopted as a resource to generate electricity. IGCC technology involves turning coal into a synthetic gas or

"syngas" that can be processed and cleaned to meet pipeline quality standards. To produce electricity, the syngas is burned in a conventional combustion turbine that drives a generator.

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

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

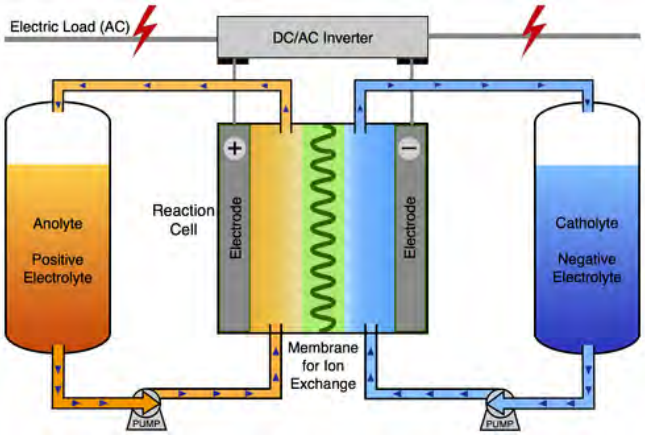
## Storage Resources

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

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

## Battery Storage

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




Basic illustration of a flow battery.[12]

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

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

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

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

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

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

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

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

## Ice-Based TES

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

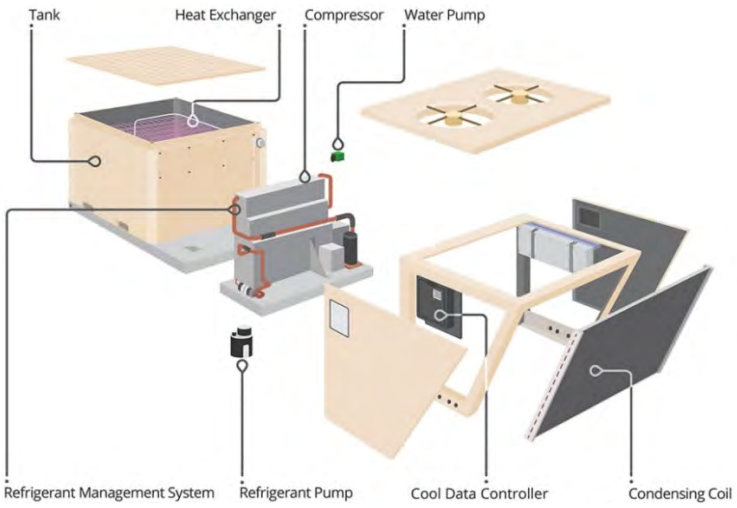



Illustration of an ice-based TES system.[13]

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

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

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

## Pumped Hydro Storage

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

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

# 5. DEMAND-SIDE RESOURCES

## DSM Program Overview

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



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

## Changes from the 2015 IRP

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

## Program Screening

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

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

# DSM Program Performance

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

## *Energy Efficiency Performance*

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

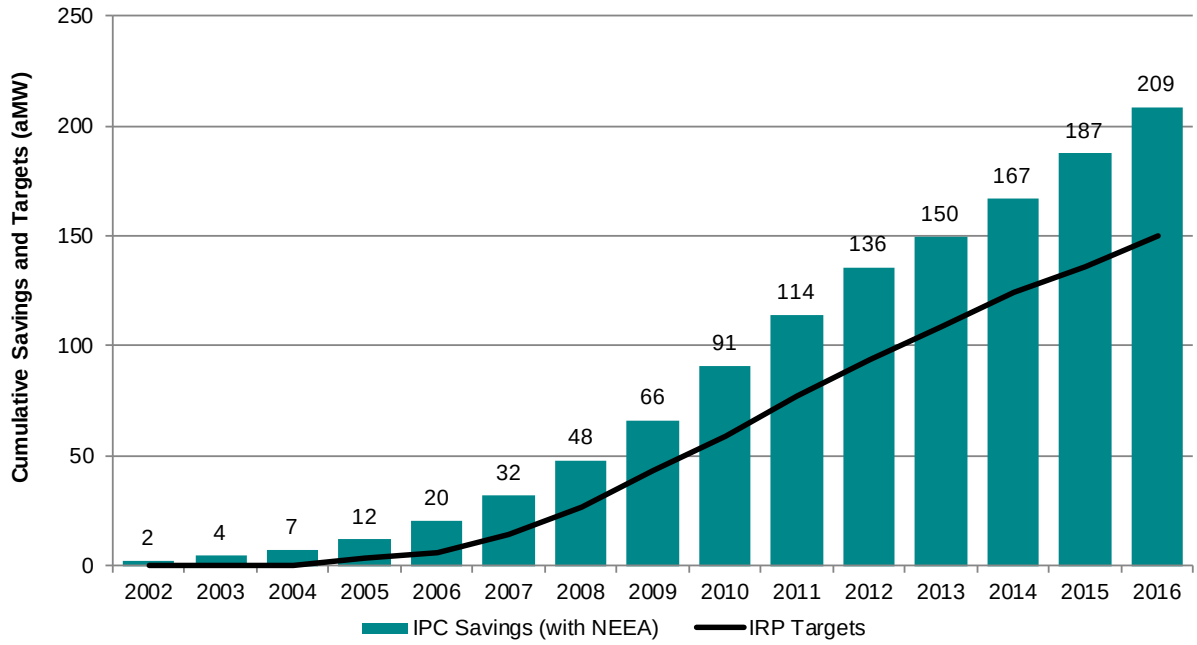



**Figure 5.1 Cumulative annual growth in energy efficiency**

## *Demand Response Performance*

Demand response resources have been part of the demand-side portfolio since the 2004 IRP. The current demand response portfolio is comprised of three programs that work together as one resource. Each program targets a different customer class. Table 5.1 lists the three programs that

make up the current demand response portfolio, along with the different program characteristics. The Irrigation Peak Rewards program represents the largest percent of potential demand reduction. During the 2016 summer season, Irrigation Peak Rewards participants contributed 81 percent of the total potential demand-reduction capacity, or 317 MW. More details on Idaho Power's demand response programs can be found in *Appendix B—Demand-Side Management 2016 Annual Report*.

**Table 5.1 Demand response programs**

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

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

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

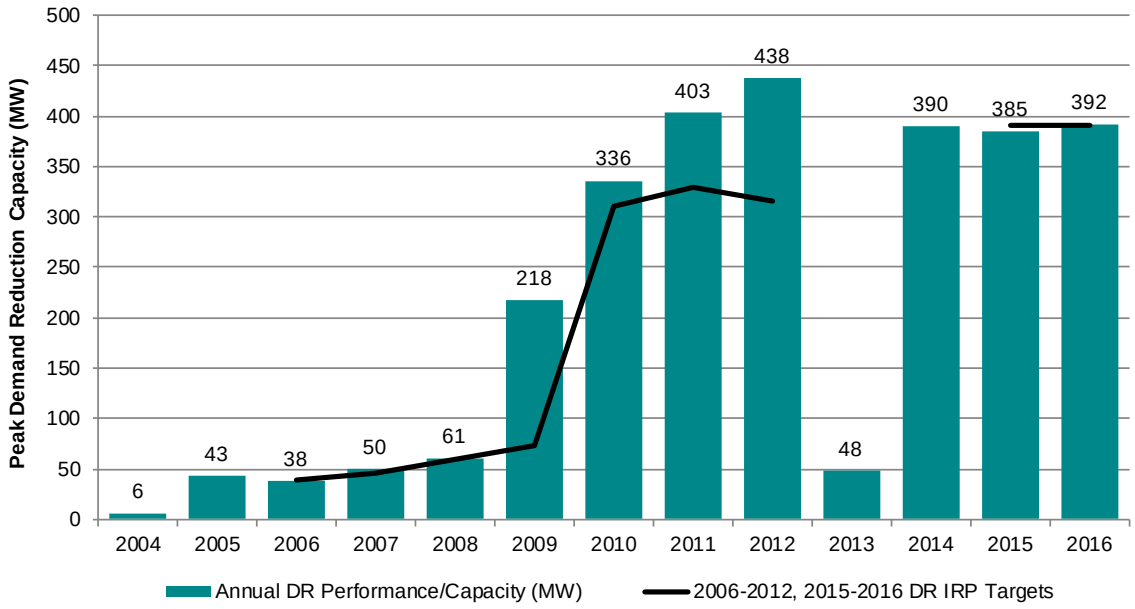



**Figure 5.2 Historical annual demand response programs**

## Committed Energy Efficiency Forecast

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



Typical irrigation pivots

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

- *Technical*—Technical potential is defined as the theoretical upper limit of energy efficiency potential. Technical potential assumes customers adopt all feasible measures regardless of cost. At the time of equipment replacement, customers are assumed to select the most efficient equipment available. In new construction, customers and developers are also assumed to choose the most efficient equipment available. Technical potential also assumes the adoption of every other applicable measure available. The retrofit measures are phased in over several years, which is increased for higher-cost measures.

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

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

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

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

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

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

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

*Totals may not add exactly due to rounding.

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

**Table 5.3 Total energy efficiency portfolio cost-effectiveness summary**

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

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

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

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

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

### *Transmission and Distribution Deferral Benefits Associated with Energy Efficiency*

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

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

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

## Committed Demand Response Forecast

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

## Additional Demand Response

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

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# 6. TRANSMISSION PLANNING

## Past and Present Transmission



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

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

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

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

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

## Transmission Planning Process

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

### *Local Transmission Planning*

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

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

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

### *Regional Transmission Planning*

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

### *Interconnection-Wide Transmission Planning*

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

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

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

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

## Existing Transmission System

Idaho Power's transmission system extends from eastern Oregon through southern Idaho to western Wyoming and is composed of 115-, 138-, 161-, 230-, 345-, and 500-kV transmission facilities. The sets of lines that transmit power from one geographic area to another are known as transmission paths. There are defined transmission paths to other states and between specific southern Idaho load centers. Idaho Power's transmission system and paths are shown in Figure 6.1.

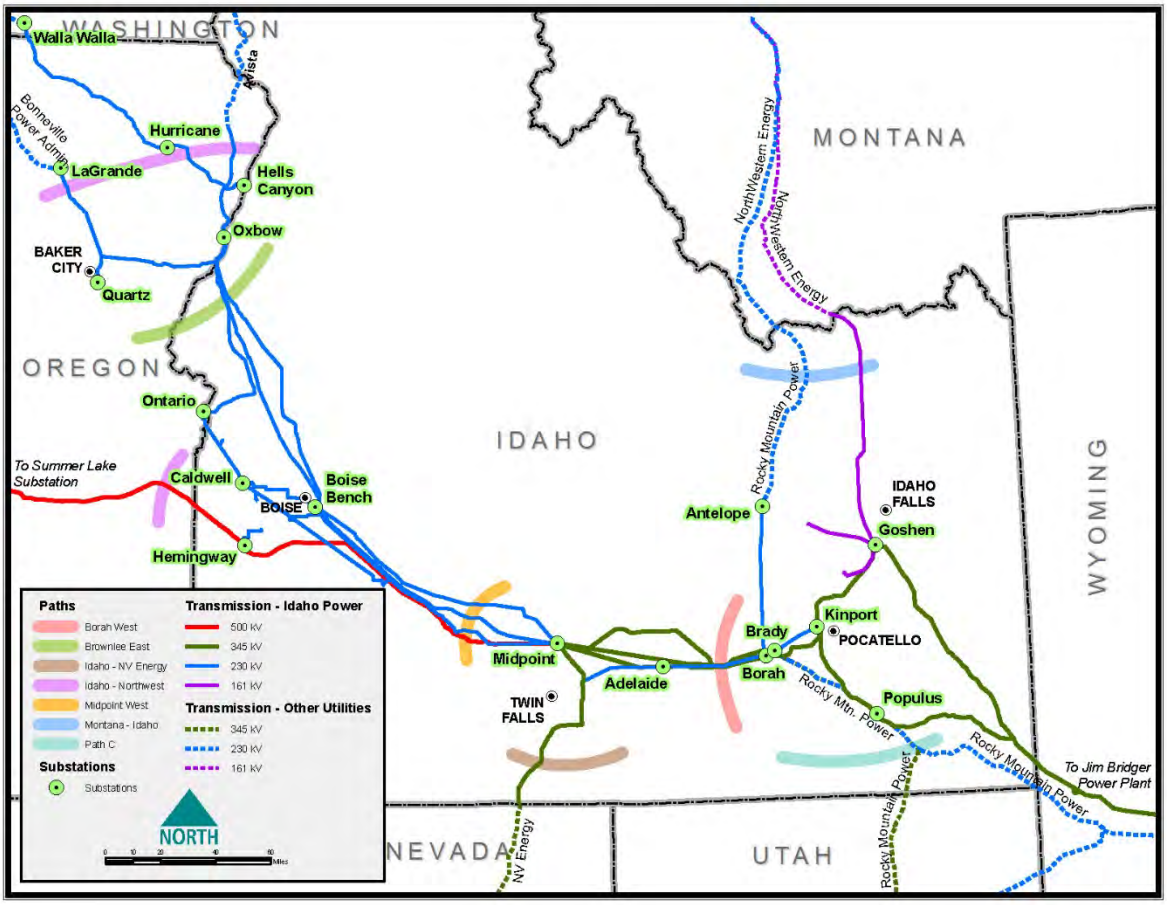



**Figure 6.1 Idaho Power transmission system map**

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

## Idaho–Northwest Path

The Idaho–Northwest transmission path consists of the 500-kV Hemingway–Summer Lake line, the three 230-kV lines between the HCC and the Pacific Northwest, and the 115-kV interconnection at Harney Substation near Burns, Oregon. The Idaho–Northwest path is capacity-limited during summer months due to energy imports from the Pacific Northwest to serve Idaho Power retail load and transmission-wheeling obligations for the BPA load in eastern Oregon and southern Idaho. To access new resources, including market purchases, located west of the path, additional transmission capacity will be required to deliver the energy to Idaho Power's service area.

## Brownlee East Path

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

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

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

### Montana–Idaho Path

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

### Borah West Path

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

### Midpoint West Path

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

## Idaho–Nevada Path

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

## Idaho–Wyoming Path

The Idaho–Wyoming path, referred to as Bridger West, is comprised of three 345-kV transmission lines between the Jim Bridger generation plant and southeastern Idaho. Idaho Power owns 774 MW of the 2,400-MW east-to-west capacity. PacifiCorp owns the remaining capacity. The Bridger West path effectively feeds into the Borah West path when power is moving east to west from Jim Bridger; consequently, the import capability of the Bridger West path is limited by Borah West path capacity constraints.

## Idaho–Utah Path

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

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

**Table 6.1 Transmission import capacity**

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

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

## B2H

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

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

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

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

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

[14] nttg.biz/site/

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

## Project Participants

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

**Table 6.2 B2H capacity and permitting cost allocation**

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

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

## Permitting Update

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

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

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

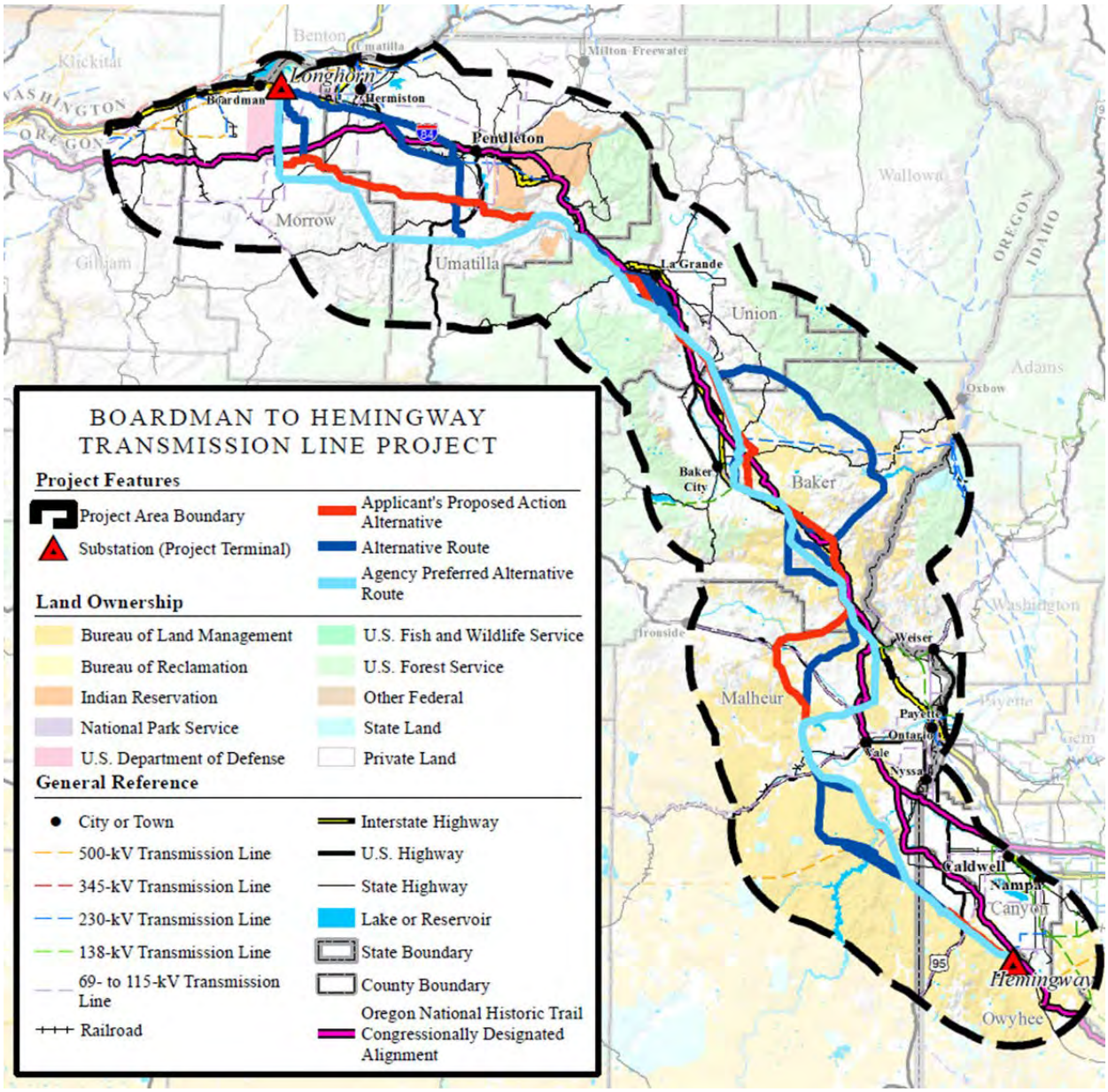



**Figure 6.2 B2H routes with the agency-preferred alternative**

## *Activities after BLM ROD*

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

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

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

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

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

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

## B2H Cost Treatment in the IRP

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

## Northwest Seasonal Resource Availability Forecast

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

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

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

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

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

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

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

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

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

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

## Gateway West

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

Figure 6.3 shows a map of the project identifying the currently authorized routes in the federal permitting process based on the BLM's November 2013 ROD for segments 1 through 7 and 10. Segments 8 and 9 were further considered through a Supplemental EIS by the BLM. The BLM issued a ROD for segments 8 and 9 on January 20, 2017. In March 2017, this ROD was rescinded by the BLM for further consideration. On May 5, 2017, the *Morley Nelson Snake River Birds of Prey National Conservation Area Boundary Modification Act of 2017* (H.R. 2104) was enacted. H.R. 2104 authorized the Gateway West route through the Birds of Prey area that was proposed by Idaho Power and PacifiCorp and supported by the Idaho Governor's Office, Owyhee County and certain other constituents. Per this legislation, the Secretary of the Interior must issue a ROW for Idaho Power's proposed routes for segments 8 and 9 by early August 2017.

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

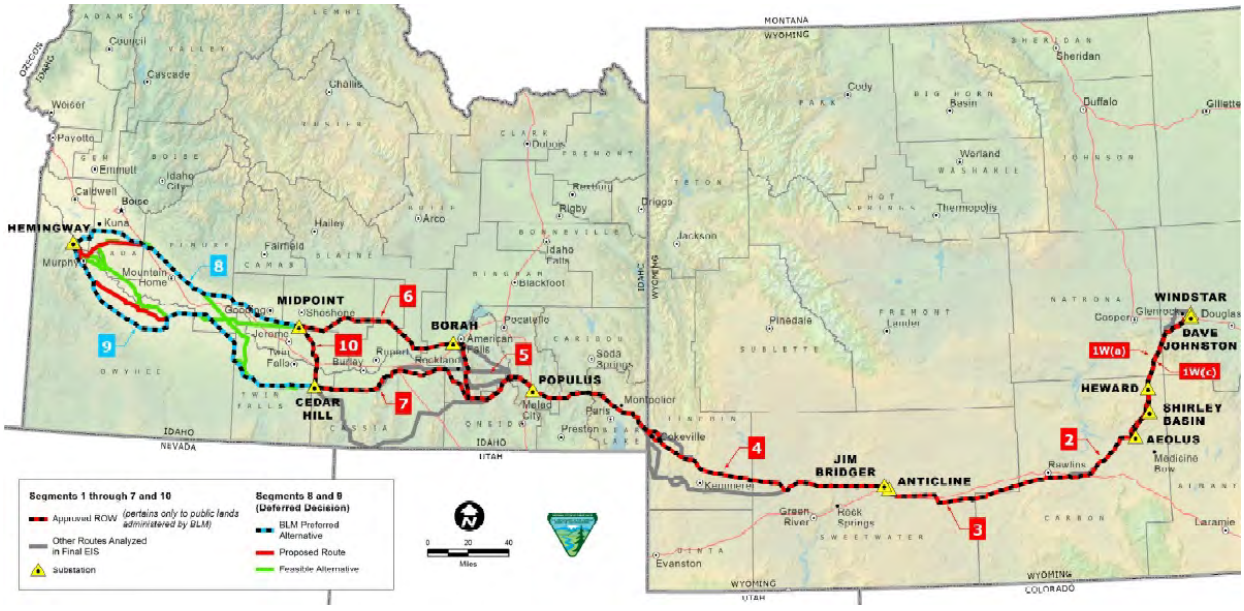



**Figure 6.3 Gateway West map**

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

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

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

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

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

## Nevada without North Valmy

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

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

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

## Transmission Assumptions in the IRP Portfolios

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



Transmission lines leading from Danskin Power Plant

**Table 6.3 Transmission assumptions and requirements**

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

| Resource | Capacity | Cost Assumption Notes | Local Interconnection Assumptions | Backbone Transmission Assumptions |
|---|---|---|---|---|
| Natural gas—SCCT frame F class (Idaho Power's peaker plants use this technology) | 170 | Assume Mountain Home location; displaces equivalent MW of portfolio resources in same region. | Assume 2-mile 230-kV line required to connect to nearby station. | Assigns pro-rata share for transmission upgrades identified for resources east of Boise. |
| Natural gas—Reciprocating gas engine Wärtsilä 34SG | 18 | Assume Mountain Home location; displaces equivalent MW of portfolio resources in same region. | Interconnecting at 230-kV Rattle Snake Substation. | Assigns pro-rata share for transmission upgrades identified for resources east of Boise. |
| Natural gas—CCCT (1x1) F class with duct firing | 300 | Assume Langley Gulch location; displaces equivalent MW of portfolio resources in same region. | New LGSY–GARNET 230-kV line w/ Garnet 230/138 transformer and Garnet 138-kV tap line. Bundle conductor on the LGSY–CDWL 230-kV line. Reconductor CDWL–LNDN. | No additional backbone upgrades required. |
| Natural gas—CCCT (1x1) F class with duct firing | 300 | Assume Mountain Home location; displaces equivalent MW of portfolio resources in same region. | Assume 2-mile 230-kV line required to connect to nearby station. | Assigns pro-rata share for transmission upgrades identified for resources east of Boise. |
| Natural gas—CCCT (2x1) F class | 550 | Build new facility south of Boise (assume Simco Road area). | New 230-kV switching station with a 22-mile 230-kV line to Boise Bench Substation and wrap 230-kV Danskin Power Plant to Hubbard line into new station. | Rebuild Rattle Snake to DRAM 230-kV line, rebuild Boise Bench to DRAM 230-kV line, rebuild Micron to Boise Bench 138-kV line. |
| Natural gas—CHP | 35 | Assume location in Treasure Valley. | Assume 1-mile tap to existing 138-kV line and new 138-kV source substation. | No backbone upgrades required. |
| Nuclear—SMR | 50 | Assume tie into ANTS 230-kV transmission substation; displaces equivalent MW of portfolio resources east of Boise. | Two 2-mile 138-kV lines to interconnect to Antelope Substation. New 138-kV terminal at Antelope Substation. | New parallel 55-mile 230-kV line from Antelope to Brady Substation. New 230-kV terminal at Brady Substation. Assigns pro-rata share for transmission upgrades identified for resources east of Boise. |
| Pumped storage—New upper reservoir and new generation/pumping plant | 100 | Assume Anderson Ranch location; displaces equivalent MW of portfolio resources in same region. | 18-mile 230-kV line to connect to Rattle Snake Substation. | Assigns pro-rata share for transmission upgrades identified for resources east of Boise. |
| Solar PV—Utility-scale 1-axis tracking | 30 | Assume Magic Valley location; displaces equivalent MW of portfolio resources in same region. | Assume 1-mile 230-kV line and associated stations equipment. | Assigns pro-rata share for transmission upgrades identified for resources east of Boise. |
| Wind—Idaho | 100 | Assume location within 5 miles of Midpoint Substation; displaces equivalent MW of portfolio resources in same region. | Assume 5-mile 230-kV transmission from Midpoint Substation to project site. | Assigns pro-rata share for transmission upgrades identified for resources east of Boise. |

# 7. PLANNING PERIOD FORECASTS

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

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



Pedestrians at the Drive Electric Week event in Boise.

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

## Load Forecast

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

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

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

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

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

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

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

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

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

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

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

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

## Weather Effects

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

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

## Economic Effects

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

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

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

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

## Average-Energy Load Forecast

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

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

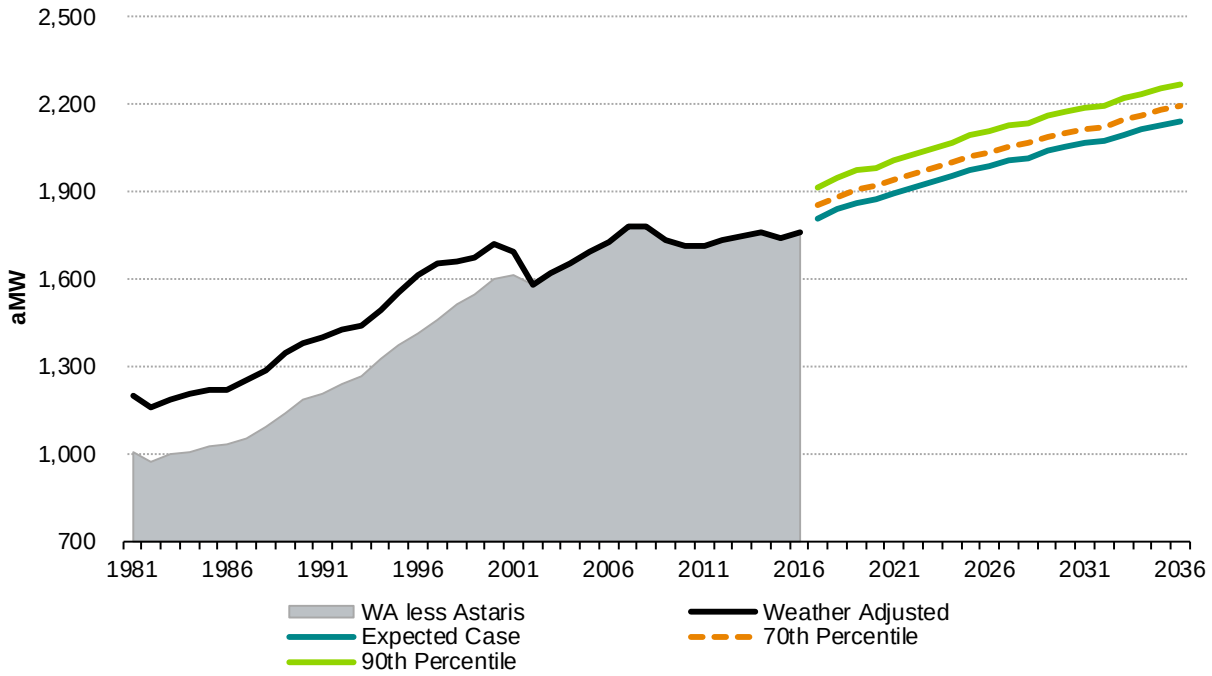



**Figure 7.1 Average monthly load-growth forecast**

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

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

## Peak-Hour Load Forecast

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

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

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

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

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

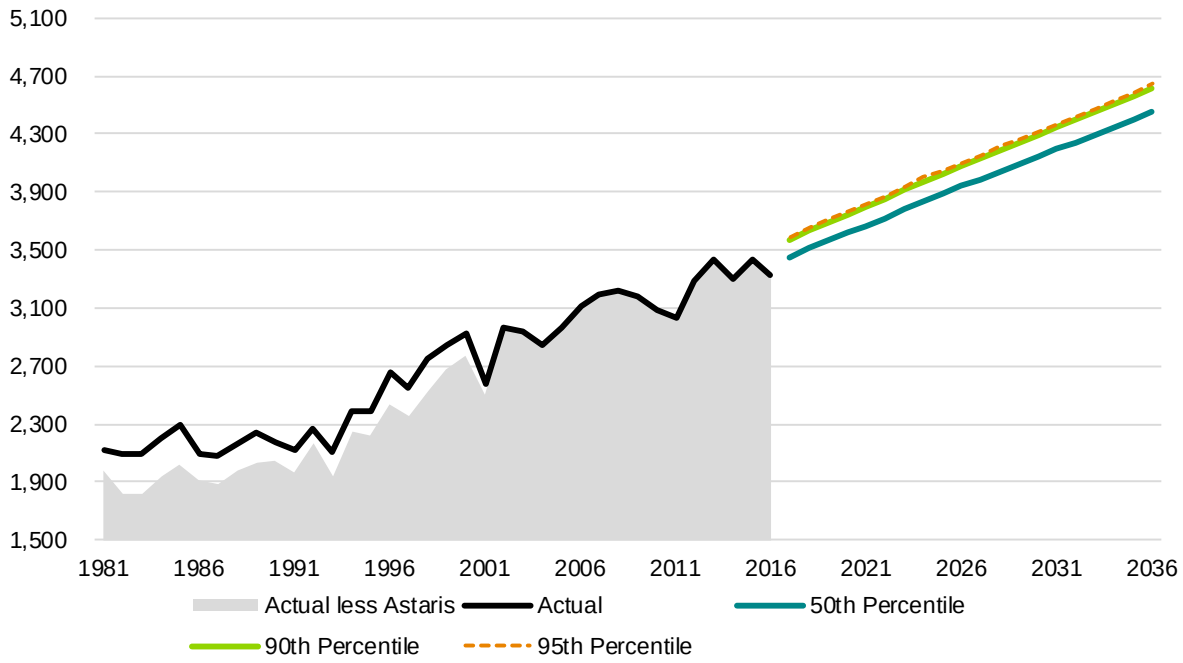



**Figure 7.2 Peak-hour load-growth forecast (MW)**

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

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

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

## Additional Firm Load

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

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

### Micron Technology

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

### Simplot Fertilizer

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

### INL

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

# Generation Forecast for Existing Resources



Hells Canyon Dam

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

## *Hydroelectric Resources*

For the 2017 IRP, Idaho Power continues the practice of using 70$^{th}$-percentile future streamflow conditions for the Snake River Basin as the basis for the projections of monthly average hydroelectric generation. The 70$^{th}$ 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 90$^{th}$-percentile streamflow conditions to project peak-hour hydroelectric generation. The 90$^{th}$ 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 50th-, 70th-, and 90th-percentile streamflow forecasts are derived from the normalized hydrologic record. Further discussion of flow modeling for the 2017 IRP is included in *Appendix C—Technical Appendix.*

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

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

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

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

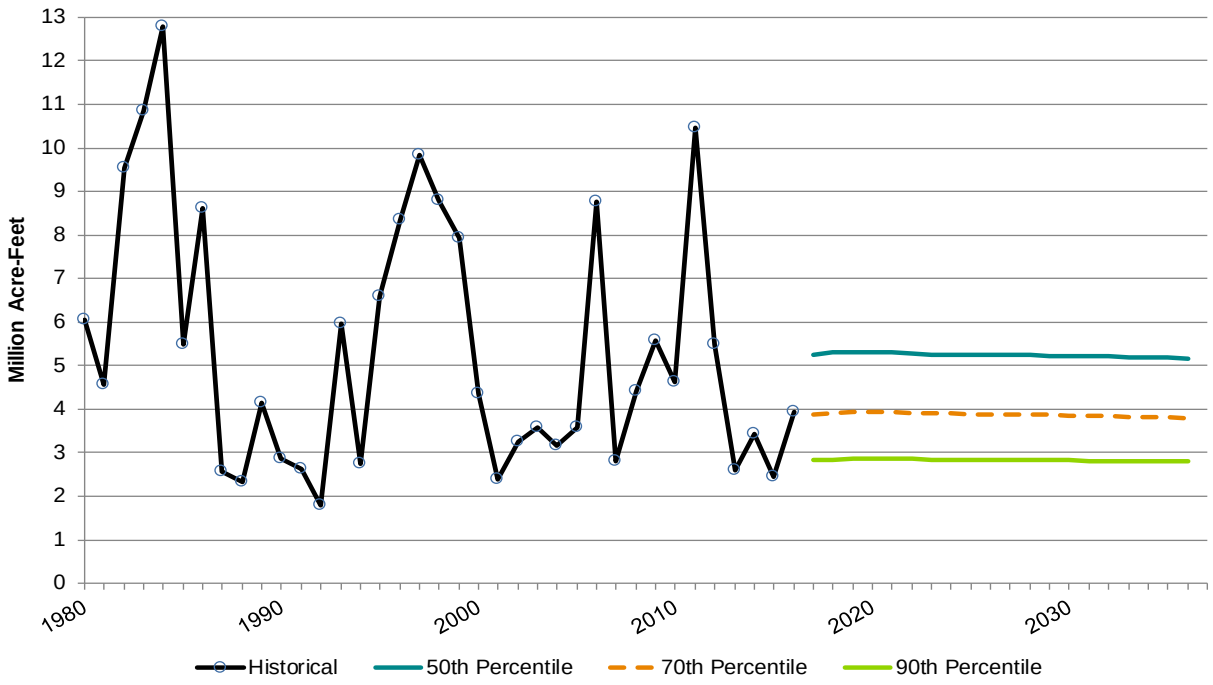



**Figure 7.3 Brownlee historical and forecast inflows, April through July**

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

## Coal Resources

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

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

### Boardman Retirement

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

### North Valmy

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

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

### Jim Bridger Units 1 and 2 Scenarios

Each of the four Jim Bridger units requires capital investment for retrofitting to comply with regional-haze regulations. The implementation of these regulations is stipulated in a state implementation plan (SIP). PacifiCorp and Idaho Power, as joint owners of the Jim Bridger plant, with the Wyoming Department of Environmental Quality (WDEQ), have developed a plan to implement the regional-haze regulation. The current SIP stipulates installation of SCR

retrofitting on Jim Bridger units 3 and 4 in 2015 and 2016, and on units 1 and 2 in 2022 and 2021, respectively. The installation of SCRs on Jim Bridger Units 3 and 4 is complete, and as a baseline assumption, units 3 and 4 are operating resources through the 20-year IRP planning period.

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

1. Make the SCR investments and operate Jim Bridger units 1 and 2 through the end of the planning period.

2. Do not make SCR investments and retire Jim Bridger units 1 and 2 year-end 2028 and year-end 2024, respectively.

3. Do not make SCR investments and retire Jim Bridger units 1 and 2 year-end 2032 and year-end 2028, respectively.

4. Do not make SCR investments and retire Jim Bridger units 1 and 2 on their respective compliance dates of year-end 2022 and year-end 2021.

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

## Natural Gas Resources

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

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

## Natural Gas Price Forecast

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

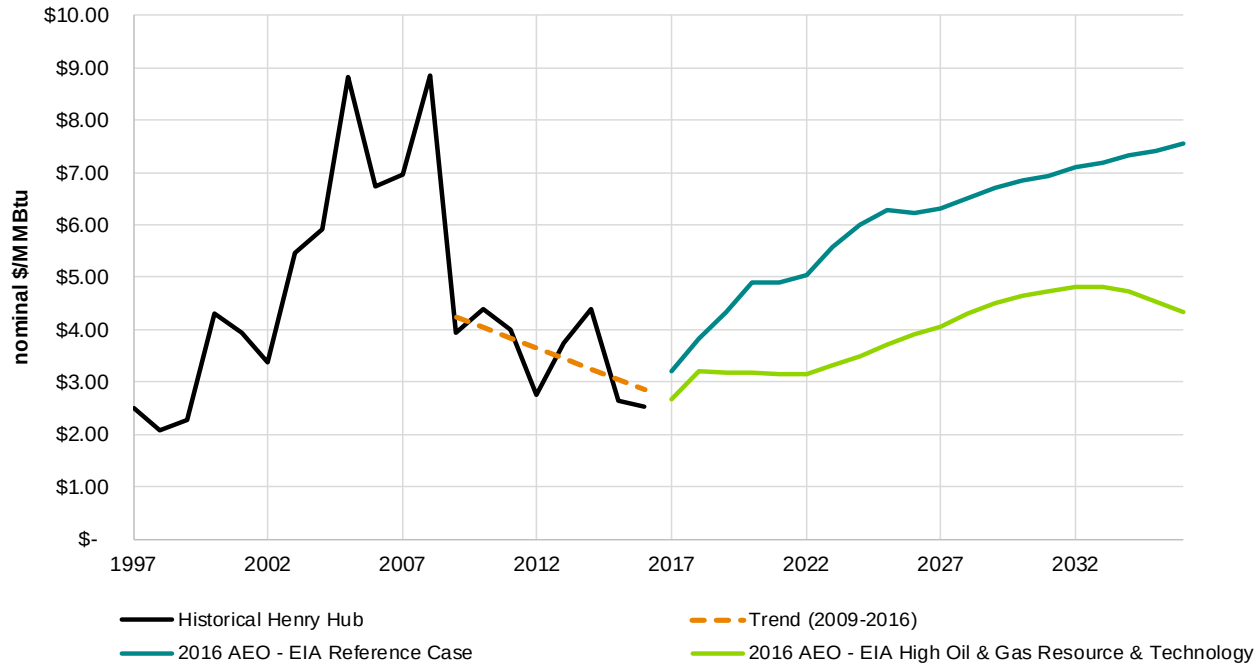



**Figure 7.4 Henry Hub natural gas spot price**

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

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

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

## Analysis of IRP Resources

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

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

### *Resource Costs—IRP Resources*

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

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

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

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

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

## LCOC—IRP Resources

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

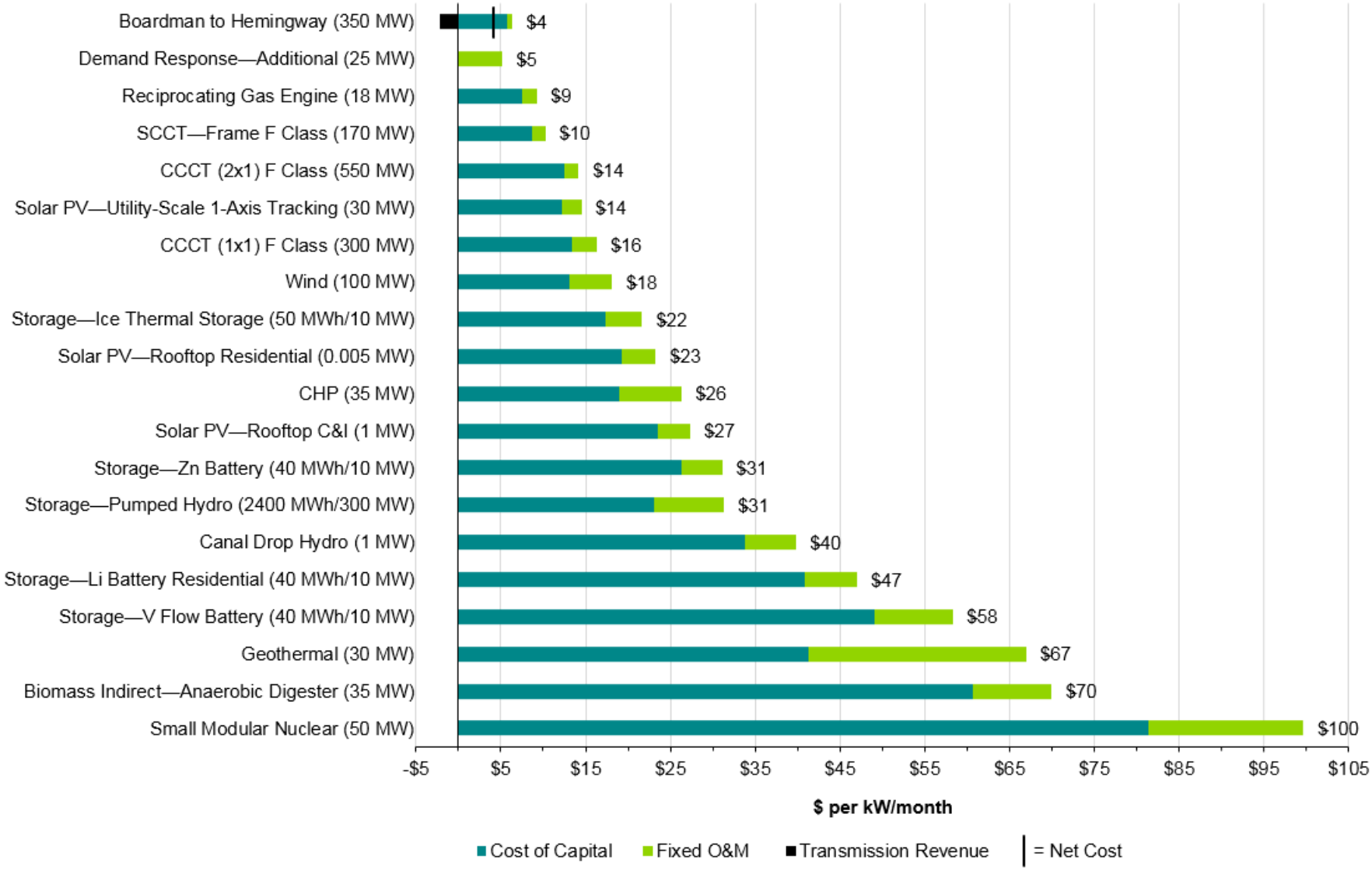



**Figure 7.5 Levelized capacity (fixed) costs**

## LCOE—IRP Resources

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

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

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

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

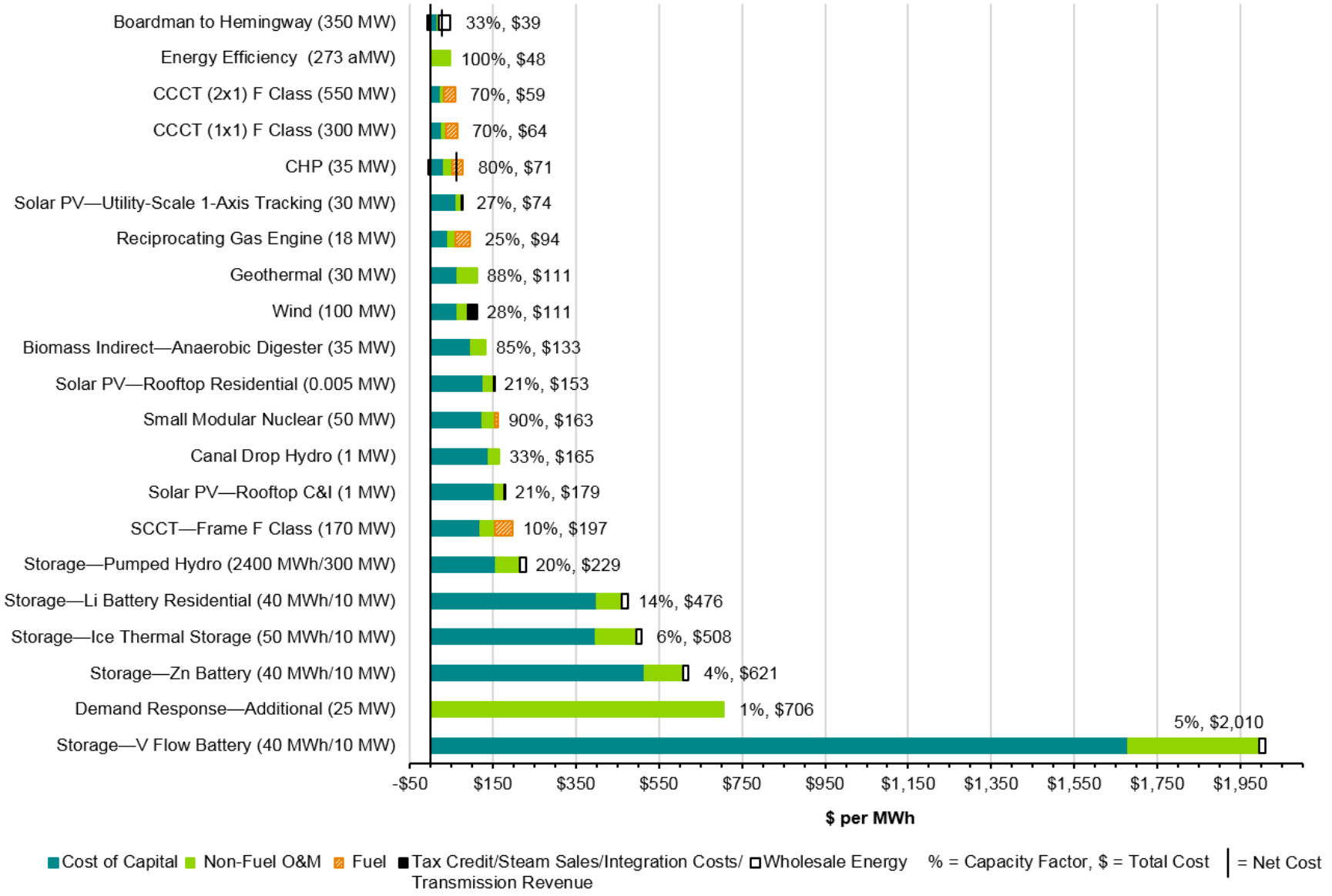



**Figure 7.6 LCOE (as stated capacity factors)**

## Resource Attributes—IRP Resources

While the cost metrics described in this section are informative, caution must be exercised when comparing costs for resources providing different attributes or qualities to the power system. For the LCOC metric, this critical distinction arises because of differences for some resources between *installed* capacity and *on-peak* capacity. Specifically, for intermittent renewable resources, an installed capacity of 1 kW equates to an on-peak capacity of less than 1 kW. For example, wind is estimated to have an LCOC of $18 per month per kW of installed capacity.[18] However, assuming wind delivers on-peak capacity equal to 5 percent of installed capacity, the LCOC ($18/month/kW) converts to $360 per month per kW of on-peak capacity.

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

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

- *Intermittent renewable*—Renewable resources, such as wind and solar, characterized by intermittent output and causing an increased need for resources providing balancing or flexibility

- *Dispatchable capacity-providing*—Resources that can be dispatched as needed to provide capacity during periods of peak-hour loading or to provide output during generally high-value periods

- *Non-dispatchable (coincidental) capacity-providing*—Resources whose output tends to naturally occur with moderate likelihood during periods of peak-hour loading or during generally high-value periods

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

- *Balancing/flexibility-providing*—Fast-ramping resources capable of balancing the variable output from intermittent renewable resources

- *Energy-providing*—Resources producing relatively predictable energy when averaged over long time periods (i.e., monthly or longer).

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

**Table 7.3 Resource attributes**

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

## IRP Resources and Portfolio Design

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

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

## T&D Deferral Benefit Associated with DERs

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

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

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

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

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

## Load and Resource Balance

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

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

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

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

All load and resource balances include the following:

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

- Firm Pacific Northwest import capability, including import capacity over the Idaho–Nevada path. The northbound capacity of this line has historically been fully subscribed with Idaho Power's share of energy from the North Valmy generation plant. The load and resource balance scenarios do not include the import capacity from the B2H transmission line or the Gateway West transmission line.

- Existing PPAs with Elkhorn Valley Wind, Raft River Geothermal, and Neal Hot Springs. The agreement with Elkhorn Valley Wind expires at the end of 2027, and a replacement contract is not contemplated. The agreement with Raft River Geothermal expires at the end of 2033 and is expected to be replaced. The agreement with Neal Hot Springs does not expire within the planning period.

- Existing PURPA projects and contracts. The 2017 IRP forecast includes all contracts completed by December 9, 2016. Since that time, one biomass project with a nameplate of 5 MW has been added and is scheduled to come on-line in 2018. Idaho Power assumes all PURPA contracts, except for wind projects, will continue to deliver energy throughout the planning period, and the renewal of contracts will be consistent with PURPA rules and regulations existing at the time the replacement contracts are negotiated.
  Wind projects are not expected to be renewed. Currently, 627 MW of wind are under PURPA contract, and contract expirations begin in October 2025. By February 2033, the total wind under contract drops to 130 MW and remains at that level through the end of the planning period.

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

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

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

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

**Note**: Darker shading indicates increasing deficit values.

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

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

**Note**: Darker shading indicates increasing deficit values.

# 8. PORTFOLIOS

## Portfolio Design

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

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

1. *Scenario* 1—Install SCRs and operate Jim Bridger units 1 and 2 through the end of the planning period.

2. *Scenario 2*—Do not make SCR investments and retire Jim Bridger units 1 and 2 at year-end 2028 and year-end 2024, respectively.

3. *Scenario 3*—Do not make SCR investments are retire Jim Bridger units 1 and 2 at year-end 2032 and year-end 2028, respectively.

4. *Scenario 4*—Do not make SCR investments and retire Jim Bridger units 1 and 2 on their respective compliance dates of year-end 2022 and year-end 2021.

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

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

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

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

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

## Studied Portfolios

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

### *Jim Bridger Scenario 1*

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

## P1

**Table 8.1 P1 timeline**

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

**Table 8.2 P1 resource summary**

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

## P2

**Table 8.3 P2 timeline**

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

*Includes demand response

**Table 8.4 P2 resource summary**

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

### P3

**Table 8.5 P3 timeline**

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

*Includes demand response

**Table 8.6 P3 resource summary**

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

## *Jim Bridger Scenario 2*

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

## P4

**Table 8.7 P4 timeline**

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

**Table 8.8 P4 resource summary**

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

## P5

**Table 8.9 P5 timeline**

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

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

*Includes demand response

**Table 8.10 P5 resource summary**

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

## P6

**Table 8.11 P6 timeline**

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

*Includes demand response

**Table 8.12 Resource P6 resource summary**

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

## *Jim Bridger Scenario 3*

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

### P7

**Table 8.13 P7 timeline**

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

**Table 8.14 P7 resource summary**

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

### P8

**Table 8.15 P8 timeline**

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

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

*Includes demand response

**Table 8.16 P8 resource summary**

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

## P9

**Table 8.17 P9 timeline**

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

*Includes demand response

**Table 8.18 P9 resource summary**

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

## *Jim Bridger Scenario 4*

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

### P10

**Table 8.19 P10 timeline**

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

**Table 8.20 P10 resource summary**

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

## P11

**Table 8.21 P11 timeline**

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

*Includes demand response

**Table 8.22 P11 resource summary**

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

### P12

**Table 8.23 P12 timeline**

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

*Includes demand response

**Table 8.24 P12 resource summary**

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

## Portfolio Design with Two Factors

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

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

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

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

**Table 8.25 Factorial design applied to portfolios**

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

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

# 9. MODELING ANALYSIS AND RESULTS

## Planning Case Portfolio Analysis

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

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

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

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

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

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

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

**Table 9.1 Financial assumptions**

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

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

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

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

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

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

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

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

## Natural Gas Price Sensitivities

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

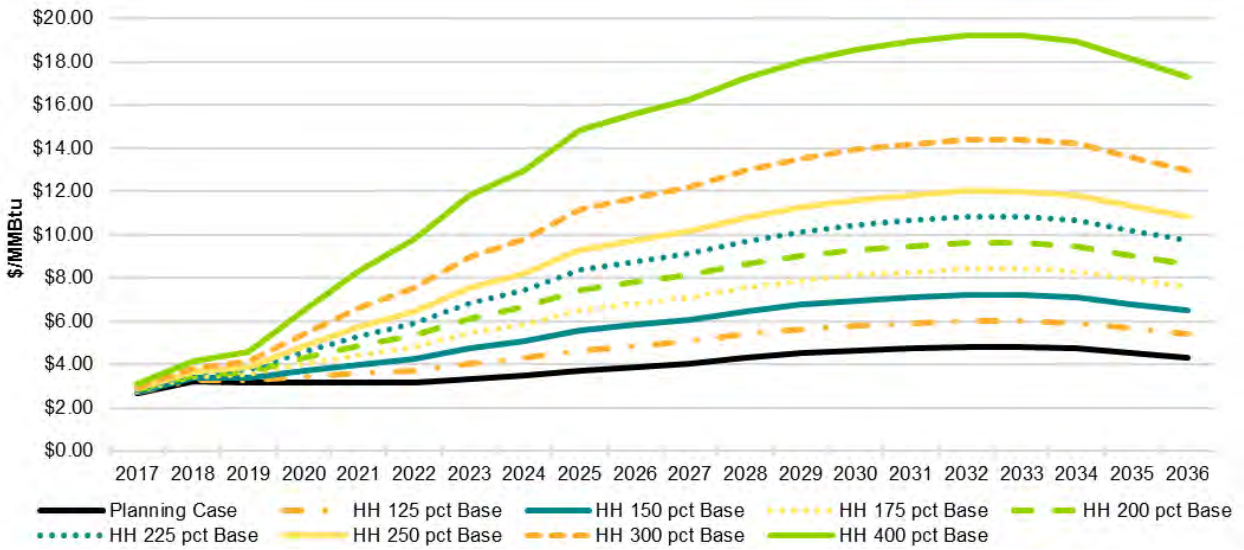



**Figure 9.1 Natural gas planning case and eight sensitivities (nominal $)**

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

**Table 9.4 Portfolio relative costs under nine natural gas price forecasts, NPV years 2017–2036 ($ x 1,000)**

| Sensitivity | P1 | P2 | P3 | P4 | P5 | P6 | P7 | P8 | P9 | P10 | P11 | P12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Planning Case | $64,925 | $161,733 | $195,084 | $2,912 | $230,796 | $172,470 | – | $167,753 | $147,229 | $64,736 | $243,998 | $335,739 |
| HH 125 Percent | $58,058 | $142,953 | $188,386 | $7,376 | $207,186 | $173,025 | – | $155,281 | $142,220 | $85,896 | $229,666 | $352,890 |
| HH 150 Percent | $58,142 | $129,040 | $186,163 | $13,472 | $183,556 | $172,346 | – | $143,472 | $138,386 | $105,611 | $212,513 | $363,972 |
| HH 175 Percent | $63,386 | $120,284 | $187,910 | $19,377 | $162,044 | $174,491 | – | $133,714 | $136,153 | $127,583 | $196,759 | $374,576 |
| HH 200 Percent | $60,514 | $102,090 | $182,606 | $23,856 | $135,130 | $171,846 | – | $119,610 | $128,671 | $143,776 | $174,778 | $378,449 |
| HH 225 Percent | $61,904 | $92,582 | $180,551 | $28,388 | $110,252 | $172,598 | – | $106,629 | $125,133 | $162,122 | $154,081 | $384,389 |
| HH 250 Percent | $60,720 | $76,879 | $177,400 | $31,620 | $84,098 | $167,438 | – | $93,640 | $118,182 | $178,368 | $130,579 | $388,352 |
| HH 300 Percent | $60,257 | $50,595 | $174,637 | $44,796 | $35,071 | $168,937 | – | $72,161 | $114,453 | $215,307 | $89,851 | $404,734 |
| HH 400 Percent | $114,023 | $50,128 | $216,370 | $126,783 | – | $230,108 | $61,658 | $82,446 | $156,364 | $342,022 | $61,587 | $494,597 |

**Note**: Darker shading indicates increasing values.

**Table 9.5 Portfolio rankings under nine natural gas price forecasts**

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

**Note**: Darker shading indicates increasing values.

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

## Stochastic Risk Analysis

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

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

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

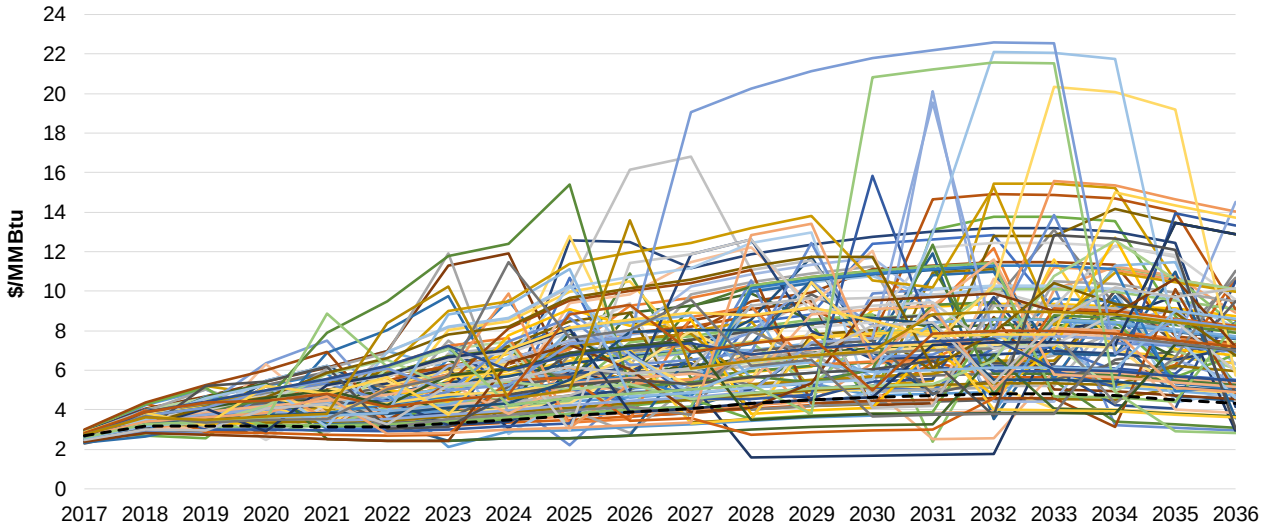



**Figure 9.2 Natural gas sampling (Nominal $/MMBtu)**

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

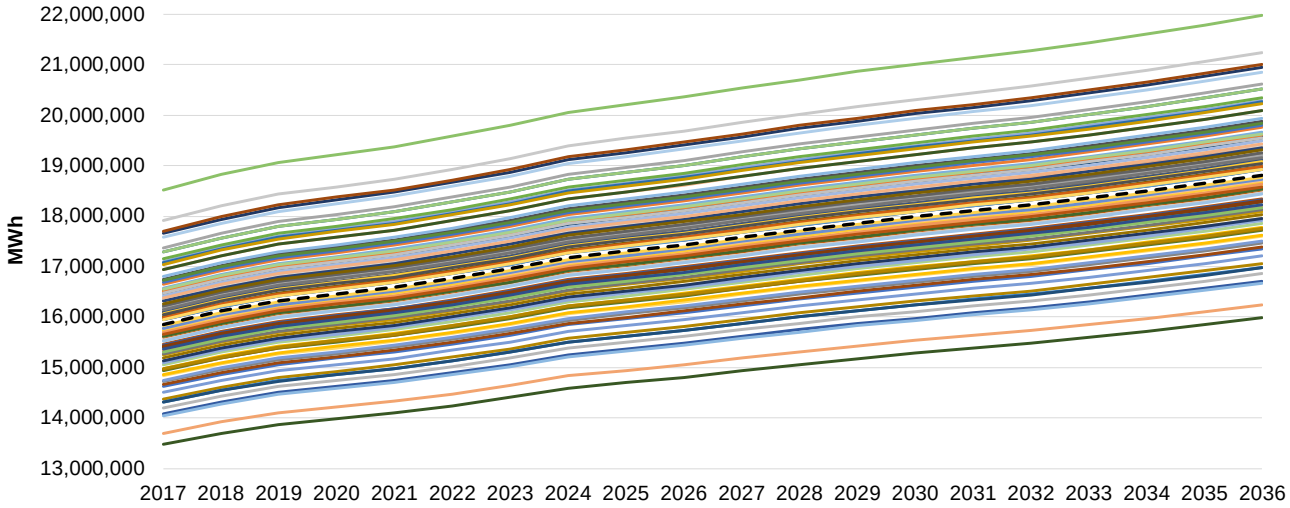



**Figure 9.3 Customer load sampling (annual MWh)**

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

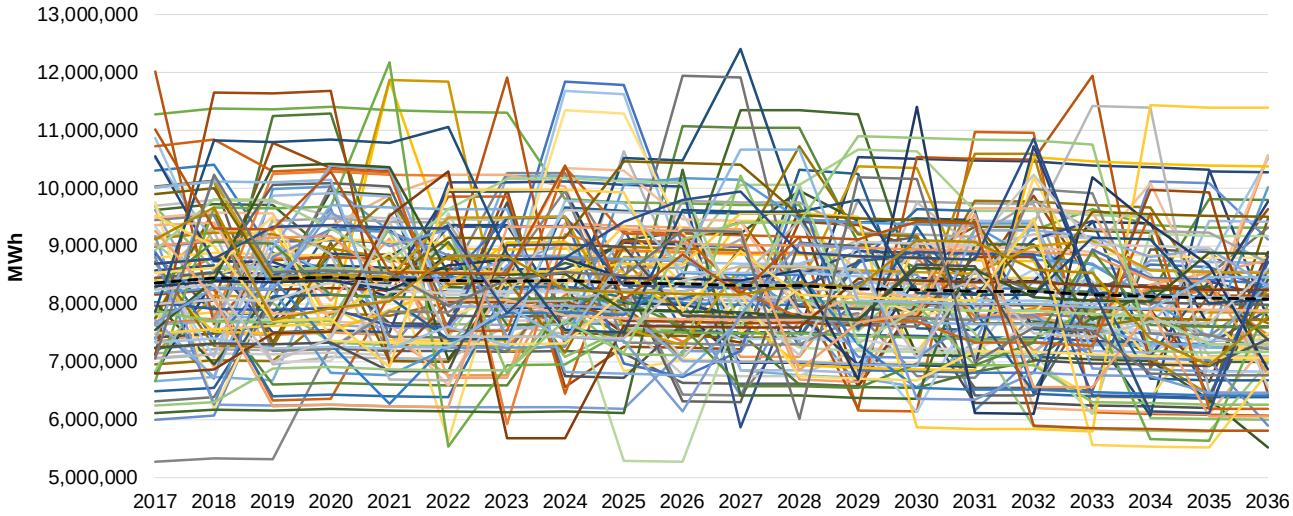



**Figure 9.4 Hydro generation sampling (annual MWh)**

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

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

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

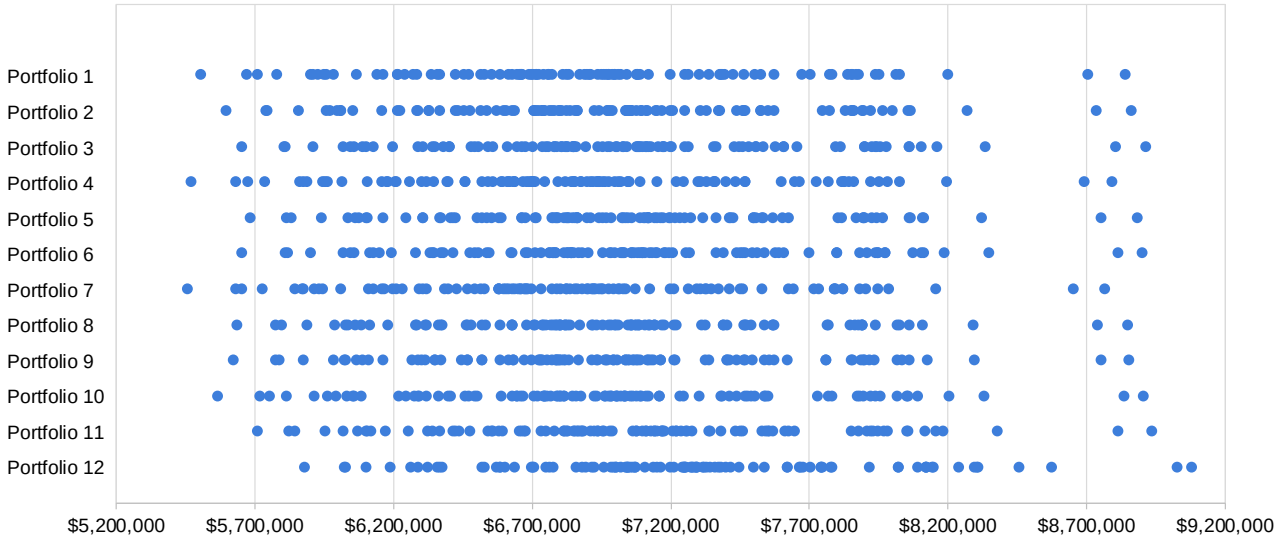



**Figure 9.5 Portfolio stochastic analysis, total portfolio cost, NPV years 2017–2036 ($ x 1,000)**

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

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

**Table 9.6 AURORA variable + fixed costs, NPV years 2017–2036 ($ x 1,000)**

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

## Portfolio Analysis Results in Factorial Design Format

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

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

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

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

## Solar Tipping-Point Analysis

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

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

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

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

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

# Qualitative Risk Analysis

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

## *Qualitative Risks*

### Hydro—Water Supply Risk

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

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

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

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

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

- The potential for underestimation of the decline in reach gains within the Snake River Basin

- Changes to funding or the ability to achieve forecasted levels of aquifer management on the ESPA.

### Relicensing Risk

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

### Regulatory Risk

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

### NOx Compliance Alternatives Risk

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

### Permitting/Siting Risk

Significant challenges are often encountered during permitting and siting for energy resources. While these challenges are not uniform for all resources or for all proposed resource locations,

it is nevertheless reasonable to assume all portfolios are exposed to permitting/siting risk, and no portfolio is markedly less exposed than P7; B2H planners have been collaborating with stakeholders for several years on resolving permitting/siting issues, and while challenges remain, much progress has been made.

### Regional Resource Adequacy

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

### DSM Implementation

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

### Technological Obsolescence

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

## *Qualitative Benefits*

### Regional Resource Diversity

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

### Regional Transmission Initiatives

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

### Transmission Tariff Revenue

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

### Local Economic Effects

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

## *Summary of Qualitative Risks and Benefits*

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

**Table 9.9 Qualitative risk analysis**

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

< Less risk
> More risk
= Equal risk

**Table 9.10 Qualitative benefit analysis**

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

< Less benefit
= Equal benefit

## *CAA Section 111(d)*

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

## Capacity Planning Margin

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

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

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

**Table 9.11 Capacity planning margin**

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

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

# Flexible Resource Needs Assessment

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

## *Historical Analysis*

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

$$Hourly\ net\ load = Hourly\ load - Hourly\ wind\ generation$$

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

$$\Delta\ Net\ Load_{0} = Net\ Load\ Hour_{0} - Net\ Load\ Hour_{-1}$$

$$\Delta\ Net\ Load_{-1} = Net\ Load\ Hour_{-1} - Net\ Load\ Hour_{-2}$$

$$\Delta\ Net\ Load_{-2} = Net\ Load\ Hour_{-2} - Net\ Load\ Hour_{-3}$$

$$\Delta\ Net\ Load_{-3} = Net\ Load\ Hour_{-3} - Net\ Load\ Hour_{-4}$$

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

$$Flexibility\ Score = [ABS(\Delta\ Net\ Load_{0}) + ABS(\Delta\ Net\ Load_{-1})$$

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

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

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

Idaho Power then specified a flexibility threshold:

$$Flexibility\ Score >= 100\ MW$$

AND

$$Flexibility\ Score/Hourly\ Net\ Load >= 0.12$$

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

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

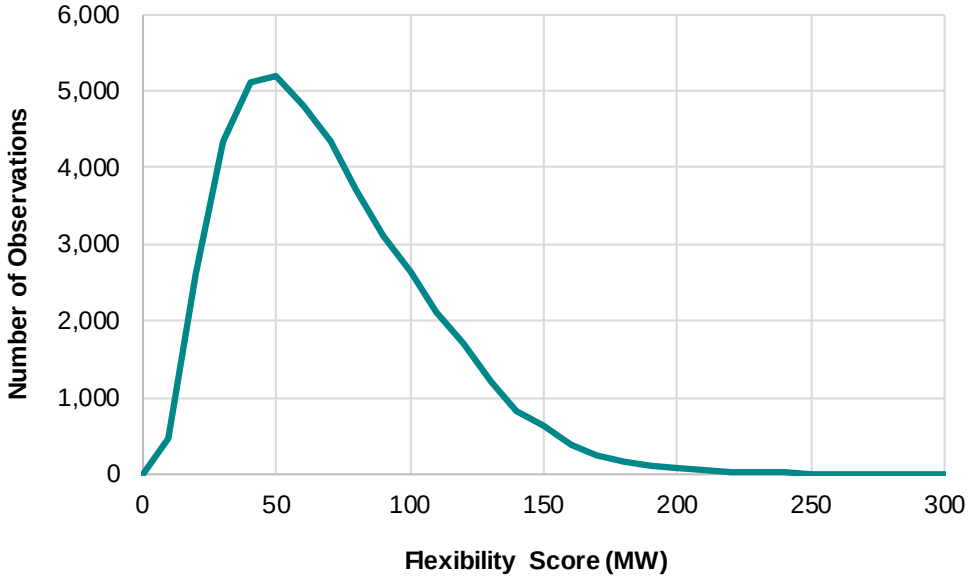



**Figure 9.6 Distribution of events with flexibility score 100 MW or greater**

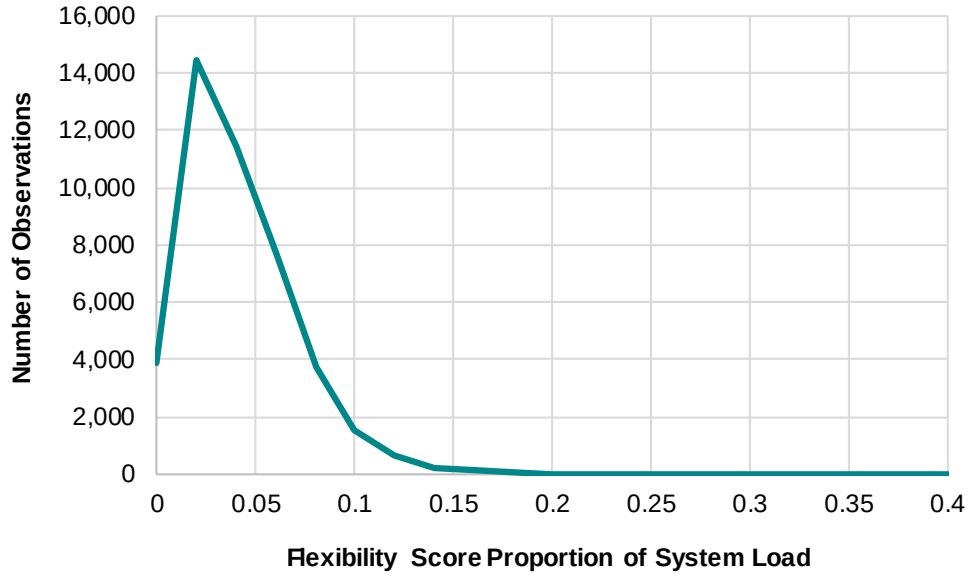



**Figure 9.7 Distribution of events with flexibility score 12 percent of net load or greater**

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

## Projected Flexibility Score in 2026

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

$$Flexibility\ Score >= 100\ MW$$

AND

$$Flexibility\ Score/Hourly\ Net\ Load >= 0.12$$

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

**Table 9.12 Hours exceeding flexibility threshold by month**

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

* Plus signs indicate a forecast change in flexibility need.

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

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

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

## Solar Capacity Credit

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

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

**Table 9.13 Solar capacity credit values**

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

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

Idaho Power selected 2025 for examination using an approximation method for a complete LOLE study. The evaluation used median hydro and load forecasts and the AURORA hourly

preferred portfolio output as a starting point. An Excel workbook was used to simulate 500 years of random outages. The 500 years of random outages resulted in an LOLE of approximately 2.07 hours per year. The 2.07 hours per year equates to an LOLE of approximately 1 day in 10 years, a frequently used standard in determining a system as resource adequate.

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

**Table 9.14 Hourly LOLP of 500 iterations for 2025**

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

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

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

**Table 9.15 Monthly probabilities**

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

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

## LOLE

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

# 10. PREFERRED PORTFOLIO AND ACTION PLAN

## Preferred Portfolio

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

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

**Table 10.1 P7 Resources**

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

## Action Plan (2017–2021)

The expressed objective of the portfolio design for the 2017 IRP was to inform the action plan regarding SCR investments at Jim Bridger units 1 and 2 and the B2H transmission line. Idaho Power characterized these two key resource actions as pivotal to this IRP, recognizing that

an essential function of the 2017 IRP is to inform the direction of these resource decisions. With respect to B2H, the action plan includes not only actions to continue permitting and planning, but also necessary preliminary construction and construction activities extending beyond 2021. These activities are described in Chapter 6.

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

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

The action plan also includes the following items:

- Continued pursuit of cost-effective energy efficiency, working with stakeholder groups, such as EEAG and regional groups, such as the Northwest Energy Efficiency Alliance (NEEA)
- Continued preparation for participation in the western EIM beginning in April 2018
- Continued involvement as a stakeholder in CAA Section 111(d) proceedings or alternative regulations constraining carbon emissions
- Investigation of solar PV contribution to peak and LOLP for use in the 2019 IRP

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

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

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

## Idaho Power and the Utility of the Future

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

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

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

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

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

## Conclusion



Hemingway Substation

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

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

Idaho Power focused the portfolio analysis for the 2017 IRP on the pivotal decisions related to SCR investments in Jim Bridger units 1 and 2 and the B2H transmission line and proffered a portfolio analysis designed to isolate these factors. However, the company recognizes resources achieving only modest market penetration to date, including notably electrochemical energy

storage, are likely to achieve greater market penetration in the coming years and may outcompete the low-cost natural gas-fired resources of today. Idaho Power recognizes the importance of understanding the cost and value characteristics of all emerging resources to effective long-term resource planning.

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

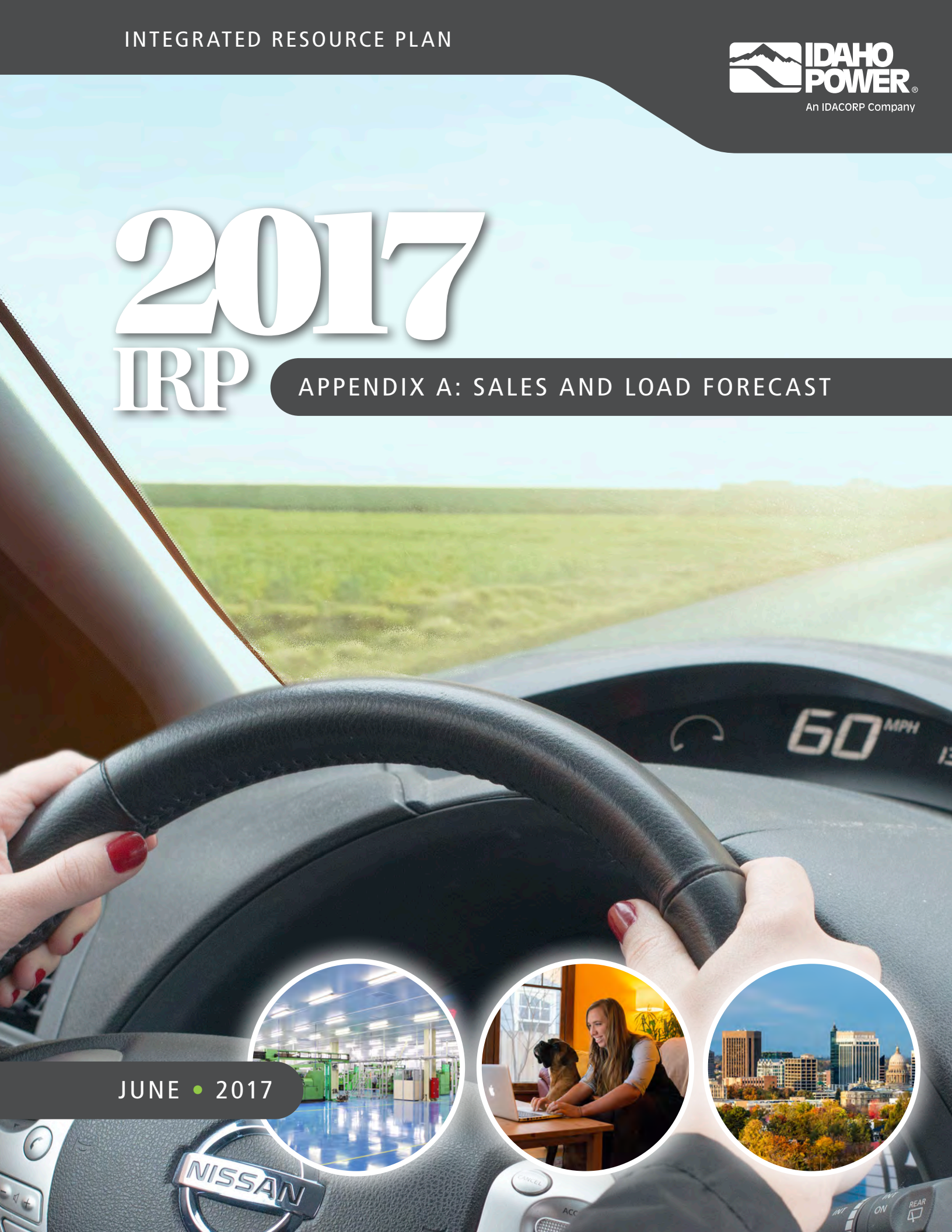
Idaho Power prepares an IRP every two years, and the next plan will be filed in 2019. The electric energy industry is experiencing what many consider a transformational era, and undoubtedly new challenges and questions necessarily addressed in integrated resource planning will be encountered in the 2019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

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# 2017 IRP

## APPENDIX A: SALES AND LOAD FORECAST




JUNE • 2017

## SAFE HARBOR STATEMENT

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

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# 2017 IRP

## APPENDIX A: SALES AND LOAD FORECAST

# ACKNOWLEDGEMENT

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

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

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

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

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# INTRODUCTION

Idaho Power has prepared *Appendix A—Sales and Load Forecast* as part of the *2017 Integrated Resource Plan* (IRP). Appendix A includes details on the energy sales and load forecast of future demand for electricity within the company's service area. The above-mentioned forecast covers a 20-year period from 2017 through 2036.

The expected-case monthly average load forecast is Idaho Power's estimate of the most probable outcome for load growth during the planning. To account for inherent uncertainty and variability, four additional load forecasts were prepared in addition to the expected-case—a low case, a 70$^{th}$-percentile case, a 90$^{th}$-percentile case, and a high case, all of which are described in more detail in this report. The high and low economic growth scenarios provide a range of possible load growths over the planning period due to variable economic, demographic, and other non-weather-related influences. Additional cases are developed around the 70$^{th}$-percentile and 90$^{th}$-percentile load forecast scenarios to assist Idaho Power in reviewing the resource requirements that would result from variable loads due to variable weather conditions for temperatures and rainfall. It is important to note that in the IRP resource planning process, Idaho Power uses the 70$^{th}$-percentile load forecast to account for the risk associated with weather impacts on load.

In the expected-case scenario, Idaho Power's system load is forecast to increase to 2,142 average megawatts (aMW) by 2036 from 1,810 aMW in 2017, representing an average yearly growth rate of 0.9 percent over the 20-year planning period (2017–2036). In the more critical 70$^{th}$-percentile load forecast used for resource planning, the system load is forecast to reach 2,193 aMW by 2036 (0.9% average annual growth)[1]. Additionally, the number of Idaho Power active retail customers is expected to increase from the December 2016 level of 533,400 customers to nearly 755,000 customers by year-end 2036 (see footnote 1).

For capacity planning purposes, it is forecasted that Idaho Power's system will grow to 4,641 megawatts (MW) in 2036 from the all-time system peak of 3,407 MW that occurred on Tuesday, July 2, 2013, at 4:00 p.m. Idaho Power's system peak increases at an average growth rate of 1.4 percent per year over the 20-year planning period (2017–2036).

The numerous external factors influencing the forecast are primarily economic and demographic in nature. Moody's Analytics serves as the primary provider for this data. The national, state, metropolitan service area (MSA), and county economic and demographic projections are tailored to Idaho Power's service area using an in-house economic database. Specific demographic projections are also developed for the service area from national and local census data.

[1] Recent company disclosures forecast load growth during the 2016 to 2035 planning period at 1.0 percent for average energy demand and 1.4 percent for peak-hour demand.

Additional data sources used to substantiate Moody's data include the Idaho Department of Labor, Woods & Poole, Construction Monitor, and Federal Reserve economic databases.

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

In addition to the economic assumptions used to drive the expected-case forecast scenario, several assumptions were incorporated into the forecasts of the residential, commercial, industrial, and irrigation sectors. Further discussions of these assumptions are presented below.

Conservation influences on the load forecast, including Idaho Power energy efficiency demand-side management (DSM) programs, statutory programs, and non-programmatic trends in conservation, are included in the load forecasts of each sector. Idaho Power DSM programs are described in detail in Idaho Power's *Demand-Side Management 2016 Annual Report,* which is incorporated into this IRP document as Appendix B.

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

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

# 2017 IRP SALES AND LOAD FORECAST

## Average Load

The economic and demographic variables driving the 2017 forecast have the impact of increasing current annual sales levels throughout the planning period. The delay in the expected "robust lift-off" of the business cycle recovery process after the Great Recession in 2008 for the national and, to a lesser extent, service-area economy halted load growth post-recession through 2011. However, in 2012, the extended recovery process was evident, and on-balance stronger growth was exhibited in most economic drivers relative to recent history at that time. It is expected that economic conditions return to long-term fundamentals during the 2017 forecast period. Significant factors and considerations that influenced the outcome of the 2017 IRP load forecast include the following:

- The load forecast used for the 2017 IRP reflects a continuance of the recovery in the service-area economy following a severe recession in 2008 and 2009. As customer growth was at a near standstill until 2012, acceleration of in-migration and business investment resulted in renewed growth in the residential and commercial connections along with increased industrial activity. As of 2017, customer additions have approached sustainable growth rates experienced prior to the housing bubble (2000–2004) and are expected to continue.

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

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

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

- The 2017 irrigation sales forecast is higher than the 2015 IRP forecast throughout the entire forecast period due to the significant trend toward more water-intensive crops, primarily alfalfa and corn, due to growth in the dairy industry. Also, farmers have put high-lift acreage back into production. Additionally, load increases have come from the conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to farmers trying to reduce labor costs.

## Peak-Hour Demands

As average demands as discussed in the preceding section are an integral component to the load forecast, so are the impact of the peak-hour demands on the system. The peak-hour forecasting regressions are expressed as a function of the sales forecast as well as the impact of peak-day temperatures. The peak forecast results and comparisons with previous forecasts differ for many reasons that include the following:

- The all-time system summer peak demand was 3,407 MW (recorded on Tuesday, July 2, 2013, at 4:00 p.m.). The system peak-hour load record was nearly matched on June 30, 2015, at 4:00 p.m., when the system peak reached 3,402 MW. Idaho Power's winter peak-hour load record is 2,527 MW, recorded on January 6, 2017, at 9:00 a.m. and matched the previous record peak dated December 10, 2009, at 8:00 a.m.

- The peak model develops peak-scenario impacts based on historical probabilities of peak-day temperatures at the 50$^{th}$, 90$^{th}$, and 95$^{th}$ percentiles of occurrence for each month of the year. The 95$^{th}$ percentile forecast of peak-hour demand is utilized for peak capacity planning purposes. These normal average peak-day temperature drivers are calculated over the 1986 to 2015 time period (the most recent 30 years).

- The 2017 IRP peak-demand forecast considers the impact of the current actualized committed and implemented energy efficiency DSM programs on peak demand.

# OVERVIEW OF THE FORECAST

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

## Forecast Probabilities

### *Load Forecasts Based on Weather Variability*

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

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

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

For example, the median HDD in December from 1986 to 2015 (the most recent 30 years) was 1,029, at the Boise Weather Service office. The 70$^{th}$-percentile HDD is 1,060 and would be exceeded in 3 out of 10 years. The 90$^{th}$-percentile HDD is 1,170 and would be exceeded in 1 out of 10 years. As an example, for a single month, the 100$^{th}$-percentile HDD (the coldest December over the 30 years) is 1,449, which occurred in December 1990. This same concept was applied in

each month throughout the year for the weather-sensitive customer classes: residential, commercial, and irrigation.

Since Idaho Power loads are highly dependent on weather, and the development of the above mentioned two scenarios allows the careful examination of load variability and how it may impact future resource requirements. It is important to understand that the probabilities associated with these forecasts apply to each month. This assumes temperatures and precipitation would maintain at the 70th-percentile or 90th-percentile level continuously, throughout the entire year. For Idaho Power to properly plan for future resource requirements, a similar methodology is needed for the hour of maximum demand for the year (referred to as peak demand). Table 1 summarizes the load scenarios prepared for the 2017 IRP.

**Table 1. Average load and peak-demand forecast scenarios**

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

The analysis of resource requirements is based on the 70th-percentile average load forecast coupled with the 95th-percentile peak-demand forecast to provide a more adverse representation of the average load and peak demand to be considered. In other Idaho Power planning, such as the preparation of the financial forecast or the operating plan, the expected-case (50th percentile) average-load forecast and the 90th-percentile peak-demand forecast are typically used.

## *Load Forecasts Based on Economic Uncertainty*

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

To provide risk assessment to economic uncertainty, two additional load forecasts for Idaho Power's service area were prepared based on the expected case forecast. The forecasts provide a range of possible load growth rates for the 2017 to 2036 planning period due to high and low economic and demographic conditions. The average growth rates for these high and low growth scenarios were derived from the historical distribution of one-year growth rates over the past 25 years (1992–2016).

Of the three scenarios 1) the expected forecast is the median growth path, 2) the standard deviation observed during the historical time period is used to estimate the dispersion around the expected-case scenario, and 3) the variation in growth rates will be equivalent to the variation in growth rates observed over the past 25 years (1992–2016).

From the above methodology, two views of probable outcomes from the forecast scenarios—the probability of exceeding and the probability of occurrence—were developed and are reported in Table 2. The probability of exceeding the likelihood the actual load growth will be greater than the projected growth rate in the specified scenario. For example, over the next 20 years, there is a 10-percent probability the actual growth rate will exceed the growth rate projected in the high scenario; additionally, it can be inferred that for the stated periods there is an 80 percent probability the actual growth rate will fall between the low and high scenarios.

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

**Table 2. Forecast probabilities**

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

This probabilistic analysis was applied to Idaho Power's system load forecast. Its impact on the system load forecast is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as special contracts (including past sales to Astaris, Inc.) and on-system contracts (including past sales to Raft River Coop and the City of Weiser).

Results of Idaho Power's system load projections are reported in Table 3 and shown in Figure 1. The expected-case system load-forecast growth rate averages 0.9 percent per year over the 20-year planning period. The low scenario projects the system load will increase at an average rate of 0.4 percent per year throughout the forecast period. The high scenario projects a load growth of 1.3 percent per year. Idaho Power has experienced both the high- and low-growth rates in the past. These forecasts provide a range of projected growth rates that cover approximately 80 percent of the probable outcomes as measured by Idaho Power's historical experience.

**Table 3. System load growth (aMW)**

| Growth | 2017 | 2021 | 2026 | 2036 | Annual Growth Rate 2017–2036 |
|---|---|---|---|---|---|
| Low | 1,748 | 1,765 | 1,810 | 1,891 | 0.4% |
| Expected | 1,810 | 1,894 | 1,990 | 2,142 | 0.9% |
| High | 1,835 | 1,968 | 2,111 | 2,351 | 1.3% |

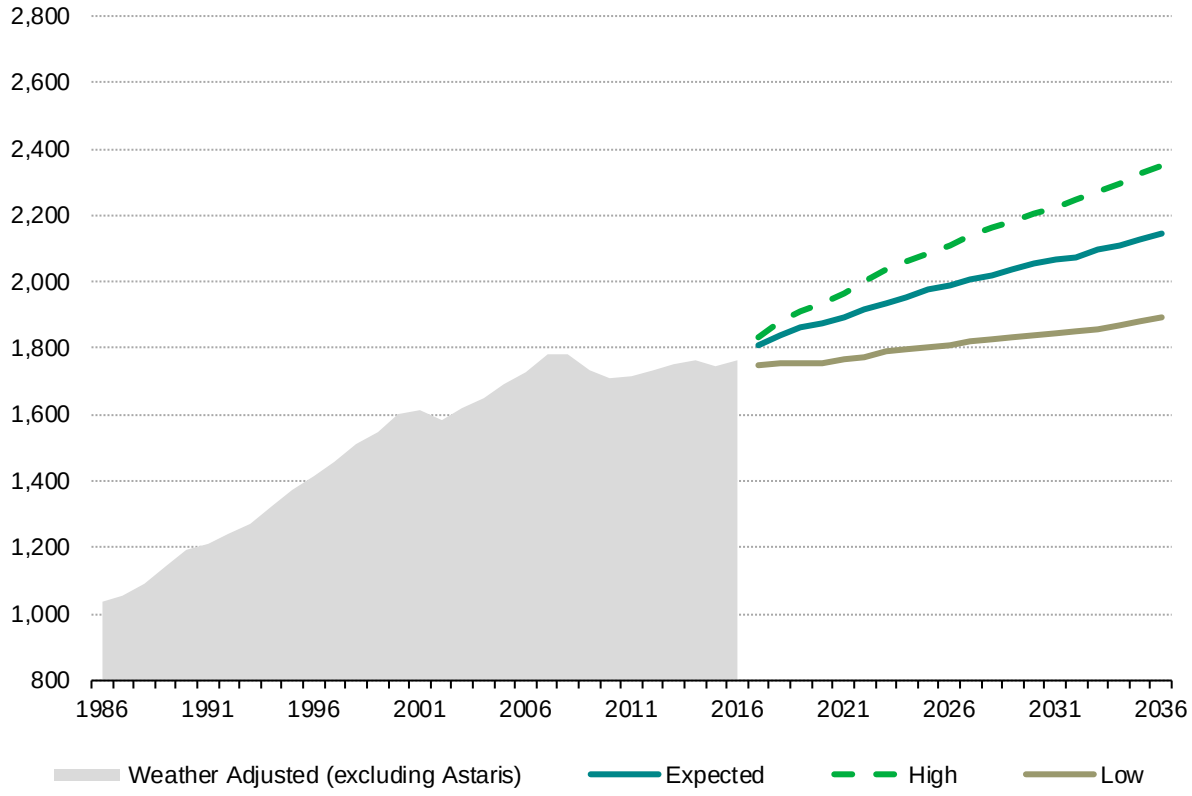



**Figure 1. Forecast system load (aMW)**

# RESIDENTIAL

The expected-case residential load is forecast to increase from 594 aMW in 2017 to 747 aMW in 2036, an average annual compound growth rate of 1.2 percent. In the 70th-percentile scenario, the residential load is forecast to increase from 612 aMW in 2017 to 772 aMW in 2036, matching the expected-case residential growth rate. The residential load forecasts are reported in Table 4 and shown in Figure 2.

**Table 4. Residential load growth (aMW)**

| Growth | 2017 | 2021 | 2026 | 2036 | Annual Growth Rate 2017–2036 |
|---|---|---|---|---|---|
| 90th Percentile | 643 | 681 | 730 | 810 | 1.2% |
| 70th Percentile | 612 | 648 | 695 | 772 | 1.2% |
| Expected Case | 594 | 628 | 673 | 747 | 1.2% |

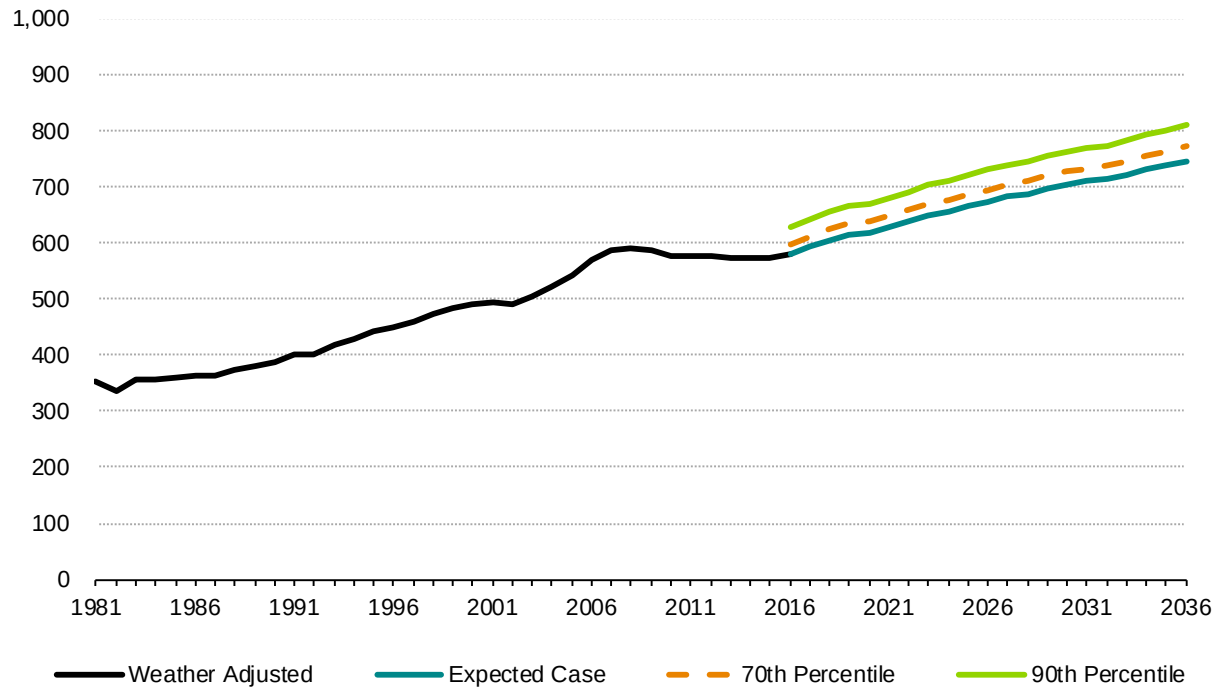



**Figure 2. Forecast residential load (aMW)**

Sales to residential customers made up 32 percent of Idaho Power's system sales in 1986 and 36 percent of system sales in 2016. The residential customer proportion of system sales is forecast to be approximately 38 percent in 2036. The number of residential customers is projected to increase to approximately 632,000 by December 2036.

The average sales per residential customer increased to over 14,700 kilowatt-hours (kWh) in 1980 before declining to 13,100 kWh in 2001. In 2002 and 2003, residential use per customer dropped dramatically—nearly 500 kWh per customer from 2001—the result of two years of significantly higher electricity prices in those years combined with a weak national and service-area economy. The reduction in electricity prices in June 2003 and a recovery in the service-area economy caused residential use per customer to stabilize through 2007. However, the recession in 2008 and 2009 and conservation efforts further reduced residential use per customer. This trend is expected to continue, as the average sales per residential customer are expected to decline to approximately 10,500 kWh per year in 2036. Average annual sales per residential customer are shown in Figure 3.

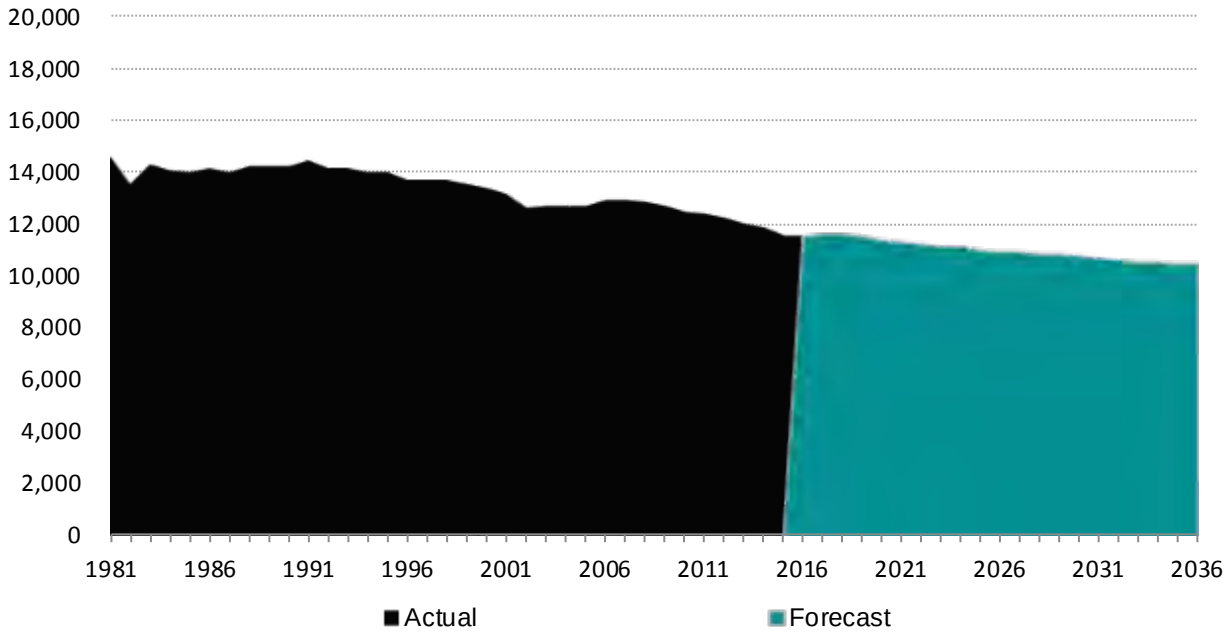



**Figure 3. Forecast residential use per customer (weather-adjusted kWh)**

Residential customer growth in Idaho Power's service area is a function of the number of new service-area households as derived from Moody's Analytics' May 2016 forecast of county housing stock and demographic data. The residential-customer forecast for 2017 to 2036 shows an average annual growth rate of 1.8 percent.

Sales to residential retail customers is an equation that considers several factors affecting electricity sales to the residential sector. Residential sales are a function of HDD (wintertime); CDD (summertime); the number of service-area households; the real price of electricity; and the real price of natural gas.

# COMMERCIAL

The commercial category is primarily made up of Idaho Power's small general-service and large general-service customers. Other customers associated with this category include unmetered general service, street-lighting service, traffic-control signal lighting service, and dusk-to-dawn customer lighting.

Within the expected-case scenario, the commercial load is projected to increase from 466 aMW in 2017 to 535 aMW in 2036 (Table 5). The average annual compound-growth rate of the commercial load is 0.7 percent during the forecast period. The commercial load in the 70$^{th}$-percentile scenario is projected to increase from 471 aMW in 2017 to 543 aMW in 2036. The commercial load forecasts are illustrated in Figure 4.

**Table 5. Commercial load growth (aMW)**

| Growth | 2017 | 2021 | 2026 | 2036 | Annual Growth Rate 2017–2036 |
|---|---|---|---|---|---|
| 90$^{th}$ Percentile | 480 | 498 | 517 | 556 | 0.8% |
| 70$^{th}$ Percentile | 471 | 489 | 507 | 543 | 0.7% |
| Expected Case | 466 | 482 | 500 | 535 | 0.7% |

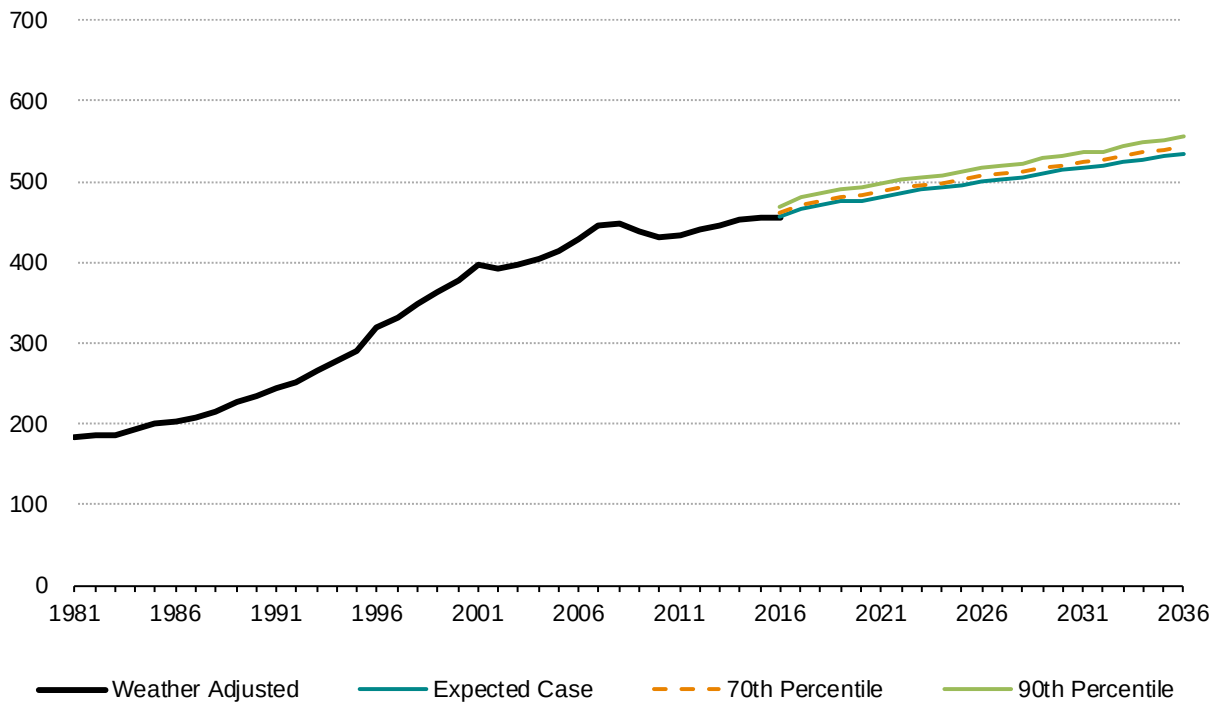



**Figure 4. Forecast commercial load (aMW)**

With a customer base of nearly 69,000, the commercial class represents the diversity of the service area economy, ranging from residential subdivision pressurized irrigation to

manufacturing. Due to this diversity, the category is further segmented into categories associated with common elements of energy-use influences, such as economic variables (e.g., employment), industry (e.g., manufacturing), and building structure characteristics (e.g., offices). Figure 5 shows the breakdown of the categories and their relative sizes based on 2016 billed energy sales.

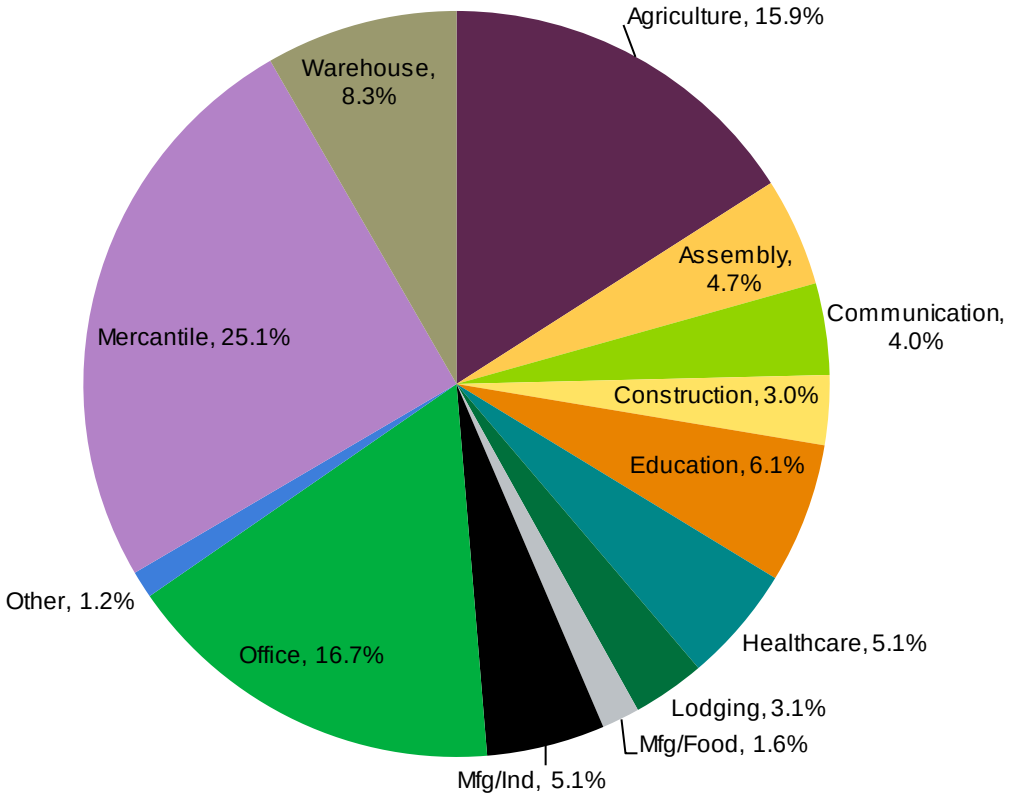



**Figure 5. Commercial building share—energy bills**

As indicated in Figure 5, the retail goods and service providers of the Mercantile category represent the largest commercial category of energy use, with 25.1% percent of total 2016 use. Total usage in this category has moderated, even considering the growth in total number of customers. This moderation is primarily due to customer consolidation, growth in internet-based sales, and energy efficient retrofit and new-construction technology implementation (particularly in the area of lighting) has grown. Categories showing significant post-recession (2011 to 2016) energy growth include Industrial/Manufacturing (+19.0%), Health Care (+19.2%), and Wholesale Trade (+17.6%).

The number of commercial customers is expected to increase at an average annual rate of 1.8 percent, reaching 97,500 customers by December 2036. The commercial customer forecast for 2017 to 2036 shows an average annual growth rate of 1.8 percent.

In 1986, customers in the commercial category consumed approximately 18 percent of Idaho Power system sales, growing to 28 percent by 2016. This share is forecast to remain at the upper end of this range throughout the planning period.

Figure 6 shows historical and forecast average use per customer (UPC) for the entire category. The commercial-use-per-customer metric in Figure 6 represents an aggregated metric for a highly diverse group of customers with significant differences in total energy use per customer, but it is instructive in aggregate for comparative purposes.

The UPC peaked in 2001 at 67,400 kWh and has declined at approximately 1.00 percent compounded annually to 2016. The UPC is forecast to decrease at an annual rate of 1.0 percent over the planning period. For this category, common elements that drive use down include increases in electricity prices, business-cycle recessions, and the adoption of energy efficiency technology. Within the commercial class UPC varies widely, reflecting the diversity of customer mix and range of operational size.

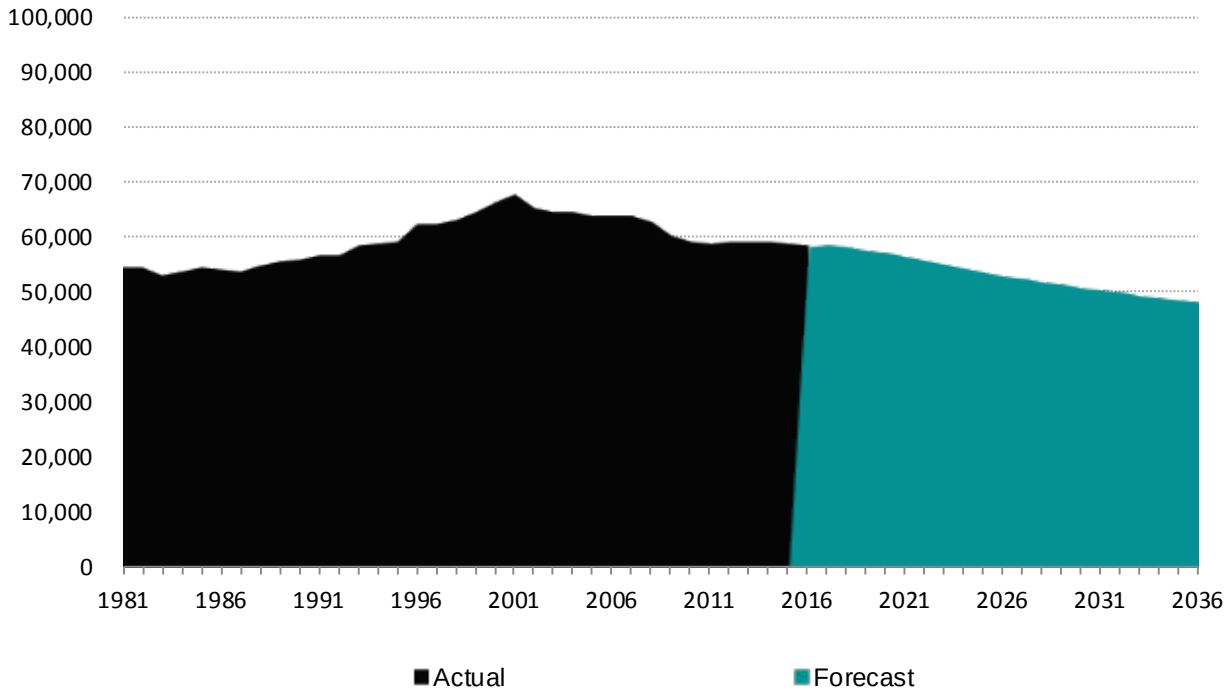



**Figure 6. Forecast commercial use per customer (weather-adjusted kWh)**

Figure 7 shows the diversity in the commercial segment's UPC as well as the trend for these sectors. The figure shows the 2016 UPC for each segment relative to the 2011 UPC. A value greater than 1.0 indicates the UPC has risen over the period. The figure supports the general decline of the aggregated trend of Figure 6 but highlights differences in energy and economic dynamics within the heterogeneous commercial category not evident in the residential category.

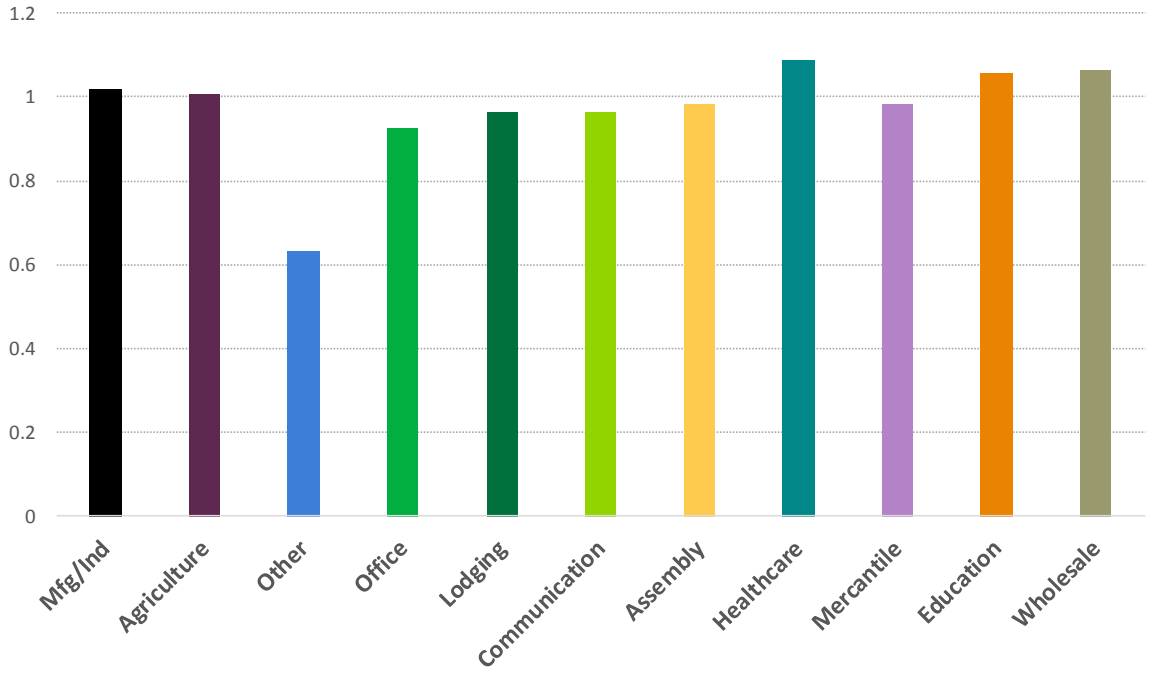



**Figure 7. Commercial categories UPC, 2016 relative to 2011**

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

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

# IRRIGATION

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

The expected-case irrigation load is forecast to increase slowly from 221 aMW in 2017 to 246 aMW in 2036, an average annual compound growth rate of 0.6 percent. The expected-case, 70$^{th}$-percentile, and 90$^{th}$-percentile scenarios forecast slow growth in irrigation load from 2017 to 2036. In the 70$^{th}$-percentile scenario, irrigation load is projected to be 235 aMW in 2017 and 260 aMW in 2036. The individual irrigation load forecasts are summarized in Table 6 and illustrated in Figure 8.

**Table 6. Irrigation load growth (aMW)**

| Growth | 2017 | 2021 | 2026 | 2036 | Annual Growth Rate 2017–2036 |
|---|---|---|---|---|---|
| 90$^{th}$ Percentile | 254 | 259 | 266 | 279 | 0.5% |
| 70$^{th}$ Percentile | 235 | 240 | 247 | 260 | 0.5% |
| Expected Case | 221 | 226 | 233 | 246 | 0.6% |

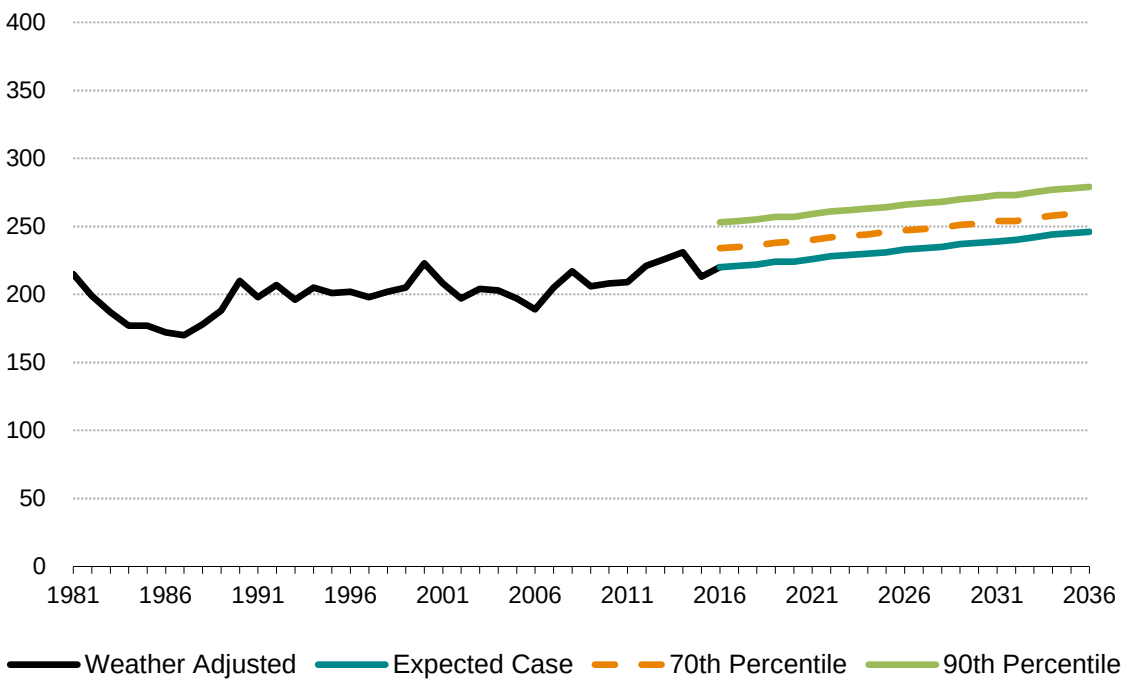



**Figure 8. Forecast irrigation load (aMW)**

The annual average loads in Table 6 and Figure 8 are calculated using the 8,760 hours in a typical year. In the highly seasonal irrigation sector, over 97 percent of the annual energy is

billed during the six months from May through October, and nearly half of the annual energy is billed in just two months, July and August. During the summer, hourly irrigation loads can reach nearly 900 MW. In a normal July, irrigation pumping accounts for roughly 25 percent of the energy consumed during the hour of the annual system peak and nearly 30 percent of the energy consumed during July for general business sales. The 2017 irrigation sales forecast is higher than the 2015 IRP forecast throughout the forecast period due to the trend toward more water-intensive crops, primarily alfalfa and corn, due to growth in the dairy industry. Also, farmers have put high-lift acreage back into production. Additionally, the increased customer count from the conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to farmers trying to reduce labor costs, explains most of the increased energy consumption in recent years.

The 2017 irrigation sales forecast model considers several factors affecting electricity sales to the irrigation class, including temperature; precipitation; spring rainfall; Palmer Z Index (calculated by the National Ocean and Atmospheric Administration [NOAA] from a combination of precipitation, temperature, and soil moisture data); Moody's Gross Product*: Agriculture, for Idaho*; *Moody's Producer Price Index: Prices Received by Farmers, All Farm Products*; and the real price of electricity. Considerations were made for the unusually low electricity consumption in the 2001 crop year due to a voluntary load-reduction program.

Actual irrigation electricity sales have grown from the 1970 level of 816,000 megawatt-hours (MWh) to a peak amount of 2,097,000 MWh in 2013. In 1977, irrigation sales reached a maximum proportion of 20 percent of Idaho Power system sales. In 2016, the irrigation proportion of system sales was 14 percent due to the much higher relative growth in other customer classes. By 2036, irrigation customers are projected to consume about 12 to 13 percent of Idaho Power system sales.

Regarding customer growth, in 1980, Idaho Power had about 10,850 active irrigation accounts. By 2016, the number of active irrigation accounts had increased to 20,042 and is projected to be nearly 26,000 at the end of the planning period in 2036.

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

# INDUSTRIAL

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

In 1980, Idaho Power had about 112 industrial customers, which represented about 12 percent of Idaho Power's system sales. By December 2016, the number of industrial customers had risen to 118, representing approximately 17 percent of system sales. As mentioned earlier in the commercial discussion, customer counts in this tariff class are impacted by migration from and to the commercial class as dictated by the tariff rules. However, generally speaking, customer count growth is primarily illustrative of the positive economic conditions in the service area. Customers with load greater than Schedule 19 ranges are known as special contract customers and are addressed in the Additional Firm Load section of this document.

In the expected-case forecast, industrial load grows from 281 aMW in 2017 to 320 aMW in 2036, an average annual growth rate of 0.7 percent (Table 7). To a large degree, industrial load variability is not associated with weather conditions as is the case with residential, commercial, and irrigation; therefore, the forecasts in the 70$^{th}$- and 90$^{th}$-percentile weather scenarios are identical to the expected-case industrial load scenario. The industrial load forecast is pictured in Figure 9.

**Table 7. Industrial load growth (aMW)**

| Growth | 2017 | 2021 | 2026 | 2036 | Annual Growth Rate 2017–2036 |
|---|---|---|---|---|---|
| Expected Case | 281 | 297 | 305 | 320 | 0.7% |

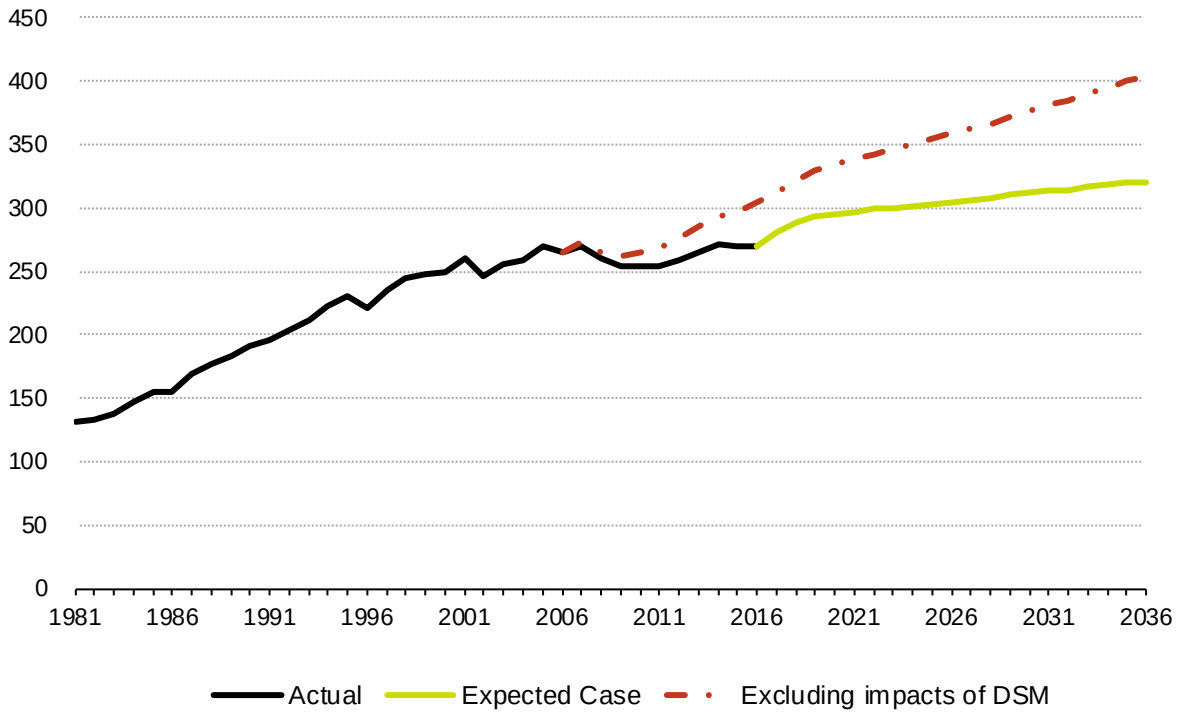



**Figure 9. Forecast industrial load (aMW)**

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

Figure 10 illustrates the 2016 share of each of the categories within the Rate 19 customers. By far, the largest share of electricity was consumed by the food manufacturing sector (36%), followed by dairy (18.7%) and electronics/technology (Electech) (7%). The categorization scheme includes a range of industrial building types (assembly, lodging, mercantile, warehouse, office, education, health care). These provide the basis for capturing, modeling, and forecasting the shifting economic landscape that influences industrial category electricity sales.

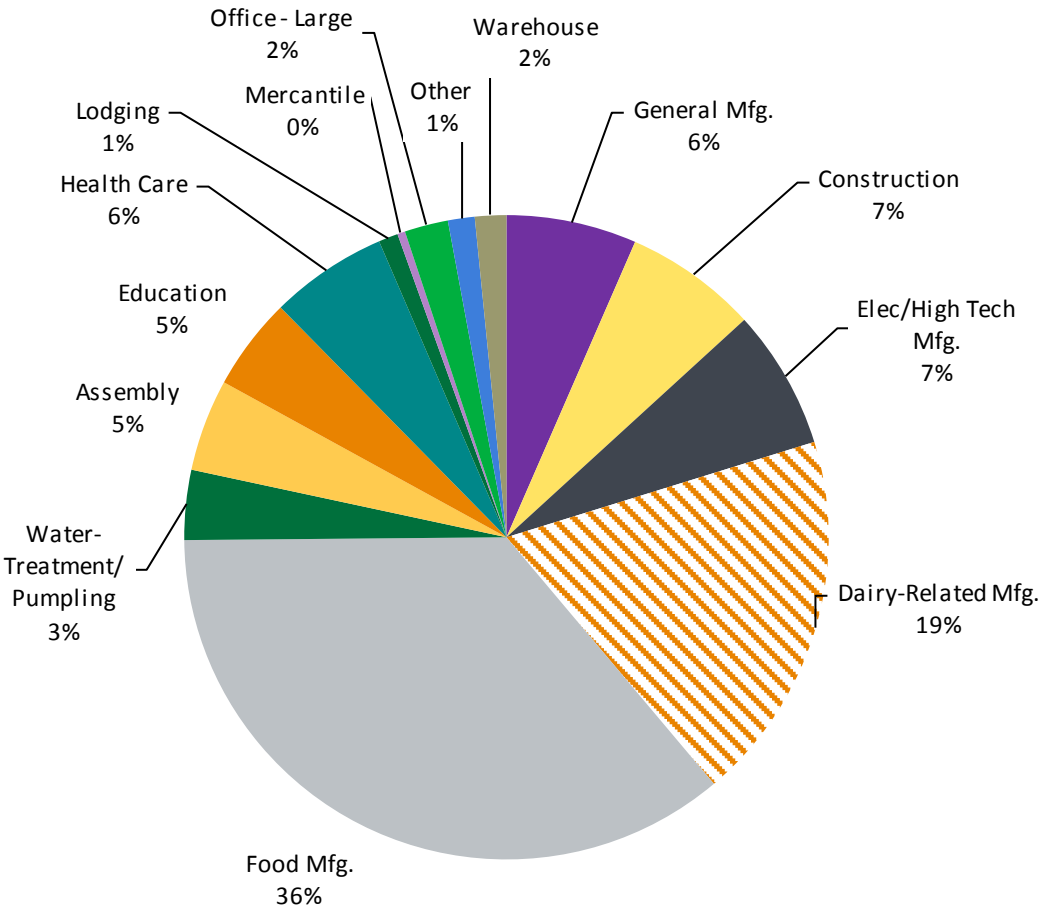



**Figure 10. Industrial electricity consumption by industry group (based on 2016 sales)**

The regression models and associated explanatory variables resulting from the categorization establish the relationship between historical electricity sales and historical independent economic, price, technological, demographic, and other influences in the form of estimated coefficients from the industry group regression models applied to the appropriate forecasts of independent time series of energy use. From this output, the history and forecast of DSM is subtracted.

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# ADDITIONAL FIRM LOAD

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

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

In the expected-case forecast, additional firm load is expected to increase from 108 aMW in 2017 to 124 aMW in 2036, an average growth rate of 0.7 percent per year over the planning period (Table 8). The additional firm load energy and demand forecasts in the 70$^{th}$- and 90$^{th}$-percentile scenarios are identical to the expected-load growth scenario. The scenario of projected additional firm load is illustrated in Figure 11.

**Table 8. Additional firm load growth (aMW)**

| Growth | 2017 | 2021 | 2026 | 2036 | Annual Growth Rate 2017–2036 |
|---|---|---|---|---|---|
| Expected Case..... | 108 | 112 | 124 | 124 | 0.7% |

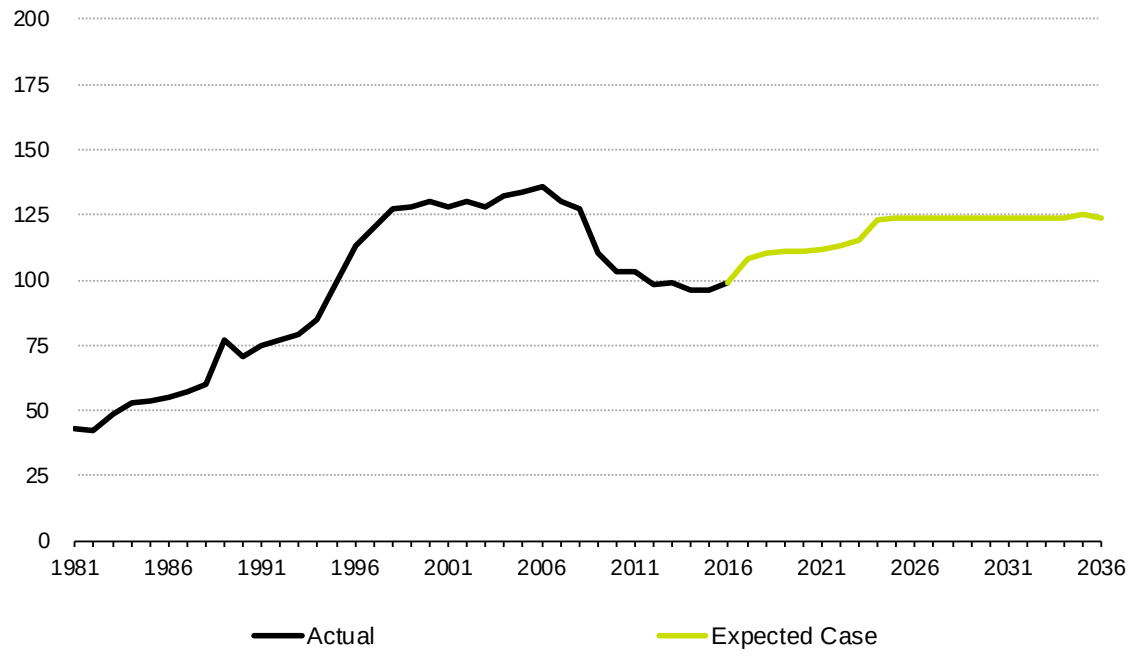



**Figure 11. Forecast additional firm load (aMW)**

## Micron Technology

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

## Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western United States (US). The future electricity usage at the plant is expected to grow slowly through 2016, then stay flat throughout the remainder of the planning period.

## Idaho National Laboratory

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

# ENERGY EFFICIENCY AND DEMAND RESPONSE

Energy efficiency and demand response impacts are treated differently in the forecasting and planning process. Energy efficiency impacts (reductions in energy use) are explicitly integrated into the forecast models. Demand response impacts are explicitly *excluded* from the forecast models; the impacts of demand response are modeled in the load and resource balance as a supply-side resource for reducing peak-demand periods.

## Energy Efficiency

Energy efficiency (EE) influences on past and future load consist of utility programs, statutory codes, and manufacturing standards for appliances, equipment, and building materials that reduce energy consumption. As the influence of statutory codes and manufacturing standards on residential and commercial customers has increased in importance relative to utility programs, Idaho Power forecast models have been modified to ensure they capture these influences. For residential models, the physical unit flow of energy-efficient products is captured through shipment data to resellers and installers. The source for this data is the DOE (the data also serves as input to the DOE National Energy Model [NEM]), and the data is refined by Itron for utility-specific applications. This data captures energy-efficient installations regardless of the source (e.g., programs, standards, and codes). However, Idaho Power closely monitors the assumptions and impacts of DOE data to ensure the model correctly captures all energy efficiency impacts.

Energy Efficiency data for irrigation customers and some commercial and industrial customers is not directly surveyed and collected by the DOE; therefore, models for efficiency impacts have been developed derived from methodologies established in Itron's white paper, *Incorporating DSM into the Load Forecast*.[2] These approaches include; isolating historical efficiency data and removing the impacts from historical sales (as previously discussed in application to the industrial customers); applying historical and forecast EE as an independent variable in the regression model (this method was utilized for the commercial customers); and marginal comparison of DSM growth rates for historical versus forecast trend. If there is a significant change in future trends (i.e., trends unseen by the regression model of historical energy and conservation trends), the forecast output is adjusted to realize the trend change embedded in the regression output. These alternate models utilize energy efficiency data provided by Idaho Power's internal DSM group. The DSM group develops an independent energy efficiency/DSM forecast in collaboration with AEG consultants. This data served as direct input into the commercial, industrial, and irrigation models. The forecast developed by Idaho Power coincides

[2] Stuart McMenamin and Mark Quan. *Incorporating DSM into the Load Forecast*. Itron, https://www.itron.com/na/PublishedContent/Incorporating%20DSM%20into%20the%20Load%20Forecast.pdf (accessed February 3, 2011).

with models that AEG developed. Output for all category forecasts are compared to the AEG output as well as data from DOE Form 861 of utility-reported data. Data from regional utility acquisition is compared to Idaho Power data to ensure the regional assumptions are consistent with Idaho Power assumptions in capturing all energy savings.

Energy savings from utility energy efficiency programs are typically measured and reported at the point of delivery (customer's meter). Therefore, energy efficiency savings are increased by the amount of energy lost in transmitting the electricity from the generation source to the customer's meter.

## Demand Response

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

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

A thorough description of each of the energy efficiency and demand response programs is included in *Appendix B—Demand Side Management 2016 Annual Report*.

# COMPANY SYSTEM PEAK

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

The all-time system summer peak demand was 3,407 MW, recorded on Tuesday, July 2, 2013, at 4:00 p.m. That record was approached when the peak demand reached 3,402 MW on Tuesday, June 30, 2015, at 4:00 p.m. The system summer peak load growth accelerated from 1998 to 2008 as a record number of residential, commercial, and industrial customers were added to the system and air conditioning (A/C) became standard in nearly all new residential homes and new commercial buildings.

Idaho Power has two peak periods: 1) a winter peak, resulting primarily from space-heating demand that normally occurs in December, January, or February and 2) a larger summer peak that normally occurs in late June or July, which coincides with cooling load and irrigation pumping demand.

For resource planning purposes in the 95$^{th}$-percentile forecast, the system summer peak load is expected to increase from 3,586 MW in 2017 to 4,641 MW in 2036. In the 90$^{th}$-percentile forecast, the system summer peak load is expected to increase from 3,566 MW in 2017 to 4,613 MW in 2036, an average growth rate of 1.4 percent per year over the planning period (Table 9).

**Table 9. System summer peak load growth (MW)**

| Growth | 2017 | 2021 | 2026 | 2036 | Annual Growth Rate 2017–2036 |
|---|---|---|---|---|---|
| 95$^{th}$ Percentile | 3,586 | 3,819 | 4,102 | 4,641 | 1.4% |
| 90$^{th}$ Percentile | 3,566 | 3,797 | 4,078 | 4,613 | 1.4% |
| 50$^{th}$ Percentile | 3,446 | 3,668 | 3,937 | 4,449 | 1.4% |

The three scenarios of projected system summer peak loads are illustrated in Figure 12. Much of the variation in peak load is due to weather conditions. Although not entirely, unique economic events as occurred in the summer of 2001, when the summer peak was dampened by the nearly 30-percent curtailment in irrigation load due to the 2001 voluntary load-reduction program.

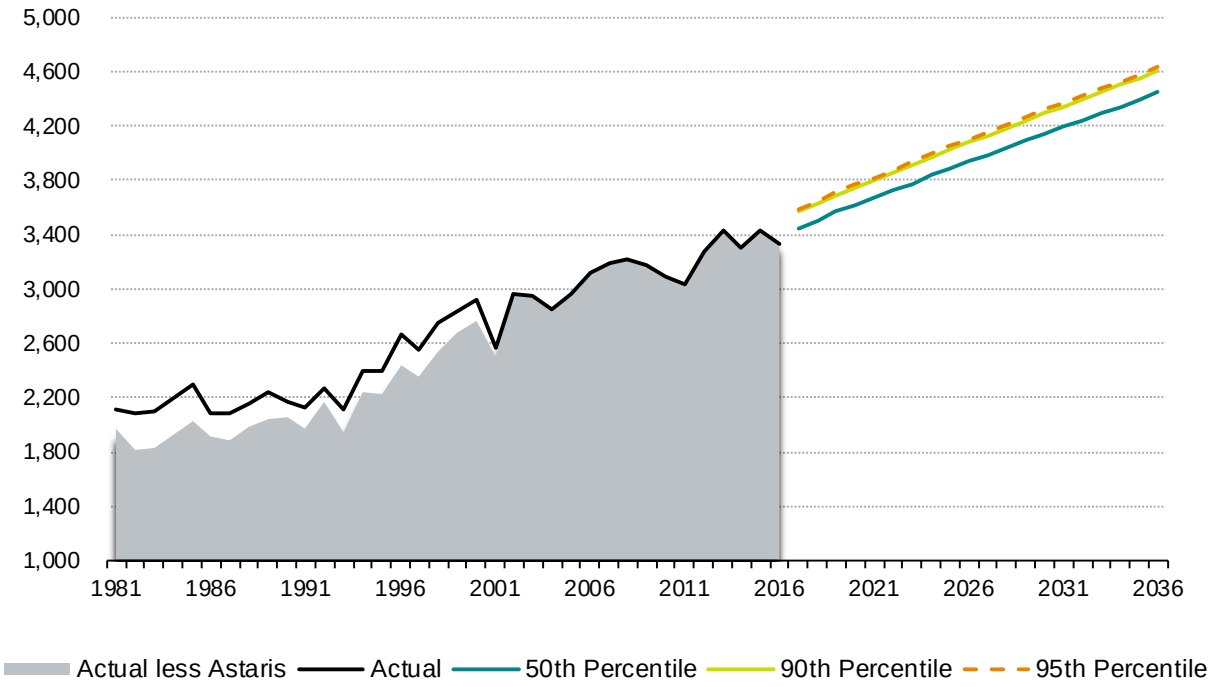



**Figure 12. Forecast system summer peak (MW)**

As of December 31, 2016, the all-time system winter peak demand was 2,527 MW, reached on Thursday, December 10, 2009, at 8:00 a.m. and January 06, 2017, at 9:00am. As shown in Figure 13, the historical system winter peak load is much more variable than the summer system peak load. This is because the variability of peak-day temperatures in winter months is more significant than the variability of peak-day temperatures in summer months. The wider spread of the winter peak forecast lines in Figure 13 illustrates the higher variability associated with winter peak-day temperatures.

For resource planning purposes, 95$^{th}$-percentile forecast, the system winter peak load is expected to increase from 2,611 MW in 2017 to 2,896 MW in 2036, an average growth rate of 0.5 percent per year over the planning period (Table 10). In the 90$^{th}$-percentile forecast, the system winter peak load is expected to increase from 2,517 MW in 2017 to 2,846 MW in 2036, an average growth rate of 0.9 percent per year over the planning period (Table 10). The three scenarios of projected system winter peak load are illustrated in Figure 13.[3]

[3] Idaho Power uses a median peak-day temperature driver in lieu of an average peak-day temperature driver in the 50/50 peak-demand forecast scenario. The median peak-day temperature has a 50-percent probability of being exceeded. Peak-day temperatures are not normally distributed and can be skewed by one or more extreme observations; therefore, the median temperature better reflects expected temperatures within the context of probabilistic percentiles. The weighted average peak-day temperature drivers are calculated over the 1986 to 2015 time period (the most recent 30 years).

**Table 10. System winter peak load growth (MW)**

| Growth | 2017 | 2021 | 2026 | 2036 | Annual Growth Rate 2017–2036 |
|---|---|---|---|---|---|
| 95th Percentile | 2,611 | 2,691 | 2,769 | 2,896 | 0.5% |
| 90th Percentile | 2,517 | 2,596 | 2,675 | 2,846 | 0.7% |
| 50th Percentile | 2,294 | 2,415 | 2,534 | 2,732 | 0.9% |

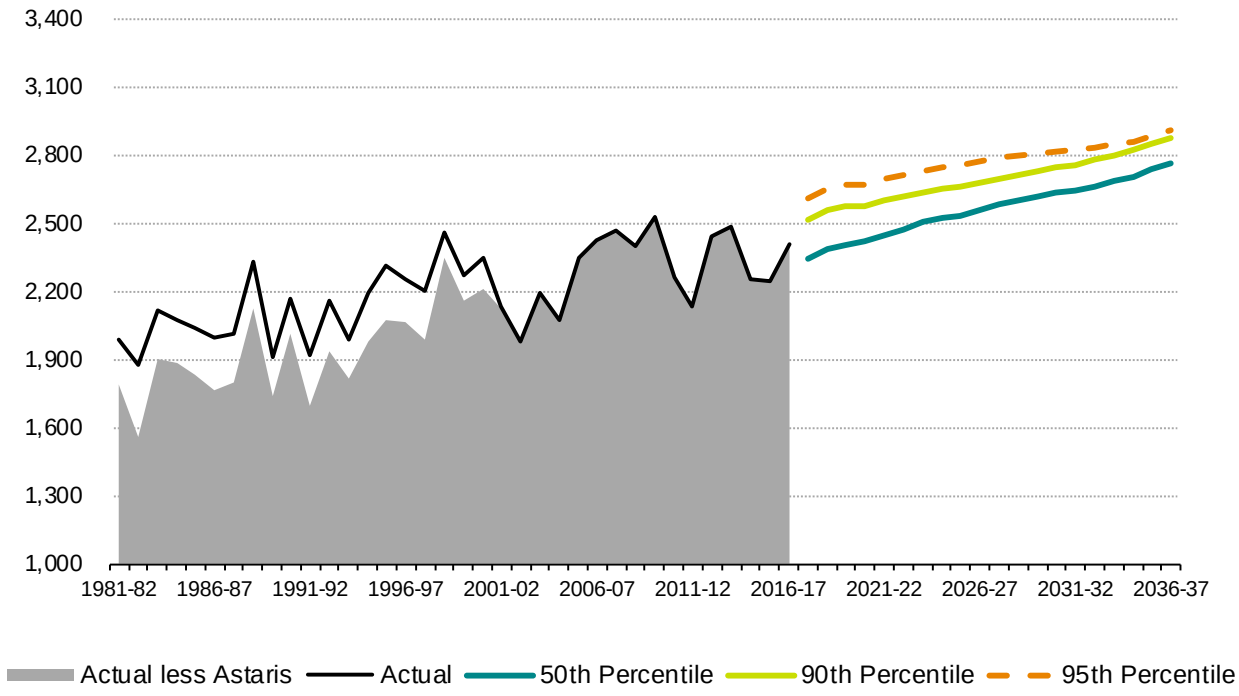



**Figure 13. Forecast system winter peak (MW)**

Additionally, note the 2017 IRP peak-demand forecast model explicitly excludes the impact of demand response programs to establish peak impacts. The exclusion allows for planning for demand response programs and supply-side resources in meeting peak demand. Demand response program impacts are accounted for in the IRP load and resource balance and are reflected as a reduction in peak demand.

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# COMPANY SYSTEM LOAD

System load is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as special contracts (including past sales to Astaris) and on-system contracts (including past sales to Raft River and the City of Weiser). The system load excludes all long-term, firm, off-system contracts.

The expected-case system load forecast is based on the output of the regression and forecasting models referenced previously and represents Idaho Power's most probable load growth during the planning period. The expected-case forecast system load growth rate averages 0.9 percent per year from 2017 to 2036. Company system load projections are reported in Table 11 and shown in Figure 14.

In the expected-case forecast, the company system load is expected to increase from 1,810 aMW in 2017 to 2,142 aMW in 2036. In the 70$^{th}$-percentile forecast, the company system load is expected to increase from 1,853 aMW in 2017 to 2,193 aMW by 2036, an average growth rate of 0.9 percent per year over the planning period (Table 11).

**Table 11. System load growth (aMW)**

| Growth | 2017 | 2021 | 2026 | 2036 | Annual Growth Rate 2017–2036 |
|---|---|---|---|---|---|
| 90$^{th}$ Percentile | 1,917 | 2,006 | 2,108 | 2,269 | 0.9% |
| 70$^{th}$ Percentile | 1,853 | 1,939 | 2,037 | 2,193 | 0.9% |
| Expected Case | 1,810 | 1,894 | 1,990 | 2,142 | 0.9% |

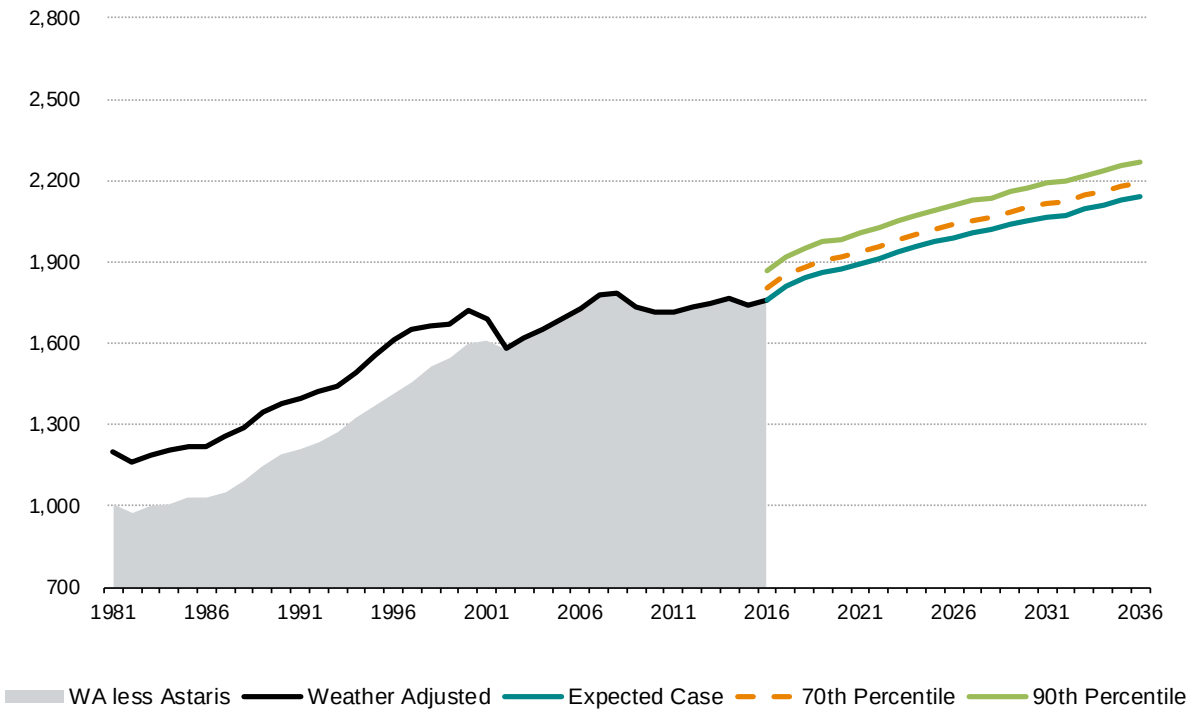



**Figure 14. Forecast system load (aMW)**

The system load, excluding Astaris[4], portrays the current underlying general business growth trend within the service area. However, the system load with Astaris is instructive in regard to the impact of a new large-load customer on system load. As noted previously, the forecast excludes any such prospective large-load customers.

Accompanied by an outlook of moderate economic growth for Idaho Power's service area throughout the forecast period, continued growth in Idaho Power's system load is projected. Total load is made up of system load plus long-term, firm, off-system contracts. At this time, there are no contracts in effect to provide long-term, firm energy off-system.

The composition of system company electricity sales by year is shown in Figure 15. Residential sales are forecast to be nearly 26 percent higher in 2036, gaining 1.4 million MWh over 2017. Commercial sales are also expected to be 15 percent higher, or 0.6 million MWh, than in 2017, followed by industrial (15 percent higher, or 0.4 million additional MWh) and irrigation (12 percent higher in 2036 than 2017).

[4] The Astaris elemental phosphorous plant (previously FMC) was located at the western edge of Pocatello, Idaho. Although no longer a customer of Idaho Power, Astaris had been Idaho Power's largest individual customer and, in some years, averaged nearly 200 aMW each month. In April 2002, the special contract between Astaris and Idaho Power was terminated.

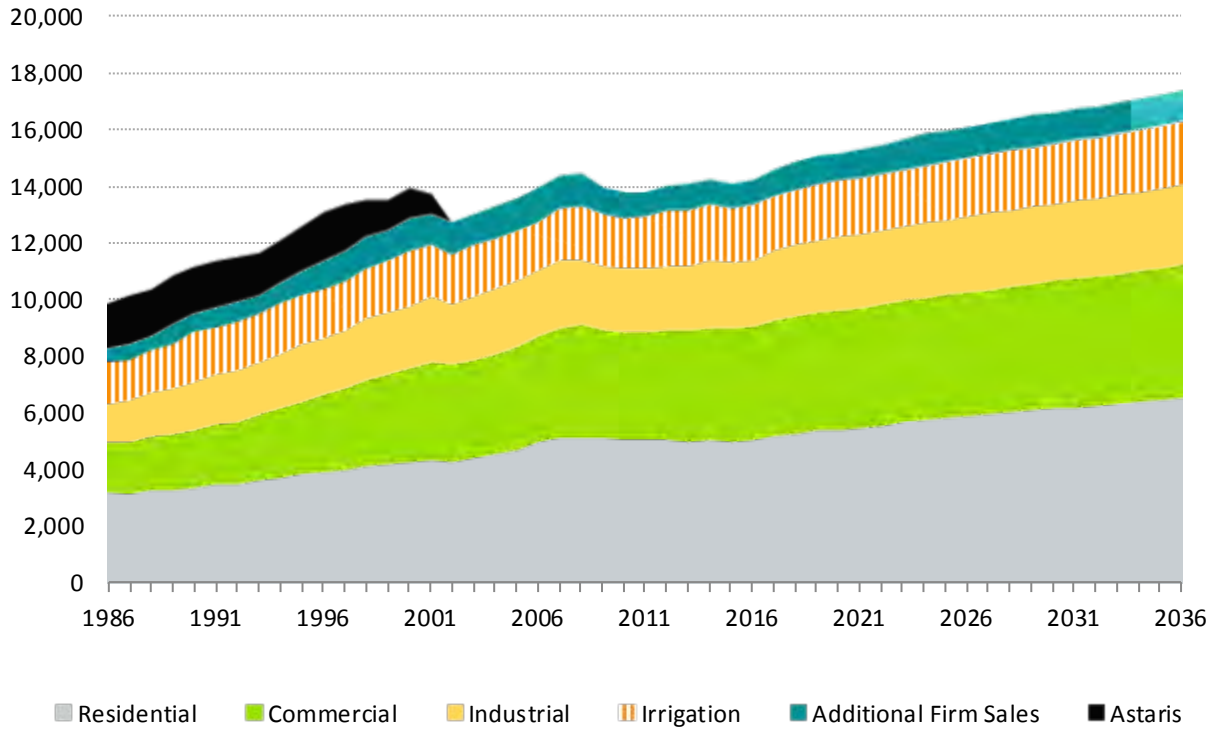



**Figure 15. Composition of system company electricity sales (thousands of MWh)**

## Fuel Prices

Fuel prices, in combination with service-area demographic and economic drivers, impact long-term trends in electricity sales. Changes in relative fuel prices can also impact the future demand for electricity. Class-level and economic-sector-level regression models were used to identify the relationships between real historical electricity prices and their impact on historical electricity sales. The estimated coefficients from these models were used as drivers in the individual sales forecast models.

Short-term and long-term nominal electricity price increases are generated internally from Idaho Power financial models. The US Energy Information Administration (EIA) provides the forecasts of long-term changes in nominal natural gas prices. The nominal price estimates are adjusted for projected inflation by applying the appropriate economic deflators to arrive at real fuel prices. The projected average annual growth rates of fuel prices in nominal and real terms (adjusted for inflation) are presented in Table 12. The growth rates shown are for residential fuel prices and can be used as a proxy for fuel-price growth rates in the commercial, industrial, and irrigation sectors.

**Table 12. Residential fuel-price escalation (2017–2036) (average annual percent change)**

| | Nominal | Real* |
|---|---|---|
| Electricity—2017 IRP | 1.2% | -0.7% |
| Electricity—2015 IRP | 2.0% | 0.0% |
| Natural Gas | 3.7% | 1.7% |

* Adjusted for inflation

Figure 16 illustrates the average electricity price paid by Idaho Power's residential customers over the historical period 1980 to 2016 and over the forecast period 2017 to 2036. Both nominal and real prices are shown. In the 2017 IRP, nominal electricity prices are expected to climb to about 13 cents per kWh by the end of the forecast period in 2036. Real electricity prices (inflation adjusted) are expected to decline over the forecast period at an average rate of 0.7 percent annually. In the 2015 IRP, nominal electricity prices were assumed to climb to about 15 cents per kWh by 2036, and real electricity prices (inflation adjusted) were expected to remain flat over the forecast period at an average rate of 0.0 percent annually.

The electricity price forecast used to prepare the sales and load forecast in the 2017 IRP reflected the additional plant investment and variable costs of integrating the resources identified in the 2015 IRP preferred portfolio. When compared to the electricity price forecast used to prepare the 2015 IRP sales and load forecast, the 2017 IRP price forecast yielded lower future prices. The retail prices are more evidently lower in the second 10 years of the planning period and impact the sales forecast positively, a consequence of the inverse relationship between electricity prices and electricity demand.

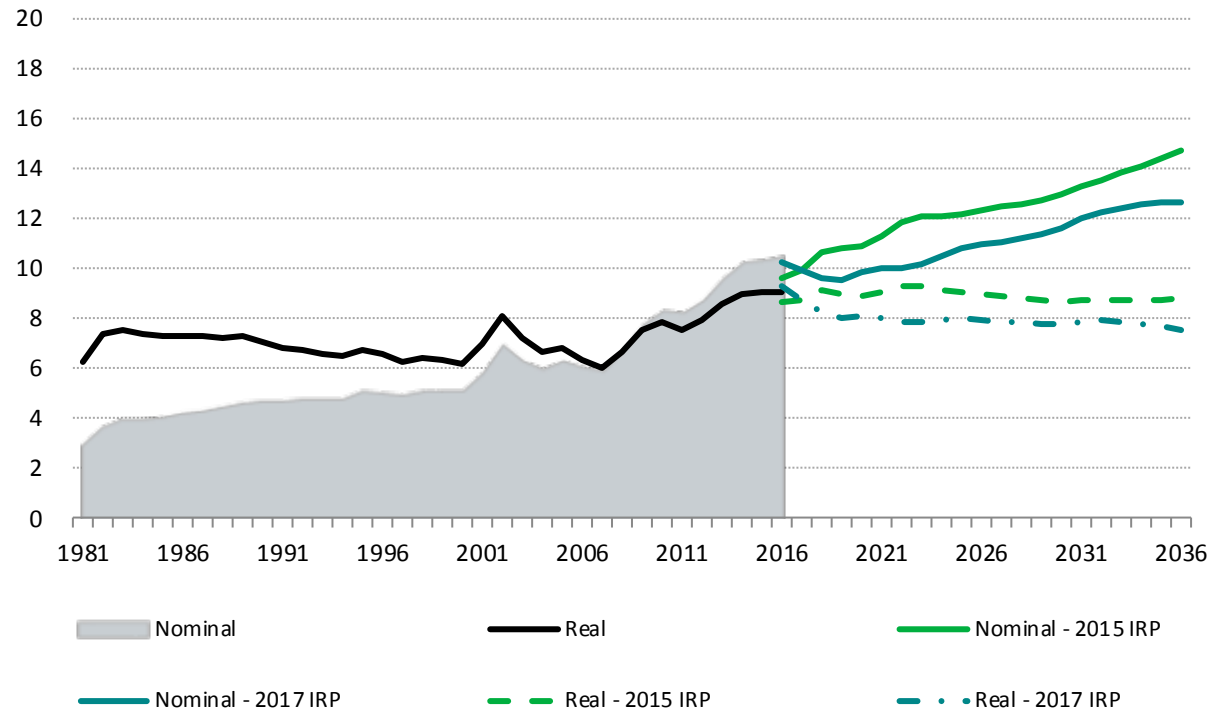



**Figure 16. Forecast residential electricity prices (cents per kWh)**

Electricity prices for Idaho Power customers increased significantly in 2001 and 2002 because of the power cost adjustment (PCA) impact on rates, a direct result of the western US energy crisis of 2000 and 2001. Prior to 2001, Idaho Power's electricity prices were historically quite stable. From 1990 to 2000, nominal electricity prices rose only 8 percent overall, an annual average compound growth rate of 0.8 percent annually. More recently, over the period 2006 to 2016, nominal electricity prices rose 72 percent overall, an annual average compound growth rate of 5.6 percent annually.

Figure 17 illustrates the average natural gas price paid by Intermountain Gas Company's residential customers over the historical period 1981 to 2015 and forecast prices from 2016 to 2036. Natural gas prices remained stable and flat throughout the 1990s before moving sharply higher in 2001. Since spiking in 2001, natural gas prices moved downward for a couple of years before moving sharply upward in 2004 through 2006. Since 2006, natural gas prices have declined about 30 percent, compared to 2015. Nominal natural gas prices are initially expected to drop by 8 percent in 2016, then rise at a steady pace throughout the remainder of the forecast period until more than doubling by 2036, growing at an average rate of 3.7 percent per year. Real natural gas prices (adjusted for inflation) are expected to increase over the same period at an average rate of 1.7 percent annually.

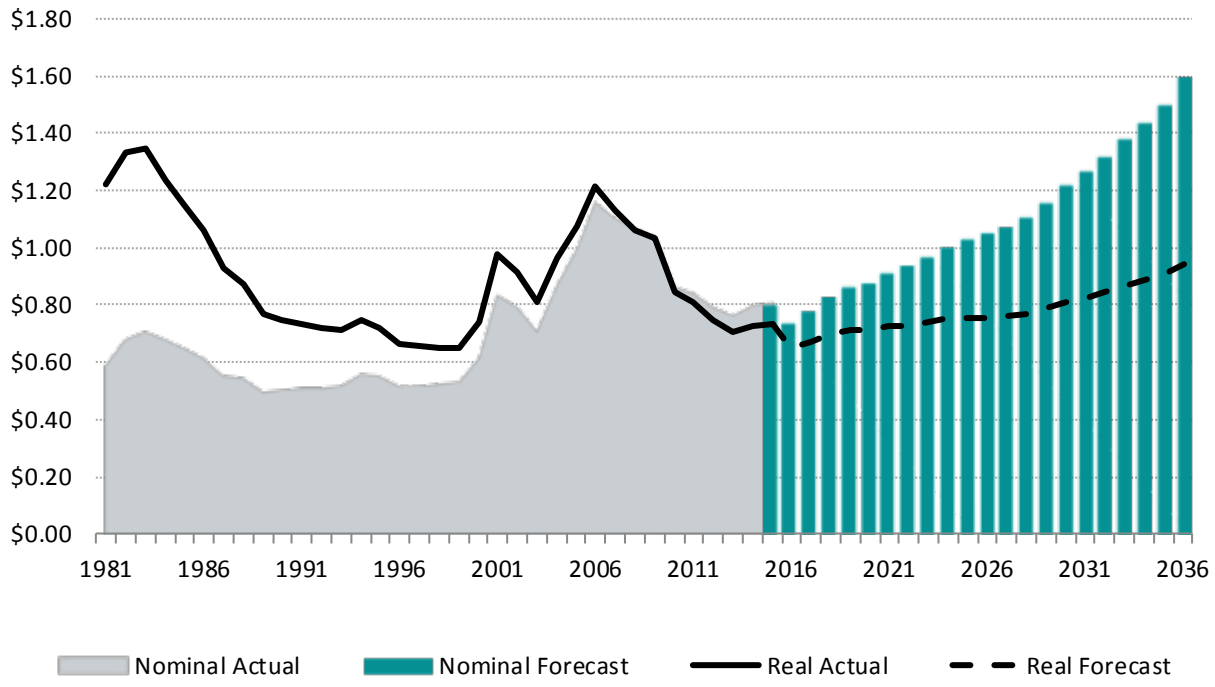



**Figure 17. Forecast residential natural gas prices (dollars per therm)**

If future natural gas price increases outpace electricity price increases, the operating costs of space heating and water heating with electricity would become more advantageous when compared to that of natural gas. However, in the 2017 IRP price forecast, the long-term growth rates of electricity and natural gas prices are nearly identical.

## Electric Vehicles

The load forecast includes an update of the impact of plug-in electric vehicles (PEV) on system load to reflect the future impact of this relatively new and evolving source of energy use. While PEV consumer adoption rates in Idaho Power's service area remain relatively low, with continued technological advancement, limiting attributes of vehicle range and re-fueling time continue to improve the competitiveness of these vehicles to non-electric models.

Since the first introduction of the Chevy Volt and Nissan Leaf, the number of PEVs offered in the marketplace has proliferated to over 50 models since 2007. Early in this period, PEVs were sold with unique model names (e.g., VOLT); however, as the market grows, the plug-in technology is increasingly offered as an option to existing models (e.g., Ford Focus).

Initially, the Idaho Power forecast for PEV impact relied on third-party forecasts from the Electric Power Research Institute (EPRI) and Oak Ridge National Laboratory due to a lack of service-area vehicle registration data; however, beginning with the 2011 IRP,

sufficient service-area data became available via vehicle registration data provided by the Idaho Transportation Department (ITD). This data provides a basis from which to develop service-area adoption rates and support the collection of charging behavior. The methodology continues to integrate the fuel and technology share forecasts of the DOE's NEM. The Idaho Power vehicle share forecast uses these models as well as a Bass consumer adoption model as informed by registration data. Load impacts from the share model output are derived from assumptions of battery-only and hybrid plug-in shares evident from Idaho Power observations and informed by the DOE.

Currently, the registration data collection methodology is being revised to capture vehicles sold with PEV technology as an option (e.g., Ford Focus). The methodology will require the unique string of characters within the vehicle identification number (VIN) to be identified and serve as a key value in the ITD data extraction.

The PEV forecast in the IRP did include registration data for the Toyota Prius PEV but did not capture all models for which PEV technology is sold as an option; however, to capture the impact of these models on future adoption, the forecast used the forecast national share assumptions from the DOE. The net effect was to rely less on the registration data than the 2015 IRP model and more on third-party assumptions, as was the case in earlier forecasts.

## Net Metering

In recent years, the number of customers signing up for net-metering service (Schedule 84) has raised dramatically, especially for residential customers. Currently, there are approximately 900 residential and 100 commercial net-metering customers. While the recent adoption of solar is relatively strong for our service area, the current population of net-metering customers comprises around one-fifth of 1 percent of the population of retail customers.

The installation of generating and storage equipment at customer sites will cause the demand for electricity delivered by Idaho Power to be reshaped throughout the year. It is important to measure the overall and future impact on the sales forecast. Therefore, this year's long term sales forecast was adjusted downward to reflect the impact of the increase in the number of net-metering customers, specifically solar, connecting to our system.

Schedule 84 (net-metering) customer billing histories were compared to billing histories prior to said customer becoming a net-metering customer. The resulting average monthly impact-per-customer (in kWh) was then multiplied by a forecast of the Schedule 84 residential and commercial customer count to estimate the future energy impact on the sales forecast. The forecast of net metering customers serves as a function of historical trends and current policy considerations.

The resulting forecast of net-metering customers multiplied by the estimated use-per-customer sales impact per customer resulted in a monthly downward adjustment to the sales forecast for each class. At the end of the forecast period, 2036, the annual residential sales reduction was about 18 aMW, and the commercial reduction was less than 1 aMW.

# OTHER CONSIDERATIONS

Since the residential, commercial, irrigation, and industrial sales forecasts provide a forecast of sales as billed, it is necessary to adjust these billed sales to the proper time frame to reflect the required generation needed in each calendar month. To determine calendar-month sales from billed sales, the billed sales must first be converted from billed periods to calendar months to synchronize them with the time period in which load is generated. The calendar-month sales are then converted to calendar-month average load by adding losses and dividing by the number of hours in each month.

Loss factors are determined by Idaho Power's Transmission Planning department. The annual average energy loss coefficients are multiplied by the calendar-month load, yielding the system load, including losses. A system loss study of 2012 was completed in May 2014. The results of the study concluded that on average, the revised loss coefficients were lower than those applied to generation forecasts developed prior to the 2015 IRP and were used in the development of the 2017 IRP sales and load forecast. This resulted in a one-time permanent reduction of nearly 20 aMW to the load forecast annually.

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# CONTRACT OFF-SYSTEM LOAD

The contract off-system category represents long-term contracts to supply firm energy to off-system customers. Long-term contracts are contracts effective during the forecast period lasting for more than one year. At this time, there are no long-term contracts.

The historical consumption for the contract off-system load category was considerable in the early 1990s; however, after 1995, off-system loads declined through 2005. As intended, the off-system contracts and their corresponding energy requirements expired as Idaho Power's surplus energy diminished due to retail load growth. In the future, Idaho Power may enter additional long-term contracts to supply firm energy to off-system customers if surplus energy is available.

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## Appendix A1. Historical and Projected Sales and Load

### Residential Load

### Historical Residential Sales and Load, 1976–2016 (weather adjusted)

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1976 | 175,720 | – | 13,280 | 2,334 | – | 267 |
| 1977 | 184,561 | 5.0% | 13,240 | 2,444 | 4.7% | 284 |
| 1978 | 194,650 | 5.5% | 14,559 | 2,834 | 16.0% | 320 |
| 1979 | 202,982 | 4.3% | 13,904 | 2,822 | -0.4% | 329 |
| 1980 | 209,629 | 3.3% | 14,657 | 3,073 | 8.9% | 350 |
| 1981 | 213,579 | 1.9% | 14,583 | 3,115 | 1.4% | 353 |
| 1982 | 216,696 | 1.5% | 13,544 | 2,935 | -5.8% | 337 |
| 1983 | 219,849 | 1.5% | 14,287 | 3,141 | 7.0% | 358 |
| 1984 | 222,695 | 1.3% | 14,078 | 3,135 | -0.2% | 357 |
| 1985 | 225,185 | 1.1% | 13,988 | 3,150 | 0.5% | 360 |
| 1986 | 227,081 | 0.8% | 14,095 | 3,201 | 1.6% | 365 |
| 1987 | 228,868 | 0.8% | 13,960 | 3,195 | -0.2% | 365 |
| 1988 | 230,771 | 0.8% | 14,237 | 3,285 | 2.8% | 375 |
| 1989 | 233,370 | 1.1% | 14,237 | 3,323 | 1.1% | 380 |
| 1990 | 238,117 | 2.0% | 14,223 | 3,387 | 1.9% | 388 |
| 1991 | 243,207 | 2.1% | 14,428 | 3,509 | 3.6% | 401 |
| 1992 | 249,767 | 2.7% | 14,099 | 3,521 | 0.4% | 402 |
| 1993 | 258,271 | 3.4% | 14,124 | 3,648 | 3.6% | 417 |
| 1994 | 267,854 | 3.7% | 13,991 | 3,748 | 2.7% | 429 |
| 1995 | 277,131 | 3.5% | 13,950 | 3,866 | 3.2% | 442 |
| 1996 | 286,227 | 3.3% | 13,713 | 3,925 | 1.5% | 448 |
| 1997 | 294,674 | 3.0% | 13,640 | 4,019 | 2.4% | 459 |
| 1998 | 303,300 | 2.9% | 13,681 | 4,150 | 3.2% | 474 |
| 1999 | 312,901 | 3.2% | 13,548 | 4,239 | 2.2% | 484 |
| 2000 | 322,402 | 3.0% | 13,365 | 4,309 | 1.6% | 492 |
| 2001 | 331,009 | 2.7% | 13,128 | 4,346 | 0.9% | 495 |
| 2002 | 339,764 | 2.6% | 12,641 | 4,295 | -1.2% | 491 |
| 2003 | 349,219 | 2.8% | 12,673 | 4,426 | 3.0% | 506 |
| 2004 | 360,462 | 3.2% | 12,675 | 4,569 | 3.2% | 522 |
| 2005 | 373,602 | 3.6% | 12,668 | 4,733 | 3.6% | 543 |
| 2006 | 387,707 | 3.8% | 12,884 | 4,995 | 5.5% | 571 |
| 2007 | 397,286 | 2.5% | 12,922 | 5,134 | 2.8% | 587 |
| 2008 | 402,520 | 1.3% | 12,838 | 5,168 | 0.7% | 589 |
| 2009 | 405,144 | 0.7% | 12,688 | 5,141 | -0.5% | 586 |
| 2010 | 407,551 | 0.6% | 12,421 | 5,062 | -1.5% | 578 |
| 2011 | 409,786 | 0.5% | 12,361 | 5,066 | 0.1% | 577 |
| 2012 | 413,610 | 0.9% | 12,251 | 5,067 | 0.0% | 576 |
| 2013 | 418,892 | 1.3% | 11,968 | 5,013 | -1.1% | 575 |
| 2014 | 425,036 | 1.5% | 11,873 | 5,047 | 0.7% | 573 |
| 2015 | 432,275 | 1.7% | 11,558 | 4,996 | -1.0% | 572 |
| 2016 | 440,362 | 1.9% | 11,515 | 5,071 | 1.5% | 579 |

**Projected Residential Sales and Load, 2017–2036**

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2017 | 448,947 | 1.9% | 11,565 | 5,192 | 2.4% | 594 |
| 2018 | 458,024 | 2.0% | 11,546 | 5,288 | 1.8% | 605 |
| 2019 | 467,730 | 2.1% | 11,518 | 5,388 | 1.9% | 615 |
| 2020 | 477,773 | 2.1% | 11,372 | 5,433 | 0.8% | 619 |
| 2021 | 487,898 | 2.1% | 11,260 | 5,494 | 1.1% | 628 |
| 2022 | 498,339 | 2.1% | 11,212 | 5,588 | 1.7% | 639 |
| 2023 | 509,058 | 2.2% | 11,159 | 5,681 | 1.7% | 649 |
| 2024 | 519,642 | 2.1% | 11,092 | 5,764 | 1.5% | 657 |
| 2025 | 529,711 | 1.9% | 11,000 | 5,827 | 1.1% | 666 |
| 2026 | 539,237 | 1.8% | 10,921 | 5,889 | 1.1% | 673 |
| 2027 | 548,388 | 1.7% | 10,882 | 5,967 | 1.3% | 682 |
| 2028 | 557,228 | 1.6% | 10,843 | 6,042 | 1.3% | 688 |
| 2029 | 565,899 | 1.6% | 10,792 | 6,107 | 1.1% | 698 |
| 2030 | 574,448 | 1.5% | 10,731 | 6,165 | 0.9% | 704 |
| 2031 | 582,924 | 1.5% | 10,666 | 6,218 | 0.9% | 710 |
| 2032 | 591,436 | 1.5% | 10,588 | 6,262 | 0.7% | 713 |
| 2033 | 600,040 | 1.5% | 10,544 | 6,327 | 1.0% | 723 |
| 2034 | 608,899 | 1.5% | 10,510 | 6,399 | 1.1% | 731 |
| 2035 | 617,979 | 1.5% | 10,474 | 6,473 | 1.1% | 740 |
| 2036 | 627,295 | 1.5% | 10,452 | 6,557 | 1.3% | 747 |

**Commercial Load**

**Historical Commercial Sales and Load, 1976–2016 (weather adjusted)**

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1976 | 26,034 | – | 52,519 | 1,367 | – | 157 |
| 1977 | 27,112 | 4.1% | 52,402 | 1,421 | 3.9% | 162 |
| 1978 | 27,831 | 2.7% | 52,502 | 1,461 | 2.8% | 169 |
| 1979 | 28,087 | 0.9% | 56,369 | 1,583 | 8.4% | 180 |
| 1980 | 28,797 | 2.5% | 54,161 | 1,560 | -1.5% | 178 |
| 1981 | 29,567 | 2.7% | 54,302 | 1,606 | 2.9% | 184 |
| 1982 | 30,167 | 2.0% | 54,124 | 1,633 | 1.7% | 186 |
| 1983 | 30,776 | 2.0% | 52,650 | 1,620 | -0.8% | 185 |
| 1984 | 31,554 | 2.5% | 53,560 | 1,690 | 4.3% | 193 |
| 1985 | 32,418 | 2.7% | 54,180 | 1,756 | 3.9% | 201 |
| 1986 | 33,208 | 2.4% | 53,937 | 1,791 | 2.0% | 204 |
| 1987 | 33,975 | 2.3% | 53,395 | 1,814 | 1.3% | 207 |
| 1988 | 34,723 | 2.2% | 54,371 | 1,888 | 4.1% | 216 |
| 1989 | 35,638 | 2.6% | 55,376 | 1,973 | 4.5% | 226 |
| 1990 | 36,785 | 3.2% | 55,746 | 2,051 | 3.9% | 235 |
| 1991 | 37,922 | 3.1% | 56,273 | 2,134 | 4.1% | 244 |
| 1992 | 39,022 | 2.9% | 56,396 | 2,201 | 3.1% | 251 |
| 1993 | 40,047 | 2.6% | 58,183 | 2,330 | 5.9% | 266 |
| 1994 | 41,629 | 4.0% | 58,274 | 2,426 | 4.1% | 278 |
| 1995 | 43,165 | 3.7% | 58,695 | 2,534 | 4.4% | 290 |
| 1996 | 44,995 | 4.2% | 62,013 | 2,790 | 10.1% | 319 |
| 1997 | 46,819 | 4.1% | 62,056 | 2,905 | 4.1% | 332 |
| 1998 | 48,404 | 3.4% | 62,718 | 3,036 | 4.5% | 348 |
| 1999 | 49,430 | 2.1% | 64,170 | 3,172 | 4.5% | 362 |
| 2000 | 50,117 | 1.4% | 65,965 | 3,306 | 4.2% | 378 |
| 2001 | 51,501 | 2.8% | 67,426 | 3,472 | 5.0% | 396 |
| 2002 | 52,915 | 2.7% | 64,794 | 3,429 | -1.3% | 392 |
| 2003 | 54,194 | 2.4% | 64,254 | 3,482 | 1.6% | 398 |
| 2004 | 55,577 | 2.6% | 63,942 | 3,554 | 2.1% | 405 |
| 2005 | 57,145 | 2.8% | 63,504 | 3,629 | 2.1% | 415 |
| 2006 | 59,050 | 3.3% | 63,484 | 3,749 | 3.3% | 429 |
| 2007 | 61,640 | 4.4% | 63,352 | 3,905 | 4.2% | 446 |
| 2008 | 63,492 | 3.0% | 62,246 | 3,952 | 1.2% | 449 |
| 2009 | 64,151 | 1.0% | 59,671 | 3,828 | -3.1% | 438 |
| 2010 | 64,421 | 0.4% | 58,853 | 3,791 | -1.0% | 432 |
| 2011 | 64,921 | 0.8% | 58,431 | 3,793 | 0.1% | 433 |
| 2012 | 65,599 | 1.0% | 58,896 | 3,863 | 1.8% | 440 |
| 2013 | 66,357 | 1.2% | 58,599 | 3,888 | 0.6% | 446 |
| 2014 | 67,113 | 1.1% | 58,948 | 3,956 | 1.7% | 452 |
| 2015 | 68,000 | 1.3% | 58,491 | 3,977 | 0.5% | 455 |
| 2016 | 68,883 | 1.3% | 58,046 | 3,998 | 0.5% | 456 |

**Projected Commercial Sales and Load, 2017–2036**

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2017 | 69,911 | 1.5% | 58,311 | 4,077 | 2.0% | 466 |
| 2018 | 71,070 | 1.7% | 58,026 | 4,124 | 1.2% | 471 |
| 2019 | 72,344 | 1.8% | 57,526 | 4,162 | 0.9% | 475 |
| 2020 | 73,720 | 1.9% | 56,864 | 4,192 | 0.7% | 477 |
| 2021 | 75,165 | 2.0% | 56,200 | 4,224 | 0.8% | 482 |
| 2022 | 76,660 | 2.0% | 55,523 | 4,256 | 0.8% | 486 |
| 2023 | 78,208 | 2.0% | 54,833 | 4,288 | 0.8% | 490 |
| 2024 | 79,791 | 2.0% | 54,094 | 4,316 | 0.6% | 492 |
| 2025 | 81,371 | 2.0% | 53,395 | 4,345 | 0.7% | 496 |
| 2026 | 82,914 | 1.9% | 52,797 | 4,378 | 0.8% | 500 |
| 2027 | 84,419 | 1.8% | 52,229 | 4,409 | 0.7% | 503 |
| 2028 | 85,894 | 1.7% | 51,648 | 4,436 | 0.6% | 505 |
| 2029 | 87,350 | 1.7% | 51,172 | 4,470 | 0.8% | 510 |
| 2030 | 88,792 | 1.7% | 50,689 | 4,501 | 0.7% | 514 |
| 2031 | 90,227 | 1.6% | 50,214 | 4,531 | 0.7% | 517 |
| 2032 | 91,661 | 1.6% | 49,753 | 4,560 | 0.7% | 519 |
| 2033 | 93,103 | 1.6% | 49,335 | 4,593 | 0.7% | 525 |
| 2034 | 94,563 | 1.6% | 48,928 | 4,627 | 0.7% | 528 |
| 2035 | 96,046 | 1.6% | 48,546 | 4,663 | 0.8% | 533 |
| 2036 | 97,553 | 1.6% | 48,191 | 4,701 | 0.8% | 535 |

**Irrigation Load**

**Historical Irrigation Sales and Load, 1976–2016 (weather adjusted)**

| Year | Maximum Active Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1976 | 9,936 | – | 157,590 | 1,566 | – | 178 |
| 1977 | 10,238 | 3.0% | 163,580 | 1,675 | 7.0% | 191 |
| 1978 | 10,476 | 2.3% | 154,417 | 1,618 | -3.4% | 185 |
| 1979 | 10,711 | 2.2% | 164,233 | 1,759 | 8.7% | 201 |
| 1980 | 10,854 | 1.3% | 160,661 | 1,744 | -0.9% | 199 |
| 1981 | 11,248 | 3.6% | 167,476 | 1,884 | 8.0% | 215 |
| 1982 | 11,312 | 0.6% | 154,133 | 1,744 | -7.4% | 199 |
| 1983 | 11,133 | -1.6% | 147,254 | 1,639 | -6.0% | 187 |
| 1984 | 11,375 | 2.2% | 136,431 | 1,552 | -5.3% | 177 |
| 1985 | 11,576 | 1.8% | 133,886 | 1,550 | -0.1% | 177 |
| 1986 | 11,308 | -2.3% | 133,605 | 1,511 | -2.5% | 172 |
| 1987 | 11,254 | -0.5% | 132,650 | 1,493 | -1.2% | 170 |
| 1988 | 11,378 | 1.1% | 137,485 | 1,564 | 4.8% | 178 |
| 1989 | 11,957 | 5.1% | 137,849 | 1,648 | 5.4% | 188 |
| 1990 | 12,340 | 3.2% | 149,397 | 1,844 | 11.8% | 210 |
| 1991 | 12,484 | 1.2% | 138,862 | 1,734 | -6.0% | 198 |
| 1992 | 12,809 | 2.6% | 141,889 | 1,817 | 4.8% | 207 |
| 1993 | 13,078 | 2.1% | 131,086 | 1,714 | -5.7% | 196 |
| 1994 | 13,559 | 3.7% | 132,337 | 1,794 | 4.7% | 205 |
| 1995 | 13,679 | 0.9% | 128,923 | 1,764 | -1.7% | 201 |
| 1996 | 14,074 | 2.9% | 126,199 | 1,776 | 0.7% | 202 |
| 1997 | 14,383 | 2.2% | 120,399 | 1,732 | -2.5% | 198 |
| 1998 | 14,695 | 2.2% | 120,340 | 1,768 | 2.1% | 202 |
| 1999 | 14,912 | 1.5% | 120,589 | 1,798 | 1.7% | 205 |
| 2000 | 15,253 | 2.3% | 128,659 | 1,962 | 9.1% | 223 |
| 2001 | 15,522 | 1.8% | 117,561 | 1,825 | -7.0% | 208 |
| 2002 | 15,840 | 2.0% | 109,186 | 1,730 | -5.2% | 197 |
| 2003 | 16,020 | 1.1% | 111,786 | 1,791 | 3.5% | 204 |
| 2004 | 16,297 | 1.7% | 109,191 | 1,779 | -0.6% | 203 |
| 2005 | 16,936 | 3.9% | 102,141 | 1,730 | -2.8% | 197 |
| 2006 | 17,062 | 0.7% | 96,870 | 1,653 | -4.5% | 189 |
| 2007 | 17,001 | -0.4% | 105,466 | 1,793 | 8.5% | 205 |
| 2008 | 17,428 | 2.5% | 109,423 | 1,907 | 6.4% | 217 |
| 2009 | 17,708 | 1.6% | 101,814 | 1,803 | -5.5% | 206 |
| 2010 | 17,846 | 0.8% | 101,998 | 1,820 | 1.0% | 208 |
| 2011 | 18,292 | 2.5% | 99,885 | 1,827 | 0.4% | 209 |
| 2012 | 18,675 | 2.1% | 104,064 | 1,943 | 6.4% | 221 |
| 2013 | 19,017 | 1.8% | 103,977 | 1,977 | 1.7% | 226 |
| 2014 | 19,328 | 1.6% | 104,762 | 2,025 | 2.4% | 231 |
| 2015 | 19,756 | 2.2% | 95,595 | 1,889 | -6.7% | 213 |
| 2016 | 20,042 | 1.4% | 96,320 | 1,930 | 2.2% | 220 |

**Projected Irrigation Sales and Load, 2017–2036**

| Year | Maximum Active Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2017 | 20,322 | 1.4% | 95,100 | 1,933 | 0.1% | 221 |
| 2018 | 20,623 | 1.5% | 94,261 | 1,944 | 0.6% | 222 |
| 2019 | 20,914 | 1.4% | 93,667 | 1,959 | 0.8% | 224 |
| 2020 | 21,211 | 1.4% | 92,910 | 1,971 | 0.6% | 224 |
| 2021 | 21,508 | 1.4% | 92,038 | 1,980 | 0.4% | 226 |
| 2022 | 21,806 | 1.4% | 91,417 | 1,993 | 0.7% | 228 |
| 2023 | 22,102 | 1.4% | 90,745 | 2,006 | 0.6% | 229 |
| 2024 | 22,393 | 1.3% | 90,067 | 2,017 | 0.6% | 230 |
| 2025 | 22,691 | 1.3% | 89,332 | 2,027 | 0.5% | 231 |
| 2026 | 22,988 | 1.3% | 88,614 | 2,037 | 0.5% | 233 |
| 2027 | 23,285 | 1.3% | 88,060 | 2,050 | 0.7% | 234 |
| 2028 | 23,581 | 1.3% | 87,483 | 2,063 | 0.6% | 235 |
| 2029 | 23,877 | 1.3% | 86,865 | 2,074 | 0.5% | 237 |
| 2030 | 24,172 | 1.2% | 86,305 | 2,086 | 0.6% | 238 |
| 2031 | 24,469 | 1.2% | 85,740 | 2,098 | 0.6% | 239 |
| 2032 | 24,766 | 1.2% | 85,113 | 2,108 | 0.5% | 240 |
| 2033 | 25,062 | 1.2% | 84,622 | 2,121 | 0.6% | 242 |
| 2034 | 25,356 | 1.2% | 84,178 | 2,134 | 0.6% | 244 |
| 2035 | 25,651 | 1.2% | 83,720 | 2,148 | 0.6% | 245 |
| 2036 | 25,946 | 1.2% | 83,336 | 2,162 | 0.7% | 246 |

**Industrial Load**

**Historical Industrial Sales and Load, 1976–2016 (not weather adjusted)**

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 1976 | 73 | – | 11,681,540 | 858 | – | 99 |
| 1977 | 85 | 15.1% | 10,988,826 | 929 | 8.3% | 106 |
| 1978 | 99 | 17.6% | 9,786,753 | 972 | 4.7% | 111 |
| 1979 | 109 | 9.6% | 9,989,158 | 1,087 | 11.8% | 126 |
| 1980 | 112 | 2.7% | 9,894,706 | 1,106 | 1.7% | 125 |
| 1981 | 118 | 5.7% | 9,718,723 | 1,148 | 3.9% | 132 |
| 1982 | 122 | 3.5% | 9,504,283 | 1,162 | 1.2% | 133 |
| 1983 | 122 | -0.3% | 9,797,522 | 1,194 | 2.7% | 138 |
| 1984 | 124 | 1.5% | 10,369,789 | 1,282 | 7.4% | 147 |
| 1985 | 125 | 1.2% | 10,844,888 | 1,357 | 5.9% | 155 |
| 1986 | 129 | 2.7% | 10,550,145 | 1,357 | -0.1% | 155 |
| 1987 | 134 | 4.1% | 11,006,455 | 1,474 | 8.7% | 169 |
| 1988 | 133 | -1.0% | 11,660,183 | 1,546 | 4.9% | 177 |
| 1989 | 132 | -0.6% | 12,091,482 | 1,594 | 3.1% | 183 |
| 1990 | 132 | 0.2% | 12,584,200 | 1,662 | 4.3% | 191 |
| 1991 | 135 | 2.5% | 12,699,665 | 1,719 | 3.4% | 196 |
| 1992 | 140 | 3.4% | 12,650,945 | 1,770 | 3.0% | 203 |
| 1993 | 141 | 0.5% | 13,179,585 | 1,854 | 4.7% | 212 |
| 1994 | 143 | 1.7% | 13,616,608 | 1,948 | 5.1% | 223 |
| 1995 | 120 | -15.9% | 16,793,437 | 2,021 | 3.7% | 230 |
| 1996 | 103 | -14.4% | 18,774,093 | 1,934 | -4.3% | 221 |
| 1997 | 106 | 2.7% | 19,309,504 | 2,042 | 5.6% | 235 |
| 1998 | 111 | 4.6% | 19,378,734 | 2,145 | 5.0% | 244 |
| 1999 | 108 | -2.3% | 19,985,029 | 2,160 | 0.7% | 247 |
| 2000 | 107 | -0.8% | 20,433,299 | 2,191 | 1.5% | 250 |
| 2001 | 111 | 3.5% | 20,618,361 | 2,289 | 4.4% | 260 |
| 2002 | 111 | -0.1% | 19,441,876 | 2,156 | -5.8% | 246 |
| 2003 | 112 | 1.0% | 19,950,866 | 2,234 | 3.6% | 255 |
| 2004 | 117 | 4.3% | 19,417,310 | 2,269 | 1.5% | 259 |
| 2005 | 126 | 7.9% | 18,645,220 | 2,351 | 3.6% | 270 |
| 2006 | 127 | 1.0% | 18,255,385 | 2,325 | -1.1% | 265 |
| 2007 | 123 | -3.6% | 19,275,551 | 2,366 | 1.8% | 270 |
| 2008 | 119 | -3.1% | 19,412,391 | 2,308 | -2.4% | 261 |
| 2009 | 124 | 4.0% | 17,987,570 | 2,224 | -3.6% | 254 |
| 2010 | 121 | -2.0% | 18,404,875 | 2,232 | 0.3% | 254 |
| 2011 | 120 | -1.1% | 18,597,050 | 2,230 | -0.1% | 254 |
| 2012 | 115 | -4.2% | 19,757,921 | 2,271 | 1.8% | 258 |
| 2013 | 114 | -0.7% | 20,281,837 | 2,314 | 1.9% | 265 |
| 2014 | 113 | -0.7% | 20,863,653 | 2,363 | 2.1% | 271 |
| 2015 | 116 | 2.8% | 20,271,082 | 2,360 | -0.1% | 269 |
| 2016 | 118 | 1.4% | 19,997,106 | 2,361 | 0.1% | 270 |

**Projected Industrial Sales and Load, 2017–2036**

| Year | Average Customers | Percent Change | kWh per Customer | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|---|---|---|
| 2017 | 119 | 0.8% | 20,602,815 | 2,452 | 3.8% | 281 |
| 2018 | 120 | 0.8% | 21,033,767 | 2,524 | 2.9% | 288 |
| 2019 | 121 | 0.8% | 21,161,810 | 2,561 | 1.4% | 293 |
| 2020 | 121 | 0.0% | 21,372,860 | 2,586 | 1.0% | 295 |
| 2021 | 121 | 0.0% | 21,497,289 | 2,601 | 0.6% | 297 |
| 2022 | 122 | 0.8% | 21,426,910 | 2,614 | 0.5% | 299 |
| 2023 | 123 | 0.8% | 21,375,415 | 2,629 | 0.6% | 300 |
| 2024 | 124 | 0.8% | 21,318,605 | 2,644 | 0.5% | 301 |
| 2025 | 125 | 0.8% | 21,253,784 | 2,657 | 0.5% | 303 |
| 2026 | 125 | 0.0% | 21,355,032 | 2,669 | 0.5% | 305 |
| 2027 | 127 | 1.6% | 21,124,323 | 2,683 | 0.5% | 306 |
| 2028 | 128 | 0.8% | 21,082,969 | 2,699 | 0.6% | 307 |
| 2029 | 128 | 0.0% | 21,208,625 | 2,715 | 0.6% | 310 |
| 2030 | 128 | 0.0% | 21,329,641 | 2,730 | 0.6% | 312 |
| 2031 | 129 | 0.8% | 21,284,186 | 2,746 | 0.6% | 314 |
| 2032 | 130 | 0.8% | 21,226,438 | 2,759 | 0.5% | 314 |
| 2033 | 130 | 0.0% | 21,325,215 | 2,772 | 0.5% | 317 |
| 2034 | 131 | 0.8% | 21,268,565 | 2,786 | 0.5% | 318 |
| 2035 | 133 | 1.5% | 21,054,677 | 2,800 | 0.5% | 320 |
| 2036 | 133 | 0.0% | 21,155,835 | 2,814 | 0.5% | 320 |

**Additional Firm Sales and Load**

**Historical Additional Firm Sales and Load, 1976–2016**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 1976 | 288 | – | 33 |
| 1977 | 311 | 7.8% | 35 |
| 1978 | 357 | 14.8% | 41 |
| 1979 | 373 | 4.4% | 43 |
| 1980 | 360 | -3.5% | 41 |
| 1981 | 376 | 4.6% | 43 |
| 1982 | 367 | -2.4% | 42 |
| 1983 | 425 | 15.7% | 49 |
| 1984 | 466 | 9.7% | 53 |
| 1985 | 471 | 1.1% | 54 |
| 1986 | 482 | 2.4% | 55 |
| 1987 | 502 | 4.2% | 57 |
| 1988 | 530 | 5.6% | 60 |
| 1989 | 671 | 26.5% | 77 |
| 1990 | 625 | -6.9% | 71 |
| 1991 | 661 | 5.8% | 75 |
| 1992 | 680 | 2.9% | 77 |
| 1993 | 689 | 1.3% | 79 |
| 1994 | 740 | 7.5% | 85 |
| 1995 | 878 | 18.6% | 100 |
| 1996 | 989 | 12.6% | 113 |
| 1997 | 1,048 | 6.0% | 120 |
| 1998 | 1,113 | 6.2% | 127 |
| 1999 | 1,121 | 0.8% | 128 |
| 2000 | 1,143 | 1.9% | 130 |
| 2001 | 1,118 | -2.1% | 128 |
| 2002 | 1,139 | 1.9% | 130 |
| 2003 | 1,120 | -1.7% | 128 |
| 2004 | 1,156 | 3.3% | 132 |
| 2005 | 1,175 | 1.6% | 134 |
| 2006 | 1,189 | 1.2% | 136 |
| 2007 | 1,141 | -4.0% | 130 |
| 2008 | 1,114 | -2.4% | 127 |
| 2009 | 965 | -13.4% | 110 |
| 2010 | 907 | -6.0% | 103 |
| 2011 | 906 | 0.0% | 103 |
| 2012 | 862 | -4.8% | 98 |
| 2013 | 867 | 0.5% | 99 |
| 2014 | 841 | -2.9% | 96 |
| 2015 | 842 | 0.1% | 96 |
| 2016 | 870 | 3.3% | 99 |

*Includes Micron Technology, Simplot Fertilizer, INL, Hoku Materials, City of Weiser, and Raft River Rural Electric Cooperative, Inc.

**Projected Additional Firm Sales and Load, 2017–2036**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 2017 | 945 | 8.6% | 108 |
| 2018 | 962 | 1.7% | 110 |
| 2019 | 972 | 1.1% | 111 |
| 2020 | 979 | 0.7% | 111 |
| 2021 | 983 | 0.4% | 112 |
| 2022 | 990 | 0.8% | 113 |
| 2023 | 1,011 | 2.1% | 115 |
| 2024 | 1,084 | 7.2% | 123 |
| 2025 | 1,086 | 0.2% | 124 |
| 2026 | 1,086 | -0.1% | 124 |
| 2027 | 1,087 | 0.1% | 124 |
| 2028 | 1,089 | 0.2% | 124 |
| 2029 | 1,088 | -0.1% | 124 |
| 2030 | 1,088 | 0.0% | 124 |
| 2031 | 1,088 | 0.0% | 124 |
| 2032 | 1,089 | 0.1% | 124 |
| 2033 | 1,090 | 0.1% | 124 |
| 2034 | 1,090 | 0.0% | 124 |
| 2035 | 1,092 | 0.2% | 125 |
| 2036 | 1,092 | 0.0% | 124 |

*Includes Micron Technology, Simplot Fertilizer, and the INL

**Company System Load (excluding Astaris)**

**Historical Company System Sales and Load, 1976–2016 (weather adjusted)**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 1976 | 6,413 | – | 799 |
| 1977 | 6,778 | 5.7% | 848 |
| 1978 | 7,242 | 6.8% | 899 |
| 1979 | 7,624 | 5.3% | 955 |
| 1980 | 7,842 | 2.8% | 971 |
| 1981 | 8,129 | 3.7% | 1,009 |
| 1982 | 7,841 | -3.5% | 976 |
| 1983 | 8,019 | 2.3% | 997 |
| 1984 | 8,125 | 1.3% | 1,007 |
| 1985 | 8,285 | 2.0% | 1,030 |
| 1986 | 8,341 | 0.7% | 1,034 |
| 1987 | 8,478 | 1.6% | 1,053 |
| 1988 | 8,814 | 4.0% | 1,092 |
| 1989 | 9,209 | 4.5% | 1,143 |
| 1990 | 9,568 | 3.9% | 1,190 |
| 1991 | 9,756 | 2.0% | 1,209 |
| 1992 | 9,990 | 2.4% | 1,238 |
| 1993 | 10,235 | 2.5% | 1,270 |
| 1994 | 10,657 | 4.1% | 1,324 |
| 1995 | 11,062 | 3.8% | 1,371 |
| 1996 | 11,414 | 3.2% | 1,413 |
| 1997 | 11,746 | 2.9% | 1,458 |
| 1998 | 12,211 | 4.0% | 1,513 |
| 1999 | 12,491 | 2.3% | 1,548 |
| 2000 | 12,911 | 3.4% | 1,599 |
| 2001 | 13,050 | 1.1% | 1,613 |
| 2002 | 12,748 | -2.3% | 1,580 |
| 2003 | 13,053 | 2.4% | 1,618 |
| 2004 | 13,327 | 2.1% | 1,651 |
| 2005 | 13,618 | 2.2% | 1,692 |
| 2006 | 13,910 | 2.2% | 1,725 |
| 2007 | 14,339 | 3.1% | 1,779 |
| 2008 | 14,449 | 0.8% | 1,784 |
| 2009 | 13,961 | -3.4% | 1,732 |
| 2010 | 13,812 | -1.1% | 1,712 |
| 2011 | 13,822 | 0.1% | 1,713 |
| 2012 | 14,007 | 1.3% | 1,732 |
| 2013 | 14,060 | 0.4% | 1,750 |
| 2014 | 14,232 | 1.2% | 1,763 |
| 2015 | 14,064 | -1.2% | 1,742 |
| 2016 | 14,231 | 1.2% | 1,762 |

**Company System Load**

**Projected Company System Sales and Load, 2017–2036**

| Year | Billed Sales (thousands of MWh) | Percent Change | Average Load (aMW) |
|---|---|---|---|
| 2017 | 14,598 | 2.6% | 1,810 |
| 2018 | 14,842 | 1.7% | 1,840 |
| 2019 | 15,041 | 1.3% | 1,864 |
| 2020 | 15,161 | 0.8% | 1,874 |
| 2021 | 15,282 | 0.8% | 1,894 |
| 2022 | 15,442 | 1.0% | 1,914 |
| 2023 | 15,615 | 1.1% | 1,935 |
| 2024 | 15,824 | 1.3% | 1,955 |
| 2025 | 15,941 | 0.7% | 1,975 |
| 2026 | 16,059 | 0.7% | 1,990 |
| 2027 | 16,196 | 0.9% | 2,007 |
| 2028 | 16,329 | 0.8% | 2,018 |
| 2029 | 16,454 | 0.8% | 2,039 |
| 2030 | 16,570 | 0.7% | 2,053 |
| 2031 | 16,680 | 0.7% | 2,067 |
| 2032 | 16,779 | 0.6% | 2,074 |
| 2033 | 16,903 | 0.7% | 2,095 |
| 2034 | 17,037 | 0.8% | 2,112 |
| 2035 | 17,175 | 0.8% | 2,129 |
| 2036 | 17,326 | 0.9% | 2,142 |

INTEGRATED RESOURCE PLAN

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# 2017 IRP

## APPENDIX B: DSM ANNUAL REPORT







MARCH 15 • 2017

## SAFE HARBOR STATEMENT

This document may contain forward-looking statements, and it is important to note that the future results could differ materially from those discussed. A full discussion of the factors that could cause future results to differ materially can be found in Idaho Power's filings with the Securities and Exchange Commission.

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# 2017 IRP

## APPENDIX B: DSM ANNUAL REPORT

# ACKNOWLEDGEMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan (IRP) every two years. Idaho Power expects that the experience gained over the next few years will likely modify the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the 2017 IRP. Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council and other concerned citizens and customers.

It takes approximately one year for a dedicated team of individuals at Idaho Power to prepare the IRP. The Idaho Power team is comprised of individuals that represent many departments within the company. The IRP team members are responsible for preparing forecasts, working with the advisory council and the public, and performing all the analyses necessary to prepare the resource plan.

Idaho Power looks forward to continuing the resource planning process with customers, public-interest groups, regulatory agencies, and other interested parties. You can learn more about the Idaho Power resource planning process at idahopower.com.

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*Supplement 1: Cost-Effectiveness*
*Supplement 2: Evaluation*
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# EXECUTIVE SUMMARY

In 2016, Idaho Power celebrated providing electric service to the residents of southern Idaho for 100 years. Since starting as a small company in 1916, Idaho Power has grown to serve over 500,000 customers in over 24,000 square miles in southern Idaho and eastern Oregon. In 2002, Idaho Power revitalized its energy efficiency programs and began the Idaho and Oregon Energy Efficiency Riders (Rider) to fund the pursuit of cost-effective energy efficiency. Energy efficiency and demand response provide economic and operational benefits to the company and its customers and supports the wise use of energy by Idaho Power customers.

Idaho Power's portfolio of energy efficiency program energy savings for 2016 increased to 170,792 megawatt-hours (MWh), including the estimated savings from the Northwest Energy Efficiency Alliance (NEEA), enough energy to power more than 14,000 average homes a year in Idaho Power's service area. This is a 4-percent increase from the 2015 energy savings of 163,672 MWh. In 2016, the company's energy efficiency portfolio was cost-effective from both the total resource cost (TRC) test and the utility cost (UC) test perspectives with ratios of 2.56 and 3.58, respectively. The portfolio was also cost-effective from the participant cost test ratio was 2.93. The savings from Idaho Power's energy efficiency programs alone, excluding NEEA savings, increased to 146,177 MWh in 2016 from 140,633 MWh in 2015.

Idaho Power successfully operated all three of its demand response programs in 2016. The total demand reduction achieved from the company's programs was 378 megawatts (MW) from an available capacity of 392 MW. Energy efficiency and demand response is an important aspect of Idaho Power's resource planning process. Idaho Power's 2016 achievements in energy savings exceeded the annual savings target identified in Idaho Power's *2015 Integrated Resource Plan* (IRP).

Total expenditures from all funding sources on demand-side management (DSM) activities increased by nearly 10 percent, to $43 million in 2016 from $39 million in 2015. DSM program funding comes from the Idaho and Oregon Riders, Idaho Power base rates, and the annual power cost adjustment (PCA). Idaho incentives for the company's demand response programs are recovered through base rates and the annual PCA, while Oregon demand response incentives are funded through the Oregon Rider.

With a goal of using customers' funds wisely, Idaho Power employees and leaders strive to provide conscientious, prudent, and responsible action and activities that result in cost-effective energy efficiency. This report's content offers descriptions of the 2016 activities and savings.

In 2016, Idaho Power expanded the reach and frequency of its residential energy efficiency campaign, added a Smart-saver Pledge to engage and encourage customers to make an energy-saving behavior change, significantly increased the amount of energy efficiency-related social media posts, and began marketing the company's commercial and industrial energy efficiency offerings as a single program. Idaho Power's residential energy efficiency advertising campaign was awarded second place at the E Source Forum in the category of Best Ad Campaign for an Investor-owned Utility.

Idaho Power continued to use stakeholder input to enhance its programs. The company met regularly with its Energy Efficiency Advisory Group (EEAG) and individual customers seeking input on program improvement. To keep growth in the program portfolio, the company relied on its Program Planning Group (PPG), initiated in 2014, and NEEA's Regional Emerging Technology Advisory Committee (RETAC) to fill the pipeline with ideas for offerings to its energy efficiency programs. Additionally, Idaho Power continued program improvement to make it easier for its customers to participate in programs.

In 2016, Idaho Power distributed Energy-Saving Kits (ESK) at no additional cost to customers on request. By the end of the year, the company had distributed over 34,000 kits to customers in Idaho and Oregon. The ESK included light-emitting diodes (LED) lightbulbs, digital thermometers, shower timers, water flow-rate test bags, LED night lights, and educational materials. Additionally, by the end of the year, Idaho Power employees had personally delivered energy-efficiency messages and distributed nearly 25,000 lightbulbs directly to customers.

This *Demand-Side Management 2016 Annual Report* provides a review of the company's DSM activities and finances throughout 2016 and outlines Idaho Power's plans for future DSM activities. This report also satisfies the reporting requirements set out in the Idaho Public Utilities Commission's (IPUC) Order Nos. 29026 and 29419. Idaho Power will provide a copy of the report to the Public Utility Commission of Oregon (OPUC) under Oregon Docket Utility Miscellaneous (UM) No. 1710.

# INTRODUCTION

In 2016, Idaho Power celebrated its 100th anniversary. For the last sixteen years, the company has pursued cost-effective energy efficiency as a primary objective. Energy efficiency and demand response provide economic and operational benefits to the company and its customers. Idaho Power provides information and programs to ensure customers have opportunities to learn about their energy use, how to use energy, and participate in programs.

This report focuses on Idaho Power's demand-side management (DSM) activities and results for 2016 and previews planned activities for 2017. The appendices provide historical and detailed information on the company's DSM activities and detailed financial information from 2002 through 2016. The two supplements provide detailed cost-effectiveness data and copies of Idaho Power's evaluations, reports, and research conducted in 2016.

Idaho Power's main objectives for DSM programs are to achieve prudent, cost-effective energy efficiency savings and to provide an optimal amount of demand reduction from its demand response programs as determined through the Integrated Resource Plan (IRP) planning process. Idaho Power considers cost-effective energy efficiency the company's least-cost resource and pays particular attention to ensuring the best value to Idaho Power's customers. Idaho Power strives to provide customers with programs and information to help them manage their energy use wisely.

The company achieves these objectives through the implementation and careful management of programs that provide energy and demand savings and through outreach and education. For economic and administrative efficiency and to reduce customer confusion, Idaho Power endeavors to implement identical programs in its Idaho and Oregon service areas. Idaho Power has been locally operated since 1916 and serves nearly 530,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon.




Figure 1. 2016 Idaho Power service area map

Idaho Power's energy efficiency programs focus on reducing energy use by identifying homes, buildings, equipment, or components for which an energy-efficient design, replacement, or repair can achieve energy savings. Energy efficiency programs sometimes include behavioral components, including the Residential Energy Efficiency Education Initiative and both the Smart-saver Pledge and the School Cohort, which began in 2016. Energy efficiency programs are available to all customer sectors in Idaho Power's service area.

Savings from these programs are measured in terms of kilowatt-hour (kWh) or megawatt-hour (MWh) savings. These programs usually supply energy savings throughout the year at different times depending on the energy-efficiency measure put in place. Idaho Power shapes these savings based on the end use to estimate energy reduction at specific times of the year and day. Idaho Power's energy efficiency offerings include programs in residential and commercial new construction (lost-opportunity savings); residential and commercial retrofit applications; and irrigation and industrial system improvement or replacement. Custom programs under the irrigation and industrial sectors offer a wide range of opportunities for Idaho Power and its customers to design and execute energy-saving projects.

Energy efficiency program and demand response funding comes from the Idaho and Oregon Energy Efficiency Riders (Rider), Idaho Power base rates, and the annual power cost adjustment (PCA). Idaho incentives for the company's demand response programs are recovered through base rates and the annual PCA, while Oregon demand response incentives are funded through the Oregon Rider. Total expenditures from all funding sources on DSM-related activities increased by about 10 percent, from $39 million in 2015 to $43 million in 2016.

Idaho Power started its modern demand response programs in 2002, and now has over 10 percent of its all-time peak load available under demand response programs. The goal of demand response at Idaho Power is to minimize or delay the need to build new supply-side peaking resources. The company estimates future capacity needs through the IRP planning process and plans resources to mitigate any system peak deficits that exist. Demand response programs are measured by the amount of demand reduction, in megawatts (MW), available to the company during system peak periods.

## DSM Programs Performance

The 2016 savings consisted of 42,269 MWh from the residential sector, 88,161 MWh from the commercial/industrial sector, and 15,747 MWh from the irrigation sector. This represents a 4-percent increase from 2015 program savings. The industrial Custom Projects (formerly Custom Efficiency) program in the Commercial and Industrial Energy Efficiency Program contributed 33 percent of Idaho Power's direct program savings, while the residential sector Energy Efficient Lighting and Educational Distributions programs contributed 86 percent of the residential savings.

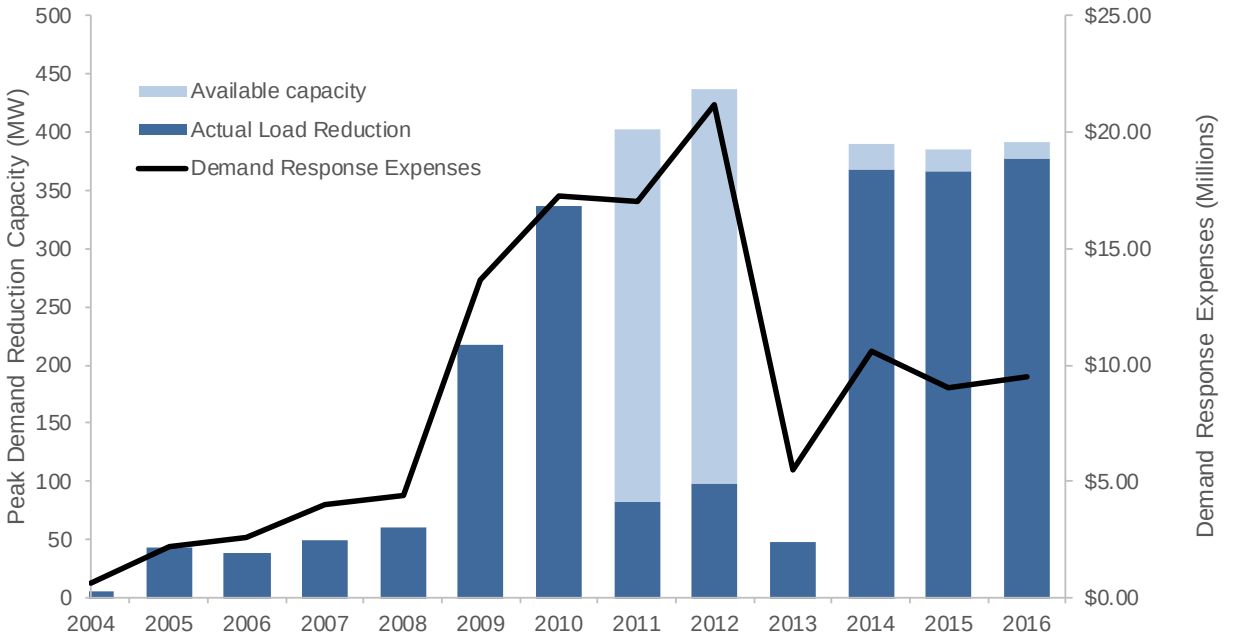



Figure 2. Peak demand-reduction capacity and demand response expenses, 2004–2016 (MW and millions [$])

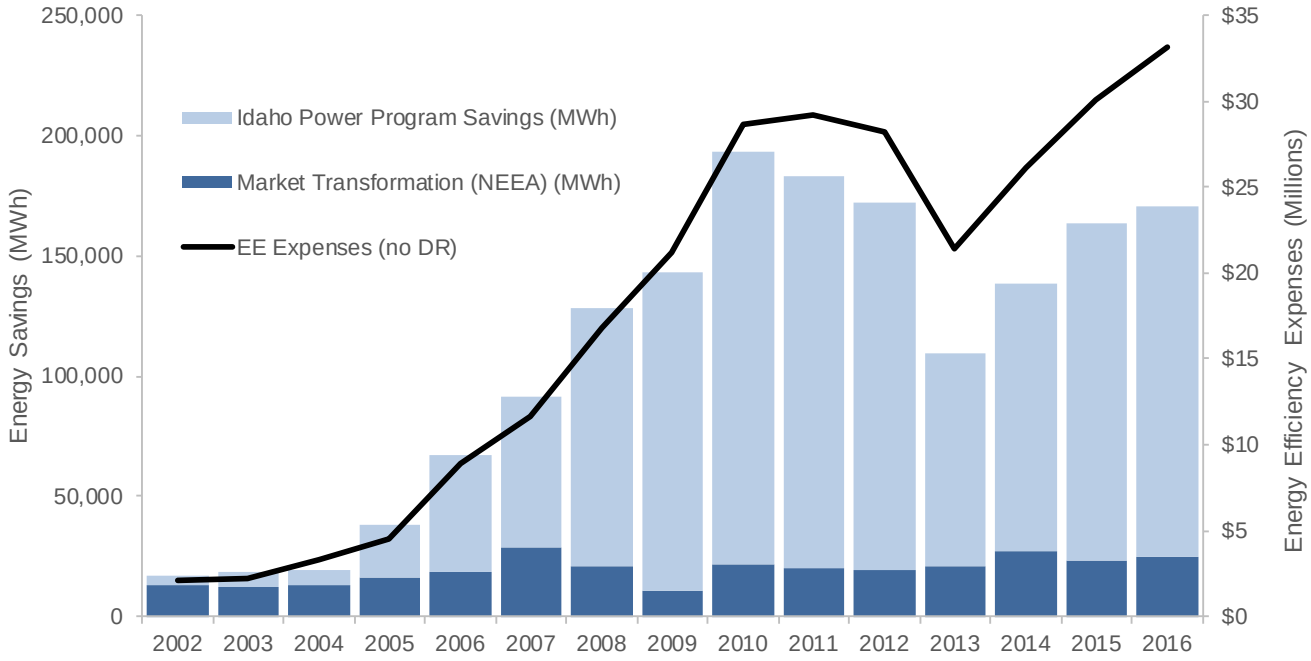



Figure 3. Annual energy savings and energy efficiency program expenses, 2002–2016 (MWh and millions [$])

Figure 3 demonstrates that as Idaho Powers energy-efficiency portfolio matures, and some savings become more difficult and costly to achieve, the expense per incremental savings increases.

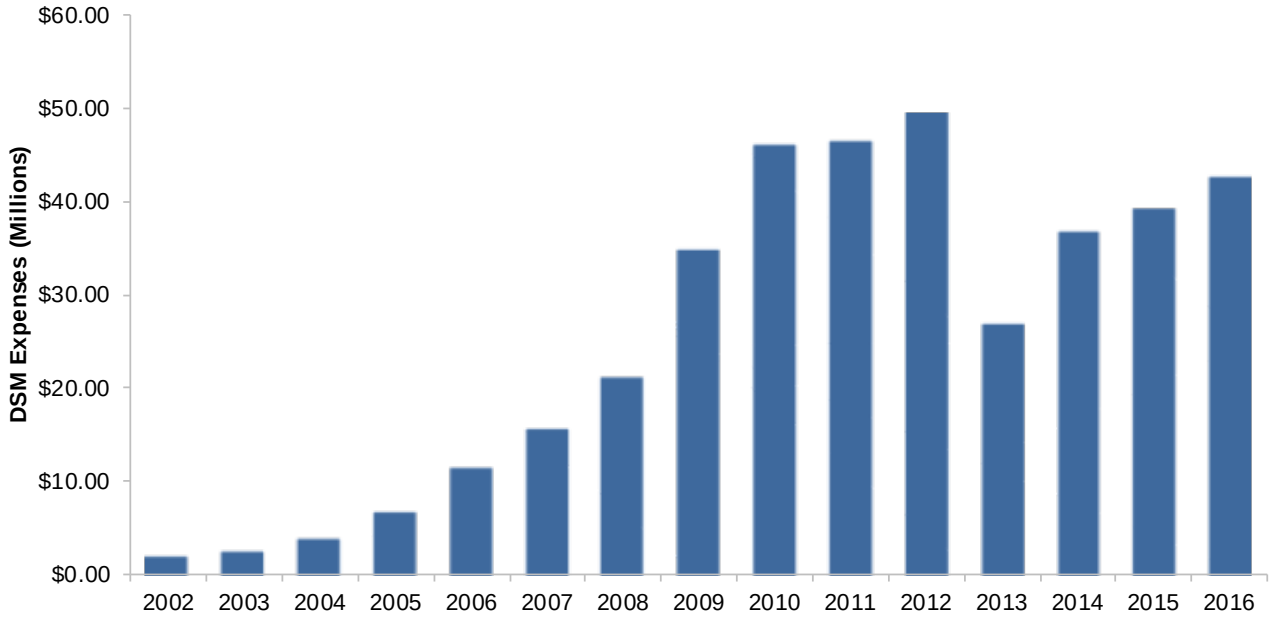



Figure 4. Total DSM expense history, including energy efficiency, demand response, and NEEA expenses, 2002–2016 (millions [$])

Energy efficiency and demand response is an important aspect of Idaho Power's resource planning process. Idaho Power's 2016 achievements in energy savings exceeded the annual savings target identified in Idaho Power's *2015 Integrated Resource Plan*. On a cumulative basis, the company's energy savings have exceeded the IRP targets every year since 2002.

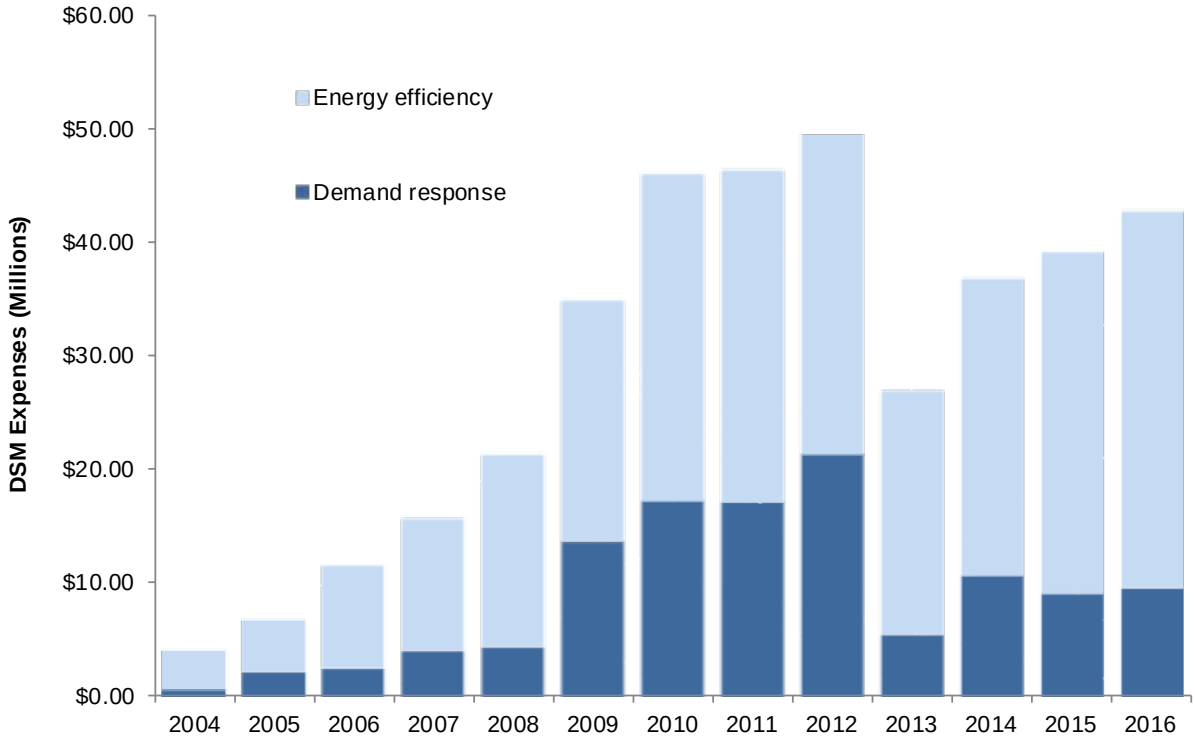



Figure 5. DSM expense history by program type, 2004–2016 (millions [$])

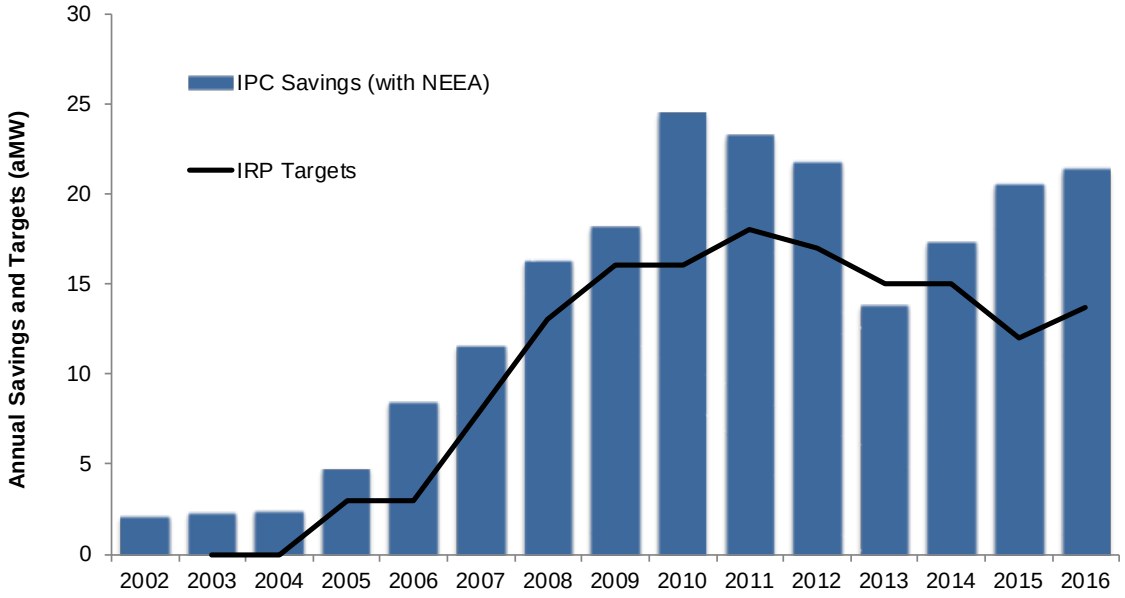



Figure 6. Annual incremental energy efficiency savings (aMW) compared with IRP targets, 2002–2016

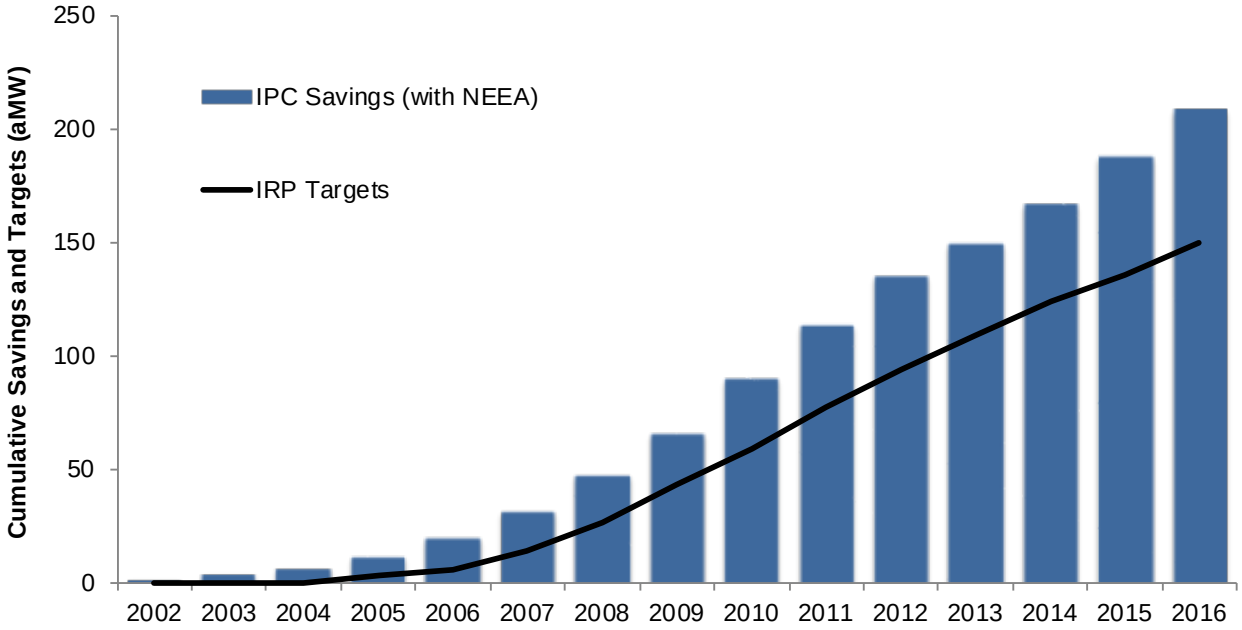



Figure 7. Annual cumulative energy efficiency savings (aMW) compared with IRP targets, 2002–2016

Idaho Power further increased its energy efficiency presence in the community by providing energy efficiency and program information through 92 outreach activities, including events, presentations, trainings, and other activities. In addition, Idaho Power customer representatives delivered 189 presentations to local organizations addressing energy efficiency programs and wise energy use.

In 2016, Idaho Power's community education representatives presented *The Power to Make a Difference* 91 times to 2,350 students and gave 53 classroom presentations of *Saving a World Full of Energy* to 1,411 students. At events and presentations, company staff distributed over 24,000 light-emitting

diodes (LED) lightbulbs in custom packaging that highlighted the advantages of energy-efficient lighting and encouraged participation in Idaho Power's myAccount online portal. The company also distributed over 34,000 Energy-Saving Kits (ESK) by request across its service area. On February 8, 2016, Idaho Power filed a request with the Public Utility Commission of Oregon (OPUC) to implement the Educational Distributions program in Oregon. The company received approval of Oregon Schedule 71 on March 9, 2016. This enabled Idaho Power to provide ESKs and LEDs to its Oregon customers.

Since 2008, commercial and industrial training activities have informed and educated commercial and industrial customers regarding energy efficiency, increased awareness of and participation in existing commercial and industrial energy efficiency and demand response programs, and enhanced customer satisfaction regarding the company's energy efficiency initiatives. Raising the knowledge level of commercial and industrial customers regarding the wise use of energy in their daily operations is important to the continued success of Idaho Power's commercial and industrial energy efficiency programs.

Idaho Power continued its internal commitment to energy efficiency in 2016. Idaho Power upgraded the company's substation buildings across its service area, renovated portions of the corporate headquarters (CHQ) in downtown Boise in 2016, and redesigned the heating, ventilation, and air conditioning (HVAC) delivery system for the Maintenance and Electrical Shop. Also in 2016, the new Twin Falls Operation Center was constructed to replace the 1951-built center used to house the operations staff. The design incorporates energy-efficient lighting, heating and cooling, daylight harvesting, and a rooftop solar array.

## Demand Response Programs

In summer 2016, Idaho Power had a combined maximum actual non-coincidental load reduction from all three programs of 378 MW at the generation level. The amount of capacity available for demand response varies based on weather, the time of year, and how programs are used and managed. The 2016 capacity of demand response programs was 392 MW. The demand response capacity is calculated using total enrolled MW from participants with an expected maximum realization rate for those participants. This maximum realization rate is not always achieved for every program in any given event. This realization rate is expected to be approximately 73 percent of billing demand for Irrigation Peak Rewards and 100 percent of actual non-coincidental load reduction for A/C Cool Credit and the Flex Peak Program.

On Wednesday, June 29, 2016, the company used the Irrigation Peak Rewards program and reached a system peak of 3,085 MW. Had the program not been used, the company estimates the load would have been approximately 3,327 MW. Idaho Power's 2016 summer peak occurred on June 28 with a peak of 3,299 MW while the all-time summer peak was 3,407 MW on July 2, 2013.

## Energy Efficiency Programs

Idaho Power's portfolio of energy efficiency program energy savings for 2016 increased to 170,792 MWh, including the estimated Northwest Energy Efficiency Alliance (NEEA) savings. This is a 4-percent increase from the 2015 energy savings of 163,672 MWh and enough to power over

14,000 average-sized homes a year in Idaho Power's service area. In 2016, the company's energy efficiency portfolio is cost effective from both the total resource cost (TRC) test and the utility cost (UC) test perspectives with ratios of 2.56 and 3.58, respectively. The savings from Idaho Power's energy efficiency programs alone (excluding NEEA savings) increased to 146,177 MWh in 2016 from 140,633 MWh in 2015.

Table 1. 2016 DSM programs by sector, operational type, location, and energy savings/demand reduction

| Program by Sector | Operational Type | State | Savings/Demand Reduction |
|---|---|---|---|
| **Residential** | | | |
| A/C Cool Credit | Demand Response | ID/OR | 34 MW |
| Easy Savings | Energy Efficiency | ID | 403 MWh |
| Educational Distributions | Energy Efficiency | ID/OR | 15,150 MWh |
| Energy Efficient Lighting | Energy Efficiency | ID/OR | 21,094 MWh |
| Energy House Calls | Energy Efficiency | ID/OR | 510 MWh |
| ENERGY STAR® Homes Northwest | Energy Efficiency | ID/OR | 150 MWh |
| Fridge and Freezer Recycling Program (See ya later, refrigerator®) | Energy Efficiency | ID/OR | 632 MWh |
| Heating & Cooling Efficiency Program | Energy Efficiency | ID/OR | 1,114 MWh |
| Home Energy Audit | Energy Efficiency | ID | 207 MWh |
| Home Improvement Program | Energy Efficiency | ID | 500 MWh |
| Multifamily Energy Savings Program | Energy Efficiency | ID/OR | 150 MWh |
| Oregon Residential Weatherization | Energy Efficiency | OR | 3 MWh |
| Rebate Advantage | Energy Efficiency | ID/OR | 411 MWh |
| Shade Tree Project | Other Programs and Activities | ID | n/a |
| Simple Steps, Smart Savings™ | Energy Efficiency | ID/OR | 577 MWh |
| Weatherization Assistance for Qualified Customers | Energy Efficiency | ID/OR | 746 MWh |
| Weatherization Solutions for Eligible Customers | Energy Efficiency | ID | 622 MWh |
| **Commercial/Industrial** | | | |
| Commercial and Industrial Efficiency Program | | | |
| Custom Projects (Custom Efficiency) | Energy Efficiency | ID/OR | 47,519 MWh |
| New Construction (Building Efficiency) | Energy Efficiency | ID/OR | 12,393 MWh |
| Retrofits (Easy Upgrades) | Energy Efficiency | ID/OR | 28,125 MWh |
| Flex Peak Program | Demand Response | ID/OR | 42 MW |
| Green Motors—Industrial | Energy Efficiency | ID/OR | 124 MWh |
| Oregon Commercial Audits | Energy Efficiency | OR | n/a |
| **Irrigation** | | | |
| Green Motors—Irrigation | Energy Efficiency | ID/OR | 74 MWh |
| Irrigation Efficiency Rewards | Energy Efficiency | ID/OR | 15,674 MWh |
| Irrigation Peak Rewards | Demand Response | ID/OR | 303 MW |
| **All Sectors** | | | |
| Northwest Energy Efficiency Alliance | Market Transformation | ID/OR | 24,616 MWh |

Table 2. 2016 program sector summary and energy usage/savings/demand reduction

| | Energy Efficiency Program Impacts [a] | | | | Idaho Power System Sales | | |
|---|---|---|---|---|---|---|---|
| | Program Expenses | Energy Savings (kWh) | Average Energy (aMW) | Peak-Load Reduction (MW)[b] | Sector Total (MWh) | Percentage of Energy Usage | Number of Customers |
| Residential | $10,724,671 | 42,268,823 | 4.8 | | 4,907,730 | 34.92% | 444,431 |
| Commercial/Industrial | $14,961,753 | 88,160,599 | 10.1 | | 7,198,357 | 51.22% | 69,462 |
| Irrigation | $2,372,352 | 15,747,130 | 1.8 | | 1,948,079 | 13.86% | 20,638 |
| Market Transformation | $2,676,387 | 24,615,600 | 2.8 | | | | |
| Demand Response | $9,471,367 | n/a | n/a | 378 | | | |
| Direct Overhead | $293,039 | n/a | n/a | | | | |
| **Total Direct Program Expenses** | **$40,499,570** | **170,792,152** | **19.5** | **378** | **14,054,166** | **100.0%** | **534,531** |

[a] Energy, average energy, and expense data have been rounded to the nearest whole unit, which may result in minor rounding differences.
[b] Includes peak-load reduction from both demand response and energy efficiency programs. Includes 9.7% peak line loss assumptions.

## Program Evaluation Strategy

Idaho Power considers program evaluation an essential component of its DSM operational activities. The company uses third-party contractors to conduct impact, process, and other evaluations on a scheduled and as required basis.

Third-party contracts are generally awarded using a competitive bid process managed by Idaho Power's Strategic Sourcing department. In some cases, research and analysis is conducted internally and managed by Idaho Power's Research and Analysis team within the Customer Relations and Energy Efficiency (CR&EE) department. Third-party evaluations are specifically managed by the company's energy efficiency evaluator.

Idaho Power uses industry standard protocols for its internal and external evaluation efforts, including the National Action Plan for Energy Efficiency—Model Energy Efficiency Program Impact Evaluation Guide, the California Evaluation Framework, the International Performance Measurement and Verification Protocol (IPMVP), the Database for Energy Efficiency Resources, and the Regional Technical Forum's (RTF) evaluation protocols.

The company also supports regional and national studies to promote the ongoing cost-effectiveness of programs, the validation of energy savings and demand reduction, and the efficient management of its programs. Idaho Power considers primary and secondary research, cost-effectiveness analyses, potential assessments, impact and process evaluations, and customer surveys to be important resources in providing accurate and transparent program-savings estimates. Recommendations and findings from evaluations research and industry best practices are used to continuously refine Idaho Power's DSM programs. Historical evaluation plans, plans for 2017, and copies of 2016 evaluations and research can be found in *Supplement 2: Evaluation.*

## Cost-Effectiveness

Idaho Power considers cost-effectiveness of primary importance in the design, implementation,

and tracking of energy efficiency and demand response programs. Idaho Power's energy efficiency and demand response opportunities are preliminarily identified through the IRP process. Idaho Power uses third-party energy efficiency potential studies to identify achievable cost-effective energy efficiency potential that is added to the resources included in the IRP. Because of Idaho Power's diversified portfolio of programs, most of the new potential for energy efficiency in Idaho Power's service area is based on additional measures to be added to existing programs rather than developing new programs.

Prior to the actual implementation of energy efficiency or demand response programs, Idaho Power performs a cost-effectiveness analysis to assess whether a potential program design or measure will be cost-effective from the perspective of Idaho Power and its customers. Incorporated in these models are inputs from various sources that use the most current and reliable information available.

Additionally, Idaho Power relies on the results of program impact evaluations and recommendations from consultants. In 2016, Idaho Power contracted with ADM Associates, Inc. (ADM); Applied Energy Group (AEG); CLEAResult Consulting, Inc. (CLEAResult); and Tetra Tech, MA for program evaluations and research.

Idaho Power's goal is for all programs to have benefit/cost (B/C) ratios greater than one for the TRC test, UC test, and participant cost test (PCT) at the program and measure level where appropriate. Each cost-effectiveness test provides a different perspective, and Idaho Power believes each test provides value when evaluating program performance. If a particular measure or program is pursued even though it will not be cost-effective from each of the three tests, Idaho Power works with the Energy Efficiency Advisory Group (EEAG) to get input. The company believes this aligns with the expectations of the Idaho Public Utilities Commission (IPUC) and OPUC.

Details on the cost-effectiveness assumptions and data are included in *Supplement 1: Cost-Effectiveness*.

## Future Plans

Idaho Power will continue to pursue all prudent cost-effective energy efficiency as identified by third-party potential studies, and an appropriate amount of demand response based on the demand response settlement agreement approved in IPUC Order No. 32923 and OPUC Order No. 13-482. The forecast level of energy efficiency and the needed level of demand response are included in Idaho Power's biennial IRP planning process. Idaho Power includes all achievable cost-effective energy savings as identified in its potential studies in each IRP. Idaho Power considers this achievable potential a reasonable 20-year planning estimate. However, the company does not consider the achievable potential as a ceiling limiting energy efficiency acquisition. The IRP is developed in a public process that details Idaho Power's strategy for economically maintaining the adequacy of its power system into the future. The IRP process balances reliability, cost, risk, environmental concerns, and efficiency to develop a preferred portfolio of future resources to meet the specific energy needs of Idaho Power's customers.

Planning activities conducted in 2016 identified an opportunity for Idaho Power to increase its focus on small and medium business customers to build relationships and promote participation in energy

efficiency programs. A new position titled customer solutions advisor has been developed as a result of this effort. Eight customer solutions advisor positions have been developed and are scheduled to be in place and performing their assigned duties by May 1, 2017. The customer solutions advisors will focus on customer outreach by phone to "on-board" new business customers and support existing business customers by familiarizing them with Idaho Power's rates, billing and payment options, and energy-usage information available through myAccount and by answering any questions they may have about services and programs offered by Idaho Power. A primary function of the customer solutions advisor role will be promoting and educating business customers on energy efficiency and demand response programs.

The company will continue to explore new energy savings potential through third-party resources, conferences, and regional organizations, and will continue to assess and develop new program offerings through its Program Planning Group (PPG). Idaho Power will work in consultation with the EEAG to expand or modify its energy efficiency portfolio. Future plans for individual programs are included under each program's *2017 Program and Marketing Strategies*.

In 2017, Idaho Power will continue to enhance its marketing and outreach efforts as described in the Marketing section of this report and within each program section. Idaho Power will continue to work with NEEA on its market transformation activities during the 2015 to 2019 funding cycle.

The company will complete its research and evaluation, measurement, and verification (EM&V) projects included in the evaluation plan in *Supplement 2: Evaluation*.

Idaho Power will incorporate energy efficiency equipment and practices into its own facilities. In 2017, the company will continue renovations at the CHQ in downtown Boise. Idaho Power plans to remodel the ninth floor of the CHQ, exchanging the old T-12 parabolic lighting fixtures with T-8 lighting, and incorporating energy efficiency measures, such as lower partitions, lighting retrofits, and automated lighting controls.

In 2016, Idaho Power redesigned the HVAC delivery system for the Maintenance and Electrical Shops; construction on these projects is planned for 2018. Idaho Power estimates that with these improvements the shops may reduce their usage by 300,000 kWh in coming years.

## DSM Annual Report Structure

The *Demand-Side Management 2016 Annual Report* consists of the main document and two supplements. *Supplement 1: Cost Effectiveness* shows the standard cost effectiveness tests for Idaho Power programs and includes a table that reports expenses by funding source and cost category. In 2016, the company continued its commitment to third party evaluation activities. Included in *Supplement 2: Evaluation* are copies of all of Idaho Power's 2016 evaluations, evaluations conducted by its regional partners, customer surveys and reports, Idaho Power's evaluation plans, general energy efficiency research, and demand response research. Additionally, the report and supplements will be provided under Oregon Docket UM 1710 to provide the OPUC and its staff information on the company's DSM programs and expenses.

This main *Demand-Side Management 2016 Annual Report* is organized primarily by the customer sectors residential, commercial/industrial, and irrigation. Each sector has a description, which is followed by information regarding programs in that sector. Each program description includes a table containing 2016 and 2015 program metrics, followed by a general description, 2016 activities, cost-effectiveness, customer satisfaction/evaluation, and 2017 plans. Each program section contains detailed information relating to program changes and the reasoning behind those changes, including information on cost-effectiveness and evaluation. Following the sector and program sections of the report are descriptions of Idaho Power's activities in other programs and activities, including market transformation, and Idaho Power's regulatory initiatives. Appendices 1 through 5 follow the written sections and contain a table on 2016 expenses and savings and historic information for all energy efficiency programs and demand response activities at Idaho Power.

In 2016, Idaho Power's commercial and industrial energy efficiency programs were combined in one umbrella program, the Commercial and Industrial Energy Efficiency Program, with options named to describe their purpose: New Construction (formerly Building Efficiency), Retrofits (formerly Easy Upgrades), and Custom Projects (formerly Custom Efficiency). The specific expenses and savings data are reported in the appendices separately for comparative purposes.

Also in 2016, Idaho Power filed with the IPUC to combine the Weatherization Assistance for Qualified Customers (WAQC) report, formerly filed with the IPUC annually on April 1, with Idaho Power's *Demand-Side Management 2016 Annual Report*. This change was approved by the IPUC in January 23, 2017, Order No. 33702 IPC-E-16-30, and the information formerly included in the WAQC annual report is now included in this report.

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# 2016 PROGRAM ACTIVITY

## DSM Expenditures

Funding for DSM programs in 2016 came from several sources. The Idaho and Oregon Rider funds are collected directly from customers on their monthly bills. For 2016, the Idaho Rider was 4 percent of base rate revenues; the 2016 Oregon Rider was 3 percent of base rate revenues. Additionally, Idaho demand response program incentives were paid through base rates and the annual PCA mechanism. Energy efficiency and demand response related expenses not funded through the Rider are included as part of Idaho Power's ongoing operation and maintenance (O&M) costs.

Total DSM expenses funded from all sources were $43 million in 2016. At the beginning of 2016, the Idaho Rider balance was approximately $6.6 million, and by December 31, 2016, the positive balance was $10.7 million. At the beginning of the year, the Oregon Rider negative balance was approximately $4.5 million, and by year-end, the negative balance was $5.6 million.

Table 3 shows the total expenditures funded by the Idaho Rider, $31,291,579; the Oregon Rider, $2,168,868; and non-rider funding, $9,303,017, resulting in Idaho Power's total DSM expenditures of $42,763,464. The non-rider funding category includes Idaho Power demand response incentives, WAQC expenses, and O&M costs.

Table 3. 2016 funding source and energy savings

| Funding Source | Expenses | kWh Savings |
|---|---|---|
| Idaho Rider | $ 31,291,579 | 162,765,429 |
| Oregon Rider | 2,168,868 | 7,280,560 |
| Non-Rider Funding | 9,303,017 | 746,162 |
| **Total** | **$ 42,763,464** | **170,792,152** |

Table 4 and Figure 8 indicate 2016 DSM program expenditures by category. The Materials & Equipment category includes items that directly benefit customers: ESKs and LED lightbulbs distributed at customer events ($2,105,557), and direct-install weatherization measures ($125,000). The expenses in the Other Expense category include marketing ($1,208,731), program evaluation ($198,210), program training ($455,117), and program audits ($174,861). The Purchased Services category includes payments made to NEEA and third-party contractors who help deliver Idaho Power's programs.

Table 4. 2016 DSM program expenditures by category

| | Total | % of Total |
|---|---|---|
| Incentive Expense | $23,676,667 | 55% |
| Labor/Administrative Expense | 3,580,600 | 8% |
| Materials & Equipment | 2,417,071 | 6% |
| Other Expense | 2,111,683 | 5% |
| Purchased Services | 10,977,442 | 26% |
| **Total 2016 DSM Expenditures, by Category** | **$42,763,464** | **100%** |

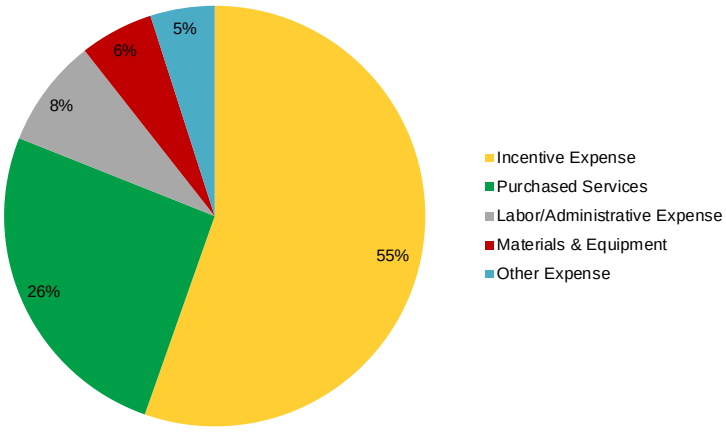



Figure 8. 2016 DSM program expenditures by category

Table 5 and Figure 9 describe the amount and percentage of incentives paid by segment and sector. There are two incentive segments (demand response and energy efficiency) and three sectors (residential, commercial/industrial, and irrigation). The incentives are funded by three mechanisms: the Idaho Rider, the Oregon Rider, and Idaho Power base rates. Market transformation related payments made to NEEA and payments made to third-party community action partners under the WAQC and Weatherization Solutions for Eligible Customers programs are not included in the incentive amounts.

Table 5. 2016 DSM program incentives totals by program type and sector

| Program Type—Sector | Total | % of Total |
|---|---|---|
| DR[a]—Residential | $ 424,565 | 2% |
| DR—Commercial/Industrial | 639,611 | 3% |
| DR—Irrigation | 6,406,340 | 27% |
| EE[b]—Irrigation | 2,007,311 | 8% |
| EE—Residential | 2,680,473 | 11% |
| EE—Commercial/Industrial | 11,518,366 | 49% |
| **Total Incentive Expense** | **$ 23,676,667** | **100%** |

[a] DR = demand response
[b] EE = energy efficiency

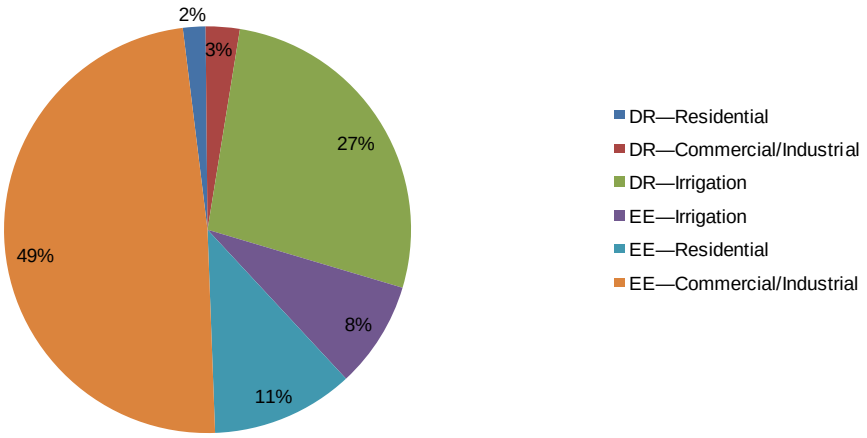



Figure 9. 2016 DSM program incentives by segment and sector

# Marketing

Idaho Power used a variety of marketing, public relations, and research in 2016 to improve communication with its customers. Idaho Power takes advantage of all types of media and marketing. Owned media (social, website, newsletters) and paid media (advertising, sponsorships) allow Idaho Power to control content. Earned unpaid media (news outlets, Idaho Power's *News Briefs* sent to reporters, third-party publications, and television news appearances) gives Idaho Power access to an audience through other channels. Though Idaho Power has less control of the content with earned unpaid media, the value is established from the third-party endorsement.

The following describes a selection of the methods, approaches, and tactics used by Idaho Power to engage with customers regarding energy efficiency, along with their results.

## *All Sectors*

### Social Media

Approximately 17 percent of the company's total social media content promoted energy efficiency in 2016, a significant increase from 8 percent in 2015. Idaho Power distributed more than 200 messages about energy efficiency throughout the year via Facebook, Twitter, LinkedIn, and Instagram. Idaho Power also enjoyed the benefit from many energy efficiency-related organic posts on social media outlets. An organic post is one that originates from the customer.

In 2016, Idaho Power continued its *#TipTuesday* posts on Facebook and Twitter, a tactic launched in late 2015. *#TipTuesday* posts provide Idaho Power's Facebook and Twitter followers with a new energy efficiency tip or program information every Tuesday of the year. The posts use photos, when applicable, and include the hashtag *#TipTuesday* so the tips can be categorized together and easily searched by social media users. The company also posted information about several energy efficiency programs, sponsorships, and events on its social media pages.

### Website

Idaho Power tracked the number of page views to the main energy efficiency pages—also known as landing pages—on the company's website. In 2016, the company's energy efficiency homepage received 34,938 page views; 74,984 page views on the residential landing page; 7,748 page views on the business landing page; and 1,829 page views on the irrigation landing page. The company uses Google Analytics to analyze web activity. Google's definition of page views is the total number of pages viewed, with repeated views of a single page being counted.

### Bill Inserts

A January bill insert was sent to 371,600 customers with winter energy-saving tips. In February, 373,189 customers received a bill insert promoting Idaho Power's em**powered** community. Other program-specific bill inserts were also sent throughout the year. Information about those can be found in each program later in this report.

### Print

Idaho Power updated the look and content of its print collateral, including a brochure and information card that provides a description of each energy efficiency program offering.

### Public Relations

Public relations supported energy efficiency programs and activities through multiple channels: *Connections*, a monthly customer newsletter distributed in approximately 420,000 monthly bills and available online; *News Briefs*, a weekly email of interesting news items sent to all media in the company's service area; pitching and participating in news stories; KTVB (Boise/Twin Falls) and KPVI (Pocatello/Blackfoot) monthly energy-efficiency news segments; news releases and events (such as check presentations).

In 2016, the October and April issues of *Connections* were devoted to energy efficiency. The cover story of the March issue of *Connections* highlighted a customer who applied energy efficient measures on the job, by participating in Idaho Power's Commercial and Industrial Energy Efficiency Program, and at home. Other public relations activities are noted later in this report.

### Staff

NEEA and Idaho Power staff held regular meetings throughout 2016 to coordinate, collaborate, and facilitate marketing. Monthly meetings were held via conference call, and meetings in person occurred in July and August in Portland, and September and November in Boise. All marketing activities are reviewed each month for progress, results, and collaborative opportunities.

To build marketing networks and to learn what works in other regions, Idaho Power staff attended the Chartwell Marketing and Communications Conference in March in Atlanta, the NEEA Efficiency Exchange in April in Coeur d'Alene, and the E Source Utility Marketing Executive Council and E Source Forum held in September in Denver.

## Residential

Idaho Power ran a multi-faceted advertising campaign in the spring (March and April) and fall (September and October) to raise awareness of Idaho Power's energy efficiency programs for residential customers, and to demonstrate that saving energy doesn't have to be challenging. These campaigns included radio, television, newspaper advertisements (ads), digital ads, Facebook ads, *News Briefs* sent to the media, the *Connections* newsletter, and Idaho Power's website to reach a variety of demographics. In 2016, the company added a Smart-saver Pledge to the campaign to engage and encourage customers to make an energy-saving behavior change.

Figure 10 is an example of the campaign materials in 2016.




Figure 10. 2016 energy efficiency awareness campaign

The goals of the campaign are to raise awareness of the programs collectively rather than by individual program; use a variety of methods to reach various customer demographics; use all the methods in the same month to increase customer exposure to the message; and to let customers know they have options when it comes to saving energy. Messaging focused on many ways to create an energy-efficient home with Energy Savings Made Easy as a central theme, illustrating how easy energy efficiency can be with Idaho Power's help. The campaign was awarded second place in the category of Best Ad Campaign for an Investor-owned Utility at the E Source Utility Ad Awards.

Outside of the campaign, Idaho Power also deployed a number of marketing tactics to promote energy saving tips and the company's energy efficiency programs throughout the year. Results of the campaign and other marketing tactics are included below.

### Television

Idaho Power used network television advertising for the spring and fall campaign. The campaign focused on primetime and news programming that reaches the highest percentage of the target market, adults age 35 to 64. Results of the spots were provided for the three major markets—Boise, Pocatello, and Twin Falls.

During the spring campaign, 95 percent of customers in Idaho Power's target audience viewing network television were exposed to the commercial. Targeted customers in Boise saw the ad an average of

13 times, while targeted customers in Pocatello and Twin Falls each saw the ad an average of 12 times. During the fall campaign, 95 percent of targeted customers saw the commercial. Targeted customers in Boise saw the ad an average of 13 times, 18 times in Pocatello, and 12 times in Twin Falls.

### Radio

As part of its spring and fall campaign, Idaho Power ran 30-second radio spots on major commercial radio stations, Spanish speaking radio stations, and National Public Radio (NPR) stations in the service area. The commercial stations that ran the spots had a variety of station formats to obtain optimum reach, including classic rock, news/talk, country, adult alternative, adult contemporary, and classic hits. The message was targeted toward adults ages 35 to 64 throughout Idaho Power's service area.

Results of the spots were provided for the three major markets: Boise, Pocatello and Twin Falls. During the spring campaign, the spots reached 55 percent of the target audience in Boise and 60 percent of the target audience in Pocatello and Twin Falls. The target audience in Boise was exposed to the ad approximately nine times, 17 times in Pocatello, and 15 times in Twin Falls. During the fall campaign, the spots reached 60 percent of the target audience in all three major markets. The target audience was exposed to the message eight times in Boise and 16 times in both Pocatello and Twin Falls during the fall campaign.

In summary, Idaho Power ran 2,616 radio spots during the spring campaign and 2,590 spots during the fall campaign, totaling 5,206 radio spots in 2016.

In April and October, these 30-second spots also ran with accompanying visual banner ads on Pandora internet radio accessed by mobile and web-based devices. In April, records show 1,416,990 impressions and 2,427 banner clicks to the Idaho Power residential energy efficiency web page. October yielded 1,430,376 impressions and 2,058 banner clicks. Impressions are defined as the number of times the ad was displayed, regardless of the media type.

### Print

As part of the spring and fall campaign, print advertising ran in the major daily and weekly newspapers throughout the service area. The ads conveyed individual energy efficiency programs or tips to customers, such as using insulation to keep cool air in and hot air out in summer. The ads were scheduled for 1,902,246 impressions in the spring and 2,087,983 impressions in the fall.

### Social Media

Idaho Power Facebook ads reached 242,224 people and received 3,238,288 impressions and 11,399 clicks to the Idaho Power website during the spring campaign. The company also initially placed a video ad on Instagram, but discontinued the ad a few days later due to low views and click-through rates, and reallocated those funds to Facebook. During the fall campaign, the company reached 223,280 people, and the ad resulted in 1,918,264 impressions and 10,883 clicks to the Idaho Power website.

Throughout the year, Idaho Power also used Facebook boosts for various programs. A boosted post resembles a traditional Facebook post, but, for a fee, Facebook promotes the post higher in users'

News Feeds, increasing the likelihood that the targeted audience will see it. Boosting posts can help increase audience engagement and get more people interacting with the content.

### Pledge

In 2016, Idaho Power launched a new offering, the Smart-saver Pledge (pledge), to encourage customers in Idaho to make an energy saving behavior change. Customers were asked to commit to making an energy-saving behavior change for 21 days, choosing from one of the following: turn thermostat down 1 to 3 degrees; wash full loads of laundry in cold water and hang dry when possible; register for myAccount, and review your energy use once a week; have a "no electronics" night once a week; and use the crockpot or barbeque once a week instead of the stove. In return, pledge participants were entered to win an ENERGY STAR® electric appliance. The pledge was primarily promoted through a bill insert that went to 367,221 customers, social media, *News Briefs*, the October issue of *Connections*, and television news segments on KTVB and KPVI.




Figure 11. The 2016 the Smart-saver Pledge bill insert

Idaho Power received 937 pledges throughout the pledge period and hundreds of additional pledges after the pledge ended. The company also received numerous positive notes from customers about the pledge and their energy habits. The company felt the participants were highly engaged and that the results were generally positive, providing good information for continuing the pledge in future years.

Customers were asked to complete a follow-up survey as part of the pledge. In return, participants were entered to win one $100 cash prize. Four hundred and eight customers responded to the follow-up survey. Highlights include the following:

- Ninety-six percent of respondents fulfilled all 21 days of their pledge.
- Of respondents who answered the question regarding whether they would continue their energy-saving changes, all but one respondent plans to continue with the energy saving changes since the pledge ended.
- Fifty-four percent of respondents indicated they were "very likely" to seek out additional ways to save energy.
- After taking the pledge, just over 97 percent of respondents are "somewhat likely" or "very likely" to participate in an Idaho Power energy efficiency program.

A copy of the full survey results can be found in *Supplement 2: Evaluation*.

### Campaign Results

The response to the spring and fall Energy Savings Made Easy campaign was measured using Idaho Power's em**powered** community, an on-line panel of over 1,000 customers asked to share perceptions and feedback on a variety of topics each month. The following 2016 spring campaign survey results were obtained from 254 community members who hadn't participated in the 2015 campaign survey:

- Forty-four percent of respondents remember seeing or hearing one of the ads.
- Fifty percent of respondents recalled the television ads, the highest rate of recall.
- Eighty-six percent of respondents indicated they are "very likely" or "somewhat likely" to make energy-saving changes in their home after seeing the ads.
- Eighty-three percent are "very interested" or "somewhat interested" in more information about energy savings programs.
- Eighty-two percent of the respondents who recalled seeing or hearing the ads felt positive about them.

A copy of the results of the study is located in *Supplement 2: Evaluation*.

### Energy-Saving Improvements Survey

In early 2016, Idaho Power used its em**powered** community to measure customer's planned energy-saving improvements and their motivation for making changes to their home. Key findings include the following:

- Nearly 74 percent of respondents were “somewhat” or “very likely” to make energy-saving improvements to their home in the next two to three years. The most common improvement is lighting, followed by windows, appliances, insulation, and other.
- The primary motivator for making energy-saving improvements is to save money.
- The biggest barriers to making energy-saving improvements are cost or already making improvements to the home, followed by the perception that these improvements are not needed.
- Financial incentives and free products and services are the top motivators for customers to participate in an Idaho Power energy-saving program.

A copy of the results of the study is located in *Supplement 2: Evaluation*.

## Commercial and Industrial

In mid-2016, Idaho Power renamed the offerings under the overall Commercial and Industrial Energy Efficiency Program to better describe that the program offers customers financial incentives for New Construction, Custom Projects, and Retrofits. The company redesigned much of the program’s marketing materials, and began marketing these offerings, along with Flex Peak, as a single entity with something for every business customer. Marketing activities were targeted toward business customers, architects, engineers, and other design professionals.

### Airport Advertising

Idaho Power expanded its use of airport signage in 2016. Each year, three million people travel through the Boise Airport. Fifty-nine percent of travelers have made purchasing decisions for their companies in the past year. To reach the business customer, Idaho Power placed two backlit display ads. One ad is located at the baggage claim and the other rotates throughout the airport display boards based on availability. Idaho Power also purchased digital network ads which played 10-second Idaho Power video clips on 15 television screens throughout the terminal as part of a three-minute advertising loop. The videos played an estimated 216,000 times per month.

### Print

Several print ads ran in 2016, promoting the Commercial and Industrial Energy Efficiency Program. Ads ran in Alaska Airline’s *Horizon Air Magazine*, Building Owners and Managers Association (BOMA) membership directory and symposium program, American Institute of Architects Idaho Chapter membership directory, Business Insider, Grow Smart Awards event program. The company also placed an ad in the *Idaho Business Review* as part of the publication’s Top Projects Awards that congratulated the 10 companies that had the most energy savings throughout the year.

Revision and updating of the Commercial and Industrial Energy Efficiency Program brochure, business card, and industry specific energy efficiency tip brochures also began in 2016.

### Bill Insert

In August, a bill insert promoting Idaho Power's Commercial and Industrial Energy Efficiency Program was included in 39,742 business customers' bills highlighting how Idaho Power's incentives can save customers money.

### Newsletters

Idaho Power promotes energy efficiency and its programs through the company's *Energy@Work* newsletter. Written for small- and medium-sized business customers, Idaho Power published this newsletter in May and September 2016. Content included customer success stories and information on training opportunities, energy efficiency programs, electric vehicles, reduced wattage T-8 lightbulbs, the water supply optimization cohort (WSOC), and more.

Idaho Power also sends an email newsletter, *Energy Insights*, quarterly to large industrial customers. Topics included how businesses use energy, Idaho Power's environmental efforts, energy efficiency success stories, LED advantages, power quality devices, and more.

### Public Relations

Idaho Power provides public relations support to commercial and industrial customers who want to publicize the work they have done to become more energy efficient. Upon request, Idaho Power creates large-format checks that are used for media events and/or board meetings. Idaho Power will continue to assist customers with public relations opportunities by creating certificates for display within the building and having an Idaho Power representative speak at press events, if requested.

### Sponsorships

Idaho Power's Commercial and Industrial Energy Efficiency Program supports a number of associations and events, including sponsoring the Grow Smart awards, Top Projects Awards, BOMA symposium, American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE) Technical Conference, and the Idaho Energy and Green Building Conference.

Idaho Power sponsored the BOMA Commercial Real Estate Symposium February 9, in Boise. Idaho Power Vice President of Customer Operations, Vern Porter, spoke about why energy efficiency makes good business sense, how Idaho Power's programs can help businesses save energy and money, and provided an example of a recent energy efficiency project and a reminder about the importance of putting down your phone in the car to Just Drive.

Idaho Power and NEEA were also major sponsors of the Idaho Energy and Green Building Conference, and had two members on the planning committee. The conference, held November 1 and 2 at The Wyndham Garden Boise Airport Hotel, provided four training tracks on energy efficiency and green building, and attracted over 100 participants. The conference targeted policy makers, developers, architects, code officials, engineers, energy professionals, and industrial plant managers and operators.

## *Irrigation*

See the Irrigation Efficiency Rewards section for 2016 irrigation-related marketing activities.

## 2017 Marketing Activities

In 2017, the Idaho Power marketing department plans on several approaches to reach and educate customers: updating the Residential Energy Efficiency Awareness Campaign, developing new Commercial and Industrial Energy Efficiency ads, and enhancing the company website.

The marketing team will refresh the Residential Energy Efficiency Awareness Campaign with new ads that promote different programs and tips. However, the campaign will continue to use the Energy Savings Made Easy theme and cartoon artwork that has resonated with customers. The team will also continue exploring a consistent look and feel for all residential program materials, and consider the potential for email marketing.

A new ad campaign will be implemented for the Commercial and Industrial Energy Efficiency Program. The campaign features former program participants and iconic local landscapes to capture the readers' attention. The ads will speak to small to large businesses, and show that saving energy and money is for everyone. Several of the customers in the ad campaign will be featured in videos about businesses that took advantage of Idaho Power's incentives and the resulting benefits. The ads will be placed in business and association publications, and event programs.

Idaho Power will also move toward a consistent look and feel for marketing materials for business customers. The company will update the remaining industry-specific energy efficiency tip brochures, and may add new industries and inserts highlighting the incentives available for each industry. Customer representatives will use these brochures on customer visits, and the company will consider mailing them to targeted customers.

The company will continue to support various organizations and programs, including the Intermountain Building Operators Association, Building Operators Certification, Center for Advanced Energy Studies Industrial Assessment Center, and more. Idaho Power will market the organizations' services during customer site visits and at technical training workshops and provide discounted registration when appropriate.

Additionally, the company will consider an ad campaign similar to the new Commercial and Industrial Energy Efficiency Program campaign for its irrigation programs.

Idaho Power will also redesign its website to an adaptive framework, including updating navigation for a better customer experience. The company's interactive approach, which began with myAccount in 2015, and saw additional user improvements in 2016, is scheduled for completion in 2017. Idaho Power's new adaptive site will enhance navigation to make energy efficiency program information easier to find. An adaptive website recognizes the device accessing the website and automatically responds or adapts to the dimensions of that device (e.g., a smart phone).

## Cost-Effectiveness

In 2016, most of Idaho Power's energy-efficiency programs were cost-effective, except the Fridge and Freezer Recycling Program, Home Improvement Program and the weatherization programs for income-qualified customers.

The Fridge and Freezer Recycling Program has a UC of 0.92 and TRC of 1.31. In November 2015, the program vendor JACO Environmental, Inc. (JACO), entered receivership and ceased operations. Idaho Power then contracted with Appliance Recycling Center of America (ARCA) and re-launched the program in June 2016. Due to the mid-year launch, the company had forecasted that participation would be at 1,000 units, and the program would likely not be cost-effective from the UC perspective but would be cost-effective from the TRC perspective. This was discussed with the EEAG in February 2016. When considering individual measures within the program, both freezers and refrigerators fail the UC test with a ratio of 0.79 and 0.91 respectively. However, both freezers and refrigerators pass the TRC. However, by allowing the less cost-effective freezers into the program, it increase overall participation and increases the program cost-effectiveness by spreading the portion of the fixed administrative costs across more units.

The Home Improvement Program has a UC of 2.54, TRC of 0.60 and PCT of 0.80. The RTF reduced savings for single-family home weatherization projects in 2015. With the changes, average savings estimates per project for both 2015 and 2016 were just under 50 percent of 2014 projects. These new savings were a result of the nearly 18-month RTF process to calibrate residential savings models. Additionally, in early 2016, the RTF finished calibrating the savings models for multifamily weatherization. These lower savings as well as the DSM avoided costs from the 2015 IRP further reduces the TRC and PCT of the program. Idaho Power analyzed ways to modify the program to improve the cost-effectiveness, but the company concluded that the program would remain not cost-effective. At the November EEAG meeting, the company presented the non-cost-effective aspects of the Home Improvement Program, the result of the company's analysis, and informed EEAG of the company's plan to end the program in 2017.

WAQC had a TRC of 0.65 and a UC ratio of 0.73, and Weatherization Solutions for Eligible Customers had a TRC of 0.70 and a UC ratio of 0.59. The programs showed increased savings and increased cost-effectiveness ratios over 2015. Idaho Power performed a billing analysis of the 2013–2014 weatherization projects from both WAQC and Weatherization Solutions for Eligible Customers. The billing analysis was needed to reflect the increased replacement of forced-air electric resistance heat systems with efficient heat pump systems.

Eleven individual measures in various programs are shown to not be cost-effective from either the UC or TRC perspective. These measures will be discontinued, analyzed for additional NEBs, modified to increase potential per-unit savings, or monitored to examine their impact on the specific program's overall cost-effectiveness.

Table 6. Cost-effectiveness summary by program

| Program/Sector | UC | TRC | Ratepayer Impact Measure (RIM) | PCT |
|---|---|---|---|---|
| Easy Savings | 1.69 | 2.04 | 0.55 | n/a |
| Educational Distributions | 3.63 | 6.33 | 0.65 | n/a |
| Energy Efficient Lighting | 4.27 | 2.52 | 0.68 | 3.17 |
| Energy House Calls | 2.11 | 2.75 | 0.56 | n/a |
| ENERGY STAR ® Homes Northwest | 1.79 | 1.00 | 0.63 | 1.46 |
| Fridge and Freezer Recycling Program | 0.92 | 1.31 | 0.43 | n/a |
| Heating & Cooling Efficiency Program | 2.33 | 1.26 | 0.71 | 1.76 |
| Home Improvement Program | 2.54 | 0.60 | 0.64 | 0.80 |
| Multifamily Energy Savings Program | 1.43 | 2.55 | 0.51 | n/a |
| Rebate Advantage | 3.89 | 3.33 | 0.62 | 6.45 |
| Simple Steps, Smart Savings | 2.40 | 1.33 | 0.61 | 2.13 |
| Weatherization Assistance for Qualified Customers | 0.73 | 0.65 | 0.41 | n/a |
| Weatherization Solutions for Eligible Customers | 0.59 | 0.70 | 0.36 | n/a |
| **Residential Energy Efficiency Sector** | **2.74** | **2.36** | **0.63** | **4.10** |
| Commercial and Industrial Energy Efficiency Program | | | | |
| Custom Projects | 5.26 | 2.86 | 1.44 | 1.92 |
| New Construction | 4.40 | 3.07 | 0.96 | 3.19 |
| Retrofits | 3.83 | 2.64 | 0.93 | 2.83 |
| **Commercial/Industrial Energy Efficiency Sector *** | **4.67** | **2.81** | **1.19** | **2.31** |
| Irrigation Efficiency | 4.95 | 3.21 | 1.34 | 2.78 |
| **Irrigation Energy Efficiency Sector **** | **5.00** | **3.17** | **1.35** | **2.73** |
| **Energy Efficiency Portfolio** | **3.58** | **2.56** | **0.95** | **2.93** |

* Commercial/Industrial Energy Efficiency Sector cost-effectiveness ratios include savings and participant costs from Green Motors projects.
** Irrigation Energy Efficiency Sector cost-effectiveness ratios include savings and participant costs from Green Motors projects.

Details on the cost-effectiveness assumptions and data are included in *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction

Based on surveys conducted in 2015, Idaho Power ranked fifth out of seven utilities included in the west region midsize segment of the J.D. Power and Associates *2016 Electric Utility Business Customer Satisfaction Study*. Forty-one percent of the business customer respondents in this study indicated they were aware of Idaho Power's energy efficiency programs, and those customers were more satisfied with Idaho Power than customers who are unaware of the programs.

Based on surveys conducted in the last six months of 2015 and the first six months of 2016, Idaho Power ranked third out of 13 utilities included in the west region midsize segment of the J.D. Power and Associates *2016 Electric Utility Residential Customer Satisfaction Study*. Forty-nine percent of the residential respondents in this study indicated they were aware of Idaho Power's energy efficiency programs, and those customers were more satisfied with Idaho Power than customers who are unaware of the programs.

Idaho Power employs Burke, Inc., an independent, third-party research vendor, to conduct quarterly customer relationship surveys to measure the overall customer relationship and satisfaction with Idaho Power. The Burke Customer Relationship Survey measures the satisfaction of a number of aspects of the customer's relationship with Idaho Power, including energy efficiency at a very high level. However, it is not the intent of this survey to measure all aspects of energy efficiency programs offered by Idaho Power.

The 2016 results of Idaho Power's customer relationship survey showed an increase in overall satisfaction from the previous year. Sixty-five percent of customers indicated their needs were met or exceeded by Idaho Power encouraging energy efficiency among its customers.

Figure 12 depicts the annual change in the percent of customers who indicated Idaho Power met or exceeded their needs concerning energy efficiency efforts encouraged by Idaho Power. In 2016, offering energy efficiency programs was one of the overall top five attributes with a positive change in the Burke Customer Relationship Survey.

In 2016, offering energy efficiency programs was one of the overall top five attributes with a positive change in the Burke Customer Relationship Survey. Three questions related to energy efficiency programs in the general relationship survey continued in the 2016 survey: 1) Have you participated in any of Idaho Power's energy efficiency programs? 2) Which energy efficiency program did you participate in? and 3) Overall, how satisfied are you with the energy efficiency program? In 2016, 44 percent of the survey respondents across all sectors indicated they participated in at least one Idaho Power energy efficiency program, and 93 percent were "very" or "somewhat" satisfied with the program they participated in.

Idaho Power will not survey most energy efficiency program participants annually. This is due primarily to a concern of over-surveying program participants and because the measures and specifics of most program designs do not change annually. To ensure meaningful research in the future, Idaho Power will conduct program research periodically (every two to three years), unless there have been major program changes.

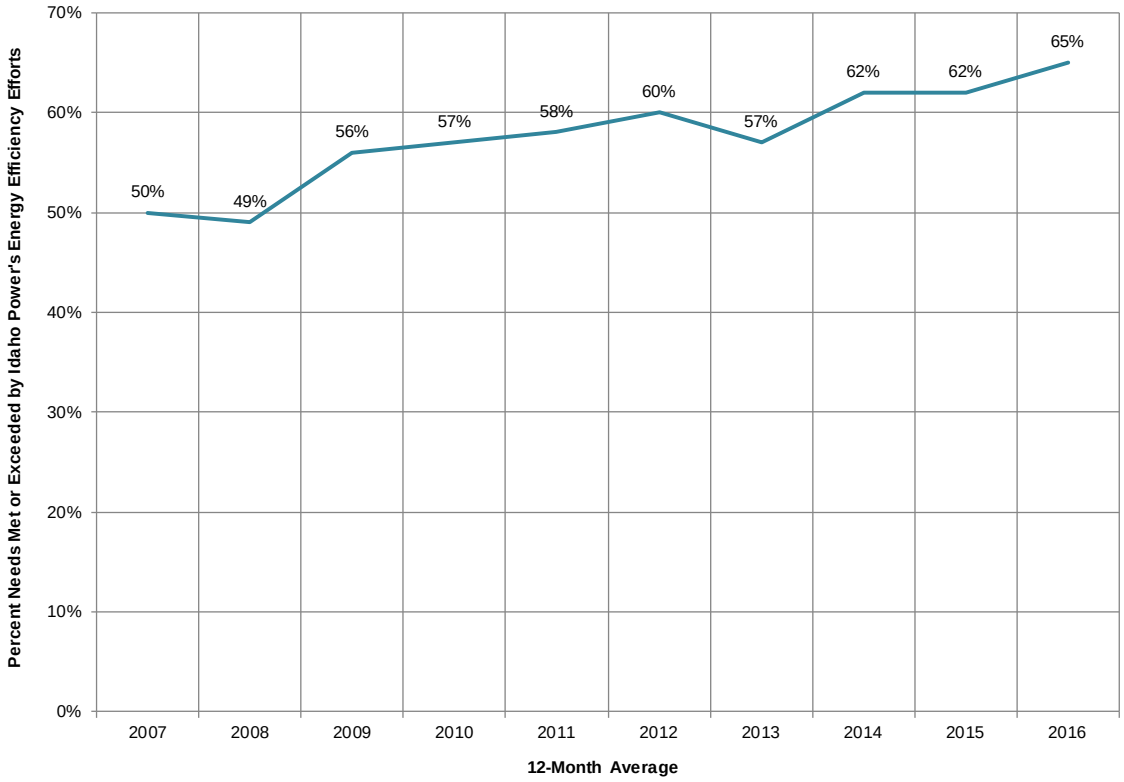



Figure 12. Customers' needs "met" or "exceeded" (percent), 2007–2016

In 2015, Idaho Power created the em**powered** community, an on-line community of residential customers, to measure customer perceptions on a variety of company-related topics, including energy efficiency. Recruiting for the community is conducted annually primarily through billing inserts and mailed postcards. The community has just over 1,000 active members. The em**powered** community includes customers from across Idaho Power's service area. Idaho Power sends out at least one survey per month to active members. Energy efficiency-related survey topics in 2016 included likelihood to install energy-saving improvements, recall of the spring 2016 energy efficiency marketing campaign, energy-efficient lighting, an engagement survey on air conditioning efficiency, thermostatic shower shut-off valves, an engagement survey on using energy-efficient cooking methods and holiday lighting. The average response rate for surveys conducted with the online community is 61.3 percent.

Results of these studies are included in *Supplement 2: Evaluation*.

## Evaluations

In 2016, Idaho Power contracted with Leidos Engineering (Leidos) to conduct four program impact evaluations and two program process evaluations. Impact evaluations were performed for the Retrofit (Easy Upgrades), New Construction (Building Efficiency), Rebate Advantage, and Irrigation Efficiency Rewards programs. Process evaluations were performed for the Rebate Advantage and Irrigation Efficiency Rewards programs. CLEAResult, conducted impact evaluations of the A/C Cool Credit, and Flex Peak programs' 2016 demand response events.

Throughout 2016, Idaho Power administered several surveys regarding energy efficiency programs to measure customer satisfaction. Some surveys were administered by a third-party contractor; other surveys were administered by Idaho Power either through traditional means or through the company's em**powered** community on-line survey.

Final reports from all evaluations, research, and surveys completed in 2016 and an evaluation schedule is provided in *Supplement 2: Evaluation*.

# Residential Sector Overview

Idaho Power's residential sector consists of over 444,431 customers. In 2016, the residential sector's number of customers increased by 8,329, an increase of 1.9 percent from 2015. The residential sector represents 43 percent of Idaho Power's actual total electricity usage and 35 percent of overall revenue in 2016.

Table 7 shows a summary of 2016 participants, costs, and savings from the residential energy efficiency programs.

Table 7. 2016 residential program summary

| Program | Participants | | Total Cost | | Savings | |
|---|---|---|---|---|---|---|
| | | | Utility | Resource | Annual Energy (kWh) | Peak Demand (MW) |
| **Demand Response** | | | | | | |
| A/C Cool Credit | 28,315 | homes | $1,103,295 | $ 1,103,295 | n/a | 34 |
| **Total** | | | **$1,103,295** | **$ 1,103,295** | **n/a** | **34** |
| **Energy Efficiency** | | | | | | |
| Easy Savings | 2,001 | kits | $127,587 | 127,587 | 402,961 | |
| Educational Distributions | 67,065 | kits/lightbulbs | 2,392,884 | 2,392,884 | 15,149,605 | |
| Energy Efficient Lighting | 1,442,561 | lightbulbs | 3,080,708 | 10,770,703 | 21,093,813 | |
| Energy House Calls | 375 | homes | 206,437 | 206,437 | 509,859 | |
| ENERGY STAR® Homes Northwest | 110 | homes | 142,158 | 297,518 | 150,282 | |
| Fridge and Freezer Recycling Program (See ya later, refrigerator®) | 1,539 | refrigerators/freezers | 257,916 | 257,916 | 632,186 | |
| Heating & Cooling Efficiency Program | 486 | projects | 594,913 | 1,404,625 | 1,113,574 | |
| Home Energy Audit | 539 | homes | 289,812 | 289,812 | 207,249 | |
| Home Improvement Program | 482 | homes | 324,024 | 1,685,301 | 500,280 | |
| Multifamily Energy Savings Program | 3 | projects | 59,046 | 59,046 | 149,760 | |
| Oregon Residential Weatherization | 7 | homes | 3,930 | 5,900 | 2,847 | |
| Rebate Advantage | 66 | homes | 111,050 | 148,142 | 411,272 | |
| Shade Tree Project | 2,070 | trees | 76,642 | 76,642 | n/a | |
| Simple Steps, Smart Savings | 7,880 | appliances/ showerheads | 153,784 | 379,752 | 577,320 | |
| Weatherization Assistance for Qualified Customers | 246 | homes/non-profits | 1,289,809 | 1,934,415 | 746,162 | |
| Weatherization Solutions for Eligible Customers | 232 | homes | 1,323,793 | 1,323,793 | 621,653 | |
| **Total** | | | **$10,434,493** | **$21,360,473** | **42,268,823** | **34** |

**Notes:**
See Appendix 3 for notes on methodology and column definitions.
Totals may not add up due to rounding.

In 2016, the company added two new residential programs and reintroduced or modified others. The Multifamily Energy Savings Program was added in March, the ESK program launched in May, and the Fridge and Freezer Recycling program was re-introduced in June. The Home Energy Audits program was extended to customers with non-electric heat sources and a smart thermostat incentive was added to the Heating and Cooling Efficiency (H&CE) Program. Additionally, the residential team supported a Drying Rack Pilot Project.

Idaho Power conducts the Burke Customer Relationship Survey each year. In 2016, 54 percent of residential survey respondents indicated Idaho Power is meeting or exceeding their needs with information on how to use energy wisely and efficiently.

Sixty-three percent of residential respondents indicated Idaho Power is meeting or exceeding their needs by encouraging energy efficiency with its customers. Forty-eight percent of Idaho Power residential customers surveyed in 2016 indicated Idaho Power is meeting or exceeding their needs in offering energy efficiency programs, and 34 percent of the residential survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of the residential survey respondents who have participated in at least one Idaho Power energy efficiency program, 86 percent are "very" or "somewhat" satisfied with the program. In 2016, offering energy efficiency programs was one of the residential top five attributes with a positive change in the Burke Customer Relationship Survey.

Forty-nine percent of the Idaho Power residential customers included in the *2016 J.D. Power and Associates Electric Utility Residential Customer Satisfaction Study* indicated they are familiar with Idaho Power's energy efficiency programs.

In 2016, the em**powered** community was surveyed regarding customer recall of the energy efficiency marketing campaign, shut-off shower valves, air conditioning efficiency, energy-efficiency tips, cooking methods, and holiday lighting. Results of these studies are included in *Supplement 2: Evaluation*.

During 2016, presentations to community groups and businesses continued to be an important method of communicating with Idaho Power customers. The company's customer representatives and community education representatives made hundreds of presentations in communities in Idaho Power's service area.

## A/C Cool Credit

| | | 2016 | 2015 |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (participants) | 28,315 | 29,000 |
| | Energy Savings (kWh) | n/a | n/a |
| | Demand Reduction (MW) | 34 | 36 |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $632,079 | $659,471 |
| | Oregon Energy Efficiency Rider | $41,833 | $45,825 |
| | Idaho Power Funds | $429,383 | $443,639 |
| | Total Program Costs—All Sources | $1,103,295 | $1,148,935 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/kWh) | n/a | n/a |
| | Total Resource Levelized Cost ($/kWh) | n/a | n/a |
| **Benefit/Cost Ratios** | | | |
| | Utility Benefit/Cost Ratio | n/a | n/a |
| | Total Resource Benefit/Cost Ratio | n/a | n/a |

### Description

Originating in 2003, A/C Cool Credit is a voluntary, dispatchable demand response program for residential customers in Idaho and Oregon. Using communication hardware and software, Idaho Power cycles participants' central air conditioning (A/C) units or heat pumps off and on via a direct load control device installed on the A/C unit. This program enables Idaho Power to reduce system capacity needs during times when summer peak load is high.

Customers' A/C units are controlled using switches that communicate by powerline carrier (PLC). A switch is installed on each customer's A/C unit and allows Idaho Power to cycle the customer's A/C unit during a cycling event.

The cycling season is June 15 through August 15. The maximum number of cycling hours available per season is 60 hours, with a minimum of three cycling events per season. The cycling rate is the percentage of an hour that the A/C unit will be turned off by the switch. For instance, with a 55 percent cycling rate, the switch should be off for 33 minutes of each hour on average, though not 33 consecutive minutes. Instead, the switch turns the A/C unit off for a period of time and then back on for a period of time.

Idaho Power measures the communication levels to validate whether the signal reaches the switches. Interruptions may be caused by a malfunctioning or broken switch, or by an A/C unit that is not powered on. The incentive is $15 per season, paid as a $5 bill credit on the July, August, and September bills. The program is not available on weekends or holidays, and the maximum length of an event is four hours.

## Program Activities

In 2016, over 28,000 customers participated in the program. Three cycling events occurred, and all were successfully deployed.

The first event was Thursday, June 30 from 4 p.m. to 7 p.m. Communication levels were between 92.10 percent and 94.78 percent. The cycling rate was 55 percent. The Boise area temperature was 97 degrees, and the Pocatello/Twin Falls area temperature was 97 degrees. The expected demand reduction for the event was 1.02 kilowatt (kW) per participant for Boise and 0.7 kW per participant for Pocatello/Twin Falls for a total reduction of 27.63 MW. Analysis results show a max reduction of 1.11 kW per participant in Boise, 0.84 kW per participant in Pocatello/Twin Falls, and a total reduction of 30.165 MW. This is 109 percent of expected demand reduction.

The second event was Tuesday, July 26 from 4 p.m. to 7 p.m. Communication levels were between 93.6 percent and 93.99 percent. The cycling rate was 55 percent. The Boise area temperature was 99 degrees, and the Pocatello/Twin Falls area temperature was 95 degrees. The expected demand reduction for the event was 1.09 kW per participant for Boise and 0.68 kW per participant for Pocatello/Twin Falls for a total reduction of 29.23 MW. Analysis results show a max reduction of 1.1 kW per participant in Boise and 0.86 kW per participant in Pocatello/Twin Falls for a total reduction of 29.77 MW. This is 102 percent of expected demand reduction.

The third event was Thursday, July 28 from 4 p.m. to 7 p.m. Communication levels were between 93.99 percent and 94.25 percent. The cycling rate was 55 percent. The Boise area temperature was 99 degrees, and the Pocatello/Twin Falls area temperature was 95 degrees. The expected demand reduction for the event was 1.09 kW per participant for Boise and 0.68 kW per participant for Pocatello/Twin Falls for a total reduction of 29.15 MW. Analysis results show a max reduction of 1.13 kW per participant in Boise, 0.93 kW per participant in Pocatello/Twin Falls, and a total reduction of 30.935 MW. This is 106 percent of expected demand reduction.

## Marketing Activities

Per the settlement agreement reached in Idaho Case No. IPC-E-13-14 and Oregon Case No. UM 1653, Idaho Power did not actively market the A/C Cool Credit program in 2016; however, Idaho Power did actively communicate with participants about the program in an effort to maintain participant retention.

Before the cycling season began, Idaho Power sent current participants a postcard reminding them of the program specifics. Idaho Power also attempted to recruit customers who had moved into a home that already had a load control device installed and previous participants who changed residences to a location that may or may not have a load-control device installed. The company used postcards, phone calls, direct-mail letters, and home visits, leaving door hangers for those not home, to recruit these customers. At the end of the summer, a thank-you postcard was sent to program participants.

## Cost-Effectiveness

Idaho Power determines cost-effectiveness for it demand response program under the terms of IPUC Order No. 32923 and OPUC Order No. 13-482. Under the terms of the orders and the settlement, all of Idaho Power's demand response programs were cost-effective for 2016.

The A/C Cool Credit program was dispatched for 9 event hours and achieved a maximum demand reduction of 33.94 MW. The total expense for 2016 was $1,103,295 and would have remained the same if the program was fully used for 60 hours because there is no variable incentive paid for events beyond the three required events.

In 2016, the cost of operating the three demand response programs was $9.47 million. Idaho Power estimates that if the three programs were dispatched for the full 60 hours, the total costs would have been approximately $12.87 million and would have remained cost-effective.

A complete description of Idaho Power cost-effectiveness of its demand response programs is included in *Supplement 1: Cost-effectiveness.*

## Customer Satisfaction and Evaluations

Idaho Power conducted no customer satisfaction surveys for this program in 2016.

Idaho Power contracted with CLEAResult to complete an impact evaluation of the 2016 A/C Cool Credit program. The goal of the evaluation was to estimate demand reduction achieved during three curtailment events and update the existing predictive model to incorporate results from the 2016 curtailment events.

CLEAResult completed analyses of curtailment events held on June 30, July 26, and July 28, each with a three-hour duration. Results of the analyses showed maximum single hour demand reductions of 1.07 kW, 1.06 kW, and 1.11 kW per participant, respectively, for the three events. The results of the curtailment event analyses showed maximum generation-level demand reductions of 33.09, 32.66, and 33.94 MW, respectively, for the three events. The results of the curtailment event analyses showed maximum meter-level demand reductions of 30.2, 29.8, and 30.9 MW, respectively, for the three events.

The results of the impact evaluation demonstrated that Idaho Power's A/C Cool Credit program functions as intended, and if properly maintained, can be relied on to provide dispatchable demand reduction to the electricity grid. Due to the distinct weather patterns between Boise and Pocatello/Twin Falls, each curtailment event analysis included region-specific results. A copy of the report is included in *Supplement 2: Evaluation*.

## 2017 Program and Marketing Strategies

Idaho Power anticipates no program changes in 2017.

Per the terms of the above-mentioned settlement agreements, Idaho Power will not actively promote the A/C Cool Credit program to solicit new participants through marketing but will accept new participants who request to participate, regardless of whether they were previous participants in the program.

Attempts will continue to be made to recruit previous participants who have moved, as well as new customers moving into homes that already have a load control device installed.

## *Easy Savings*

| | 2016 | 2015 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (kits) | 2,001 | 2,068 |
| Energy Savings (kWh) | 402,961 | 624,536 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $0 | $0 |
| Oregon Energy Efficiency Rider | $0 | $0 |
| Idaho Power Funds | $127,587 | $127,477 |
| Total Program Costs—All Sources | $127,587 | $127,477 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.035 | $0.021 |
| Total Resource Levelized Cost ($/kWh) | $0.035 | $0.021 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.69 | 2.61 |
| Total Resource Benefit/Cost Ratio | 2.04 | 2.95 |

### Description

The desired outcomes of the Easy Savings program are to educate recipients about saving energy in their homes by using energy wisely, to allow hands-on experience while installing low-cost measures, and to reduce the energy burden for energy assistance/Low Income Home Energy Assistance Program (LIHEAP) recipients.

As a result of IPUC Case No. IPC-E-08-10 under Order Nos. 30722 and 30754, Idaho Power committed to fund energy efficiency education for low-income customers and provide $125,000 to Community Action Partnership (CAP) agencies in the Idaho Power service area on a prorated basis. These orders specified that Idaho Power provide educational information to customers who heat their homes with electricity provided by Idaho Power in Idaho. This is accomplished through the development and distribution of kits containing low cost, self-install energy efficiency items and educational materials.

Initiated in 2009, the Easy Savings program straddles two calendar years. The LIHEAP program cycle starts annually in November at CAP agencies and follows the federal fiscal calendar, while Idaho Power summarizes activities annually based on a January to December cycle. However, the following report summarizes activities from November 2015 through October 2016 and covers future plans for the 2016 to 2017 program.

### Program Activities

By April 2016, 2,001 kits from the 2015 to 2016 program year were distributed by regional CAP agencies to Idaho Power customers approved to receive LIHEAP benefits on their Idaho Power bills.

Each kit contained the following low-cost and no-cost energy-saving items and a survey:

- Three LED lightbulbs—9 watts (W)
- Set of draft stopping outlet gaskets
- Digital thermometer
- 1.5 gallons per minute (gpm) kitchen faucet aerator
- One single-line indoor clothesline
- LED nightlight with photocell and a set of reminder stickers and magnets
- Easy Savings Quick Start Guide to installation
- Mail-in survey and energy-savings information

### Marketing Activities

Idaho Power does not actively market this program.

### Cost-Effectiveness

The RTF LED giveaway deemed savings values are used for the three LED lightbulbs included in the kit because the savings are discounted to reflect the potential that all the kit items may not be installed. For the faucet aerator, the RTF does not provide a deemed savings estimate. In Idaho Power's 2012 *Energy Efficiency Potential Study*¸ AEG estimates the annual faucet aerator savings to be 106 kWh. For the single-line clothes line, Idaho Power used the assumptions for the clothes drying racks and discounted the annual savings to be 68 kWh. For further information regarding the clothes drying rack savings, see the *Cost-Effectiveness* section for the Educational Distributions program.

### Customer Satisfaction and Evaluations

A mail-in survey inquiring about installation experiences and actions taken to reduce energy use was included in the 2,001 kits distributed. Returned surveys were analyzed to track the effectiveness and educational impact of the program.

There were 213 completed surveys received from customers describing their experience in installing kit items in their homes during the 2015 to 2016 program. The survey included questions about whether the customer took specific actions to reduce energy use as a result of receiving the kit, as well as questions confirming the installation of kit items.

Over 92 percent of respondents reported they have, or will lower their heat during the day, and just over 90 percent reported they have, or will lower their heat at night. Just over 85 percent of the respondents reported installing at least one of the LEDs provided in the kit. Just over 38 percent of the respondents reported installing the high indoor clothesline and another 30 percent reported they planned to install it.

Overall, survey results showed that almost 39 percent of the respondents installed all kit items. Just over 77 percent of the respondents reported learning a lot about saving energy and money in their home after

completing the *Easy Savings Quick Start Guide*. Copies of the survey and survey results can be found in *Supplement 2: Evaluation*.

During the 2015 to 2016 program, three gift certificates valued at $100 each were provided by Community Action Partnership Association of Idaho, Inc. (CAPAI), to encourage survey completion. A drawing from all returned surveys was held, and three households won a $100 gift certificate.

Idaho Power conducted no program evaluations in 2016.

### 2016 to 2017 Program and Marketing Strategies

For the 2016 to 2017 program period, Idaho Power sent checks totaling $125,000 in October to the five Idaho regional CAP agencies. Each agency signed a Memorandum of Understanding (MOU) agreeing to use 30 percent of the agency's allotment to cover expenses for administering the program at their agency. The 30 percent includes the provision for an agency certified energy educator to inform kit recipients about installation techniques and energy efficiency information.

CAP agencies ordered 2,470 kits in October 2016, and received them from the vendor in November. These kits, which include five LED lightbulbs and an indoor clothesline, will be distributed to customers throughout the 2016 to 2017 LIHEAP season.

Upon completion of kit distribution and receipt of corresponding surveys, Idaho Power and CAPAI will consider program changes for the future.

## Educational Distributions

| | | 2016 | 2015 |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (kits/lightbulbs) | 67,065 | 28,197 |
| | Energy Savings (kWh) | 15,149,605 | 1,669,495 |
| | Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $2,334,206 | $432,185 |
| | Oregon Energy Efficiency Rider | $56,164 | $0 |
| | Idaho Power Funds | $2,514 | $0 |
| | Total Program Costs—All Sources | $2,392,884 | $432,185 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/kWh) | $0.016 | $0.026 |
| | Total Resource Levelized Cost ($/kWh) | $0.016 | $0.026 |
| **Benefit/Cost Ratios** | | | |
| | Utility Benefit/Cost Ratio | 3.63 | 2.05 |
| | Total Resource Benefit/Cost Ratio | 6.33 | 2.60 |

### Description

Designated as a specific program in 2015, the Educational Distributions effort is administered through the Residential Energy Efficiency Education Initiative and seeks to use low-cost and no-cost channels to deliver energy efficiency items with energy savings directly to customers. As with the initiative, the goal for these distributions is to drive behavior change and create awareness of and demand for energy efficiency programs in Idaho Power's service area.

Items selected for distribution have an initial cost-effectiveness analysis that indicates the installed measure is either currently cost-effective or is expected to be cost-effective in the near future. Typically, selected items have additional benefits beyond traditional energy savings, such as educating customers about energy efficiency, expediting the opportunity for customers to experience newer technology, or allowing Idaho Power to gather data or validate potential energy savings resulting from behavior change.

Idaho Power recognizes that behavioral measures and programs require appropriate education and guidance to optimize savings and will plan education accordingly. Items may be distributed at events, presentations, through direct-mail, or home visits conducted by customer representatives.

#### *Drying Rack Pilot Project*

Idaho Power distributed drying racks to determine whether customers can comfortably shift about 25 percent of their clothes drying from an automatic dryer to a drying rack.

#### *Energy-Saving Kits*

Idaho Power knows that managing household energy use can be a challenge. To help make it easier for families, Idaho Power works with a kit vendor to provide two versions of free ESKs—one for homes

with electric water heaters and one for homes with alternate-source water heaters. Customers enroll online at idahopower.com/save2day, by calling 800-465-6045, or by returning a postcard. Kits are sent directly to the customer's home.

Each ESK contains nine LED lightbulbs—six 60-watt equivalent lightbulbs, three 45-watt equivalent lightbulbs, a digital thermometer (to check refrigerator, freezer and water temperatures), a shower timer, a water flow-rate test bag, an LED night light and educational materials. In addition, the kit for homes with electric water heaters contains a high-efficiency showerhead and three faucet aerators.




Figure 13. Ad for Idaho Power residential customers to order a 2016 ESK

***LED Lightbulbs as Giveaways***

LED lightbulbs are a welcome and effective way to connect Idaho Power with customers, and to begin productive conversations around energy efficiency. Idaho Power field staff and energy efficiency program managers seek opportunities to educate customers about LEDs, and to offer customers a free lightbulb to use immediately in their own homes.

***Student Energy Efficiency Kit Program***

The Student Energy Efficiency Kit (SEEK) program provides fourth- to sixth-grade students in schools in Idaho Power's service area with quality, age-appropriate instruction regarding the wise use of electricity. Each child who participates receives an energy efficiency kit. The products in the kit are selected specifically to encourage energy savings at home and engage families in activities that support and reinforce the concepts taught at school.

Once a class enrolls in the program, teachers receive curriculum and supporting materials. Students receive classroom study materials, a workbook, and a take-home kit containing three LED lightbulbs, a high-efficiency showerhead, an LED nightlight, a furnace filter alarm, a digital thermometer for measuring water, refrigerator and freezer temperatures, a water flow-rate test bag, and a shower timer. At the conclusion of the program, students and teachers return feedback to the vendor indicating how the program was received and which measures have been installed. The vendor uses this feedback to provide a comprehensive program summary report showing program results and savings.

Unlike other residential programs offered by Idaho Power, SEEK results are reported on a school-year basis.

## Program Activities

On February 8, 2016, Idaho Power filed a request with the OPUC seeking authority to implement the Educational Distributions program in Oregon. The company received approval of Oregon Schedule 71 on March 9, 2016.

### *Drying Rack Pilot Project*

Idaho Power gave away approximately 1,300 drying racks at eight events, primarily in the Treasure Valley and Pocatello areas. In the Boise area, attendees at select 2015 fall events filled out a card expressing interest in receiving a free drying rack. Idaho Power representatives explained the enrollment and distribution process, and enrollment emails were sent early in January 2016. Most participants enrolled online, confirming their eligibility and completing a survey about their current laundry habits. Customer distribution events in Boise and Nampa occurred in late January.

The first Pocatello event was held in Fort Hall in March with a slightly different distribution model—customers were enrolled on-site when they presented a current Idaho Power bill. Idaho Power staff administered the pre-survey verbally to each Fort Hall participant.

The Salmon and Pocatello events followed—again with the on-line enrollment strategy. The remaining drying racks were given to American Falls residents in August using a third distribution model. Participants were not pre-enrolled. Instead, customers reviewed eligibility requirements and signed an agreement confirming their eligibility and committing to take the survey within 24 hours of receiving the drying rack.

Education and information regarding efficient laundry practices was conveyed via the website enrollment tool, the enrollment survey, at each event via a "Ways to Save" card addressing ways to "Lighten Your Laundry Load," and through follow-up email prompts.

### *Energy-Saving Kits*

By the end of 2016, 34,546 kits had been shipped—19,715 kits to homes with electric water heaters and 14,831 to homes with alternate-source water heaters. Kits were distributed to all geographic regions within Idaho Power's service area, including 33,682 to Idaho residences and 864 to Oregon homes.

### *LED Lightbulbs as Giveaways*

Field staff distributed over 8,000 lightbulbs at Spring Home and Garden Shows in Pocatello, Twin Falls, and Boise. Participants in Earth Day Events and employee sustainability fairs in Caldwell, Nampa, and Pocatello received lightbulbs. In Boise at Wells Fargo and Hewlett Packard (HP) World Environment Day events attendees received lightbulbs. Oregon customers received lightbulbs at a St. Alphonsus's Safety Fair, Platt Electric Days and a Home Depot children's safety fair. LEDs were also distributed at the Smart Women, Smart Money Conference, West Valley Medical Center employee meetings, Paint the Town™, the Mountain Home Air Force Base, FitOne™ Expo, and through presentations at chambers of commerce and senior centers.

By the end of the year, Idaho Power employees had personally delivered a brief energy efficiency message and distributed 24,913 lightbulbs directly to customers.

#### *SEEK Program*

During the 2015 to 2016 school year, Idaho Power community education representatives actively recruited fourth- to sixth-grade teachers to participate in SEEK. As a result, Resource Action Programs (RAP) delivered 6,305 kits to 219 classrooms in 70 schools within Idaho Power's service area. This resulted in 1,542 MWh of savings.

## Marketing Activities

#### *Drying Rack Pilot Project*

In the Boise area, attendees at select 2015 fall events filled out a card expressing interest in receiving a free drying rack. In other areas, flyers, posters, print ads, online calendars and social media marketing boosted participation to the desired levels. The cover story of the October *Connections* featured customers who had participated in the project, and KPVI in Pocatello ran a news story on the distribution of the drying racks.

#### *Energy-Saving Kits*

Marketing efforts included a direct-mail campaign from the kit vendor to about 15,000 customers in May, publicity via television news segments in May and June on KPVI and KTVB, and social media posts. The program was greatly bolstered by unsolicited social media—in one case, a single Facebook post garnered over 10,000 kit requests.

#### *LED Lightbulbs as Giveaways*

In 2016, Idaho Power field staff and energy efficiency program managers continued to seek opportunities to educate customers about LEDs, and offer customers a free LED lightbulb to use immediately in their own homes.

#### *Student Energy Efficiency Kit Program*

During the 2015 to 2016 school year, Idaho Power community education representatives actively recruited fourth- to sixth-grade teachers to participate in SEEK. In addition, community education representatives appeared on both KPVI (September) and KTVB (October) news segments sharing information about the kits.

## Cost-Effectiveness

In situations where Idaho Power manages the education and distribution through existing distribution channels, the cost-effectiveness calculations will be based on the actual cost of the items. Conversely, if outside vendors are used to assist with distribution, the cost-effectiveness calculations will include all vendor-related charges.

#### *Drying Rack Pilot Project*

Idaho Power is currently assessing if this is an energy-saving and cost-effective measure to continue in the future. To determine an estimate of the potential savings for the drying rack, Idaho Power used estimates from NEEA's *2011 Residential Building Stock Assessment: Single-Family Characteristics and*

*Energy Use (RBSA)*. Based on the Residential Building Stock Assessment (RBSA), study participants in Idaho wash 5.71 loads of laundry per week. Approximately 87.4 percent of those washer loads are dried in a clothes dryer. According to a RTF clothes washer workbook, the baseline dryer uses between 1.36 to 1.27 kWh per load. Using a simple average of these two values, Idaho Power estimates that clothes dryers use approximately 342 kWh per year. However, it must be noted that the NEEA 2014 RBSA Laundry Study estimates that dryers use 805 to 915 kWh per year. For a conservative estimate, Idaho Power kept the 342 kWh per year estimate and assumed that if customers shifted 25 percent of their drying load to a drying rack, they could save at least 85.5 kWh per year.

#### *Energy-Saving Kits*

The RTF provides mail-by-request deemed savings for LED lightbulbs and 1.75 gpm low-flow showerheads. The RTF mail-by-request deemed savings values are discounted to reflect the potential that all of the kit items may not be installed. The LED lightbulbs have a deemed savings value of 10 to 11 kWh per year depending on the lumens of the lightbulb. The 1.75 gpm low-flow showerhead is estimated to save 187 kWh per year. For the faucet aerator, the RTF does not provide a deemed savings estimate. In Idaho Power's 2012 *Energy Efficiency Potential Study*¸ AEG estimates the annual faucet aerator savings to be 106 kWh. The annual savings for an ESK for a home with an electric water heater is 601 kWh. The annual savings for a kit for a home with a non-electric water heater is 96 kWh.

#### *LED Lightbulbs as Giveaways*

In 2016, Idaho Power used the same savings and assumptions as were used in 2014. For the LED giveaways, Idaho Power used the giveaway deemed savings provided by the RTF. The RTF-deemed annual savings of 9 kWh includes assumptions regarding the installation rate, efficiency levels of the existing equipment, and the location of the installation.

#### *SEEK Program*

The cost-effectiveness analysis for the SEEK offering is based on the savings reported by RAP during the 2015 to 2016 school year. RAP calculated the annual savings based on information collected from the participants' home surveys and the installation rate of the kit items. Questions on the survey included the number of individuals in each home, water-heater fuel type, flow rate of old showerheads, and the wattage of any replaced lightbulbs. The response rate for the survey was nearly 71 percent. The survey gathers information on the efficiency level of the existing measure within the home and which efficient measure is installed. The energy savings will vary for each household based on the measures offered within the kit, the number of items installed, and the existing measure that is replaced. Based on the feedback received from the 2015 to 2016 school year, each kit saved approximately 245 kWh annually per household on average. A copy of the report is included in *Supplement 2: Evaluation*.

## Customer Satisfaction and Evaluations

#### *Drying Rack Pilot Project*

When customers enrolled in this pilot, they completed a survey about their current laundry habits. Combined with the post-survey conducted in 2017, the company will analyze the results and determine the potential energy savings of a drying rack. While approximately 1,300 drying racks were distributed in 2016, 2,120 customers completed the pre-survey. Several hundred customers completed the survey, but did not pick up a drying rack

Of customers who own a clothes washer, nearly 35 percent of respondents indicated they have a washer that is less than 5 years old while just over 42 percent of respondents indicated they have a washer that is 5 to 10 years old. Approximately 50 percent of respondents said they own a top-loading clothes washer with a center agitator. Just over 51 percent of respondents wash 3 to 5 loads of laundry each week, while nearly 31 percent of respondents wash 6 to 10 loads of laundry each week.

Of customers who own a clothes dryer, nearly 30 percent of respondents reported that their dryer is less than 5 years old, while nearly 43 percent of respondents indicate their dryer is 5 to10 years old. Just over 29 percent of respondents said they dry 100 percent of their laundry in the dryer, while nearly 53 percent indicated they dry 75 to 99 percent of their laundry in the dryer. Of customers who indicated they dry some of their clothes outside of a clothes dryer, 72 percent of respondents indicated they hang their clothes to dry indoors. When asked how likely they would shift an additional 25 percent or more of their drying to the drying rack, nearly 72 percent of respondents said “very likely,” while just over 26 percent of respondents said “somewhat likely.” A copy of this report is included in *Supplement 2: Evaluation*.

At pickup events, customers were engaged and grateful, tweeting and sharing Facebook posts to let their friends and family know what they were doing.




Figure 14. Customer picking up his drying rack, 2016

Other customers sent emails: “Thank you for the clothes drying rack. I have already used it after picking it up on Saturday at 5 Mile and Franklin. The people were very kind and cheerful and all was organized well. Just wanted to say thank you”

The following Facebook post was indicative of those posted by a number of customers.




Figure 15. Screenshot showing customer appreciation for the drying rack, 2016

But the best part was when participants began to share their stories.

- One customer emailed saying "My drying rack has been so wonderful. About 99% of my laundry is on it. I bought a second one so I can hang the entire weekly batch. Thank you."
- Another emailed, "I am using the drying rack right at the moment! I have loved it. I really appreciate receiving it; I know we have saved energy because of it this summer.
- Another stopped by Idaho Power's booth at the FitOne Expo and raved about her drying rack, stating that she was saving $20 each month.

Other customers' stories were featured in the October edition of *Connections*.

#### *Energy-Saving Kits*

When customers ordered a kit, they completed a short enrollment survey. Upon receipt of the kit, they were encouraged to return a more in-depth survey to indicate which measures had been installed and how satisfied they were with the ordering process. Results from both surveys are included in Supplement 2: *Evaluation*.

Of the 19,715 electric kits distributed, RAP received 2,790 returned surveys for a response rate of just over 14 percent. Of the 14,831 non-electric kits distributed, RAP received 2,588 returned surveys for a response rate of over 17 percent. The overall response rate was over 15 percent.

Approximately 95 percent of respondents indicated they were "very satisfied" with the kit ordering process with 4 percent indicating they "somewhat satisfied." Nearly 94 percent of respondents said they were "very likely" to tell a friend or family member to order a kit. While just over 54 percent of respondents said they were not aware of that Idaho Power had energy efficiency programs and incentives prior to receiving their kit, 99 percent said they were either "very likely" or "somewhat likely" to participate in another energy efficiency program.

Customers organically promoted the ESKs through numerous social media posts similar to the one below. This single post generated tremendous buzz, receiving over 3000 shares and generating over 10,000 enrollments.




Figure 16. Screenshot showing customer excitement on Facebook about the Energy-Saving Kits, 2016

Another customer from Midvale reached out to Idaho Power via the website with this message, "After receiving the free package of LED light bulbs you offered, we have since retrofitted our home and shop with all LED light bulbs, and we love the increased brightness. Thank you for prompting us to make these changes. We definitely want to conserve energy and reduce our power bill to boot!"

***LED Lightbulbs as Giveaways***

Idaho Power conducted no customer satisfaction surveys for this offering in 2016.

Customers at events and presentations continued to readily express appreciation for receiving free LED lightbulbs.

#### *SEEK Program*

The SEEK program is evaluated annually regarding participant satisfaction. For more details on the SEEK program, view the most recent annual report, *Energy Wise® Program Summary Report* located in *Supplement 2: Evaluation*.

Teachers continued to be pleased with the program. One hundred percent of teachers who completed surveys would recommend the program to other colleagues, and 97 percent would conduct the program again. Student engagement remained high as well—71 percent of student surveys were returned, and 69 percent indicated their families changed the way they used energy as a result of the program. Parents also responded favorably, indicating the program was easy to use, they would like to see it continued in local schools, and they would continue to use the kit items at home after completion of the program.

Some participants posted YouTube videos reviewing their kits and the home activities: youtube.com/watch?v=0UrhdTP4ZKc and youtube.com/watch?v=-lyHxacMqvo.

### 2017 Program and Marketing Strategies

#### *Drying Rack Pilot Project*

The Drying Rack Project will be fully evaluated and analyzed to determine how effective the drying racks were in producing the desired behavior change, i.e., reducing automatic dryer use by at least 25 percent. If the project results are favorable, the project may be offered again.

#### *Energy-Saving Kits*

Idaho Power will augment its ESK program with an opportunity to use the basic non-electric water-heating kit as a giveaway, in limited quantities, to garner additional interest and participation at presentations and small events. Promotional materials will be readily available for staff-use at larger events. Social media posts and advertising in the semi-annual *Energy Efficiency Guide*s, *Connections*, and Idaho Power's website will all be used to promote ESKs. Direct and targeted digital marketing campaigns will be considered, as needed, to boost participation with more challenging geographic or demographic populations.

#### *LED Lightbulbs as Giveaways*

Idaho Power plans to continue to offer LED lightbulbs to customers at community events, presentations, and customer visits.

#### *Other Educational Distributions*

Idaho Power will continue to look for opportunities to engage customers with new technologies that stress the importance of energy-efficient behaviors at home. Idaho Power is currently evaluating thermostatic shower valves.

#### *SEEK Program*

Plans for the 2016 to 2017 school year include updating the marketing flyer and developing an electronic marketing piece for distribution to more remote schools and districts. The company will continue to leverage the positive relationships Idaho Power's community education representatives have

within the schools to maintain program participation levels and will heighten visibility to enrollments to add an element of competition amongst the geographic regions. Curriculum will be reviewed for continued relevance to state standards.

## *Energy Efficient Lighting*

| | | 2016 | 2015 |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (lightbulbs) | 1,442,561 | 1,343,255 |
| | Energy Savings (kWh) | 21,093,813 | 15,876,117 |
| | Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $3,009,970 | $1,997,292 |
| | Oregon Energy Efficiency Rider | $63,200 | $60,800 |
| | Idaho Power Funds | $7,538 | $5,291 |
| | Total Program Costs—All Sources | $3,080,708 | $2,063,383 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/kWh) | $0.014 | $0.013 |
| | Total Resource Levelized Cost ($/kWh) | $0.049 | $0.028 |
| **Benefit/Cost Ratios** | | | |
| | Utility Benefit/Cost Ratio | 4.27 | 4.53 |
| | Total Resource Benefit/Cost Ratio | 2.52 | 4.23 |

### Description

Idaho Power and other regional utilities participate in the Simple Steps, Smart Savings™ program, managed by CLEAResult. Idaho Power promotes Simple Steps, Smart Savings offerings to customers in two areas: this lighting program and the appliance promotion program (see the Simple Steps, Smart Savings section of this report).

Initiated in 2002, the Energy Efficient Lighting program follows a markdown model that provides incentives directly to the manufacturers or retailers, with savings passed on to the customer at the point of purchase. The benefits of this model are low administration costs, better availability of products to the customer, and the ability to provide an incentive for specific products. The program goal is to help Idaho Power's Idaho and Oregon residential customers afford to adopt more efficient lighting technology.

ENERGY STAR® lightbulbs, including compact fluorescent lightbulbs (CFL) and LEDs, are a more efficient alternative to standard incandescent and halogen incandescent lightbulbs. Lightbulbs come in a variety of wattages, colors, and styles, including lightbulbs for three-way lights and dimmable fixtures. ENERGY STAR lightbulbs use 70 to 90 percent less energy and last 10 to 25 times longer than traditional incandescent lightbulbs.

Idaho Power pays a flat fee for each kWh savings achieved. The minimum base amount goes directly to buy down the price the product was reduced; the amount applied to administration and marketing varies and can be used for things like retailer promotions. Promotions may include special product placement, additional discounts, and other retail merchandising tactics designed to increase sales.

In addition to managing the program's promotions, CLEAResult is responsible for contracting with retailers and manufacturers, providing marketing materials at the point of purchase, and supporting and training to retailers.

### Program Activities

In 2016, LED lightbulbs comprised 59 percent of lightbulb sales each month, an increase from the 32 percent of lightbulb sales in 2015. LED fixtures comprised approximately 5 percent of lighting sales, up from 3 percent of lighting sales in 2015.

Idaho Power continued to participate in the Bonneville Power Administration (BPA) Simple Steps, Smart Savings program focusing on ENERGY STAR CFLs and LEDs and light fixtures.

In 2016, Idaho Power worked with 16 participating retailers, representing 89 individual store locations throughout its service area. Of those participating retailers, 55 percent were smaller grocery, drug, and hardware stores, and the remaining 45 percent are big box retailers.

### Marketing Activities

In 2016, CLEAResult and participating Simple Steps, Smart Savings utility partners decided the current logo was outdated and needed a new look. CLEAResult developed several new designs, and the utility partners decided the new logo would have a simple message: Simple + Smart. The logo colors were selected so they would standout on shelves to help customers identify qualifying products. Throughout the year, the old point-of-purchase pieces were replaced with the new Simple + Smart pieces.

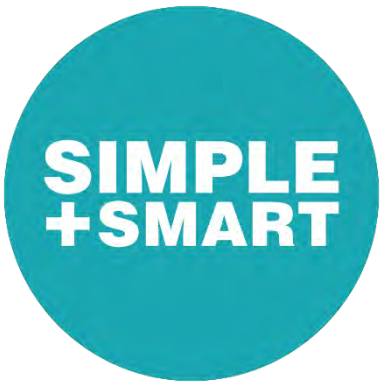



Figure 17. The new 2016 Simple + Smart logo

Several Simple Steps, Smart Savings promotions were conducted through CLEAResult at retail stores in 2016. These promotions generally involved special product placement and signs. CLEAResult staff continued to conduct monthly store visits in 2016 to check on stock, point-of-purchase signs, and displays.

Additional activities in 2016 involved education and marketing. During events where Idaho Power staffed a booth and distributed LED lightbulbs, customers were informed about the importance of using energy-efficient lighting, the quality of LED lightbulbs, and the special pricing available for the Simple Steps, Smart Savings products.

The company continued to host an Energy Efficient Lighting program website; to make available a *Change a Light* program brochure, designed to help customers select the right lightbulb for their needs; and to discuss energy-efficient lighting with customers at community events. Also, ads for the Fridge and Freezer Recycling Program promoted the free LED lightbulb offer. Several #*TipTuesday* posts on social media throughout the year also focused on energy-efficient lighting.

The Idaho Power winter *Energy Efficiency Guide* included two lighting-related articles, and the summer *Energy Efficiency Guide* included a mini-home assessment where customers could gauge how efficient their behaviors are in areas including, lighting, heating and cooling, and more. During energy efficiency segments in November on the KPVI morning news (broadcast in Pocatello) and on KTVB news (broadcast in Boise and Twin Falls), the discussion focused on energy-efficient holiday lighting, timers, inflatables, and laser lights.

### Cost-Effectiveness

In 2016, the Energy Efficient Lighting program provided 50 percent of all energy savings derived from residential energy efficiency customer programs.

In 2016, Idaho Power used the same RTF-deemed savings for both CFLs and LEDs as were used in 2015. For other non-RTF lightbulb types, Idaho Power used the site savings approved by the BPA for the Simple Steps, Smart Savings promotion.

In August 2015, RTF updated and revisited the assumptions for both CFLs and LEDs to account for market changes due to the federal standards compliance. The number of lightbulb types was further reduced to combine three-ways with the general purpose and dimmables. Additionally, the lumen categories were shifted to reflect current consumer trends. Due to the timing of the RTF's update, BPA and CLEAResult did not implement the new savings in the Simple Steps, Smart Savings promotion in 2016.

For detailed cost-effectiveness assumptions, metrics, and sources, see *Supplement 1: Cost-Effectiveness*.

### Customer Satisfaction and Evaluations

Idaho Power conducted no customer satisfaction surveys or program evaluations in 2016.

### 2017 Program and Marketing Strategies

Idaho Power will continue to participate in the Simple Steps, Smart Savings lighting program in 2017 by contracting with CLEAResult, who was awarded the annual BPA implementation contract. New savings will be calculated using the new RTF workbook, version 4.2.

Idaho Power will continue to monitor the number of participating retailers and geographic spread of these retailers, and to develop on-line promotions that allow customers to access promotional pricing regardless of location.

CLEAResult will continue to manage marketing at retailers, including point-of-purchase signs, special product placement, and displays. The program specialist and customer representatives will continue to staff educational events to promote the importance of using energy-efficient lighting.

## *Energy House Calls*

| | 2016 | 2015 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 375 | 362 |
| Energy Savings (kWh) | 509,859 | 754,646 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $188,253 | $194,939 |
| Oregon Energy Efficiency Rider | $15,815 | $15,057 |
| Idaho Power Funds | $2,368 | $4,108 |
| Total Program Costs—All Sources | $206,437 | $214,103 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.029 | $0.020 |
| Total Resource Levelized Cost ($/kWh) | $0.029 | $0.020 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 2.11 | 2.81 |
| Total Resource Benefit/Cost Ratio | 2.75 | 2.96 |

### Description

Initiated in 2002, the Energy House Calls program gives homeowners of electrically heated manufactured homes an opportunity to reduce electricity use by improving the home's efficiency. Specifically, this program provides free duct-sealing and additional efficiency measures to Idaho Power customers living in Idaho or Oregon who use an electric furnace or heat pump. Participation is limited to one service call per residence.

Services and products offered through the Energy House Calls program include duct testing and sealing according to Performance Tested Comfort System (PTCS) standards set by the RTF and adopted by the BPA; installing up to eight LED lightbulbs; testing the temperature set on the water heater; installing water heater pipe covers when applicable; up to two low-flow showerheads and bathroom faucet aerators; a kitchen faucet aerator; two replacement furnace filters with installation instructions; and energy efficiency educational materials appropriate for manufactured-home occupants.

Idaho Power provides contractor contact information on its website and marketing materials. The customer schedules an appointment directly with one of the certified contractors in their region. The contractor verifies the customer's initial eligibility by testing the home to determine if it qualifies for duct-sealing. Additionally, contractors have been instructed to install LED lightbulbs only in high-use areas of the home and install bathroom aerators and showerheads only if the upgrade can be performed without damage to a customer's existing fixtures.

The actual energy savings and benefits realized by each customer depend on the measures installed and the repairs and/or adjustments made. Although participation in the program is free, a typical cost for a similar service call would be $400 to $600, depending on the complexity of the repair and the specific measures installed.

## Program Activities

Since the addition of the direct-install measures in March 2015, there has been a slight increase in participation. In 2016, 375 homes received products and/or services through this program, resulting in 509,859 kWh savings (Figure 18).

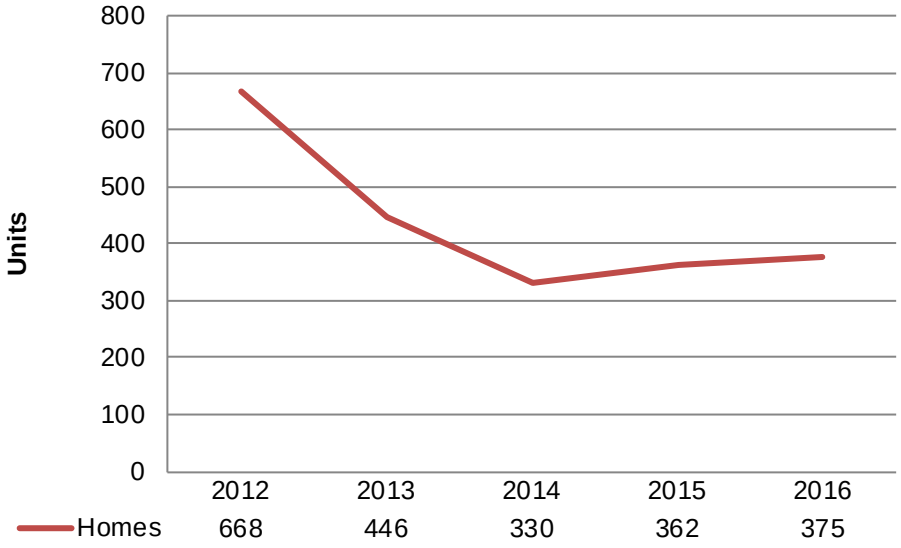



Figure 18. 2012–2016 participation in the Energy House Calls program

Of the total participating homes, 48 percent were located in the Canyon–West Region, 26 percent were located in the Capital Region, and 26 percent were located in the South–East Region.

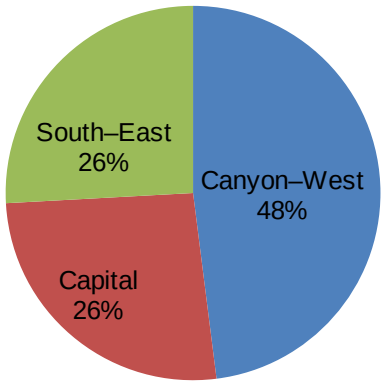



Figure 19. 2016 Energy House Calls participation by region

***Duct-Sealing***

Each year, a number of customers who apply for the Energy House Calls program cannot be served because the ducts do not require duct-sealing or cannot be sealed, for various reasons. These jobs are billed as a test-only job. Some reasons may be the home is too difficult to seal, or the initial duct blaster test identifies the depressurization with respect to the outdoors is less than 150 cubic feet per minute (CFM) and sealing is not needed. Additionally, if, after sealing the duct work, the contractor is unable to reduce leakage by 50 percent, the contractor will bill the job as a test-only job. Prior to 2015, these test-only jobs were not reported in the overall number of jobs completed for that year, because

there was no kWh savings to report. Because Idaho Power now offers direct-install measures in addition to the duct-sealing component, all homes are reported. While some homes may not have been duct sealed, they all would have had some of the direct-install measures included, which would allow us to report kWh savings for each home. Of the 375 homes that participated in 2016, 52 homes were serviced as test-only.

If a home had a blower door and duct blaster test completed, and it is determined that only duct-sealing is necessary, it will be billed as test and seal. For a home with a crossover duct system that needs replaced in addition to the duct-sealing, it will be charged as an x-over. When a home requires the existing belly return system to be decommissioned and have a new return installed along with the duct-sealing, it will be billed as a complex system. A complex system that also requires the installation of a new crossover and duct-sealing will be billed as a complex system and x-over job.

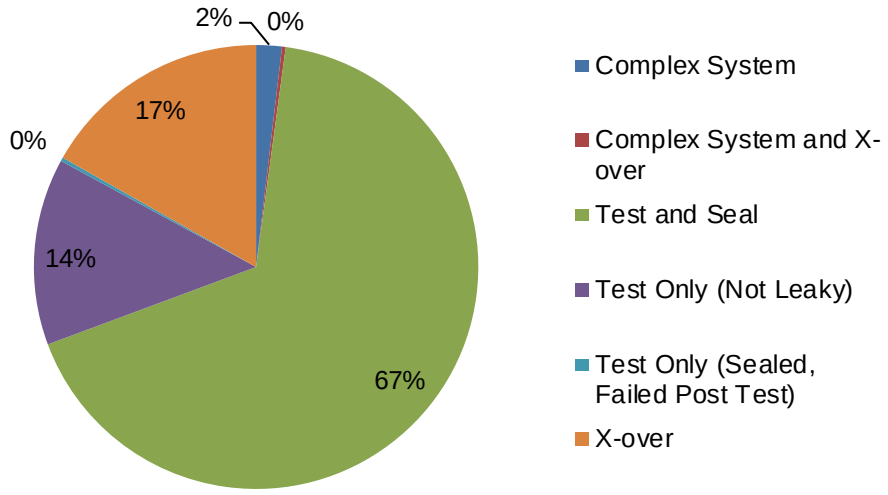



Figure 20. 2016 Energy House Calls participation by job type

***Direct-Install Measures***

In 2016, contractors installed 3,079 LED lightbulbs, 206 showerheads, 351 bathroom aerators and 233 kitchen faucet aerators.

## Marketing Activities

Idaho Power updated all marketing materials in late 2015 and began using them in 2016 to better highlight the program as a free service for manufactured homes and to capture the attention of the target audience. Idaho Power sent two bill inserts to all residential customers in Idaho and Oregon. The March bill insert was shared with the Rebate Advantage program and sent to 374,301 customers, and the October bill insert promoted only the Energy House Calls program and was sent to 378,955 customers. The company sent postcards in February and September to residents of electrically heated manufactured homes who had not yet participated in the program. Written in English and Spanish, 9,042 postcards were delivered in February and 8,650 in September.

Idaho Power also used Facebook ads in February and July. The February ad reached 40,044 people and resulted in 707 website clicks and an increase in enrollments. The July ad reached 60,288 people and resulted in 1,303 website clicks and an increase in enrollment. In addition, Idaho Power customer

representatives and customer service representatives knowledgeable about the program continued to promote the program to qualified customers.

### Cost-Effectiveness

In late 2015, RTF updated savings for performance-based duct-sealing in manufactured homes based on both the Simplified Energy Enthalpy Model (SEEM) calibration and the move toward prescriptive savings only. RTF approved the removal of PTCS requirements for duct-sealing. As a result of these changes, the 2016 deemed savings for duct-sealing are 19 to 60 percent lower than the deemed savings used in 2015.

Savings and a cost-effectiveness analysis for the direct-install measures, including low-flow showerheads, faucet aerators, and LED lightbulbs, were completed using deemed savings from the RTF.

For more detailed information about the cost-effectiveness savings and assumptions, see *Supplement 1: Cost-Effectiveness*.

### Customer Satisfaction and Evaluations

Again this year, Idaho Power contractors reported that customers appreciated receiving the program services and direct-install measures, with most positive comments regarding the free LED lightbulbs. Customers continue to be pleased with the program.

To monitor quality assurance (QA) in 2016, third-party verifications were conducted by Momentum, LLC on approximately 5 percent of the 375 participant homes, resulting in 19 home audits. Homes were selected at random. The QA reports indicate customers were pleased with the work sub-contractors completed in their homes. Each home inspection included an on-site visual confirmation that the reported work had been completed. Weather permitting, blower door and duct blaster tests were also conducted to verify the results submitted by the sub-contractor.

### 2017 Program and Marketing Strategies

Idaho Power will continue to provide free duct-sealing and selected direct-install efficiency measures for all-electric manufactured/mobile homes in its service area.

Idaho Power will continue to include program promotional materials in its bill, to send direct-mail postcards, and to use social media and other proven marketing tactics. Contractors and customer representatives will also distribute door hangers in mobile-home parks and program literature at appropriate events and presentations. Idaho Power will continue to provide Energy House Calls program postcards to CAP agencies for distribution to customers who need assistance but do not qualify to receive weatherization assistance through these agencies.

## *ENERGY STAR® Homes Northwest*

| | | 2016 | 2015 |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (homes) | 110 | 598 |
| | Energy Savings (kWh) | 150,282 | 820,684 |
| | Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $138,203 | $646,991 |
| | Oregon Energy Efficiency Rider | $1,510 | $2,692 |
| | Idaho Power Funds | $2,445 | $3,990 |
| | Total Program Costs—All Sources | $142,158 | $653,674 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/kWh) | $0.051 | $0.046 |
| | Total Resource Levelized Cost ($/kWh) | $0.107 | $0.099 |
| **Benefit/Cost Ratios** | | | |
| | Utility Benefit/Cost Ratio | 1.79 | 2.10 |
| | Total Resource Benefit/Cost Ratio | 1.00 | 1.04 |

### Description

Initiated at Idaho Power in 2003, this program targets the lost-opportunity energy savings and summer-demand reduction that is achieved by increasing the efficiency of the residential-building envelope and air-delivery system above current building codes and building practices.

An ENERGY STAR® certified home is a home that has been inspected and tested by an independent, third-party ENERGY STAR Residential Services Network (RESNET)-certified rater working under a RESNET certified provider. The rater is hired by the builder to ensure the stringent ENERGY STAR requirements have been met. In addition to verifying the installation of building components and equipment during on-site inspections, the rater ensures the home passes a blower door test, an air-duct leakage test, and combustion back-draft tests. The ENERGY STAR Homes Northwest residential construction program promotes homes that use electric heat pump technology and are at least 15 percent more energy-efficient than those built to standard Idaho and Oregon code.

ENERGY STAR homes are more efficient, comfortable, and durable than homes constructed to standard building codes. Homes that earn the ENERGY STAR certification must meet six specifications: 1) effective insulation, 2) high-performance windows, 3) air-tight construction and sealed ductwork, 4) energy-efficient lighting, 5) ENERGY STAR qualified appliances, and 6) efficient heating and cooling equipment.

Prior to January 1, 2016, this ENERGY STAR Homes Northwest program was supported by a partnership between Idaho Power and NEEA's Northwest ENERGY STAR Homes to improve and promote the construction of energy-efficient homes using regional program guidelines approved by the United States (US) Environmental Protection Agency (EPA). NEEA has ended their oversight of the regional, single-family Northwest ENERGY STAR Homes program as of January 1, 2016.

All homes throughout the Northwest that were permitted on or after January 1, 2016, are now required to meet national EPA's ENERGY STAR program certification requirements. To receive the Idaho Power program incentive, certified homes in the company's service area must meet the national EPA Version 3, ENERGY STAR Homes requirements and be electrically heated. Additionally, an ENERGY STAR Homes RESNET-certified rater must enter home-related data into the regional AXIS database, which is maintained by NEEA. The AXIS database allows for utility tracking and review. The rater must also generate a Northwest Compliance Report that is consistent with Northwest REM/Rate™ modeling guidelines.

All single-family homes permitted prior to January 1, 2016 and certified by September 30, 2016, were allowed to be certified under the pre-existing NEEA Northwest ENERGY STAR Homes specifications. The regional Northwest ENERGY STAR Homes program retains oversight of multi-family ENERGY STAR Home certifications. To qualify for an Idaho Power Multifamily ENERGY STAR Homes incentive, the rater must certify the homes according to the Northwest Multifamily Builder Option Package (BOP) 1. The rater must enter the multi-family units into the AXIS database for utility tracking and review.

## Program Activities

To encourage the construction of ENERGY STAR homes, the program offered qualified builders a $1,000 incentive per home built to the Northwest ENERGY STAR Single and Multifamily Homes requirements with heat pump technology. Builders who entered their homes in a Parade of Homes were eligible to receive the standard $1,000 incentive plus an additional $500 marketing incentive to cover their expenses for ENERGY STAR signage and brochures. Builders benefit by earning the right to use the ENERGY STAR Homes logo and the ENERGY STAR name to promote themselves as an ENERGY STAR qualified builder.

A large part of the program's role in 2016 was to provide support for the building contractors associations (BCA) throughout Idaho Power's service area.

The regional trend toward increased ENERGY STAR certifications for multi-family homes continued in 2016. Out of 110 total incentives paid through Idaho Power's program, 108 were for multi-family dwellings. The other two were for single-family homes located in McCall as part of NEEA's Next Step Home (NSH) pilot program.

## Marketing Activities

Idaho Power maintained a strong presence in the building industry by supporting the Idaho Building Contractors Association (IBCA) and several of its local affiliates throughout Idaho Power's service area in 2016. The company presented the Energy Efficient Design and Construction Awards to builders who integrated energy efficiency features in their parade homes at the Building Contractors Association of Southwest Idaho (BCASWI) Parade of Homes awards banquet. In addition, the company participated in the BCASWI builder's expo and the Snake River Valley Building Contractors Association (SRVBCA) builder's expo.

Idaho Power supported Parade of Homes events with full-page ENERGY STAR ads in the Parade of Homes magazines of the following BCAs: The Magic Valley Builders Association (MVBA), the BCASWI, SRVBCA, and the Building Contractors Association of Southeast Idaho (BCASEI). Idaho Power also ran ads in the April 20 *Business Insider* and June 10 *Idaho Business Review* targeting residential contractors. Inserts were added to residential customers' billing statements in April and May informing them of Parade of Homes events in their area. Due to a change in tactics, one bill insert was not used in 2016 as originally planned. Instead, social media and a weekly *News Briefs* article to media were used to promote ENERGY STAR Homes and local Parade of Homes events. These tactics allowed Idaho Power to better target potential participants. In addition, the company sponsored the IBCA annual winter and summer meetings.

The program, in collaboration with NEEA, sponsored a Lunch & Learn course on September 27, 2016. This was a two-hour course presented by energy professionals from Advanced Energy. The purpose of this course was to facilitate a summit of residential real estate professionals to explore solutions leading to the increased market value of energy-efficient and green homes. The 35 professionals in attendance included sales agents, brokers, lenders, home inspectors, and home energy experts.

### Cost-Effectiveness

Savings and cost-effectiveness assumptions for the primary multi-family-style home for 2016 were the same compared with 2015. The townhome/multi-family homes in the Boise–Nampa–Caldwell climate zone were cost-effective from a UC and a TRC perspective with the inclusion of the non-energy benefits (NEB). No single-family homes were certified in 2016. Two homes in NEEA's NSH pilot program were completed and incentives were paid in 2016.

For more detailed information about the cost-effectiveness savings and assumptions, see *Supplement 1: Cost-Effectiveness*.

### Customer Satisfaction and Evaluations

Idaho Power conducted no customer satisfaction surveys for this program in 2016.

Independent, RESNET-certified program providers verified the rater's input for accuracy and confirmed that program requirements had been met. The provider then certified each home within the AXIS database. Providers performed file and on-site field QA, and offered technical assistance to the raters who had contracted with them. Per RESNET guidelines, the provider performed QA on minimum of 10 percent of files or desk checks and 1 percent QA on-site field QA of all projects. In 2016, the raters reported no issues resulting from the QAs.

### 2017 Program and Marketing Strategies

Idaho Power will continue to support NEEA's NSH, high-performance specification pilot program. This specification is designed to build homes that are 30 percent more efficient than homes built to standard building codes. Though NEEA is no longer recruiting homes for the pilot, it plans to analyze the data collected through in-home monitoring from all three phases of the pilot. Results are expected by the second quarter of 2017. Homes built during Phase III incorporated NSH minimum requirements,

guidelines, and best practices learned from Phase I and II. When completed, the final version of the NSH specification will be made available to utilities interested in offering NSH incentives. At this time, NEEA does not plan to offer a branded, customer-facing program, based on this specification, to the region.

Idaho Power plans to continue marketing efforts to promote this program to builders and new homebuyers. These marketing efforts include Parade of Homes ads in parade magazines for the BCASWI, SRVBCA, MVBA, and the BCASEI. The company also plans to continue supporting the general events and activities of the IBCA and its local affiliates. Bill inserts, social media, and other advertising will be considered based on past effectiveness.

## *Fridge and Freezer Recycling Program (See ya later, refrigerator®)*

| | | 2016 | 2015 |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (refrigerators/freezers) | 1,539 | 1,630 |
| | Energy Savings (kWh) | 632,186 | 720,208 |
| | Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $250,535 | $212,674 |
| | Oregon Energy Efficiency Rider | $4,555 | $11,497 |
| | Idaho Power Funds | $2,826 | $3,007 |
| | Total Program Costs—All Sources | $257,916 | $227,179 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/kWh) | $0.062 | $0.048 |
| | Total Resource Levelized Cost ($/kWh) | $0.062 | $0.048 |
| **Benefit/Cost Ratios** | | | |
| | Utility Benefit/Cost Ratio | 0.92 | 1.21 |
| | Total Resource Benefit/Cost Ratio | 1.31 | 1.53 |

### Description

Since 2009, the Fridge and Freezer Recycling program (formerly See ya later, refrigerator®) achieves energy savings by removing and recycling qualified refrigerators and stand-alone freezers from residential homes throughout Idaho Power's service area.

Idaho Power uses a third-party contractor to provide most services for this program, including customer service and scheduling, unit pickup, unit recycling, and reporting. Applicants enroll online or by phone, and the contractor screens each to confirm the refrigerator or freezer unit under consideration meets these initial program eligibility requirements: residential grade; at least 10 cubic feet ($ft^3$) as measured using inside dimensions, but no larger than 30 $ft^3$; and in working condition. Idaho Power then screens each applicant to confirm participation eligibility; the program targets older, extra refrigerator and freezer units for maximum savings.

### Program Activities

In late November 2015, Idaho Power learned the program vendor, JACO had entered into receivership and ceased operations. After multiple internal conversations and consulting with EEAG, Idaho Power reintroduced the program using a new vendor, Appliance Recycling Center of America (ARCA), and a new name, Fridge and Freezer Recycling Program. Idaho Power re-launched the program on June 1, 2016.

Despite temporarily suspending the program and reintroducing the program mid-year, Idaho Power received almost as many participants in 2016 as it did in 2015. Idaho Power was invoiced by JACO for 292 units that it picked up in October and November 2015. The invoices were received after JACO entered into receivership. To allow time to ensure all appliances were disposed of according to the terms

of the contract, Idaho Power paid the invoices in 2016. Because no savings from these units were claimed in 2015, the unit count and savings will be claimed in 2016.

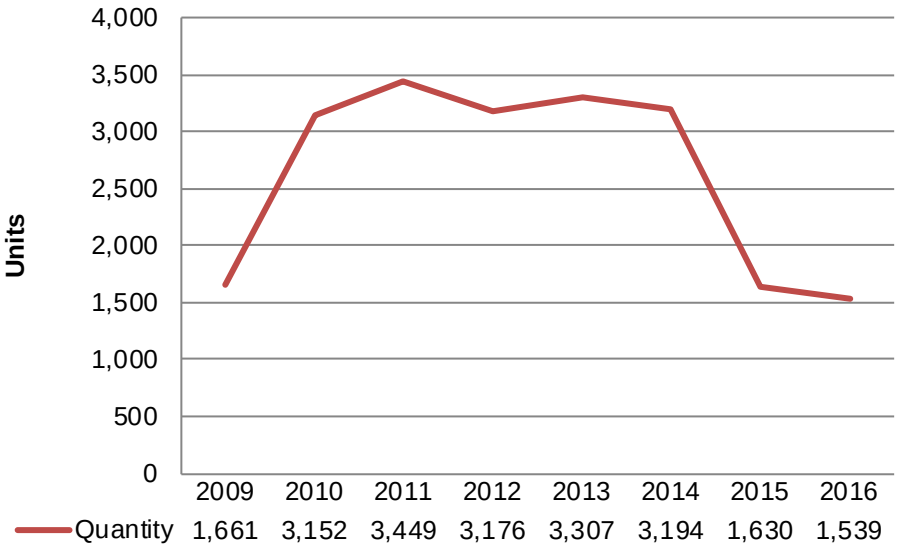



Figure 21. 2009–2016 Fridge and Freezer Recycling Program (See ya later, refrigerator®) participation by year

## Marketing Activities

Idaho Power re-launched the program in June with a new name, new look, and updated web page. The marketing materials used the theme "Retire Your Old Fridge (or Freezer)" with images of a refrigerator retiring on the beach, lake, and Europe among other locations (Figure 22). The new messaging and imagery was chosen to resonate with the program's primary target audience, customers age 35 to 64, but skewing 55 and older. Idaho Power used bill inserts, direct-mail, Facebook, and earned media to promote the program.




Figure 22. 2016 Fridge and Freezer Recycling Program customer postcard

A *News Briefs* email was sent to reporters in June to alert the media and customers of the re-launch of the program. Bill inserts were sent to 228,961 residential customers in June; 377,345 customers in July; 378,671 customers in August; and 378,243 customers in September. In September, a postcard was

mailed to 15,000 customers thought to have a higher propensity to own a second fridge or freezer. The September issue of *Connections* included an ad for the Fridge and Freezer Recycling Program, and the re-launch of the program was mentioned in further detail in the October issue of *Connections*.

Idaho Power placed a Facebook ad in July targeted to customers ages 35 to 65 or older who have an interest in energy efficiency, home improvement, and do-it-yourself efforts. The ad reached nearly 35,000 customers and resulted in 615 clicks to the Fridge and Freezer Recycling Program web page.

In June, Idaho Power promoted the program and the savings that can occur as a result of recycling an older or second fridge or freezer on Pocatello's KPVI live morning news.

Although appliance retailers also refer customers to the program, Idaho Power does not pursue this marketing channel because the goal of the program is to promote the removal of secondary units rather than replacing existing units.

### Cost-Effectiveness

In 2016, Idaho Power used the same savings and assumptions used in 2015. When Idaho Power re-introduced the program in mid-2016, the company forecasted that participation would be at 1,000 units, and the program would likely not be cost-effective from the UC perspective but would be cost-effective from the TRC perspective. Idaho Power discussed this with EEAG in February 2016. When the company filed for program reinstatement in Oregon, the company requested a cost-effectiveness exception as outlined in OPUC Order No. 94-590. The exception was approved by the OPUC in Advice No. 16-07.

Despite the temporary suspension of the program, 1,539 units were recycled in 2016. As a result, the program had a TRC of 1.31 and a UC of 0.92. Had the program been operational for the full 12 months, it is likely that the program would have passed the UC test. In late 2016, RTF revisited and approved new, lower savings for freezer and refrigerator decommissioning, as well as LED bulbs. Idaho Power believes the Fridge and Freezer Recycling Program could be cost-effective in 2017 at the TRC level because of the non-energy benefits associated with decommissioning a refrigerator and freezer. However, the program may not pass the UC test. The company will re-evaluate the program in 2017.

For cost-effectiveness details and assumptions, see *Supplement 1: Cost-Effectiveness*.

### Customer Satisfaction and Evaluations

ARCA tracks individual statistics for each unit collected, including information on how customers heard about the program and when customers enrolled. Statistics about the unit collected include the age of the unit, its location on the customer's property, and other data.

The 2016 unit data showed 19 percent of units the program picked up were stand-alone freezers, and 81 percent of the units were refrigerators. Sixty-nine percent of the units were secondary, 27 percent were primary, and 4 percent were unknown. In 2016, 21 percent of the units collected were manufactured between 1965 and 1990, which generally represents the least efficient years of refrigerator

manufacturing. By comparison, in 2015, 34 percent of the units collected through this program were of this vintage.

ARCA and Idaho Power also tracked data related to the marketing effectiveness of the program. Results of customer tracking information indicate 42 percent of customers learned of the program through bill inserts, and 11 percent from a friend or neighbor.

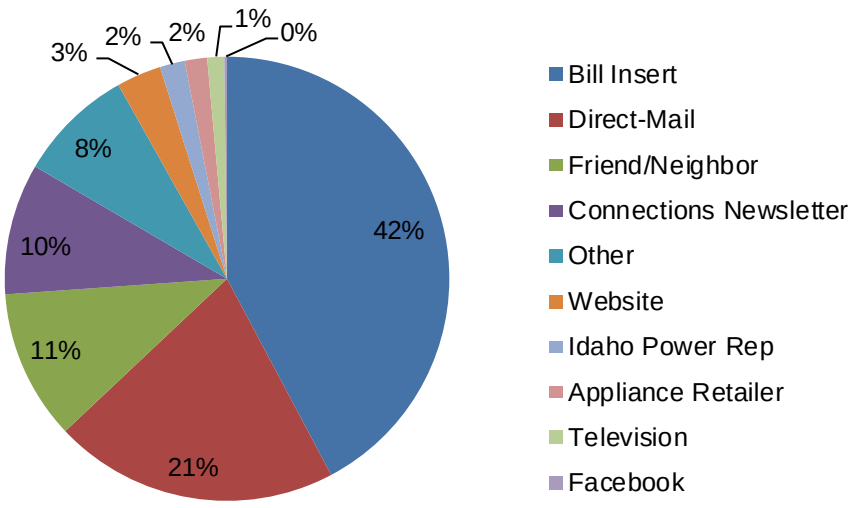



Figure 23. How customers heard about Fridge and Freezer Recycling Program in 2016

Figure 23 indicates ways customers heard about the program. The "Other" category includes sources, such as community events, repeat customers, the truck wrap ad, and unknown sources.

Sixty-seven percent of customers who enrolled used the toll-free telephone number, and 33 percent used the on-line enrollment form.

### 2017 Program and Marketing Strategies

Idaho Power plans to continue the Fridge and Freezer Recycling Program using the current program strategy in 2017, and to monitor its cost-effectiveness for long-term viability.

Idaho Power will continue to use customer information ARCA collected and the surveys from in-house evaluations to target future marketing efforts and increase the effectiveness of marketing. The company plans to use bill inserts, direct-mail, and paid and organic social media posts, and to reach out to customers at community events.

## *Heating & Cooling Efficiency Program*

| | 2016 | 2015 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 486 | 427 |
| Energy Savings (kWh) | 1,113,574 | 1,502,172 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $545,454 | $583,663 |
| Oregon Energy Efficiency Rider | $27,184 | $25,186 |
| Idaho Power Funds | $22,275 | $17,520 |
| Total Program Costs—All Sources | $594,913 | $626,369 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.036 | $0.028 |
| Total Resource Levelized Cost ($/kWh) | $0.085 | $0.092 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 2.33 | 3.11 |
| Total Resource Benefit/Cost Ratio | 1.26 | 1.05 |

### Description

The Heating & Cooling Efficiency (H&CE) Program provides incentives to residential customers in Idaho Power's Idaho and Oregon service area for the purchase and proper installation of qualified heating and cooling equipment and services.

Initiated in 2007, the objective of the program is to acquire energy savings by providing customers with energy-efficient options for electric space heating and cooling. Incentive payments are provided to the residential customers for all measures. Three of the measures also include a payment to the installing contractor. The available measures in 2016 include ducted air-source heat pumps, ducted open-loop water-source heat pumps, ductless air-source heat pumps, duct-sealing, whole-house fans (WHF), electronically commutated motors (ECM), evaporative coolers, and smart thermostats.

Idaho Power requires licensed contractors to perform the installation services related to these measures, with the exception of evaporative coolers that can be self-installed. A licensed contractor must also be an Idaho Power participating contractor for the ducted air-source heat pump, ducted open-loop water-source heat pump, ductless air-source heat pump, and duct-sealing measures.

The H&CE Program's list of measures and incentives includes the following:

- Customer incentive for replacing an existing ducted air-source heat pump with a new ducted air-source heat pump is $250 for a minimum efficiency 8.5 Heating Seasonal Performance Factor (HSPF).

- Customer incentive for replacing an existing oil or propane heating system with a new ducted air-source heat pump is $400 for a minimum efficiency 8.5 HSPF. Participating homes must be located in areas where natural gas is unavailable.
- Customer incentive for replacing an existing electric forced-air or zonal electric heating system with a new ducted air-source heat pump is $800 for a minimum efficiency 8.5 HSPF.
- Incentive for customers or builders of new construction installing a ducted air-source heat pump in a new home is $400 for a minimum efficiency 8.5 HSPF. Participating homes must be located in areas where natural gas is unavailable.
- Customer incentive for replacing an existing ducted air-source heat pump with a new ducted open-loop water-source heat pump is $500 for a minimum efficiency 3.5 coefficient of performance (COP).
- The customer incentive for replacing an existing electric forced-air or zonal electric, oil, or propane heating system with a new ducted open-loop water-source heat pump is $1,000 for a minimum efficiency 3.5 COP. Participating homes with oil or propane heating systems must be located in areas where natural gas is unavailable.
- The incentive for customers or builders of new construction installing a ducted open-loop water-source heat pump in a new home is $1,000 for a minimum efficiency 3.5 COP. Participating homes must be located in areas where natural gas is unavailable.
- The customer incentive for displacing a zonal electric heating system with a new ductless air-source heat pump is $750.
- The customer incentive for duct-sealing services performed in an existing home with an electric forced-air heating system or a heat pump is $350.
- The customer incentive for a WHF installed in an existing home with central A/C, zonal cooling, or a heat pump is $200.
- The customer incentive for replacing a Permanent Split Capacitor (PSC) air handler motor with an ECM in an existing home with oil or propane or natural gas forced-air heat, electric forced-air heat, or a heat pump is $50.
- The customer incentive for installing an evaporative-cooler is $150.
- The customer incentive for a smart thermostat installed in an existing home with an electric forced-air furnace or a heat pump is $75.

Idaho Power uses Honeywell, Inc., a third-party contractor, to review and enter incentive applications into the Idaho Power system. Honeywell reviews and submits incentive applications for Idaho Power payment using a program database portal developed by Idaho Power. This allows Idaho Power to maintain the database within the company's system, which is secure yet accessible to the third-party contractor. They also perform on-site verifications (OSV) and provide technical support to the customer representatives and contractors. Honeywell offers local program and technical assistance to contractors through on-site visits at their businesses.

## Program Activities

Idaho Power began offering one new measure through the program on March 31, 2016. The measure provided a cash incentive to customers who installed a smart thermostat. During the development stage of this measure, the company provided updates and requested input from EEAG at quarterly meetings. EEAG's feedback regarding the measure was generally positive. With EEAG's recommendation, Idaho Power piloted the measure in 2016, and additional recommendations will be considered when the pilot expands.

The expansion of Idaho Power's network of participating contractors remained a key growth strategy for the program. Idaho Power's goal is to support contractors currently in the program while adding new contractors. The company held meetings with several prospective contractors to support this strategy, and added 15 new companies to the program as authorized participating contractors in 2016.

To qualify to participate in this program, a contractor must first complete the required training regarding program guidelines and technical information on HVAC equipment. Idaho Power held 13 of these training sessions for contractors in 2016.

The 2016 Heating and Cooling Efficiency Program paid incentives are listed in Table 8.

Table 8. H&CE Program incentives paid in 2016 Program incentives paid in 2016

| Incentive Measure | 2016 Project Quantity |
|---|---|
| Ducted Air-Source Heat Pump | 169 |
| Ducted Open-Loop Water-Source Heat Pump | 17 |
| Ductless Heat Pump | 150 |
| Evaporative Cooler | 22 |
| Whole-House Fan | 19 |
| Electronically Commutated Motor | 50 |
| Duct-Sealing | 3 |
| Smart Thermostat | 56 |

The customer representatives, Idaho Power's program contractor, and the program specialist continually engaged with over half of the participating contractors to help them increase participation in the program. Some of the barriers to participation were uncovered anecdotally. One barrier stems from, in many cases, a need for improved technical skills in the HVAC technicians. Employee turnover and a lack of having a repeatable sales process are other barriers addressed. These barriers were addressed by the program specialist through one-on-one discussions with the participating contractors, usually in person. The program has 109 participating contractors therefore much more work will be done in this area.

## Marketing Activities

Idaho Power used multiple marketing methods for its H&CE Program. The company mailed a bill insert to 374,173 residential customers in April and 378,239 residential customers in September. The H&CE Program was also mentioned in the April issue of *Connections*, mailed to all residential customers with

their bill. Several *#TipTuesday* social media posts throughout 2016 focused on heating- and cooling-related tips. Two versions of a direct-mail postcard were sent to a total of 39,457 residential customers in November. The two versions were used as an A/B test (or a comparative test) to determine which new look resonated best with customers.

On several occasions, Idaho Power marketed the new smart thermostat incentive separate from the overall H&CE Program: on May 23, Idaho Power sent a *News Briefs* article to local media that was picked up by 1310 KLIX in Twin Falls; a May *#TipTuesday* social media post; the summer *Energy Efficiency Guide*; and the October issue of *Connections*.

In 2016, emphasis on Idaho Power's contractor portal was reduced since it was not being used by contractors and was found to be of lesser value compared to other support tactics, such as ongoing training on the program process and HVAC technical skills for new and existing contractor employees.

### Cost-Effectiveness

Idaho Power implemented numerous changes to the H&CE Program measures for 2016 savings. Most changes were related to the measure definitions of heat pumps that were adopted by RTF in 2015.

Savings values for retrofit air source heat pumps were changed in 2015 by RTF to reflect different savings values that result from differing weatherization levels of the homes. The updated measure standard requires that a home's savings be assigned by whether the level of insulation is considered, "good," "fair," or "poor." Because of the quality installation component of the program, the overall condition of the home could be determined through contractor worksheets. Most homes had an insulation level of "fair" or "good" resulting in a slight decrease in savings than would have been seen from the previous measure definition not requiring judgment on the home's overall level of insulation.

For the measure level cost-effectiveness, cost data from RTF was used in lieu of actual project costs reported by customers. RTF costs contain updated baseline information for electric forced-air furnaces and air conditioning systems that was not available through local contractor surveys for 2016.

Air-source heat pumps installed in new construction or installed to replace existing less efficient heat pumps saw their claimed savings for 2016 drop significantly from approximately 2,500 kWh per unit to between 55 to 90 kWh depending on the climate zone. The drop was caused by the increased federal manufacturing standard for split system air source heat pumps in January 2015. This change was the biggest reason savings in the program dropped from 2015 levels while overall program participation increased. The air-source heat pump replacing an existing air-source heat pump measure, as with all heat pump measures in the program, mandates proper equipment commissioning, control setting, and sizing (CCS). CCS allows for an additional claimed savings of between 630 and 1,014 kWh per installed heat pump as deemed by RTF.

RTF geothermal heat pump savings, while specifically designed around closed loop systems, were deemed appropriate by RTF to be applied to open loop heat installations. Idaho Power replaced its previous engineering estimate of savings with the savings from the RTF workbook resulting in an

increase in average retrofit savings of 900 kWh and a decline of 300 kWh in annual savings for new construction situations.

Ductless heat pumps (DHP) continue to be not cost-effective using RTF regional costs rather than prices reported on customer applications. RTF costs were used for 2016 cost-effectiveness analysis because the DHP measure definition was changed to reflect differing heating system performance factors. The company does not have sufficient cost data from its projects to split out costs by different levels of efficiency.

For more detailed information about the cost-effectiveness savings, sources, calculations, and assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Honeywell performed random OSV on 47 (10 percent) of the completed installations in Idaho Power's service area. These OSVs confirmed that the information submitted on the paperwork matched what was installed at customers' sites. Overall, the OSV results were favorable with respect to the contractors' quality of work. The program specialist continues to work with contractors to help them understand the importance of accurate documentation and quality installations.

Idaho Power accessed additional information from other sources. In 2016, NEEA provided two reports with identical content that updated the DHP Initiative. A copy of each is included on the CD accompanying *Supplement 2: Evaluation*. The following are highlights from the reports.

#### *NEEA Reports E16-334 and E16-337, released July 2016*

NEEA published this fifth Market Progress Evaluation Report (MPER) for the NW Ductless Heat Pump Project (Initiative). The report discusses findings obtained through extensive surveys, interviews, and focus groups comprised of homeowners, utilities, installers, and supply chain actors. The initiative was launched as a pilot in 2008 to demonstrate that DHPs were a viable technology to displace electric resistance heat in existing homes. The report describes the Initiative as well-designed and continuing to have a positive influence on the market. Some of the findings include the indication that interest continues to grow although lack of awareness remains a barrier. Word of mouth continues to be an initial source of information. DHP owners relied on their own research when making their purchasing decision. Financial considerations can be an opportunity or barrier because while DHPs can provide energy savings they can also be seen as expensive. The report provides detailed recommendations for NEEA to consider in the future.

## 2017 Program and Marketing Strategies

Idaho Power will provide program training to existing and prospective contractors to assist them in meeting program requirements and further their product knowledge. Sessions will be held on-site at contractor businesses and at Idaho Power facilities. Training sessions remain an important part of the program because they create opportunities to invite additional contractors into the program. The sessions also provide refresher training for existing participating contractors, and help them increase their customers' participation while improving the contractors' work quality. An additional dozen other interested companies will be taken through the authorization process by the program specialist.

Developing the existing network of participating contractors remains a key strategy for the program. The performance of the program is substantially dependent on the contractors' abilities to promote and leverage the measures offered. Idaho Power's primary goal in 2017 is to develop contractors currently in the program while adding new contractors. To meet this objective, the program specialist, along with Idaho Power customer representatives, will arrange frequent individual meetings to discuss the program with contractors in 2017.

The 2017 marketing strategy will include several tactics previously used, such as bill inserts, direct-mail, and social media, and will explore using additional tactics to market individual measures and the program as a whole.

## Home Energy Audit

| | 2016 | 2015 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes) | 539 | 351 |
| Energy Savings (kWh) | 207,249 | 136,002 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $278,959 | $192,873 |
| Oregon Energy Efficiency Rider | $0 | $0 |
| Idaho Power Funds | $10,853 | $9,084 |
| Total Program Costs—All Sources | $289,812 | $201,957 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Levelized Cost ($/kWh) | n/a | n/a |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | n/a |
| Total Resource Benefit/Cost Ratio | n/a | n/a |

### Description

The current Home Energy Audit program is based on the insights gained from the Boise City Home Audit project conducted in 2011 and 2012, as described in the *Demand-Side Management 2012 Annual Report*. In 2014, the audit project became the Home Energy Audit program under Idaho Power's management.

The Home Energy Audit program is an in-home energy evaluation by a certified, third-party home performance specialist (HPS). It is used to identify areas of concern, and to provide specific recommendations to improve the efficiency, comfort, and health of the home. An audit includes a visual inspection of the crawl space and attic, a health and safety inspection, and a blower door test to identify and locate air leaks. In addition to the evaluation, some energy-saving improvements are installed at no additional cost to the customer if appropriate. After the audit is complete, the customer is supplied with a hardcopy or password-protected electronic copy of the HPS's findings and recommendations. Improvements available from Idaho Power include installation of the following:

- Up to 20 efficient lightbulbs (CFLs and LEDs)
- One high-efficiency showerhead
- Pipe insulation from the water heater to the home wall (approximately 3 feet)

To qualify for the Home Energy Audit program, a participant must live in Idaho and be the Idaho Power customer of record for a home. The home must be an existing site built home, and up until 2016, homes had to be all electric. Renters may participate with prior written permission from the landlord. Single-family homes, duplexes, triplexes, and fourplexes qualify, though multi-family homes must have

discrete heating units and meters for each unit. Manufactured homes, new construction, or buildings with more than four units do not qualify.

Participating customers pay $99 (all-electric homes) or $149 (other homes: gas, propane or other fuel sources) for the audit and installation of measures, with the remaining cost covered by the Home Energy Audit program. The difference in cost covers the additional testing that is necessary for homes that are not all-electric. These types of energy audits normally cost $300 or more, not including the select energy saving measures, materials, and labor. The retail cost of the materials installed in each home averages $145.

### Program Activities

In 2016, this became a fuel-neutral program. This change allows more customers to participate and learn ways to be energy efficient. Even if the space or water heating source in a home is not electric, often there can be many opportunities to use electricity wisely.

Seven HPS companies served the program in 2016. Homes were randomly assigned to the HPSs serving each service area, grouping locations for each HPS to save on travel time and expense. When the program became fuel-neutral, Idaho Power required HPSs who hadn't had previous training in Combustion Appliance Zone (CAZ) testing within the last six months to participate in Idaho Power's CAZ refresher class, or to attend a refresher class offered through another source. Although all HPSs had previous CAZ training, Idaho Power provided a refresher course in February 2016, and all HPSs participated.

In 2016, the program completed 539 energy audits. The average age of participating homes was 34 years old. The homes were built between 1898 and 2015. Home sizes ranged from 288 square feet ($ft^2$) to 8,500 $ft^2$, with 2,403 $ft^2$average home size. Figure 24 depicts the program's reach across Idaho Power's service area, and Figure 25 depicts the space and water heating fuel types.

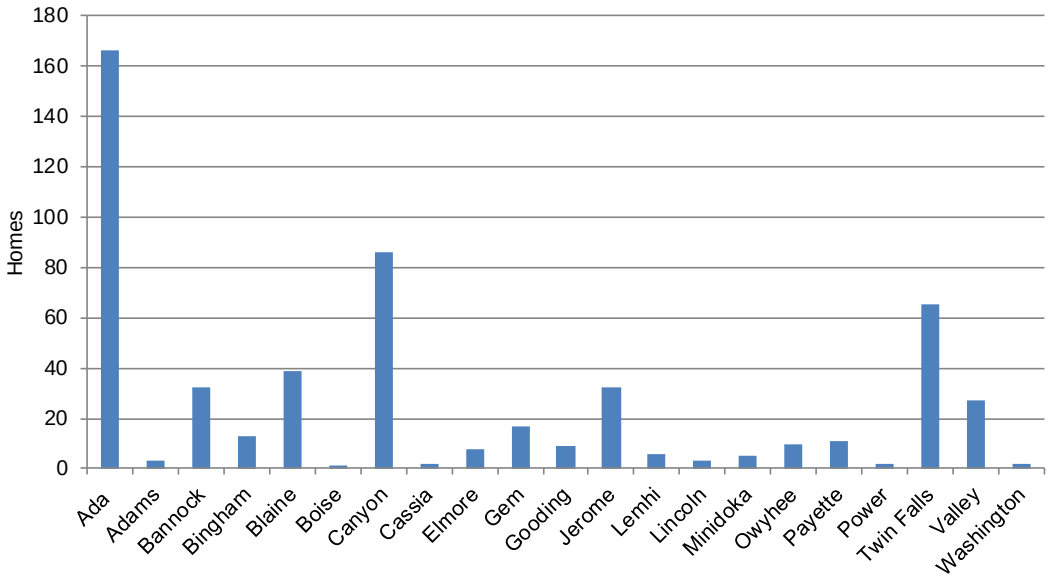



Figure 24. Home Energy Audit summary of participating homes in 2016, by county

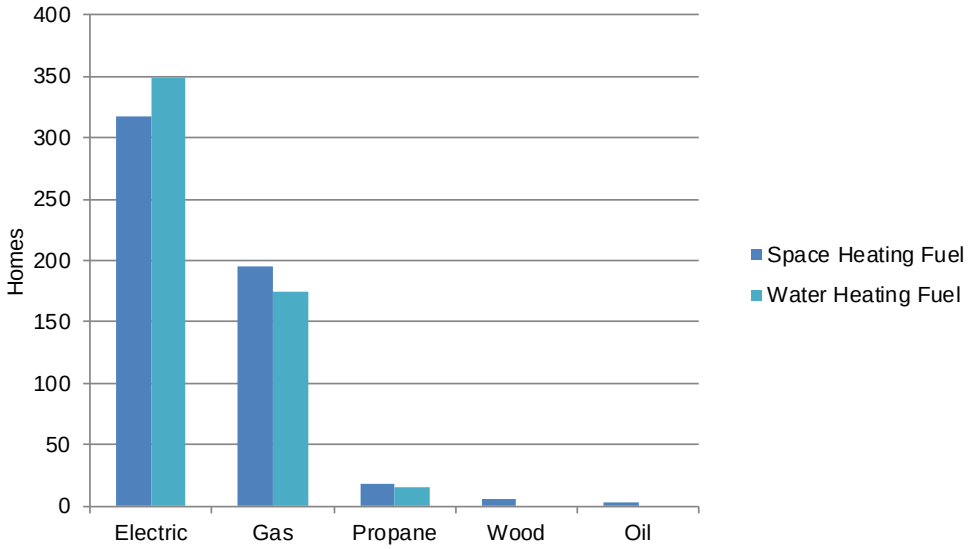



Figure 25. Home Energy Audit summary of space and water heating fuel types, 2016

The HPSs collected information on types and quantities of appliances and lighting in each home. The average number of incandescent lights per home was 21, and the average number of fluorescent or LED lights was 13. When performing an audit, the HPS determined which available measures were appropriate for the home, and, with homeowner approval, those measures were installed. Figure 26 indicates the total quantity of items installed by measure.

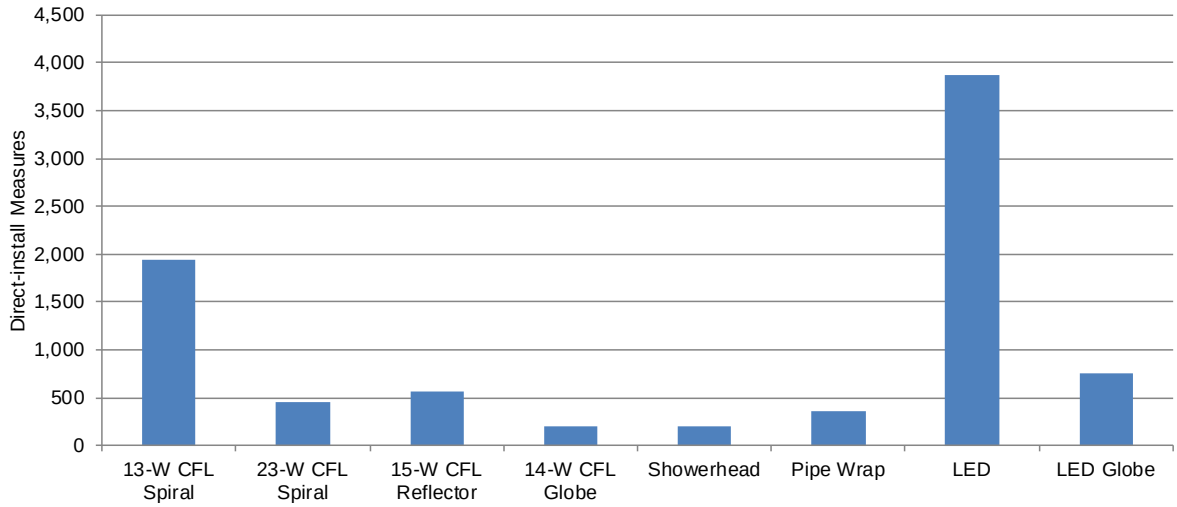



Figure 26. Home Energy Audit measures installed in participating homes in 2016

As Idaho Power's existing stock of CFLs has been used and the cost of LEDs has come down, all new lightbulb orders are for LEDs. With the exception of the CFL 15-watt reflectors, all lightbulbs being installed by the end of 2016 were LEDs.

The QA goal for the program was inspection of 10 percent of all audits, translating into approximately 53 audits in 2016. Ultimately, 34 QAs were completed in 2016, with all audits passing inspection. The 10 percent goal was unmet in 2016 because it was challenging to find participants willing to allow

the auditor into their home for a 1- to 2-hour period, especially if the participant worked outside the home.

### Marketing Activities

In January 2016, all program materials including the website were updated to promote eligibility changes to include all Idaho residential customers, regardless of fuel type. Additionally, an infographic was designed and used online and in social media to provide a visual representation and additional detail on what occurs during the audit.

Idaho Power recruited participants for the program through small batches of 1,000 to 2,000 direct-mail letters. Customers interested in participating were directed to a website for additional information and the on-line application. Those who did not have internet access or were uncomfortable using the on-line application were encouraged to call Idaho Power to apply. A program brochure was added to some mailings, but did not result in an increase in enrollment compared to mailings without the brochure.

In October 2016, Idaho Power partnered with the University of Idaho's Valley County Extension Office to host an energy efficiency workshop in McCall, Idaho. Direct-mail letters were sent to residents, and posters were hung at local businesses inviting the community to attend the evening workshop. Attendees learned how to check their homes for efficiency, how to make improvements, and how to use myAccount. The Home Energy Audit program was emphasized as were various other Idaho Power efficiency programs. For attending, each person was given an LED lightbulb.

Bill inserts were sent to 369,000 residential customers in June and 355,000 residential customers in December. Articles highlighting the Home Energy Audit program were also included in the April and October issues of *Connections*, which is mailed along with the customer's bill.

The Home Energy Audit program was mentioned in the Idaho Power *Winter Energy Efficiency Guide* as a way to improve your home's performance. In addition, the program was the focus of the Idaho Power energy-efficiency segment on the KTVB afternoon news program in March.

Idaho Power used social media, including boosted Facebook posts, throughout 2016 to highlight the Home Energy Audit program. In May, a boosted post targeted to Idaho homeowners ages 35 and older with an interest in home improvement or energy efficiency reached 45,495 people, resulting in 1,745 post engagements (likes, comments and shares). In November and December, Idaho Power used boosted posts targeted to South–East Region customers. These boosted posts reached 44,662 people with 1,229 engagements, 97 shares, and 694 post clicks.

For several months throughout 2016, a short article about the program was also placed in the Pocatello-Chubbuck Chamber of Commerce e-newsletter.

Digital re-targeting advertising was also used to target the South-East Region customers. Customers who visited the Idaho Power website and then moved onto a different website were "followed" by a Home Energy Audits digital ad. Overall, 787,293 impressions were served resulting in 1,993 clicks with a total

click-through rate of 0.25 percent. The total click-through rate was 3.6 times higher than the national average.

## Cost-Effectiveness

One of the goals of the Home Energy Audit program is to increase participants' understanding of how their home uses energy and to encourage their participation in Idaho Power's energy efficiency programs. Since the Home Energy Audit program is primarily an educational and marketing program, the company does not apply the traditional cost-effectiveness tests to the program.

For the items installed directly in the homes, Idaho Power used the same assumptions during 2016 as were used in 2015. Idaho Power used RTF savings for direct-install bulbs, which range from 17 to 30 kWh per year. RTF savings for 2.0 gpm showerheads directly installed in a home are 139 to 166 kWh per year. In Idaho Power's *Energy Efficiency Potential Study*, AEG estimates that pipe wraps save 150 kWh per year. Savings for both showerheads and pipe wrap were only counted for homes with electric water heaters.

In 2015 and 2016, the RTF reviewed and updated the savings assumptions for CFLs, LEDs, and showerheads. These new savings will be applied in 2017.

## Customer Satisfaction and Evaluations

Throughout 2016, a survey was sent to 482 customers who had participated in the program between October 2015 and September 2016. The purpose of the survey was to assess customers' satisfaction with program enrollment, scheduling, the auditor, the personalized report, and information learned. Participants who supplied an email address on the initial program enrollment form were sent an electronic survey (320 participants); those without an email address were sent a hardcopy of the survey with a postage-paid envelope (162 participants). The response rate was just over 43 percent, with 208 participants responding. Program strengths and areas for improvement were also assessed. Results were reviewed for the program as a whole and for responses related to individual HPSs.

When asked a series of questions about their experience with the program, 96 percent of respondents "strongly agree" or "somewhat agree" they would recommend the program to a friend or relative, and just over 94 percent of respondents "strongly agree" or "somewhat agree" they were satisfied with their overall experience with the program. And, over 97 percent of the respondents indicated it was "very easy" or "somewhat easy" to apply for the program.

Over 34 percent of respondents reported accessing their report online through an email address supplied to Idaho Power on the enrollment application, while over 37 percent reported receiving a paper copy, and 28 percent reported receiving their report both ways. Of those who accessed their report online, nearly 64 percent indicated that accessing the report online was "very easy" or "somewhat easy."

HPSs were rated on a number of attributes including courteousness, professionalism, explanation of work/measurement to be performed, explanation of audit recommendations, and overall experience with the HPS. Respondents rated their HPSs as "good" or "excellent" 93 to 100 percent of the time.

When asked how strongly they agree or disagree with statements about what they learned during the audit process, just over 95 percent of respondents "strongly agree" or "somewhat agree" they were more informed about the energy use in their home. Over 81 percent reported they "strongly agree" or "somewhat agree" they were more informed about energy efficiency programs available through Idaho Power. Just over 89 percent indicated they "strongly agree" or "somewhat agree" they learned what additional no- to low-cost actions they could take.

According to the survey, nearly 48 percent of respondents indicated they visited the Idaho Power website after the audit, just over 50 percent unplugged appliances when not in use, over 33 percent signed up for myAccount, and just over 72 percent shared their experience with relatives and/or friends. Just over 78 percent of the respondents reported they replaced additional incandescent lightbulbs with CFLs or LEDs. Just over 37 percent indicated they serviced their heating equipment, and almost 35 percent serviced cooling equipment. Additional information on the actions respondents indicated they already completed or planned to do within the next year are shown in the survey results included in *Supplement 2: Evaluation*.

Survey participants were asked to identify all of the benefits they experienced from participating in the program. Over 73 percent of respondents indicated the biggest benefit they found in the audit was personal satisfaction, with over 75 percent citing raised awareness of energy use, almost 61 percent citing cost savings, nearly 49 percent citing home improvement, approximately 44 percent citing comfort, and almost 37 percent citing benefit to the environment. When survey participants were asked to identify all of the barriers they encounter when making energy-saving changes in their home, over 77 percent of respondents indicated the biggest barrier was cost. Figure 27 shows participant benefits experienced by category and percent.

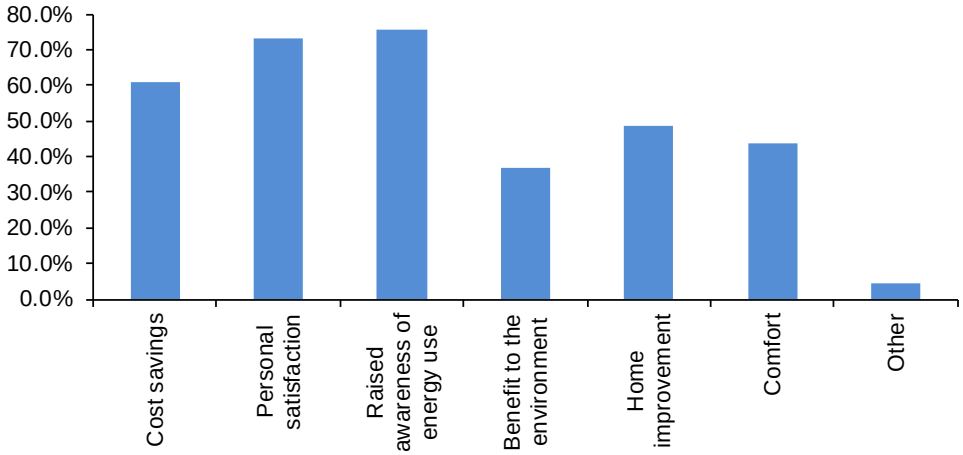



Figure 27. Home Energy Audit program participants' benefits experienced in 2016

Idaho Power conducted no program evaluations in 2016.

## 2017 Program and Marketing Strategies

The 2017 program goal is 500 participants, with approximately half being for all-electric homes and half for homes with other fuel sources for space and water heating. When the Home Energy Audit program

began, the company's goal was to perform QA on 10 percent of the homes audited. The cost of this level of QA was justified to make sure the auditors were complying with the program's specifications. The program is now more established and the QA is verifying that the auditors are meeting and exceeding the requirements. The company believes it is more reasonable to reduce the QA to 5 percent in addition to the online QA and survey results review. Additionally, the company has found it logistically difficult to find 10 percent of the participants who will take the additional time to allow a second visit by a QA auditor.

In 2017, Idaho Power will continue recruiting participants through small batches of direct-mail, social media, advertising, bill inserts and through the use of the trade show booth backdrop at select events. Additional digital advertising may be considered if the program needs to be strategically promoted in specific regions.

## Home Improvement Program

| | | 2016 | 2015 |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (homes) | 482 | 408 |
| | Energy Savings (kWh) | 500,280 | 303,580 |
| | Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $309,799 | $259,898 |
| | Oregon Energy Efficiency Rider | $0 | $0 |
| | Idaho Power Funds | $14,225 | $12,611 |
| | Total Program Costs—All Sources | $324,024 | $272,509 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/kWh) | $0.034 | $0.046 |
| | Total Resource Levelized Cost ($/kWh) | $0.174 | $0.152 |
| **Benefit/Cost Ratios** | | | |
| | Utility Benefit/Cost Ratio | 2.54 | 1.91 |
| | Total Resource Benefit/Cost Ratio | 0.60 | 0.67 |

### Description

Since 2008, the Home Improvement Program has offered incentives for upgrading insulation and windows in electrically heated homes/units. To qualify for an incentive under this program, the home must be a single-family home, a multi-family structure with individually metered residential units, or a manufactured home in Idaho Power's service area in Idaho. The home/units must have an electric heating system serving at least 80 percent of the home's conditioned floor area. The heating system can be a permanently installed electric furnace, heat pump, or electric zonal heating system.

#### *Insulation*

Insulation must be professionally installed between conditioned and unconditioned space by an insulation contractor.

- Customer incentives are 15 cents per $ft^2$ for attic insulation and 50 cents per $ft^2$ for wall and under-floor insulation for additional insulation professionally installed by Idaho residential customers, multi-family building owners, and property managers in Idaho Power's Idaho service area.
- Existing attic insulation must be an R-20 or less to qualify, and the final R-value must meet the local energy code. Idaho Power's service area includes climate zones 5 and 6, resulting in an R-38 requirement for climate zone 5 and R-49 requirement for climate zone 6.
- The existing insulation level in walls must be R-5 or less, and the final R-value must be R-19 or fill the cavity.
- The existing insulation level under floors must be R-5 or less, and the final R-value must be R-30 or fill the cavity.

#### *Windows*

Windows must be professionally installed.

- Customer incentives are $2.50 per $ft^2$ of window area to Idaho residential customers for installing energy-efficient windows and/or sliding glass doors with a U-factor of 0.30 or lower.
- Pre-existing windows/sliding glass doors must be single- or double-pane aluminum or single-pane wood.
- Customers must use a participating contractor to qualify for the Idaho Power incentive, which is processed by Idaho Power.

### Program Activities

During 2016, the Home Improvement Program paid incentives on 482 window and insulation upgrades. Attic insulation accounted for 20 percent, under-floor insulation accounted for 9 percent, wall insulation accounted for 2 percent and windows accounted for 69 percent of completed jobs. Both multi-family and single-family homes took advantage of these program incentives.

### Marketing Activities

In early 2016, Idaho Power developed a new look for all Home Improvement Program marketing materials to better capture the attention of customers, including multi-family building owners, and highlight available incentives. Based on customer feedback, the application form became a part of the updated brochure. The brochure also included a checklist of required documentation to enhance clarification for the customer.

To promote the program, the company ran a series of newspaper ads multiple times during February, March, and September 2016. Idaho Power placed ads in newspapers in rural areas with a higher concentration of electrically heated homes (a program eligibility requirement). The company also sent bill inserts to 361,455 customers in February; 362,473 customers in April; and 364,100 customers in May and a targeted direct-mail letter to 40,000 customers in April and November 2016.

Idaho Power ran Facebook ads in September and reached 86,631 customers, resulting in 10,586 link clicks, 83 likes, 12 shares and had a total cost-per-click of $0.19. Anything at or under that level is good; the $0.19 cost-per-click is considered above expectations for a utility company niche product.

In the April energy efficiency issue of *Connections*, the cover story focused on a customer who had participated in the Home Improvement Program and saw a large reduction in her bill since replacing 13 windows in her home. The *Connections* issue and the customer story was promoted through a *News Briefs* item in April.

### Cost-Effectiveness

In 2015 and 2016, the Home Improvement Program was not cost-effective from the TRC perspective. RTF reduced savings for single-family home weatherization projects between 2013 and 2014, and the reduced savings were updated prior to the 2015 program year. With the changes, average savings

estimates per project were just under 50 percent of 2014 savings levels. These savings estimates were a result of an 18-month RTF process to calibrate residential savings models to billing and housing-characteristic data collected in the northwest, including Idaho, during 2011 as part of the RBSA. As a consequence, the majority of measure combinations in the Home Improvement Program are no longer cost-effective from the TRC perspective--neither is the overall program.

There are several factors that are impacting cost-effectiveness beyond the reduced regional average savings estimates. The few measure combinations that are cost-effective (insulations levels with R-values near zero or existing single-pane windows) are not common in single-family homes. Very little savings from weatherization measures occurs during the summer peak which limits the peak capacity cost-effectiveness benefits in the program.

Home Improvement Program was the only program in Idaho Power's energy efficiency portfolio requiring customer investment where the PCT B/C ratio was less than one at 0.80, which means the customer investment in weatherization on average exceeds the lifetime energy savings benefits, or that for every $1.00 invested by the customer to participate in the program, the customer only sees a $0.80 return through bill savings over 45 years.

For more detailed information about the cost-effectiveness calculations and assumptions, see *Supplement 1: Cost-Effectiveness*.

### Customer Satisfaction and Evaluations

For QA purposes, third-party contractors performed random reviews of at least 5 percent of all installations completed in the Home Improvement Program. QA contractors verified the correct installation of measures. In addition, the QA contractors assisted and educated the contractors on program requirements. Of the 30 QA inspections completed in 2016, no major issues were reported.

The program incentive application form included an optional question asking customers how they heard about the program. The 482 projects came in on 459 applications. Customers answered the marketing question on 437 applications. The results are as follows:

- 248 respondents (56.8%) heard about the program from a program contractor.
- 114 respondents (26.1%) heard about the program from an Idaho Power bill insert.
- 45 respondents (10.3%) heard about the program from the Idaho Power website.
- 18 respondents (4.1%) received a referral from a friend or acquaintance.
- 4 respondents (.9%) heard about the program from a direct-mail piece.
- 8 respondents (1.8%) heard about the program from a newspaper, online, or television/radio ad.
- 0 respondents (0%) heard about the program from a home improvement show or fair.

## 2017 Program and Marketing Strategies

As reported in the *Demand-Side Management 2015 Annual Report*, the recalibrated savings from the RTF resulted in four of the six measures not being cost-effective from the TRC perspective. This program was not cost-effective from a TRC perspective in 2015. In 2016, the program was not cost-effective from a TRC or PCT perspective but was cost-effective from the UC perspective.

In 2016, the company evaluated the non-cost-effective measures and the potential impact of those measures on the program's overall cost-effectiveness. Idaho Power first discussed the concerns it had regarding the continued deterioration in cost-effectiveness of the Home Improvement Program with EEAG during the August 30, 2016 EEAG meeting, and Idaho Power committed to presenting its preliminary 2016 cost-effectiveness findings at the November 3, 2016 EEAG meeting.

At the November meeting, the company informed EEAG that the program was not cost-effective in 2016 based on preliminary savings information. The company advised EEAG that under the scenarios it evaluated, the cost-effectiveness of the Home Improvement Program would not improve. The company assured EEAG it would continue to encourage customers through education to continue to upgrade these measures even though an incentive may no longer be offered and asked for suggestions from EEAG members as to how Idaho Power could best sunset the program.

At this meeting, EEAG suggested the company wait until 2017 to end the program to ensure customers had adequate time to benefit from program incentives and look at a more targeted approach for the program.

Idaho Power analyzed different scenarios to modify the program to improve its cost-effectiveness. One scenario was to consider only offering the highest savings measure combinations in only the coldest climate zone (heating zone 3). These areas produce on average less than 5 percent of the projects annually. Under this scenario, the modified program would fail all the cost-effectiveness tests except the PCT.

In another scenario, Idaho Power analyzed offering only those measure combinations closest to being cost-effective; this modified program would only include window replacements in situations where there are existing single pane window, and insulation incentives where the existing home's R-value is essentially zero. Under this scenario, the program would remain not cost-effective under all tests except the UC test which would decrease from 2.54 as the program exists today to 1.42.

Due to the continued lack of cost-effectiveness, Idaho Power ceased marketing the program in the fourth quarter of 2016. The company plans to sunset the Home Improvement Program beginning on June 30, 2017. Customers will have 90 days from the day the job is started to submit their incentive applications, and those customers whose jobs were started on or before June 30, 2017, will qualify for an incentive.

## *Multifamily Energy Savings Program*

| | 2016 | 2015 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 3 | n/a |
| Energy Savings (kWh) | 149,760 | n/a |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $55,758 | n/a |
| Oregon Energy Efficiency Rider | $0 | n/a |
| Idaho Power Funds | $3,288 | n/a |
| Total Program Costs—All Sources | $59,046 | n/a |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.040 | n/a |
| Total Resource Levelized Cost ($/kWh) | $0.040 | n/a |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 1.43 | n/a |
| Total Resource Benefit/Cost Ratio | 2.55 | n/a |

### Description

The Multifamily Energy Savings Program provides for the direct installation of energy-saving products in electrically heated, multi-family dwellings in Idaho and Oregon. The definition of multi-family dwelling is a building consisting of five or more rental units. The products are: ENERGY STAR® LED lightbulbs, high-efficiency showerheads, kitchen and bathroom faucet aerators, and water heater pipe insulation, and are installed at no cost to the property owner/property manager or the tenant. To ensure energy savings and applicability, each building is pre-approved by the contracted energy efficiency measure installation contractor.

### Program Activities

The program began in March 2016 with a successful pilot project in Pocatello. This was followed by direct install projects in Boise and Twin Falls in September and December respectively. Between all three projects, a total of 196 apartment units received some if not all of the following; ENERGY STAR LED lightbulbs, high-efficiency showerheads, kitchen and bathroom faucet aerators, and water heater pipe insulation.

- Fairway Apartments, Pocatello: 73 units
- Greenbriar Apartments, Boise: 43 units
- Washington Park Apartments, Twin Falls: 80 units

### Marketing Activities

Tenants in participating apartment complexes received a door hanger before the service date informing them that contractors would be entering their home to install energy-saving products. Once installation

was complete, Idaho Power left materials to explain the new energy efficiency measures and to provide contact information should the tenant have any questions.

### Cost-Effectiveness

The RTF provides deemed savings for LED lightbulbs and 2.0 gpm low-flow showerheads. The LED lightbulbs have a deemed savings value of 11 to 32 kWh per year depending on the type and lumens of the lightbulb. The 2.0 gpm low-flow showerhead is estimated to save 139 kWh per year. For the faucet aerator and pipe wrap, RTF does not provide a deemed savings estimate. In Idaho Power's 2012 *Energy Efficiency Potential Study*¸ AEG estimated the annual faucet aerator savings to be 106 kWh and the annual pipe wrap savings to be 150 kWh.

### Customer Satisfaction and Evaluations

Idaho Power included a satisfaction survey on the leave behind materials for the Pocatello pilot project. Both an online and mail-in option were offered. The response rate was very low with only six of the 73 residents responding by mailing in the stamped survey cards, no on-line surveys were submitted. These results will be considered with the expansion of this program.

### 2017 Program and Marketing Strategies

In 2017, Idaho Power plans to expand the program to include a minimum of two, energy-efficient measure direct-installation projects in multi-family dwellings in each of our three regions. The satisfaction survey will be revised and included in 2017 leave behind materials for all projects. Property managers/owners will also be surveyed.

Idaho Power will continue to use informative pre-installation door hangers and post-installation informational marketing pieces. Use of direct-mail will be explored to encourage engagement and participation from property owners/managers, and to increase program visibility.

## Oregon Residential Weatherization

| | 2016 | 2015 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (audits/projects) | 7 | 19 |
| Energy Savings (kWh) | 2,847 | 11,910 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $0 | $0 |
| Oregon Energy Efficiency Rider | $3,906 | $5,341 |
| Idaho Power Funds | $24 | $467 |
| Total Program Costs—All Sources | $3,930 | $5,808 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.079 | $0.028 |
| Total Resource Levelized Cost ($/kWh) | $0.118 | $0.050 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | n/a |
| Total Resource Benefit/Cost Ratio | n/a | n/a |

### Description

Idaho Power offers free energy audits for electrically heated customer homes within the Oregon service area. This is a program required by Oregon Revised Statute (ORS) 469.633 offered under Oregon Tariff Schedule 78 since 1980. Upon a customer's request, an Idaho Power customer representative visits the home to analyze it for energy efficiency opportunities. An estimate of costs and savings for specific measures is given to the customer. Customers may choose either a cash incentive or a 6.5-percent interest loan for a portion of the costs for weatherization measures.

### Program Activities

Seven customers returned a card from the brochure indicating interest in a home energy audit, weatherization loan, or incentive payment. Seven customers requested audits, three audits met the program requirements and were completed, and three customers did not have electric heat and were advised to contact their heating source supplier for program information. One customer did not move forward with the recommended energy efficiency upgrades. Two incentives were paid.

Idaho Power issued two incentives totaling $426.44 for 2,847 kWh savings. Both incentives and related savings were for ceiling insulation measures. There were no loans made through this program during 2016.

### Marketing Activities

During May, as required, Idaho Power sent every Oregon residential customer an informational brochure about energy audits and home weatherization financing.

## Cost-Effectiveness

The Oregon Residential Weatherization program is a statutory program described in Oregon Schedule 78, and includes a cost-effectiveness definition of this program. Pages three and four of the schedule identify the measures determined to be cost-effective and the specified measure life cycles for each. This schedule also includes the cost-effective limit (CEL) for measure lives of seven, 15, 25, and 30 years.

Two savings projects were completed under this program in 2016; both consisted of increasing attic insulation. Combined, the projects' annual energy savings is 2,847 kWh at a levelized TRC of $0.12 per kWh over the 30-year attic insulation measure life compared to a CEL of $0.85 per kWh as defined by Oregon Schedule 78.

## Customer Satisfaction and Evaluations

Idaho Power conducted no customer satisfaction surveys or program evaluations in 2016.

## 2017 Program and Marketing Strategies

Idaho Power will complete requested audits and fulfill all incentives deemed cost-effective and loan applications as required by under Tariff Schedule 78. The company will continue to market the program to customers with a bill insert/brochure in their May bill.

## *Rebate Advantage*

| | 2016 | 2015 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (participants) | 66 | 58 |
| Energy Savings (kWh) | 411,272 | 358,683 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $103,056 | $80,243 |
| Oregon Energy Efficiency Rider | $6,392 | $4,351 |
| Idaho Power Funds | $1,602 | $843 |
| Total Program Costs—All Sources | $111,050 | $85,438 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.016 | $0.014 |
| Total Resource Levelized Cost ($/kWh) | $0.022 | $0.020 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 3.89 | 4.54 |
| Total Resource Benefit/Cost Ratio | 3.33 | 3.45 |

### Description

Initiated in 2003, the Rebate Advantage program helps Idaho Power customers in Idaho and Oregon with the initial costs associated with purchasing a new, energy-efficient, ENERGY STAR® qualified manufactured home. This enables the homebuyer to enjoy the long-term benefit of lower electric bills and greater comfort provided by these homes. The program also provides an incentive to the sales consultants to encourage more sales of ENERGY STAR qualified homes and more discussion of energy efficiency with their customers during the sales process.

In addition to offering financial incentives, the Rebate Advantage program promotes and educates buyers and retailers of manufactured homes about the benefits of owning energy-efficient models. The Northwest Energy Efficient Manufactured (NEEM) housing program establishes quality control (QC) and energy efficiency specifications for qualified homes. NEEM is a consortium of manufacturers and state energy offices in the Northwest. In addition to specifications and quality, NEEM tracks the production and on-site performance of ENERGY STAR qualified manufactured homes.

### Program Activities

Idaho Power residential customers who purchased a new, all-electric, ENERGY STAR qualified manufactured home in 2016, and sited it in Idaho Power's service area were eligible for a $1,000 incentive through the Rebate Advantage program. Salespersons received $200 for each qualified home they sold.

During 2016, Idaho Power paid 66 incentives on new manufactured homes, which accounted for 411,272 annual kWh savings.

### Marketing Activities

One bill insert, shared with the Energy House Calls program, was sent to 374,301 customers in Idaho and Oregon in March. A second bill insert and Facebook ads were not used because the program had exceeded its goal, and both techniques identified had limited options to target potential participants and proved less successful than direct dealer support.

Idaho Power continued to support dealerships in 2016 by providing them with Rebate Advantage program brochures, banners, and applications as needed. The program specialist and the customer representatives visited some of these dealerships to distribute materials, promote the program, and answer salespersons' questions.

### Cost-Effectiveness

In 2016, Idaho Power used the same savings and assumptions as were used in 2015. The measures remained cost-effective for 2016.

### Customer Satisfaction and Evaluations

Idaho Power conducted no customer satisfaction surveys for this program in 2016.

In 2016, Idaho Power contracted with Leidos to perform an impact and process evaluation for this program. The impact evaluation found that submitted applications were accurately assigned ex-ante unit energy savings values according to assigned equipment type, cooling zone, and heating zone codes in the tracking database.

Equipment type was determined to vary between ENERGY STAR with electric resistance heating, Eco-Rated with electric resistance heating, and ENERGY STAR with electric heat pump heating. This equipment appeared to be accurately coded in the tracking database (with the exception of two Eco-Rated projects which were assigned "regular" ENERGY STAR savings values). Accuracy of cooling zone and heating zone coding for each project could not be verified due to lack of information about how these codes were assigned. Overall, this impact evaluation found an ex-post savings realization rate that exceeds 100 percent.

The process evaluation found that the program processes in place are effective, efficient, and result in a high degree of accuracy in program tracking.

A copy of the evaluation can be found in *Supplement 2: Evaluation.*

### 2017 Program and Marketing Strategies

Idaho Power plans to distribute a bill insert to Idaho and Oregon customers and will look for additional opportunities to engage potential manufactured home buyers. Idaho Power will also continue to support dealers by providing them with program materials.

## *Shade Tree Project*

| | 2016 | 2015 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (trees) | 2,070 | 1,925 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $70,669 | $99,672 |
| Oregon Energy Efficiency Rider | $0 | –$66* |
| Idaho Power Funds | $5,973 | $5,786 |
| Total Program Costs—All Sources | $76,642 | $105,392 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Levelized Cost ($/kWh) | n/a | n/a |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | n/a |
| Total Resource Benefit/Cost Ratio | n/a | n/a |

*Reversal of a 2014 charge to the Oregon Rider.

### Description

The Shade Tree Project began as a pilot in 2013. According to the US Department of Energy (DOE), a well-placed shade tree can reduce energy used for summer cooling by 15 percent or more. Utility programs throughout the country report high customer satisfaction with shade tree programs and an enhanced public image for the utility related to sustainability and environmental stewardship. Other utilities report energy savings between 40 kWh per year (coastal climate San Diego) and over 200 kWh per year (Phoenix) per tree planted.

To be successful, trees should be planted to maximize energy savings and ensure survivability. Two technological developments in urban forestry—the state-sponsored Treasure Valley Urban Tree Canopy Assessment and the Arbor Day Foundation's Energy-Saving Trees tool—provided Idaho Power with the information to facilitate a shade tree project.

The Shade Tree Project operates in Ada and Canyon counties (Idaho), offering free shade trees to residential customers. Participants enroll using the on-line Energy-Saving Trees tool and pick up their tree at specific events. Unclaimed trees are donated to city partners and schools.

Using the on-line enrollment tool, participants locate their home on a map, select from a list of available trees, and evaluate the potential energy savings associated with planting in different locations. During enrollment, participants learn how trees planted to the west and east save more energy over time than trees planted to the south and north.

Ensuring the tree is planted properly helps it grow to provide maximum energy savings. At the tree pickup events, participants receive additional education on where to plant trees for maximum energy

savings and other tree care guidance from experts. Local specialists include city arborists from Boise, Kuna, Nampa, and Meridian; Idaho Power utility arborists; Canyon County master gardeners; and College of Western Idaho horticulture students.

In August each year, Idaho Power sends participants from the previous two offerings a newsletter filled with reminders on proper tree care and links to resources, such as tree care classes and educational opportunities in the region. This newsletter was developed after the 2015 field audits identified common customer tree care questions and concerns.

### Program Activities

In 2016, Idaho Power distributed 2,070 shade trees to residential customers through the Shade Tree Project. Because the best time to plant shade trees is in the spring and fall, Idaho Power held offerings in April and October, with 701 trees and 1,369 trees distributed, respectively. Idaho Power purchased the trees from a local wholesale nursery in advance of each event. The species offered for each event depended on the trees available at the time of purchase. Idaho Power worked with city and state arborists to select a variety of large-growing, deciduous trees that traditionally grow well in the climate and soils of the two participating counties.

Participants picked up the trees at events throughout the Treasure Valley—four in the spring and four in the fall. By offering several pickup days, locations, and times, 88 percent of spring trees and 90 percent of fall trees were distributed to homeowners.

Idaho Power continues to track the program data in the DSM database. The database is also used to screen applicants during enrollment to determine whether participants meet the eligibility requirements for the project, such as residential status within the eligible counties (customer type and location).

In 2016, this project was partially funded by a US Forest Service Western Competitive States Grant, which was used to purchase all of the trees for both offerings. The grant also funded the development of an instructional tree planting video posted to Idaho Power's website.

### Marketing Activities

For both offerings, Idaho Power developed a direct-mailing list using the state-sponsored Treasure Valley Urban Tree Canopy Assessment tool (tvcanopy.net/). The tool is the result of a geographic information system (GIS)-based study that mapped land use throughout the Treasure Valley, including existing trees and vegetation, buildings, roads, waterways, and parking lots. The study identified areas where a large-growing shade tree could be planted. Idaho Power used the tool to identify residential properties with potential planting sites to the west of the homes.

For both offerings, Idaho Power also sent emails to customers who had requested information about the project through Idaho Power's website. Project partners, such as the cities of Nampa, Kuna, Meridian and Boise, shared information through their networks. Idaho Power announced its Shade Tree Project to allied groups, such as the Idaho Conservation League, Idaho Chapter of the US Green Building Council (USGBC), and Treasure Valley Canopy Network. Information was sent to Green

Team leads at large employers, such as HP, Wells Fargo, Ch2MHill, and Citi Bank. The company also distributed program flyers at local events, where appropriate.

An Idaho Power Facebook post in the spring reached 1,478 people and resulted in 20 shares, 3 comments, 30 likes and 68 link clicks. A boosted Facebook post was used in the fall and reached 16,668 people and resulted in 909 post engagements (which includes likes, shares and comments). The boosted post cost-per-engagement was $0.07. The company also promoted the program in specific neighborhoods on Nextdoor.com in the spring and fall. This combination of marketing tactics was successful. The spring offering filled in 20 days; the fall offering filled in 16 days.

### Cost-Effectiveness

Idaho Power does not calculate the cost-effectiveness tests for this program since no savings are currently being attributed to this program. The company plans to begin counting energy saving for the Shade Tree Program when the originally planted trees are five years old.

### Customer Satisfaction and Evaluations

After each offering, a survey was emailed to participants. The survey asked questions related to program marketing, tree-planting education, and participant experience with the enrollment and tree pickup processes. Results are compared, offering to offering, to look for trends to ensure the program processes are still working, and to identify opportunities for improvement. Data are also collected about where and when the participant planted the tree. This data will be used by Idaho Power to refine energy-savings estimates.

In total, the survey was sent to 1,112 Shade Tree Project participants. The company received 531 responses for a response rate of 48 percent. Participants were asked how much they would agree or disagree that they would recommend the project to a friend; nearly 96 percent of respondents said they "strongly agree," and just over 3 percent said they "somewhat agree." Participants were asked how much they would agree or disagree that they were satisfied with the overall experience with the Shade Tree Project; nearly 93 percent of respondents indicated they "strongly agree," and just over 6 percent "somewhat agree" they were satisfied. View survey information in *Supplement 2: Evaluation*.

Idaho Power conducted no program evaluations in 2016.

### 2017 Program and Marketing Strategies

Idaho Power plans to continue the Shade Tree Project in 2017 using the Arbor Day enrollment tool; trees will be distributed at multiple events. This will be the last year of US Forest Service grant funding to help support the program. Idaho Power will use these funds to purchase some trees, and to send a representative to visit a subset of planting sites to collect data on tree placement and health.

Idaho Power will also explore expanding the program to new areas in western Idaho, such as Elmore County (Mountain Home) and the Payette area.

Idaho Power will continue to market the program through direct-mail, focusing on customers identified using the Urban Tree-Canopy Assessment. In addition, Idaho Power maintains a waiting list of

customers who were unable to enroll before previous offerings filled. Idaho Power will reach out to these customers through direct-mail or email for the 2017 offerings. Idaho Power will continue to leverage allied interest groups, and will use social media and boosted Facebook posts if enrollment response rates decline.

## *Simple Steps, Smart Savings™*

| | | 2016 | 2015 |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (products) | 7,880 | 9,343 |
| | Energy Savings (kWh) | 577,320 | 770,822 |
| | Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $147,055 | $130,575 |
| | Oregon Energy Efficiency Rider | $3,535 | $6,676 |
| | Idaho Power Funds | $3,194 | $1,845 |
| | Total Program Costs—All Sources | $153,784 | $139,096 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/kWh) | $0.025 | $0.018 |
| | Total Resource Levelized Cost ($/kWh) | $0.063 | $0.054 |
| **Benefit/Cost Ratios** | | | |
| | Utility Benefit/Cost Ratio | 2.40 | 3.37 |
| | Total Resource Benefit/Cost Ratio | 1.33 | 4.83 |

### Description

Initiated in 2015, the Simple Steps, Smart Savings™ program is a promotion-based appliance program that aims to increase sales of qualified energy-efficient appliances. The payments provided by Idaho Power through this program are applied during special promotions, which align with holidays or events throughout the year at retail stores. Incentives are shared between the retailer, manufacturer, and the customer, though they may differ between promotions and between retailers and manufacturers.

Retailer and manufacturer incentives may be provided as co-marketing dollars to the retailer or manufacturer to fund activities such as promotional events, special product placement, point-of-purchase signage, retailer activities, event kits, sales associate training, training material, and other marketing activities during the promotional periods.

Customer rewards may include, but are not limited to, retailer gift cards, retailer credit to the customer or free laundry products for the purchase of qualified products. These promotions are available in Idaho and Oregon.

The program also includes promotions using retailer markdowns and retailer/manufacturer incentives. Markdowns reduce retail-end prices to the customer at the point-of-purchase. Retailer/manufacturer incentives drive the manufacture, distribution, and promotion of more energy-efficient consumer products. For example, since 2010 Idaho Power has offered retailer markdowns for low-flow showerheads. Program payments reduce the cost of the showerheads for customers at the retail level, as well as to retailers and manufacturers to drive the manufacture, distribution, and promotion of these products.

Idaho Power also participates in the BPA-sponsored, Simple Steps, Smart Savings energy-efficient lighting program, which is discussed further in the Energy Efficient Lighting program section of this report.

All Simple Steps, Smart Savings promotions are administered by the BPA and coordinated by CLEAResult.

## Program Activities

On May 18, 2016, Idaho Power received approval to begin offering the appliance promotion to our customers in Oregon.

### *Appliances*

In 2016, Idaho Power participated in five major Simple Steps, Smart Savings appliance promotions with these retailers: Sears, Sears Hometown, Dell's Home Appliance, Home Depot, and RC Willey. At each event, CLEAResult personnel staffed a table and answered customer questions about the appliance promotion. To further educate customers about the promotions, CLEAResult created an Idaho Power-branded promotional landing page that highlights promotion details and participating retailers.

The five promotions took place on the following dates: 1) the 2015 Black Friday took place in November through the first week of December—because these sales data were delayed, the sales from this promotion will be included with the remaining four 2016 promotions; 2) the President's Day promotion ran for two weeks in February; 3) the Memorial Day promotion ran for the last week in May and first week in June; 4) the Independence Day promotion ran for the last week in June and first two weeks in July; and 5) the Labor Day promotion ran for the last week in August and first week in September. In-store events were held at all participating retailers in Idaho Power's service area during the promotion.

Incentives for the purchase of an ENERGY STAR® clothes washer included a $10 gift card at Sears and Home Depot; a 180-load supply of free laundry detergent at Sears Hometown; a gift of free laundry products at Dell's Home Appliances; and a $25 gift card at RC Willey. RC Willey added their own $15 to the $10 provided to allow them to offer a $25 gift card to customers.

### *Showerheads*

In early 2016, The Home Depot's contract to offer buy downs on qualified showerheads ended. Due to the length of time to prepare monthly reports for these sales, they declined to continue participating in the showerhead buy down. To make up for the decrease in showerhead sales after The Home Depot's departure, CLEAResult engaged Costco and Lowe's to begin offering qualified showerheads to their list of available buy down products.

## Marketing Activities

In 2016, CLEAResult and participating Simple Steps, Smart Savings utility partners, decided the marketing was outdated and needed a new, fresh look. Several new designs were presented, and it was decided that the new logo would be Simple + Smart. See Figure 17 to see the updated logo. All table

tents and clings used for the 2016 Simple Steps, Smart Savings appliance promotions used the new Simple + Smart logo.

To help support the promotions, table tents and static clings were displayed on all qualifying appliances. These pieces informed customers about the promotion and the incentive they would receive. In-store gift cards were placed in gift card holders that displayed the Idaho Power logo. For purchases from Sears Hometown, where the customer received an instant markdown, customers also received a thank-you card with the Idaho Power logo.

During the promotions, Idaho Power placed Facebook and Twitter posts to notify customers of the details.

### Cost-Effectiveness

Idaho Power used the same savings and cost assumptions for showerheads in 2016 as were used in 2015. In 2015 and 2016, RTF reviewed and updated the savings assumptions for showerheads, and Idaho Power will adopt those in 2017. The parameters that impacted the savings for showerheads the most were changes to the baseline showerhead, the showers per person per year, and the annual usage of each showerhead. Due to the timing of RTF's update, BPA and CLEAResult did not implement the new savings in the Simple Steps, Smart Savings promotion in 2016. The new RTF workbook, version 2.4, will be used in 2017.

In 2016, Idaho Power participated in five clothes washer promotions. Idaho Power applied the per-unit savings from the approved BPA's unit energy savings (UES) Measure List. While BPA applies the annual generator busbar savings of 73 kWh per unit, Idaho Power applies the annual site savings of 67 kWh per unit. This difference is due to the different line losses applied by Idaho Power and BPA. For the NEBs, Idaho Power used RTF's clothes washer workbook to determine the water and wastewater savings for the ENERGY STAR clothes washers.

For detailed information for all measures within the Simple Steps, Smart Savings program, see *Supplement 1: Cost-Effectiveness*.

### Customer Satisfaction and Evaluations

Idaho Power conducted no customer satisfaction surveys or program evaluations in 2016.

### 2017 Program and Marketing Strategies

Idaho Power has committed to participate in the 2017 Simple Steps, Smart Savings appliance promotions. Five promotions are scheduled: 1) February for President's Day, 2) May to June for Memorial Day, 3) July for Independence Day, 4) August to September for Labor Day, and 5) November to December for Black Friday. Current participating retailers are Sears, Sears Hometown, RC Willey, and Dell's Home Appliance.

CLEAResult is in the process of working with local independent retailers to encourage their participation in the program. For each promotion, Idaho Power will provide incentives only for products that meet Idaho Power's cost-effectiveness requirements.

Idaho Power will also continue participation in the Simple Steps, Smart Savings energy-efficient showerheads buy-down program in 2017.

CLEAResult will continue to manage marketing at retailers, including point-of-purchase signs, Idaho Power-branded gift card holders, and thank-you cards. When provided, Idaho Power will continue to use Idaho Power-branded promotion landing pages and Facebook posts to notify customers of the promotions.

## *Weatherization Assistance for Qualified Customers*

| | 2016 | 2015 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (homes/non-profits) | 246 | 243 |
| Energy Savings (kWh) | 746,162 | 550,021 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $0 | $0 |
| Oregon Energy Efficiency Rider | $0 | $0 |
| Idaho Power Funds | $1,289,809 | $1,315,032 |
| Total Program Costs—All Sources | $1,289,809 | $1,315,032 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $0.105 | $0.145 |
| Total Resource Levelized Cost ($/kWh) | $0.158 | $0.235 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 0.73 | 0.54 |
| Total Resource Benefit/Cost Ratio | 0.65 | 0.43 |

### Description

The Weatherization Assistance for Qualified Customers (WAQC) program provides financial assistance to regional CAP agencies in Idaho Power's service area. This assistance helps fund weatherization costs of electrically heated homes occupied by qualified customers who have limited incomes. The WAQC program also provides a limited pool of funds for the weatherization of buildings occupied by non-profit organizations serving primarily special-needs populations, regardless of heating source, with priority given to buildings with electric heat. Weatherization improvements enable residents to maintain a more comfortable, safe and energy-efficient home while reducing their monthly electricity consumption. Improvements are available at no cost to qualified customers who own or rent their homes. These customers also receive educational materials and ideas on using energy wisely in their homes. Local CAP agencies determine participant eligibility according to federal and state guidelines.

In 1989, Idaho Power began offering weatherization assistance in conjunction with the State of Idaho Weatherization Assistance Program (WAP). In Oregon, Idaho Power offers weatherization assistance in conjunction with the State of Oregon WAP. Through the WAQC program, Idaho Power provides supplementary funding to state-designated CAP agencies for additional weatherization of electrically heated homes occupied by qualified customers and buildings occupied by non-profit organizations that serve special-needs populations. This allows CAP agencies to combine Idaho Power funds with federal LIHEAP weatherization funds to serve more customers in electrically heated homes with special needs.

Idaho Power has an agreement with each CAP agency for the WAQC program that specifies the funding allotment, billing requirements, and program guidelines. Currently, Idaho Power oversees the program in Idaho through five regional CAP agencies: Eastern Idaho Community Action Partnership (EICAP), El Ada Community Action Partnership (EL ADA), Aging, Weatherization and Human Services (CCOA,

now Metro Community Services), South Central Community Action Partnership (SCCAP), and Southeastern Idaho Community Action Agency (SEICAA). In Oregon, Community Connection of Northeast Oregon, Inc. (CCNO), and Community in Action (CINA) provide weatherization services for qualified customers in Idaho Power's service area.

The Idaho Department of Health and Welfare (IDHW) uses the energy audit program (EA5) for the Idaho WAP and therefore, the Idaho CAP agencies use the EA5. The EA5 is a software program approved for use by the DOE.

Annually, Idaho Power physically verifies approximately 10 percent of the homes that were weatherized under the WAQC program. This is done through two methods. The first method includes the Idaho Power program specialist participating in Idaho's and Oregon's state monitoring process that reviews weatherized homes. The process involves utility representatives; weatherization personnel from the CAP agencies; CAPAI; and a Building Performance Institute (BPI)-certified quality control inspector hired by the state reviewing homes weatherized by each of the CAP agencies.

The second method involves Idaho Power contracting with two companies—The Energy Auditor, Inc. (The Energy Auditor), and Momentum, LLC (Momentum)—that employ certified building performance specialists to verify installed measures in customer homes. The Energy Auditor verifies homes weatherized for the WAQC program in Idaho Power's eastern and southern Idaho regions. The owner of The Energy Auditor is certified by PTCS and is an ENERGY STAR® HPS. Momentum verifies weatherization services provided through the WAQC program in the Capital and Canyon–West regions of Idaho and in the company's Oregon service area. The owner of Momentum is a RESNET® certified home energy rater. After these companies verify installed measures, any required follow-up is done by the CAP agency personnel.

## Regulatory Compliance

Idaho Power reports the activities related to the WAQC program in compliance with the IPUC Order No. 29505, as updated in Case No. IPC-E-16-30, Order No. 33702. This order approved Idaho Power's request to modify Order No. 29505 to consolidate the WAQC Annual Report with the DSM Annual Report.

## Program Activities

All information previously available in the WAQC Annual Report is available in this section of the DSM Annual Report. In the future, WAQC activities will be reported solely in this manner. This report includes the following topics:

- Review of weatherized homes and non-profit buildings by county
- Review of measures installed
- Overall cost-effectiveness
- Customer education and satisfaction
- Plans for 2017

***Weatherized Homes and Non-Profit Buildings by County***

In 2016, Idaho Power made $1,250,693 available to Idaho CAP agencies. Of the funds provided, $1,186,192 were paid to Idaho CAP agencies in 2016, while $64,501 were accrued for future funding. Of the funds paid in 2016, $1,055,649 directly funded audits, energy efficiency measures, and health and safety measures for qualified customers' homes (production costs) in Idaho, and $105,565 funded administration costs to Idaho CAP agencies for those homes weatherized.

These funds provided for the weatherization of 231 Idaho homes and 3 Idaho non-profit buildings. The production cost of the non-profit building weatherization measures was $22,707, while $2,271 in administrative costs were paid for the Idaho non-profit building weatherization jobs. In Oregon, Idaho Power paid $29,742 in production costs for 12 qualified homes and $2,974 in CAP agency administrative costs for homes in Malheur and Baker Counties. Table 9 shows each CAP agency, the number of homes weatherized, production costs, the average cost per home, administration payments, and total payments per county made by Idaho Power.

Table 9. 2016 WAQC activities and Idaho Power expenditures by agency and county

| Agency<br>Idaho Homes | County | Number of Homes | Production Cost | Average Cost[1] | Administration Payment to Agency | Total Payment |
|---|---|---|---|---|---|---|
| CCOA | Adams | 1 | $ 6,313 | $ 6,313 | $ 631 | $ 6,944 |
| | Boise | 1 | 5,588 | 5,588 | 559 | 6,146 |
| | Canyon | 35 | 170,066 | 4,859 | 17,007 | 187,073 |
| | Gem | 4 | 23,389 | 5,847 | 2,339 | 25,728 |
| | Payette | 4 | 38,345 | 9,586 | 3,834 | 42,179 |
| | Valley | 3 | 24,643 | 8,214 | 2,464 | 27,107 |
| | Washington | 1 | 6,201 | 6,201 | 620 | 6,821 |
| | **Agency Total** | **49** | **$ 274,545** | **$ 5,603** | **$ 27,454** | **$ 301,999** |
| EICAP | Lemhi | 4 | 11,625 | 2,906 | 1,163 | 12,788 |
| | **Agency Total** | **4** | **$ 11,625** | **$ 2,906** | **$ 1,163** | **$ 12,788** |
| EL ADA | Ada | 69 | 342,706 | 4,967 | 34,271 | 376,977 |
| | Elmore | 19 | 88,319 | 4,648 | 8,832 | 97,151 |
| | Owyhee | 17 | 85,773 | 5,045 | 8,577 | 94,351 |
| | **Agency Total** | **105** | **$ 516,799** | **$ 4,922** | **$ 51,680** | **$ 568,479** |
| SCCAP | Blaine | 3 | 6,737 | 2,246 | 674 | 7,411 |
| | Gooding | 2 | 9,302 | 4,651 | 930 | 10,232 |
| | Jerome | 8 | 34,366 | 4,296 | 3,437 | 37,803 |
| | Lincoln | 1 | 7,262 | 7,262 | 726 | 7,988 |
| | Twin Falls | 23 | 90,594 | 3,939 | 9,059 | 99,653 |
| | **Agency Total** | **37** | **$ 148,261** | **$ 4,007** | **$ 14,826** | **$ 163,087** |

Table 9. 2016 WAQC activities and Idaho Power expenditures by agency and county (continued)

| Agency | County | Number of Homes | Production Cost | Average Cost[1] | Administration Payment to Agency | Total Payment |
|---|---|---|---|---|---|---|
| **Idaho Homes** | | | | | | |
| SEICAA | Bannock | 14 | $ 41,254 | $ 2,947 | $ 4,125 | $ 45,380 |
| | Bingham | 10 | 29,394 | 2,939 | 2,939 | 32,333 |
| | Power | 12 | 33,771 | 2,814 | 3,377 | 37,148 |
| | **Agency Total** | **36** | **$ 104,419** | **$ 2,901** | **$ 10,442** | **$ 114,861** |
| **Total Idaho Homes** | | **231** | **$ 1,055,649** | **$ 4,570** | **$ 105,565** | **$ 1,161,214** |
| Non-profit | Ada | 1 | 10,387 | | 1,039 | 11,426 |
| Buildings | Lemhi | 1 | 9,518 | | 952 | 10,470 |
| | Twin Falls | 1 | 2,802 | | 280 | 3,082 |
| **Total Non-Profit Buildings** | | **3** | **$ 22,707** | **$ 7,569** | **$ 2,271** | **$ 24,978** |
| **Total Idaho** | | **234** | **$ 1,078,356** | | **$ 107,836** | **$ 1,186,192** |
| **Oregon Homes** | | | | | | |
| CCNO | Baker | 1 | 3,831 | 3,831 | 383 | 4,214 |
| | **Agency Total** | **1** | **$ 3,831** | **$ 3,831** | **$ 383** | **$ 4,214** |
| CINA | Malheur | 11 | 25,911 | 2,356 | 2,591 | 28,503 |
| | **Agency Total** | **11** | **$ 25,911** | **$ 2,356** | **$ 2,591** | **$ 28,503** |
| **Total Oregon Homes** | | **12** | **$ 29,742** | **$ 2,479** | **$ 2,974** | **$ 32,717** |
| **Total Program** | | **246** | **$ 1,108,098** | | **$ 110,810** | **$ 1,218,908** |

Note: Dollars are rounded.

The base funding for Idaho CAP agencies is $1,212,534 annually, which does not include carryover from the previous year. Idaho Power's agreements with CAP agencies include a provision that identifies a maximum annual average cost per home up to a dollar amount specified in the agreement between the CAP agency and Idaho Power. The intent of the maximum annual average cost is to allow CAP agency flexibility to service some homes with greater or fewer weatherization needs. It also provides a monitoring tool for Idaho Power to forecast year-end outcomes. The average cost per home weatherized is calculated by dividing the total annual Idaho Power production cost of homes weatherized by the total number of homes weatherized that the CAP agencies billed to Idaho Power during the year.
The maximum annual average cost per home the CAP agencies were allowed under the 2016 agreement was $6,000. In 2016, Idaho CAP agencies had a combined average cost per home weatherized of $4,570. In Oregon, the average was $2,479 per home weatherized.

There is no maximum annual average cost for the weatherization of buildings occupied by non-profit agencies.

CAP agency administration fees are equal to 10 percent of Idaho Power's per-job production costs. The average administration cost paid to agencies per Idaho home weatherized in 2016 was $457, and the average administration cost paid to Oregon agencies per Oregon home weatherized during the same period was $248. Not included in this report's tables are additional Idaho Power staff labor, marketing, home verification, and support costs for the WAQC program totaling $55,087 for 2016. These expenses were in addition to the WAQC program funding requirements in Idaho specified in IPUC Order No. 29505.

In compliance with IPUC Order No. 29505, WAQC program funds are tracked separately, with unspent funds carried over and made available to Idaho CAP agencies in the following year. In 2016, $38,159 in unspent funds from 2015 were made available for expenditures in Idaho. Table 10 details the funding base and available funds from 2015 and the total amount of 2016 spending. In 2015, the Idaho non-profit-pooled fund overspent by $10,529 which was deducted from the carryover amount to 2016.

Table 10. 2016 WAQC base funding and unspent funds made available

| Agency | 2016 Base | Available Funds from 2015 | Total 2016 Allotment | 2016 Spending |
|---|---|---|---|---|
| **Idaho** | | | | |
| CCOA | $ 302,259 | $ – | $ 302,259 | $ 301,999 |
| EICAP | 12,788 | – | 12,788 | 12,788 |
| EL ADA | 568,479 | – | 568,479 | 568,479 |
| SCCAP | 167,405 | 45,430 | 212,835 | 163,087 |
| SEICAA | 111,603 | 3,258 | 114,861 | 114,861 |
| Non-profit buildings | 50,000 | (10,529) | 39,471 | 24,978 |
| **Idaho Total** | **$ 1,212,534** | **$ 38,159** | **$ 1,250,693** | **$ 1,186,192** |
| **Oregon** | | | | |
| CCNO | 6,750 | 12,322 | 19,072 | 28,503 |
| CINA | 38,250 | 4,277 | 42,527 | 4,214 |
| **Oregon Total** | **$ 45,000** | **$ 16,599** | **$ 61,599** | **$ 32,717** |

Note: Dollars are rounded. Overspending of non-profit pooled fund in 2015 was deducted from 2016 non-profit available fund.

***Weatherization Measures Installed***

Table 11 details home and non-profit building counts for which Idaho Power paid all or a portion of each measure cost during 2016. The home counts column shows the number of times any percentage of that measure was billed to Idaho Power during the year. If totaled, measure counts would be higher than total homes weatherized because the number of measures installed in each home varies. For example, Table 11 shows 68 homes in Idaho received a lightbulb replacements measure. Each home received more than one lightbulb. Consistent with the Idaho WAP, the WAQC program offers several measures that have costs but do not necessarily save energy, or for which the savings cannot be measured. Included in this category are health and safety measures, vents, furnace repairs, other, and home energy audits. Health and safety measures are necessary to ensure weatherization activities do not cause unsafe situations in a customer's home or compromise a home's existing indoor air quality. Examples of health and safety items are smoke and carbon monoxide detectors, bathroom fans, and dryer vents.
Other non-energy-saving measures are allowed under this program because they interact with the energy-saving measures. Examples of items included in the other measure category include vapor barriers, dryer vent hoods, and necessary electrical upgrades.

Table 11. 2016 WAQC review of measures installed

| | Home Counts | | Production Costs |
|---|---|---|---|
| **Idaho Homes** | | | |
| Audit | 142 | $ | 14,139 |
| Ceiling Insulation | 111 | | 86,188 |
| Doors | 93 | | 63,495 |
| Ducts | 62 | | 34,794 |
| Floor Insulation | 95 | | 100,979 |
| Furnace Repair | 16 | | 11,604 |
| Furnace Replace | 132 | | 480,421 |
| Health and Safety | 45 | | 14,423 |
| Infiltration | 143 | | 36,850 |
| Lighting Replacement | 68 | | 1,602 |
| Other | 37 | | 9,807 |
| Pipes | 46 | | 4,625 |
| Refrigerator | 8 | | 6,373 |
| Vents | 14 | | 912 |
| Wall Insulation | 12 | | 5,909 |
| Water Heater | 24 | | 23,204 |
| Windows | 110 | | 160,324 |
| **Total Idaho Homes** | | **$** | **1,055,650** |
| **Oregon Homes** | | | |
| Ceiling Insulation | 7 | | 8,582 |
| Ducts | 4 | | 2,437 |
| Floor Insulation | 2 | | 5,084 |
| Health and Safety | 7 | | 3,251 |
| Infiltration | 5 | | 1,605 |
| Pipes | 2 | | 105 |
| Vents | 1 | | 660 |
| Wall Insulation | 2 | | 2,141 |
| Windows | 3 | | 5,878 |
| **Total Oregon Homes** | | **$** | **29,742** |
| **Idaho Non-Profits** | | | |
| Audit | 3 | | $513 |
| Ceiling Insulation | 1 | | 1,003 |
| Doors | 1 | | 575 |
| Ducts | 1 | | 988 |
| Floor Insulation | 1 | | 3,546 |
| Furnace Repair | 1 | | 509 |
| Health and Safety | 2 | | 623 |
| Infiltration | 2 | | 1,462 |
| Lighting Replacement | 2 | | 35 |

Table 11. 2016 WAQC review of measures installed (continued)

| | Home Counts | | Production Costs |
|---|---|---|---|
| **Idaho Non-Profits** | | | |
| Other | 1 | $ | 120 |
| Pipes | 2 | | 211 |
| Refrigerator | 1 | | 10,357 |
| Vents | 1 | | 67 |
| Wall Insulation | 1 | | 667 |
| Water Heater | 1 | | 20 |
| Windows | 1 | | 2,013 |
| **Total Idaho Non-Profit Measures** | | **$** | **22,707** |

Note: Dollars are rounded.

## Marketing Activities

Idaho Power provided educational materials to each CAP agency to help qualified customers who receive weatherization assistance learn how to use energy efficiently. Included in the materials were copies of the Idaho Power publications: *Energy Efficiency Guide, Maintenance of Your High-Efficiency Water Fixtures,* and *Energy Saving Tips*, which describe energy conservation tips for the heating and cooling seasons, saving water, and a pamphlet that describes the energy-saving benefits of using CFLs, LEDs, and other tips for choosing the right lightbulb. Idaho Power developed and distributed a brochure that provided information about both the WAQC program and Weatherization Solutions for Eligible Customers program. This was meant to help customers realize there is more than one way to qualify for weatherization services. Idaho Power actively informed customers about WAQC through energy and resource fairs and other customer contacts including communication from its Customer Service Center.

## Cost-Effectiveness

The WAQC program, while showing increases in savings and cost-effectiveness ratios, remains not cost-effective. The program had a total UC B/C ratio of 0.73, and a TRC B/C ratio of 0.65.

New savings values were introduced in 2016 that reflect an updated billing analysis completed in 2015. This analysis considered pre- and post-weather normalized consumption in homes weatherized during the 2013-2014 program years from both WAQC and Weatherization Solutions for Eligible Customers programs. The billing analysis was needed to reflect the increased replacement of forced-air electric resistance heat systems with efficient heat pump systems, and to ensure that the proper level of savings was captured for the average home. Variable-based degree-day analysis methods were used, consistent with other regional billing data studies and with whole-house consumption analysis methods published as part of the DOE's Uniform Methods project.

Table 12 shows the updated results that identify the difference between homes that only received weatherization versus homes that were weatherized and upgraded with an efficient heat pump.

Table 12. 2016 savings values for WAQC program

| Home Type | Weatherization only | | Weatherization and heating system change | |
|---|---|---|---|---|
| | kWh/project | kWh/project/ft$^2$ | kWh/project | kWh/project/ft$^2$ |
| Single-family Homes | 1,797 | 1.16 | 4,154 | 2.48 |
| Manufactured Homes | 1,734 | 1.36 | 4,418 | 4.30 |
| Multi-family Homes | n/a | 1.16 | n/a | 2.48 |
| Non-profit Buildings | n/a | 1.16 | n/a | 2.48 |

Table 12 also shows, as expected, weatherization combined with the installation of an efficient heat pump results in savings nearly twice that from just installing weatherization measures. Manufactured homes demonstrate a higher savings per square foot of weatherized space than single-family homes in both projects where only weatherization measures were installed and cases where heating system upgrades occurred.

Idaho Power used savings of 1.16 kWh/ft$^2$ of weatherized heated space for multi-family projects where only weatherization measures were installed and 2.48 kWh/ft$^2$ where heating system were changed. In 2016 and previous program years, there has been insufficient data from multi-family projects in both the WAQC and Weatherization Solutions for Eligible Customers programs to conduct a billing analysis so savings are assumed to be similar on a savings per square foot basis as single-family homes where like measures were installed.

Idaho Power used savings of 1.16 kWh/ft$^2$ of weatherized heated space for non-profit projects where only weatherization measures were installed, which is the average per square foot savings values for weatherized single-family homes from the updated billing analysis. It is not feasible at this time to conduct a post-weatherization billing analysis or to create a commercial whole building simulation model prior to weatherization for non-profit projects.

The initial phase for assessing cost-effectiveness occurs during the initial contacts between CAP agency weatherization staff and the customer. In customer homes, the agency weatherization auditor uses the EA5 to conduct the initial audit of potential energy savings for a home. The EA5 compares the efficiency of the home prior to weatherization to the efficiency after the proposed improvements and calculates the value of the efficiency change into a savings-to-investment ratio (SIR). The output of the SIR is similar to the PCT ratio. If the EA5 computes an SIR of 1.0 or higher, the CAP agency is authorized to complete the proposed measures. The weatherization manager can split individual measure costs between Idaho Power and other funding sources with a maximum charge of 85 percent of total production costs to Idaho Power. Using the audit form to pre-screen projects ensures that each weatherization project will result in energy savings. The use of the audit tool is one of the primary reasons that consistent results have been seen from recent billing analysis of weatherization projects.

The following recommendations from the IPUC Order No. 32788 were used for the 2016 cost-effectiveness analysis:

- Applying a 100-percent net-to-gross (NTG) value to reflect the likelihood that WAQC weatherization projects would not be initiated without the presence of a program
- Claiming 100 percent of project savings
- Including an allocated portion of the indirect overhead costs
- Applying the 10-percent conservation preference adder
- Claiming $1 of benefits for each dollar invested in health, safety, and repair measures
- Amortizing evaluation expenses over a three-year period

### Customer Satisfaction and Evaluations

Idaho Power used independent, third-party verification companies to ensure the stated measures were installed in the homes, and to discuss the program with these customers. In 2016, home verifiers visited 36 homes, requesting feedback about the program. When asked how much customers learned about saving electricity, 30 customers answered they learned "a lot" or "some." When asked how many ways they tried to save electricity, 31 customers responded "a lot" or "some."

A customer survey was used to assess major indicators of customer satisfaction throughout the service area. The *2016 Weatherization Programs Customer Survey* was provided to all program participants in all regions upon completion of weatherization in their homes. Survey questions gathered information about how customers learned of the program, reasons for participating, how much customers learned about saving energy in their homes, and the likelihood of household members changing behaviors to use energy wisely.

Idaho Power received survey results from 238 of 243 households weatherized by the program in 2016. Of the 238 completed surveys, 227 were from Idaho customers and 11 were from Oregon customers. Some highlights include the following:

- Over 37 percent of respondents learned of the program from a friend or relative, and another almost 23 percent learned of the program from an agency flyer. Nearly 8 percent learned about the weatherization program from direct-mail.
- Over 84 percent of the respondents reported that their primary reason for participating in the weatherization program was to reduce utility bills, and over 39 percent wanted to improve the comfort of their home.
- Over 73 percent reported they learned how air leaks affect energy usage, and just over 67 percent indicated they learned how insulation affects energy usage during the weatherization process.
- Over 56 percent of respondents said they learned how to use energy wisely. Seventy-five percent reported they were very likely to change habits to save energy, and almost 66 percent reported they have shared all of the information about energy use with members of their household.

- Over 87 percent of the respondents reported they think the weatherization they received will significantly affect the comfort of their home, and almost 94 percent said they were very satisfied with the program.
- Almost 86 percent of the respondents reported the habit they were most likely to change was turning off lights when not in use, and 61 percent said that washing full loads of clothes was a habit they were likely to adopt to save energy. Turning the thermostat up in the summer was reported by over 53 percent of the respondents, and turning the thermostat down in the winter was reported by 65 percent as a habit they and members of the household were most likely to adopt to save energy.

A summary of the report is included in the *Supplement 2: Evaluation*.

### 2017 Program and Marketing Strategies

As in previous years, unless directed otherwise, Idaho Power will continue to provide financial assistance to CAP agencies while exploring changes to improve program delivery. The company will continue to provide the most benefit possible to special-needs customers while working with Idaho and Oregon WAP personnel.

Idaho Power will continue to participate in the Idaho and Oregon state monitoring process of weatherized homes and will continue to verify approximately 10 percent of the homes weatherized under the WAQC program via certified home-verification companies.

In 2017, Idaho Power will support the whole-house philosophy of the WAQC program and Idaho and Oregon WAP by continuing to allow a $6,000 annual maximum average per-home cost. Based on the required funding, Idaho Power estimates approximately 182 homes and four non-profit buildings in Idaho will be weatherized, and approximately 11 homes in Oregon will be weatherized in 2017.

In Idaho during 2017, Idaho Power expects to contribute the base amount plus available funds from 2016 to total approximately $1,350,000 in weatherization measures and agency administration fees. Of this amount, approximately $64,490 will be provided to the non-profit pooled fund to weatherize buildings housing non-profit agencies that primarily serve qualified customers in Idaho.

## *Weatherization Solutions for Eligible Customers*

| | | 2016 | 2015 |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (homes) | 232 | 171 |
| | Energy Savings (kWh) | 621,653 | 432,958 |
| | Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $1,226,540 | $1,204,147 |
| | Oregon Energy Efficiency Rider | $56,571* | $0 |
| | Idaho Power Funds | $40,681 | $39,122 |
| | Total Program Costs—All Sources | $1,323,793 | $1,243,269 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/kWh) | $0.130 | $0.175 |
| | Total Resource Levelized Cost ($/kWh) | $0.130 | $0.175 |
| **Benefit/Cost Ratios** | | | |
| | Utility Benefit/Cost Ratio | 0.59 | 0.45 |
| | Total Resource Benefit/Cost Ratio | 0.70 | 0.50 |

* Oregon Rider charges were reversed and charged to the Idaho Rider in February 2017.

### Description

Weatherization Solutions for Eligible Customers is an energy efficiency program designed to serve Idaho Power residential customers in Idaho whose income falls between 175 percent and 250 percent of the most current federal poverty level. Initiated in 2008, the program is designed to mirror the WAQC program. These customers often do not have disposable income to participate in other residential energy efficiency programs, and they typically live in similar housing as WAQC customers.

Potential participants are interviewed by a contractor to determine household occupant income eligibility, as well as to confirm the home is electrically heated. If the home is a rental, the landlord must agree to maintain the unit's current rent for a minimum of one year, and to help fund a portion of the cost of weatherization. If the customer is eligible, an auditor inspects the home to determine which upgrades will save energy, improve indoor air quality, and/or provide health and safety for the residents. To be approved, energy efficiency measures and repairs must have a SIR of 1.0 or higher, interact with an energy-saving measure, or be necessary for the health and safety of the occupants.

The Weatherization Solutions for Eligible Customers program uses a home audit tool called the HAT14.1 which is similar to the EA5 audit tool used in WAQC. The home is audited for energy efficiency measures and the auditor proposes upgrades based on the SIR ratio calculated by HAT14.1. As in WAQC, if the SIR is 1.0 or greater, the contractor is authorized to upgrade that measure. Measures considered for improvement are window and door replacement, ceiling, floor and wall insulation, HVAC repair and replacement, water heater repair and replacement and pipe wrap. Also included is the potential to replace lightbulbs and refrigerators. Contractors invoice Idaho Power for the project costs and if the home is a rental, a minimum landlord payment of 10 percent of the cost is required.

Idaho Power's agreement with contractors includes a provision that identifies a maximum annual average cost per home for the program. The intent of the maximum annual average cost is to allow Contractors the flexibility to service homes with greater or fewer weatherization needs. It also provides a monitoring tool for Idaho Power to forecast year-end outcomes.

### Program Activities

In 2016, a new contractor provided weatherization services to customers residing in Lemhi County, Idaho. Energy Solutions weatherized two homes in 2016 for the program with an average of approximately $4,125 each. With the addition of this new contractor, Idaho Power offers the Weatherization Solutions for Eligible Customers in all of its Idaho service area.

In 2016, the five contractors weatherized 232 Idaho homes for the program. In eastern Idaho, contractors Savings Around Power and Energy Solutions weatherized 26 homes. In Idaho Power's Canyon–West Region, Metro Contractors weatherized 56 homes. HEM-LLC weatherized 36 homes in south central Idaho, and Power Savers weatherized 114 homes in the Capital Region. Of those 232 homes weatherized, 148 were single-family and manufactured homes and 84 were low income multi-family apartments where LEDs, showerheads, kitchen and bath sink aerators, indoor clotheslines, and smoke detectors were installed.

### Marketing Activities

Marketing was adjusted in 2016 to reach more customers who live in electrically heated homes and income-eligible households to increase participation in the program. Inserts were included in 263,625 residential bills in February and 367,222 bills in October. The program was promoted throughout the year at seasonal, resource, and conservation fairs, as well as at other events targeting people with limited incomes, including seniors. Ads and articles promoted the program in the *Seniors BlueBook*, *Healthy Idaho Magazine*, *Idaho Senior News*, and the *Idaho State Journal* boomers' edition. The program was also mentioned in Idaho Power's winter *Energy Efficiency Guide*.

Idaho Power's community relations representatives and customer representatives promoted the program at meetings in their communities, with specific emphasis on smaller Idaho communities. The program specialist and customer representatives promoted the program to home healthcare provider groups, religious groups, and members of the Idaho Nonprofit Center. Customer representatives used updated brochures (in English and Spanish) that included current income qualifications and location-specific contractor information. New contractor door hangers and flyers were also created so the program could be promoted by canvassing specific neighborhoods. Weatherization tips were also mentioned in various social media postings.

### Cost-Effectiveness

While showing increases in savings and cost-effectiveness ratios from updated billing analysis and the addition of cost-effective direct-install options, the WAQC program remains not cost-effective. The 2016 program total UC B/C ratio is 0.59, and a TRC B/C ratio is 0.70. New savings values were introduced for 2016 that reflect an updated billing analysis completed in 2015 that analyzed pre- and post-weather normalized consumption in homes weatherized during the 2013-2014 program years from

both WAQC and Weatherization Solutions for Eligible Customers. The WAQC program section in this report offers a discussion of the billing analysis changes from previous versions.

Table 13 shows the updated savings results that identify the difference between homes that only received weatherization versus homes that were weatherized and upgraded with an efficient heat pump.

Table 13. 2016 savings values for Weatherization Solutions for Eligible Customers program

| | Weatherization | | Weatherization and heating system change | |
|---|---|---|---|---|
| **Home Type** | **kWh/project** | **kWh/project/ft²** | **kWh/project** | **kWh/project/ft²** |
| Single-family Homes | 1,453 | 0.83 | 6,321 | 3.47 |
| Manufactured Homes | 897 | 0.39 | 5,355 | 4.50 |
| Multi-family Homes | n/a | 0.83 | n/a | 3.47 |

Similar to billing analysis results for WAQC, weatherization combined with the installation of an efficient heat pump results in savings nearly twice that from just installing weatherization measures. Manufactured homes demonstrate a higher savings per square foot of weatherized space than single family homes in cases where both weatherization and heating system upgrades occurred.

Idaho Power used savings of .83 kWh/ft$^2$ of weatherized heated space for multi-family projects where only weatherization measures were installed and 3.47 kwh/ft$^2$ where heating system where changed. Prior to 2015, insufficient data from multi-family projects existed to conduct a billing analysis so savings are assumed to be similar on a savings per square foot basis as single-family homes where like measures were installed.

Weatherization Solutions for Eligible Customers projects, similar to WAQC program guidelines, benefit from a pre-screening of measures through a home audit process. The home audit process ensures that there is an adequate number of kWh savings to justify the project and provides more consistent savings for billing analysis. See WAQC cost-effectiveness for a discussion of the audit and prescreening process which are similar for both programs.

For further details on the overall program cost-effectiveness assumptions, see *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

A 2016 customer survey was provided to all program participants upon completion of weatherization in their homes. Survey questions gathered information about how customers learned of the program, reasons for participating, the amount of information customers learned about saving energy in their homes, and the likelihood that household members would change their behavior to use energy wisely. Additionally, demographic information was gathered to determine future marketing strategies.

Idaho Power received survey results from 130 of the 232 households weatherized by the program in 2016. Some key highlights include the following:

- Almost 27 percent of respondents learned of the program through a letter in the mail and another 22 percent learned of the program from a friend or relative.
- Over 86 percent of the respondents reported their primary reason for participating in the weatherization program was to reduce utility bills.
- Almost 80 percent indicated they learned how insulation affects energy usage during the weatherization process, and over 85 percent reported they learned how air leaks affect energy usage. Another almost 60 percent of respondents said they learned how to use energy wisely.
- Over 79 percent reported they were very likely to change habits to save energy, and over 71 percent reported they have shared all of the information about energy use with members of their household.
- Almost 91 percent of the respondents reported they think the weatherization they received will significantly affect the comfort of their home, and nearly 92 percent said they were very satisfied with the program.

A summary of the report is included in *Supplement 2: Evaluation*.

Two independent companies performed random verifications of weatherized homes and visited with customers about the program. In 2016, 35 homes were verified, and 23 (66 percent), of those customers reported they learned "a lot" or "some" about saving electricity in their home. Another 33 customers (95 percent) reported they had tried "a lot" or "some" ways to save energy in their home.

### 2017 Program and Marketing Strategies

Idaho Power will update brochures to help spread the word about the program in all communities. Additional marketing for the program will include bill inserts and advertisements in *Healthy Idaho Magazine*, *Seniors BlueBook*, *Idaho Senior News*, and *Idaho State Journal* boomers, edition. Idaho Power will send a direct-mail letter to targeted residential customers mid-year, and use social media in an effort to reach a more customers. Customer testimonials will be posted online, and the door hangers produced late in 2016 will continue to be used when canvassing neighborhoods.

# Commercial/Industrial Sector Overview

Idaho Power's commercial sector consists of over 69,341 customers. In 2016, the commercial sector's number of customers increased by 830, an increase of a little over 1 percent from 2015. The energy usage of commercial customers varies from a few kWh each month to several hundred thousand kWh per month. The commercial sector represents 28 percent of Idaho Power's actual total electricity sales.

The industrial and special contracts customers are Idaho Power's largest individual energy consumers. There are 121 Rate 19 and special contract industrial customers. These customers account for approximately 23 percent of Idaho Power's total electricity sales.

In June 2016, the three Commercial and Industrial Energy Efficiency programs were combined into a single program. Previously, the programs were: Building Efficiency, Custom Efficiency, and Easy Upgrades. The measure offerings to the customers remained relatively unchanged with prescriptive measures for new construction and major renovations, custom incentives for complex projects, and prescriptive measures for simple retrofits. The programs were combined with the intention to clarify program offerings and to improve marketing to customers. The combined program continues to be successful, with a reported overall savings of 88,161 MWh on 1,903 projects.

The 2016 season was the second year of the internally managed Flex Peak Program. The results were greatly improved from 2015 as was participation, including 65 participants enrolled with 137 sites in the program. Of those 137 sites, 67 were new—a 90 percent increase over 2015. Idaho Power also offers the statutory-required Oregon Commercial Audits program to medium and small commercial customers. The program identifies opportunities for commercial building owners to achieve energy savings.

Table 14. 2016 commercial/industrial program summary

| | | Total Cost | | Savings | |
|---|---|---|---|---|---|
| **Program** | **Participants** | **Utility** | **Resource** | **Energy (kWh)** | **Demand (MW)** |
| **Demand Response** | | | | | |
| Flex Peak Program | 137 sites | $ 767,997 | $ 767,997 | n/a | 42 |
| **Total** | | **$ 767,997** | **$ 767,997** | | **42** |
| **Energy Efficiency** | | | | | |
| Custom Projects (Custom Efficiency) | 196 projects | $ 7,982,624 | $ 16,123,619 | 47,518,871 | |
| Green Motors—Industrial | 14 projects | | | 123,700 | |
| New Construction (Building Efficiency) | 116 projects | 1,931,222 | 4,560,826 | 12,393,249 | |
| Oregon Commercial Audits | 7 audits | 7,717 | 7,717 | n/a | |
| Retrofits (Easy Upgrades) | 1,577 projects | 5,040,190 | 8,038,791 | 28,124,779 | |
| **Total** | | **$ 14,961,753** | **$ 28,730,952** | **88,160,599** | **42** |

**Note:** See Appendix 3 for notes on methodology and column definitions.

## Customer Satisfaction and Evaluations

Customer satisfaction research by sector includes the Idaho Power quarterly customer relationship surveys that ask questions about customer perceptions related to Idaho Power's energy efficiency

programs. Sixty-five percent of Idaho Power's large commercial and industrial customers surveyed in 2016 for the Burke Customer Relationship Survey indicated Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Sixty-one percent of survey respondents indicated Idaho Power was meeting or exceeding their needs with information on how to use energy wisely and efficiently. Seventy-four percent of respondents indicated Idaho Power was meeting or exceeding their needs by encouraging energy efficiency with its customers. Overall, 78 percent of the large commercial and industrial survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of the large commercial and industrial customers surveyed and who had participated in at least one Idaho Power energy efficiency program, 98 percent are "very" or "somewhat" satisfied with the program. In 2016, offering energy efficiency programs was one of the large commercial and industrial top five attributes with a positive change in the Burke Customer Relationship Survey.

The results from surveying Idaho Power's small business customers indicated 51 percent of these customers said Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Fifty-four percent of survey respondents indicated Idaho Power was meeting or exceeding their needs with information on how to use energy wisely and efficiently. Sixty-three percent of respondents indicated Idaho Power was meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 39 percent of the small business survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of small business survey respondents who have participated in at least one Idaho Power energy efficiency program, 92 percent are "very" or "somewhat" satisfied with the program.

Forty-one percent of the Idaho Power business customers included in the *2016 J. D. Power and Associates Electric Utility Business Customer Satisfaction Study* indicated they are familiar with Idaho Power's energy efficiency programs.

### Training and Education

Technical training and education continue to be important in helping Idaho Power commercial and industrial customers identify where they may have energy efficiency opportunities within their facilities. These activities increase awareness and participation in existing commercial and industrial energy efficiency and demand response programs, and enhance customer satisfaction regarding the company's energy efficiency activities.

Educating commercial and industrial customers requires working with and supporting multiple stakeholders and organizations. Examples of key stakeholders include the Integrated Design Lab (IDL), BOMA, USGBC, ASHRAE, and International Building Operators Association (IBOA). Through funding provided by Idaho Power, the IDL performed several tasks aimed at increasing the energy efficiency knowledge of architects, engineers, trade allies, and customers. Specific activities included sponsoring a Building Simulation Users Group (BSUG), conducting Lunch & Learn sessions held at various design and engineering firms, and offering a Tool Loan Library (TLL).

Idaho Power also used two newsletters to educate and inform our customers about energy efficiency. *Energy at Work*, which is new in 2016, was mailed to commercial and industrial customers twice in

2016; the major customer representatives emailed *Energy Insights* to 400 of Idaho Power's largest industrial customers each quarter.

Idaho Power delivered eight technical classroom-based training sessions in 2016. Of the eight sessions, one was a two-day class, and the others were one-day classes. Topics included industrial refrigeration, energy auditing, an introduction to unitary A/C, advanced unitary A/C, pump systems, motors, variable speed drives, and commercial refrigeration. A schedule of training events is posted on Idaho Power's website and marketed through *Energy at Work* and *Energy Insights*. Commercial and Industrial Energy Efficiency personnel or the major customer representatives also give an overview of the commercial and industrial programs during each technical training session offered to commercial and industrial customers.

The level of participation in 2016 remained high, with 217 attendees. Customer feedback indicated the average satisfaction level was 94 percent.

Idaho Power's average cost to deliver trainings in 2016 was approximately $5,300 per class. For NEEA's 2015 to 2019 funding period, Idaho Power chose not to participate in NEEAs industrial trainings. Prior to the current funding period from 2010 to 2014, NEEA offered an average of nine trainings per year at an approximate cost of $22,000 per class. By Idaho Power providing these trainings directly to Idaho Power customers, the company has realized significant cost reduction for its customers.

Idaho Power posted prior years' webinar recordings and related PDFs on the commercial and industrial training page on the Idaho Power website. Also, on Idaho Power's industrial training page is a listing of all IBOA events. Idaho Power covered at least 50 percent of cost for Idaho Power customers to take part in their educational classes including the Building Operator Certification Level 1, consisting of eight day-long classes, and Level 2, consisting of seven day-long classes. In 2016, 42 customers attended the Level 1 classes, and eight attended the Level 2 classes.

### Field Staff Activities

Idaho Power field staff are on-site with customers each day. The field staff uses a variety of Idaho Power-developed programs, tools, and services to help customers with their energy-related questions and challenges. The customer representatives and major customer representatives have specific goals related to proactive activities, such as a specific number of visits or projects, designed to engage commercial and industrial customers in the energy efficiency. Additionally, program specialists and engineers work closely with customer representatives and major customer representatives to use their established relationships with customers. Customer representatives and major customer representatives distribute informational materials to trade allies and other market participants who, in turn, support and promote Idaho Power's energy efficiency programs.

Customers regularly ask how to get the most out of their energy dollar. Idaho Power staff has been trained to properly advise customers in the wise use of energy-specific energy efficiency measures and, when needed, can recommend where to find answers. Idaho Power is equipped with experienced

engineers, technically proficient personnel, and an extensive network of nationally recognized organizations and energy efficiency clearing houses to handle energy-related questions.

## Commercial and Industrial Energy Efficiency Program

| | | 2016* | 2015* |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (projects) | 1,903 | 1,463 |
| | Energy Savings (kWh)** | 88,160,599 | 102,073,910 |
| | Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $14,319,999 | $14,629,149 |
| | Oregon Energy Efficiency Rider | $508,538 | $798,424 |
| | Idaho Power Funds | $125,500 | $97,921 |
| | Total Program Costs—All Sources | $14,954,036 | $15,525,494 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/kWh) | $0.014 | $0.014 |
| | Total Resource Levelized Cost ($/kWh) | $0.026 | $0.031 |
| **Benefit/Cost Ratios** | | | |
| | Utility Benefit/Cost Ratio | 4.67 | 4.48 |
| | Total Resource Benefit/Cost Ratio | 2.81 | 2.13 |

*Metrics for each option (New Construction, Custom Projects, and Retrofits) are reported separately in appendices and in *Supplement 1: Cost-Effectiveness.*

***2016 total includes 123,700 kWh of energy savings from 14 Green Motors projects.*

### Description

Three major program options targeting different energy efficiency projects are available to commercial/industrial customers in the company's Idaho and Oregon service areas.

#### *Custom Projects (Custom Efficiency)*

The Custom Projects option incentivizes energy efficiency modifications for new and existing facilities. The goal is to encourage commercial and industrial energy savings in Idaho and Oregon service areas by helping customers implement energy efficiency upgrades. Incentives reduce customers' payback periods for customize modifications that might not be completed otherwise. The Custom Projects option offers an incentive level 70 percent of the project cost or 18 cents per kWh for first year estimated savings, whichever is less. The Custom Projects option also offers energy auditing services to help identify and evaluate potential energy saving modifications or projects.

Interested customers submit applications to Idaho Power for potential modifications that have been identified by the customers, Idaho Power, or by a third-party consultant. Idaho Power reviews each application and works with the customer and vendors to gather sufficient information to support the energy-savings calculations.

Once completed, customers submit a payment application; in some cases, large, complex projects may take as long as two years to complete. Every payment application is verified by Idaho Power staff or an Idaho Power contractor. All lighting modifications utilize the Idaho Power lighting tool to determine incentive.

Each project is reviewed to ensure energy savings are achieved. Idaho Power engineering staff or a third-party consultant verifies the energy savings methods and calculations. Through the verification process, end-use measure information, project photographs, and project costs are collected.

On many projects, especially the larger and more complex projects, Idaho Power or a third-party consultant conducts on-site power monitoring and data collection before and after project implementation. The measurement and verification process helps ensure the achievement of projected energy savings. Verifying applicants' information confirms energy savings are obtained and are within program guidelines. If changes in scope take place in a project, a recalculation of energy savings and incentive amounts occurs based on the actual installed equipment and performance. The measurement and verification reports provided to Idaho Power include a verification of energy savings, costs, estimates of measure life, and any final recommendations.

#### *New Construction (Building Efficiency)*

The New Construction option enables customers in Idaho Power's Idaho and Oregon service areas to apply energy-efficient design features and technologies in new commercial or industrial construction, expansion, or major remodeling projects. New construction and major renovation project design and construction life is much longer than small retrofits and often encompasses multiple calendar years. Originated in 2004, the program currently offers a menu of measures and incentives for efficient lighting, cooling, building shell, controls, appliances, and refrigeration options. These measures may otherwise be lost opportunities for savings on customers' projects.

Twenty-four prescriptive measures are offered: interior lighting, exterior lighting, daylight photo controls, occupancy sensors, high-efficiency exit signs, efficient A/C and heat pump units, efficient variable refrigerant flow units, efficient chillers, air-side economizers, direct evaporative coolers, evaporative pre-coolers on air-cooled condensers, reflective roof treatment, energy-management control systems, guest room energy-management systems, HVAC variable-speed drives, kitchen hood variable-speed drives, onion/potato shed ventilation variable-speed drives, efficient laundry machines, ENERGY STAR® under-counter dishwashers, ENERGY STAR commercial dishwashers, refrigeration head-pressure controls, refrigeration floating-suction controls, efficient condensers, and smart power strips.

#### *Retrofits (Easy Upgrades)*

The Retrofits option is Idaho Power's prescriptive measure option for existing commercial and industrial facilities. This part of the program encourages commercial and industrial customers in Idaho and Oregon to implement energy efficiency upgrades by offering incentives on a defined list of measures. Eligible measures cover a variety of energy-saving opportunities in lighting, HVAC, building shell, variable-frequency drives (VFD), food-service equipment, and other commercial measures. Customers can also apply non-standard lighting incentives. A complete list of the measures offered through Retrofits (Easy Upgrades) is included in *Supplement 1: Cost-Effectiveness*.

## Program Activities

### *Custom Projects*

Incentive levels for the non-lighting projects remained the same in 2016 at 18 cents per kWh of first year savings with a 70-percent project cost cap on the incentive.

The Custom Projects option had another very successful year with a total of 196 projects, including 11 in Oregon, completed by 103 customers. However, related energy savings decreased in 2016 by 14 percent over 2015, from 55,186 MWh to 47,519 MWh. Idaho Power also received 248 new applications representing a potential of 61,240 MWh of savings on future projects.

Idaho Power made the following tariff changes in 2016: The required 100,000 kWh minimum savings was removed to allow for projects that may not meet that threshold to receive a Custom Projects incentive, such as Streamlined Custom Efficiency (SCE). The three-year term requirement was removed for the self-direct projects, which eliminates the need to file for tariff changes for every new three-year term.

Custom Projects may reach some level of saturation through program maturity, over 95 percent of the large-power service customers have participated in the program. With the high percentage of industrial customers who have taken advantage of the program, deeper energy savings may be challenging to achieve. The company is addressing this ongoing challenge in several ways by continuing to use multiple channels to reach customers and to encourage new energy-saving modifications. The company has expanded the cohort offerings, SCE, and expanded its ability to conduct energy audits through an expanded list of engineering firms.

Table 15 indicates the program's 2016 annual energy savings by primary project measures.

Table 15. 2016 Custom Projects annual energy savings by primary project measure

| Program Summary by Measure | Number of Projects | kWh Saved |
|---|---|---|
| Lighting | 117 | 9,386,277 |
| Refrigeration | 11 | 23,681,463 |
| HVAC | 6 | 4,839,312 |
| Compressed Air | 18 | 2,726,482 |
| Commissioning | 7 | 2,739,491 |
| Controls | 1 | 224,756 |
| Pump | 3 | 708,555 |
| VFD | 32 | 3,158,906 |
| Other | 1 | 53,629 |
| Total [a] | 196 | 47,518,871 |

[a] Does not include Green Motor Initiative project counts and savings.

Facility energy auditing, customer technical training, and education services are key components used to encourage customers to consider energy efficiency modifications. The Municipal Water Supply Optimization Cohort (MWSOC) and Wastewater Energy Efficiency Cohort (WWEEC) program offerings are also driving a significant number of new projects in addition to increasing vendor engagement from the SCE offering. The 2016 activities in the key components are described below.

**Facility Energy Auditing**

Idaho Power funds the cost of engineering services, up to $3,500, for conducting energy scoping audits to encourage its larger customers to adopt energy efficiency improvements. Currently, there are 11 different firms on contract to provide scoping audits and general energy efficiency engineering support services.

In 2016, Idaho Power consultants completed 25 scoping audits and two detailed audits on behalf of Idaho Power customers. These audits identified over 20,000 MWh of savings potential. Most of the customers engaged in these audits used the information to move forward with projects or expressed interest in moving forward in the near future.

**Program Education and Offerings**

Custom Projects engineers and the major customer representatives set up numerous visits with the large commercial and industrial customers in 2016. The visits ranged from commercial/industrial efficiency program training to a comprehensive targeted technical training sessions for a larger audience on potential energy-saving opportunities for different measure types, such as refrigeration, pumps and fans, compressed air, HVAC, lighting, etc. In addition to the eight comprehensive targeted technical training sessions that were held by Idaho Power, Custom Projects engineers also gave presentations on Idaho Power programs and offerings at a multi-industrial customer program training sessions, such as the Northwest Chapter of American Association of Airport Executives Airfield and Facilities Management Conference, the International Society of Healthcare Engineers (ISHE) Conference, the Energy Community Partnership Workshop facilitated by Mountain Home Air Force Base, and the Idaho Green Building and Energy Conference. In 2016, Custom Projects continued three offerings to increase the total program savings—WWEEC, MWSOC, and SCE. A new, fourth offering launched in November 2016—Continuous Energy Improvement (CEI) Cohort for Schools.

Wastewater Energy Efficiency Cohort

In January 2014, Custom Projects launched WWEEC, its third program offering since 2013, to increase the total program savings. WWEEC is a cohort training approach to low-cost or no-cost energy improvements. WWEEC is a two-year engagement with 11 Idaho Power service area municipalities and ended in 2016. WWEEC provided a series of five technical training workshops with a cohort training approach. In addition, WWEEC provided energy audits in conjunction with a qualified wastewater system expert and an energy management assessment conducted by a strategic energy management professional for each participating facility. Customers were able to immediately implement low-cost and no-cost energy efficiency improvements by actions as simple as turning off equipment or adjusting control points for systems. They also implemented many energy management principles, including forming an energy team, setting energy goals, and establishing energy policies in their organization for persistence of savings. Energy savings were tracked via Idaho Power-provided, third-party software using an energy model for each facility. WWEEC participants also completed several capital projects that received separate incentives from our Commercial and Industrial Energy Efficiency Program. Additionally, multiple pre-planning meetings were held with consultants and municipalities for upcoming new wastewater construction projects.

Due to involvement with our WWEEC, Custom Projects engineers also set up multiple program informational meetings with the area civil engineering firms specializing in water and wastewater designs to educate them on the Commercial and Industrial Energy Efficiency Program, audit process, energy efficiency opportunities, and available tools and resources. Presentations on Idaho Power offerings were given at a multi-industrial customer program training session in Boise, the annual Southwest Idaho Operators Section (SWIOS) Conference, the national annual Water Environment Federation Technical Exhibition and Conference (WEFTEC) in New Orleans, and Idaho Power had a booth at the Pacific Northwest Section American Water Works Association (PNWS-AWWA) regional conference.

Year-one incentives and savings totaled $57,559 and 2,561,177 kWh/year. In all cases, the incentive was capped at 70 percent of the eligible costs. Year-one incentives and savings were processed in 2016. Additionally, some WWEEC participants completed capital projects that were encouraged and discussed in the workshops and energy audits. These capital projects' savings are captured separately and not included in the above number. Year-two of the offering consisted of phone call check-ins with the participants and model data updates. Year-two incentives and savings will be processed in 2017.

Municipal Water Supply Optimization Cohort

In September 2015, Idaho Power held a recruiting/training session for municipal water supply operators and public works personnel garnering interest in a third Strategic Energy Management cohort—the MWSOC, similar to WWEEC but for clean water operators. The program officially launched in January 2016. The goal of the cohort is to equip water professionals with the skills necessary to identify and implement energy efficiency opportunities on their own, and to ensure that these energy and cost savings are maintained long term.

A series of three workshops were held in the Twin Falls area with representatives from the 15 participating organizations. Sessions included technical training, hands-on learning exercises to demonstrate simple low-cost and no-cost actions to diagnose problems and save energy, and peer-to-peer sharing of lessons learned as the classes progressed. MWSOC provided energy audits of the participants' facilities. Customers were able to immediately implement low-cost and no-cost energy efficiency improvements by actions as simple as changing pressure regulating valve (PRV) settings or well level adjustments. Participants had engineering support between each workshop, facilitated by an expert team of energy engineers with specific experience in optimizing water supply systems. Participants all received tools, such as a baseline hydraulic model (updated and modernized with the energy modules loaded), a mass balance for water, and an energy map showing locations of stored and lost energy, as well as the energy footprint of the various pumps within each system. A top down baseline energy model was constructed for each participant that uses electric data normalized for system operating data and weather. The baseline energy model will be used in conjunction with on-going actual energy, production and weather data to determine the energy savings for the offering.

Continuous Energy Improvement Cohort for Schools

In November 2016, Idaho Power held a recruiting/training session for school district personnel garnering interest in this cohort. Representatives from 19 school districts attended. The session introduced the

upcoming cohort whose goal is to equip district personnel with hands-on training and guidance to help get the most out of their systems while reducing energy consumption. Idaho Power and the company's consultants gave an overview what Continuous Energy Improvement is and how numerous low-cost or no-cost measures can be uncovered in schools. By 2016 year-end, 9 school districts have signed up for the cohort. The Cohort for Schools Kickoff Workshop is scheduled for late January 2017, in Boise with a final Report-out Workshop to be scheduled in December 2017. Energy savings for this offering are tracked with multi-variant regression models that are custom-built for each participating facility and based on historical utility data and current operations.

Streamlined Custom Efficiency

The SCE offering was initially started in 2013 and continues to keep vendor engagement high and provides custom incentives for small compressed air system improvements, fast-acting doors in cold-storage spaces, refrigeration controllers for walk-in coolers, and process-related VFDs. This offering targets projects that may have typically been too small to participate in the Custom Projects due to the resources required to adequately determine measure savings. Idaho Power contracted with a third party to manage SCE data collection and analysis for each project. In 2016, the SCE offering processed 42 projects, totaling 2,837,200 kWh per year of savings and $399,523 in incentives paid.

#### *New Construction*

The New Construction option completed 116 projects, the largest total number of projects completed in a calendar year, resulting in 12,393,249 kWh in annual energy savings in Idaho and Oregon. The total number of projects increased by over 43 percent from 81 projects in 2015.

Maintaining a consistent offering is important for large projects with long construction periods, though changes are made to enhance customers' options or to meet new code changes. Idaho Power ideally tries to keep the New Construction option consistent by making less frequent changes, approximately every other year. The option was modified in mid-2016 to include the addition of four new measures; evaporative pre-coolers on air-cooled condensers, kitchen hood variable-speed drives, onion/potato shed ventilation variable-speed drives, and smart-strip power strips.

Idaho Power contracted with ADM in 2015 to update the Technical Reference Manual (TRM) to address code changes that occurred January 1, 2015 in Idaho. The revised TRM provided updated savings for existing measures and savings for new measures that were added to the program. Minor modifications were also made to several existing measures to update requirements based on the code changes.

Thirty projects received the Professional Assistance Incentive, an incentive given to architects and/or engineers for supporting technical aspects and documentation of the project, in 2016 (equal to 10 percent of the participant's total incentive, up to a maximum amount of $2,500) compared to nine projects in 2015.

In 2016, Idaho Power continued its contract with GreenSteps to target the commercial real estate industry by continuing to support the Kilowatt Crackdown™ competition past participants. The original competition, which included benchmarking each building in ENERGY STAR® Portfolio Manager,

encouraged builders to implement low-cost and no-cost efficiency measures. Idaho Power also expanded engagement with participants through Strategic Energy Management (SEM). GreenSteps worked with 26 buildings in Boise and Ketchum, and six property management firms. A summary of the report is located in *Supplement 2: Evaluations.*

Idaho Power customer representatives visited 20 architectural and engineering firms in Boise, Meridian, Nampa, Hailey, Ketchum, Twin Falls, and Pocatello in 2016. Customer representatives visited with 100 professionals total to build relationships with the local design community, and to discuss Idaho Power's commercial and industrial energy efficiency programs.

#### *Retrofits*

The Retrofits option experienced increases in participation and energy savings in 2016. Some of the increase was attributed to the mid-June program change to adjust the screw-in LED incentive. The option received a noticeable number of projects with screw-in LED product before that change became effective. This also resulted in increased energy savings. Overall, Retrofits received more LED-only projects, which had a significant contribution to energy savings.

Several measure changes were implemented mid-year. The most notable changes were to adjust the screw-in LED incentive, to add the tube LEDs (TLED), and to add seven non-lighting measures to the incentive menu.

For the Retrofits option, Idaho Power facilitated eight workshops across the Idaho Power service area targeting contractors and large customers. The purpose of the workshops was to review option updates with market participants.

Idaho Power staff and contractors contacted over 195 trade allies to respond to inquiries, strengthen relationships, encourage participation, increase knowledge of the incentives, and receive feedback about the market, and individual experiences. This targeted outreach was to electrical contractors, electrical distributors, HVAC contractors, and food service equipment suppliers.

Idaho Power continued its contracts with Evergreen Consulting Group, LLC, Honeywell, Inc., and RM Energy Consulting to provide ongoing program support for lighting and non-lighting reviews and inspections as well as trade ally outreach.

### Marketing Activities

Most marketing activities engaged in for the Commercial and Industrial Energy Efficiency Program can be found in the Marketing section of this report. Below are the 2016 activities specific to the option within the overall program.

#### *Custom Projects*

Idaho Power's Custom Projects option is unique from the company's other energy efficiency options by providing individualized energy efficiency solutions to a somewhat limited number of customers. Idaho Power's major customer representatives often act as the company's sales force. Marketing supports the major customer representatives by providing written program materials to help

them inform customers of the measures and benefits available to them. Idaho Power presented the Simplot Don Plant in Pocatello an incentive check for $197,335 toward energy efficiency upgrades to a pumping project.

#### *New Construction*

Idaho Power placed ads in the Idaho Association of General Contractors membership directory specific to the New Construction option. The New Construction brochure was also updated to include a list of current measures and provided to customers planning new construction and major renovation projects. Idaho Power alerted the media to its presentation of a cash incentive to Vallivue School District 139. During a board meeting, the School District accepted a check for more than $193,000 it had earned for adopting energy-efficient construction measures at two schools in Caldwell, Idaho.

#### *Retrofits*

Ads thanking contractors for their participation ran in numerous papers in December 2015, and continued in the *Business Insider, Southeast Idaho Business Journal, Idaho Business Review,* and *Business News* within the *Blackfoot Morning-News* in January 2016. Idaho Power also ran an ad promoting energy-efficient Retrofit incentives in the January Boise Chamber of Commerce newsletter.

### Cost-Effectiveness

#### *Custom Projects*

All projects submitted through the Custom Projects option must meet cost-effectiveness requirements, which include TRC, UC, and PCT tests from a project perspective. The program requires all costs related to the energy efficiency implementation and energy-savings calculations are gathered and submitted with the program application. Payback is calculated with and without incentives, along with the estimated dollar savings for installing energy efficiency measures. As a project progresses, any changes to the project are used to recalculate energy savings and incentives before the incentives are paid to the participant. To aid in gathering or verifying the data required to conduct cost-effectiveness and energy-savings calculations, third-party engineering firms are sometimes used via a scoping audit, detailed audit, or engineering measurement and verification services available under the Custom Projects option. Details for cost-effectiveness are in *Supplement 1: Cost-Effectiveness*.

#### *New Construction*

To calculate energy savings for the New Construction option, Idaho Power verifies the incremental efficiency of each measure over a code or standard practice installation baseline. Savings are calculated through two main methods. When available, savings are calculated using actual measurement parameters, including the efficiency of the installed measure compared to code-related efficiency. Another method for calculating savings is based on industry standard assumptions, when precise measurements are unavailable. Since the New Construction option is prescriptive and the measures are installed in new buildings, there are no baselines of previous measurable kWh usage in the building. Therefore, Idaho Power uses industry standard assumptions from the International Energy Conservation Code (IECC) to calculate the savings achieved over how the building would have used energy absent of efficiency measures.

New Construction incentives are based on a variety of methods depending on the measure type. Incentives are calculated mainly through a dollar-per-unit equation using square footage, tonnage, operating hours, or kW reduction.

To prepare for 2016 program changes, ADM, under contract with Idaho Power, updated the TRM for New Construction. The TRM, which provides savings and costs related to existing and new measures for the New Construction option, was updated to include the IECC 2012 baseline. These new savings were applied in 2016 when other program changes were implemented.

Based on the deemed savings value from the TRM, nearly all measures were cost-effective, with the exception of some air conditioning units and daylight photo controls. Idaho Power determined these measures met at least one of the cost-effectiveness exceptions outlined in OPUC Order No. 94-590. Idaho Power had received a cost-effectiveness exception on these measures when it filed changes to the program in 2014 under Advice No. 14-10. When Idaho Power filed Advice No. 16-08 for the combined commercial and industrial program, the company requested and received another cost-effectiveness exception for variant refrigerant flow (VRF) heat pumps.

Complete measure level details for cost-effectiveness can be found in *Supplement 1: Cost-Effectiveness*.

#### *Retrofits*

In 2016, Idaho Power used most of the same savings and assumptions as were used in 2015 for the Retrofits option. For all lighting measures, Idaho Power uses a lighting tool calculator developed by Evergreen Consulting, Group LLC. An initial analysis was conducted to see if the lighting measures shown in the tool were cost-effective based on the average input of watts and hours of operation, while the actual savings for each project are calculated based on specific information regarding the existing and replacement fixture. For most non-lighting measures, deemed savings from the TRM or RTF are used to calculate the cost-effectiveness. To prepare for 2016 program changes, ADM, under contract with Idaho Power, updated the TRM for the Retrofit option. The TRM which provides savings and costs related to existing and new measures for the Retrofit option. The TRM was updated to include the IECC 2012 baseline for several heating and cooling measures.

Several measures that are not cost-effective remain in the program. These measures include high-efficiency A/C units and heat pump units. After reviewing these measures, Idaho Power determined the measures met at least one of the cost-effectiveness exceptions outlined in OPUC Order No. 94-590. These cost-effectiveness exceptions were approved by the OPUC in Advice No 14-06 in 2014. When Idaho Power filed Advice No. 16-08 for the combined commercial and industrial program, the company requested and received another cost-effectiveness exception for VRF heat pumps.

Complete measure level details for cost-effectiveness can be found in *Supplement 1: Cost-Effectiveness*.

### Customer Satisfaction and Evaluations

Customer satisfaction with regards to the Commercial and Industrial Energy Efficiency Program is mentioned in the Commercial and Industrial sector overview. Activities that are specific to each component of the program are mentioned below.

#### *Custom Projects*

No specific activities were conducted in 2016.

#### *New Construction*

The New Construction option continued random installation verification on 10 percent of projects in 2016. The purpose of the verifications is to confirm program guidelines and requirements are adequate and ensure participants are able to provide accurate and precise information with regard to energy efficiency measure installations. The IDL completed on-site field verifications on 12 of the 116 projects, which encompass approximately 10 percent of the total completed projects in the program. Out of the 12 projects verified, only minor discrepancies were discovered. The minor discrepancies consist of the addition or subtraction of lighting fixtures compared to what was claimed on the application. Random project installation verification will continue in 2017.

In 2016, Idaho Power contracted with Leidos to conduct an impact evaluation of this option. The evaluation determined a high level of ex-post realization for option demand and energy savings at .99 and .98 respectively, as well as high realization at the measure level. The kWh confidence and precision ratios were 90 percent confidence at +/- 0.2 percent precision and 90 percent confidence at +/-4.8 percent for kW. In general, project documentation was adequate for verifying most measure impacts, and project data are recorded and tracked with high accuracy. Final reports are provided in *Supplement 2: Evaluation*.

#### *Retrofits*

In 2016, Idaho Power contracted with Leidos Engineering to perform an impact evaluation for the incentives paid in 2015 under the Retrofits option. The final report indicated that the option is well designed, well managed, and well implemented. The project documentation was adequate for verifying most measure impacts, and project data are recorded and tracked with high accuracy. The evaluation also determined a high level of ex-post realization for energy savings, as well as high realizations at the measure level. The 2015 kWh savings realization rate was 0.99 with 90 percent confidence at +/- 0.2 percent precision. Final reports are provided in *Supplement 2: Evaluation*.

### 2017 Program and Marketing Strategies

Future marketing for the overall Commercial and Industrial Energy Efficiency Program is described in the Marketing section of this report. Below are specific strategies that apply to the individual components of the program.

#### *Custom Projects*

Over the years, the Custom Projects option has achieved a high service-area penetration rate. As stated previously, over 95 percent of the large-power service customers have submitted applications for a project. Company staff is actively working to support these customers in new ways and find additional opportunities for cost-effective energy saving projects. Additional program offerings are currently under consideration for implementation in 2017.

Idaho Power will report the second year of energy savings and incentives for WWEEC in the *Demand-Side Management 2017 Annual Report*. Idaho Power will report the first year of energy

savings, and incentives in 2017 or early 2018 for the MWSOC offering. Activities and coaching will continue for the MWSOC participants and the report-out workshop will be held in 2017. The first year of the CEI Cohort for Schools will commence in January 2017. Three half-day workshops and a final report-out workshop will be held in 2017 along with monthly activities and frequent coaching. The SCE offering will continue in 2017, and new measures, processes, and other improvements will be evaluated to continuously improve the effectiveness of this offering.

Idaho Power will continue to provide site visits by Custom Projects engineers and energy scoping audits for project identification and energy-savings opportunities; measurement and verification of larger, complex projects; technical training for customers; and funding for detailed energy audits for larger, complex projects.

Custom Projects will continue to be marketed as part of Idaho Power's Commercial and Industrial Energy Efficiency Program.

#### *New Construction*

The following strategies are planned for 2017:

- Continue to perform random post-project verifications on a minimum of 10 percent of completed projects.
- Continue to sponsor technical training through the IDL to address the energy efficiency education needs of design professionals throughout the Idaho Power service area.
- Support organizations focused on promoting energy efficiency in commercial construction.
- Actively support the 2017 Idaho Energy and Green Building Conference as a member of the conference planning committee. Participate in planning the conference agenda and energy efficiency sessions.
- Continue to sponsor the BOMA symposium and offer energy efficiency training and support to the real estate market.
- Continue customer representative relationship building with local design professionals by targeting Idaho Power's Boise and Pocatello areas.

The New Construction option will continue to be marketed as part of Idaho Power's Commercial and Industrial Energy Efficiency Program.

#### *Retrofits*

Idaho Power will review and address the recommendations from the Leidos impact evaluation, and offer technical lighting classes to trade allies.

Retrofits will continue to be marketed as part of Idaho Power's Commercial and Industrial Energy Efficiency Program.

## *Flex Peak Program*

| | | 2016 | 2015 |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (sites) | 137 | 72 |
| | Energy Savings (kWh) | n/a | n/a |
| | Demand Reduction (MW) | 42 | 26 |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $105,116 | $86,445 |
| | Oregon Energy Efficiency Rider | $247,897 | $219,654 |
| | Idaho Power Funds | $414,984 | $286,773 |
| | Total Program Costs—All Sources | $767,997 | $592,872 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/kWh) | n/a | n/a |
| | Total Resource Levelized Cost ($/kWh) | n/a | n/a |
| **Benefit/Cost Ratios** | | | |
| | Utility Benefit/Cost Ratio | n/a | n/a |
| | Total Resource Benefit/Cost Ratio | n/a | n/a |

### Description

The Flex Peak Program is a voluntary program available in Idaho and Oregon service areas. It's designed for Idaho Power's large commercial and industrial customers, with the objective to reduce the demand on Idaho Power's system during periods of extreme peak electricity use. By reducing demand on extreme system load days during summer months, the program reduces the amount of generation and transmission resources required to serve customers. Program participants earn a financial incentive for reducing load during peak electricity use: non-holiday weekdays, June 15 to August 15, between the hours 2:00 p.m. and 8:00 p.m. Reduction events may be called a maximum of 60 hours per season.

Customers with the ability to offer load reduction of at least 20 kW are eligible to enroll in the program. The 20-kW threshold allows a broad range of customers the ability to participate in the program. Participants receive notification of a load reduction event two hours prior to the start of the event, and events last between two to four hours.

The program originated in 2009 as the FlexPeak Management program managed by a third-party contractor. In 2015, Idaho Power took over full administration, and changed the name to Flex Peak Program. The IPUC issued Order No. 33292 on May 7, 2015, while the OPUC approved Advice No. 15-03 on May 1, 2015, authorizing Idaho Power to implement an internally managed Flex Peak Program (Schedule No. 82 in Idaho and Schedule No. 76 in Oregon), and to continue recovery of its demand response program costs in the previous manner.

## Program Activities

In 2016, 65 participants enrolled 137 sites in the program. Of those 137 sites, 67 were new—a 90-percent increase over 2015. Participants had a nominated load reduction of 34.2 MW in the first week of the program, which was the highest committed load reduction for the season. This weekly commitment, or nomination, was comprised of all 137 sites, 70 of which had participated in the 2015 season. The maximum realization rate during the season was 120 percent and the average for all three events combined was 98.8 percent. The realization rate is the percentage of load reduction achieved versus the amount of load reduction committed for an event. The highest hourly load reduction achieved was 41.5 MW during the July 26 event.

The first event was called on Thursday, June 30. Participants were notified at 2:00 p.m. of a four-hour event from 4:00 p.m. to 8:00 p.m. The total nomination for this event was 34.2 MW for each hour. The average load reduction was 32.8 MW, with the highest hourly load reduction of 34.8 MW from 6:00 p.m. to 7:00 p.m. The realization rate for this event was 96 percent.

A second event was called on Tuesday, July 26. Participants were notified at 2:00 p.m. of a four-hour event from 4:00 p.m. and 8:00 p.m. The total nomination for this event was 33.5 MW for each hour. The average load reduction was 40.3 MW, with the highest hourly load reduction of 41.5 MW from 4:00 p.m. to 5:00 p.m. The realization rate for this event was 120 percent.

The third event was called on Thursday, July 28. Participants were notified at 2:00 p.m. of a four-hour event from 4:00 p.m. to 8:00 p.m. The total nomination for this event was 33.9 MW. The average load reduction was 27 MW, with the highest hourly load reduction of 27.7 MW from 4:00 p.m. to 5:00 p.m. The realization rate for this event was 80 percent. Some larger sites underperformed or reduced participation because this was the second event in one week, therefore the realization rate was lower.

The Idaho Power CHQ building participated in the program again in 2016, and committed to reduce up to 200 kW of electrical demand during events—an increase from the 150 kWs nominated during the 2015 season. Unlike other program participants, Idaho Power does not receive any financial incentives for its participation. Idaho Power's CHQ participated in all three demand response events in 2016. The average reduction achieved by the facility across the three events was 348 kW, which exceeded the nominated amount. The maximum hourly reduction was 685 kW, achieved on July 28. Reductions were mostly obtained by turning off lights, adjusting chiller set points, decreasing fan speeds, and curtailing elevator use. Besides the benefit of experiencing firsthand what participants experience with the program, Idaho Power now has a quantifiable energy-reduction plan in place that can be executed when needed. Idaho Power will continue to look for opportunities to enroll more of its facilities in the program for future seasons.

## Marketing Activities

Idaho Power developed new program literature including a new program brochure. These were sent by direct-mail to encourage both past participants and new customers to enroll in 2016. Idaho Power launched an additional marketing campaign early in 2016 using customer representatives to recruit new participants. Customer representatives conducted field visits in early winter and followed up with

additional communication in early spring. This marketing campaign focused on identifying customer characteristics that make successful program participants based on load size, load shape, and type of operation. Customer representatives also communicated available incentive amounts based on customer load size.

The program's marketing campaign goals were expanded to increase the number and size diversity (in terms of nominated load reduction) of customers enrolled. By having a larger diversity of customer sizes enrolled, it was expected that the program would be less prone to volatility in its realization rate. The company also included an advertisement in the spring *Energy at Work* newsletter and published an article promoting the program in its commercial and industrial electronic newsletter, *Energy Insights*.

Idaho Power implemented an educational campaign with currently enrolled participants and potential participants to promote a variety of demand-reduction strategies. The goal was to refine the amount of nominated load reduction from each site to more realistically align with load reduction potential.

The Flex Peak Program was also marketed along with the Commercial and Industrial Energy Efficiency Program. Additional details can be found in the Marketing section of this report.

### Cost-Effectiveness

Idaho Power determines cost-effectiveness for it demand response program under the terms of IPUC Order No. 32923 and OPUC Order No. 13-482. Under the terms of the orders and the settlement, all of Idaho Power's demand response programs were cost-effective for 2016.

The Flex Peak Program was dispatched for 12 event hours and achieved a maximum reduction of 41.5 MW. The total cost of the program in 2016 was $767,997, had the Flex Peak Program been used for the full 60 hours, the cost would have been approximately $1,004,000.

In 2016, the cost of operating the three demand response programs was $9.47 million. Idaho Power estimates that if the three programs were dispatched for the full 60 hours, the total costs would have been approximately $12.87 million and would have remained cost-effective. A complete description of Idaho Power cost-effectiveness of its demand response programs is included in *Supplement 1: Cost-effectiveness.*

### Customer Satisfaction and Evaluations

Idaho Power conducted a post-season survey that was sent via email to all participants enrolled in the program. The survey was sent to 97 individuals representing 64 participating customer sites. Idaho Power received feedback from 34 individuals for a response rate of 35 percent. When customers were asked how satisfied they were with the Flex Peak Program, nearly 97 percent of respondents indicated they were "very satisfied" or "somewhat satisfied." When asked how likely they would be to re-enroll in the Flex Peak Program, 100 percent of respondents indicated they were likely to re-enroll next year with just over 91 percent indicating they were "very likely" to re-enroll. The complete details of the survey results are in *Supplement 2: Evaluation*, as is the *Flex Peak Program 2016 Report*.

Idaho Power contracted CLEAResult to conduct an impact evaluation of the 2016 Flex Peak Program. The goals of the impact evaluation were to determine the demand reduction (in MW) and realization rate for the three curtailment events during the program's June 15 through August 15, 2016 season.

The results of the analyses showed maximum demand reductions of 34.8, 41.5, and 27.7 MW, respectively, for the three events, and an average of 34.7 MW. The events achieved realization rates of 96.0 percent, 120 percent, and 80 percent, respectively, averaging 98.8 percent. These results are different than those listed in the CLEAResult report; these have been converted to generation-level reductions, while the CLEAResult report lists meter-level reductions.

The results of the impact evaluation show that Idaho Power's 2016 Flex Peak Program functioned as intended, and provided up to 42 MW to the electricity grid. A summary of the results is in *Supplement 2: Evaluation*.

## 2017 Program and Marketing Strategies

The company is exploring opportunities to improve the re-enrollment process for participants, and has filed a tariff advice with both the IPCU and OPUC to request that existing participants would be automatically enrolled each year without having to complete a new application and program agreement. Customers would still have the ability to change their nomination amounts and decline participation.

Recruitment efforts for the 2017 season will begin in the first quarter to encourage participation. Idaho Power will meet with existing participants during the winter/spring months to discuss past-season performance and upcoming season details.

For the upcoming season, Idaho Power plans to focus on retaining currently enrolled customers and to recruit new customers that show interest and are a good fit for the program. However, the company does not plan to actively market the program like it did in 2016 because the capacity from this past season remained around 35 MW, which comports with the desired program capacity set forth in the settlement agreement.

The company will continue to use its customer representatives to retain the currently enrolled sites and encourage new sites to participate. Flex Peak will also be marketed along with Idaho Power's Commercial and Industrial Energy Efficiency Program. See the Marketing section of this report for 2017 marketing strategies.

## Oregon Commercial Audits

| | 2016 | 2015 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (a) | 7 | 17 |
| Energy Savings (kWh) | n/a | n/a |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $0 | $0 |
| Oregon Energy Efficiency Rider | $7,717 | $4,251 |
| Idaho Power Funds | $0 | $0 |
| Total Program Costs—All Sources | $7,717 | $4,251 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | n/a | n/a |
| Total Resource Levelized Cost ($/kWh) | n/a | n/a |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | n/a | n/a |
| Total Resource Benefit/Cost Ratio | n/a | n/a |

### Description

The Oregon Commercial Audits identifies opportunities for commercial building owners to achieve energy savings. Initiated in 1983, this statutory required program (ORS 469.865) is offered under Oregon Tariff Schedule No. 82.

Through this program, Idaho Power provides free energy audits, evaluations, and educational products to customers. Energy audits provide the opportunity to discuss utility incentives available to customers who install qualifying energy efficiency measures. Business owners can make the decisions to change operating practices, or make capital improvements designed to use energy wisely.

### Program Activities

Seven customers requested audits. Of those audits, EnerTech Services, a third-party contractor, completed four, Idaho Power personnel completed two, and one customer received only the program-related booklet. No customers cancelled their audits. The costs were down in 2016 from 2015 because the third-party contractor performed only four audits.

Auditors inspected the building shell, HVAC equipment, lighting systems, and operating schedules, if available, and reviewed the customer's past billing data. Additionally, these visits provided a venue for auditors to discuss incorporating specific business operating practices for energy savings, and to distribute energy efficiency program information.

### Marketing Activities

Idaho Power sent out its annual mailing to 1,413 Oregon commercial customers in mid-September 2016 regarding the no-cost or low-cost energy audits, and the availability of Idaho Power's *Saving Energy Dollars* booklet.

### Cost-Effectiveness

As previously stated, the Oregon Commercial Audits program is a statutory program offered under Oregon Schedule 82, the Commercial Energy Conservation Services Program. Because the required parameters of the Oregon Commercial Audit program are specified in Oregon Schedule 82 and the company abides by these specifications, this program is deemed to be cost-effective. Idaho Power claims no energy savings from this program.

### Customer Satisfaction and Evaluations

Idaho Power conducted no customer satisfaction surveys or evaluations in 2016.

Historically, customers have been pleased with the audit process because the audits help identify energy-saving opportunities that may not be obvious to the business owner.

### 2017 Program and Marketing Strategies

The Oregon Commercial Audits program will continue to be an important avenue for Idaho Power to help customers identify energy-saving opportunities.

Idaho Power will continue to market the program through the annual customer notification.

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# Irrigation Sector Overview

The irrigation sector is comprised of agricultural customers operating water-pumping or water-delivery systems to irrigate agricultural crops or pasturage. End-use electrical equipment primarily consists of agricultural irrigation pumps and center pivots. The irrigation sector does not include water pumping for non-agricultural purposes, such as the irrigation of lawns, parks, cemeteries, golf courses, or domestic water supply.

In December 2016, the active and inactive irrigation service locations totaled 20,638 system-wide. This was an increase of 1.7 percent compared to 2015, primarily due to the addition of service locations for pumps and pivots to convert land previously furrow irrigated to sprinkler irrigation. Irrigation customers accounted for 1,948,079 MWh of energy usage in 2016, which was a decrease from 2015 of approximately 4.8 percent primarily due to variations in weather. This sector represented nearly 14 percent of Idaho Power's total electricity sales, and approximately 33 percent of July sales. Energy usage for this sector has not grown significantly in many years; however, there is substantial yearly variation in usage due primarily to the impact of weather on customer irrigation needs.

Idaho Power offers two programs to the irrigation sector:

1. Irrigation Efficiency Rewards, an energy efficiency program designed to encourage the replacement or improvement of inefficient systems and components

2. Irrigation Peak Rewards, a demand response program designed to provide a system peak resource

The Irrigation Efficiency Rewards program, including Green Motor Initiative, experienced increased annual savings, from 14,027 MWh in 2015 to 15,747 MWh in 2016. Annual savings were up in 2016 likely because several large projects were completed this year.

In 2016, the Irrigation Peak Rewards program was in its third full season of full operation after temporarily being suspended for the 2013 season. Idaho Power successfully recruited the majority of prior participants to continue their participation in 2016, with a small increase of 1.2 percent in eligible service points participating over 2015.

Table 16 summarizes the overall expenses and program performance for both the energy efficiency and demand response programs provided to irrigation customers.

Table 16. 2016 irrigation program summary

| Program | Participants | Total Cost | | Savings | |
|---|---|---|---|---|---|
| | | Utility | Resource | Annual Energy (kWh) | Peak Demand (MW) |
| **Demand Response** | | | | | |
| Irrigation Peak Rewards | 2,286 service points | $ 7,600,076 | $ 7,600,076 | n/a | 303 |
| **Total** | | **$ 7,600,076** | **$ 7,600,076** | **n/a** | **303** |
| **Energy Efficiency** | | | | | |
| Green Motors—Irrigation | 23 motor rewinds | | | 73,617 | |
| Irrigation Efficiency Rewards | 851 projects | $ 2,372,352 | $ 8,162,206 | 15,673,513 | |
| **Total** | | **$ 2,372,352** | **$ 8,162,206** | **15,747,130** | **303** |

**Note:** See Appendix 3 for notes on methodology and column definitions.

Each year, the company conducts a customer relationship survey. Overall, 56 percent of Idaho Power irrigation customers surveyed in 2016 for the Burke Customer Relationship Survey indicated Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Fifty-three percent of survey respondents indicated Idaho Power is meeting or exceeding their needs with information on how to use energy wisely and efficiently. Sixty-seven percent of respondents indicated Idaho Power is meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 41 percent of the irrigation survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of irrigation survey respondents who have participated in at least one Idaho Power energy efficiency program, 93 percent are “very” or “somewhat” satisfied with the program.

## Training and Education

Idaho Power continued to market its irrigation programs by varying the location of workshops and offering new presentations to irrigation customers. In 2016, Idaho Power provided eight workshops promoting the Irrigation Efficiency Rewards program. Approximately 200 customers attended workshops in Twin Falls, Emmett, McCall, Homedale, Mini-Cassia, Shoshone, American Falls, and Oxbow. The company displayed exhibits at regional agricultural trade shows, including the Eastern Idaho Agriculture Expo, Western Idaho Agriculture Expo, the Agri-Action Ag show and the Treasure Valley Irrigation Conference.

Idaho Power sends out *Irrigation News* to all irrigation customers in Idaho and Oregon. The newsletter focuses on the Idaho Power Irrigation topics. This newsletter provides an opportunity to increase awareness, and to promote our Irrigation programs.

## Field Staff Activities

Idaho Power’s agricultural representatives offer customer education, training, and irrigation-system assessments and audits across the service area. Agricultural representatives also engage agricultural irrigation equipment dealers in training sessions, with the goal to share expertise about energy-efficient system designs, and to bring awareness about the program. Agricultural representatives and the irrigation segment coordinator, a licensed agricultural engineer, participate in annual training to maintain

or obtain their Certified Irrigation Designer and Certified Agricultural Irrigation Specialist accreditation. This training allows Idaho Power to maintain its high level of expertise in the irrigation industry and is sponsored by the nationally based Irrigation Association.

## *Irrigation Efficiency Rewards*

| | 2016 | 2015 |
|---|---|---|
| **Participation and Savings** | | |
| Participants (projects) | 851 | 902 |
| Energy Savings (kWh)* | 15,747,130 | 14,027,411 |
| Demand Reduction (MW) | n/a | n/a |
| **Program Costs by Funding Source** | | |
| Idaho Energy Efficiency Rider | $1,672,328 | $1,714,399 |
| Oregon Energy Efficiency Rider | $634,101 | $61,295 |
| Idaho Power Funds | $65,923 | $60,018 |
| Total Program Costs—All Sources | $2,372,352 | $1,835,711 |
| **Program Levelized Costs** | | |
| Utility Levelized Cost ($/kWh) | $.018 | $0.016 |
| Total Resource Levelized Cost ($/kWh) | $.063 | $0.085 |
| **Benefit/Cost Ratios** | | |
| Utility Benefit/Cost Ratio | 4.95 | 6.00 |
| Total Resource Benefit/Cost Ratio | 3.21 | 3.84 |

*2016 total includes 73,617 kWh of energy savings from 23 Green Motors projects.

### Description

Initiated in 2003, the Irrigation Efficiency Rewards program encourages energy-efficient equipment use and design in irrigation systems. Qualified irrigators in Idaho Power's Idaho and Oregon service areas can receive financial incentives and reduce their electricity usage through participation in the program. Two options help meet the needs for major or minor changes to new or existing systems: Custom Incentive and Menu Incentive.

#### *Custom Incentive Option*

The Custom Incentive Option addresses extensive retrofits or installation of an efficient new system.

New Systems: For a new system, the incentive is based on installation of a system Idaho Power determines to be more energy efficient than standard. Water source changes to an existing system are treated as a new system. The incentive is 25 cents per annual kWh saved, not to exceed 10 percent of the project cost.

Existing Systems: For existing system upgrades, the incentive is 25 cents per annual kWh saved or $450 per kW demand reduction, whichever is greater. The incentive is limited to 75 percent of the total project cost.

The qualifying energy efficiency measures include any hardware changes that result in a reduction of the potential kWh use of an irrigation system.

Idaho Power reviews, analyzes, and makes recommendations on each project. All project information is reviewed for each completed project before final payment. Prior usage history, actual invoices, and, in most situations, post-usage demand data are used to verify savings and incentives.

#### *Menu Incentive Option*

The Menu Incentive Option covers a significant portion of the costs of repairing and replacing specific components that help the irrigation system use less energy. This option is designed for systems where small maintenance upgrades provide energy savings from 11 separate measures. These measures are as follows:

- New flow-control type nozzles
- New nozzles for impact, rotating, or fixed-head sprinklers
- New or rebuilt impact or rotating type sprinklers
- New or rebuilt wheel-line levelers
- New complete low-pressure pivot package
- New drains for pivots or wheel-lines
- New riser caps and gaskets for hand-lines, wheel-lines, and portable mainlines
- New wheel-line hubs
- New pivot gooseneck and drop tube
- Leaky pipe repair
- New center pivot base boot gasket

Payments are calculated on predetermined average kWh savings per component.

### Program Activities

Of the 851 irrigation efficiency projects completed in 2016, 728 were associated with the Menu Incentive Option, providing an estimated 10,357 MWh of energy savings and 2.02 MW of demand reduction. The Custom Incentive Option had 123 projects, of which 65 were new irrigation systems and 58 were on existing systems. This option provided 5,316 MWh of energy savings and 2.03 MW of demand reduction for the year.

### Marketing Activities

In addition to training and education mentioned in the overview section, Idaho Power agricultural representatives targeted visits with a selected number of customers who had not participated in the program to increase customer education. Idaho Power maintained a database of irrigation dealers and vendors for direct-mail communication. Irrigation dealers and vendors are a key component to the successful marketing of the program. Therefore, Idaho Power's face-to-face interactions and direct-mailings containing the most up-to-date program information, brochures, and dealer-specific meetings ensured correct program promotion.

In 2016, the company sent a copy of *Irrigation News* to all irrigation customers in Idaho and Oregon. The August 2016 newsletter focused on the Irrigation Efficiency Rewards program: why read dates are important and summary bill options. This newsletter provides an opportunity to increase transparency, and to promote the Irrigation Efficiency Rewards program.

Idaho Power also placed numerous ads in print agricultural publications including the *Argus Observer*, *Gem State Producer*, *Capital Press, Power County Press,* and *Potato Grower Magazine;* updated and distributed the program brochure; and used radio advertising during Agri-Action and FFA week.

## Cost-Effectiveness

Idaho Power calculates cost-effectiveness using different savings and benefits assumptions and measurements under the Custom Incentive Option and the Menu Incentive Option of Irrigation Efficiency Rewards.

Each application under the Custom Incentive Option received by Idaho Power undergoes an assessment to estimate the energy savings that will be achieved through a customer's participation in the program. On existing system upgrades, Idaho Power calculates the savings of a project by determining what changes are being made and comparing it to the service point's previous five years of electricity usage history on a case-by-case basis. On new system installations, the company uses standard practices as the baseline and determines the efficiency of the applicant's proposed project. Based on the specific equipment to be installed, the company calculates the estimated post-installation energy consumption of the system. The company verifies the completion of the system design through aerial photographs, maps, and field visits to ensure the irrigation system is installed and used in the manner the applicant's documentation describes.

Each application under the Menu Incentive Option received by Idaho Power also undergoes an assessment to ensure deemed savings are appropriate and reasonable. Payments are calculated on a prescribed basis by measure. In some cases, the energy-savings estimates in the Menu Incentive Option are adjusted downward from deemed RTF savings to better reflect known information on how the components are actually being used. For example, a half-circle rotation center pivot will only save half as much energy per sprinkler head as a full-circle rotation center pivot. All deemed savings are based on seasonal operating hour assumptions by region. If a system's usage history indicates it has lower operating hours than the assumptions, like the example above, the deemed savings are adjusted.

Based on the deemed savings from the RTF, all the measures offered under the Menu Incentive Option are cost-effective. Complete measure-level details for cost-effectiveness can be found in *Supplement 1: Cost-Effectiveness*.

## Customer Satisfaction and Evaluations

Idaho Power conducted no customer satisfaction surveys for this program.

In 2016, Idaho Power contracted with Leidos to conduct an impact and process evaluation of this program. The evaluation team conducted 46 desk reviews; 30 for a stratified sample of Menu Option

projects and 16 for a stratified sample of Custom Option projects. The team also completed site visits for 11 custom incentive projects.

The findings of the impact evaluation indicate a realization rate of 98 percent, with a relative precision of +/- 2.4 percent overall at 90 percent confidence, on the ex-post kWh savings for both the Menu Option and the Custom Option savings combined. The realization rate on the ex-post kW impacts was 97 percent for the Menu Option and 75 percent for the Custom Option, respectively. The overall combined realization rate for the program demand savings was 90 percent with a relative precision of +/-3.3 percent at 90 percent confidence. The realization rate is the percent comparison of the expected savings or load reduction to the realized savings or load reduction.

The process evaluation indicated that the program is well designed, well managed and well implemented. A summary of the results is in *Supplement 2: Evaluation*.

### 2017 Program and Marketing Strategies

Marketing plans for 2017 include conducting six to eight customer-based irrigation workshops. Additionally, Idaho Power will continue to participate in four regional agricultural trade shows. Idaho Power will work closely with customers who have participated in the Irrigation Efficiency Rewards program, and continue to take photos for program promotion highlighting efficient irrigation system designs.

Idaho Power will continue to promote the program in agriculturally focused editions of newspapers and magazines, and to provide valuable information in its *Irrigation News* newsletter.

## *Irrigation Peak Rewards*

| | | 2016 | 2015 |
|---|---|---|---|
| **Participation and Savings** | | | |
| | Participants (participants) | 2,286 | 2,259 |
| | Energy Savings (kWh) | n/a | n/a |
| | Demand Reduction (MW) | 303 | 305 |
| **Program Costs by Funding Source** | | | |
| | Idaho Energy Efficiency Rider | $1,082,113 | $1,018,139 |
| | Oregon Energy Efficiency Rider | $218,906 | $222,614 |
| | Idaho Power Funds | $6,299,056 | $6,018,079 |
| | Total Program Costs—All Sources | $7,600,076 | $7,258,831 |
| **Program Levelized Costs** | | | |
| | Utility Levelized Cost ($/kWh) | n/a | n/a |
| | Total Resource Levelized Cost ($/kWh) | n/a | n/a |
| **Benefit/Cost Ratios** | | | |
| | Utility Benefit/Cost Ratio | n/a | n/a |
| | Total Resource Benefit/Cost Ratio | n/a | n/a |

### Description

Idaho Power's Irrigation Peak Rewards program is a voluntary program available only to Idaho and Oregon agricultural irrigation customers with metered service locations that have participated in the past. Initiated in 2004, the purpose of the program is to minimize or delay the need to build new supply-side resources. By reducing demand on the most extreme load days in the most extreme summer conditions, the Irrigation Peak Rewards program can reduce the amount of generation and transmission resources Idaho Power needs to build.

The program pays irrigation customers a financial incentive to interrupt the operation of specified irrigation pumps with the use of one or more load control devices. Historically, the Irrigation Peak Rewards program provides approximately 300 MW of load reduction during the program season of June 15 through August 15, which is nearly 9 percent of Idaho Power's all-time system peak.

The program offers two interruption options: an Automatic Dispatch Option and a Manual Dispatch Option. To participate in the Automatic Dispatch Option, either an advanced metering infrastructure (AMI) or a cellular control device is attached to the customer's electrical panel that allows Idaho Power to remotely control the pumps. To participate in the Manual Dispatch Option, Idaho Power must determine that the service location cannot take advantage of the current installation and communication technology, or the service point offers at least 1,000 cumulative horse power (hp). These customers must nominate a particular amount of kW reduction by June 1 of the program year.

For either interruption option, load control events could occur up to four hours per day, up to 15 hours per week, but no more than 60 hours per season. Customers will experience at least three events per season between 1:00 p.m. and 9:00 p.m. on weekdays and Saturday.

The incentive structure consists of fixed and variable payments. The fixed incentive is paid to those who participate during each of the first three events. A variable incentive is paid to those who participate in subsequent events. Customers who participate from 5:00 p.m. until 9:00 p.m. can receive a higher variable incentive.

Program rules allow customers the ability to opt out of dispatch events up to five times per service point. The first three opt outs each incur a penalty of $5 per kW, while the remaining two each incur a penalty of $1 per kW based on the current month's billing kW. The opt-out penalty may be prorated to correspond with the dates of program operation, and are accomplished through manual bill adjustments. The penalties will never exceed the amount of the incentive that would have been paid with full participation.

### Program Activities

Idaho Power filed a request in December 2015 to modify the existing Irrigation Peak Rewards program to allow the company to use more of its AMI technology for load control as well as to allow greater flexibility for some customers to participate in the Manual Dispatch Option. After approval in Idaho and Oregon in February 2016, Idaho Power decided not to renew the contract with program provider, EnerNOC/M2M Communications.

Idaho Power enrolled 2,286 service points in the program in 2016, an increase of 1 percent over 2015. The enrolled service points accounted for approximately 82 percent of the eligible service points (where there is a load control device installed). The incentive rate remained the same in 2016. The customer's incentive is a demand credit of $5.00/kW and an energy credit of $0.0076/kWh applied to the monthly bills for the period of June 15 through August 15. The demand credit is calculated by multiplying the monthly billing kW by the demand-related incentive amount. The energy credit is calculated by multiplying the monthly billing kWh usage by the energy-related incentive amount. Credits were prorated for periods when reading/billing cycles did not align with the program season dates from June 15 to August 15. The incentive structure also includes a "variable" payment for more than three events of $0.148/event kWh, with an increased variable credit of $0.198/event kWh for service points that voluntarily participate in the "extended" 9 p.m. interruption period.

The three load control events occurred June 29, July 27, and July 29, 2016 with the highest load reduction occurring on June 29, providing an estimated 316.9 MW at the generation level.

### Marketing Activities

Idaho Power used workshops, trade shows, and direct-mailings to encourage past participants to re-enroll in the program. See the Irrigation Sector Overview section. The company updated an informational flyer to increase appeal and readability by using a brochure format. Idaho Power mailed the new brochure, program enrollment application, and program agreement, to all eligible participants in February 2016.

## Cost-Effectiveness

Idaho Power determines cost-effectiveness for it demand response program under the terms of IPUC Order No. 32923 and OPUC Order No. 13-482. Under the terms of the orders and the settlement, all of Idaho Power's demand response programs were cost-effective for 2016.

The Irrigation Peak Rewards program was dispatched for 12 event hours and achieved a maximum demand reduction of 302.7 MW. The total expense for 2016 was $7,600,075 and would have been approximately $10.8 million if the program was fully used for 60 hours.

In 2016, the cost of operating the three demand response programs was $9.47 million. Idaho Power estimates that if the three programs were dispatched for the full 60 hours, the total costs would have been approximately $12.87 million and would have remained cost-effective. A complete description of Idaho Power cost-effectiveness of its demand response programs is included in *Supplement 1: Cost-Effectiveness.*

## Customer Satisfaction and Evaluations

On the June 29 event, the program experienced two unexpected problems. The AMI signal to the load control device was not able to process all of the necessary commands because the communication settings were incorrect. The issue was discovered near the beginning of the event, and was corrected within two hours of the event starting time. Additionally, the EnerNOC/M2M device notification process did not work as intended, consequently not all of the participants were notified. EnerNOC/M2M corrected the issue, and it did not happen in subsequent events.

Each year, Idaho Power produces an internal annual report for the Irrigation Peak Rewards program. This report includes a load-reduction analysis, cost-effectiveness information, and program changes. A copy is included in *Supplement 2: Evaluation.*

In 2016, Idaho Power conducted a potential realization rate analysis and, as in past years, that potential event date has a large influence on the expected realization rate. Table 18 shows the season in two-week blocks and the potential realization rate associated with each. The rate drops off significantly in August due to a higher percentage of pumps turned off during the baseline period. The 2016 counterfactual realization rate peaked the last two weeks of June. The analysis determined that the highest realization rate of 76.9 percent occurred June 29. A further breakdown of the load reduction for each event by is shown in Table 17.

Table 17. Irrigation Peak Rewards program load reduction for each 2016 event by program option

| Event | Automatic Dispatch Option (MW) | Manual Dispatch Option (MW) | Total Load (MW) |
|---|---|---|---|
| June 29 | 233,589 | 69,171 | 302,760 |
| July 27 | 177,685 | 66,911 | 244,569 |
| July 29 | 185,180 | 64,096 | 249,275 |

Table 18. Irrigation Peak Rewards 2016 potential realization rate

| 2016 Season Timeframe | Average Potential Realization Rate |
|---|---|
| June 15–June 30 | 68.82% |
| July 1–July 15 | 62.42% |
| July 16–July 31 | 58.89% |
| August 1– August 15 | 55.66% |

## 2017 Program and Marketing Strategies

The company is in the process of exchanging all of the EnerNOC/M2M communication devices with load control units that work with its AMI meters or company designed cell phone-controlled devices. Once the exchanges are complete, the program will no longer use EnerNOC/M2M to provide services for the program. This change out of devices is expected to reduce overall program costs and potentially reduce the complexity of coordinating communications and load control commands.

Idaho Power will continue to recruit past participants in this program for the 2017 irrigation season. The company will conduct six to eight workshops throughout its service area to familiarize customers with the program details and eligibility requirements. Each eligible customer will be sent a comprehensive packet containing an informational brochure, sign-up worksheet, and contract agreement encouraging their participation. Idaho Power agricultural representatives will continue one-on-one customer contact to inform and encourage program participation.

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# OTHER PROGRAMS AND ACTIVITIES

Idaho Power recognizes the value of energy efficiency awareness and education to create behavioral change to help customers use energy wisely. The goal of other programs and activities is to promote energy efficiency programs, projects, and behavior in customers. These awareness efforts increase customer demand for, and satisfaction with, Idaho Power's programs and activities. These activities include customer outreach, marketing, research, project development, and education programs. This category includes the Residential Energy Efficiency Education Initiative, Easy Savings Program, Commercial Education, and Educational Distributions.

## Building-Code Improvement

Since 2005, the State of Idaho has been adopting a state-specific version of the IECC. The Idaho Building Code Board convened another Energy Code Collaborative in late 2015 in an effort to address implementation of the new series of building-related codes.

The Idaho Building Code Board requested the collaborative review of the 2015 codes and suggested recommendations to the board regarding adoption of codes. The first meeting occurred on December 2, 2015 and three subsequent meetings occurred in 2016.

Idaho Power participated and offered support in those collaborative meetings, which was attended by members of the building industry, local building officials, code development officials, and other interested stakeholders. The Energy Code Collaborative is an ongoing effort in which Idaho Power will continue to participate. Additional meetings will be scheduled in 2017.

## Energy Efficiency Advisory Group

Formed in 2002, EEAG provides input on enhancing existing DSM programs and on implementing energy efficiency programs. Currently, EEAG consists of 13 members from Idaho Power's service area and the Northwest. Members represent a cross-section of customers from the residential, industrial, commercial, and irrigation sectors, as well as representatives from low-income households, environmental organizations, state agencies, public utility commissions, and Idaho Power. EEAG meetings are generally open to the public and attract a diverse audience. Idaho Power appreciates the input from the group, and acknowledges the commitment of time and resources the individual members give to participate in EEAG meetings and activities.

EEAG met four times in 2016: February 18, May 5, August 30, and November 3. Additionally, EEAG held two conference calls on February 16 and November 28. During these meetings, Idaho Power discussed and requested feedback on new program ideas and new measure proposals, marketing methods, and specific measure details; provided a status of the Idaho and Oregon Rider funding and expenses; gave an update of ongoing programs and projects; and supplied general information on DSM issues and other important issues occurring in the region. Idaho Power relies on input from EEAG to provide a customer and public-interest view of energy efficiency and demand

response programs and expenses. A summary of each meeting and phone call is below; the complete notes from the 2016 EEAG meetings are included in *Supplement 2: Evaluation*.

February 16, 2016: EEAG members participated in a confidential conference call to discuss the *2015 Flex Peak Program One-Time Report*. This report was submitted to the IPUC by May 7, 2016, and compares the current Flex Peak Program to the prior program managed by EnerNOC.

February 18, 2016: Darrel Anderson, President and CEO of Idaho Power, addressed the group and thanked members of EEAG for their time and guidance throughout the years. He commented that Idaho Power has benefited by having the EEAG as a resource that brings new thoughts and ideas about energy efficiency. CLEAResult presented results of the demand response program evaluations. Idaho Power sought feedback from the group on two programs: See ya later, refrigerator® and the Multifamily Direct Install project (Multifamily Energy Savings Program). The group supported continuing See ya later, refrigerator® in 2016, and provided good ideas for other measures that could be included in the Multifamily Direct Install project. Idaho Power also discussed its website redesign; spring 2016 residential energy efficiency ad campaign tactics, including a new customer pledge; and results from an em**powered** community survey to gauge customers' interest in making energy-saving improvements to their homes.

May 5, 2016: Idaho Power demonstrated its myAccount web tool, and handed out an abridged home assessment form for the group to fill out. The Energy Savings Pledge (later named the Smart-saver Pledge) was discussed and EEAG was asked for feedback on behavioral change options that could be included in the pledge. The group provided several options that pledge participants could choose from. Idaho Power presented its Program Planning Update, and asked EEAG for feedback on a couple of new residential ideas it is researching. The group suggested Idaho Power continues the Multifamily Direct Install project and continues to look for ways to encourage the installation of DHPs into new multi-family housing units if they appear to be cost-effective. The history of the Idaho and Oregon Rider was presented to the group and included the financial history for both Idaho and Oregon balances since their inception. Idaho Power provided EEAG with results from the spring residential energy efficiency ad campaign, further discussed plans for the Smart-saver Pledge, and reviewed Idaho Power's social media channels and specific energy efficiency posts and ads on each channel.

August 30, 2016: EEAG member and CSHQA president, Kent Hanway, hosted this meeting at the CSHQA office on Broad Street in Boise. Along with a presentation of the building's energy efficiency measures, EEAG members and guest were given a tour of the building. A presentation covering 2017 preliminary cost-effectiveness provided a summary of all programs and how anticipated changes may impact programs for 2017. Idaho Power updated the group on activities related to customer alerts and home energy reports, and presented the results of an analysis conducted by the company to quantify the estimated value of deferral of transmission and distribution investments that could occur as a result of energy-efficiency efforts. Idaho Power discussed results from an em**powered** community survey about the spring residential energy efficiency ad campaign, plans for the fall ad campaign, and 2017 marketing efforts.

November 3, 2016: EEAG members were given an update on the development of a home energy report pilot to be deployed in 2017. EEAG was asked for feedback on target audience type for these reports. The Commercial Program Performance presentation highlighted energy savings and participation and feedback was requested from EEAG regarding some possible changes to the Flex Peak Program for 2017. Idaho Power provided an update about its various surveys and how they impact marketing, shared results from the fall residential energy efficiency ad campaign and Smart-saver Pledge, discussed plans for new Commercial and Industrial Energy Efficiency Program ads, and shared some new initiatives and successes from 2016. The company presented the non-cost-effective aspects of the Home Improvement Program and advised EEAG of the company's plan no longer offer the program.

November 28, 2016: A conference call was held to discuss Idaho Power's recommendations to decrease the collection percentage of the Rider.

## Green Motors Initiative

Idaho Power participates in the Green Motors Practices Group's (GMPG) Green Motors Initiative (GMI). Under the GMI, service center personnel are trained and certified to repair and rewind motors in an effort to improve reliability and efficiency. If a rewind returns a motor to its original efficiency, the process is called a "Green Rewind." By rewinding a motor under this initiative, customers may save up to 40 percent when compared to buying a new motor. The GMI is available to Idaho Power's agricultural, commercial, and industrial customers.

Twenty-one service centers in Idaho Power's service area have the training and equipment to participate in the GMI, and perform an estimated 1,200 Green Rewinds annually. Of the 21 service centers, currently nine have signed on as GMPG members. The GMPG will work to expand the number of service centers participating in the GMI, leading to market transformation and an expected kWh savings in southern Idaho and eastern Oregon.

Under the initiative, Idaho Power pays service centers $2 per hp for each National Electrical Manufacturers Association (NEMA)-rated motor up to 5,000 hp that received a verified Green Rewind. Half of that incentive is passed on to customers as a credit on their rewind invoice. The GMPG requires all member service centers to sign and adhere to the GMPG Annual Member Commitment Quality Assurance agreement. The GMPG is responsible for verifying quality assurance.

In 2016, a total of 37 motors were rewound under the GMI. Table 19 provides a breakdown of energy savings and the number of motors by customer segment.

Table 19. 2016 Green Motor Initiative savings, by sector and state

| Sector | State | Number of Motors | Sum of kWh Savings |
|---|---|---|---|
| Irrigation | ID | 22 | 72,871 |
| | OR | 1 | 746 |
| **Irrigation Total** | | **23** | **73,617** |
| Commercial and Industrial | ID | 12 | 50,955 |
| | OR | 2 | 72,745 |
| **Commercial and Industrial Total** | | **14** | **123,700** |
| **Grand Total** | | **37** | **197,317** |

## Idaho Power's Internal Energy-Efficiency Commitment

Idaho Power continues to upgrade the company's substation buildings across its service area. Focus for 2017 will be to provide energy-efficient heating and cooling, and to develop a plan to replace all T-12 lighting with LED fixtures in substation buildings.

Renovation projects continued at CHQ in downtown Boise in 2016. The company remodeled the eighth floor, and exchanged the old T-12 parabolic lighting fixtures with T-8 lighting. Remodels continue to incorporate energy efficiency measures, such as lower partitions, lighting retrofits, and automated lighting controls. In 2017, Idaho Power plans to remodel the ninth floor of the CHQ.

Also in 2106, the new Twin Falls Operation Center was constructed to replace the 1951-built center used to house the South-East Region operations staff. The design incorporates LED lighting, energy-efficient heating and cooling by way of a VRF design, and lighting control that includes daylight harvesting to reduce power consumption. The building also features a rooftop solar array to offset the amount of energy the building uses from the grid.

In 2016, Idaho Power redesigned the HVAC delivery system for the Maintenance and Electrical Shops; construction on these projects is planned for 2018. Idaho Power estimates that with these improvements the shops may reduce their usage by 300,000 kWh in coming years.

Idaho Power continued its major sustainability initiative by installing more electric vehicle (EV) charging stations at the company's EV Workplace Charging Center at CHQ and at several operations centers. The company continues to provide a variety of models of EV charging stations to promote awareness, use, and information dissemination about EVs. More employees now have the opportunity to charge their EV while at work. In addition to adding more EVs to the Idaho Power fleet, employees' personal use of EVs will further promote the financial and environmental benefits of EVs.

Idaho Power's internal energy efficiency projects and initiatives are funded by non-rider funds.

## Local Energy Efficiency Funds

The purpose of LEEF is to provide modest funding for short-term projects and activities that do not fit within other categories of energy efficiency programs, but still provide energy savings or a defined benefit to the promotion of energy-efficient behaviors or activities.

Idaho Power received two applications for LEEF in 2016. Both applications were reviewed and found to be standard practice, and not appropriate for LEEF. A residential program specialist followed up with these applicants, and directed them to the residential energy efficiency resources found on Idaho Power's website. One project involved replacing all lighting in the applicant's house with LED lighting. The other project involved replacing single-pane windows with new, more energy-efficient windows.

## Market Transformation

Market transformation is an effort to change the existing market for energy efficiency goods and services by engaging and influencing large national companies to manufacture or supply more energy-efficient equipment. Market transformation can also attempt to identify barriers and opportunities to increase the market adoption of efficiency. Idaho Power achieves market transformation savings primarily through its participation in the NEEA.

### *Northwest Energy Efficiency Alliance*

Idaho Power has been a funding member of NEEA since its inception in 1997. NEEA's role in this process is to look to the future to find emerging opportunities and to create a path forward to make those opportunities a reality in the region.

NEEA's current, five-year funding cycle began 2015. In this cycle the 2015 to 2019 NEEA business plan is forecast to obtain 145 average megawatt (aMW) of regional energy savings at a cost savings of about $3 million over the next five years to Idaho Power customers as compared to the previous five-year business plan. The NEEA plan also offered some optional programs and activities to prevent overlap of activities when local utilities have the capability to provide the same services at a lower cost or more effectively.

Idaho Power participates in all of NEEA's committees and workgroups including representation on the Regional Portfolio Advisory Committee and the Board of Directors. In 2016, Idaho Power continued to help with the implementation of the Commercial and Industrial Lighting Regional Market Plan.

NEEA performs several MPERs on various energy efficiency efforts each year. In addition to the MPERs, NEEA provides market-research reports, through third-party contractors, for energy efficiency initiatives throughout the Pacific Northwest. Copies of these reports are included on the CD accompanying *Supplement 2: Evaluation* and on NEEA's website under Market Effects Evaluation.

## NEEA Marketing

As stated in Idaho Power's agreement with NEEA for the 2015 to 2019 funding cycle: "Idaho Power will fund, create, and deliver specific market transformation activities for all initiatives that are relevant for the Idaho Power service area." In 2016, these activities included educating residential customers on heat pump technology and heat pump water heaters, and promoting reduced wattage T-8 lightbulbs to business customers.

Idaho Power placed an article about heat pump technology and included heat pump water heaters as an example in its summer *Energy Efficiency Guide*. The company also issued a *News Briefs* article titled *New, More-Efficient Heat Pump Water Heater!* on heat pump water heaters to media April 25, and promoted the products on social media and in the October issue of *Connections.*

To promote reduced wattage lightbulb replacement, Idaho Power published an article in its fall *Energy @Work* newsletter, placed a promo pod linking to a newly developed flyer (PDF) on the company's Retrofits web page, and wrote an article that was included in BOMA's member email in November.

## Residential NEEA Activities

Idaho Power participates in the Residential Advisory Committee, Efficient Homes Workgroup, the Manufactured Homes Interest Group, the Retail Products Platform (RPP) Initiative, the DHP research project, the Smart Water Heat Initiative (previously known as the HPWH Initiative), Efficient Homes Workgroup, the Super Efficient Dryers Workgroup, the Northwest Regional Strategic Market Plan for Consumer Products group, and Northwest Regional Retail Collaborative. During 2016, NEEA combined the Efficient Homes Workgroup and the Manufactured Homes Interest Group and renamed it the Better Built NW Workgroup.

NEEA provides Better Built NW builder and contractor training, manages the regional-homes database, develops regional marketing campaigns, and coordinates energy-efficient new construction activities with utilities in Idaho, Montana, Oregon, and Washington.

In 2016, NEEA completed the sun setting of their ENERGY STAR® Homes Northwest program. All single-family and multi-family builders seeking ENERGY STAR certification must now go through the national EPA ENERGY STAR Homes program. NEEA will continue oversight of a regional database for utilities to access ENERY STAR Home certifications for incentive payments and will continue working towards the creation of a single-family Residential Performance Path program to offer utilities flexibility in program design and the opportunity to capture all above building code savings on residential new construction projects.

In 2016, NEEA formed the Super Efficient Dryers Initiative to support the acceleration of heat pump dryers into the market and Idaho Power participated in the workgroup. The initiative focuses on influencing manufacturer product development and executing strategies to overcome the barriers of this new technology. Barriers include a high incremental cost, limited consumer awareness, and product availability. The initiative offers incentives to reduce the retail price. A second goal of the initiative is

lab and field-testing to better understand how heat pump dryers perform in real-world conditions, evaluate consumer preferences, and gather data to support RTF provisional energy savings.

Idaho Power participated in RETAC which met quarterly to review the emerging technology pipeline for BPA, NEEA, and the Northwest Power and Conservation Council (NWPCC) Seventh Power Plan. RETAC is developing a regional database to increase coordination among the utilities to identify and track emerging technologies; plan and conduct research; and develop, implement, and assess pilots and field demonstrations.

Idaho Power continued participation in the RBSA. The purpose of the RBSA is to determine common attributes of residential homes, and develop a profile of the existing residential buildings in the Northwest.

### Commercial and Industrial NEEA Activities

NEEA continued to provide support for commercial and industrial energy efficiency activities in Idaho in 2016, which included partial funding of the IDL for trainings and additional tasks.

The Idaho Building Code Board requested the Idaho Code Collaborative review the 2015 codes and make a recommendation to the board on adoption. NEEA facilitated the Code Collaborative meetings and Idaho Power participated.

NEEA facilitated regional webinars for the Commercial Code Enhancement (CCE) initiative for new construction to discuss how utilities can effectively align code changes and utility programs. NEEA is using the code collaborative in Idaho and Montana as examples of success for other regions.

NEEA facilitated the conference planning committee and, along with Idaho Power, supported the 2016 Idaho Energy and Green Building Conference held in Boise on November 1 and 2, 2016. Idaho Power had two active members on the conference planning committee.

NEEA's work on SEM in the commercial and industrial sectors continued in 2016. The primary focus in 2016 was to consolidate all of the SEM templates, guidelines, and documents into the new SEM Hub website.

NEEA's work with the Refrigerating Engineers & Technicians Association (RETA) on the RETA certified refrigeration energy specialist (CRES) certification process continued in 2016. A new CRES contractor was hired in 2016 to work with RETA marketing of the RETA CRES certification, improving the RETA CRES training materials, and improving the RETA CRES practice exams.

Idaho Power kept abreast on NEEA's initiatives in the commercial lighting arena via periodic conference calls and in-person meetings. Idaho Power continued participation as a member of the NEEA Commercial Lighting Program Manager Work Group.

The Reduced Wattage Lamp Replacement (RWLR) initiative achieved some success in 2016, especially in Idaho. NEEA worked with 20 branches across five electrical distributor organizations in Idaho Power's service area, with new distributors added to the initiative in 2016. Preliminary data shows

the 2016 market penetration of reduced wattage T-8 lightbulb in the company's service area is between 30 to33 percent, which is higher than the average 22 percent penetration across all four Pacific Northwest states. Overall, linear fluorescent lightbulb sales continue to decline at roughly 10 percent per year. Market sales of linear LEDs are increasing, which is having an impact on the RWLR initiative; however, NEEA estimates 2017 will continue to see good participation from distributors in reduced wattage T-8 sales.

In 2016, the NEEA Top-Tier Trade Ally (TTTA) training was renamed NXT Level. Ultimately, the plan is to offer lighting trade allies throughout the region the opportunity for multi-tiered training, each level building on the one before, over the next few years. NEEA rolled out Level 1 on-line training to the Idaho Power service area June 2016. Level 1 is geared toward more seasoned trade allies. In October, the company's first trade ally completed the course and received the Level 1 designation. Several other trade allies in the Idaho Power service area are in process of taking the course.

Idaho Power continued participation in the Regional Strategic Market Planning Collaborative for commercial and industrial lighting. The collaborative formed in 2015 to create regional strategic market plans in four market segments. Commercial and industrial lighting was the first segment of focus because it was identified as the collaborative's top priority. Idaho Power is represented on a steering committee formed to monitor and oversee the progress of the regional commercial and industrial lighting plan.

The NEEA Existing Building Renewal (EBR) pilot project in Boise, which began in 2013 and phased through 2016, saw no significant results in 2016. The project has not resulted in any Idaho Power incentive applications.

NEEA completed several assessment studies related to irrigated agriculture to support their scanning activities. Idaho Power has kept apprised of these activities, and has reviewed each of these assessments. Copies of the reports are included on the CD accompanying *Supplement 2: Evaluation* and on NEEA's website under NEEA Market Effects Evaluations.

### NEEA Funding

In 2016, Idaho Power began the second year of the 2015 to 2019 *Regional Energy Efficiency Initiative Agreement* with NEEA. Per this agreement, Idaho Power is committed to fund NEEA based on a quarterly estimate of expenses up to the five-year total direct funding amount of $16.5 million in support of NEEA's implementation of market transformation programs in Idaho Power's service area. Of this amount in 2016, 100 percent was funded through the Idaho and Oregon Riders.

In 2016, Idaho Power paid $2,676,387 to NEEA. The Idaho jurisdictional allocation of the payments was $2,542,567, while $133,820 was paid for the Oregon jurisdiction. Other expenses associated with Idaho Power's participation in NEEA activities, such as administration and travel, were paid from Idaho and Oregon Riders.

Final NEEA savings for 2016 will be released in June 2017. Preliminary estimates reported by NEEA for 2016 indicate Idaho Power's share of regional market transformation MWh savings for 2016 is

24,616 MWh. These savings are reported in two categories; codes- and standards-related savings of 20,060 MWh and non-codes and standards related savings of 4,556 MWh.

In the *Demand-Side Management 2015 Annual Report*, preliminary funding share estimated savings reported were 21,900 MWh. The revised estimate included in this report for 2015 final funding share NEEA savings is 23,039 MWh. These saving include savings from code-related initiatives as well as non-code-related initiatives. Idaho Power relies on NEEA to report the energy savings and other benefits of NEEA's regional portfolio of initiatives. For further information about NEEA, visit their website at neea.org.

## Program Planning Group

In 2014, Idaho Power convened an internal PPG to explore new opportunities to expand current DSM programs and offerings. The group consisted of residential program specialists, commercial and industrial engineers, energy efficiency analysts, marketing specialists, energy efficiency program leaders, and the research and analysis leader. The PPG does not perform program execution. Instead, the group's role is to determine if a measure has energy-saving potential, has market adoption potential, and is potentially cost-effective.

Throughout 2016, the group met regularly to explore new ideas to promote energy efficiency including evaluating new potential programs and measures. Idaho Power incorporated five new ideas from the PPG into the overall portfolio of residential program offerings: 1) mailing energy efficiency kits, 2) initiating a multi-family direct-install project, 3) installing smart thermostats, and 4) distributing clothes drying racks for educational purposes. The first three offerings will continue to be available in 2017. Idaho Power will evaluate the drying rack offering for its long-term viability.

In the commercial sector, the company began the school cohort. In November 2016, Idaho Power recruited school districts to establish a structured energy program where each district will have an individualized initiative and develop a program to implement energy efficiency measures and behaviors at their schools.

Three other PPG ideas were presented to EEAG and are being considered for implementation in 2017: 1) Home Energy Reports, mailed to customers to inform them of their energy use and how it compares to others; 2) an on-line marketplace for customers to review and purchase energy-efficient appliances; and 3) installation of a thermostatic shower valve to reduce hot water use. Each of these measures has an element of behavior change.

Idaho Power will continue to use the PPG to review, evaluate, and deliver new energy efficiency offerings in 2017 and beyond.

## Regional Technical Forum

The RTF is a technical advisory committee to the NWPCC, established in 1999 to develop standards to verify and evaluate energy efficiency savings. Since 2004, Idaho Power has supported the RTF by

providing annual financial support, regularly attending monthly meetings, participating in sub-committees, and sharing research and data beneficial to the forum's efforts.

The forum is made up of both voting members and corresponding members from investor-owned and public utilities, consultant firms, advocacy groups, Energy Trust of Oregon, and BPA, all with varied expertise in engineering, evaluation, statistics, and program administration. The RTF advises the NWPCC during the development and implementation of the regional power plan in regards to the following listed in the RTF charter:

- Developing and maintaining a readily accessible list of eligible conservation resources, including the estimated lifetime costs and savings associated with those resources and the estimated regional power system value associated with those savings.
- Establishing a process for updating the list of eligible conservation resources as technology and standard practices change, and an appeals process through which utilities, trade allies, and customers can demonstrate that different savings and value estimates should apply.
- Developing a set of protocols by which the savings and system value of conservation resources should be estimated with a process for applying the protocols to existing or new measures.
- Assisting the Council in assessing: 1) the current performance, cost and availability of new conservation technologies and measures; 2) technology development trends; and 3) the effect of these trends on the future performance, cost and availability of new conservation resources.
- Tracking regional progress toward the achievement of the region's conservation targets by collecting and reporting on regional research findings and energy savings annually.

When possible, Idaho Power uses the savings estimates, measure protocols, and supporting work documents provided by the RTF, and when the work products are applicable to the Idaho climate zones and load characteristics. In 2016, Idaho Power staff participated in all RTF meetings as a voting member and the RTF Policy Advisory Committee.

During 2016, RTF impacted measure changes include savings tier additions to DHPs, updates to multi-family weatherization and new construction measures, updates to low-flow showerhead savings, and the addition of connected or "smart" thermostats as a supported RTF measure. All implementations of changes were accounted for in planning and budgeting for 2017. Idaho Power considered the multi-family weatherization measure updates when it decided to sunset the Home Improvement Program. A complete list of RTF decisions in 2016 can be accessed at rtf.nwcouncil.org.

## Residential Energy Efficiency Education Initiative

Idaho Power recognizes the value of general energy efficiency awareness and education in creating behavioral change and customer demand for, and satisfaction with, its programs. The Residential Energy Efficiency Education Initiative (REEEI) promotes energy efficiency to the residential sector. The company achieves this by creating and delivering educational materials and programs that result in

wise and informed choices regarding energy use and increase Idaho Power's energy efficiency program participation.

REEEI continued to produce semiannual *Energy Efficiency Guide*s in 2016. Idaho Power distributed these guides primarily via insertion in local newspapers and at events across Idaho Power's service area. The *Winter Energy Efficiency Guide* was published and distributed by 16 newspapers in Idaho Power's service area the week of January 26, in accordance with the new distribution plan outlined in 2015. The *Boise Weekly* also inserted the guide, increasing circulation by 30,000, which focused on ways to find the truth about energy-saving claims, seven ways to improve a home's energy efficiency, ventilation and lighting for optimum health and efficiency, and tips for hiring a home improvement contractor. The information was applicable to all residential customers, but the design was adapted and enhanced for particular usefulness and appeal to the senior population. Idaho Power included a story from the guide in the January *News Briefs* and promoted it that month on KPVI during the energy efficiency news segment.

The *Summer Energy Efficiency Guide* was delivered nearly 222,000 homes the week of July 24, 2016. This guide focused on saving energy as a family and highlighted why Idaho Power promotes energy efficiency, energy-saving computer settings, behavior change, smart technology, and making saving energy fun for the whole family. The guide also featured a mini home assessment so customers could gauge how energy efficient their behaviors were.

The release of the summer guide received public relations support through numerous communication channels, including an item in Idaho Power's weekly *News Briefs* email to all media in the Idaho Power service area on July 18 and 25, promotion on KTVB and KPVI in the July energy efficiency news segments, on Idaho Power's social media accounts, and using banner ads and native ads on the Idaho Statesman website. A banner ad appears as a traditional advertisement; a native ad is formatted as an on-line news article, with several paragraphs of text, but is, in fact, paid media. The native ad includes a disclaimer that reads "Advertisement."

In 2016, the company distributed over 6,000 guides, including issues from past years, at energy efficiency presentations and events, which continued to reinforce the overall value of these guides. On its website, Idaho Power provides a link to the most current seasonal guide, and to a list of historical guides.

REEEI distributed energy efficiency messages through a variety of other communication methods during 2016. Idaho Power increased customer awareness of energy-saving ideas via continued distribution of the third printing of the 96-page booklet *30 Simple Things You Can Do to Save Energy*, a joint publishing project between Idaho Power and The Earthworks Group. In 2016, the program distributed 2,595 English and 480 Spanish copies directly to customers. This was accomplished via community events and local libraries; by customer representatives during in-home visits; by participating contractors in the Home Improvement Program, Energy House Calls program, H&CE Program, and Fridge and Freezer Recycling Program; through direct web requests; and in response to inquiries received by Idaho Power's Customer Service Center. Agency partners also used the books to educate clients about Energy Efficiency. Additionally, more than 34,000 customers had an opportunity

to request the booklet and/or the most recent *Energy Efficiency Guide* when they ordered their ESK online.

Idaho Power continues to recognize that educated employees are effective advocates for energy efficiency and Idaho Power's energy efficiency programs. Idaho Power customer relations and energy-efficiency staff reached out to each of Idaho Power's geographical regions and the Customer Service Center to speak with customer representatives and other employees to discuss educational initiatives and answer questions about the company's energy efficiency programs.

The Kill A Watt™ Meter Program remained active in 2016. Idaho Power's Customer Service Center and field staff continued to encourage customers to learn about the energy used by specific appliances and activities within their homes by visiting a local library to check out a Kill A Watt meter. The Kill A Watt meters were mentioned on live television studio news programs on KTVB and KPVI in Idaho Power's monthly energy efficiency segments.

As in previous years, Idaho Power continued to strengthen the energy education partnership with secondary school educators through continued participation on the Idaho Science, Technology, Engineering and Mathematics (iSTEM) Steering Committee. In 2016, 16 teachers completed the four-day, two-credit professional development seminar, Energy for Future Citizens, facilitated by Idaho Power and co-sponsored by Intermountain Gas and the Idaho National Laboratory (INL). Among other things, participating teachers received a classroom kit containing Kill A Watt meters and other tools to facilitate student learning related to energy efficiency and wise energy use.

Idaho Power continued to engage customers in energy efficiency discussions at many community events throughout Idaho Power's service area. In February, Idaho Power participated in the Smart Women, Smart Money conference for the second year and educated nearly 2,000 women about the benefits of energy-efficient choices and LED lighting. In February, March, April, and May Idaho Power participated in the Twin Falls Home and Garden Show, the College of Southern Idaho's Sustainability Show, the Centennial Ribbon Cutting at the Twin Falls Visitor Center, Platt's Super Tool Day, Pocatello's Spring Home Show and the Portneuf Valley Community Environmental Fair—actively promoting wise energy use and participation in energy efficiency programs while distributing over 16,000 LED lightbulbs at these specific events.

In September 2016, Idaho Power participated in the FitOne Expo in Boise, Idaho. The event continued to be important to the initiative due to the size of the audience and because Idaho Power's prior participation confirmed the demographics of attendees appear to align with the company's residential energy efficiency target audience. In 2016, Idaho Power staff at the event once again focused attendee attention on the benefits of LED lighting technology, distributed LED lightbulbs, and promoted participation in the ESK program.

Idaho Power further increased its energy efficiency presence in the community by providing energy efficiency and program information through 92 outreach activities, including events, presentations, trainings, and other activities. In addition, Idaho Power customer representatives delivered 189 presentations to local organizations addressing energy efficiency programs and wise

energy use. In 2016, Idaho Power's Community Education team provided 91 presentations on *The Power to Make a Difference* to 2,350 students and 53 classroom presentations on *Saving a World Full of Energy* to 1,411 students. The community education representatives and other staff also completed 14 senior citizen presentations on energy efficiency programs and shared information about saving energy to 592 senior citizens in the company's service area. Additionally, Idaho Power's energy efficiency program managers responded with detailed answers to 364 customer questions about energy efficiency and related topics received via Idaho Power's website.

As part of National Energy Awareness Month in October, Idaho Power held its sixth annual student art contest in the Idaho Power service area, bringing energy education into the classroom and inspiring students and families to think more about energy. This year, the contest set a new record with more than 2,239 entries representing all regions. The contest, which featured "Ways to Save Energy" as one of the highlighted categories, was promoted in a late September *News Briefs* and results were publicized in *Connections*. Regional and overall winning students and their teachers were recognized.

The Residential Energy Efficiency Education Initiative continued to provide energy efficiency tips in response to media inquiries and in support of Idaho Power's *#TipTuesday* posts. In addition to supplying information for various Idaho Power publications, such as the *News Scans* weekly employee newsletter, the *Connections* customer newsletter, and Idaho Power's Facebook page, energy efficiency tips, and content was provided for weekly *News Briefs* and monthly KTVB (Boise) and KPVI (Pocatello) live news segments.

The initiative completed the program design phase of the ESK program and implemented the new program. Each kit was shipped with a mini-home assessment to cross-market other energy efficiency programs, promote the use of myAccount and help families learn about other energy-saving behavior changes. Savings and expenses have been reported under Educational Distributions.

The initiative continued to coordinate LED lightbulb distributions aimed at getting the newest lighting technology into customer hands along with customer education and answers to their common questions. At events and presentations, company staff distributed over 24,900 LEDs in custom packaging that highlighted the advantages of energy-efficient lighting and encouraged participation in Idaho Power's myAccount on-line portal. LED lightbulbs were mentioned on nine of the news segments on KTVB and KPVI. The energy savings resulting from this effort and from the SEEK for the school year 2015 to 2016, are reported in the Educational Distributions program section of this report.

In 2016, the initiative implemented the Drying Rack Pilot Project—a behavioral change program with the goal of helping customers reduce their automatic clothes dryer use by 25 percent or more. Educational messages to support the behavior change were delivered to customers at the point of enrollment, when drying racks were picked up and during the project period. Additional information about the project can be found in the Educational Distributions program in this report.

In the fall, the initiative conducted a survey with the em**powered** community to learn more about customers' shower behaviors—in particular, details around how they warm up the water prior to taking a shower. Information from the survey may be used to improve potential future offerings such as the

addition of a thermostatic shower valve as an educational distribution option. A copy of the survey can be found in *Supplement 2: Evaluation*.

The initiative's 2017 goals are to increase program participation and promote education and energy saving ideas that result in energy-efficient, conservation-oriented behaviors and choices. In addition to producing and distributing educational materials, the initiative will continue to manage the company's Educational Distributions program responsible for distributing educational measures that have associated savings. Examples of activities conducted under Educational Distributions include LED lighting education, distribution of LED lightbulbs to customers, the SEEK program, the Drying Rack Project and the ESK program. In addition to these activities, the initiative plans to implement a home energy report pilot project.

The initiative will continue to work with the PPG to explore additional behavioral program opportunities that may include distribution of thermostatic shower valves, increased promotion of myAccount, or a pilot program to test other behavioral messages.

## Evaluation and Best Practices Review

In 2016, the company contracted with Leidos to perform a process evaluation and best practices review of the REEEI. Leidos found that REEEI is comprised of 23 different activities, efforts and elements that educate, inform, and persuade residential electric customers to install energy-efficient measures and to take other actions that decrease energy use. They also found the initiative both investigates and engages in various behavioral change strategies.

Leidos also found Idaho Power has a comprehensive presence on both traditional and social media channels. The 23 initiative elements reach over 415,000 customers in a variety of ways ranging from: 1) in-person contacts and presentations, courtesy of five community educational and approximately 20 customer representatives in the field daily; 2) newsletters, guides, mailers, conventional broadcasting, social media; and 3) gamification reward systems, sponsorships, educational materials and training.

Interviews with Idaho Power staff and initiative efforts indicate a strong focus on driving customers to use the myAccount on-line portal located on the company website, where customers check on energy use via near real-time smart-meters, billing and account information with links to tools, rebates and other resources that aid in understanding their energy use and reduction strategies. Daily customer logins to myAccount have steadily increased over the last four and a half years, from 2,000 logins in mid-2012, to about 5,000 in late-2016. Moreover, the number of myAccount registrations per month is also increasing, from 2,000 to4,000 accounts per month in 2010 through 2011, up to 3,000 to 5,000 per month more recently.

Idaho Power is marketing energy-savings programs and activities by linking them to home improvement, money savings, comfort, and other NEBs to capture interest in energy efficiency and move it to top-of-mind. Surveys conducted with external program managers, subject-matter experts, and Idaho Power staff rated their customers' non-energy motivational drivers on a 10-point scale.

"Saving money" was rated highest (9.4), followed by improved comfort (9.1), health and safety (7.6), and being/feeling "green" and reducing environmental impacts (7.3).

External program managers, subject-matter experts, and Idaho Power staff rated marketing channels that involve person-to-person interaction and active learning environments higher than more passive, informal channels, to reach and educate customers. On a 10-point scale, situations where strong in-group social identity exists were rated most effective/useful (8.0), followed by on-line customer utility accounts (7.7), universities and college settings (7.6), public or community events, on-line energy dashboards and smart or real-time meters (all 7.3).

Leidos estimates conservatively that Idaho Power staff conducted over 590 in-person (or webinar) outreach activities, training sessions and events recorded in the Outreach Tracker database (from early 2012 to mid-2016) with an average attendance of 8091 people per event.

The SEEK and *The Power to Make a Difference* presentation (given by Idaho Power staff 124 times to 3,359 students in 2015) are also features of REEEI. Both received numerous positive comments from customers and build strong customer-utility relations. "The children always express that they tried everything included [in the kits] with their parents or family members. The adults express they are happy to have the free materials especially the lightbulbs and showerheads…teachers cannot thank us enough for this program!" Eighteen high school teachers participated in a three-day professional development seminar (facilitated by iSTEM) that empowered teachers with information and classroom tools to teach students to think critically about energy, including; the science of energy, energy generation and sources, wise energy use and social impacts.

A literature review of best practices regarding energy education programs was performed and indicated there are four basic types of behavioral change programs and strategies: 1) informational programs, 2) socially interactive approaches, 3) education and training, and 4) a stacked approach. Leidos states the four types of behavioral change strategies are well represented in the breadth of REEEI elements described in the final report.

The final report can be found in *Supplement 2: Evaluation.*

## University of Idaho Integrated Design Lab

Idaho Power is a founding supporter of the IDL. The IDL is dedicated to the development of high-performance, energy-efficient buildings in the Intermountain West. Idaho Power has worked with the IDL since its inception in 2004 to educate the public about how energy-efficient business practices benefit the business and the customer. In 2016, Idaho Power entered into an agreement with the IDL to perform the following tasks and services.

### *Foundational Services*

The goal of this task was to provide energy efficiency technical assistance and project-based training to building industry professionals and customers. When the IDL receives requests for their involvement in

building projects, the projects are categorized into one of three types. Phase I projects are simple requests that can be addressed with minimal IDL time. Phase II projects are more complex requests that require more involvement and resources from the lab. Phase III projects are significantly more complex and must be co-funded by the customer.

In 2016, the IDL provided technical assistance on a total of 38 projects in the Idaho Power service area. There were 32 Phase I projects, five Phase II projects, and one Phase III project. An additional three projects, currently in early stages, and the full scope of work is yet to be determined. Overall, 44 percent of the projects were on new buildings, 38 percent were on existing buildings and 18 percent were not building specific. The report is located in the IDL section of *Supplement 2: Evaluation*.

## Lunch & Learn

The goal of the Lunch & Learn task was to educate architects, engineers, and other design and construction professionals about energy efficiency topics through a series of educational lunch sessions.

In 2016, the IDL scheduled 20 technical training lunches in Boise, and Ketchum. The trainings were coordinated directly with architecture and engineering firms and organizations; a total of 161 architects, engineers, interior designers, project managers, and others attended.

Eighteen lunches were offered in Boise, and two in Ketchum. The topics of the lunches (and number of each) were: The Classroom of the Future: A DOE project (1); New Design Recommendations for Exterior Lighting (1); Case Study—Daimler Truck North America (1); Passive House Standard for Multifamily Projects (1); Life Sciences Building Path to High-Performance Design and Construction (1); Integrated Design Principles (1); Daylight Performance Metrics for Human Health, Productivity, and Satisfaction (1); Cold Feet: Managing Controls and Condensation with Simulating Radiant Slab Cooling (1); Daylight in Buildings: Schematic Design Methods (1); Radiant Heating and Cooling Design Considerations (1); Benchmarking and Energy Goal Setting (1); Integrated Design Case Studies (2); Hybrid Ground Source Heat Pump (2); and Daylight in Buildings: Getting the Details Right (5). The report is located in the IDL section of *Supplement 2: Evaluation*.

## Building Simulation Users Group

The goal of this task was to facilitate the Idaho BSUG, which is designed to improve the energy efficiency-related simulation skills of local design and engineering professionals.

In 2016, six monthly BSUG sessions were hosted by IDL. The sessions were attended by 73 professionals in person and were made available remotely, attended by 48 professionals. Evaluation forms were completed by attendees for each session. On a scale of 1 to 5, with 5 being “excellent” and 1 being “poor,” analyzing results from the first six questions, the average session rating was 4.34 for 2016. For the final question “The content of the presentation was…” on a scale of 1 to 5, with 1 being “too basic,” 3 being “just right,” and 5 being “too advanced,” the average session rating was 3.15 for 2016.

Each presentation was archived on the BSUG 2.0 website along with general BSUG-related content. The BSUG 2.0 site logged 994 page views with 234 specific to Idaho users in 2016. The report is located in the IDL section of *Supplement 2: Evaluation*.

## New Construction (Building Efficiency) Verification

The goal of this task was to continue random installation verification of over 10 percent of New Construction program participants who received incentives. This consisted of conducting a full review of documentation and complete on-site inspections to validate whether noted systems and components had been installed. The purpose of this verification was to confirm program guidelines and requirements were adequately facilitating participants to provide accurate and precise information with regard to energy efficiency measure installations.

This task also included the review of all daylight photo-control incentives to verify site conditions and improve the quality of design and installation.

The IDL completed on-site field verifications for the New Construction program as summarized in the New Construction Customer Satisfaction and Evaluations section presented earlier in this report. The verification report is located in the IDL section of *Supplement 2: Evaluation*.

## Tool Loan Library

The TLL gives customers access to equipment that enables them to measure and monitor energy consumption on various systems within their operation. The goal of this task was to operate and maintain measurement equipment, including a web-based equipment tool loan-tracking system, and to provide technical training on how each tool is intended to be used.

The inventory of the TLL now consists of over 900 individual pieces of equipment. In 2016, two new tools and eight manuals were added to the library. Additionally, 25 tools were calibrated in 2016. The tools and manuals are available for customers, engineers, architects, and contractors in Idaho Power's service area to borrow at no cost to aid in the evaluation of energy efficiency projects and equipment they are considering.

There were 49 tool loan requests in 2016, which included a total of 206 tools loaned. The tools were loaned to 30 unique customers, including engineering firms, equipment representatives, educational institutions, industrial plants, and office/commercial facilities. The report is located in the IDL section of *Supplement 2: Evaluation*.

## Building Metrics Labeling

The goal of this task was to continue the support and promotion of the Building Metrics Labeling (BML) sheet, a graphical display of four building metrics on a single sheet that was developed in a task that began in 2012. The metrics displayed are Energy Use Intensity, ENERGY STAR® score, Walk Score®, and Space Daylit Area. The purpose of the BML sheet is to increase awareness of building energy use and to promote energy efficiency during the sale or lease of commercial properties. The final version of the BML tool became available for public use in early 2014.

The IDL continued support and maintenance of the sheet in 2016. The tool was discussed and/or flyers were distributed at twenty Lunch & Learn presentations to architecture or engineering firms and organizations, multiple Central Addition Planning meetings hosted by the USGBC, six BSUG events, and during calls or visits to five building owners within the Central Addition (LIV District). One-on-one support was also available if requested, but no requests were made in 2016. The report is located in the IDL section of *Supplement 2: Evaluation*.

## Heat Pump Calculator/Climate Design Tools

This task was a continuation of work done in a task that began in 2013 and continued through 2016. The goal of the original task was to develop an Excel-based heat pump analysis tool to calculate energy use and savings based on site-specific variables for commercial buildings. Previously, IDL identified a lack of sophisticated heat pump energy-use calculators available with the capability of comparing the energy use of heat pumps in commercial buildings against other technologies in a quick, simple fashion.

The calculator has been updated to reflect feedback from validation testing, including an improved user interface and the ability to integrate Typical Meteorological Year, version three (TMY3) weather files for locations where that data is available. A few years ago, the IDL completed a set of Climate Design Tools intended to inform sustainable design and calculate the impacts of five innovative types of systems: earth tubes, passive heating, cross ventilation, stack ventilation, and night flush ventilation/thermal mass. In 2015, the IDL integrated three of the five climate design tools into the Heat Pump Calculator. This unification produced a single platform life-cycle analysis tool for several energy efficiency measures not currently well-supported with other tools in the industry.

The work in 2016 included the unification of two additional climate design tools to the calculator and the addition of seven unique weather files for sites around Idaho. The report for this task is located in the IDL section of *Supplement 2: Evaluation*.

## Daylight Training

New in 2016, this task involved advance preparation work to provide daylight training sessions for local professionals in 2017. The training will enhance knowledge of, and appreciation for, daylight, and keep professionals informed of the latest advances in daylighting technologies.

The 2016 preparation included recommissioning lighting controls in the IDL, gathering of installed lighting controls manuals, writing a protocol for demonstration, and reviewing new lighting control technologies. A market-needs assessment was performed in the third quarter of 2016 to determine the need for a daylight training class, as well as to help develop the curriculum. Initial marketing began in November 2016 for the 2017 sessions. The report for this task is located in the IDL section of *Supplement 2: Evaluation*.

## 2017 IDL Strategies

In 2017, the IDL will continue or expand work on the Foundational Services, Lunch & Learn sessions, BSUG, Building Efficiency Verifications, TLL, Heat Pump Calculator, and Daylight Training tasks. IDL will also provide work on one new task in 2017, an Absorption Chiller Feasibility Study.

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# REGULATORY OVERVIEW

Idaho Power believes there are three essential components of an effective regulatory model for DSM: 1) the timely recovery of DSM program costs, 2) the removal of financial disincentives, and 3) the availability of financial incentives. By working with its stakeholders and regulators through negotiations and filings, Idaho Power seeks to move DSM regulatory treatment toward achieving all of these goals.

## Timely Recovery of DSM Program Costs: Energy Efficiency Rider and Prudence Determination of Expenditures

Since 2002, Idaho Power has recovered most of its DSM program costs through the Rider with the intended result of providing a more timely recovery of DSM expenditures. In addition, since January 1, 2012, Idaho demand response program incentives expenses have been included in base rates and tracked in the annual PCA mechanism.

### *Annual DSM Expense Review Filing and Order No. 33583*

On March 15, 2016, Idaho Power filed Case No. IPC-E-16-03 with the IPUC requesting an order finding the company had prudently incurred $35,196,964 in DSM expenses in 2015, including $28,495,701 in Rider expenses and $6,701,263 in demand response program incentives. The filing included three reports: *Demand-Side Management 2015 Annual Report*, *Supplement 1: Cost-Effectiveness*, and *Supplement 2: Evaluation*. Due to previous IPUC decisions in Order Nos. 32667, 32690, and 32953 to defer Idaho Power's request to deem prudent the increases in the company's Rider-funded labor-related expenses for 2011and 2012, Idaho Power did not request a prudence determination for labor-related expenses of $441,856 in the 2015 filing. The 2015 labor-related expenses of $441,856 bring the cumulative balance of increases in Rider-funded labor-related expenses that have not yet received a prudence determination to $1,313,407 through 2015. Idaho Power plans to request a prudence determination on these amounts in its 2016 DSM prudence request.

In Order No. 33583, dated September 14, 2016, the IPUC deemed $35,196,964 as prudently incurred.

Since 2012, the company has experienced a mismatch in Rider funding levels compared to expenditures in that the Rider has been collecting more than the company has been spending on its DSM efforts. As part of Order No. 33583, the IPUC directed Idaho Power to work with staff and other stakeholders to examine an adjustment to the Rider percentage and to submit a proposal for revising the Rider percentage to the commission no later than December 30, 2016.

Following collaboration with the parties to the case (staff, Industrial Customers of Idaho Power [ICIP] and Idaho Conservation League [ICL]) and a conference call with EEAG, on December 22, 2016, Idaho Power filed an application in Case No. IPC-E-16-33 requesting an order approving: 1) a decrease to the Rider collection percentage from 4 to 3.75 percent of base rate revenues, effective March 1, 2017; 2) a $13 million refund of previously collected Rider funds to be included in the 2017/2018 PCA effective June 1, 2017, and 3) the elimination of the annual transfer of $4 million of Rider funds through

the PCA. The annual transfer of $4 million of Rider funds through the PCA is more fully described in the following paragraph.

### *Energy Efficiency Rider-Funds Transfer*

On April 15, 2016, Idaho Power filed the annual PCA Case No. IPC-E-16-08 with the IPUC. As part of that case, the company proposed that the commission approve a transfer of $3,970,036 from the Rider to customers as a credit, or reduction, in the 2016/2017 PCA on customers' bills. In Order No. 33526, the commission approved the transfer. This transfer is needed to maintain the revenue neutrality associated with the June 2014 update to the normalized level of net power supply expense included in base rates approved by Order No. 33000.

## Removal of Financial Disincentives: Fixed-Cost Adjustment

To address the removal of financial disincentives, Idaho Power has in place a fixed-cost adjustment (FCA) mechanism in Idaho. Under the FCA, rates for Idaho residential and small general-service customers are adjusted annually up or down to recover or refund the difference between the fixed costs authorized by the IPUC in the most recent general rate case and the fixed costs Idaho Power received the previous year through actual energy sales. This mechanism removes the financial disincentive that exists when Idaho Power promotes energy efficiency programs designed to reduce customer usage. The FCA addresses, for residential and small general-service customers, the percentage of fixed costs that are recovered through their volumetric energy charges.

On May 27, 2016, the IPUC issued Order No. 33527 approving the company's request to implement FCA rates beginning June 1, 2016, for the 2015 fixed-cost deferrals. The overall rate adjustment was a 2.2 percent increase for residential and small general-service customers to collect a combined $28 million. This adjustment was an increase of $11 million from the previous year's FCA. Residential customers pay an FCA of 0.5416 cents per kWh, while small general-service customers pay an FCA of 0.6875 cents per kWh. The rate will be in place until May 31, 2017.

## Promotion of Energy Efficiency through Electricity Rate Design

Idaho Power believes rates offered to customers should reflect their cost of service to provide cost-based price signals, and encourage the wise and efficient use of energy.

Since 2012, Idaho Power has offered a Time-of-Day (TOD) Pilot pricing plan to residential customers in Idaho. The overall goal of this TOD pricing plan is to use the AMI system to offer customers a choice of pricing plans while providing them with tools to manage their energy use, to provide the company with the opportunity to further study the effects of a time-variant rate on customers' use, and to help shape the company's future communication efforts. The plan provides participants the opportunity to shift their usage from higher-priced, on-peak time periods to lower-priced, off-peak time periods and possibly lower their bills. As of the end of 2016, approximately 1,300 Idaho customers were TOD plan participants. A description of this plan is at Idaho Power's website (idahopower.com/TOD).

# GLOSSARY OF ACRONYMS

A/C—Air Conditioning/Air Conditioners
ADM—ADM Associates, Inc.
Ads—Advertisement
AEG—Applied Energy Group
AMI—Advanced Metering Infrastructure
aMW—Average Megawatt
ARCA—Appliance Recycling Center of America
ASHRAE—American Society of Heating, Refrigeration, and Air Conditioning Engineers
B/C—Benefit/Cost
BCA—Building Contractors Association
BCASEI—Building Contractors Association of Southeast Idaho
BCASWI—Building Contractors Association of Southwestern Idaho
BML—Building Metrics Labeling
BOMA—Building Owners and Managers Association
BOP—Builder Option Package
BPA—Bonneville Power Administration
BPI—Building Performance Institute
BSUG—Building Simulation Users Group
CAP—Community Action Partnership
CAPAI—Community Action Partnership Association of Idaho, Inc.
CAZ—Combustion Appliance Zone
CCE—Commercial Code Enhancement
CCOA—Aging, Weatherization and Human Services
CCNO—Community Connection of Northeast Oregon, Inc.
CEI—Continuous Energy Improvement
CEL—Cost-Effective Limit
CFL—Compact Fluorescent Lamp/Lightbulb
CFM—Cubic Feet per Minute
CHQ—Corporate Headquarters (Idaho Power)
CINA—Community in Action
CLEAResult—CLEAResult Consulting, Inc.
COP—Coefficient of Performance
CR&EE—Customer Relations and Energy Efficiency
CRES—Certified Refrigeration Energy Specialist
DHP—Ductless Heat Pump
DOE—Department of Energy
DSM—Demand-Side Management
EA5—EA5 Energy Audit Program
EBR—Existing Building Renewal
ECM—Electronically Commutated Motors

EEAG—Energy Efficiency Advisory Group
EICAP—Eastern Idaho Community Action Partnership
EL ADA—El Ada Community Action Partnership
EM&V—Evaluation, Measurement, and Verification
EPA—Environmental Protection Agency
ESK—Energy-Savings Kit
EV—Electric Vehicle
FCA—Fixed-Cost Adjustment
$ft^2$—Square Feet
$ft^3$—Cubic Feet
GIS—Geographic Information System
GMI—Green Motors Initiative
GMPG—Green Motors Practice Group
gpm—Gallons per Minute
H&CE—Heating & Cooling Efficiency Program
HP—Hewlett Packard
hp—Horsepower
HPS—Home Performance Specialist
HPWH—Heat Pump Water Heater
HSPF—Heating Seasonal Performance Factor
HUD—Housing and Urban Development
HVAC—Heating, Ventilation, and Air Conditioning
IBCA—Idaho Building Contractors Association
IBOA—International Building Operators Association
ICIP—Industrial Customers of Idaho Power
ICL—Idaho Conservation League
IDHW—Idaho Department of Health and Welfare
IDL—Integrated Design Lab (in Boise)
IECC—International Energy Conservation Code
INL—Idaho National Laboratory
IPMVP—International Performance Measurement and Verification Protocol
IPUC—Idaho Public Utilities Commission
IRP—Integrated Resource Plan
ISHE—International Society of Healthcare Engineers
iSTEM—Idaho Science, Technology, Engineering and Mathematics
JACO—JACO Environmental, Inc.
kW—Kilowatt
kWh—Kilowatt-hour
LED—Light-Emitting Diode
LEEF—Local Energy Efficiency Funds
LIHEAP—Low Income Home Energy Assistance Program
MOU—Memorandum of Understanding
MPER—Market Progress Evaluation Report

MVBA—Magic Valley Builders Association
MW—Megawatt
MWh—Megawatt-hour
MWSOC—Municipal Water Supply Optimization Cohort
n/a—Not Applicable
NEB—Non-Energy Benefit
NEEA—Northwest Energy Efficiency Alliance
NEEM—Northwest Energy Efficient Manufactured
NEMA—National Electrical Manufacturers Association
NPR—National Public Radio
NSH—Next Step Home
NTG—Net to Gross
NWPCC—Northwest Power and Conservation Council
O&M—Operation and Maintenance
OHCS—Oregon Housing and Community Services
OPUC—Public Utility Commission of Oregon
ORS—Oregon Revised Statute
OSV—On-Site Verification
PCA—Power Cost Adjustment
PCT—Participant Cost Test
PLC—Powerline Carrier
PNWS–AWWA—Pacific Northwest Section American Water Works Association
PPG—Program Planning Group
PRV—Pressure Regulating Valve
PSC—Permanent Split Capacitor
PTCS—Performance Tested Comfort System
QA—Quality Assurance
QC—Quality Control
RAP—Resource Action Programs
RBSA—Residential Building Stock Assessment
REEEI—Residential Energy Efficiency Education Initiative
RESNET—Residential Services Network
RETA—Refrigerating Engineers and Technicians Association
RETAC—Regional Emerging Technologies Advisory Committee
Rider—Idaho Energy Efficiency Rider and Oregon Energy Efficiency Rider
RIM—Ratepayer Impact Measure
RPP—Retail Products Platform
RTF—Regional Technical Forum
RWLR—Reduced Wattage Lamp Replacement
SCCAP—South Central Community Action Partnership
SCE—Streamlined Custom Efficiency
SEEK—Students for Energy Efficiency Kit
SEEM—Simplified Energy Enthalpy Model

SEICAA—Southeastern Idaho Community Action Agency
SEM—Strategic Energy Management
SIR—Savings-to-Investment Ratio
SRVBCA—Snake River Valley Building Contractors Association
SWIOS—Southwest Idaho Operators Conference
TLED—Tube LED
TLL—Tool Loan Library
TMY3—Typical Meteorological Year, version three
TOD—Time of Day
TRC—Total Resource Cost
TRM—Technical Reference Manual
TTTA—Top-Tier Trade Ally
UC—Utility Cost
UES—Unit Energy Savings
UM—Utility Miscellaneous
US—United States
USGBC—US Green Building Council
VFD—Variable-Frequency Drive
VRF—Variable Refrigerant Flow
W—Watt
WAP—Weatherization Assistance Program
WAQC—Weatherization Assistance for Qualified Customers
WEFTEC—Water Environment Federation Technical Exhibition and Conference
WHF—Whole-House Fan
WSOC—Water Supply Optimization Cohort
WWEEC—Wastewater Energy Efficiency Cohort

# APPENDICES

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## **Appendix 1.** Idaho Rider, Oregon Rider, and NEEA payment amounts (January–December 2016)

| | | |
|---|---|---|
| **Idaho Energy Efficiency Rider [a]** | | |
| 2016 Beginning Balance | $ | 6,554,074 |
| 2016 Funding plus Accrued Interest as of 12-31-16 | | 39,437,692 |
| **Total 2016 Funds** | | **45,991,766** |
| 2016 Expenses as of 12-31-16 | | (31,291,579) |
| Rider Transfer to PCA (IPUC Order 33306) | | (3,970,036) |
| **Ending Balance as of 12-31-2016** | **$** | **10,730,151** |
| **Oregon Energy Efficiency Rider** | | |
| 2016 Beginning Balance | $ | (4,482,485) |
| 2016 Funding plus Accrued Interest as of 12-31-16 | | 1,099,211 |
| **Total 2016 Funds** | | **(3,383,273)** |
| 2016 Expenses as of 12-31-16 | | (2,168,868) |
| **Ending Balance as of 12-31-2016** | **$** | **(5,552,141)** |
| **NEEA Payments** | | |
| 2016 NEEA Payments as of 12-31-2016 | $ | 2,676,387 |
| **Total** | **$** | **2,676,387** |

[a] Liability accounts

## **Appendix 2.** 2016 DSM expenses by funding source (dollars)

| Sector/Program | Idaho Rider | Oregon Rider | Non-Rider Funds | Total |
|---|---|---|---|---|
| **Energy Efficiency/Demand Response** | | | | |
| **Residential** | | | | |
| A/C Cool Credit | $ 632,079 | $ 41,833 | $ 429,383 | $ 1,103,295 |
| Easy Savings | – | – | 127,587 | 127,587 |
| Educational Distributions | 2,334,206 | 56,164 | 2,514 | 2,392,884 |
| Energy Efficient Lighting | 3,009,970 | 63,200 | 7,538 | 3,080,708 |
| Energy House Calls | 188,253 | 15,815 | 2,368 | 206,437 |
| ENERGY STAR® Homes Northwest | 138,203 | 1,510 | 2,445 | 142,158 |
| Fridge and Freezer Recycling Program (See ya later, refrigerator®) | 250,535 | 4,555 | 2,826 | 257,916 |
| Heating & Cooling Efficiency Program/DHP Pilot | 545,454 | 27,184 | 22,275 | 594,913 |
| Home Energy Audit | 278,959 | – | 10,853 | 289,812 |
| Home Improvement Program | 309,799 | – | 14,225 | 324,024 |
| Multifamily Energy Savings Program | 55,758 | – | 3,288 | 59,046 |
| Oregon Residential Weatherization | – | 3,906 | 24 | 3,930 |
| Rebate Advantage | 103,056 | 6,392 | 1,602 | 111,050 |
| Shade Tree Program | 70,669 | – | 5,973 | 76,642 |
| Simple Steps, Smart Savings™ | 147,055 | 3,535 | 3,194 | 153,784 |
| Weatherization Assistance for Qualified Customers | – | – | 1,289,809 | 1,289,809 |
| Weatherization Solutions for Eligible Customers | 1,226,540 | 56,571 | 40,681 | 1,323,793 |
| **Commercial/Industrial** | | | | |
| Building Efficiency | 1,863,584 | 42,559 | 25,079 | 1,931,222 |
| Custom Efficiency | 7,664,563 | 237,146 | 80,916 | 7,982,624 |
| Easy Upgrades | 4,791,852 | 228,834 | 19,505 | 5,040,190 |
| Flex Peak Program | 105,116 | 247,897 | 414,984 | 767,997 |
| Oregon Commercial Audit | – | 7,717 | – | 7,717 |
| **Irrigation** | | | | |
| Irrigation Efficiency Rewards | 1,672,328 | 634,101 | 65,923 | 2,372,352 |
| Irrigation Peak Rewards | 1,082,113 | 218,906 | 6,299,056 | 7,600,076 |
| **Energy Efficiency/Demand Response Total** | **$ 26,470,093** | **$ 1,897,824** | **$ 8,872,049** | **$ 37,239,965** |
| **Market Transformation** | | | | |
| NEEA | 2,542,567 | 133,820 | – | 2,676,387 |
| **Market Transformation Total** | **$ 2,542,567** | **$ 133,820** | **$ –** | **$ 2,676,387** |
| **Other Programs and Activities** | | | | |
| Residential Energy Efficiency Education Initiative | 259,301 | 12,071 | 18,806 | 290,179 |
| Energy Efficiency Direct Program Overhead | 238,767 | 16,965 | 37,307 | 293,039 |
| **Other Programs and Activities Total** | **$ 498,068** | **$ 29,036** | **$ 56,114** | **$ 583,218** |
| **Indirect Program Expenses** | | | | |
| Commercial/Industrial Energy Efficiency Overhead | 222,704 | 16,653 | 86,715 | 326,072 |
| Energy Efficiency Accounting & Analysis | 848,975 | 49,358 | 251,197 | 1,149,530 |
| Energy Efficiency Advisory Group | 14,365 | 806 | 954 | 16,125 |
| Residential Energy Efficiency Overhead | 783,384 | 44,818 | 35,987 | 864,189 |
| Special Accounting Entries | (88,576) | (3,447) | – | (92,024) |
| **Indirect Program Expenses Total** | **$ 1,780,851** | **$ 108,187** | **$ 374,854** | **$ 2,263,893** |
| **Grand Total** | **$ 31,291,579** | **$ 2,168,868** | **$ 9,303,017** | **$ 42,763,464** |

## **Appendix 3.** 2016 DSM program activity

| Program | Participants | Total Costs | | Savings | | Measure Life (Years) | Nominal Levelized Costs [a] | |
|---|---|---|---|---|---|---|---|---|
| | | Utility [b] | Resource [c] | Annual Energy (kWh) | Peak Demand [d] (MW) | | Utility ($/kWh) | Total Resource ($/kWh) |
| **Demand Response** | | | | | | | | |
| A/C Cool Credit[1] | 28,315 homes | $ 1,103,295 | $ 1,103,295 | n/a | 34 | n/a | n/a | n/a |
| Flex Peak Program[1] | 137 sites | 767,997 | 767,997 | n/a | 42 | n/a | n/a | n/a |
| Irrigation Peak Rewards[1] | 2,286 service points | 7,600,076 | 7,600,076 | n/a | 303 | n/a | n/a | n/a |
| **Total** | | **$ 9,471,367** | **$ 9,471,367** | **n/a** | **378** | | | |
| **Energy Efficiency** | | | | | | | | |
| **Residential** | | | | | | | | |
| Easy Savings | 2,001 kits | $ 127,587 | $127,587 | 402,961 | 9 | | $0.035 | $0.035 |
| Educational Distributions | 67,065 kits/lightbulbs | 2,392,884 | 2,392,884 | 15,149,605 | 10 | | 0.016 | 0.016 |
| Energy Efficient Lighting | 1,442,561 lightbulbs | 3,080,708 | 10,770,703 | 21,093,813 | 11 | | 0.014 | 0.049 |
| Energy House Calls | 375 homes | 206,437 | 206,437 | 509,859 | 18 | | 0.029 | 0.029 |
| ENERGY STAR® Homes Northwest | 110 homes | 142,158 | 297,518 | 150,282 | 36 | | 0.051 | 0.107 |
| Fridge and Freezer Recycling Program (See ya later, refrigerator®) | 1,539 refrigerators/freezers | 257,916 | 257,916 | 632,186 | 6 | | 0.062 | 0.062 |
| Heating & Cooling Efficiency Program | 486 projects | 594,913 | 1,404,625 | 1,113,574 | 20 | | 0.036 | 0.085 |
| Home Energy Audit | 539 audits | 289,812 | 289,812 | 207,249 | 11 | | n/a | n/a |
| Home Improvement Program | 482 projects | 324,024 | 1,685,301 | 500,280 | 45 | | 0.034 | 0.178 |
| Multifamily Energy Savings Program | 3 projects | 59,046 | 59,046 | 149,760 | 10 | | 0.040 | 0.040 |
| Oregon Residential Weatherization | 7 homes | 3,930 | 5,900 | 2,847 | 30 | | 0.079 | 0.118 |
| Rebate Advantage | 66 homes | 111,050 | 148,142 | 411,272 | 25 | | 0.016 | 0.022 |
| Simple Steps, Smart Savings™ | 7,880 appliances/showerheads | 153,784 | 379,752 | 577,320 | 11 | | 0.025 | 0.063 |
| Weatherization Assistance for Qualified Customers | 246 homes/non-profits | 1,289,809 | 1,934,415 | 746,162 | 25 | | 0.105 | 0.158 |
| Weatherization Solutions for Eligible Customers | 232 homes | 1,323,793 | 1,323,793 | 621,653 | 25 | | 0.130 | 0.130 |
| **Sector Total** | | **$ 10,357,850** | **$21,283,831** | **42,259,823** | **8** | | **$ 0.029** | **$ 0.059** |
| **Commercial** | | | | | | | | |
| Custom Projects (Custom Efficiency) | 196 projects | $ 7,982,624 | $16,123,619 | 47,518,871 | 11 | | $ 0.013 | $ 0.026 |
| Green Motors—Industrial | 14 motor rewinds | | | 123,700 | 16 | | n/a | n/a |
| New Construction (Building Efficiency) | 116 projects | 1,931,222 | 4,560,826 | 12,393,249 | 12 | | 0.014 | 0.033 |
| Retrofits (Easy Upgrades) | 1,577 projects | 5,040,190 | 8,038,791 | 28,124,779 | 11 | | 0.016 | 0.026 |
| **Sector Total** | | **$ 14,954,036** | **$ 28,723,235** | **88,160,599** | **14** | | **$ 0.014** | **$ 0.026** |

## **Appendix 3**. 2016 DSM program activity (continued)

| Program | Participants | Total Costs | | Savings | | Measure Life (Years) | Nominal Levelized Costs [a] | |
|---|---|---|---|---|---|---|---|---|
| | | Utility [b] | Resource [c] | Annual Energy (kWh) | Peak Demand [d] (MW) | | Utility ($/kWh) | Total Resource ($/kWh) |
| **Irrigation** | | | | | | | | |
| Green Motors—Irrigation | 23 motor rewinds | | | 73,617 | | 11 | n/a | n/a |
| Irrigation Efficiency Reward | 851 projects | $ 2,372,352 | $ 8,162,206 | 15,673,513 | | 8 | $ 0.018 | $ 0.063 |
| **Sector Total** | | **$ 2,372,352** | **$ 8,162,206** | **15,747,130** | | **8** | **$ 0.018** | **$ 0.062** |
| **Energy Efficiency Portfolio Total** | | **$ 27,684,239** | **$ 58,169,272** | **146,176,552** | | **12** | **$ 0.017** | **$ 0.036** |
| **Market Transformation** | | | | | | | | |
| Northwest Energy Efficiency Alliance | | $ 2,676,387 | $ 2,676,387 | 24,615,600 | | | | |
| **Other Programs and Activities** | | | | | | | | |
| **Residential** | | | | | | | | |
| Residential Energy Efficiency Education Initiative | | $ 290,179 | $ 290,179 | | | | | |
| Shade Tree Project | 2,070 trees | 76,642 | 76,642 | | | | | |
| **Commercial** | | | | | | | | |
| Oregon Commercial Audits | 7 audits | 7,717 | 7,717 | | | | | |
| **Other** | | | | | | | | |
| Energy Efficiency Direct Program Overhead | | 293,039 | 293,039 | | | | | |
| **Total Program Direct Expense** | | **$ 40,499,570** | **$ 70,984,603** | **170,792,152** | **378** | | | |
| Indirect Program Expenses | | 2,263,893 | | | | | | |
| **Total DSM Expense** | | **$ 42,763,464** | | | | | | |

[a] Levelized Costs are based on financial inputs from Idaho Power's 2013 IRP, and calculations include line-loss adjusted energy savings.

[b] The Total Utility Cost is the cost incurred by Idaho Power to implement and manage a DSM program.

[c] The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.

[d] Demand response program reductions are reported with 9.7-percent peak loss assumptions.

[1] Peak demand is the peak performance of the program during summer 2016.

[2] Savings are preliminary estimates provided by NEEA. Final savings for 2016 will be provided by NEEA May 2017.

## **Appendix 4.** Historical DSM expense and performance, 2002–2016

| Program/Year | Participants | Total Costs | | Savings and Demand Reductions | | | Measure Life (Years) | Levelized Costs [a] | | Program Life Benefit/Cost Ratios [b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost [c] | Resource Cost [d] | Annual Energy (kWh) | Average Energy [e] (aMW) | Peak Demand [f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Demand Response** | | | | | | | | | | | |
| A/C Cool Credit | | | | | | | | | | | |
| 2003 | 204 | $ 275,645 | $ 275,645 | | | 0.0 | | | | | |
| 2004 | 420 | 287,253 | 287,253 | | | 0.5 | | | | | |
| 2005 | 2,369 | 754,062 | 754,062 | | | 3 | | | | | |
| 2006 | 5,369 | 1,235,476 | 1,235,476 | | | 6 | | | | | |
| 2007 | 13,692 | 2,426,154 | 2,426,154 | | | 12 | | | | | |
| 2008 | 20,195 | 2,969,377 | 2,969,377 | | | 26 | | | | | |
| 2009 | 30,391 | 3,451,988 | 3,451,988 | | | 39 | | | | | |
| 2010 | 30,803 | 2,002,546 | 2,002,546 | | | 39 | | | | | |
| 2011 | 37,728 | 2,896,542 | 2,896,542 | | | 24 | | | | | |
| 2012 | 36,454 | 5,727,994 | 5,727,994 | | | 45 | | | | | |
| 2013 | n/a | 663,858 | 663,858 | | | n/a | | | | | |
| 2014 | 29,642 | 1,465,646 | 1,465,646 | | | 44 | | | | | |
| 2015 | 29,000 | 1,148,935 | 1,148,935 | | | 36 | | | | | |
| 2016 | 28,315 | 1,103,295 | 1,103,295 | | | 34 | | | | | |
| **Total** | | **$26,408,770** | **$ 26,408,770** | | | | | | | | |
| Flex Peak Program | | | | | | | | | | | |
| 2009 | 33 | 528,681 | 528,681 | | | 19 | | | | | |
| 2010 | 60 | 1,902,680 | 1,902,680 | | | 48 | | | | | |
| 2011 | 111 | 2,057,730 | 2,057,730 | | | 59 | | | | | |
| 2012 | 102 | 3,009,822 | 3,009,822 | | | 53 | | | | | |
| 2013 | 100 | 2,743,615 | 2,743,615 | | | 48 | | | | | |
| 2014 | 93 | 1,563,211 | 1,563,211 | | | 40 | | | | | |
| 2015 | 72 | 592,872 | 592,872 | | | 26 | | | | | |
| 2016 | 137 | 767,997 | 767,997 | | | 42 | | | | | |
| **Total** | | **$13,166, 608** | **$ 13,166,608** | | | | | | | | |
| Irrigation Peak Rewards | | | | | | | | | | | |
| 2004 | 58 | 344,714 | 344,714 | | | 6 | | | | | |
| 2005 | 894 | 1,468,282 | 1,468,282 | | | 40 | | | | | |
| 2006 | 906 | 1,324,418 | 1,324,418 | | | 32 | | | | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2016 (continued)

| Program/Year | Participants | Total Costs: Utility Cost [c] | Total Costs: Resource Cost [d] | Savings and Demand Reductions: Annual Energy (kWh) | Savings and Demand Reductions: Average Energy [e] (aMW) | Savings and Demand Reductions: Peak Demand [f] (MW) | Measure Life (Years) | Levelized Costs [a]: Total Utility ($/kWh) | Levelized Costs [a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios [b]: Utility | Program Life Benefit/Cost Ratios [b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Demand Response** | | | | | | | | | | | |
| Irrigation Peak Rewards | | | | | | | | | | | |
| 2007 | 947 | $ 1,615,881 | $ 1,615,881 | | | 37 | | | | | |
| 2008 | 897 | 1,431,840 | 1,431,840 | | | 35 | | | | | |
| 2009 | 1,512 | 9,655,283 | 9,655,283 | | | 160 | | | | | |
| 2010 | 2,038 | 13,330,826 | 13,330,826 | | | 250 | | | | | |
| 2011 | 2,342 | 12,086,222 | 12,086,222 | | | 320 | | | | | |
| 2012 | 2,433 | 12,423,364 | 12,423,364 | | | 340 | | | | | |
| 2013 | n/a | 2,072,107 | 2,072,107 | | | n/a | | | | | |
| 2014 | 2,225 | 7,597,213 | 7,597,213 | | | 295 | | | | | |
| 2015 | 2,259 | 7,258,831 | 7,258,831 | | | 305 | | | | | |
| 2016 | 2,286 | 7,600,076 | 7,600,076 | | | 303 | | | | | |
| **Total** | | **$ 78,209,056** | **$ 78,209,056** | | | | | | | | |
| **Residential Efficiency** | | | | | | | | | | | |
| Ductless Heat Pump Pilot | | | | | | | | | | | |
| 2009 | 96 | 202,005 | 451,605 | 409,180 | 0.05 | | 18 | $ 0.031 | $ 0.086 | | |
| 2010 | 104 | 189,231 | 439,559 | 364,000 | 0.04 | | 20 | 0.044 | 0.103 | | |
| 2011 | 131 | 191,183 | 550,033 | 458,500 | 0.05 | | 20 | 0.028 | 0.081 | | |
| 2012 | 127 | 159,867 | 617,833 | 444,500 | 0.05 | | 20 | 0.024 | 0.094 | | |
| 2013 | 215 | 237,575 | 992,440 | 589,142 | 0.07 | | 15 | 0.032 | 0.132 | | |
| 2014 | 179 | 251,446 | 884,211 | 462,747 | 0.05 | | 15 | 0.042 | 0.148 | | |
| **Total** | **852** | **$ 1,231,307** | **$ 3,935,681** | **2,728,069** | | | **15** | **$ 0.044** | **$ 0.138** | | |
| Easy Savings Kits | | | | | | | | | | | |
| 2015 | 2,068 | 127,477 | 127,477 | 624,536 | | | 10 | 0.021 | 0.021 | | |
| 2016 | 2,001 | 127,587 | 127,587 | 402,961 | | | 9 | 0.035 | 0.035 | | |
| **Total** | **4,069** | **$ 255,063** | **$ 255,063** | **1,027,497** | | | **9** | **$0.033** | **$0.033** | **2.24** | **2.24** |
| Educational Distributions | | | | | | | | | | | |
| 2015 | 28,197 | 432,185 | 432,185 | 1,669,495 | | | 10 | 0.026 | 0.026 | | |
| 2016 | 67,065 | 2,392,884 | 2,392,884 | 15,149,605 | | | 10 | 0.016 | 0.016 | | |
| **Total** | | **$ 2,825,069** | **$ 2,825,069** | **16,819,100** | | | **10** | **$0.021** | **$0.021** | **3.41** | **3.41** |

## **Appendix 4.** Historical DSM expense and performance, 2002–2016 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reductions | | | Measure Life (Years) | Levelized Costs [a] | | Program Life Benefit/Cost Ratios [b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost [c] | Resource Cost [d] | Annual Energy (kWh) | Average Energy [e] (aMW) | Peak Demand [f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Residential Efficiency** | | | | | | | | | | | |
| Energy Efficiency Packets | | | | | | | | | | | |
| 2002 | 2,925 | 755 | 755 | 155,757 | | | 7 | 0.001 | 0.001 | | |
| **Total** | **2,925** | **$ 755** | **$ 755** | **155,757** | | | **7** | **$ 0.001** | **$ 0.001** | **4.24** | **2.05** |
| Energy Efficient Lighting | | | | | | | | | | | |
| 2002 | 11,618 | 243,033 | 310,643 | 3,299,654 | 0.38 | | 7 | 0.012 | 0.015 | | |
| 2003 | 12,662 | 314,641 | 464,059 | 3,596,150 | 0.41 | | 7 | 0.014 | 0.021 | | |
| 2004 | | | | | | | | | | | |
| 2005 | 43,760 | 73,152 | 107,810 | 1,734,646 | 0.20 | | 7 | 0.007 | 0.010 | | |
| 2006 | 178,514 | 298,754 | 539,877 | 6,302,794 | 0.72 | | 7 | 0.008 | 0.014 | | |
| 2007 | 219,739 | 557,646 | 433,626 | 7,207,439 | 0.82 | | 7 | 0.012 | 0.017 | | |
| 2008 | 436,234 | 1,018,292 | 793,265 | 14,309,444 | 1.63 | | 7 | 0.011 | 0.013 | | |
| 2009 | 549,846 | 1,207,366 | 1,456,796 | 13,410,748 | 1.53 | | 5 | 0.020 | 0.024 | | |
| 2010 | 1,190,139 | 2,501,278 | 3,976,476 | 28,082,738 | 3.21 | | 5 | 0.020 | 0.031 | | |
| 2011 | 1,039,755 | 1,719,133 | 2,764,623 | 19,694,381 | 2.25 | | 5 | 0.015 | 0.024 | | |
| 2012 | 925,460 | 1,126,836 | 2,407,355 | 16,708,659 | 1.91 | | 5 | 0.012 | 0.025 | | |
| 2013 | 1,085,225 | 1,356,926 | 4,889,501 | 9,995,753 | 1.14 | | 8 | 0.016 | 0.058 | | |
| 2014 | 1,161,553 | 1,909,823 | 7,148,427 | 12,882,151 | 1.47 | | 8 | 0.018 | 0.066 | | |
| 2015 | 1,343,255 | 2,063,383 | 4,428,676 | 15,876,117 | 1.81 | | 10 | 0.013 | 0.028 | | |
| 2016 | 1,442,561 | 3,080,708 | 10,770,703 | 21,093,813 | 2.41 | | 11 | 0.014 | 0.049 | | |
| **Total** | **9,640,321** | **$ 17,470,970** | **$ 40,491,837** | **174,194,487** | | | **8** | **$ 0.012** | **$ 0.027** | **4.32** | **1.87** |
| Energy House Calls | | | | | | | | | | | |
| 2002 | 17 | 26,053 | 26,053 | 25,989 | 0.00 | | 20 | 0.082 | 0.082 | | |
| 2003 | 420 | 167,076 | 167,076 | 602,723 | 0.07 | | 20 | 0.023 | 0.023 | | |
| 2004 | 1,708 | 725,981 | 725,981 | 2,349,783 | 0.27 | | 20 | 0.025 | 0.025 | | |
| 2005 | 891 | 375,610 | 375,610 | 1,775,770 | 0.20 | | 20 | 0.017 | 0.017 | | |
| 2006 | 819 | 336,701 | 336,701 | 777,244 | 0.09 | | 20 | 0.035 | 0.035 | | |
| 2007 | 700 | 336,372 | 336,372 | 699,899 | 0.08 | | 20 | 0.039 | 0.039 | | |
| 2008 | 1,099 | 484,379 | 484,379 | 883,038 | 0.10 | | 20 | 0.045 | 0.045 | | |
| 2009 | 1,266 | 569,594 | 569,594 | 928,875 | 0.11 | | 20 | 0.052 | 0.052 | | |
| 2010 | 1,602 | 762,330 | 762,330 | 1,198,655 | 0.14 | | 20 | 0.054 | 0.054 | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2016 (continued)

| Program/Year | Participants | Total Costs: Utility Cost [c] | Total Costs: Resource Cost [d] | Savings and Demand Reductions: Annual Energy (kWh) | Savings and Demand Reductions: Average Energy [e] (aMW) | Savings and Demand Reductions: Peak Demand [f] (MW) | Measure Life (Years) | Levelized Costs [a]: Total Utility ($/kWh) | Levelized Costs [a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios [b]: Utility | Program Life Benefit/Cost Ratios [b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Efficiency** | | | | | | | | | | | |
| Energy House Calls | | | | | | | | | | | |
| 2011 | 881 | 483,375 | 483,375 | 1,214,004 | 0.14 | | 20 | 0.027 | 0.027 | | |
| 2012 | 668 | 275,884 | 275,884 | 1,192,039 | 0.14 | | 18 | 0.016 | 0.016 | | |
| 2013 | 411 | 199,995 | 199,995 | 837,261 | 0.10 | | 18 | 0.016 | 0.016 | | |
| 2014 | 297 | 197,987 | 197,987 | 579,126 | 0.07 | | 18 | 0.030 | 0.030 | | |
| 2015 | 362 | 214,103 | 214,103 | 754,646 | 0.09 | | 18 | 0.020 | 0.020 | | |
| 2016 | 375 | 206,437 | 206,437 | 509,859 | 0.06 | | 18 | 0.029 | 0.029 | | |
| **Total** | **11,516** | **$ 5,361,876** | **$ 5,361,877** | **14,328,911** | | | **18** | **$ 0.032** | **$ 0.032** | **2.47** | **2.47** |
| ENERGY STAR® Homes Northwest | | | | | | | | | | | |
| 2003 | | 13,597 | 13,597 | 0 | | | | | | | |
| 2004 | 44 | 140,165 | 335,437 | 101,200 | 0.01 | | 25 | 0.103 | 0.246 | | |
| 2005 | 200 | 253,105 | 315,311 | 415,600 | 0.05 | | 25 | 0.045 | 0.056 | | |
| 2006 | 439 | 469,609 | 602,651 | 912,242 | 0.10 | | 25 | 0.038 | 0.049 | | |
| 2007 | 303 | 475,044 | 400,637 | 629,634 | 0.07 | | 25 | 0.056 | 0.047 | | |
| 2008 | 254 | 302,061 | 375,007 | 468,958 | 0.05 | | 25 | 0.048 | 0.059 | | |
| 2009 | 474 | 355,623 | 498,622 | 705,784 | 0.08 | | 25 | 0.039 | 0.055 | | |
| 2010 | 630 | 375,605 | 579,495 | 883,260 | 0.10 | | 25 | 0.033 | 0.051 | | |
| 2011 | 308 | 259,762 | 651,249 | 728,030 | 0.08 | | 32 | 0.020 | 0.051 | | |
| 2012 | 410 | 453,186 | 871,310 | 537,447 | 0.06 | | 35 | 0.046 | 0.089 | | |
| 2013 | 267 | 352,882 | 697,682 | 365,370 | 0.04 | | 36 | 0.053 | 0.104 | | |
| 2014 | 243 | 343,277 | 689,021 | 332,682 | 0.04 | | 36 | 0.055 | 0.111 | | |
| 2015 | 598 | 653,674 | 1,412,126 | 773,812 | 0.09 | | 36 | 0.046 | 0.099 | | |
| 2016 | 110 | 142,158 | 297,518 | 150,282 | 0.02 | | 36 | 0.051 | 0.107 | | |
| **Total** | **4,280** | **$ 4,589,747** | **$ 7,739,664** | **7,004,301** | | | **36** | **$ 0.043** | **$ 0.073** | **2.48** | **1.47** |
| ENERGY STAR Homes Northwest (gas heated) | | | | | | | | | | | |
| 2014 | 282 | | | 195,372 | 0.04 | | 22 | | | | |
| 2015 | 69 | | | 46,872 | 0.09 | | 22 | | | | |
| **Total** | **351** | | | **242,244** | | | | | | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2016 (continued)

| Program/Year | Participants | Total Costs: Utility Cost [c] | Total Costs: Resource Cost [d] | Savings and Demand Reductions: Annual Energy (kWh) | Savings and Demand Reductions: Average Energy [e] (aMW) | Savings and Demand Reductions: Peak Demand [f] (MW) | Measure Life (Years) | Levelized Costs [a]: Total Utility ($/kWh) | Levelized Costs [a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios [b]: Utility | Program Life Benefit/Cost Ratios [b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Efficiency** | | | | | | | | | | | |
| Fridge and Freezer Recycling Program/See ya later, refrigerator® | | | | | | | | | | | |
| 2009 | 1,661 | $ 305,401 | $ 305,401 | 1,132,802 | 0.13 | | 8 | $ 0.041 | $ 0.041 | | |
| 2010 | 3,152 | 565,079 | 565,079 | 1,567,736 | 0.18 | | 8 | 0.054 | 0.054 | | |
| 2011 | 3,449 | 654,393 | 654,393 | 1,712,423 | 0.20 | | 8 | 0.046 | 0.046 | | |
| 2012 | 3,176 | 613,146 | 613,146 | 1,576,426 | 0.18 | | 8 | 0.046 | 0.046 | | |
| 2013 | 3,307 | 589,054 | 589,054 | 1,442,344 | 0.16 | | 6 | 0.061 | 0.061 | | |
| 2014 | 3,194 | 576,051 | 576,051 | 1,390,760 | 0.16 | | 6 | 0.062 | 0.062 | | |
| 2015 | 1,630 | 227,179 | 227,179 | 720,208 | 0.08 | | 6 | 0.048 | 0.048 | | |
| 2016 | 1,539 | 257,916 | 257,916 | 632,186 | 0.07 | | 6 | 0.062 | 0.062 | | |
| **Total** | **21,108** | **$ 3,788,219** | **$ 3,788,219** | **10,174,885** | | | **6** | **$ 0.068** | **$ 0.068** | **1.21** | **1.21** |
| Heating & Cooling Efficiency Program | | | | | | | | | | | |
| 2006 | | 17,444 | 17,444 | | | | | | | | |
| 2007 | 4 | 488,211 | 494,989 | 1,595 | 0.00 | | 18 | 27.344 | 27.710 | | |
| 2008 | 359 | 473,551 | 599,771 | 561,440 | 0.06 | | 18 | 0.073 | 0.092 | | |
| 2009 | 349 | 478,373 | 764,671 | 1,274,829 | 0.15 | | 18 | 0.034 | 0.054 | | |
| 2010 | 217 | 327,669 | 1,073,604 | 1,104,497 | 0.13 | | 20 | 0.025 | 0.083 | | |
| 2011 | 130 | 195,770 | 614,523 | 733,405 | 0.08 | | 20 | 0.018 | 0.056 | | |
| 2012 | 141 | 182,281 | 676,530 | 688,855 | 0.08 | | 20 | 0.018 | 0.066 | | |
| 2013 | 210 | 329,674 | 741,586 | 1,003,730 | 0.11 | | 20 | 0.022 | 0.050 | | |
| 2014 | 230 | 362,014 | 1,247,560 | 1,099,464 | 0.13 | | 20 | 0.022 | 0.075 | | |
| 2015 | 427 | 626,369 | 2,064,055 | 1,502,172 | 0.17 | | 20 | 0.028 | 0.092 | | |
| 2016 | 486 | 594,913 | 1,404,625 | 1,113,574 | 0.13 | | 20 | 0.036 | 0.085 | | |
| **Total** | **2,553** | **$ 4,076,270** | **$ 9,699,358** | **9,083,561** | | | **20** | **$ 0.037** | **$ 0.087** | **2.87** | **1.20** |
| Home Energy Audit | | | | | | | | | | | |
| 2013 | | 88,740 | 88,740 | | | | | | | | |
| 2014 | 354 | 170,648 | 170,648 | 141,077 | | | 10 | | | | |
| 2015 | 351 | 201,957 | 201,957 | 136,002 | | | 10 | | | | |
| 2016 | 539 | 289,812 | 289,812 | 207,249 | | | 11 | | | | |
| **Total** | **1,244** | **$ 751,157** | **$ 776,006** | **483,569** | | | **11** | | | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2016 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reductions | | | Measure Life (Years) | Levelized Costs [a] | | Program Life Benefit/Cost Ratios [b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost [c] | Resource Cost [d] | Annual Energy (kWh) | Average Energy [e] (aMW) | Peak Demand [f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Residential Efficiency** | | | | | | | | | | | |
| Home Improvement | | | | | | | | | | | |
| 2008 | 282 | 123,454 | 157,866 | 317,814 | 0.04 | | 25 | $ 0.029 | $ 0.037 | | |
| 2009 | 1,188 | 321,140 | 550,148 | 1,338,876 | 0.15 | | 25 | 0.019 | 0.032 | | |
| 2010 | 3,537 | 944,716 | 2,112,737 | 3,986,199 | 0.46 | | 45 | 0.016 | 0.035 | | |
| 2011 | 2,275 | 666,041 | 2,704,816 | 917,519 | 0.10 | | 45 | 0.038 | 0.155 | | |
| 2012 | 840 | 385,091 | 812,827 | 457,353 | 0.05 | | 45 | 0.044 | 0.093 | | |
| 2013 | 365 | 299,497 | 1,061,314 | 616,044 | 0.07 | | 45 | 0.025 | 0.090 | | |
| 2014 | 555 | 324,717 | 896,246 | 838,929 | 0.10 | | 45 | 0.020 | 0.055 | | |
| 2015 | 408 | 272,509 | 893,731 | 303,580 | 0.03 | | 45 | 0.046 | 0.152 | | |
| 2016 | 482 | 324,024 | 1,685,301 | 500,280 | 0.06 | | 45 | 0.034 | 0.177 | | |
| **Total** | **9,932** | **$ 3,661,190** | **$ 10,874,986** | **9,267,594** | | | **45** | **$ 0.025** | **$ 0.074** | **4.30** | **1.45** |
| Multifamily Energy Savings Program | | | | | | | | | | | |
| 2016 | 3 | 59,046 | 59,046 | 149,760 | 0.02 | | 10 | 0.040 | 0.040 | | |
| **Total** | **3** | **$ 59,046** | **$ 59,046** | **149,760** | | | **10** | **$ 0. 040** | **$ 0.040** | **1.43** | **1.43** |
| Oregon Residential Weatherization | | | | | | | | | | | |
| 2002 | 24 | (662) | 23,971 | 4,580 | | | 25 | 0.010 | 0.389 | | |
| 2003 | | (943) | | | | | | | | | |
| 2004 | 4 | 1,057 | 1,057 | | | | | | | | |
| 2005 | 4 | 612 | 3,608 | 7,927 | 0.00 | | 25 | 0.006 | 0.034 | | |
| 2006 | | 4,126 | 4,126 | | | | | | | | |
| 2007 | 1 | 3,781 | 5,589 | 9,971 | 0.00 | | 25 | 0.028 | 0.042 | | |
| 2008 | 3 | 7,417 | 28,752 | 22,196 | 0.00 | | 25 | 0.025 | 0.096 | | |
| 2009 | 1 | 7,645 | 8,410 | 2,907 | 0.00 | | 25 | 0.203 | 0.223 | | |
| 2010 | 1 | 6,050 | 6,275 | 320 | 0.00 | | 30 | 0.011 | 0.062 | | |
| 2011 | 8 | 7,926 | 10,208 | 21,908 | 0.00 | | 30 | 0.021 | 0.027 | | |
| 2012 | 5 | 4,516 | 11,657 | 11,985 | 0.00 | | 30 | 0.022 | 0.056 | | |
| 2013 | 14 | 9,017 | 14,369 | 14,907 | 0.00 | | 30 | 0.035 | 0.055 | | |
| 2014 | 13 | 5,462 | 9,723 | 11,032 | 0.00 | | 30 | 0.028 | 0.050 | | |
| 2015 | 19 | 5,808 | 10,388 | 11,910 | 0.00 | | 30 | 0.028 | 0.050 | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2016 (continued)

| Program/Year | Participants | Total Costs: Utility Cost [c] | Total Costs: Resource Cost [d] | Savings and Demand Reductions: Annual Energy (kWh) | Savings and Demand Reductions: Average Energy [e] (aMW) | Savings and Demand Reductions: Peak Demand [f] (MW) | Measure Life (Years) | Levelized Costs [a]: Total Utility ($/kWh) | Levelized Costs [a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios [b]: Utility | Program Life Benefit/Cost Ratios [b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Residential Efficiency** | | | | | | | | | | | |
| Oregon Residential Weatherization | | | | | | | | | | | |
| 2016 | 7 | $ 3,930 | $ 5,900 | 2,847 | 0.00 | | 30 | $ 0.079 | $ 0.118 | | |
| **Total** | **89** | **$ 65,742** | **$ 144,033** | **122,490** | | | **30** | **$ 0.037** | **$ 0.082** | **2.94** | **1.34** |
| Rebate Advantage | | | | | | | | | | | |
| 2003 | 73 | 27,372 | 79,399 | 227,434 | 0.03 | | 45 | 0.008 | 0.022 | | |
| 2004 | 105 | 52,187 | 178,712 | 332,587 | 0.04 | | 45 | 0.010 | 0.034 | | |
| 2005 | 98 | 46,173 | 158,462 | 312,311 | 0.04 | | 45 | 0.009 | 0.032 | | |
| 2006 | 102 | 52,673 | 140,289 | 333,494 | 0.04 | | 45 | 0.010 | 0.027 | | |
| 2007 | 123 | 89,269 | 182,152 | 554,018 | 0.06 | | 45 | 0.010 | 0.021 | | |
| 2008 | 107 | 90,888 | 179,868 | 463,401 | 0.05 | | 45 | 0.012 | 0.025 | | |
| 2009 | 57 | 49,525 | 93,073 | 247,348 | 0.03 | | 25 | 0.015 | 0.029 | | |
| 2010 | 35 | 39,402 | 66,142 | 164,894 | 0.02 | | 25 | 0.018 | 0.031 | | |
| 2011 | 25 | 63,469 | 85,044 | 159,325 | 0.02 | | 25 | 0.024 | 0.033 | | |
| 2012 | 35 | 37,241 | 71,911 | 187,108 | 0.02 | | 25 | 0.012 | 0.024 | | |
| 2013 | 42 | 60,770 | 92,690 | 269,891 | 0.03 | | 25 | 0.014 | 0.021 | | |
| 2014 | 44 | 63,231 | 89,699 | 269,643 | 0.03 | | 25 | 0.014 | 0.020 | | |
| 2015 | 58 | 85,438 | 117,322 | 358,683 | 0.04 | | 25 | 0.014 | 0.020 | | |
| 2016 | 66 | 111,050 | 148,142 | 411,272 | 0.05 | | 25 | 0.016 | 0.022 | | |
| **Total** | **970** | **$ 868,688** | **$ 1,682,906** | **4,291,409** | | | **25** | **$ 0.015** | **$ 0.029** | **7.40** | **3.82** |
| Simple Steps Smart Savings | | | | | | | | | | | |
| 2007 | | 9,275 | 9,275 | 0 | | | | | | | |
| 2008 | 3,034 | 250,860 | 468,056 | 541,615 | 0.06 | | 15 | 0.044 | 0.082 | | |
| 2009 | 9,499 | 511,313 | 844,811 | 1,638,038 | 0.19 | | 15 | 0.031 | 0.051 | | |
| 2010 | 16,322 | 832,161 | 1,025,151 | 1,443,580 | 0.16 | | 15 | 0.057 | 0.070 | | |
| 2011 | 15,896 | 638,323 | 1,520,977 | 1,485,326 | 0.17 | | 15 | 0.034 | 0.080 | | |
| 2012 | 16,675 | 659,032 | 817,924 | 887,222 | 0.10 | | 14 | 0.061 | 0.075 | | |
| 2013 | 13,792 | 405,515 | 702,536 | 885,980 | 0.10 | | 12 | 0.041 | 0.071 | | |
| 2014 | 10,061 | 227,176 | 302,289 | 652,129 | 0.07 | | 12 | 0.031 | 0.041 | | |
| 2015 | 9,343 | 139,096 | 408,032 | 770,822 | 0.09 | | 10 | 0.018 | 0.053 | | |
| 2016 | 7,880 | 153,784 | 379,752 | 577,320 | 0.07 | | 11 | 0.025 | 0.063 | | |
| **Total** | **102,502** | **$ 3,826,535** | **$ 6,468,669** | **8,882,032** | | | **11** | **$ 0.050** | **$ 0.085** | **1.93** | **1.14** |

## **Appendix 4.** Historical DSM expense and performance, 2002–2016 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reductions | | | Measure Life (Years) | Levelized Costs [a] | | Program Life Benefit/Cost Ratios [b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost [c] | Resource Cost [d] | Annual Energy (kWh) | Average Energy [e] (aMW) | Peak Demand [f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Residential Efficiency** | | | | | | | | | | | |
| Weatherization Solutions for Eligible Customers | | | | | | | | | | | |
| 2008 | 16 | 52,807 | 52,807 | 71,680 | 0.01 | | 25 | 0.057 | 0.057 | | |
| 2009 | 41 | 162,995 | 162,995 | 211,719 | 0.02 | | 25 | 0.059 | 0.059 | | |
| 2010 | 47 | 228,425 | 228,425 | 313,309 | 0.04 | | 25 | 0.056 | 0.056 | | |
| 2011 | 117 | 788,148 | 788,148 | 1,141,194 | 0.13 | | 25 | 0.042 | 0.042 | | |
| 2012 | 141 | 1,070,556 | 1,070,556 | 257,466 | 0.03 | | 25 | 0.254 | 0.254 | | |
| 2013 | 166 | 1,267,791 | 1,267,791 | 303,116 | 0.03 | | 25 | 0.240 | 0.240 | | |
| 2014 | 118 | 791,344 | 791,344 | 290,926 | 0.03 | | 25 | 0.163 | 0.163 | | |
| 2015 | 171 | 1,243,269 | 1,243,269 | 432,958 | 0.05 | | 25 | 0.175 | 0.175 | | |
| 2016 | 232 | 1,323,793 | 1,323,793 | 621,653 | 0.07 | | 25 | 0.130 | 0.130 | | |
| **Total** | **1,049** | **$ 6,929,127** | **$ 6,929,128** | **3,644,021** | | | **30** | **$ 0.132** | **$ 0.132** | **0.74** | **0.74** |
| Window AC Trade-Up Pilot | | | | | | | | | | | |
| 2003 | 99 | 6,687 | 10,492 | 14,454 | | | 12 | 0.051 | 0.079 | | |
| **Total** | **99** | **$ 6,687** | **$ 10,492** | **14,454** | | | **12** | **$ 0.051** | **$ 0.079** | | |
| **Residential—Weatherization Assistance for Qualified Customers (WAQC)** | | | | | | | | | | | |
| WAQC—Idaho | | | | | | | | | | | |
| 2002 | 197 | 235,048 | 492,139 | | | | | | | | |
| 2003 | 208 | 228,134 | 483,369 | | | | | | | | |
| 2004 | 269 | 498,474 | 859,482 | 1,271,677 | 0.15 | | 25 | 0.029 | 0.050 | | |
| 2005 | 570 | 1,402,487 | 1,927,424 | 3,179,311 | 0.36 | | 25 | 0.033 | 0.045 | | |
| 2006 | 540 | 1,455,373 | 2,231,086 | 2,958,024 | 0.34 | | 25 | 0.037 | 0.056 | | |
| 2007 | 397 | 1,292,930 | 1,757,105 | 3,296,019 | 0.38 | | 25 | 0.029 | 0.040 | | |
| 2008 | 439 | 1,375,632 | 1,755,749 | 4,064,301 | 0.46 | | 25 | 0.025 | 0.032 | | |
| 2009 | 427 | $ 1,260,922 | $ 1,937,578 | 4,563,832 | 0.52 | | 25 | 0.021 | 0.033 | | |
| 2010 | 373 | 1,205,446 | 2,782,597 | 3,452,025 | 0.39 | | 25 | 0.026 | 0.060 | | |
| 2011 | 273 | 1,278,112 | 1,861,836 | 2,648,676 | 0.30 | | 25 | 0.036 | 0.053 | | |
| 2012 | 228 | 1,321,927 | 1,743,863 | 621,464 | 0.07 | | 25 | 0.159 | 0.210 | | |
| 2013 | 245 | 1,336,742 | 1,984,173 | 657,580 | 0.08 | | 25 | 0.152 | 0.226 | | |
| 2014 | 244 | 1,267,212 | 1,902,615 | 509,620 | 0.06 | | 25 | 0.185 | 0.277 | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2016 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reductions | | | Measure Life (Years) | Levelized Costs [a] | | Program Life Benefit/Cost Ratios [b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost [c] | Resource Cost [d] | Annual Energy (kWh) | Average Energy [e] (aMW) | Peak Demand [f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Residential—(WAQC)** | | | | | | | | | | | |
| WAQC—Idaho | | | | | | | | | | | |
| 2015 | 233 | $ 1,278,159 | $ 2,072,901 | 529,426 | 0.06 | | 25 | $ 0.179 | $ 0.291 | | |
| 2016 | 234 | 1,254,338 | 1,870,481 | 722,430 | 0.08 | | 25 | 0.129 | 0.192 | | |
| **Total** | **4,877** | **$ 16,690,936** | **$ 25,662,398** | **28,474,386** | | | **25** | **$ 0.043** | **$ 0.067** | **2.79** | **1.82** |
| WAQC—Oregon | | | | | | | | | | | |
| 2002 | 31 | 24,773 | 47,221 | 68,323 | 0.01 | | 25 | 0.027 | 0.051 | | |
| 2003 | 29 | 22,255 | 42,335 | 102,643 | 0.01 | | 25 | 0.016 | 0.031 | | |
| 2004 | 17 | 13,469 | 25,452 | 28,436 | 0.00 | | 25 | 0.035 | 0.067 | | |
| 2005 | 28 | 44,348 | 59,443 | 94,279 | 0.01 | | 25 | 0.035 | 0.047 | | |
| 2006 | | | | | | | 25 | | | | |
| 2007 | 11 | 30,694 | 41,700 | 42,108 | 0.00 | | 25 | 0.054 | 0.074 | | |
| 2008 | 14 | 43,843 | 74,048 | 73,841 | 0.01 | | 25 | 0.040 | 0.068 | | |
| 2009 | 10 | 33,940 | 46,513 | 114,982 | 0.01 | | 25 | 0.023 | 0.031 | | |
| 2010 | 27 | 115,686 | 147,712 | 289,627 | 0.03 | | 25 | 0.030 | 0.038 | | |
| 2011 | 14 | 46,303 | 63,981 | 134,972 | 0.02 | | 25 | 0.026 | 0.035 | | |
| 2012 | 10 | 48,214 | 76,083 | 26,840 | 0.00 | | 25 | 0.134 | 0.212 | | |
| 2013 | 9 | 54,935 | 67,847 | 24,156 | 0.00 | | 25 | 0.170 | 0.210 | | |
| 2014 | 11 | 52,900 | 94,493 | 24,180 | 0.00 | | 25 | 0.162 | 0.290 | | |
| 2015 | 10 | 36,873 | 46,900 | 20,595 | 0.00 | | 25 | 0.133 | 0.169 | | |
| 2016 | 12 | 35,471 | 63,934 | 23,732 | 0.00 | | 25 | 0.111 | 0.200 | | |
| **Total** | **233** | **$ 603,703** | **$ 897,662** | **1,068,714** | | | **25** | **$ 0.042** | **$ 0.062** | **2.79** | **1.87** |
| WAQC—BPA Supplemental | | | | | | | | | | | |
| 2002 | 75 | 55,966 | 118,255 | 311,347 | 0.04 | | 25 | 0.013 | 0.028 | | |
| 2003 | 57 | 49,895 | 106,915 | 223,591 | 0.03 | | 25 | 0.017 | 0.036 | | |
| 2004 | 40 | 69,409 | 105,021 | 125,919 | 0.01 | | 25 | 0.041 | 0.062 | | |
| **Total** | **172** | **$ 175,270** | **$ 330,191** | **660,857** | | | **25** | **$ 0.020** | **$ 0.037** | **5.75** | **3.05** |
| **WAQC Total** | | **$ 17,469,910** | **$ 26,890,251** | **30,203,957** | | | **25** | **$ 0.043** | **$ 0.066** | **2.83** | **1.84** |

## **Appendix 4.** Historical DSM expense and performance, 2002–2016 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reductions | | | Measure Life (Years) | Levelized Costs [a] | | Program Life Benefit/Cost Ratios [b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost [c] | Resource Cost [d] | Annual Energy (kWh) | Average Energy [e] (aMW) | Peak Demand [f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Commercial** | | | | | | | | | | | |
| Air Care Plus Pilot | | | | | | | | | | | |
| 2003 | 4 | $ 5,764 | $ 9,061 | 33,976 | | | 10 | $ 0.021 | $ 0.033 | | |
| 2004 | | 344 | 344 | | | | | | | | |
| **Total** | **4** | **$ 6,108** | **$ 9,405** | **33,976** | | | **10** | **$ 0.022** | **$ 0.034** | | |
| New Construction (Building Efficiency) | | | | | | | | | | | |
| 2004 | | 28,821 | 28,821 | | | | | | | | |
| 2005 | 12 | 194,066 | 233,149 | 494,239 | 0.06 | 0.2 | 12 | 0.043 | 0.052 | | |
| 2006 | 40 | 374,008 | 463,770 | 704,541 | 0.08 | 0.3 | 12 | 0.058 | 0.072 | | |
| 2007 | 22 | 669,032 | 802,839 | 2,817,248 | 0.32 | 0.5 | 12 | 0.015 | 0.040 | | |
| 2008 | 60 | 1,055,009 | 1,671,375 | 6,598,123 | 0.75 | 1.0 | 12 | 0.017 | 0.028 | | |
| 2009 | 72 | 1,327,127 | 2,356,434 | 6,146,139 | 0.70 | 1.3 | 12 | 0.024 | 0.043 | | |
| 2010 | 70 | 1,509,682 | 3,312,963 | 10,819,598 | 1.24 | 0.9 | 12 | 0.016 | 0.035 | | |
| 2011 | 63 | 1,291,425 | 3,320,015 | 11,514,641 | 1.31 | 0.9 | 12 | 0.010 | 0.026 | | |
| 2012 | 84 | 1,592,572 | 8,204,883 | 20,450,037 | 2.33 | 0.6 | 12 | 0.007 | 0.036 | | |
| 2013 | 59 | 1,507,035 | 3,942,880 | 10,988,934 | 1.25 | 1.1 | 12 | 0.012 | 0.032 | | |
| 2014 | 69 | 1,258,273 | 3,972,822 | 9,458,059 | 1.08 | 1.2 | 12 | 0.012 | 0.037 | | |
| 2015 | 81 | 2,162,001 | 6,293,071 | 23,232,017 | 2.65 | | 12 | 0.008 | 0.024 | | |
| 2016 | 116 | 1,931,222 | 4,560,826 | 12,393,249 | 1.41 | | 12 | 0.014 | 0.033 | | |
| **Total** | **748** | **$ 14,900,273** | **$ 39,163,849** | **115,616,825** | | | **12** | **$ 0.014** | **$ 0.037** | **5.55** | **2.11** |
| Retrofits (Easy Upgrades) | | | | | | | | | | | |
| 2006 | | 31,819 | 31,819 | | | | | | | | |
| 2007 | 104 | 711,494 | 1,882,035 | 5,183,640 | 0.59 | 0.8 | 12 | 0.015 | 0.040 | | |
| 2008 | 666 | 2,992,261 | 10,096,627 | 25,928,391 | 2.96 | 4.5 | 12 | 0.013 | 0.043 | | |
| 2009 | 1,224 | 3,325,505 | 10,076,237 | 35,171,627 | 4.02 | 6.1 | 12 | 0.011 | 0.032 | | |
| 2010 | 1,535 | 3,974,410 | 7,655,397 | 35,824,463 | 4.09 | 7.8 | 12 | 0.013 | 0.024 | | |
| 2011 | 1,732 | 4,719,466 | 9,519,364 | 38,723,073 | 4.42 | | 12 | 0.011 | 0.022 | | |
| 2012 | 1,838 | 5,349,753 | 9,245,297 | 41,568,672 | 4.75 | | 12 | 0.012 | 0.020 | | |
| 2013 | 1,392 | 3,359,790 | 6,738,645 | 21,061,946 | 2.40 | | 12 | 0.014 | 0.029 | | |
| 2014 | 1,095 | 3,150,942 | 5,453,380 | 19,118,494 | 2.18 | | 12 | 0.015 | 0.025 | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2016 (continued)

| Program/Year | Participants | Total Costs: Utility Cost [c] | Total Costs: Resource Cost [d] | Savings and Demand Reductions: Annual Energy (kWh) | Savings and Demand Reductions: Average Energy [e] (aMW) | Savings and Demand Reductions: Peak Demand [f] (MW) | Measure Life (Years) | Levelized Costs [a]: Total Utility ($/kWh) | Levelized Costs [a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios [b]: Utility | Program Life Benefit/Cost Ratios [b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Commercial** | | | | | | | | | | | |
| Retrofits (Easy Upgrades) | | | | | | | | | | | |
| 2015 | 1,222 | $ 4,350,865 | $ 7,604,200 | 23,594,701 | 2.69 | | 12 | $ 0.017 | $ 0.029 | | |
| 2016 | 1,577 | 5,040,190 | 8,038,791 | 28,124,779 | 3.21 | | 12 | 0.016 | 0.026 | | |
| **Total** | **12,385** | **$ 37,006,495** | **$ 76,341,791** | **274,299,786** | | | **12** | **$ 0.015** | **$ 0.031** | **5.36** | **2.60** |
| Holiday Lighting | | | | | | | | | | | |
| 2008 | 14 | 28,782 | 73,108 | 259,092 | 0.03 | | 10 | 0.014 | 0.035 | | |
| 2009 | 32 | 33,930 | 72,874 | 142,109 | 0.02 | | 10 | 0.031 | 0.066 | | |
| 2010 | 25 | 46,132 | 65,308 | 248,865 | 0.03 | | 10 | 0.024 | 0.034 | | |
| 2011 | 6 | 2,568 | 2,990 | 66,189 | 0.01 | | 10 | 0.004 | 0.005 | | |
| **Total** | **77** | **$ 111,412** | **$ 214,280** | **716,255** | | | **10** | **$ 0.019** | **$ 0.037** | **2.89** | **1.50** |
| Oregon Commercial Audit | | | | | | | | | | | |
| 2002 | 24 | 5,200 | 5,200 | | | | | | | | |
| 2003 | 21 | 4,000 | 4,000 | | | | | | | | |
| 2004 | 7 | 0 | 0 | | | | | | | | |
| 2005 | 7 | 5,450 | 5,450 | | | | | | | | |
| 2006 | 6 | | | | | | | | | | |
| 2007 | | 1,981 | 1,981 | | | | | | | | |
| 2008 | | 58 | 58 | | | | | | | | |
| 2009 | 41 | 20,732 | 20,732 | | | | | | | | |
| 2010 | 22 | 5,049 | 5,049 | | | | | | | | |
| 2011 | 12 | 13,597 | 13,597 | | | | | | | | |
| 2012 | 14 | 12,470 | 12,470 | | | | | | | | |
| 2013 | 18 | 5,090 | 5,090 | | | | | | | | |
| 2014 | 16 | 9,464 | 9,464 | | | | | | | | |
| 2015 | 17 | 4,251 | 4,251 | | | | | | | | |
| 2016 | 7 | 7,717 | 7,717 | | | | | | | | |
| **Total** | **212** | **$ 95,059** | **$ 95,059** | | | | | | | | |
| Oregon School Efficiency | | | | | | | | | | | |
| 2005 | | 86 | 86 | | | | | | | | |
| 2006 | 6 | 24,379 | 89,771 | 223,368 | 0.03 | | 12 | $ 0.012 | $ 0.044 | | |
| **Total** | **6** | **$ 24,465** | **$ 89,857** | **223,368** | | | **12** | **$ 0.012** | **$ 0.044** | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2016 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reductions | | | Measure Life (Years) | Levelized Costs [a] | | Program Life Benefit/Cost Ratios [b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost [c] | Resource Cost [d] | Annual Energy (kWh) | Average Energy [e] (aMW) | Peak Demand [f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Industrial** | | | | | | | | | | | |
| Custom Projects (Custom Efficiency) | | | | | | | | | | | |
| 2003 | | $ 1,303 | $ 1,303 | | | | | | | | |
| 2004 | 1 | 112,311 | 133,441 | 211,295 | 0.02 | | 12 | $ 0.058 | $ 0.069 | | |
| 2005 | 24 | 1,128,076 | 3,653,152 | 12,016,678 | 1.37 | | 12 | 0.010 | 0.033 | | |
| 2006 | 40 | 1,625,216 | 4,273,885 | 19,211,605 | 2.19 | | 12 | 0.009 | 0.024 | | |
| 2007 | 49 | 3,161,866 | 7,012,686 | 29,789,304 | 3.40 | 3.6 | 12 | 0.012 | 0.026 | | |
| 2008 | 101 | 4,045,671 | 16,312,379 | 41,058,639 | 4.69 | 4.8 | 12 | 0.011 | 0.044 | | |
| 2009 | 132 | 6,061,467 | 10,848,123 | 51,835,612 | 5.92 | 6.7 | 12 | 0.013 | 0.024 | | |
| 2010 | 223 | 8,778,125 | 17,172,176 | 71,580,075 | 8.17 | 9.5 | 12 | 0.014 | 0.027 | | |
| 2011 | 166 | 8,783,811 | 19,830,834 | 67,979,157 | 7.76 | 7.8 | 12 | 0.012 | 0.026 | | |
| 2012 | 126 | 7,092,581 | 12,975,629 | 54,253,106 | 6.19 | 7.6 | 12 | 0.012 | 0.021 | | |
| 2013 | 73 | 2,466,225 | 5,771,640 | 21,370,350 | 2.43 | 2.4 | 12 | 0.010 | 0.024 | | |
| 2014 | 131 | 7,173,054 | 13,409,922 | 50,363,052 | 5.75 | 5.6 | 12 | 0.013 | 0.024 | | |
| 2015 | 160 | 9,012,628 | 20,533,742 | 55,247,192 | 6.31 | | 11 | 0.016 | 0.035 | | |
| 2016 | 196 | 7,982,624 | 16,123,619 | 47,518,871 | 5.42 | | 16 | 0.013 | 0.026 | | |
| **Total** | **1,422** | **$ 67,424,957** | **$148,052,531** | **522,434,936** | | | **12** | **$ 0.014** | **$ 0.031** | **5.75** | **2.62** |
| **Irrigation** | | | | | | | | | | | |
| Irrigation Efficiency Rewards | | | | | | | | | | | |
| 2003 | 2 | $ 41,089 | $ 54,609 | 36,792 | 0.00 | 0.0 | 15 | $ 0.106 | $ 0.141 | | |
| 2004 | 33 | 120,808 | 402,978 | 802,812 | 0.09 | 0.4 | 15 | 0.014 | 0.048 | | |
| 2005 | 38 | 150,577 | 657,460 | 1,012,883 | 0.12 | 0.4 | 15 | 0.014 | 0.062 | | |
| 2006 | 559 | 2,779,620 | 8,514,231 | 16,986,008 | 1.94 | 5.1 | 8 | 0.024 | 0.073 | | |
| 2007 | 816 | 2,001,961 | 8,694,772 | 12,304,073 | 1.40 | 3.4 | 8 | 0.024 | 0.103 | | |
| 2008 | 961 | 2,103,702 | 5,850,778 | 11,746,395 | 1.34 | 3.5 | 8 | 0.026 | 0.073 | | |
| 2009 | 887 | 2,293,896 | 6,732,268 | 13,157,619 | 1.50 | 3.4 | 8 | 0.026 | 0.077 | | |
| 2010 | 753 | 2,200,814 | 6,968,598 | 10,968,430 | 1.25 | 3.3 | 8 | 0.030 | 0.096 | | |
| 2011 | 880 | 2,360,304 | 13,281,492 | 13,979,833 | 1.60 | 3.8 | 8 | 0.020 | 0.113 | | |
| 2012 | 908 | 2,373,201 | 11,598,185 | 12,617,164 | 1.44 | 3.1 | 8 | 0.022 | 0.110 | | |
| 2013 | 995 | 2,441,386 | 15,223,928 | 18,511,221 | 2.11 | 3.0 | 8 | 0.016 | 0.098 | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2016 (continued)

| Program/Year | Participants | Total Costs: Utility Cost [c] | Total Costs: Resource Cost [d] | Savings and Demand Reductions: Annual Energy (kWh) | Savings and Demand Reductions: Average Energy [e] (aMW) | Savings and Demand Reductions: Peak Demand [f] (MW) | Measure Life (Years) | Levelized Costs [a]: Total Utility ($/kWh) | Levelized Costs [a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios [b]: Utility | Program Life Benefit/Cost Ratios [b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Irrigation** | | | | | | | | | | | |
| Irrigation Efficiency Rewards | | | | | | | | | | | |
| 2014 | 1,128 | $ 2,446,507 | $ 18,459,781 | 18,463,611 | 2.11 | 4.6 | 8 | $ 0.016 | $ 0.119 | | |
| 2015 | 902 | 1,835,711 | 9,939,842 | 14,027,411 | 1.60 | 1.6 | 8 | 0.016 | 0.085 | | |
| 2016 | 851 | 2,372,352 | 8,162,206 | 15,673,513 | 1.79 | | 8 | 0.018 | 0.063 | | |
| **Total** | **9,713** | **$ 25,521,929** | **$114,541,128** | **160,287,765** | | | **8** | **$ 0.023** | **$ 0.105** | **4.93** | **1.61** |
| **Other Programs** | | | | | | | | | | | |
| Building Operator Training | | | | | | | | | | | |
| 2003 | 71 | $ 48,853 | $ 48,853 | 1,825,000 | 0.21 | | 5 | $ 0.006 | $ 0.006 | | |
| 2004 | 26 | 43,969 | 43,969 | 650,000 | 0.07 | | 5 | 0.014 | 0.014 | | |
| 2005 | 7 | 1,750 | 4,480 | 434,167 | 0.05 | | 5 | 0.001 | 0.002 | | |
| **Total** | **104** | **$ 94,572** | **$ 97,302** | **2,909,167** | | | **5** | **$ 0.007** | **$ 0.007** | | |
| Commercial Education Initiative | | | | | | | | | | | |
| 2005 | | 3,497 | 3,497 | | | | | | | | |
| 2006 | | 4,663 | 4,663 | | | | | | | | |
| 2007 | | 26,823 | 26,823 | | | | | | | | |
| 2008 | | 72,738 | 72,738 | | | | | | | | |
| 2009 | | 120,584 | 120,584 | | | | | | | | |
| 2010 | | 68,765 | 68,765 | | | | | | | | |
| 2011 | | 89,856 | 89,856 | | | | | | | | |
| 2012 | | 73,788 | 73,788 | | | | | | | | |
| 2013 | | 66,790 | 66,790 | | | | | | | | |
| 2014 | | 76,606 | 76,606 | | | | | | | | |
| 2015 | | 65,250 | 65,250 | | | | | | | | |
| **Total** | | **$ 669,360** | **$ 669,360** | | | | | | | | |
| Comprehensive Lighting | | | | | | | | | | | |
| 2011 | | 2,404 | 2,404 | | | | | | | | |
| 2012 | | 64,094 | 64,094 | | | | | | | | |
| **Total** | | **$ 66,498** | **$ 66,498** | | | | | | | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2016 (continued)

| Program/Year | Participants | Total Costs: Utility Cost [c] | Total Costs: Resource Cost [d] | Savings and Demand Reductions: Annual Energy (kWh) | Savings and Demand Reductions: Average Energy [e] (aMW) | Savings and Demand Reductions: Peak Demand [f] (MW) | Measure Life (Years) | Levelized Costs [a]: Total Utility ($/kWh) | Levelized Costs [a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios [b]: Utility | Program Life Benefit/Cost Ratios [b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Other Programs** | | | | | | | | | | | |
| Distribution Efficiency Initiative | | | | | | | | | | | |
| 2005 | | 21,552 | 43,969 | | | | | | | | |
| 2006 | | 24,306 | 24,306 | | | | | | | | |
| 2007 | | 8,987 | 8,987 | | | | | | | | |
| 2008 | | (1,913) | (1,913) | | | | | | | | |
| **Total** | | **$ 52,932** | **$ 75,349** | | | | | | | | |
| DSM Direct Program Overhead | | | | | | | | | | | |
| 2007 | | $ 56,909 | $ 56,909 | | | | | | | | |
| 2008 | | 169,911 | 169,911 | | | | | | | | |
| 2009 | | 164,957 | 164,957 | | | | | | | | |
| 2010 | | 117,874 | 117,874 | | | | | | | | |
| 2011 | | 210,477 | 210,477 | | | | | | | | |
| 2012 | | 285,951 | 285,951 | | | | | | | | |
| 2013 | | 380,957 | 380,957 | | | | | | | | |
| 2014 | | 478,658 | 478,658 | | | | | | | | |
| 2015 | | 272,858 | 272,858 | | | | | | | | |
| 2016 | | 293,039 | 293,039 | | | | | | | | |
| **Total** | | **$ 2,431,591** | **$ 2,431,591** | | | | | | | | |
| Green Motors Rewind—Industrial | | | | 123,700 | | | 7 | | | | |
| 2016 | | | | | | | | | | | |
| **Total** | | | | **123,700** | | | **7** | | | **n/a** | **n/a** |
| Green Motors Rewind—Irrigation | | | | 73,617 | | | 19 | | | | |
| 2016 | | | | | | | | | | | |
| **Total** | | | | **73,617** | | | **19** | | | **n/a** | **n/a** |
| Local Energy Efficiency Fund | | | | | | | | | | | |
| 2003 | 56 | 5,100 | 5,100 | | | | | | | | |
| 2004 | | 23,449 | 23,449 | | | | | | | | |
| 2005 | 2 | 14,896 | 26,756 | 78,000 | 0.01 | | 10 | $ 0.024 | $ 0.042 | | |
| 2006 | 480 | 3,459 | 3,459 | 19,027 | 0.00 | | 7 | 0.009 | 0.009 | | |
| 2007 | 1 | 7,520 | 7,520 | 9,000 | 0.00 | | 7 | 0.135 | 0.135 | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2016 (continued)

| Program/Year | Participants | Total Costs: Utility Cost [c] | Total Costs: Resource Cost [d] | Savings and Demand Reductions: Annual Energy (kWh) | Savings and Demand Reductions: Average Energy [e] (aMW) | Savings and Demand Reductions: Peak Demand [f] (MW) | Measure Life (Years) | Levelized Costs [a]: Total Utility ($/kWh) | Levelized Costs [a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios [b]: Utility | Program Life Benefit/Cost Ratios [b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Other Programs** | | | | | | | | | | | |
| Local Energy Efficiency Fund | | | | | | | | | | | |
| 2008 | 2 | 22,714 | 60,100 | 115,931 | 0.01 | | 15 | 0.019 | 0.049 | | |
| 2009 | 1 | 5,870 | 4,274 | 10,340 | 0.00 | | 12 | 0.064 | 0.047 | | |
| 2010 | 1 | 251 | 251 | | 0.00 | | | | | | |
| 2011 | 1 | 1,026 | 2,052 | 2,028 | | | 30 | 0.036 | 0.071 | | |
| 2012 | | | | | | | | | | | |
| 2013 | | | | | | | | | | | |
| 2014 | 1 | 9,100 | 9,100 | 95,834 | | | 18 | | | | |
| **Total** | **545** | **$ 93,385** | **$ 142,061** | **330,160** | | | **14** | **$ 0.028** | **$ 0.043** | **2.80** | **1.84** |
| Other C&RD and CRC BPA | | | | | | | | | | | |
| 2002 | | $ 55,722 | $ 55,722 | | | | | | | | |
| 2003 | | 67,012 | 67,012 | | | | | | | | |
| 2004 | | 108,191 | 108,191 | | | | | | | | |
| 2005 | | 101,177 | 101,177 | | | | | | | | |
| 2006 | | 124,956 | 124,956 | | | | | | | | |
| 2007 | | 31,645 | 31,645 | | | | | | | | |
| 2008 | | 6,950 | 6,950 | | | | | | | | |
| **Total** | | **$ 495,654** | **$ 495,654** | | | | | | | | |
| Residential Economizer Pilot | | | | | | | | | | | |
| 2011 | | 101,713 | 101,713 | | | | | | | | |
| 2012 | | 93,491 | 93,491 | | | | | | | | |
| 2013 | | 74,901 | 74,901 | | | | | | | | |
| **Total** | | **$ 270,105** | **$ 270,105** | | | | | | | | |
| Residential Education Initiative | | | | | | | | | | | |
| 2005 | | 7,498 | 7,498 | | | | | | | | |
| 2006 | | 56,727 | 56,727 | | | | | | | | |
| 2007 | | | | | | | | | | | |
| 2008 | | 150,917 | 150,917 | | | | | | | | |
| 2009 | | 193,653 | 193,653 | | | | | | | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2016 (continued)

| Program/Year | Participants | Total Costs: Utility Cost [c] | Total Costs: Resource Cost [d] | Savings and Demand Reductions: Annual Energy (kWh) | Savings and Demand Reductions: Average Energy [e] (aMW) | Savings and Demand Reductions: Peak Demand [f] (MW) | Measure Life (Years) | Levelized Costs [a]: Total Utility ($/kWh) | Levelized Costs [a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios [b]: Utility | Program Life Benefit/Cost Ratios [b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Other Programs** | | | | | | | | | | | |
| Residential Education Initiative | | | | | | | | | | | |
| 2010 | | $ 222,092 | $ 222,092 | | | | | | | | |
| 2011 | | 159,645 | 159,645 | | | | | | | | |
| 2012 | | 174,738 | 174,738 | | | | | | | | |
| 2013 | | 416,166 | 416,166 | | | | | | | | |
| 2014 | 6,312 | 423,091 | 423,091 | 1,491,225 | | | 10 | | | | |
| 2015 | | 149,903 | 149,903 | | | | | | | | |
| 2016 | | 290,179 | 290,179 | | | | | | | | |
| **Total** | **6,312** | **$ 2,244,609** | **$ 2,244,609** | **1,491,225** | | | **10** | | | | |
| Shade Tree Project | | | | | | | | | | | |
| 2014 | 2,041 | 147,290 | 147,290 | | | | | | | | |
| 2015 | 1,925 | 105,392 | 105,392 | | | | | | | | |
| 2016 | 2,070 | 76,642 | 76,642 | | | | | | | | |
| **Total** | **6,036** | **$ 329,324** | **$ 329,324** | | | | | | | | |
| Solar 4R Schools | | | | | | | | | | | |
| 2009 | | 42,522 | 42,522 | | | | | | | | |
| **Total** | | **$ 42,522** | **$ 42,522** | | | | | | | | |
| **Market Transformation** | | | | | | | | | | | |
| Consumer Electronic Initiative | | | | | | | | | | | |
| 2002 | | 160,762 | 160,762 | | | | | | | | |
| **Total** | | **$ 160,762** | **$ 160,762** | | | | | | | | |
| NEEA | | | | | | | | | | | |
| 2002 | | 1,286,632 | 1,286,632 | 12,925,450 | 1.48 | | | | | | |
| 2003 | | 1,292,748 | 1,292,748 | 11,991,580 | 1.37 | | | | | | |
| 2004 | | 1,256,611 | 1,256,611 | 13,329,071 | 1.52 | | | | | | |
| 2005 | | 476,891 | 476,891 | 16,422,224 | 1.87 | | | | | | |
| 2006 | | 930,455 | 930,455 | 18,597,955 | 2.12 | | | | | | |
| 2007 | | 893,340 | 893,340 | 28,601,410 | 3.27 | | | | | | |
| 2008 | | 942,014 | 942,014 | 21,024,279 | 2.40 | | | | | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2016 (continued)

| Program/Year | Participants | Total Costs: Utility Cost [c] | Total Costs: Resource Cost [d] | Savings and Demand Reductions: Annual Energy (kWh) | Savings and Demand Reductions: Average Energy [e] (aMW) | Savings and Demand Reductions: Peak Demand [f] (MW) | Measure Life (Years) | Levelized Costs [a]: Total Utility ($/kWh) | Levelized Costs [a]: Total Resource ($/kWh) | Program Life Benefit/Cost Ratios [b]: Utility | Program Life Benefit/Cost Ratios [b]: Total Resource |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Market Transformation** | | | | | | | | | | | |
| NEEA | | | | | | | | | | | |
| 2009 | | $ 968,263 | $ 968,263 | 10,702,998 | 1.22 | | | | | | |
| 2010 | | 2,391,217 | 2,391,217 | 21,300,366 | 2.43 | | | | | | |
| 2011 | | 3,108,393 | 3,108,393 | 20,161,728 | 2.30 | | | | | | |
| 2012 | | 3,379,756 | 3,379,756 | 19,567,984 | 2.23 | | | | | | |
| 2013 | | 3,313,058 | 3,313,058 | 20,567,965 | 2.35 | | | | | | |
| 2014 | | 3,305,917 | 3,305,917 | 26,805,600 | 3.06 | | | | | | |
| 2015 | | 2,582,919 | 2,582,919 | 23,038,800 | 2.50 | | | | | | |
| 2016 | | 2,676,387 | 2,676,387 | 24,615,600 | 2.81 | | | | | | |
| **Total** | | **$ 28,804,600** | **$ 28,804,600** | **289,653,011** | | | | | | | |
| **Annual Totals** | | | | | | | | | | | |
| 2002 | | 1,932,520 | 2,366,591 | 16,791,100 | 1.92 | 0 | | | | | |
| 2003 | | 2,566,228 | 3,125,572 | 18,654,343 | 2.12 | 0 | | | | | |
| 2004 | | 3,827,213 | 4,860,912 | 19,202,780 | 2.19 | 7 | | | | | |
| 2005 | | 6,523,348 | 10,383,577 | 37,978,035 | 4.34 | 44 | | | | | |
| 2006 | | 11,174,181 | 20,950,110 | 67,026,303 | 7.65 | 44 | | | | | |
| 2007 | | 14,896,816 | 27,123,018 | 91,145,357 | 10.40 | 59 | | | | | |
| 2008 | | 20,213,216 | 44,775,829 | 128,508,579 | 14.67 | 75 | | | | | |
| 2009 | | 33,821,062 | 53,090,852 | 143,146,365 | 16.34 | 236 | | | | | |
| 2010 | | 44,643,541 | 68,981,324 | 193,592,637 | 22.10 | 358 | | | | | |
| 2011 | | 44,877,117 | 79,436,532 | 183,476,312 | 20.94 | 420 | | | | | |
| 2012 | | 47,991,350 | 77,336,341 | 172,054,327 | 19.64 | 454 | | | | | |
| 2013 | | 26,100,091 | 54,803,353 | 109,505,690 | 12.23 | 55 | | | | | |
| 2014 | | 35,648,260 | 71,372,414 | 145,475,713 | 16.40 | 390 | | | | | |
| 2015 | | 37,149,893 | 70,467,082 | 163,671,955 | 18.27 | 367 | | | | | |
| 2016 | | 41,705,957 | 70,984,603 | 170,792,152 | 19.50 | 379 | | | | | |
| **Total Direct Program** | | **$ 373,070,793** | **$ 660,058,113** | **1,661,021,647** | | | | | | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2016 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reductions | | | Measure Life (Years) | Levelized Costs [a] | | Program Life Benefit/Cost Ratios [b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost [c] | Resource Cost [d] | Annual Energy (kWh) | Average Energy [e] (aMW) | Peak Demand [f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Indirect Program Expenses** | | | | | | | | | | | |
| DSM Overhead and Other Indirect | | | | | | | | | | | |
| 2002 | | 128,855 | | | | | | | | | |
| 2003 | | (41,543) | | | | | | | | | |
| 2004 | | 142,337 | | | | | | | | | |
| 2005 | | 177,624 | | | | | | | | | |
| 2006 | | 309,832 | | | | | | | | | |
| 2007 | | 765,561 | | | | | | | | | |
| 2008 | | 980,305 | | | | | | | | | |
| 2009 | | 1,025,704 | | | | | | | | | |
| 2010 | | 1,189,310 | | | | | | | | | |
| 2011 | | 1,389,135 | | | | | | | | | |
| 2012 | | 1,335,509 | | | | | | | | | |
| 2013 | | 741,287 | | | | | | | | | |
| 2014 | | 1,065,072 | | | | | | | | | |
| 2015 | | 1,891,042 | | | | | | | | | |
| 2016 | | 2,263,893 | | | | | | | | | |
| **Total** | | **$ 13,363,923** | | | | | | | | | |
| **Total Expenses** | | | | | | | | | | | |
| 2002 | | 2,061,375 | | | | | | | | | |
| 2003 | | 2,524,685 | | | | | | | | | |
| 2004 | | 3,969,550 | | | | | | | | | |
| 2005 | | 6,700,972 | | | | | | | | | |
| 2006 | | 11,484,013 | | | | | | | | | |
| 2007 | | 15,662,377 | | | | | | | | | |
| 2008 | | 21,193,521 | | | | | | | | | |
| 2009 | | 34,846,766 | | | | | | | | | |
| 2010 | | 45,832,851 | | | | | | | | | |
| 2011 | | 46,266,252 | | | | | | | | | |
| 2012 | | 49,326,859 | | | | | | | | | |

## **Appendix 4.** Historical DSM expense and performance, 2002–2016 (continued)

| Program/Year | Participants | Total Costs | | Savings and Demand Reductions | | | Measure Life (Years) | Levelized Costs [a] | | Program Life Benefit/Cost Ratios [b] | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Utility Cost [c] | Resource Cost [d] | Annual Energy (kWh) | Average Energy [e] (aMW) | Peak Demand [f] (MW) | | Total Utility ($/kWh) | Total Resource ($/kWh) | Utility | Total Resource |
| **Total Expenses** | | | | | | | | | | | |
| 2013 | | $ 26,841,378 | | | | | | | | | |
| 2014 | | 36,713,333 | | | | | | | | | |
| 2015 | | 39,040,935 | | | | | | | | | |
| 2016 | | 42,763,464 | | | | | | | | | |
| **Total 2002–2016** | | **$ 385,228,330** | | | | | | | | | |

[a] Levelized Costs are based on financial inputs from Idaho Power's *2013 Integrated Resource Plan* and calculations include line loss adjusted energy savings.

[b] Program life benefit/cost ratios are provided for active programs only.

[c] The Total Utility Cost is all cost incurred by Idaho Power to implement and manage a DSM program.

[d] The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers as a whole.

[e] Average Demand = Annual Energy/8,760 annual hours.

[f] Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season. Peak demand reduction for demand response programs is reported at the generation level assuming 13 percent peak line losses.

[1] Savings are preliminary funder share estimates. Final results will be provided by NEEA in May 2017.

## **Appendix 5.** 2016 DSM program activity by state jurisdiction

| Program | Idaho Participants | Idaho Utility Costs | Idaho Demand Reduction/ Annual Energy Savings (MW) | Oregon Participants | Oregon Utility Costs [a] | Oregon Demand Reduction/ Annual Energy Savings(MW) |
|---|---|---|---|---|---|---|
| **Demand Response** | | | | | | |
| A/C Cool Credit | 27,947 homes | $ 1,061,450 | 33 | 368 homes | $ 41,845 | 0.4 |
| Flex Peak Program | 128 sites | 520,088 | 29 | 9 sites | 247,909 | 13 |
| Irrigation Peak Rewards | 2,236 service points | 7,378,725 | 295 | 50 service points | 221,351 | 7 |
| **Total** | | **$ 8,960,263** | **357** | | **$ 511,104** | **21** |
| **Energy Efficiency** | | | | | | |
| **Residential** | | | | | | |
| Easy Savings | 2,001 kits | 127,587 | 402,961 | – kits | – | – |
| Educational Distributions | 65,749 kits/bulbs | 2,336,721 | 14,680,660 | 1,316 kits/bulbs | 56,164 | 468,945 |
| Energy Efficient Lighting | 1,405,052 bulbs | 3,017,507 | 20,646,094 | 37,509 bulbs | 63,200 | 447,719 |
| Energy House Calls | 343 homes | 190,621 | 470,535 | 32 homes | 15,815 | 39,324 |
| ENERGY STAR® Homes Northwest | 110 homes | 140,648 | 150,282 | – homes | 1,510 | – |
| Fridge and Freezer Recycling Program | 1,527 refrigerators/ freezers | 253,362 | 627,104 | 12 refrigerators/freezers | 4,555 | 5,082 |
| Heating & Cooling Efficiency Program | 469 projects | 567,729 | 1,073,380 | 17 projects | 27,184 | 40,194 |
| Home Energy Audit | 539 audits | 289,812 | 207,249 | audits | | |
| Home Improvement Program | 482 projects | 324,024 | 500,280 | projects | | |
| Multifamily Energy Savings Program | 3 projects | 59,046 | 149,760 | projects | | |
| Oregon Residential Weatherization | | | | 7 homes | 3,930 | 2,847 |
| Rebate Advantage | 62 homes | 104,658 | 385,528 | 4 homes | 6,392 | 25,744 |
| Simple Steps, Smart Savings™ | 7,822 appliances/ showerheads | 150,249 | 570,581 | 94 appliances/showerheads | 3,535 | 6,739 |
| Weatherization Assistance for Qualified Customers | 234 homes/ non-profits | 1,254,338 | 722,430 | 12 homes/non-profits | 35,471 | 23,732 |
| Weatherization Solutions for Eligible Customers | 232 homes | 1,323,793 | 621,653 | homes | | |
| **Sector Total** | | **$ 10,140,095** | **41,208,496** | | **$ 217,756** | **1,060,326** |
| **Commercial** | | | | | | |
| Custom Projects (Custom Efficiency) | 185 projects | 7,745,408 | 46,614,955 | 11 projects | 237,216 | 903,916 |
| Green Motors—Industrial | 2 motor rewinds | | 50,955 | 2 motor rewinds | 0 | 72,745 |
| New Construction (Building Efficiency) | 113 projects | 1,888,663 | 12,254,358 | 3 projects | 42,559 | 138,891 |
| Retrofits (Easy Upgrades) | 1,518 projects | 4,811,357 | 27,040,532 | 59 projects | 228,834 | 1,084,247 |
| **Sector Total** | | **$ 14,445,428** | **85,960,800** | | **$ 508,608** | **2,199,799** |

## **Appendix 5**. 2016 DSM program activity by state jurisdiction (continued)

| Program | Idaho Participants | Idaho Utility Costs | Idaho Demand Reduction/ Annual Energy Savings | Oregon Participants | Oregon Utility Costs | Oregon Demand Reduction/ Annual Energy Savings |
|---|---|---|---|---|---|---|
| **Irrigation** | | | | | | |
| Green Motors—Irrigation | 22 motor rewinds | | 72,871 | 1 motor rewind | | 746 |
| Irrigation Efficiency Rewards | 798 projects | $ 1,737,168 | 12,860,872 | 53 projects | $ 635,185 | 2,812,641 |
| **Sector Total** | | **$ 1,737,168** | **12,933,743** | | **$ 635,185** | **2,813,387** |
| **Market Transformation** | | | | | | |
| Northwest Energy Efficiency Alliance [1] | | 2,542,567 | 23,384,820 | | 133,820 | 1,230,780 |
| **Other Programs and Activities** | | | | | | |
| **Residential** | | | | | | |
| Energy Efficiency Education Initiative | | 278,108 | | | 12,071 | |
| Shade Tree Project | | 76,642 | | | – | |
| **Commercial** | | | | | | |
| Oregon Commercial Audits | | – | | | 7,717 | |
| **Other** | | | | | | |
| Energy Efficiency Direct Program Overhead | | 276.074 | | | 16,964 | |
| **Total Program Direct Expense** | | **$ 38,456,344** | | | **$ 2,043,225** | |
| Indirect Program Expenses | | 2,147,479 | | | 116,414 | |
| **Total Annual Savings** | | | **163,487,859** | | | **7,304,292** |
| **Total DSM Expense** | | **$ 40,603,823** | | | **$ 2,159,639** | |

[a] Levelized Costs are based on financial inputs from Idaho Power's *2013 Integrated Resource Plan* and calculations include line loss adjusted energy savings.

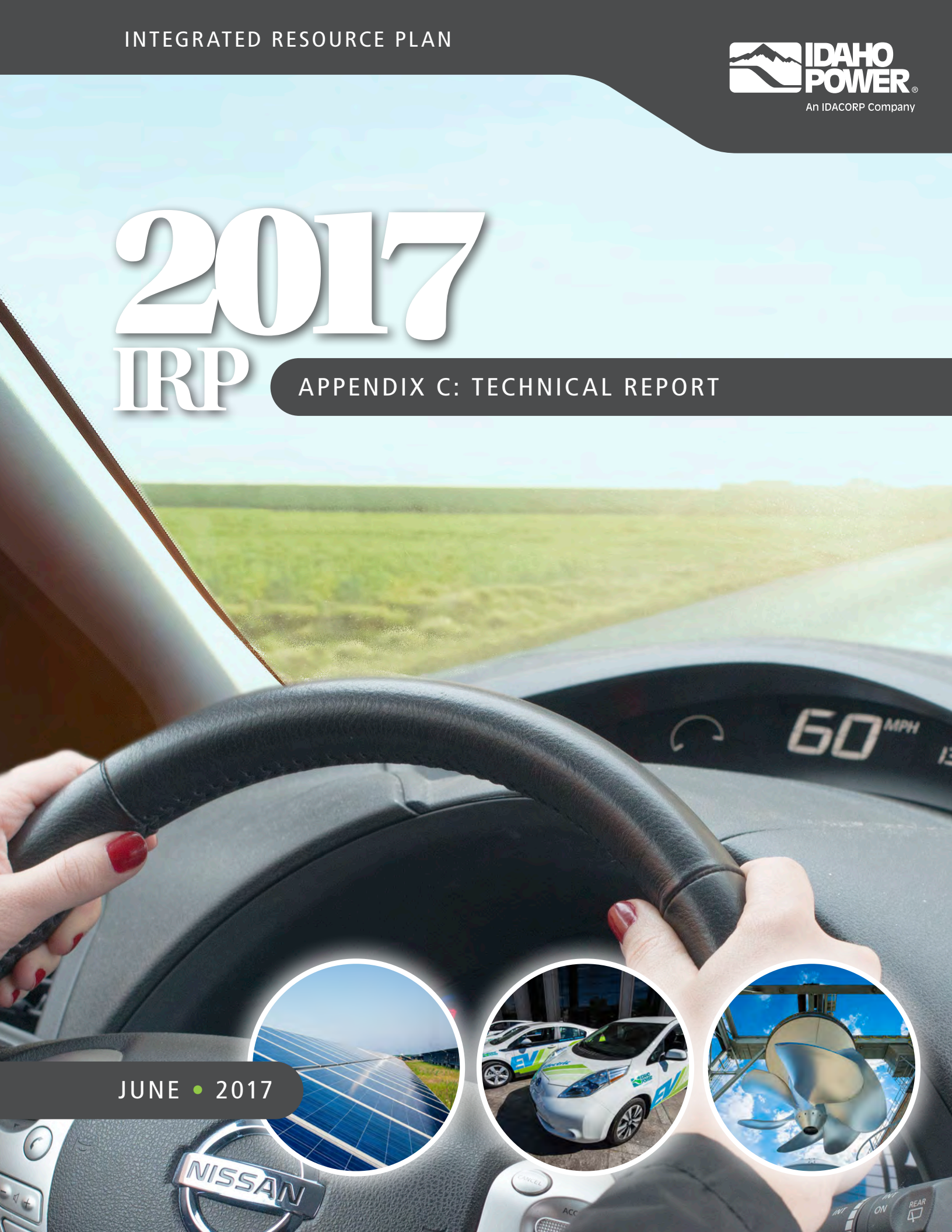
[1] Savings are preliminary funder share estimates provided by NEEA. Final savings for 2016 will be provided by NEEA May 2017.

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# 2017 IRP

## APPENDIX C: TECHNICAL REPORT




JUNE • 2017

## SAFE HARBOR STATEMENT

This document may contain forward-looking statements, and it is important to note that the future results could differ materially from those discussed. A full discussion of the factors that could cause future results to differ materially can be found in Idaho Power's filings with the Securities and Exchange Commission.

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# INTRODUCTION

*Appendix C–Technical Appendix* contains supporting data and explanatory materials used to develop Idaho Power's *2017 Integrated Resource Plan* (IRP).

The main document, the IRP, contains a full narrative of Idaho Power's resource planning process. Additional information regarding the 2017 IRP sales and load forecast is contained in *Appendix A–Sales and Load Forecast*, and details on Idaho Power's demand-side management efforts are explained in *Appendix B–Demand-Side Management 2014 Annual Report*. The IRP, including the three appendices, was filed with the Idaho and Oregon public utility commissions in June 2017.

For information or questions concerning the resource plan or the resource planning process, contact Idaho Power:

Idaho Power—Resource Planning

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Boise, Idaho 83702

208-388-2623

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# IRP ADVISORY COUNCIL

Idaho Power has involved representatives of the public in the IRP planning process since the early 1990s. This public forum is known as the IRP Advisory Council (IRPAC). The IRPAC generally meets monthly during the development of the IRP, and the meetings are open to the public. Members of the council include regulatory, political, environmental, and customer representatives, as well as representatives of other public-interest groups.

Idaho Power hosted 8 IRPAC meetings, including a workshop designed to explore the potential for distributed energy resources to defer grid investment. Idaho Power values these opportunities to convene, and the IRPAC members and the public have made significant contributions to this plan.

Idaho Power believes working with members of the IRPAC and the public is rewarding, and the IRP is better because of public involvement. Idaho Power and the members of the IRPAC recognize outside perspective is valuable, but also understand that final decisions on the IRP are made by Idaho Power.

### Customer Representatives

| | |
|---|---|
| Agricultural Representative | Sid Erwin |
| Boise State University | Barry Burbank |
| Idaho National Laboratory | Kurt Myers |
| Micron | Clancy Kelley |
| Simplot | Don Sturtevant |

### Public Interest Representatives

| | |
|---|---|
| Boise Metro Chamber of Commerce | Ray Stark |
| Boise State University Energy Policy Institute | David Solan |
| City of Boise | Steve Burgos |
| Idaho Conservation League | Ben Otto |
| Idaho Legislature | Representative Robert Anderst |
| Idaho Office of Energy and Mineral Resources | John Chatburn/Scott Pugrud |
| Idaho Sierra Club | Mike Heckler/Zack Waterman/Casey Mattoon |
| Idaho Technology Council | Jay Larsen |
| Idaho Water Resource Board | Roger Chase |
| Northwest Power and Conservation Council | Shirley Lindstrom/Jim Yost |
| Oil and Gas Industry Advisor | David Hawk |
| Oregon State University—Malheur Experiment Station | Clint Shock |
| Snake River Alliance | Wendy Wilson/Chad Worth |
| University of Idaho Center for Ecohydraulics Research | Daniele Tonina |

**Regulatory Commission Representatives**

| | |
|---|---|
| Idaho Public Utilities Commission | Stacey Donohue |
| Public Utility Commission of Oregon | Nadine Hanhan |

# IRP Advisory Council Meeting Schedule and Agenda

| Meeting Dates | | Agenda Items |
|---|---|---|
| 2016 | Thursday, September 8 | Introductions/meeting overview<br>Welcome and opening remarks<br>IRP process explanation<br>Pilot projects update<br>Clean Power Plan update<br>Natural gas forecast |
| 2016 | Thursday, October 13 | Review of September IRPAC meeting<br>T&D deferral benefit<br>Demand-side resources<br>Streamflow forecast<br>Hydro production forecast |
| 2016 | Thursday, November 10 | Review of October IRPAC meeting<br>Transmission system overview<br>Boardman-Hemingway/Gateway West update<br>Load forecast<br>Contract purchased power forecast |
| 2016 | Thursday, December 19 | Deferral of Distribution Investment Workshop |
| 2017 | Thursday, January 12 | Review of November IRPAC meeting<br>Energy efficiency potential study<br>Recap/review<br>Resource stack of IRP resources<br>Final load and resource balance<br>Resource portfolio design |
| 2017 | Thursday, March 9 | Review of January IRPAC meeting<br>Revisit of natural gas price forecast<br>AURORA and portfolio analysis<br>NW Power and Conservation Council Regional Perspective<br>Flexibility analysis<br>500 kV transmission projects update<br>Overview of remaining steps |
| 2017 | Thursday, April 13 | Review of March IRPAC meeting<br>Stochastic risk analysis results<br>Demand response as a resource<br>Resource stack costs – IRP resources<br>Qualitative risk analysis discussion<br>Closing-remaining schedule |

| Meeting Dates | | Agenda Items |
|---|---|---|
| 2017 | Thursday, May 11 | Action plan (2017—2020)<br>Hells Canyon Complex relicensing<br>Spring runoff and power system operations<br>Energy imbalance market (EIM) overview<br>IPC sustainability programs<br>Loss-of-load analysis<br>Closing comments |

# SALES AND LOAD FORECAST DATA

## Average Annual Forecast Growth Rates

| | 2017–2022 | 2017–2027 | 2017–2036 |
|---|---|---|---|
| **Sales** | | | |
| Residential Sales | 1.48% | 1.40% | 1.24% |
| Commercial Sales | 0.87% | 0.79% | 0.75% |
| Irrigation Sales | 0.62% | 0.59% | 0.59% |
| Industrial Sales | 1.29% | 0.90% | 0.73% |
| Additional Firm Sales | 0.94% | 1.40% | 0.76% |
| System Sales | 1.13% | 1.04% | 0.91% |
| Total Sales | 1.13% | 1.04% | 0.91% |
| **Loads** | | | |
| Residential Load | 1.48% | 1.40% | 1.22% |
| Commercial Load | 0.86% | 0.78% | 0.74% |
| Irrigation Load | 0.62% | 0.59% | 0.58% |
| Industrial Load | 1.25% | 0.89% | 0.70% |
| Additional Firm Sales | 0.94% | 1.40% | 0.76% |
| System Load Losses | 1.12% | 1.03% | 0.91% |
| System Load | 1.12% | 1.04% | 0.89% |
| Total Load | 1.12% | 1.04% | 0.89% |
| **Peaks** | | | |
| System Peak | 1.57% | 1.49% | 1.36% |
| Total Peak | 1.57% | 1.49% | 1.36% |
| Winter Peak | 1.22% | 1.05% | 0.88% |
| Summer Peak | 1.78% | 1.66% | 1.53% |
| **Customers** | | | |
| Residential Customers | 2.11% | 2.02% | 1.78% |
| Commercial Customers | 1.86% | 1.90% | 1.77% |
| Irrigation Customers | 1.42% | 1.37% | 1.29% |
| Industrial Customers | 0.50% | 0.65% | 0.59% |

# Expected-Case Load Forecast

| Monthly Summary[1] | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 814 | 671 | 592 | 506 | 446 | 512 | 621 | 588 | 469 | 455 | 650 | 799 |
| Commercial | 494 | 466 | 434 | 430 | 429 | 462 | 503 | 499 | 467 | 444 | 460 | 499 |
| Irrigation | 2 | 3 | 9 | 130 | 345 | 587 | 643 | 503 | 328 | 73 | 5 | 3 |
| Industrial | 281 | 279 | 277 | 263 | 268 | 292 | 285 | 289 | 286 | 289 | 279 | 278 |
| Additional Firm | 113 | 111 | 106 | 106 | 105 | 102 | 108 | 108 | 107 | 104 | 112 | 114 |
| Loss | 145 | 129 | 118 | 120 | 135 | 169 | 189 | 172 | 140 | 113 | 126 | 144 |
| **System Load** | **1,850** | **1,658** | **1,537** | **1,555** | **1,728** | **2,123** | **2,350** | **2,159** | **1,796** | **1,477** | **1,631** | **1,836** |
| Light Load | 1,718 | 1,527 | 1,408 | 1,405 | 1,564 | 1,930 | 2,118 | 1,913 | 1,616 | 1,316 | 1,505 | 1,695 |
| Heavy Load | 1,964 | 1,757 | 1,630 | 1,675 | 1,858 | 2,265 | 2,549 | 2,337 | 1,941 | 1,604 | 1,733 | 1,957 |
| **Total Load** | **1,850** | **1,658** | **1,537** | **1,555** | **1,728** | **2,123** | **2,350** | **2,159** | **1,796** | **1,477** | **1,631** | **1,836** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,408 | 2,279 | 2,018 | 2,009 | 2,663 | 3,395 | 3,566 | 3,213 | 2,767 | 2,072 | 2,264 | 2,517 |
| **Total Peak Load** | **2,408** | **2,279** | **2,018** | **2,009** | **2,663** | **3,395** | **3,566** | **3,213** | **2,767** | **2,072** | **2,264** | **2,517** |

| Monthly Summary[1] | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 829 | 682 | 602 | 514 | 455 | 522 | 634 | 601 | 478 | 463 | 661 | 813 |
| Commercial | 501 | 471 | 438 | 435 | 434 | 467 | 509 | 506 | 473 | 449 | 465 | 504 |
| Irrigation | 2 | 3 | 9 | 131 | 347 | 590 | 647 | 506 | 330 | 73 | 5 | 3 |
| Industrial | 289 | 288 | 285 | 271 | 276 | 300 | 294 | 298 | 294 | 297 | 287 | 282 |
| Additional Firm | 115 | 113 | 108 | 107 | 107 | 103 | 110 | 110 | 109 | 106 | 114 | 116 |
| Loss | 148 | 131 | 120 | 122 | 137 | 171 | 191 | 175 | 143 | 114 | 128 | 146 |
| **System Load** | **1,884** | **1,688** | **1,563** | **1,581** | **1,756** | **2,155** | **2,385** | **2,195** | **1,826** | **1,502** | **1,660** | **1,864** |
| Light Load | 1,749 | 1,554 | 1,432 | 1,428 | 1,589 | 1,958 | 2,150 | 1,945 | 1,642 | 1,339 | 1,531 | 1,721 |
| Heavy Load | 1,990 | 1,788 | 1,657 | 1,703 | 1,887 | 2,299 | 2,587 | 2,375 | 1,986 | 1,621 | 1,763 | 1,987 |
| **Total Load** | **1,884** | **1,688** | **1,563** | **1,581** | **1,756** | **2,155** | **2,385** | **2,195** | **1,826** | **1,502** | **1,660** | **1,864** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,454 | 2,315 | 2,053 | 2,037 | 2,701 | 3,453 | 3,630 | 3,269 | 2,818 | 2,100 | 2,292 | 2,554 |
| **Total Peak Load** | **2,454** | **2,315** | **2,053** | **2,037** | **2,701** | **3,453** | **3,630** | **3,269** | **2,818** | **2,100** | **2,292** | **2,554** |

| Monthly Summary[1] | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 844 | 695 | 612 | 523 | 464 | 533 | 648 | 614 | 487 | 470 | 672 | 823 |
| Commercial | 505 | 475 | 442 | 439 | 438 | 471 | 513 | 511 | 477 | 453 | 470 | 508 |
| Irrigation | 3 | 3 | 9 | 132 | 350 | 595 | 652 | 510 | 332 | 74 | 5 | 3 |
| Industrial | 294 | 292 | 289 | 275 | 280 | 305 | 298 | 302 | 299 | 302 | 291 | 285 |
| Additional Firm | 117 | 115 | 109 | 109 | 108 | 104 | 111 | 111 | 110 | 107 | 115 | 117 |
| Loss | 150 | 133 | 122 | 124 | 139 | 174 | 194 | 177 | 144 | 116 | 130 | 147 |
| **System Load** | **1,912** | **1,711** | **1,583** | **1,601** | **1,778** | **2,182** | **2,416** | **2,225** | **1,849** | **1,521** | **1,682** | **1,883** |
| Light Load | 1,776 | 1,576 | 1,450 | 1,447 | 1,609 | 1,983 | 2,178 | 1,971 | 1,663 | 1,356 | 1,551 | 1,739 |
| Heavy Load | 2,020 | 1,813 | 1,688 | 1,714 | 1,911 | 2,341 | 2,604 | 2,408 | 2,012 | 1,641 | 1,787 | 2,007 |
| **Total Load** | **1,912** | **1,711** | **1,583** | **1,601** | **1,778** | **2,182** | **2,416** | **2,225** | **1,849** | **1,521** | **1,682** | **1,883** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,497 | 2,347 | 2,084 | 2,062 | 2,735 | 3,505 | 3,692 | 3,322 | 2,861 | 2,122 | 2,316 | 2,572 |
| **Total Peak Load** | 2,497 | 2,347 | 2,084 | 2,062 | 2,735 | 3,505 | 3,692 | 3,322 | 2,861 | 2,122 | 2,316 | 2,572 |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2017 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 851 | 676 | 616 | 526 | 468 | 539 | 656 | 621 | 492 | 473 | 676 | 831 |
| Commercial | 510 | 462 | 444 | 442 | 441 | 475 | 517 | 515 | 481 | 456 | 473 | 512 |
| Irrigation | 3 | 3 | 9 | 133 | 352 | 599 | 656 | 513 | 334 | 74 | 5 | 3 |
| Industrial | 297 | 285 | 292 | 278 | 283 | 308 | 301 | 305 | 302 | 305 | 294 | 287 |
| Additional Firm | 118 | 112 | 110 | 109 | 108 | 105 | 112 | 111 | 110 | 108 | 116 | 118 |
| Loss | 151 | 129 | 122 | 125 | 140 | 175 | 196 | 179 | 146 | 117 | 131 | 149 |
| **System Load** | **1,929** | **1,665** | **1,594** | **1,613** | **1,792** | **2,200** | **2,437** | **2,245** | **1,865** | **1,533** | **1,695** | **1,899** |
| Light Load | 1,791 | 1,533 | 1,460 | 1,457 | 1,622 | 1,999 | 2,197 | 1,989 | 1,677 | 1,365 | 1,563 | 1,753 |
| Heavy Load | 2,038 | 1,762 | 1,699 | 1,727 | 1,939 | 2,346 | 2,626 | 2,446 | 2,015 | 1,653 | 1,810 | 2,014 |
| **Total Load** | **1,929** | **1,665** | **1,594** | **1,613** | **1,792** | **2,200** | **2,437** | **2,245** | **1,865** | **1,533** | **1,695** | **1,899** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,517 | 2,360 | 2,097 | 2,076 | 2,758 | 3,538 | 3,745 | 3,364 | 2,890 | 2,136 | 2,329 | 2,576 |
| **Total Peak Load** | **2,517** | **2,360** | **2,097** | **2,076** | **2,758** | **3,538** | **3,745** | **3,364** | **2,890** | **2,136** | **2,329** | **2,576** |

| Monthly Summary[1] | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 861 | 707 | 621 | 531 | 473 | 546 | 665 | 630 | 498 | 477 | 682 | 843 |
| Commercial | 514 | 481 | 447 | 445 | 445 | 478 | 520 | 519 | 485 | 459 | 477 | 516 |
| Irrigation | 3 | 3 | 9 | 134 | 354 | 601 | 659 | 516 | 336 | 75 | 5 | 3 |
| Industrial | 298 | 297 | 294 | 279 | 284 | 310 | 303 | 307 | 303 | 306 | 296 | 288 |
| Additional Firm | 118 | 116 | 111 | 110 | 109 | 105 | 112 | 112 | 111 | 108 | 116 | 119 |
| Loss | 153 | 135 | 123 | 126 | 141 | 176 | 197 | 180 | 147 | 117 | 132 | 150 |
| **System Load** | **1,946** | **1,738** | **1,605** | **1,625** | **1,806** | **2,216** | **2,456** | **2,264** | **1,879** | **1,544** | **1,708** | **1,918** |
| Light Load | 1,807 | 1,601 | 1,470 | 1,468 | 1,634 | 2,014 | 2,214 | 2,006 | 1,690 | 1,375 | 1,575 | 1,771 |
| Heavy Load | 2,066 | 1,841 | 1,702 | 1,739 | 1,954 | 2,364 | 2,647 | 2,467 | 2,031 | 1,676 | 1,814 | 2,034 |
| **Total Load** | **1,946** | **1,738** | **1,605** | **1,625** | **1,806** | **2,216** | **2,456** | **2,264** | **1,879** | **1,544** | **1,708** | **1,918** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,529 | 2,372 | 2,105 | 2,087 | 2,780 | 3,570 | 3,797 | 3,406 | 2,917 | 2,149 | 2,343 | 2,596 |
| **Total Peak Load** | **2,529** | **2,372** | **2,105** | **2,087** | **2,780** | **3,570** | **3,797** | **3,406** | **2,917** | **2,149** | **2,343** | **2,596** |

| Monthly Summary[1] | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 875 | 718 | 630 | 539 | 482 | 556 | 678 | 643 | 507 | 485 | 692 | 856 |
| Commercial | 518 | 485 | 450 | 449 | 448 | 482 | 524 | 524 | 489 | 463 | 481 | 520 |
| Irrigation | 3 | 3 | 9 | 134 | 356 | 605 | 663 | 519 | 338 | 75 | 5 | 3 |
| Industrial | 300 | 298 | 295 | 281 | 286 | 311 | 304 | 308 | 305 | 308 | 297 | 290 |
| Additional Firm | 119 | 117 | 112 | 111 | 110 | 106 | 113 | 113 | 111 | 109 | 117 | 120 |
| Loss | 155 | 136 | 125 | 127 | 143 | 178 | 199 | 182 | 148 | 119 | 133 | 152 |
| **System Load** | **1,970** | **1,757** | **1,621** | **1,641** | **1,824** | **2,239** | **2,482** | **2,290** | **1,899** | **1,558** | **1,726** | **1,940** |
| Light Load | 1,829 | 1,618 | 1,485 | 1,483 | 1,650 | 2,034 | 2,238 | 2,029 | 1,708 | 1,388 | 1,592 | 1,791 |
| Heavy Load | 2,091 | 1,861 | 1,719 | 1,756 | 1,973 | 2,388 | 2,693 | 2,478 | 2,052 | 1,692 | 1,833 | 2,058 |
| **Total Load** | **1,970** | **1,757** | **1,621** | **1,641** | **1,824** | **2,239** | **2,482** | **2,290** | **1,899** | **1,558** | **1,726** | **1,940** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,558 | 2,393 | 2,124 | 2,104 | 2,807 | 3,612 | 3,854 | 3,453 | 2,952 | 2,165 | 2,361 | 2,614 |
| **Total Peak Load** | **2,558** | **2,393** | **2,124** | **2,104** | **2,807** | **3,612** | **3,854** | **3,453** | **2,952** | **2,165** | **2,361** | **2,614** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2017 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 890 | 729 | 640 | 547 | 490 | 566 | 691 | 656 | 516 | 492 | 702 | 869 |
| Commercial | 522 | 488 | 452 | 452 | 452 | 485 | 528 | 528 | 493 | 466 | 484 | 523 |
| Irrigation | 3 | 3 | 9 | 135 | 358 | 609 | 668 | 522 | 340 | 76 | 5 | 3 |
| Industrial | 301 | 300 | 297 | 282 | 288 | 313 | 306 | 310 | 307 | 310 | 299 | 291 |
| Additional Firm | 122 | 120 | 114 | 113 | 112 | 108 | 115 | 115 | 113 | 111 | 120 | 123 |
| Loss | 157 | 138 | 126 | 128 | 144 | 180 | 202 | 184 | 150 | 120 | 135 | 154 |
| **System Load** | **1,995** | **1,778** | **1,638** | **1,658** | **1,843** | **2,262** | **2,509** | **2,316** | **1,919** | **1,574** | **1,745** | **1,963** |
| Light Load | 1,853 | 1,637 | 1,501 | 1,498 | 1,668 | 2,056 | 2,262 | 2,052 | 1,726 | 1,402 | 1,610 | 1,812 |
| Heavy Load | 2,118 | 1,883 | 1,737 | 1,786 | 1,982 | 2,413 | 2,722 | 2,507 | 2,073 | 1,709 | 1,854 | 2,093 |
| **Total Load** | **1,995** | **1,778** | **1,638** | **1,658** | **1,843** | **2,262** | **2,509** | **2,316** | **1,919** | **1,574** | **1,745** | **1,963** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,586 | 2,415 | 2,143 | 2,123 | 2,835 | 3,654 | 3,912 | 3,501 | 2,987 | 2,183 | 2,382 | 2,630 |
| **Total Peak Load** | **2,586** | **2,415** | **2,143** | **2,123** | **2,835** | **3,654** | **3,912** | **3,501** | **2,987** | **2,183** | **2,382** | **2,630** |

| Monthly Summary[1] | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 903 | 714 | 648 | 555 | 498 | 576 | 704 | 668 | 524 | 498 | 711 | 879 |
| Commercial | 526 | 474 | 454 | 455 | 455 | 488 | 531 | 532 | 497 | 469 | 487 | 527 |
| Irrigation | 3 | 3 | 10 | 136 | 360 | 613 | 671 | 525 | 342 | 76 | 5 | 3 |
| Industrial | 303 | 291 | 298 | 284 | 289 | 315 | 308 | 312 | 308 | 311 | 300 | 293 |
| Additional Firm | 133 | 126 | 123 | 121 | 119 | 116 | 122 | 121 | 119 | 118 | 130 | 133 |
| Loss | 159 | 135 | 127 | 130 | 146 | 182 | 204 | 187 | 152 | 121 | 136 | 156 |
| **System Load** | **2,026** | **1,742** | **1,660** | **1,680** | **1,866** | **2,289** | **2,539** | **2,345** | **1,942** | **1,593** | **1,770** | **1,991** |
| Light Load | 1,881 | 1,604 | 1,521 | 1,518 | 1,689 | 2,080 | 2,289 | 2,078 | 1,747 | 1,419 | 1,633 | 1,838 |
| Heavy Load | 2,141 | 1,844 | 1,770 | 1,798 | 2,006 | 2,456 | 2,737 | 2,538 | 2,113 | 1,719 | 1,881 | 2,122 |
| **Total Load** | **2,026** | **1,742** | **1,660** | **1,680** | **1,866** | **2,289** | **2,539** | **2,345** | **1,942** | **1,593** | **1,770** | **1,991** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,621 | 2,441 | 2,168 | 2,145 | 2,867 | 3,699 | 3,974 | 3,554 | 3,025 | 2,206 | 2,410 | 2,653 |
| **Total Peak Load** | **2,621** | **2,441** | **2,168** | **2,145** | **2,867** | **3,699** | **3,974** | **3,554** | **3,025** | **2,206** | **2,410** | **2,653** |

| Monthly Summary[1] | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 913 | 747 | 653 | 560 | 504 | 583 | 713 | 677 | 530 | 502 | 717 | 888 |
| Commercial | 530 | 494 | 457 | 458 | 458 | 491 | 534 | 537 | 501 | 472 | 491 | 531 |
| Irrigation | 3 | 3 | 10 | 137 | 362 | 616 | 675 | 528 | 344 | 76 | 5 | 3 |
| Industrial | 305 | 303 | 300 | 285 | 291 | 316 | 309 | 313 | 310 | 313 | 302 | 294 |
| Additional Firm | 133 | 130 | 123 | 121 | 119 | 116 | 122 | 122 | 120 | 118 | 130 | 134 |
| Loss | 160 | 141 | 128 | 130 | 147 | 183 | 205 | 188 | 153 | 122 | 137 | 157 |
| **System Load** | **2,043** | **1,817** | **1,671** | **1,691** | **1,880** | **2,305** | **2,559** | **2,365** | **1,957** | **1,603** | **1,783** | **2,007** |
| Light Load | 1,897 | 1,674 | 1,530 | 1,528 | 1,701 | 2,095 | 2,307 | 2,096 | 1,760 | 1,429 | 1,644 | 1,853 |
| Heavy Load | 2,159 | 1,925 | 1,781 | 1,810 | 2,021 | 2,474 | 2,758 | 2,577 | 2,114 | 1,730 | 1,904 | 2,128 |
| **Total Load** | **2,043** | **1,817** | **1,671** | **1,691** | **1,880** | **2,305** | **2,559** | **2,365** | **1,957** | **1,603** | **1,783** | **2,007** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,635 | 2,454 | 2,177 | 2,156 | 2,888 | 3,731 | 4,026 | 3,595 | 3,051 | 2,218 | 2,423 | 2,659 |
| **Total Peak Load** | **2,635** | **2,454** | **2,177** | **2,156** | **2,888** | **3,731** | **4,026** | **3,595** | **3,051** | **2,218** | **2,423** | **2,659** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2017 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 923 | 754 | 659 | 565 | 509 | 590 | 723 | 687 | 536 | 506 | 724 | 899 |
| Commercial | 534 | 498 | 459 | 461 | 461 | 495 | 538 | 541 | 505 | 475 | 495 | 535 |
| Irrigation | 3 | 3 | 10 | 137 | 364 | 619 | 678 | 531 | 345 | 77 | 5 | 3 |
| Industrial | 306 | 304 | 301 | 287 | 292 | 318 | 311 | 315 | 311 | 314 | 303 | 296 |
| Additional Firm | 133 | 130 | 123 | 121 | 119 | 116 | 122 | 122 | 120 | 118 | 130 | 134 |
| Loss | 162 | 142 | 129 | 131 | 148 | 185 | 207 | 190 | 154 | 123 | 138 | 158 |
| **System Load** | **2,060** | **1,831** | **1,681** | **1,702** | **1,893** | **2,322** | **2,579** | **2,385** | **1,972** | **1,614** | **1,795** | **2,024** |
| Light Load | 1,913 | 1,686 | 1,540 | 1,538 | 1,713 | 2,110 | 2,325 | 2,113 | 1,773 | 1,438 | 1,656 | 1,869 |
| Heavy Load | 2,177 | 1,939 | 1,792 | 1,822 | 2,048 | 2,477 | 2,779 | 2,599 | 2,130 | 1,741 | 1,917 | 2,146 |
| **Total Load** | **2,060** | **1,831** | **1,681** | **1,702** | **1,893** | **2,322** | **2,579** | **2,385** | **1,972** | **1,614** | **1,795** | **2,024** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,649 | 2,464 | 2,185 | 2,167 | 2,910 | 3,763 | 4,078 | 3,636 | 3,078 | 2,229 | 2,435 | 2,675 |
| **Total Peak Load** | **2,649** | **2,464** | **2,185** | **2,167** | **2,910** | **3,763** | **4,078** | **3,636** | **3,078** | **2,229** | **2,435** | **2,675** |

| Monthly Summary[1] | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 935 | 763 | 666 | 571 | 516 | 599 | 735 | 698 | 544 | 512 | 732 | 910 |
| Commercial | 539 | 501 | 462 | 465 | 465 | 498 | 542 | 546 | 509 | 479 | 498 | 538 |
| Irrigation | 3 | 3 | 10 | 138 | 366 | 623 | 682 | 534 | 348 | 77 | 5 | 3 |
| Industrial | 308 | 306 | 303 | 288 | 293 | 319 | 312 | 316 | 313 | 316 | 305 | 297 |
| Additional Firm | 133 | 130 | 123 | 121 | 119 | 116 | 122 | 122 | 120 | 118 | 130 | 134 |
| Loss | 163 | 143 | 130 | 132 | 149 | 186 | 209 | 192 | 156 | 124 | 140 | 160 |
| **System Load** | **2,080** | **1,846** | **1,694** | **1,716** | **1,909** | **2,342** | **2,602** | **2,408** | **1,989** | **1,626** | **1,810** | **2,042** |
| Light Load | 1,932 | 1,700 | 1,551 | 1,550 | 1,727 | 2,128 | 2,346 | 2,134 | 1,789 | 1,448 | 1,669 | 1,885 |
| Heavy Load | 2,208 | 1,956 | 1,796 | 1,836 | 2,065 | 2,498 | 2,805 | 2,624 | 2,149 | 1,765 | 1,922 | 2,166 |
| **Total Load** | **2,080** | **1,846** | **1,694** | **1,716** | **1,909** | **2,342** | **2,602** | **2,408** | **1,989** | **1,626** | **1,810** | **2,042** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,672 | 2,481 | 2,200 | 2,181 | 2,934 | 3,800 | 4,132 | 3,680 | 3,109 | 2,243 | 2,450 | 2,689 |
| **Total Peak Load** | **2,672** | **2,481** | **2,200** | **2,181** | **2,934** | **3,800** | **4,132** | **3,680** | **3,109** | **2,243** | **2,450** | **2,689** |

| Monthly Summary[1] | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 947 | 746 | 673 | 577 | 523 | 608 | 746 | 709 | 551 | 517 | 739 | 920 |
| Commercial | 542 | 486 | 464 | 468 | 468 | 501 | 545 | 550 | 512 | 482 | 501 | 542 |
| Irrigation | 3 | 3 | 10 | 139 | 368 | 627 | 687 | 537 | 350 | 78 | 5 | 3 |
| Industrial | 309 | 297 | 305 | 290 | 295 | 321 | 314 | 318 | 315 | 318 | 307 | 299 |
| Additional Firm | 134 | 126 | 123 | 121 | 119 | 116 | 123 | 122 | 120 | 118 | 130 | 134 |
| Loss | 165 | 139 | 131 | 133 | 151 | 188 | 211 | 194 | 157 | 125 | 141 | 161 |
| **System Load** | **2,100** | **1,797** | **1,706** | **1,728** | **1,924** | **2,361** | **2,625** | **2,430** | **2,005** | **1,637** | **1,824** | **2,059** |
| Light Load | 1,950 | 1,655 | 1,562 | 1,562 | 1,741 | 2,146 | 2,366 | 2,153 | 1,803 | 1,459 | 1,682 | 1,901 |
| Heavy Load | 2,229 | 1,902 | 1,809 | 1,862 | 2,069 | 2,518 | 2,847 | 2,630 | 2,166 | 1,778 | 1,937 | 2,195 |
| **Total Load** | **2,100** | **1,797** | **1,706** | **1,728** | **1,924** | **2,361** | **2,625** | **2,430** | **2,005** | **1,637** | **1,824** | **2,059** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,695 | 2,496 | 2,214 | 2,195 | 2,958 | 3,837 | 4,187 | 3,725 | 3,140 | 2,257 | 2,465 | 2,701 |
| **Total Peak Load** | **2,695** | **2,496** | **2,214** | **2,195** | **2,958** | **3,837** | **4,187** | **3,725** | **3,140** | **2,257** | **2,465** | **2,701** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2017 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 958 | 780 | 678 | 582 | 529 | 615 | 756 | 719 | 558 | 521 | 746 | 929 |
| Commercial | 547 | 507 | 467 | 471 | 471 | 505 | 549 | 554 | 517 | 485 | 505 | 546 |
| Irrigation | 3 | 3 | 10 | 140 | 370 | 630 | 690 | 540 | 352 | 78 | 5 | 3 |
| Industrial | 311 | 309 | 306 | 292 | 297 | 323 | 316 | 320 | 317 | 320 | 308 | 301 |
| Additional Firm | 133 | 130 | 123 | 121 | 119 | 116 | 122 | 122 | 120 | 118 | 130 | 134 |
| Loss | 166 | 145 | 132 | 134 | 152 | 189 | 213 | 195 | 158 | 126 | 142 | 163 |
| **System Load** | **2,118** | **1,875** | **1,717** | **1,740** | **1,939** | **2,379** | **2,646** | **2,451** | **2,021** | **1,648** | **1,837** | **2,075** |
| Light Load | 1,966 | 1,727 | 1,573 | 1,572 | 1,754 | 2,162 | 2,386 | 2,172 | 1,817 | 1,468 | 1,694 | 1,916 |
| Heavy Load | 2,237 | 1,986 | 1,820 | 1,874 | 2,084 | 2,537 | 2,871 | 2,653 | 2,198 | 1,778 | 1,951 | 2,212 |
| **Total Load** | **2,118** | **1,875** | **1,717** | **1,740** | **1,939** | **2,379** | **2,646** | **2,451** | **2,021** | **1,648** | **1,837** | **2,075** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,712 | 2,509 | 2,224 | 2,207 | 2,981 | 3,871 | 4,240 | 3,768 | 3,169 | 2,269 | 2,478 | 2,713 |
| **Total Peak Load** | **2,712** | **2,509** | **2,224** | **2,207** | **2,981** | **3,871** | **4,240** | **3,768** | **3,169** | **2,269** | **2,478** | **2,713** |

| Monthly Summary[1] | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 967 | 787 | 683 | 586 | 534 | 622 | 765 | 728 | 563 | 525 | 751 | 937 |
| Commercial | 551 | 510 | 469 | 474 | 475 | 508 | 552 | 559 | 521 | 488 | 509 | 550 |
| Irrigation | 3 | 3 | 10 | 141 | 373 | 634 | 694 | 543 | 354 | 79 | 5 | 3 |
| Industrial | 313 | 311 | 308 | 293 | 299 | 325 | 318 | 322 | 318 | 322 | 310 | 303 |
| Additional Firm | 133 | 130 | 123 | 121 | 119 | 116 | 122 | 122 | 120 | 118 | 130 | 134 |
| Loss | 168 | 146 | 133 | 135 | 153 | 191 | 214 | 197 | 159 | 126 | 143 | 164 |
| **System Load** | **2,135** | **1,888** | **1,727** | **1,751** | **1,952** | **2,396** | **2,667** | **2,471** | **2,035** | **1,658** | **1,848** | **2,090** |
| Light Load | 1,982 | 1,739 | 1,582 | 1,582 | 1,766 | 2,177 | 2,404 | 2,190 | 1,831 | 1,477 | 1,705 | 1,929 |
| Heavy Load | 2,255 | 2,000 | 1,840 | 1,874 | 2,098 | 2,571 | 2,874 | 2,675 | 2,214 | 1,789 | 1,963 | 2,228 |
| **Total Load** | **2,135** | **1,888** | **1,727** | **1,751** | **1,952** | **2,396** | **2,667** | **2,471** | **2,035** | **1,658** | **1,848** | **2,090** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,730 | 2,522 | 2,235 | 2,218 | 3,002 | 3,903 | 4,292 | 3,809 | 3,195 | 2,280 | 2,489 | 2,722 |
| **Total Peak Load** | **2,730** | **2,522** | **2,235** | **2,218** | **3,002** | **3,903** | **4,292** | **3,809** | **3,195** | **2,280** | **2,489** | **2,722** |

| Monthly Summary[1] | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 976 | 793 | 687 | 590 | 539 | 629 | 774 | 737 | 569 | 528 | 756 | 944 |
| Commercial | 555 | 513 | 472 | 478 | 478 | 511 | 556 | 563 | 524 | 491 | 512 | 553 |
| Irrigation | 3 | 3 | 10 | 142 | 375 | 637 | 698 | 546 | 356 | 79 | 5 | 3 |
| Industrial | 315 | 313 | 310 | 295 | 300 | 327 | 320 | 324 | 320 | 323 | 312 | 304 |
| Additional Firm | 133 | 130 | 123 | 121 | 119 | 116 | 122 | 122 | 120 | 118 | 130 | 134 |
| Loss | 169 | 147 | 133 | 136 | 154 | 192 | 216 | 199 | 161 | 127 | 144 | 165 |
| **System Load** | **2,151** | **1,900** | **1,736** | **1,761** | **1,965** | **2,412** | **2,686** | **2,491** | **2,049** | **1,667** | **1,859** | **2,103** |
| Light Load | 1,997 | 1,750 | 1,590 | 1,591 | 1,778 | 2,192 | 2,421 | 2,207 | 1,843 | 1,486 | 1,715 | 1,942 |
| Heavy Load | 2,262 | 2,013 | 1,850 | 1,885 | 2,100 | 2,588 | 2,877 | 2,714 | 2,200 | 1,799 | 1,975 | 2,220 |
| **Total Load** | **2,151** | **1,900** | **1,736** | **1,761** | **1,965** | **2,412** | **2,686** | **2,491** | **2,049** | **1,667** | **1,859** | **2,103** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,747 | 2,534 | 2,245 | 2,230 | 3,023 | 3,935 | 4,344 | 3,851 | 3,222 | 2,292 | 2,501 | 2,725 |
| **Total Peak Load** | **2,747** | **2,534** | **2,245** | **2,230** | **3,023** | **3,935** | **4,344** | **3,851** | **3,222** | **2,292** | **2,501** | **2,725** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2017 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2032 | 2/2032 | 3/2032 | 4/2032 | 5/2032 | 6/2032 | 7/2032 | 8/2032 | 9/2032 | 10/2032 | 11/2032 | 12/2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 983 | 770 | 691 | 593 | 543 | 634 | 782 | 744 | 573 | 530 | 760 | 953 |
| Commercial | 559 | 499 | 474 | 481 | 481 | 514 | 559 | 567 | 528 | 495 | 516 | 557 |
| Irrigation | 3 | 3 | 10 | 142 | 377 | 640 | 702 | 549 | 357 | 80 | 6 | 3 |
| Industrial | 316 | 304 | 311 | 296 | 302 | 328 | 321 | 325 | 322 | 325 | 314 | 305 |
| Additional Firm | 133 | 126 | 123 | 121 | 119 | 116 | 123 | 122 | 120 | 118 | 130 | 134 |
| Loss | 170 | 143 | 134 | 137 | 155 | 193 | 218 | 200 | 162 | 128 | 144 | 166 |
| **System Load** | **2,165** | **1,845** | **1,744** | **1,770** | **1,976** | **2,427** | **2,704** | **2,508** | **2,062** | **1,676** | **1,869** | **2,119** |
| Light Load | 2,010 | 1,699 | 1,597 | 1,599 | 1,788 | 2,206 | 2,437 | 2,223 | 1,855 | 1,493 | 1,724 | 1,956 |
| Heavy Load | 2,277 | 1,963 | 1,849 | 1,895 | 2,125 | 2,589 | 2,896 | 2,734 | 2,214 | 1,820 | 1,975 | 2,236 |
| **Total Load** | **2,165** | **1,845** | **1,744** | **1,770** | **1,976** | **2,427** | **2,704** | **2,508** | **2,062** | **1,676** | **1,869** | **2,119** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,755 | 2,544 | 2,248 | 2,237 | 3,042 | 3,963 | 4,394 | 3,890 | 3,245 | 2,301 | 2,511 | 2,737 |
| **Total Peak Load** | **2,755** | **2,544** | **2,248** | **2,237** | **3,042** | **3,963** | **4,394** | **3,890** | **3,245** | **2,301** | **2,511** | **2,737** |

| Monthly Summary[1] | 1/2033 | 2/2033 | 3/2033 | 4/2033 | 5/2033 | 6/2033 | 7/2033 | 8/2033 | 9/2033 | 10/2033 | 11/2033 | 12/2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 994 | 806 | 696 | 597 | 548 | 642 | 792 | 754 | 580 | 534 | 766 | 963 |
| Commercial | 563 | 520 | 477 | 484 | 485 | 518 | 563 | 572 | 532 | 498 | 520 | 561 |
| Irrigation | 3 | 3 | 10 | 143 | 379 | 644 | 706 | 552 | 360 | 80 | 6 | 3 |
| Industrial | 318 | 316 | 313 | 298 | 303 | 330 | 323 | 327 | 323 | 327 | 315 | 307 |
| Additional Firm | 134 | 131 | 124 | 121 | 119 | 117 | 123 | 122 | 120 | 119 | 130 | 134 |
| Loss | 172 | 150 | 135 | 138 | 156 | 195 | 219 | 202 | 163 | 129 | 145 | 168 |
| **System Load** | **2,184** | **1,925** | **1,754** | **1,781** | **1,991** | **2,445** | **2,725** | **2,530** | **2,078** | **1,686** | **1,882** | **2,136** |
| Light Load | 2,027 | 1,773 | 1,607 | 1,610 | 1,801 | 2,222 | 2,457 | 2,242 | 1,869 | 1,502 | 1,736 | 1,972 |
| Heavy Load | 2,307 | 2,039 | 1,860 | 1,907 | 2,140 | 2,608 | 2,937 | 2,738 | 2,231 | 1,831 | 1,989 | 2,255 |
| **Total Load** | **2,184** | **1,925** | **1,754** | **1,781** | **1,991** | **2,445** | **2,725** | **2,530** | **2,078** | **1,686** | **1,882** | **2,136** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,775 | 2,554 | 2,260 | 2,249 | 3,064 | 3,997 | 4,447 | 3,932 | 3,274 | 2,313 | 2,524 | 2,752 |
| **Total Peak Load** | **2,775** | **2,554** | **2,260** | **2,249** | **3,064** | **3,997** | **4,447** | **3,932** | **3,274** | **2,313** | **2,524** | **2,752** |

| Monthly Summary[1] | 1/2034 | 2/2034 | 3/2034 | 4/2034 | 5/2034 | 6/2034 | 7/2034 | 8/2034 | 9/2034 | 10/2034 | 11/2034 | 12/2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 1,007 | 814 | 702 | 603 | 555 | 650 | 803 | 765 | 587 | 539 | 773 | 975 |
| Commercial | 568 | 524 | 479 | 488 | 488 | 521 | 567 | 577 | 537 | 502 | 523 | 566 |
| Irrigation | 3 | 3 | 10 | 144 | 381 | 648 | 710 | 556 | 362 | 81 | 6 | 3 |
| Industrial | 319 | 318 | 315 | 299 | 305 | 332 | 324 | 329 | 325 | 328 | 317 | 309 |
| Additional Firm | 134 | 131 | 124 | 121 | 119 | 117 | 123 | 122 | 120 | 119 | 130 | 134 |
| Loss | 173 | 151 | 136 | 139 | 157 | 196 | 221 | 204 | 164 | 130 | 147 | 169 |
| **System Load** | **2,204** | **1,940** | **1,766** | **1,794** | **2,006** | **2,464** | **2,748** | **2,553** | **2,094** | **1,697** | **1,896** | **2,155** |
| Light Load | 2,046 | 1,787 | 1,617 | 1,621 | 1,815 | 2,240 | 2,478 | 2,262 | 1,884 | 1,512 | 1,748 | 1,990 |
| Heavy Load | 2,328 | 2,055 | 1,872 | 1,932 | 2,143 | 2,629 | 2,962 | 2,763 | 2,248 | 1,843 | 2,003 | 2,286 |
| **Total Load** | **2,204** | **1,940** | **1,766** | **1,794** | **2,006** | **2,464** | **2,748** | **2,553** | **2,094** | **1,697** | **1,896** | **2,155** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,799 | 2,571 | 2,274 | 2,263 | 3,088 | 4,034 | 4,502 | 3,978 | 3,305 | 2,327 | 2,539 | 2,765 |
| **Total Peak Load** | **2,799** | **2,571** | **2,274** | **2,263** | **3,088** | **4,034** | **4,502** | **3,978** | **3,305** | **2,327** | **2,539** | **2,765** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2017 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2035 | 2/2035 | 3/2035 | 4/2035 | 5/2035 | 6/2035 | 7/2035 | 8/2035 | 9/2035 | 10/2035 | 11/2035 | 12/2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 1,019 | 823 | 709 | 608 | 561 | 658 | 814 | 777 | 594 | 544 | 780 | 987 |
| Commercial | 573 | 527 | 482 | 491 | 492 | 525 | 571 | 582 | 541 | 505 | 528 | 570 |
| Irrigation | 3 | 3 | 10 | 145 | 384 | 652 | 715 | 559 | 364 | 81 | 6 | 3 |
| Industrial | 321 | 319 | 316 | 301 | 306 | 333 | 326 | 330 | 326 | 330 | 318 | 310 |
| Additional Firm | 134 | 131 | 124 | 122 | 120 | 117 | 123 | 122 | 120 | 119 | 131 | 134 |
| Loss | 175 | 152 | 137 | 140 | 159 | 198 | 223 | 206 | 166 | 130 | 148 | 171 |
| **System Load** | **2,225** | **1,956** | **1,778** | **1,806** | **2,021** | **2,484** | **2,772** | **2,576** | **2,112** | **1,709** | **1,910** | **2,176** |
| Light Load | 2,066 | 1,801 | 1,629 | 1,632 | 1,829 | 2,258 | 2,499 | 2,283 | 1,899 | 1,523 | 1,762 | 2,009 |
| Heavy Load | 2,340 | 2,072 | 1,885 | 1,946 | 2,160 | 2,650 | 2,987 | 2,788 | 2,281 | 1,844 | 2,019 | 2,308 |
| **Total Load** | **2,225** | **1,956** | **1,778** | **1,806** | **2,021** | **2,484** | **2,772** | **2,576** | **2,112** | **1,709** | **1,910** | **2,176** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,820 | 2,585 | 2,286 | 2,276 | 3,112 | 4,072 | 4,557 | 4,023 | 3,336 | 2,340 | 2,553 | 2,783 |
| **Total Peak Load** | **2,820** | **2,585** | **2,286** | **2,276** | **3,112** | **4,072** | **4,557** | **4,023** | **3,336** | **2,340** | **2,553** | **2,783** |

| Monthly Summary[1] | 1/2036 | 2/2036 | 3/2036 | 4/2036 | 5/2036 | 6/2036 | 7/2036 | 8/2036 | 9/2036 | 10/2036 | 11/2036 | 12/2036 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | | | |
| Residential | 1,034 | 805 | 716 | 614 | 568 | 668 | 827 | 789 | 602 | 549 | 789 | 1,000 |
| Commercial | 578 | 513 | 486 | 495 | 496 | 530 | 575 | 587 | 546 | 509 | 532 | 575 |
| Irrigation | 3 | 3 | 10 | 146 | 386 | 657 | 720 | 563 | 367 | 82 | 6 | 3 |
| Industrial | 323 | 310 | 318 | 302 | 308 | 335 | 328 | 332 | 328 | 331 | 320 | 311 |
| Additional Firm | 134 | 126 | 124 | 122 | 120 | 117 | 123 | 122 | 120 | 119 | 131 | 134 |
| Loss | 177 | 148 | 138 | 141 | 160 | 200 | 225 | 208 | 167 | 131 | 149 | 173 |
| **System Load** | **2,248** | **1,905** | **1,791** | **1,820** | **2,038** | **2,506** | **2,798** | **2,602** | **2,130** | **1,722** | **1,926** | **2,197** |
| Light Load | 2,087 | 1,755 | 1,641 | 1,644 | 1,844 | 2,277 | 2,522 | 2,305 | 1,916 | 1,534 | 1,776 | 2,028 |
| Heavy Load | 2,364 | 2,017 | 1,909 | 1,948 | 2,178 | 2,688 | 2,997 | 2,835 | 2,287 | 1,857 | 2,046 | 2,319 |
| **Total Load** | **2,248** | **1,905** | **1,791** | **1,820** | **2,038** | **2,506** | **2,798** | **2,602** | **2,130** | **1,722** | **1,926** | **2,197** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,846 | 2,604 | 2,301 | 2,291 | 3,138 | 4,112 | 4,613 | 4,070 | 3,370 | 2,354 | 2,569 | 2,801 |
| **Total Peak Load** | **2,846** | **2,604** | **2,301** | **2,291** | **3,138** | **4,112** | **4,613** | **4,070** | **3,370** | **2,354** | **2,569** | **2,801** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2017 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

# Annual Summary

| | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 5,192,299 | 5,288,270 | 5,387,516 | 5,433,174 | 5,493,900 | 5,587,539 | 5,680,823 | 5,764,006 | 5,826,598 | 5,889,242 |
| Commercial | 4,076,548 | 4,123,898 | 4,161,677 | 4,191,974 | 4,224,260 | 4,256,416 | 4,288,363 | 4,316,202 | 4,344,798 | 4,377,647 |
| Irrigation | 1,932,624 | 1,943,945 | 1,958,945 | 1,970,715 | 1,979,560 | 1,993,436 | 2,005,655 | 2,016,870 | 2,027,030 | 2,037,054 |
| Industrial | 2,451,735 | 2,524,052 | 2,560,579 | 2,586,116 | 2,601,172 | 2,614,083 | 2,629,176 | 2,643,507 | 2,656,723 | 2,669,379 |
| Additional Firm | 945,167 | 961,532 | 972,050 | 979,308 | 982,862 | 990,453 | 1,011,238 | 1,083,805 | 1,086,225 | 1,085,654 |
| **System Sales** | 14,598,372 | 14,841,697 | 15,040,768 | 15,161,288 | 15,281,755 | 15,441,927 | 15,615,255 | 15,824,391 | 15,941,373 | 16,058,976 |
| **Total Sales** | **14,598,372** | **14,841,697** | **15,040,768** | **15,161,288** | **15,281,755** | **15,441,927** | **15,615,255** | **15,824,391** | **15,941,373** | **16,058,976** |
| **Generation Month Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 5,199,316 | 5,295,568 | 5,390,883 | 5,437,684 | 5,500,755 | 5,594,373 | 5,686,930 | 5,768,617 | 5,831,239 | 5,895,050 |
| Commercial | 4,079,292 | 4,126,078 | 4,163,415 | 4,193,828 | 4,226,101 | 4,258,242 | 4,289,946 | 4,317,830 | 4,346,675 | 4,379,442 |
| Irrigation | 1,932,630 | 1,943,953 | 1,958,952 | 1,970,720 | 1,979,568 | 1,993,443 | 2,005,661 | 2,016,876 | 2,027,036 | 2,037,061 |
| Industrial | 2,457,663 | 2,527,046 | 2,562,672 | 2,587,350 | 2,602,230 | 2,615,320 | 2,630,351 | 2,644,590 | 2,657,760 | 2,670,478 |
| Additional Firm | 945,167 | 961,532 | 972,050 | 979,308 | 982,862 | 990,453 | 1,011,238 | 1,083,805 | 1,086,225 | 1,085,654 |
| **System Sales** | 14,614,068 | 14,854,177 | 15,047,972 | 15,168,890 | 15,291,516 | 15,451,831 | 15,624,126 | 15,831,717 | 15,948,935 | 16,067,685 |
| **Total Sales** | **14,614,068** | **14,854,177** | **15,047,972** | **15,168,890** | **15,291,516** | **15,451,831** | **15,624,126** | **15,831,717** | **15,948,935** | **16,067,685** |
| Loss | 1,242,079 | 1,261,466 | 1,277,968 | 1,288,110 | 1,298,996 | 1,313,309 | 1,327,880 | 1,342,679 | 1,353,186 | 1,364,020 |
| **Required Generation** | 15,856,147 | 16,115,643 | 16,325,941 | 16,457,000 | 16,590,511 | 16,765,141 | 16,952,006 | 17,174,396 | 17,302,121 | 17,431,705 |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | |
| Residential | 594 | 605 | 615 | 619 | 628 | 639 | 649 | 657 | 666 | 673 |
| Commercial | 466 | 471 | 475 | 477 | 482 | 486 | 490 | 492 | 496 | 500 |
| Irrigation | 221 | 222 | 224 | 224 | 226 | 228 | 229 | 230 | 231 | 233 |
| Industrial | 281 | 288 | 293 | 295 | 297 | 299 | 300 | 301 | 303 | 305 |
| Additional Firm | 108 | 110 | 111 | 111 | 112 | 113 | 115 | 123 | 124 | 124 |
| Loss | 142 | 144 | 146 | 147 | 148 | 150 | 152 | 153 | 154 | 156 |
| **System Load** | 1,810 | 1,840 | 1,864 | 1,874 | 1,894 | 1,914 | 1,935 | 1,955 | 1,975 | 1,990 |
| Light Load | 1,644 | 1,671 | 1,693 | 1,702 | 1,720 | 1,738 | 1,758 | 1,776 | 1,794 | 1,808 |
| Heavy Load | 1,941 | 1,972 | 1,997 | 2,008 | 2,030 | 2,051 | 2,075 | 2,095 | 2,117 | 2,133 |
| **Total Load** | **1,810** | **1,840** | **1,864** | **1,874** | **1,894** | **1,914** | **1,935** | **1,955** | **1,975** | **1,990** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | |
| System Peak (1 Hour) | 3,566 | 3,630 | 3,692 | 3,745 | 3,797 | 3,854 | 3,912 | 3,974 | 4,026 | 4,078 |
| **Total Peak Load** | **3,566** | **3,630** | **3,692** | **3,745** | **3,797** | **3,854** | **3,912** | **3,974** | **4,026** | **4,078** |

| | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Billed Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 5,967,300 | 6,042,091 | 6,107,379 | 6,164,550 | 6,217,671 | 6,262,116 | 6,326,691 | 6,399,357 | 6,472,617 | 6,556,711 |
| Commercial | 4,409,099 | 4,436,214 | 4,469,871 | 4,500,782 | 4,530,660 | 4,560,429 | 4,593,200 | 4,626,751 | 4,662,614 | 4,701,216 |
| Irrigation | 2,050,468 | 2,062,925 | 2,074,075 | 2,086,155 | 2,097,975 | 2,107,907 | 2,120,788 | 2,134,429 | 2,147,505 | 2,162,226 |
| Industrial | 2,682,789 | 2,698,620 | 2,714,704 | 2,730,194 | 2,745,660 | 2,759,437 | 2,772,278 | 2,786,182 | 2,800,272 | 2,813,726 |
| Additional Firm | 1,086,654 | 1,089,273 | 1,087,891 | 1,087,891 | 1,087,891 | 1,088,891 | 1,089,891 | 1,089,891 | 1,091,891 | 1,091,891 |
| **System Sales** | 16,196,310 | 16,329,123 | 16,453,920 | 16,569,573 | 16,679,857 | 16,778,781 | 16,902,848 | 17,036,610 | 17,174,899 | 17,325,771 |
| **Total Sales** | **16,196,310** | **16,329,123** | **16,453,920** | **16,569,573** | **16,679,857** | **16,778,781** | **16,902,848** | **17,036,610** | **17,174,899** | **17,325,771** |
| **Generation Month Sales (MWh)–50th Percentile** | | | | | | | | | | |
| Residential | 5,972,903 | 6,047,037 | 6,111,779 | 6,168,711 | 6,221,263 | 6,267,266 | 6,332,524 | 6,405,338 | 6,479,512 | 6,563,740 |
| Commercial | 4,410,638 | 4,438,137 | 4,471,632 | 4,502,482 | 4,532,353 | 4,562,298 | 4,595,114 | 4,628,801 | 4,664,824 | 4,703,281 |
| Irrigation | 2,050,475 | 2,062,931 | 2,074,082 | 2,086,162 | 2,097,981 | 2,107,914 | 2,120,796 | 2,134,436 | 2,147,513 | 2,162,234 |
| Industrial | 2,684,087 | 2,699,938 | 2,715,974 | 2,731,462 | 2,746,789 | 2,760,490 | 2,773,418 | 2,787,337 | 2,801,375 | 2,814,823 |
| Additional Firm | 1,086,654 | 1,089,273 | 1,087,891 | 1,087,891 | 1,087,891 | 1,088,891 | 1,089,891 | 1,089,891 | 1,091,891 | 1,091,891 |
| **System Sales** | 16,204,757 | 16,337,317 | 16,461,358 | 16,576,708 | 16,686,278 | 16,786,859 | 16,911,743 | 17,045,803 | 17,185,114 | 17,335,969 |
| **Total Sales** | **16,204,757** | **16,337,317** | **16,461,358** | **16,576,708** | **16,686,278** | **16,786,859** | **16,911,743** | **17,045,803** | **17,185,114** | **17,335,969** |
| Loss | 1,376,496 | 1,388,365 | 1,399,639 | 1,410,019 | 1,419,853 | 1,428,827 | 1,440,150 | 1,452,371 | 1,464,969 | 1,478,800 |
| **Required Generation** | 17,581,253 | 17,725,682 | 17,860,997 | 17,986,727 | 18,106,130 | 18,215,685 | 18,351,893 | 18,498,173 | 18,650,084 | 18,814,769 |
| **Average Load (aMW)–50th Percentile** | | | | | | | | | | |
| Residential | 682 | 688 | 698 | 704 | 710 | 713 | 723 | 731 | 740 | 747 |
| Commercial | 503 | 505 | 510 | 514 | 517 | 519 | 525 | 528 | 533 | 535 |
| Irrigation | 234 | 235 | 237 | 238 | 239 | 240 | 242 | 244 | 245 | 246 |
| Industrial | 306 | 307 | 310 | 312 | 314 | 314 | 317 | 318 | 320 | 320 |
| Additional Firm | 124 | 124 | 124 | 124 | 124 | 124 | 124 | 124 | 125 | 124 |
| Loss | 157 | 158 | 160 | 161 | 162 | 163 | 164 | 166 | 167 | 168 |
| **System Load** | 2,007 | 2,018 | 2,039 | 2,053 | 2,067 | 2,074 | 2,095 | 2,112 | 2,129 | 2,142 |
| Light Load | 1,823 | 1,833 | 1,852 | 1,865 | 1,877 | 1,884 | 1,903 | 1,918 | 1,934 | 1,946 |
| Heavy Load | 2,151 | 2,164 | 2,186 | 2,201 | 2,209 | 2,216 | 2,239 | 2,258 | 2,275 | 2,289 |
| **Total Load** | **2,007** | **2,018** | **2,039** | **2,053** | **2,067** | **2,074** | **2,095** | **2,112** | **2,129** | **2,142** |
| **Peak Load (MW)–90th Percentile** | | | | | | | | | | |
| System Peak (1 Hour) | 4,132 | 4,187 | 4,240 | 4,292 | 4,344 | 4,394 | 4,447 | 4,502 | 4,557 | 4,613 |
| **Total Peak Load** | **4,132** | **4,187** | **4,240** | **4,292** | **4,344** | **4,394** | **4,447** | **4,502** | **4,557** | **4,613** |

# 70th Percentile Annual Forecast Growth Rates

| | 2017–2022 | 2017–2027 | 2017–2036 |
|---|---|---|---|
| **Sales** | | | |
| Residential Sales | 1.49% | 1.41% | 1.24% |
| Commercial Sales | 0.88% | 0.80% | 0.77% |
| Irrigation Sales | 0.58% | 0.56% | 0.56% |
| Industrial Sales | 1.29% | 0.90% | 0.73% |
| Additional Firm Sales | 0.94% | 1.40% | 0.76% |
| System Sales | 1.13% | 1.05% | 0.91% |
| Total Sales | 1.13% | 1.05% | 0.91% |
| **Loads** | | | |
| Residential Load | 1.49% | 1.40% | 1.22% |
| Commercial Load | 0.88% | 0.80% | 0.75% |
| Irrigation Load | 0.58% | 0.56% | 0.54% |
| Industrial Load | 1.25% | 0.89% | 0.70% |
| Additional Firm Sales | 0.94% | 1.40% | 0.76% |
| System Load Losses | 1.12% | 1.03% | 0.91% |
| System Load | 1.12% | 1.04% | 0.89% |
| Total Load | 1.12% | 1.04% | 0.89% |
| **Peaks** | | | |
| System Peak | 1.57% | 1.49% | 1.37% |
| Total Peak | 1.57% | 1.49% | 1.37% |
| Winter Peak | 1.20% | 1.03% | 0.87% |
| Summer Peak | 1.57% | 1.49% | 1.37% |
| **Customers** | | | |
| Residential Customers | 2.11% | 2.02% | 1.78% |
| Commercial Customers | 1.86% | 1.90% | 1.77% |
| Irrigation Customers | 1.42% | 1.37% | 1.29% |
| Industrial Customers | 0.50% | 0.65% | 0.59% |

# 70th Percentile Load Forecast

| Monthly Summary[1] | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 845 | 690 | 604 | 513 | 460 | 542 | 653 | 614 | 483 | 463 | 664 | 819 |
| Commercial | 504 | 472 | 437 | 433 | 435 | 471 | 511 | 504 | 474 | 447 | 463 | 504 |
| Irrigation | 2 | 3 | 10 | 152 | 394 | 633 | 664 | 516 | 341 | 78 | 5 | 3 |
| Industrial | 281 | 279 | 277 | 263 | 268 | 292 | 285 | 289 | 286 | 289 | 279 | 278 |
| Additional Firm | 113 | 111 | 106 | 106 | 105 | 102 | 108 | 108 | 107 | 104 | 112 | 114 |
| Loss | 149 | 131 | 120 | 123 | 142 | 177 | 194 | 176 | 144 | 114 | 128 | 146 |
| **System Load** | **1,894** | **1,686** | **1,555** | **1,591** | **1,803** | **2,217** | **2,415** | **2,207** | **1,834** | **1,495** | **1,650** | **1,863** |
| Light Load | 1,759 | 1,553 | 1,424 | 1,437 | 1,631 | 2,015 | 2,177 | 1,956 | 1,650 | 1,332 | 1,522 | 1,720 |
| Heavy Load | 2,011 | 1,786 | 1,649 | 1,714 | 1,938 | 2,365 | 2,620 | 2,389 | 1,982 | 1,624 | 1,753 | 1,986 |
| **Total Load** | **1,894** | **1,686** | **1,555** | **1,591** | **1,803** | **2,217** | **2,415** | **2,207** | **1,834** | **1,495** | **1,650** | **1,863** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,441 | 2,358 | 2,067 | 2,020 | 2,686 | 3,431 | 3,586 | 3,248 | 2,781 | 2,091 | 2,307 | 2,611 |
| **Total Peak Load** | **2,441** | **2,358** | **2,067** | **2,020** | **2,686** | **3,431** | **3,586** | **3,248** | **2,781** | **2,091** | **2,307** | **2,611** |

| Monthly Summary[1] | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 860 | 702 | 614 | 522 | 469 | 553 | 667 | 627 | 492 | 471 | 674 | 833 |
| Commercial | 510 | 477 | 442 | 438 | 440 | 477 | 517 | 511 | 480 | 452 | 469 | 509 |
| Irrigation | 2 | 3 | 10 | 153 | 396 | 636 | 667 | 519 | 343 | 78 | 5 | 3 |
| Industrial | 289 | 288 | 285 | 271 | 276 | 300 | 294 | 298 | 294 | 297 | 287 | 282 |
| Additional Firm | 115 | 113 | 108 | 107 | 107 | 103 | 110 | 110 | 109 | 106 | 114 | 116 |
| Loss | 152 | 133 | 122 | 125 | 144 | 180 | 197 | 179 | 146 | 116 | 130 | 148 |
| **System Load** | **1,929** | **1,716** | **1,581** | **1,617** | **1,831** | **2,250** | **2,452** | **2,243** | **1,864** | **1,521** | **1,679** | **1,891** |
| Light Load | 1,791 | 1,580 | 1,448 | 1,461 | 1,657 | 2,045 | 2,211 | 1,988 | 1,677 | 1,355 | 1,548 | 1,745 |
| Heavy Load | 2,038 | 1,818 | 1,676 | 1,742 | 1,969 | 2,400 | 2,660 | 2,428 | 2,028 | 1,640 | 1,783 | 2,015 |
| **Total Load** | **1,929** | **1,716** | **1,581** | **1,617** | **1,831** | **2,250** | **2,452** | **2,243** | **1,864** | **1,521** | **1,679** | **1,891** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,487 | 2,393 | 2,101 | 2,048 | 2,724 | 3,489 | 3,651 | 3,305 | 2,833 | 2,118 | 2,335 | 2,648 |
| **Total Peak Load** | **2,487** | **2,393** | **2,101** | **2,048** | **2,724** | **3,489** | **3,651** | **3,305** | **2,833** | **2,118** | **2,335** | **2,648** |

| Monthly Summary[1] | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 876 | 714 | 624 | 530 | 478 | 565 | 682 | 642 | 502 | 478 | 685 | 843 |
| Commercial | 515 | 481 | 445 | 442 | 444 | 481 | 521 | 516 | 485 | 456 | 473 | 513 |
| Irrigation | 3 | 3 | 11 | 154 | 399 | 641 | 672 | 523 | 346 | 79 | 5 | 3 |
| Industrial | 294 | 292 | 289 | 275 | 280 | 305 | 298 | 302 | 299 | 302 | 291 | 285 |
| Additional Firm | 117 | 115 | 109 | 109 | 108 | 104 | 111 | 111 | 110 | 107 | 115 | 117 |
| Loss | 154 | 135 | 123 | 127 | 146 | 182 | 200 | 181 | 148 | 117 | 131 | 150 |
| **System Load** | **1,958** | **1,740** | **1,601** | **1,637** | **1,854** | **2,278** | **2,485** | **2,274** | **1,889** | **1,540** | **1,701** | **1,910** |
| Light Load | 1,818 | 1,602 | 1,467 | 1,480 | 1,678 | 2,070 | 2,240 | 2,015 | 1,699 | 1,372 | 1,569 | 1,764 |
| Heavy Load | 2,068 | 1,843 | 1,707 | 1,753 | 1,993 | 2,444 | 2,678 | 2,461 | 2,055 | 1,661 | 1,807 | 2,036 |
| **Total Load** | **1,958** | **1,740** | **1,601** | **1,637** | **1,854** | **2,278** | **2,485** | **2,274** | **1,889** | **1,540** | **1,701** | **1,910** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour | 2,530 | 2,426 | 2,132 | 2,073 | 2,758 | 3,540 | 3,713 | 3,359 | 2,876 | 2,141 | 2,359 | 2,666 |
| **Total Peak Load** | **2,530** | **2,426** | **2,132** | **2,073** | **2,758** | **3,540** | **3,713** | **3,359** | **2,876** | **2,141** | **2,359** | **2,666** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2017 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 883 | 695 | 628 | 534 | 483 | 571 | 690 | 650 | 507 | 481 | 690 | 851 |
| Commercial | 519 | 468 | 448 | 446 | 447 | 485 | 525 | 520 | 489 | 460 | 477 | 517 |
| Irrigation | 3 | 3 | 11 | 155 | 401 | 645 | 676 | 526 | 348 | 79 | 5 | 3 |
| Industrial | 297 | 285 | 292 | 278 | 283 | 308 | 301 | 305 | 302 | 305 | 294 | 287 |
| Additional Firm | 118 | 112 | 110 | 109 | 108 | 105 | 112 | 111 | 110 | 108 | 116 | 118 |
| Loss | 155 | 131 | 124 | 128 | 147 | 183 | 202 | 183 | 149 | 118 | 132 | 151 |
| **System Load** | **1,975** | **1,693** | **1,613** | **1,650** | **1,869** | **2,297** | **2,506** | **2,295** | **1,904** | **1,551** | **1,714** | **1,926** |
| Light Load | 1,834 | 1,559 | 1,477 | 1,490 | 1,691 | 2,087 | 2,259 | 2,034 | 1,713 | 1,382 | 1,581 | 1,778 |
| Heavy Load | 2,086 | 1,792 | 1,719 | 1,766 | 2,022 | 2,450 | 2,701 | 2,501 | 2,057 | 1,673 | 1,831 | 2,043 |
| **Total Load** | **1,975** | **1,693** | **1,613** | **1,650** | **1,869** | **2,297** | **2,506** | **2,295** | **1,904** | **1,551** | **1,714** | **1,926** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,550 | 2,438 | 2,146 | 2,087 | 2,780 | 3,574 | 3,766 | 3,402 | 2,904 | 2,154 | 2,373 | 2,671 |
| **Total Peak Load** | **2,550** | **2,438** | **2,146** | **2,087** | **2,780** | **3,574** | **3,766** | **3,402** | **2,904** | **2,154** | **2,373** | **2,671** |

| Monthly Summary[1] | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 893 | 727 | 634 | 539 | 489 | 579 | 701 | 659 | 513 | 486 | 696 | 863 |
| Commercial | 524 | 488 | 450 | 449 | 451 | 488 | 529 | 525 | 493 | 463 | 481 | 521 |
| Irrigation | 3 | 3 | 11 | 156 | 402 | 647 | 679 | 528 | 349 | 80 | 5 | 3 |
| Industrial | 298 | 297 | 294 | 279 | 284 | 310 | 303 | 307 | 303 | 306 | 296 | 288 |
| Additional Firm | 118 | 116 | 111 | 110 | 109 | 105 | 112 | 112 | 111 | 108 | 116 | 119 |
| Loss | 157 | 137 | 125 | 129 | 148 | 185 | 203 | 185 | 150 | 119 | 133 | 153 |
| **System Load** | **1,993** | **1,768** | **1,624** | **1,662** | **1,883** | **2,315** | **2,527** | **2,316** | **1,920** | **1,562** | **1,727** | **1,946** |
| Light Load | 1,850 | 1,628 | 1,488 | 1,501 | 1,704 | 2,104 | 2,278 | 2,052 | 1,727 | 1,392 | 1,593 | 1,796 |
| Heavy Load | 2,115 | 1,872 | 1,722 | 1,779 | 2,038 | 2,469 | 2,723 | 2,524 | 2,074 | 1,696 | 1,835 | 2,064 |
| **Total Load** | **1,993** | **1,768** | **1,624** | **1,662** | **1,883** | **2,315** | **2,527** | **2,316** | **1,920** | **1,562** | **1,727** | **1,946** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,562 | 2,450 | 2,153 | 2,098 | 2,803 | 3,606 | 3,819 | 3,444 | 2,932 | 2,168 | 2,387 | 2,691 |
| **Total Peak Load** | **2,562** | **2,450** | **2,153** | **2,098** | **2,803** | **3,606** | **3,819** | **3,444** | **2,932** | **2,168** | **2,387** | **2,691** |

| Monthly Summary[1] | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 908 | 738 | 643 | 547 | 498 | 590 | 715 | 673 | 522 | 493 | 706 | 877 |
| Commercial | 528 | 492 | 453 | 453 | 455 | 492 | 533 | 530 | 497 | 466 | 484 | 525 |
| Irrigation | 3 | 3 | 11 | 156 | 405 | 652 | 684 | 532 | 352 | 80 | 5 | 3 |
| Industrial | 300 | 298 | 295 | 281 | 286 | 311 | 304 | 308 | 305 | 308 | 297 | 290 |
| Additional Firm | 119 | 117 | 112 | 111 | 110 | 106 | 113 | 113 | 111 | 109 | 117 | 120 |
| Loss | 159 | 139 | 126 | 130 | 150 | 187 | 206 | 187 | 152 | 120 | 135 | 155 |
| **System Load** | **2,017** | **1,787** | **1,640** | **1,678** | **1,902** | **2,338** | **2,554** | **2,342** | **1,939** | **1,577** | **1,745** | **1,968** |
| Light Load | 1,872 | 1,645 | 1,502 | 1,516 | 1,721 | 2,125 | 2,303 | 2,075 | 1,744 | 1,405 | 1,610 | 1,817 |
| Heavy Load | 2,141 | 1,892 | 1,739 | 1,796 | 2,058 | 2,494 | 2,771 | 2,535 | 2,095 | 1,712 | 1,854 | 2,087 |
| **Total Load** | **2,017** | **1,787** | **1,640** | **1,678** | **1,902** | **2,338** | **2,554** | **2,342** | **1,939** | **1,577** | **1,745** | **1,968** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,591 | 2,472 | 2,173 | 2,116 | 2,830 | 3,647 | 3,876 | 3,492 | 2,966 | 2,184 | 2,405 | 2,708 |
| **Total Peak Load** | **2,591** | **2,472** | **2,173** | **2,116** | **2,830** | **3,647** | **3,876** | **3,492** | **2,966** | **2,184** | **2,405** | **2,708** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2017 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 923 | 750 | 652 | 555 | 507 | 602 | 729 | 687 | 532 | 500 | 716 | 889 |
| Commercial | 533 | 495 | 456 | 456 | 458 | 496 | 537 | 534 | 501 | 470 | 488 | 529 |
| Irrigation | 3 | 3 | 11 | 157 | 407 | 655 | 688 | 535 | 354 | 81 | 6 | 3 |
| Industrial | 301 | 300 | 297 | 282 | 288 | 313 | 306 | 310 | 307 | 310 | 299 | 291 |
| Additional Firm | 122 | 120 | 114 | 113 | 112 | 108 | 115 | 115 | 113 | 111 | 120 | 123 |
| Loss | 161 | 140 | 128 | 131 | 151 | 189 | 208 | 189 | 154 | 121 | 136 | 156 |
| **System Load** | **2,043** | **1,808** | **1,657** | **1,695** | **1,922** | **2,363** | **2,582** | **2,369** | **1,960** | **1,592** | **1,765** | **1,991** |
| Light Load | 1,896 | 1,665 | 1,518 | 1,532 | 1,739 | 2,147 | 2,328 | 2,100 | 1,763 | 1,419 | 1,628 | 1,838 |
| Heavy Load | 2,168 | 1,915 | 1,757 | 1,826 | 2,066 | 2,520 | 2,801 | 2,564 | 2,118 | 1,729 | 1,875 | 2,123 |
| **Total Load** | **2,043** | **1,808** | **1,657** | **1,695** | **1,922** | **2,363** | **2,582** | **2,369** | **1,960** | **1,592** | **1,765** | **1,991** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,619 | 2,493 | 2,192 | 2,134 | 2,858 | 3,690 | 3,934 | 3,541 | 3,002 | 2,202 | 2,426 | 2,725 |
| **Total Peak Load** | **2,619** | **2,493** | **2,192** | **2,134** | **2,858** | **3,690** | **3,934** | **3,541** | **3,002** | **2,202** | **2,426** | **2,725** |

| Monthly Summary[1] | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 936 | 733 | 660 | 563 | 515 | 612 | 742 | 699 | 540 | 506 | 725 | 900 |
| Commercial | 537 | 481 | 458 | 459 | 461 | 499 | 540 | 538 | 505 | 473 | 491 | 532 |
| Irrigation | 3 | 3 | 11 | 158 | 409 | 659 | 692 | 538 | 356 | 81 | 6 | 3 |
| Industrial | 303 | 291 | 298 | 284 | 289 | 315 | 308 | 312 | 308 | 311 | 300 | 293 |
| Additional Firm | 133 | 126 | 123 | 121 | 119 | 116 | 122 | 121 | 119 | 118 | 130 | 133 |
| Loss | 163 | 137 | 129 | 133 | 153 | 191 | 210 | 191 | 155 | 123 | 138 | 158 |
| **System Load** | **2,074** | **1,771** | **1,679** | **1,717** | **1,945** | **2,390** | **2,614** | **2,400** | **1,984** | **1,612** | **1,790** | **2,019** |
| Light Load | 1,926 | 1,631 | 1,538 | 1,551 | 1,760 | 2,172 | 2,356 | 2,126 | 1,784 | 1,436 | 1,651 | 1,864 |
| Heavy Load | 2,191 | 1,875 | 1,790 | 1,838 | 2,091 | 2,565 | 2,817 | 2,597 | 2,158 | 1,739 | 1,902 | 2,152 |
| **Total Load** | **2,074** | **1,771** | **1,679** | **1,717** | **1,945** | **2,390** | **2,614** | **2,400** | **1,984** | **1,612** | **1,790** | **2,019** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,654 | 2,520 | 2,217 | 2,156 | 2,890 | 3,735 | 3,998 | 3,594 | 3,040 | 2,225 | 2,454 | 2,747 |
| **Total Peak Load** | **2,654** | **2,520** | **2,217** | **2,156** | **2,890** | **3,735** | **3,998** | **3,594** | **3,040** | **2,225** | **2,454** | **2,747** |

| Monthly Summary[1] | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 946 | 767 | 666 | 568 | 521 | 620 | 753 | 709 | 546 | 510 | 731 | 909 |
| Commercial | 541 | 501 | 460 | 462 | 464 | 502 | 543 | 542 | 509 | 476 | 495 | 536 |
| Irrigation | 3 | 3 | 11 | 159 | 411 | 662 | 695 | 540 | 357 | 81 | 6 | 3 |
| Industrial | 305 | 303 | 300 | 285 | 291 | 316 | 309 | 313 | 310 | 313 | 302 | 294 |
| Additional Firm | 133 | 130 | 123 | 121 | 119 | 116 | 122 | 122 | 120 | 118 | 130 | 134 |
| Loss | 164 | 143 | 130 | 134 | 154 | 192 | 212 | 193 | 156 | 124 | 139 | 159 |
| **System Load** | **2,091** | **1,848** | **1,690** | **1,728** | **1,959** | **2,408** | **2,635** | **2,420** | **1,999** | **1,622** | **1,803** | **2,035** |
| Light Load | 1,942 | 1,702 | 1,548 | 1,562 | 1,773 | 2,189 | 2,375 | 2,145 | 1,798 | 1,445 | 1,663 | 1,879 |
| Heavy Load | 2,209 | 1,957 | 1,801 | 1,850 | 2,106 | 2,584 | 2,839 | 2,638 | 2,159 | 1,750 | 1,926 | 2,158 |
| **Total Load** | **2,091** | **1,848** | **1,690** | **1,728** | **1,959** | **2,408** | **2,635** | **2,420** | **1,999** | **1,622** | **1,803** | **2,035** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,668 | 2,533 | 2,226 | 2,167 | 2,911 | 3,766 | 4,050 | 3,636 | 3,066 | 2,236 | 2,466 | 2,754 |
| **Total Peak Load** | **2,668** | **2,533** | **2,226** | **2,167** | **2,911** | **3,766** | **4,050** | **3,636** | **3,066** | **2,236** | **2,466** | **2,754** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2017 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 956 | 774 | 671 | 573 | 527 | 628 | 763 | 720 | 553 | 515 | 738 | 919 |
| Commercial | 545 | 505 | 463 | 465 | 468 | 506 | 547 | 547 | 513 | 479 | 499 | 540 |
| Irrigation | 3 | 3 | 11 | 159 | 412 | 665 | 698 | 543 | 359 | 82 | 6 | 3 |
| Industrial | 306 | 304 | 301 | 287 | 292 | 318 | 311 | 315 | 311 | 314 | 303 | 296 |
| Additional Firm | 133 | 130 | 123 | 121 | 119 | 116 | 122 | 122 | 120 | 118 | 130 | 134 |
| Loss | 166 | 144 | 131 | 135 | 155 | 194 | 214 | 195 | 158 | 124 | 140 | 161 |
| **System Load** | **2,109** | **1,861** | **1,700** | **1,740** | **1,973** | **2,426** | **2,656** | **2,441** | **2,014** | **1,633** | **1,815** | **2,052** |
| Light Load | 1,958 | 1,714 | 1,558 | 1,572 | 1,786 | 2,205 | 2,394 | 2,163 | 1,811 | 1,455 | 1,674 | 1,895 |
| Heavy Load | 2,228 | 1,971 | 1,813 | 1,863 | 2,135 | 2,588 | 2,862 | 2,660 | 2,176 | 1,761 | 1,939 | 2,177 |
| **Total Load** | **2,109** | **1,861** | **1,700** | **1,740** | **1,973** | **2,426** | **2,656** | **2,441** | **2,014** | **1,633** | **1,815** | **2,052** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,682 | 2,542 | 2,233 | 2,178 | 2,933 | 3,798 | 4,102 | 3,678 | 3,093 | 2,248 | 2,479 | 2,769 |
| **Total Peak Load** | **2,682** | **2,542** | **2,233** | **2,178** | **2,933** | **3,798** | **4,102** | **3,678** | **3,093** | **2,248** | **2,479** | **2,769** |

| Monthly Summary[1] | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 968 | 784 | 679 | 579 | 534 | 638 | 776 | 732 | 561 | 520 | 746 | 930 |
| Commercial | 550 | 508 | 466 | 469 | 472 | 509 | 551 | 552 | 517 | 483 | 502 | 544 |
| Irrigation | 3 | 3 | 11 | 160 | 415 | 669 | 703 | 547 | 361 | 82 | 6 | 3 |
| Industrial | 308 | 306 | 303 | 288 | 293 | 319 | 312 | 316 | 313 | 316 | 305 | 297 |
| Additional Firm | 133 | 130 | 123 | 121 | 119 | 116 | 122 | 122 | 120 | 118 | 130 | 134 |
| Loss | 167 | 146 | 132 | 136 | 156 | 195 | 216 | 197 | 159 | 125 | 141 | 162 |
| **System Load** | **2,129** | **1,877** | **1,713** | **1,753** | **1,990** | **2,447** | **2,680** | **2,465** | **2,031** | **1,645** | **1,830** | **2,071** |
| Light Load | 1,977 | 1,729 | 1,569 | 1,584 | 1,800 | 2,224 | 2,416 | 2,184 | 1,827 | 1,465 | 1,688 | 1,912 |
| Heavy Load | 2,260 | 1,988 | 1,817 | 1,877 | 2,153 | 2,610 | 2,888 | 2,686 | 2,195 | 1,786 | 1,944 | 2,196 |
| **Total Load** | **2,129** | **1,877** | **1,713** | **1,753** | **1,990** | **2,447** | **2,680** | **2,465** | **2,031** | **1,645** | **1,830** | **2,071** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour | 2,705 | 2,559 | 2,248 | 2,192 | 2,957 | 3,836 | 4,157 | 3,723 | 3,124 | 2,262 | 2,493 | 2,784 |
| **Total Peak Load** | **2,705** | **2,559** | **2,248** | **2,192** | **2,957** | **3,836** | **4,157** | **3,723** | **3,124** | **2,262** | **2,493** | **2,784** |

| Monthly Summary[1] | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 980 | 765 | 685 | 585 | 541 | 647 | 788 | 743 | 568 | 525 | 753 | 941 |
| Commercial | 554 | 494 | 468 | 472 | 475 | 512 | 554 | 556 | 521 | 486 | 506 | 548 |
| Irrigation | 3 | 3 | 11 | 161 | 417 | 673 | 707 | 550 | 363 | 83 | 6 | 3 |
| Industrial | 309 | 297 | 305 | 290 | 295 | 321 | 314 | 318 | 315 | 318 | 307 | 299 |
| Additional Firm | 134 | 126 | 123 | 121 | 119 | 116 | 123 | 122 | 120 | 118 | 130 | 134 |
| Loss | 169 | 142 | 133 | 137 | 158 | 197 | 218 | 199 | 161 | 126 | 142 | 164 |
| **System Load** | **2,149** | **1,827** | **1,725** | **1,766** | **2,005** | **2,467** | **2,704** | **2,488** | **2,048** | **1,656** | **1,844** | **2,088** |
| Light Load | 1,995 | 1,682 | 1,580 | 1,596 | 1,815 | 2,242 | 2,438 | 2,205 | 1,842 | 1,476 | 1,701 | 1,928 |
| Heavy Load | 2,281 | 1,934 | 1,829 | 1,902 | 2,156 | 2,632 | 2,933 | 2,692 | 2,213 | 1,799 | 1,959 | 2,226 |
| **Total Load** | **2,149** | **1,827** | **1,725** | **1,766** | **2,005** | **2,467** | **2,704** | **2,488** | **2,048** | **1,656** | **1,844** | **2,088** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,728 | 2,574 | 2,263 | 2,206 | 2,981 | 3,872 | 4,212 | 3,768 | 3,155 | 2,276 | 2,509 | 2,796 |
| **Total Peak Load** | **2,728** | **2,574** | **2,263** | **2,206** | **2,981** | **3,872** | **4,212** | **3,768** | **3,155** | **2,276** | **2,509** | **2,796** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2017 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 991 | 800 | 691 | 591 | 548 | 656 | 799 | 754 | 575 | 530 | 760 | 949 |
| Commercial | 558 | 515 | 471 | 475 | 478 | 516 | 558 | 561 | 525 | 489 | 509 | 552 |
| Irrigation | 3 | 3 | 11 | 162 | 419 | 676 | 711 | 553 | 365 | 83 | 6 | 3 |
| Industrial | 311 | 309 | 306 | 292 | 297 | 323 | 316 | 320 | 317 | 320 | 308 | 301 |
| Additional Firm | 133 | 130 | 123 | 121 | 119 | 116 | 122 | 122 | 120 | 118 | 130 | 134 |
| Loss | 171 | 148 | 134 | 138 | 159 | 199 | 220 | 201 | 162 | 127 | 144 | 165 |
| **System Load** | **2,167** | **1,906** | **1,736** | **1,778** | **2,020** | **2,486** | **2,726** | **2,510** | **2,064** | **1,667** | **1,857** | **2,104** |
| Light Load | 2,012 | 1,756 | 1,590 | 1,607 | 1,828 | 2,259 | 2,458 | 2,224 | 1,856 | 1,485 | 1,713 | 1,942 |
| Heavy Load | 2,290 | 2,019 | 1,841 | 1,915 | 2,172 | 2,652 | 2,957 | 2,716 | 2,246 | 1,799 | 1,973 | 2,243 |
| **Total Load** | **2,167** | **1,906** | **1,736** | **1,778** | **2,020** | **2,486** | **2,726** | **2,510** | **2,064** | **1,667** | **1,857** | **2,104** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,745 | 2,588 | 2,273 | 2,218 | 3,004 | 3,906 | 4,265 | 3,811 | 3,183 | 2,288 | 2,521 | 2,807 |
| **Total Peak Load** | **2,745** | **2,588** | **2,273** | **2,218** | **3,004** | **3,906** | **4,265** | **3,811** | **3,183** | **2,288** | **2,521** | **2,807** |

| Monthly Summary[1] | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 1,000 | 807 | 696 | 595 | 553 | 663 | 809 | 764 | 581 | 533 | 765 | 958 |
| Commercial | 563 | 518 | 473 | 479 | 482 | 520 | 562 | 565 | 529 | 492 | 513 | 555 |
| Irrigation | 3 | 3 | 11 | 163 | 421 | 680 | 715 | 556 | 367 | 84 | 6 | 3 |
| Industrial | 313 | 311 | 308 | 293 | 299 | 325 | 318 | 322 | 318 | 322 | 310 | 303 |
| Additional Firm | 133 | 130 | 123 | 121 | 119 | 116 | 122 | 122 | 120 | 118 | 130 | 134 |
| Loss | 172 | 149 | 134 | 139 | 160 | 200 | 222 | 202 | 163 | 128 | 144 | 166 |
| **System Load** | **2,184** | **1,919** | **1,746** | **1,789** | **2,034** | **2,504** | **2,748** | **2,531** | **2,079** | **1,677** | **1,869** | **2,119** |
| Light Load | 2,028 | 1,768 | 1,600 | 1,617 | 1,841 | 2,276 | 2,477 | 2,243 | 1,870 | 1,494 | 1,724 | 1,956 |
| Heavy Load | 2,307 | 2,033 | 1,861 | 1,915 | 2,187 | 2,687 | 2,961 | 2,739 | 2,262 | 1,809 | 1,985 | 2,259 |
| **Total Load** | **2,184** | **1,919** | **1,746** | **1,789** | **2,034** | **2,504** | **2,748** | **2,531** | **2,079** | **1,677** | **1,869** | **2,119** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,763 | 2,601 | 2,284 | 2,230 | 3,025 | 3,939 | 4,317 | 3,853 | 3,210 | 2,299 | 2,533 | 2,817 |
| **Total Peak Load** | **2,763** | **2,601** | **2,284** | **2,230** | **3,025** | **3,939** | **4,317** | **3,853** | **3,210** | **2,299** | **2,533** | **2,817** |

| Monthly Summary[1] | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 1,009 | 813 | 700 | 599 | 558 | 671 | 819 | 773 | 586 | 537 | 770 | 965 |
| Commercial | 567 | 522 | 476 | 482 | 485 | 523 | 566 | 569 | 533 | 496 | 517 | 559 |
| Irrigation | 3 | 3 | 11 | 164 | 423 | 683 | 719 | 559 | 369 | 84 | 6 | 3 |
| Industrial | 315 | 313 | 310 | 295 | 300 | 327 | 320 | 324 | 320 | 323 | 312 | 304 |
| Additional Firm | 133 | 130 | 123 | 121 | 119 | 116 | 122 | 122 | 120 | 118 | 130 | 134 |
| Loss | 173 | 150 | 135 | 139 | 161 | 202 | 223 | 204 | 164 | 129 | 145 | 168 |
| **System Load** | **2,200** | **1,931** | **1,755** | **1,799** | **2,048** | **2,522** | **2,768** | **2,551** | **2,094** | **1,687** | **1,880** | **2,132** |
| Light Load | 2,043 | 1,779 | 1,608 | 1,626 | 1,853 | 2,292 | 2,496 | 2,261 | 1,883 | 1,503 | 1,734 | 1,969 |
| Heavy Load | 2,314 | 2,046 | 1,871 | 1,926 | 2,188 | 2,706 | 2,965 | 2,780 | 2,247 | 1,819 | 1,997 | 2,251 |
| **Total Load** | **2,200** | **1,931** | **1,755** | **1,799** | **2,048** | **2,522** | **2,768** | **2,551** | **2,094** | **1,687** | **1,880** | **2,132** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,780 | 2,613 | 2,294 | 2,241 | 3,047 | 3,971 | 4,370 | 3,896 | 3,237 | 2,311 | 2,545 | 2,820 |
| **Total Peak Load** | **2,780** | **2,613** | **2,294** | **2,241** | **3,047** | **3,971** | **4,370** | **3,896** | **3,237** | **2,311** | **2,545** | **2,820** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2017 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2032 | 2/2032 | 3/2032 | 4/2032 | 5/2032 | 6/2032 | 7/2032 | 8/2032 | 9/2032 | 10/2032 | 11/2032 | 12/2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 1,017 | 790 | 703 | 602 | 563 | 677 | 827 | 781 | 591 | 539 | 774 | 973 |
| Commercial | 571 | 507 | 478 | 485 | 489 | 526 | 569 | 574 | 537 | 499 | 520 | 563 |
| Irrigation | 3 | 3 | 11 | 164 | 425 | 686 | 722 | 562 | 371 | 84 | 6 | 3 |
| Industrial | 316 | 304 | 311 | 296 | 302 | 328 | 321 | 325 | 322 | 325 | 314 | 305 |
| Additional Firm | 133 | 126 | 123 | 121 | 119 | 116 | 123 | 122 | 120 | 118 | 130 | 134 |
| Loss | 175 | 146 | 136 | 140 | 162 | 203 | 225 | 206 | 165 | 129 | 146 | 169 |
| **System Load** | **2,215** | **1,875** | **1,763** | **1,809** | **2,060** | **2,537** | **2,787** | **2,570** | **2,107** | **1,695** | **1,890** | **2,148** |
| Light Load | 2,057 | 1,727 | 1,615 | 1,634 | 1,864 | 2,306 | 2,512 | 2,277 | 1,895 | 1,510 | 1,743 | 1,983 |
| Heavy Load | 2,330 | 1,996 | 1,870 | 1,936 | 2,214 | 2,707 | 2,985 | 2,800 | 2,261 | 1,841 | 1,997 | 2,267 |
| **Total Load** | **2,215** | **1,875** | **1,763** | **1,809** | **2,060** | **2,537** | **2,787** | **2,570** | **2,107** | **1,695** | **1,890** | **2,148** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,788 | 2,623 | 2,297 | 2,248 | 3,065 | 3,998 | 4,420 | 3,935 | 3,260 | 2,320 | 2,555 | 2,832 |
| **Total Peak Load** | **2,788** | **2,623** | **2,297** | **2,248** | **3,065** | **3,998** | **4,420** | **3,935** | **3,260** | **2,320** | **2,555** | **2,832** |

| Monthly Summary[1] | 1/2033 | 2/2033 | 3/2033 | 4/2033 | 5/2033 | 6/2033 | 7/2033 | 8/2033 | 9/2033 | 10/2033 | 11/2033 | 12/2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 1,028 | 826 | 709 | 606 | 569 | 685 | 838 | 792 | 598 | 543 | 780 | 984 |
| Commercial | 576 | 528 | 481 | 488 | 492 | 530 | 573 | 579 | 542 | 502 | 524 | 567 |
| Irrigation | 3 | 3 | 11 | 165 | 427 | 690 | 726 | 565 | 373 | 85 | 6 | 3 |
| Industrial | 318 | 316 | 313 | 298 | 303 | 330 | 323 | 327 | 323 | 327 | 315 | 307 |
| Additional Firm | 134 | 131 | 124 | 121 | 119 | 117 | 123 | 122 | 120 | 119 | 130 | 134 |
| Loss | 176 | 152 | 137 | 141 | 163 | 205 | 227 | 207 | 167 | 130 | 147 | 170 |
| **System Load** | **2,234** | **1,956** | **1,774** | **1,820** | **2,074** | **2,557** | **2,809** | **2,592** | **2,123** | **1,705** | **1,903** | **2,166** |
| Light Load | 2,074 | 1,802 | 1,625 | 1,645 | 1,877 | 2,323 | 2,533 | 2,297 | 1,909 | 1,519 | 1,755 | 2,000 |
| Heavy Load | 2,360 | 2,072 | 1,881 | 1,948 | 2,230 | 2,727 | 3,028 | 2,805 | 2,279 | 1,852 | 2,011 | 2,286 |
| **Total Load** | **2,234** | **1,956** | **1,774** | **1,820** | **2,074** | **2,557** | **2,809** | **2,592** | **2,123** | **1,705** | **1,903** | **2,166** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,808 | 2,633 | 2,309 | 2,260 | 3,087 | 4,032 | 4,474 | 3,979 | 3,288 | 2,332 | 2,567 | 2,847 |
| **Total Peak Load** | **2,808** | **2,633** | **2,309** | **2,260** | **3,087** | **4,032** | **4,474** | **3,979** | **3,288** | **2,332** | **2,567** | **2,847** |

| Monthly Summary[1] | 1/2034 | 2/2034 | 3/2034 | 4/2034 | 5/2034 | 6/2034 | 7/2034 | 8/2034 | 9/2034 | 10/2034 | 11/2034 | 12/2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 1,040 | 835 | 715 | 612 | 575 | 694 | 850 | 804 | 605 | 548 | 787 | 995 |
| Commercial | 581 | 532 | 484 | 492 | 496 | 534 | 577 | 583 | 546 | 506 | 528 | 572 |
| Irrigation | 3 | 3 | 11 | 166 | 430 | 694 | 731 | 568 | 376 | 85 | 6 | 3 |
| Industrial | 319 | 318 | 315 | 299 | 305 | 332 | 324 | 329 | 325 | 328 | 317 | 309 |
| Additional Firm | 134 | 131 | 124 | 121 | 119 | 117 | 123 | 122 | 120 | 119 | 130 | 134 |
| Loss | 178 | 154 | 138 | 142 | 165 | 206 | 229 | 209 | 168 | 131 | 148 | 172 |
| **System Load** | **2,254** | **1,972** | **1,786** | **1,832** | **2,090** | **2,577** | **2,834** | **2,615** | **2,140** | **1,717** | **1,916** | **2,185** |
| Light Load | 2,093 | 1,816 | 1,636 | 1,656 | 1,891 | 2,342 | 2,554 | 2,318 | 1,924 | 1,530 | 1,768 | 2,017 |
| Heavy Load | 2,381 | 2,088 | 1,894 | 1,974 | 2,234 | 2,749 | 3,054 | 2,831 | 2,297 | 1,864 | 2,025 | 2,317 |
| **Total Load** | **2,254** | **1,972** | **1,786** | **1,832** | **2,090** | **2,577** | **2,834** | **2,615** | **2,140** | **1,717** | **1,916** | **2,185** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,832 | 2,649 | 2,323 | 2,274 | 3,112 | 4,070 | 4,529 | 4,025 | 3,319 | 2,346 | 2,582 | 2,860 |
| **Total Peak Load** | **2,832** | **2,649** | **2,323** | **2,274** | **3,112** | **4,070** | **4,529** | **4,025** | **3,319** | **2,346** | **2,582** | **2,860** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2017 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

| Monthly Summary[1] | 1/2035 | 2/2035 | 3/2035 | 4/2035 | 5/2035 | 6/2035 | 7/2035 | 8/2035 | 9/2035 | 10/2035 | 11/2035 | 12/2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 1,053 | 844 | 721 | 617 | 582 | 703 | 862 | 815 | 612 | 552 | 794 | 1,008 |
| Commercial | 585 | 536 | 487 | 496 | 500 | 538 | 581 | 589 | 551 | 510 | 532 | 576 |
| Irrigation | 3 | 3 | 11 | 167 | 432 | 698 | 735 | 572 | 378 | 86 | 6 | 3 |
| Industrial | 321 | 319 | 316 | 301 | 306 | 333 | 326 | 330 | 326 | 330 | 318 | 310 |
| Additional Firm | 134 | 131 | 124 | 122 | 120 | 117 | 123 | 122 | 120 | 119 | 131 | 134 |
| Loss | 180 | 155 | 139 | 143 | 166 | 208 | 231 | 211 | 170 | 132 | 150 | 174 |
| **System Load** | **2,275** | **1,988** | **1,798** | **1,845** | **2,106** | **2,598** | **2,858** | **2,640** | **2,157** | **1,728** | **1,931** | **2,205** |
| Light Load | 2,113 | 1,830 | 1,647 | 1,667 | 1,905 | 2,361 | 2,577 | 2,339 | 1,940 | 1,540 | 1,781 | 2,036 |
| Heavy Load | 2,393 | 2,105 | 1,906 | 1,988 | 2,251 | 2,771 | 3,080 | 2,857 | 2,331 | 1,865 | 2,041 | 2,339 |
| **Total Load** | **2,275** | **1,988** | **1,798** | **1,845** | **2,106** | **2,598** | **2,858** | **2,640** | **2,157** | **1,728** | **1,931** | **2,205** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,853 | 2,664 | 2,334 | 2,287 | 3,135 | 4,107 | 4,584 | 4,070 | 3,350 | 2,359 | 2,597 | 2,878 |
| **Total Peak Load** | **2,853** | **2,664** | **2,334** | **2,287** | **3,135** | **4,107** | **4,584** | **4,070** | **3,350** | **2,359** | **2,597** | **2,878** |

| Monthly Summary[1] | 1/2036 | 2/2036 | 3/2036 | 4/2036 | 5/2036 | 6/2036 | 7/2036 | 8/2036 | 9/2036 | 10/2036 | 11/2036 | 12/2036 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Average Load (aMW)–70th Percentile** | | | | | | | | | | | | |
| Residential | 1,067 | 825 | 729 | 623 | 589 | 713 | 875 | 828 | 620 | 558 | 803 | 1,021 |
| Commercial | 591 | 521 | 490 | 500 | 504 | 542 | 586 | 594 | 556 | 514 | 537 | 581 |
| Irrigation | 3 | 3 | 11 | 168 | 435 | 703 | 740 | 576 | 380 | 87 | 6 | 3 |
| Industrial | 323 | 310 | 318 | 302 | 308 | 335 | 328 | 332 | 328 | 331 | 320 | 311 |
| Additional Firm | 134 | 126 | 124 | 122 | 120 | 117 | 123 | 122 | 120 | 119 | 131 | 134 |
| Loss | 182 | 151 | 140 | 144 | 167 | 210 | 233 | 214 | 171 | 133 | 151 | 175 |
| **System Load** | **2,299** | **1,936** | **1,811** | **1,859** | **2,123** | **2,620** | **2,885** | **2,666** | **2,176** | **1,741** | **1,947** | **2,227** |
| Light Load | 2,134 | 1,783 | 1,659 | 1,680 | 1,921 | 2,381 | 2,601 | 2,362 | 1,957 | 1,551 | 1,796 | 2,056 |
| Heavy Load | 2,417 | 2,049 | 1,931 | 1,990 | 2,269 | 2,811 | 3,090 | 2,905 | 2,336 | 1,878 | 2,068 | 2,350 |
| **Total Load** | **2,299** | **1,936** | **1,811** | **1,859** | **2,123** | **2,620** | **2,885** | **2,666** | **2,176** | **1,741** | **1,947** | **2,227** |
| **Peak Load (MW)–95th Percentile** | | | | | | | | | | | | |
| System Peak (1 hour) | 2,879 | 2,682 | 2,350 | 2,302 | 3,161 | 4,148 | 4,641 | 4,118 | 3,384 | 2,373 | 2,612 | 2,896 |
| **Total Peak Load** | **2,879** | **2,682** | **2,350** | **2,302** | **3,161** | **4,148** | **4,641** | **4,118** | **3,384** | **2,373** | **2,612** | **2,896** |

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2017 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

# LOAD AND RESOURCE BALANCE DATA

## Monthly Average Energy Load and Resource Balance

| | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast—included EE | 10 | 11 | 10 | 10 | 12 | 14 | 15 | 15 | 13 | 12 | 11 | 10 |
| Load Forecast (70th% w/EE) | (1,894) | (1,686) | (1,555) | (1,591) | (1,803) | (2,217) | (2,415) | (2,207) | (1,834) | (1,495) | (1,650) | (1,863) |
| Adjustment for EE Potential Study Forecast | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| **Net Load Forecast (70th% w/ EE)** | (1,893) | (1,685) | (1,554) | (1,590) | (1,802) | (2,216) | (2,414) | (2,206) | (1,834) | (1,494) | (1,649) | (1,862) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 958 | 958 | 926 | 751 | 754 | 958 | 958 | 958 | 958 | 958 | 958 | 958 |
| **Total Gas** | 527 | 286 | 280 | 281 | 279 | 511 | 507 | 508 | 277 | 281 | 284 | 527 |
| Hydro (70th%)—HCC | 582 | 647 | 591 | 729 | 870 | 591 | 536 | 367 | 413 | 442 | 347 | 453 |
| Hydro (70th%)—Other | 202 | 214 | 211 | 266 | 318 | 328 | 283 | 212 | 223 | 198 | 182 | 189 |
| **Total Hydro (70th%)** | 784 | 861 | 801 | 995 | 1,187 | 919 | 819 | 578 | 636 | 640 | 529 | 642 |
| **CSPP (PURPA)** | 230 | 303 | 328 | 411 | 418 | 414 | 397 | 362 | 334 | 291 | 271 | 247 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 35 | 35 | 39 | 35 | 33 | 34 | 36 | 32 | 29 | 30 | 42 | 39 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange—Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| **Total PPAs** | **75** | **75** | **58** | **53** | **65** | **68** | **66** | **59** | **58** | **37** | **57** | **77** |
| **Transmission Capacity available for Market Purchases** | 203 | 245 | 320 | 285 | 222 | 399 | 313 | 335 | 175 | 290 | 237 | 182 |
| **Existing Resource Subtotal** | **2,777** | **2,728** | **2,713** | **2,776** | **2,925** | **3,268** | **3,060** | **2,801** | **2,439** | **2,496** | **2,335** | **2,634** |
| **Monthly Surplus/Deficit** | **884** | **1,043** | **1,159** | **1,186** | **1,123** | **1,052** | **646** | **595** | **605** | **1,002** | **686** | **772** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engines | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| **Monthly Surplus/Deficit** | **884** | **1,043** | **1,159** | **1,186** | **1,123** | **1,052** | **646** | **595** | **605** | **1,002** | **686** | **772** |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast—included EE | 21 | 21 | 20 | 21 | 24 | 27 | 28 | 28 | 24 | 23 | 21 | 21 |
| Load Forecast (70th% w/EE) | (1,929) | (1,716) | (1,581) | (1,617) | (1,831) | (2,250) | (2,452) | (2,243) | (1,864) | (1,521) | (1,679) | (1,891) |
| Adjustment for EE Potential Study Forecast | 4 | 4 | 4 | 4 | 5 | 5 | 5 | 5 | 5 | 4 | 4 | 4 |
| **Net Load Forecast (70th% w/ EE)** | (1,925) | (1,712) | (1,577) | (1,613) | (1,827) | (2,245) | (2,447) | (2,238) | (1,860) | (1,516) | (1,674) | (1,887) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 958 | 958 | 926 | 751 | 754 | 958 | 958 | 958 | 958 | 958 | 958 | 958 |
| **Total Gas** | 527 | 286 | 280 | 281 | 279 | 511 | 507 | 508 | 277 | 281 | 284 | 527 |
| Hydro (70th%)—HCC | 582 | 647 | 591 | 729 | 870 | 591 | 536 | 367 | 413 | 442 | 347 | 453 |
| Hydro (70th%)—Other | 202 | 214 | 211 | 266 | 318 | 328 | 283 | 212 | 223 | 198 | 182 | 189 |
| **Total Hydro (70th%)** | 784 | 861 | 801 | 995 | 1,187 | 919 | 819 | 578 | 636 | 640 | 529 | 642 |
| **CSPP (PURPA)** | 230 | 303 | 328 | 411 | 418 | 414 | 397 | 362 | 334 | 291 | 271 | 247 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 35 | 35 | 39 | 35 | 33 | 34 | 36 | 32 | 29 | 30 | 42 | 39 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange—Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| **Total PPAs** | **75** | **75** | **58** | **53** | **65** | **68** | **66** | **59** | **58** | **37** | **57** | **77** |
| **Transmission Capacity available for Market Purchases** | 202 | 243 | 318 | 284 | 220 | 399 | 313 | 333 | 174 | 289 | 236 | 182 |
| **Existing Resource Subtotal** | **2,760** | **2,776** | **2,689** | **2,788** | **2,956** | **3,285** | **3,060** | **2,798** | **2,438** | **2,495** | **2,328** | **2,641** |
| **Monthly Surplus/Deficit** | **835** | **1,064** | **1,112** | **1,175** | **1,129** | **1,040** | **613** | **560** | **579** | **979** | **654** | **754** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engines | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **835** | **1,064** | **1,112** | **1,175** | **1,129** | **1,040** | **613** | **560** | **579** | **979** | **654** | **754** |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast—included EE | 32 | 31 | 30 | 31 | 36 | 40 | 41 | 41 | 36 | 35 | 32 | 31 |
| Load Forecast (70th% w/EE) | (1,958) | (1,740) | (1,601) | (1,637) | (1,854) | (2,278) | (2,485) | (2,274) | (1,889) | (1,540) | (1,701) | (1,910) |
| Adjustment for EE Potential Study Forecast | 8 | 8 | 8 | 8 | 9 | 11 | 11 | 11 | 10 | 9 | 8 | 8 |
| **Net Load Forecast (70th% w/ EE)** | (1,950) | (1,732) | (1,594) | (1,629) | (1,845) | (2,268) | (2,474) | (2,264) | (1,879) | (1,530) | (1,693) | (1,902) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 956 | 956 | 909 | 838 | 733 | 956 | 956 | 956 | 956 | 956 | 956 | 956 |
| **Total Gas** | 527 | 286 | 280 | 281 | 279 | 511 | 507 | 508 | 277 | 281 | 284 | 527 |
| Hydro (70th%)—HCC | 560 | 670 | 590 | 742 | 872 | 614 | 536 | 366 | 407 | 443 | 346 | 459 |
| Hydro (70th%)—Other | 194 | 252 | 215 | 285 | 323 | 332 | 284 | 213 | 224 | 198 | 174 | 182 |
| **Total Hydro (70th%)** | 755 | 921 | 805 | 1,027 | 1,195 | 946 | 820 | 579 | 631 | 642 | 520 | 641 |
| **CSPP (PURPA)** | 230 | 303 | 328 | 411 | 418 | 414 | 397 | 362 | 334 | 293 | 272 | 248 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 35 | 35 | 39 | 35 | 33 | 34 | 36 | 32 | 29 | 30 | 42 | 39 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange—Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| **Total PPAs** | **75** | **75** | **58** | **53** | **65** | **68** | **66** | **59** | **58** | **37** | **57** | **77** |
| **Transmission Capacity available for Market Purchases** | 201 | 242 | 317 | 293 | 226 | 387 | 302 | 332 | 177 | 288 | 236 | 183 |
| **Existing Resource Subtotal** | **2,744** | **2,783** | **2,695** | **2,902** | **2,916** | **3,281** | **3,048** | **2,796** | **2,434** | **2,496** | **2,325** | **2,633** |
| **Monthly Surplus/Deficit** | **795** | **1,052** | **1,102** | **1,273** | **1,071** | **1,013** | **574** | **533** | **555** | **966** | **632** | **731** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engines | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **795** | **1,052** | **1,102** | **1,273** | **1,071** | **1,013** | **574** | **533** | **555** | **966** | **632** | **731** |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast—included EE | 46 | 48 | 44 | 47 | 53 | 59 | 61 | 60 | 54 | 51 | 47 | 45 |
| Load Forecast (70th% w/EE) | (1,975) | (1,693) | (1,613) | (1,650) | (1,869) | (2,297) | (2,506) | (2,295) | (1,904) | (1,551) | (1,714) | (1,926) |
| Adjustment for EE Potential Study Forecast | 7 | 7 | 6 | 7 | 8 | 9 | 9 | 9 | 8 | 7 | 7 | 7 |
| **Net Load Forecast (70th% w/ EE)** | (1,968) | (1,686) | (1,606) | (1,643) | (1,861) | (2,288) | (2,497) | (2,286) | (1,896) | (1,543) | (1,707) | (1,920) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 841 | 842 | 843 | 698 | 633 | 841 | 841 | 841 | 841 | 841 | 841 | 841 |
| **Total Gas** | 527 | 286 | 280 | 281 | 279 | 511 | 507 | 508 | 277 | 281 | 284 | 527 |
| Hydro (70th%)—HCC | 561 | 670 | 590 | 742 | 874 | 615 | 536 | 365 | 406 | 443 | 346 | 460 |
| Hydro (70th%)—Other | 194 | 256 | 215 | 286 | 323 | 332 | 284 | 213 | 224 | 198 | 174 | 182 |
| **Total Hydro (70th%)** | 755 | 925 | 805 | 1,028 | 1,198 | 946 | 819 | 578 | 630 | 641 | 520 | 642 |
| **CSPP (PURPA)** | 231 | 304 | 330 | 414 | 421 | 417 | 401 | 365 | 337 | 293 | 272 | 248 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 35 | 35 | 39 | 35 | 33 | 34 | 36 | 32 | 29 | 30 | 42 | 39 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange—Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| **Total PPAs** | **75** | **75** | **58** | **53** | **65** | **68** | **66** | **59** | **58** | **37** | **57** | **77** |
| **Transmission Capacity available for Market Purchases** | 201 | 243 | 317 | 293 | 227 | 387 | 301 | 331 | 176 | 288 | 235 | 182 |
| **Existing Resource Subtotal** | **2,631** | **2,675** | **2,632** | **2,767** | **2,823** | **3,170** | **2,936** | **2,683** | **2,320** | **2,381** | **2,209** | **2,518** |
| **Monthly Surplus/Deficit** | **663** | **989** | **1,026** | **1,125** | **961** | **882** | **439** | **397** | **423** | **838** | **502** | **599** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engines | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **663** | **989** | **1,026** | **1,125** | **961** | **882** | **439** | **397** | **423** | **838** | **502** | **599** |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast—included EE | 5 | 5 | 5 | 6 | 9 | 12 | 12 | 12 | 8 | 6 | 5 | 5 |
| Load Forecast (70th% w/EE) | (1,894) | (1,686) | (1,555) | (1,591) | (1,803) | (2,217) | (2,415) | (2,207) | (1,834) | (1,495) | (1,650) | (1,863) |
| Adjustment for EE Potential Study Forecast | 0 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 |
| **Net Load Forecast (70th% w/ EE)** | (1,894) | (1,686) | (1,554) | (1,590) | (1,802) | (2,216) | (2,414) | (2,206) | (1,834) | (1,495) | (1,650) | (1,862) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 787 | 787 | 700 | 563 | 608 | 787 | 787 | 787 | 787 | 787 | 787 | 787 |
| **Total Gas** | 527 | 286 | 280 | 281 | 279 | 511 | 507 | 508 | 277 | 281 | 284 | 527 |
| Hydro (70th%)—HCC | 558 | 668 | 590 | 744 | 873 | 612 | 536 | 365 | 403 | 443 | 346 | 458 |
| Hydro (70th%)—Other | 191 | 251 | 213 | 288 | 324 | 331 | 284 | 212 | 223 | 198 | 174 | 180 |
| **Total Hydro (70th%)** | 749 | 919 | 803 | 1,032 | 1,197 | 944 | 819 | 577 | 627 | 641 | 520 | 638 |
| **CSPP (PURPA)** | 231 | 304 | 330 | 414 | 421 | 417 | 401 | 365 | 337 | 293 | 272 | 248 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 35 | 35 | 39 | 35 | 33 | 34 | 36 | 32 | 29 | 30 | 42 | 39 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **70** | **69** | **71** | **64** | **55** | **57** | **56** | **52** | **54** | **56** | **74** | **73** |
| **Transmission Capacity available for Market Purchases** | 261 | 302 | 376 | 352 | 285 | 445 | 360 | 389 | 234 | 348 | 294 | 242 |
| **Existing Resource Subtotal** | **2,625** | **2,667** | **2,559** | **2,706** | **2,845** | **3,161** | **2,930** | **2,679** | **2,316** | **2,406** | **2,230** | **2,515** |
| **Monthly Surplus/Deficit** | **640** | **907** | **943** | **1,052** | **970** | **856** | **414** | **374** | **405** | **852** | **511** | **577** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engines | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **640** | **907** | **943** | **1,052** | **970** | **856** | **414** | **374** | **405** | **852** | **511** | **577** |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast—included EE | 70 | 70 | 68 | 72 | 82 | 92 | 94 | 93 | 82 | 77 | 72 | 70 |
| Load Forecast (70th% w/EE) | (2,017) | (1,787) | (1,640) | (1,678) | (1,902) | (2,338) | (2,554) | (2,342) | (1,939) | (1,577) | (1,745) | (1,968) |
| Adjustment for EE Potential Study Forecast | 9 | 9 | 9 | 9 | 10 | 12 | 12 | 12 | 10 | 10 | 9 | 9 |
| **Net Load Forecast (70th% w/ EE)** | (2,008) | (1,778) | (1,631) | (1,668) | (1,891) | (2,326) | (2,542) | (2,330) | (1,929) | (1,567) | (1,736) | (1,959) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 787 | 787 | 684 | 603 | 650 | 787 | 787 | 787 | 787 | 787 | 787 | 787 |
| **Total Gas** | 527 | 286 | 280 | 281 | 279 | 511 | 507 | 508 | 277 | 281 | 284 | 527 |
| Hydro (70th%)—HCC | 562 | 671 | 590 | 725 | 873 | 601 | 535 | 364 | 403 | 442 | 346 | 461 |
| Hydro (70th%)—Other | 197 | 245 | 212 | 248 | 324 | 331 | 283 | 212 | 222 | 197 | 174 | 183 |
| **Total Hydro (70th%)** | 759 | 916 | 802 | 973 | 1,197 | 932 | 818 | 576 | 625 | 639 | 520 | 644 |
| **CSPP (PURPA)** | 231 | 304 | 330 | 414 | 421 | 417 | 401 | 365 | 337 | 293 | 272 | 248 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 35 | 35 | 39 | 35 | 33 | 34 | 36 | 32 | 29 | 30 | 42 | 39 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **70** | **69** | **71** | **64** | **55** | **57** | **56** | **52** | **54** | **56** | **74** | **73** |
| **Transmission Capacity available for Market Purchases** | 260 | 302 | 375 | 352 | 284 | 444 | 357 | 389 | 233 | 347 | 293 | 241 |
| **Existing Resource Subtotal** | **2,634** | **2,664** | **2,541** | **2,687** | **2,886** | **3,148** | **2,926** | **2,678** | **2,313** | **2,403** | **2,230** | **2,521** |
| **Monthly Surplus/Deficit** | **627** | **886** | **911** | **1,019** | **995** | **821** | **384** | **348** | **385** | **836** | **494** | **561** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engines | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **627** | **886** | **911** | **1,019** | **995** | **821** | **384** | **348** | **385** | **836** | **494** | **561** |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast—included EE | 82 | 83 | 79 | 82 | 94 | 107 | 110 | 112 | 96 | 92 | 84 | 82 |
| Load Forecast (70th% w/EE) | (2,043) | (1,808) | (1,657) | (1,695) | (1,922) | (2,363) | (2,582) | (2,369) | (1,960) | (1,592) | (1,765) | (1,991) |
| Adjustment for EE Potential Study Forecast | 10 | 11 | 10 | 10 | 12 | 14 | 14 | 14 | 12 | 12 | 11 | 11 |
| **Net Load Forecast (70th% w/ EE)** | (2,032) | (1,797) | (1,647) | (1,685) | (1,910) | (2,349) | (2,568) | (2,355) | (1,948) | (1,581) | (1,755) | (1,981) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 787 | 787 | 717 | 602 | 759 | 787 | 787 | 787 | 787 | 787 | 787 | 787 |
| **Total Gas** | 527 | 286 | 280 | 281 | 279 | 511 | 507 | 508 | 277 | 281 | 284 | 527 |
| Hydro (70th%)—HCC | 562 | 670 | 590 | 725 | 875 | 600 | 534 | 363 | 396 | 443 | 347 | 459 |
| Hydro (70th%)—Other | 197 | 244 | 211 | 248 | 324 | 330 | 283 | 212 | 221 | 197 | 173 | 183 |
| **Total Hydro (70th%)** | 758 | 914 | 801 | 973 | 1,199 | 930 | 817 | 575 | 617 | 639 | 520 | 642 |
| **CSPP (PURPA)** | 231 | 304 | 330 | 414 | 421 | 417 | 401 | 365 | 337 | 293 | 272 | 248 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 35 | 35 | 39 | 35 | 33 | 34 | 36 | 32 | 29 | 30 | 42 | 39 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **70** | **69** | **71** | **64** | **55** | **57** | **56** | **52** | **54** | **56** | **74** | **73** |
| **Transmission Capacity available for Market Purchases** | 259 | 301 | 375 | 352 | 283 | 443 | 356 | 388 | 232 | 346 | 292 | 240 |
| **Existing Resource Subtotal** | **2,632** | **2,661** | **2,573** | **2,686** | **2,996** | **3,145** | **2,924** | **2,675** | **2,304** | **2,401** | **2,229** | **2,517** |
| **Monthly Surplus/Deficit** | **600** | **864** | **926** | **1,002** | **1,087** | **796** | **355** | **320** | **356** | **821** | **474** | **536** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engines | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 600 | 864 | 926 | 1,002 | 1,087 | 796 | 355 | 320 | 356 | 821 | 474 | 536 |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast—included EE | 95 | 100 | 91 | 96 | 109 | 122 | 128 | 128 | 110 | 105 | 97 | 92 |
| Load Forecast (70th% w/EE) | (2,074) | (1,771) | (1,679) | (1,717) | (1,945) | (2,390) | (2,614) | (2,400) | (1,984) | (1,612) | (1,790) | (2,019) |
| Adjustment for EE Potential Study Forecast | 12 | 13 | 12 | 12 | 14 | 16 | 16 | 16 | 14 | 13 | 12 | 12 |
| **Net Load Forecast (70th% w/ EE)** | (2,062) | (1,758) | (1,668) | (1,705) | (1,931) | (2,375) | (2,597) | (2,383) | (1,970) | (1,598) | (1,778) | (2,007) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 786 | 763 | 744 | 602 | 616 | 690 | 786 | 786 | 786 | 786 | 786 | 786 |
| **Total Gas** | 527 | 286 | 280 | 281 | 279 | 511 | 507 | 508 | 277 | 281 | 284 | 527 |
| Hydro (70th%)—HCC | 561 | 669 | 589 | 725 | 875 | 599 | 534 | 363 | 392 | 443 | 346 | 456 |
| Hydro (70th%)—Other | 196 | 241 | 211 | 248 | 324 | 330 | 282 | 211 | 220 | 196 | 173 | 183 |
| **Total Hydro (70th%)** | 757 | 910 | 800 | 973 | 1,199 | 929 | 816 | 573 | 612 | 639 | 519 | 639 |
| **CSPP (PURPA)** | 231 | 304 | 330 | 414 | 421 | 417 | 401 | 365 | 337 | 293 | 272 | 248 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 35 | 35 | 39 | 35 | 33 | 34 | 36 | 32 | 29 | 30 | 42 | 39 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **70** | **69** | **71** | **64** | **55** | **57** | **56** | **52** | **54** | **56** | **74** | **73** |
| **Transmission Capacity available for Market Purchases** | 258 | 300 | 375 | 351 | 282 | 442 | 355 | 387 | 232 | 345 | 292 | 240 |
| **Existing Resource Subtotal** | **2,630** | **2,632** | **2,598** | **2,684** | **2,852** | **3,045** | **2,921** | **2,672** | **2,299** | **2,400** | **2,226** | **2,514** |
| **Monthly Surplus/Deficit** | **568** | **874** | **931** | **980** | **921** | **670** | **324** | **289** | **329** | **801** | **449** | **506** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engines | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **568** | **874** | **931** | **980** | **921** | **670** | **324** | **289** | **329** | **801** | **449** | **506** |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast—included EE | 109 | 110 | 104 | 111 | 125 | 140 | 146 | 145 | 126 | 120 | 110 | 109 |
| Load Forecast (70th% w/EE) | (2,091) | (1,848) | (1,690) | (1,728) | (1,959) | (2,408) | (2,635) | (2,420) | (1,999) | (1,622) | (1,803) | (2,035) |
| Adjustment for EE Potential Study Forecast | 13 | 13 | 12 | 13 | 14 | 16 | 17 | 17 | 15 | 14 | 13 | 13 |
| **Net Load Forecast (70th% w/ EE)** | (2,079) | (1,835) | (1,678) | (1,716) | (1,945) | (2,392) | (2,618) | (2,403) | (1,984) | (1,608) | (1,790) | (2,022) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 786 | 763 | 744 | 602 | 616 | 690 | 786 | 786 | 786 | 786 | 786 | 786 |
| **Total Gas** | 527 | 286 | 280 | 281 | 279 | 511 | 507 | 508 | 277 | 281 | 284 | 527 |
| Hydro (70th%)—HCC | 560 | 669 | 587 | 725 | 875 | 598 | 533 | 362 | 388 | 443 | 347 | 453 |
| Hydro (70th%)—Other | 196 | 238 | 210 | 248 | 324 | 329 | 282 | 210 | 219 | 195 | 172 | 182 |
| **Total Hydro (70th%)** | 756 | 907 | 798 | 972 | 1,199 | 927 | 814 | 571 | 607 | 638 | 519 | 636 |
| **CSPP (PURPA)** | 231 | 304 | 330 | 414 | 421 | 417 | 401 | 365 | 337 | 290 | 269 | 245 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 35 | 35 | 39 | 35 | 33 | 34 | 36 | 32 | 29 | 30 | 42 | 39 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **70** | **69** | **71** | **64** | **55** | **57** | **56** | **52** | **54** | **56** | **74** | **73** |
| **Transmission Capacity available for Market Purchases** | 259 | 300 | 374 | 351 | 280 | 440 | 354 | 385 | 230 | 345 | 292 | 239 |
| **Existing Resource Subtotal** | **2,630** | **2,629** | **2,595** | **2,684** | **2,850** | **3,041** | **2,919** | **2,669** | **2,292** | **2,396** | **2,223** | **2,506** |
| **Monthly Surplus/Deficit** | **551** | **794** | **918** | **968** | **905** | **649** | **301** | **265** | **308** | **788** | **433** | **484** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engines | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **551** | **794** | **918** | **968** | **905** | **649** | **301** | **265** | **308** | **788** | **433** | **484** |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast—included EE | 123 | 123 | 117 | 125 | 140 | 157 | 165 | 162 | 142 | 132 | 124 | 122 |
| Load Forecast (70th% w/EE) | (2,109) | (1,861) | (1,700) | (1,740) | (1,973) | (2,426) | (2,656) | (2,441) | (2,014) | (1,633) | (1,815) | (2,052) |
| Adjustment for EE Potential Study Forecast | 10 | 10 | 10 | 10 | 12 | 13 | 14 | 13 | 12 | 11 | 10 | 10 |
| **Net Load Forecast (70th% w/ EE)** | (2,099) | (1,851) | (1,691) | (1,730) | (1,962) | (2,413) | (2,642) | (2,428) | (2,002) | (1,622) | (1,805) | (2,042) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 673 | 650 | 641 | 502 | 502 | 576 | 673 | 673 | 673 | 673 | 673 | 673 |
| **Total Gas** | 527 | 286 | 280 | 281 | 279 | 511 | 507 | 508 | 277 | 281 | 284 | 527 |
| Hydro (70th%)—HCC | 559 | 665 | 587 | 723 | 876 | 596 | 532 | 361 | 384 | 443 | 347 | 449 |
| Hydro (70th%)—Other | 196 | 235 | 209 | 247 | 324 | 329 | 281 | 209 | 219 | 194 | 171 | 182 |
| **Total Hydro (70th%)** | 755 | 900 | 796 | 970 | 1,201 | 925 | 813 | 570 | 602 | 637 | 518 | 631 |
| **CSPP (PURPA)** | 228 | 301 | 323 | 408 | 417 | 415 | 399 | 363 | 333 | 288 | 265 | 241 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 35 | 35 | 39 | 35 | 33 | 34 | 36 | 32 | 29 | 30 | 42 | 39 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **70** | **69** | **71** | **64** | **55** | **57** | **56** | **52** | **54** | **56** | **74** | **73** |
| **Transmission Capacity available for Market Purchases** | 258 | 299 | 373 | 350 | 280 | 440 | 353 | 385 | 229 | 344 | 291 | 240 |
| **Existing Resource Subtotal** | **2,512** | **2,504** | **2,484** | **2,575** | **2,734** | **2,923** | **2,801** | **2,552** | **2,169** | **2,279** | **2,105** | **2,385** |
| **Monthly Surplus/Deficit** | **413** | **653** | **793** | **846** | **772** | **510** | **159** | **124** | **167** | **657** | **300** | **343** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engines | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | **613** | **853** | **993** | **1,346** | **1,272** | **1,010** | **659** | **624** | **667** | **857** | **500** | **543** |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast—included EE | 136 | 136 | 131 | 139 | 156 | 176 | 183 | 179 | 157 | 146 | 138 | 136 |
| Load Forecast (70th% w/EE) | (2,129) | (1,877) | (1,713) | (1,753) | (1,990) | (2,447) | (2,680) | (2,465) | (2,031) | (1,645) | (1,830) | (2,071) |
| Adjustment for EE Potential Study Forecast | 8 | 8 | 8 | 8 | 9 | 10 | 11 | 10 | 9 | 8 | 8 | 8 |
| **Net Load Forecast (70th% w/ EE)** | (2,121) | (1,869) | (1,705) | (1,745) | (1,981) | (2,437) | (2,670) | (2,454) | (2,022) | (1,636) | (1,822) | (2,063) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 673 | 650 | 641 | 502 | 502 | 576 | 673 | 673 | 673 | 673 | 673 | 673 |
| **Total Gas** | 527 | 286 | 280 | 281 | 279 | 511 | 507 | 508 | 277 | 281 | 284 | 527 |
| Hydro (70th%)—HCC | 558.3 | 655.9 | 586.4 | 721.6 | 874.6 | 594.3 | 530.6 | 359.4 | 379.3 | 443.7 | 346.4 | 443.2 |
| Hydro (70th%)—Other | 195.2 | 228.9 | 207.4 | 246.5 | 324.8 | 328.1 | 280.5 | 208.9 | 217.6 | 193.8 | 170.5 | 181.3 |
| **Total Hydro (70th%)** | 754 | 885 | 794 | 968 | 1,199 | 922 | 811 | 568 | 597 | 637 | 517 | 624 |
| **CSPP (PURPA)** | 224 | 297 | 323 | 408 | 417 | 415 | 399 | 363 | 333 | 288 | 265 | 241 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 35 | 35 | 39 | 35 | 33 | 34 | 36 | 32 | 29 | 30 | 42 | 39 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **70** | **69** | **71** | **64** | **55** | **57** | **56** | **52** | **54** | **56** | **74** | **73** |
| **Transmission Capacity available for Market Purchases** | 257 | 299 | 373 | 349 | 279 | 438 | 352 | 384 | 229 | 344 | 291 | 239 |
| **Existing Resource Subtotal** | **2,505** | **2,486** | **2,481** | **2,572** | **2,732** | **2,919** | **2,798** | **2,549** | **2,164** | **2,279** | **2,104** | **2,378** |
| **Monthly Surplus/Deficit** | **384** | **617** | **776** | **827** | **751** | **482** | **129** | **95** | **142** | **643** | **282** | **315** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engines | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | **584** | **817** | **976** | **1,327** | **1,251** | **982** | **629** | **595** | **642** | **843** | **482** | **515** |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast—included EE | 150 | 151 | 144 | 147 | 170 | 191 | 200 | 203 | 172 | 162 | 151 | 150 |
| Load Forecast (70th% w/EE) | (2,149) | (1,827) | (1,725) | (1,766) | (2,005) | (2,467) | (2,704) | (2,488) | (2,048) | (1,656) | (1,844) | (2,088) |
| Adjustment for EE Potential Study Forecast | 6 | 6 | 6 | 6 | 7 | 7 | 8 | 8 | 7 | 6 | 6 | 6 |
| **Net Load Forecast (70th% w/ EE)** | (2,143) | (1,821) | (1,720) | (1,760) | (1,999) | (2,460) | (2,696) | (2,480) | (2,041) | (1,650) | (1,838) | (2,082) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 673 | 650 | 641 | 502 | 502 | 576 | 673 | 673 | 673 | 673 | 673 | 673 |
| **Total Gas** | 527 | 286 | 280 | 281 | 279 | 511 | 507 | 508 | 277 | 281 | 284 | 527 |
| Hydro (70th%)—HCC | 556 | 647 | 585 | 721 | 875 | 593 | 530 | 358 | 376 | 443 | 347 | 442 |
| Hydro (70th%)—Other | 195 | 216 | 203 | 246 | 325 | 327 | 280 | 208 | 217 | 193 | 170 | 181 |
| **Total Hydro (70th%)** | 751 | 863 | 788 | 967 | 1,199 | 920 | 810 | 566 | 593 | 636 | 516 | 622 |
| **CSPP (PURPA)** | 224 | 297 | 323 | 408 | 417 | 415 | 399 | 363 | 333 | 288 | 265 | 241 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **35** | **35** | **31** | **29** | **23** | **22** | **20** | **20** | **25** | **26** | **33** | **34** |
| **Transmission Capacity available for Market Purchases** | 257 | 299 | 372 | 349 | 277 | 437 | 351 | 383 | 228 | 344 | 290 | 239 |
| **Existing Resource Subtotal** | **2,467** | **2,429** | **2,435** | **2,536** | **2,697** | **2,881** | **2,760** | **2,514** | **2,129** | **2,248** | **2,061** | **2,337** |
| **Monthly Surplus/Deficit** | **324** | **608** | **716** | **776** | **699** | **421** | **64** | **34** | **88** | **598** | **223** | **254** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engines | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | **524** | **808** | **916** | **1,276** | **1,199** | **921** | **564** | **534** | **588** | **798** | **423** | **454** |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast—included EE | 164 | 164 | 156 | 162 | 186 | 208 | 220 | 221 | 186 | 177 | 164 | 163 |
| Load Forecast (70th% w/EE) | (2,167) | (1,906) | (1,736) | (1,778) | (2,020) | (2,486) | (2,726) | (2,510) | (2,064) | (1,667) | (1,857) | (2,104) |
| Adjustment for EE Potential Study Forecast | 3 | 3 | 2 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| **Net Load Forecast (70th% w/ EE)** | (2,165) | (1,904) | (1,734) | (1,776) | (2,017) | (2,483) | (2,723) | (2,506) | (2,061) | (1,664) | (1,854) | (2,101) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 505 | 487 | 481 | 377 | 377 | 432 | 505 | 505 | 505 | 505 | 505 | 505 |
| **Total Gas** | 527 | 286 | 280 | 281 | 279 | 511 | 507 | 508 | 277 | 281 | 284 | 527 |
| Hydro (70th%)—HCC | 553 | 637 | 584 | 719 | 875 | 592 | 529 | 357 | 373 | 443 | 346 | 441 |
| Hydro (70th%)—Other | 195 | 212 | 201 | 244 | 324 | 326 | 280 | 207 | 216 | 192 | 169 | 178 |
| **Total Hydro (70th%)** | 748 | 849 | 785 | 964 | 1,199 | 918 | 808 | 564 | 589 | 635 | 515 | 620 |
| **CSPP (PURPA)** | 216 | 286 | 312 | 391 | 403 | 402 | 389 | 355 | 324 | 277 | 252 | 228 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **35** | **35** | **31** | **29** | **23** | **22** | **20** | **20** | **25** | **26** | **33** | **34** |
| **Transmission Capacity available for Market Purchases** | 256 | 298 | 372 | 348 | 276 | 435 | 350 | 382 | 226 | 343 | 290 | 238 |
| **Existing Resource Subtotal** | **2,286** | **2,241** | **2,261** | **2,390** | **2,556** | **2,720** | **2,580** | **2,335** | **1,945** | **2,067** | **1,879** | **2,152** |
| **Monthly Surplus/Deficit** | **121** | **337** | **527** | **614** | **539** | **237** | **(143)** | **(172)** | **(116)** | **403** | **24** | **51** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engines | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | **321** | **537** | **727** | **1,114** | **1,039** | **737** | **357** | **328** | **384** | **603** | **224** | **251** |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast—included EE | 180 | 180 | 170 | 179 | 203 | 227 | 242 | 240 | 203 | 192 | 179 | 178 |
| Load Forecast (70th% w/EE) | (2,184) | (1,919) | (1,746) | (1,789) | (2,034) | (2,504) | (2,748) | (2,531) | (2,079) | (1,677) | (1,869) | (2,119) |
| Adjustment for EE Potential Study Forecast | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net Load Forecast (70th% w/ EE)** | (2,184) | (1,919) | (1,746) | (1,789) | (2,034) | (2,504) | (2,748) | (2,531) | (2,079) | (1,677) | (1,869) | (2,119) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 505 | 487 | 481 | 377 | 377 | 432 | 505 | 505 | 505 | 505 | 505 | 505 |
| **Total Gas** | 527 | 286 | 280 | 281 | 279 | 511 | 507 | 508 | 277 | 281 | 284 | 527 |
| Hydro (70th%)—HCC | 551 | 630 | 583 | 719 | 874 | 590 | 528 | 356 | 370 | 443 | 347 | 440 |
| Hydro (70th%)—Other | 193 | 205 | 195 | 242 | 323 | 325 | 279 | 206 | 215 | 191 | 168 | 178 |
| **Total Hydro (70th%)** | 743 | 835 | 778 | 961 | 1,197 | 916 | 806 | 562 | 584 | 634 | 515 | 618 |
| **CSPP (PURPA)** | 213 | 283 | 309 | 391 | 403 | 394 | 383 | 350 | 317 | 270 | 243 | 219 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **35** | **35** | **31** | **29** | **23** | **22** | **20** | **20** | **25** | **26** | **33** | **34** |
| **Transmission Capacity available for Market Purchases** | 255 | 298 | 371 | 349 | 275 | 435 | 349 | 381 | 226 | 343 | 289 | 238 |
| **Existing Resource Subtotal** | **2,278** | **2,223** | **2,250** | **2,388** | **2,554** | **2,710** | **2,570** | **2,327** | **1,935** | **2,059** | **1,868** | **2,142** |
| **Monthly Surplus/Deficit** | **94** | **304** | **503** | **599** | **519** | **205** | **(177)** | **(204)** | **(144)** | **382** | **(1)** | **23** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engines | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Surplus/Deficit** | **294** | **504** | **703** | **1,099** | **1,019** | **705** | **323** | **296** | **356** | **582** | **199** | **223** |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast—included EE | 195 | 195 | 184 | 195 | 220 | 247 | 263 | 258 | 220 | 207 | 193 | 195 |
| Load Forecast (70th% w/EE) | (2,200) | (1,931) | (1,755) | (1,799) | (2,048) | (2,522) | (2,768) | (2,551) | (2,094) | (1,687) | (1,880) | (2,132) |
| Adjustment for EE Potential Study Forecast | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net Load Forecast (70th% w/ EE)** | (2,200) | (1,931) | (1,755) | (1,799) | (2,048) | (2,522) | (2,768) | (2,551) | (2,094) | (1,687) | (1,880) | (2,132) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 505 | 487 | 481 | 377 | 377 | 432 | 505 | 505 | 505 | 505 | 505 | 505 |
| **Total Gas** | 527 | 286 | 280 | 281 | 279 | 511 | 507 | 508 | 277 | 281 | 284 | 527 |
| Hydro (70th%)—HCC | 551 | 628 | 582 | 718 | 872 | 588 | 527 | 355 | 365 | 443 | 348 | 439 |
| Hydro (70th%)—Other | 197 | 206 | 197 | 241 | 322 | 323 | 278 | 205 | 214 | 190 | 168 | 179 |
| **Total Hydro (70th%)** | 748 | 835 | 779 | 958 | 1,194 | 911 | 805 | 560 | 579 | 633 | 516 | 617 |
| **CSPP (PURPA)** | 182 | 208 | 237 | 315 | 333 | 336 | 335 | 309 | 273 | 217 | 172 | 151 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **35** | **35** | **31** | **29** | **23** | **22** | **20** | **20** | **25** | **26** | **33** | **34** |
| **Transmission Capacity available for Market Purchases** | 255 | 297 | 372 | 348 | 275 | 434 | 348 | 380 | 226 | 342 | 289 | 237 |
| **Existing Resource Subtotal** | **2,252** | **2,147** | **2,180** | **2,308** | **2,481** | **2,646** | **2,520** | **2,282** | **1,885** | **2,004** | **1,798** | **2,072** |
| **Monthly Surplus/Deficit** | **51** | **215** | **424** | **508** | **433** | **124** | **(248)** | **(269)** | **(209)** | **317** | **(82)** | **(60)** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engines | 20 | 0 | 0 | 0 | 0 | 20 | 20 | 20 | 20 | 0 | 0 | 20 |
| **New Resource Subtotal** | 220 | 200 | 200 | 500 | 500 | 520 | 520 | 520 | 520 | 200 | 200 | 220 |
| **Monthly Surplus/Deficit** | **271** | **415** | **624** | **1,008** | **933** | **644** | **272** | **251** | **311** | **517** | **118** | **160** |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2032 | 2/2032 | 3/2032 | 4/2032 | 5/2032 | 6/2032 | 7/2032 | 8/2032 | 9/2032 | 10/2032 | 11/2032 | 12/2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast—included EE | 210 | 216 | 200 | 212 | 238 | 268 | 282 | 276 | 237 | 219 | 210 | 202 |
| Load Forecast (70th% w/EE) | (2,215) | (1,875) | (1,763) | (1,809) | (2,060) | (2,537) | (2,787) | (2,570) | (2,107) | (1,695) | (1,890) | (2,148) |
| Adjustment for EE Potential Study Forecast | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net Load Forecast (70th% w/ EE)** | (2,215) | (1,875) | (1,763) | (1,809) | (2,060) | (2,537) | (2,787) | (2,570) | (2,107) | (1,695) | (1,890) | (2,148) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 505 | 487 | 481 | 377 | 377 | 432 | 505 | 505 | 505 | 505 | 505 | 505 |
| **Total Gas** | 527 | 286 | 280 | 281 | 279 | 511 | 507 | 508 | 277 | 281 | 284 | 527 |
| Hydro (70th%)—HCC | 550 | 620 | 580 | 716 | 870 | 585 | 525 | 354 | 361 | 443 | 347 | 438 |
| Hydro (70th%)—Other | 196 | 201 | 189 | 237 | 321 | 322 | 278 | 204 | 213 | 190 | 167 | 178 |
| **Total Hydro (70th%)** | 746 | 822 | 769 | 952 | 1,191 | 907 | 803 | 558 | 574 | 632 | 514 | 616 |
| **CSPP (PURPA)** | 140 | 191 | 221 | 296 | 325 | 329 | 329 | 303 | 267 | 210 | 172 | 151 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **35** | **35** | **31** | **29** | **23** | **22** | **20** | **20** | **25** | **26** | **33** | **34** |
| **Transmission Capacity available for Market Purchases** | 254 | 297 | 371 | 348 | 274 | 433 | 347 | 380 | 225 | 342 | 289 | 237 |
| **Existing Resource Subtotal** | **2,206** | **2,117** | **2,153** | **2,284** | **2,469** | **2,634** | **2,511** | **2,274** | **1,873** | **1,996** | **1,796** | **2,071** |
| **Monthly Surplus/Deficit** | **(9)** | **242** | **390** | **475** | **409** | **96** | **(276)** | **(295)** | **(234)** | **301** | **(94)** | **(77)** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engines | 40 | 0 | 0 | 0 | 0 | 40 | 40 | 40 | 40 | 0 | 0 | 40 |
| **New Resource Subtotal** | 240 | 200 | 200 | 500 | 500 | 540 | 540 | 540 | 540 | 200 | 200 | 240 |
| **Monthly Surplus/Deficit** | **231** | **442** | **590** | **975** | **909** | **636** | **264** | **245** | **306** | **501** | **106** | **162** |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2033 | 2/2033 | 3/2033 | 4/2033 | 5/2033 | 6/2033 | 7/2033 | 8/2033 | 9/2033 | 10/2033 | 11/2033 | 12/2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast—included EE | 225 | 224 | 215 | 227 | 257 | 289 | 301 | 296 | 253 | 233 | 225 | 226 |
| Load Forecast (70th% w/EE) | (2,234) | (1,956) | (1,774) | (1,820) | (2,074) | (2,557) | (2,809) | (2,592) | (2,123) | (1,705) | (1,903) | (2,166) |
| Adjustment for EE Potential Study Forecast | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net Load Forecast (70th% w/ EE)** | (2,234) | (1,956) | (1,774) | (1,820) | (2,074) | (2,557) | (2,809) | (2,592) | (2,123) | (1,705) | (1,903) | (2,166) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 336 | 325 | 320 | 251 | 251 | 288 | 336 | 336 | 336 | 336 | 336 | 336 |
| **Total Gas** | 527 | 286 | 280 | 281 | 279 | 511 | 507 | 508 | 277 | 281 | 284 | 527 |
| Hydro (70th%)—HCC | 549 | 618 | 580 | 715 | 870 | 583 | 524 | 352 | 357 | 443 | 347 | 437 |
| Hydro (70th%)—Other | 193 | 199 | 187 | 232 | 321 | 321 | 277 | 204 | 212 | 189 | 167 | 177 |
| **Total Hydro (70th%)** | 743 | 818 | 767 | 947 | 1,192 | 904 | 801 | 556 | 568 | 632 | 514 | 615 |
| **CSPP (PURPA)** | 98 | 134 | 164 | 231 | 276 | 284 | 290 | 271 | 229 | 167 | 122 | 103 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **35** | **35** | **31** | **29** | **23** | **22** | **20** | **20** | **25** | **26** | **33** | **34** |
| **Transmission Capacity available for Market Purchases** | 254 | 296 | 370 | 347 | 272 | 431 | 345 | 378 | 224 | 341 | 288 | 237 |
| **Existing Resource Subtotal** | **1,993** | **1,893** | **1,932** | **2,087** | **2,293** | **2,440** | **2,300** | **2,070** | **1,661** | **1,784** | **1,576** | **1,853** |
| **Monthly Surplus/Deficit** | **(241)** | **(63)** | **158** | **267** | **219** | **(117)** | **(509)** | **(522)** | **(462)** | **78** | **(326)** | **(313)** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2033 Combined Cycle Combustion Turbine | 292 | 286 | 280 | 281 | 279 | 276 | 272 | 273 | 277 | 281 | 284 | 292 |
| 2030s Reciprocating Gas Engines | 40 | 0 | 0 | 0 | 0 | 40 | 40 | 40 | 40 | 0 | 0 | 40 |
| **New Resource Subtotal** | 532 | 486 | 480 | 781 | 779 | 816 | 812 | 813 | 817 | 481 | 484 | 532 |
| **Monthly Surplus/Deficit** | **291** | **423** | **638** | **1,048** | **998** | **699** | **302** | **291** | **355** | **559** | **158** | **219** |

# Monthly Average Energy Load and Resource Balance (continued)

| | 1/2034 | 2/2034 | 3/2034 | 4/2034 | 5/2034 | 6/2034 | 7/2034 | 8/2034 | 9/2034 | 10/2034 | 11/2034 | 12/2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast—included EE | 242 | 243 | 229 | 235 | 270 | 303 | 324 | 327 | 272 | 253 | 239 | 242 |
| Load Forecast (70th% w/EE) | (2,254) | (1,972) | (1,786) | (1,832) | (2,090) | (2,577) | (2,834) | (2,615) | (2,140) | (1,717) | (1,916) | (2,185) |
| Adjustment for EE Potential Study Forecast | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net Load Forecast (70th% w/ EE)** | (2,254) | (1,972) | (1,786) | (1,832) | (2,090) | (2,577) | (2,834) | (2,615) | (2,140) | (1,717) | (1,916) | (2,185) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 336 | 325 | 320 | 251 | 251 | 288 | 336 | 336 | 336 | 336 | 336 | 336 |
| **Total Gas** | 527 | 286 | 280 | 281 | 279 | 511 | 507 | 508 | 277 | 281 | 284 | 527 |
| Hydro (70th%)—HCC | 549 | 616 | 579 | 712 | 869 | 581 | 523 | 351 | 353 | 442 | 347 | 436 |
| Hydro (70th%)—Other | 193 | 198 | 186 | 221 | 321 | 320 | 276 | 203 | 211 | 188 | 166 | 177 |
| **Total Hydro (70th%)** | 741 | 814 | 765 | 933 | 1,190 | 901 | 800 | 554 | 564 | 631 | 513 | 613 |
| **CSPP (PURPA)** | 98 | 134 | 164 | 231 | 276 | 284 | 290 | 271 | 229 | 167 | 122 | 103 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **35** | **35** | **31** | **29** | **23** | **22** | **20** | **20** | **25** | **26** | **33** | **34** |
| **Transmission Capacity available for Market Purchases** | 254 | 296 | 370 | 347 | 272 | 430 | 344 | 377 | 223 | 341 | 288 | 237 |
| **Existing Resource Subtotal** | **1,992** | **1,889** | **1,930** | **2,073** | **2,291** | **2,435** | **2,298** | **2,067** | **1,655** | **1,782** | **1,576** | **1,851** |
| **Monthly Surplus/Deficit** | **(262)** | **(82)** | **144** | **240** | **201** | **(141)** | **(536)** | **(549)** | **(485)** | **66** | **(341)** | **(334)** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2033 Combined Cycle Combustion Turbine | 292 | 286 | 280 | 281 | 279 | 276 | 272 | 273 | 277 | 281 | 284 | 292 |
| 2030s Reciprocating Gas Engines | 40 | 0 | 0 | 0 | 0 | 40 | 40 | 40 | 40 | 0 | 0 | 40 |
| **New Resource Subtotal** | 532 | 486 | 480 | 781 | 779 | 816 | 812 | 813 | 817 | 481 | 484 | 532 |
| **Monthly Surplus/Deficit** | **269** | **404** | **624** | **1,021** | **980** | **674** | **276** | **264** | **332** | **547** | **143** | **198** |

# Monthly Average Energy Load and Resource Balance (continued)

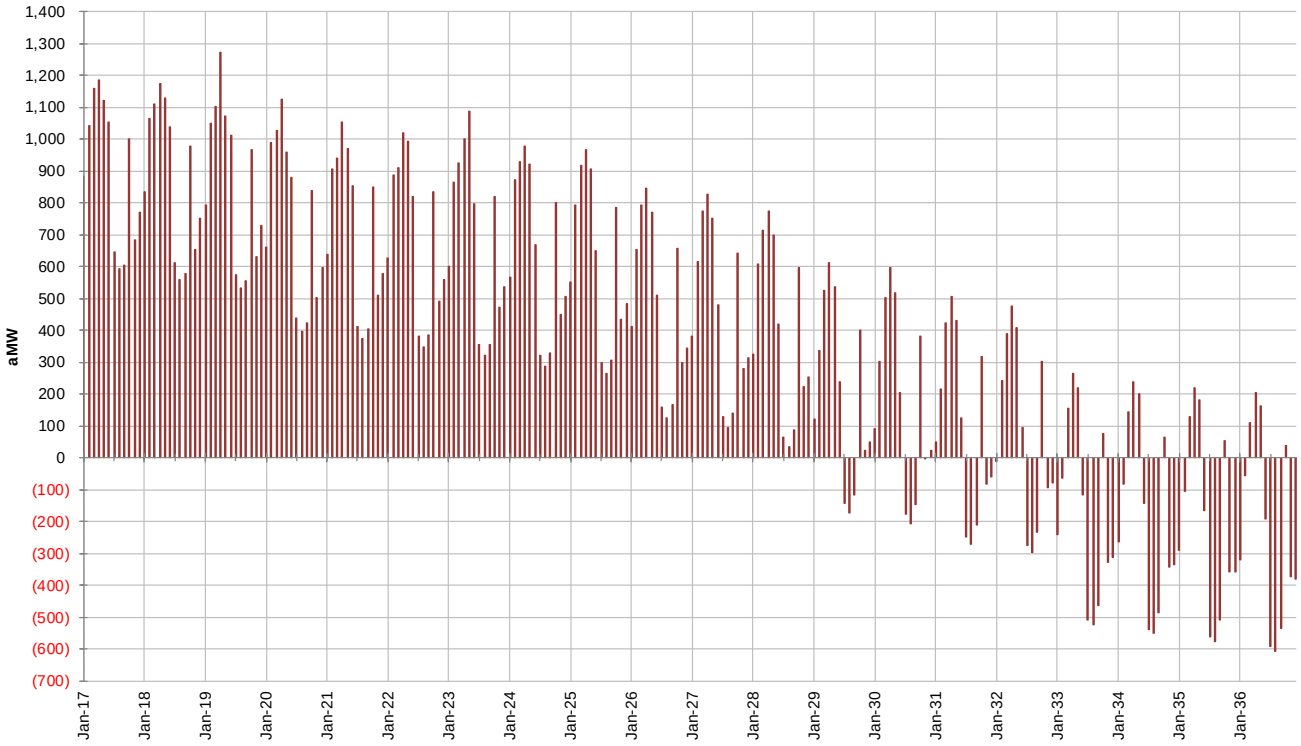
| | 1/2035 | 2/2035 | 3/2035 | 4/2035 | 5/2035 | 6/2035 | 7/2035 | 8/2035 | 9/2035 | 10/2035 | 11/2035 | 12/2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast—included EE | 260 | 258 | 244 | 253 | 288 | 322 | 347 | 347 | 287 | 270 | 254 | 258 |
| Load Forecast (70th% w/EE) | (2,275) | (1,988) | (1,798) | (1,845) | (2,106) | (2,598) | (2,858) | (2,640) | (2,157) | (1,728) | (1,931) | (2,205) |
| Adjustment for EE Potential Study Forecast | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net Load Forecast (70th% w/ EE)** | (2,275) | (1,988) | (1,798) | (1,845) | (2,106) | (2,598) | (2,858) | (2,640) | (2,157) | (1,728) | (1,931) | (2,205) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 336 | 325 | 320 | 251 | 251 | 288 | 336 | 336 | 336 | 336 | 336 | 336 |
| **Total Gas** | 527 | 286 | 280 | 281 | 279 | 511 | 507 | 508 | 277 | 281 | 284 | 527 |
| Hydro (70th%)—HCC | 548 | 612 | 578 | 712 | 867 | 580 | 522 | 350 | 348 | 443 | 348 | 435 |
| Hydro (70th%)—Other | 191 | 197 | 185 | 215 | 321 | 319 | 276 | 202 | 210 | 187 | 165 | 176 |
| **Total Hydro (70th%)** | 738 | 809 | 763 | 927 | 1,188 | 898 | 798 | 552 | 558 | 630 | 513 | 611 |
| **CSPP (PURPA)** | 98 | 134 | 164 | 231 | 276 | 284 | 290 | 271 | 229 | 167 | 122 | 103 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **35** | **35** | **31** | **29** | **23** | **22** | **20** | **20** | **25** | **26** | **33** | **34** |
| **Transmission Capacity available for Market Purchases** | 253 | 296 | 369 | 346 | 271 | 430 | 344 | 377 | 222 | 341 | 287 | 236 |
| **Existing Resource Subtotal** | **1,988** | **1,885** | **1,927** | **2,065** | **2,288** | **2,433** | **2,296** | **2,065** | **1,648** | **1,782** | **1,574** | **1,849** |
| **Monthly Surplus/Deficit** | **(288)** | **(103)** | **129** | **220** | **182** | **(165)** | **(562)** | **(575)** | **(509)** | **54** | **(357)** | **(357)** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2033 Combined Cycle Combustion Turbine | 292 | 286 | 280 | 281 | 279 | 276 | 272 | 273 | 277 | 281 | 284 | 292 |
| 2030s Reciprocating Gas Engines | 69 | 0 | 0 | 0 | 0 | 69 | 69 | 69 | 69 | 0 | 0 | 69 |
| **New Resource Subtotal** | 561 | 486 | 480 | 781 | 779 | 845 | 841 | 842 | 846 | 481 | 484 | 561 |
| **Monthly Surplus/Deficit** | **274** | **383** | **609** | **1,001** | **961** | **681** | **279** | **268** | **338** | **535** | **127** | **205** |

# Monthly Average Energy Load and Resource Balance (continued)

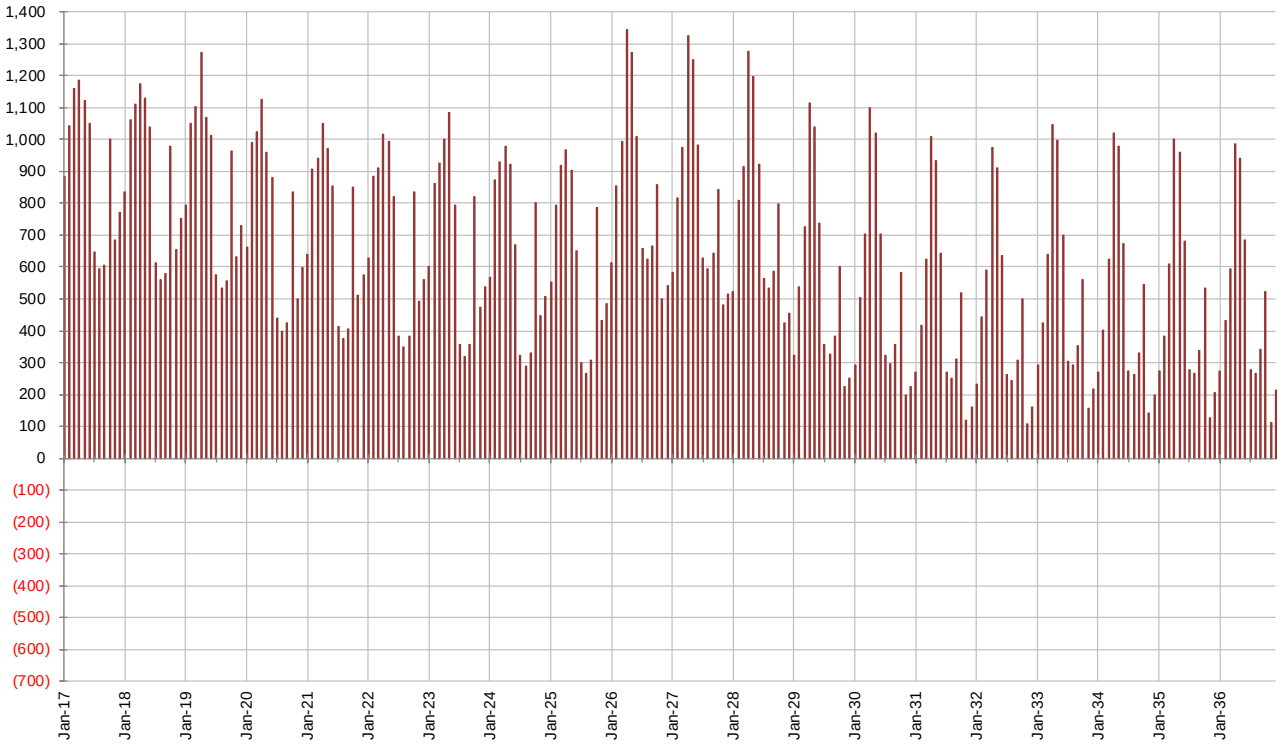
| | 1/2036 | 2/2036 | 3/2036 | 4/2036 | 5/2036 | 6/2036 | 7/2036 | 8/2036 | 9/2036 | 10/2036 | 11/2036 | 12/2036 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Load Forecast—included EE | 277 | 284 | 258 | 273 | 306 | 343 | 372 | 364 | 306 | 285 | 269 | 266 |
| Load Forecast (70th% w/EE) | (2,299) | (1,936) | (1,811) | (1,859) | (2,123) | (2,620) | (2,885) | (2,666) | (2,176) | (1,741) | (1,947) | (2,227) |
| Adjustment for EE Potential Study Forecast | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net Load Forecast (70th% w/ EE)** | (2,299) | (1,936) | (1,811) | (1,859) | (2,123) | (2,620) | (2,885) | (2,666) | (2,176) | (1,741) | (1,947) | (2,227) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 336 | 325 | 320 | 251 | 251 | 288 | 336 | 336 | 336 | 336 | 336 | 336 |
| **Total Gas** | 527 | 286 | 280 | 281 | 279 | 511 | 507 | 508 | 277 | 281 | 284 | 527 |
| Hydro (70th%)—HCC | 546 | 609 | 577 | 710 | 868 | 578 | 521 | 349 | 343 | 443 | 347 | 435 |
| Hydro (70th%)—Other | 185 | 197 | 184 | 214 | 320 | 318 | 275 | 201 | 209 | 187 | 165 | 176 |
| **Total Hydro (70th%)** | 731 | 806 | 761 | 924 | 1,188 | 896 | 796 | 550 | 552 | 629 | 512 | 611 |
| **CSPP (PURPA)** | 98 | 134 | 164 | 231 | 276 | 284 | 290 | 271 | 229 | 167 | 122 | 103 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **35** | **35** | **31** | **29** | **23** | **22** | **20** | **20** | **25** | **26** | **33** | **34** |
| **Transmission Capacity available for Market Purchases** | 252 | 295 | 368 | 346 | 270 | 429 | 343 | 375 | 222 | 341 | 287 | 236 |
| **Existing Resource Subtotal** | **1,980** | **1,881** | **1,924** | **2,063** | **2,287** | **2,430** | **2,293** | **2,061** | **1,642** | **1,781** | **1,573** | **1,848** |
| **Monthly Surplus/Deficit** | **(319)** | **(55)** | **113** | **204** | **164** | **(190)** | **(592)** | **(605)** | **(533)** | **40** | **(373)** | **(379)** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2033 Combined Cycle Combustion Turbine | 292 | 286 | 280 | 281 | 279 | 276 | 272 | 273 | 277 | 281 | 284 | 292 |
| 2030s Reciprocating Gas Engines | 99 | 0 | 0 | 0 | 0 | 99 | 99 | 99 | 99 | 0 | 0 | 99 |
| **New Resource Subtotal** | 591 | 486 | 480 | 781 | 779 | 875 | 871 | 872 | 876 | 481 | 484 | 591 |
| **Monthly Surplus/Deficit** | **272** | **431** | **593** | **985** | **943** | **685** | **279** | **267** | **343** | **521** | **111** | **212** |

# Monthly Average Energy Surplus/Deficit Charts

### Average energy monthly surpluses and deficits with IRP DSM and existing resources




### Average energy monthly surpluses and deficits with IRP DSM, existing resources, and IRP Resources



# Peak-Hour Load and Resource Balance

| | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,449) | (2,367) | (2,078) | (2,032) | (2,702) | (3,444) | (3,605) | (3,266) | (2,801) | (2,105) | (2,315) | (2,620) |
| Load Forecast—included EE | 9 | 9 | 11 | 12 | 16 | 13 | 18 | 18 | 20 | 15 | 8 | 9 |
| Load Forecast (95th% w/DSM and EE) | (2,441) | (2,358) | (2,067) | (2,020) | (2,686) | (3,431) | (3,586) | (3,248) | (2,781) | (2,091) | (2,307) | (2,611) |
| Adjustment for EE Potential Study Forecast | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM and EE** | (2,440) | (2,357) | (2,066) | (2,019) | (2,685) | (3,040) | (3,195) | (2,910) | (2,780) | (2,090) | (2,307) | (2,611) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 950 | 900 | 950 | 850 | 1,050 | 1,000 | 1,000 | 800 | 750 | 750 | 650 | 900 |
| Hydro (90th%)—Other | 190 | 195 | 172 | 203 | 291 | 301 | 285 | 208 | 215 | 197 | 185 | 189 |
| **Total Hydro (90th%)** | 1,140 | 1,095 | 1,122 | 1,053 | 1,341 | 1,301 | 1,285 | 1,008 | 965 | 947 | 835 | 1,089 |
| **CSPP (PURPA)** | 66 | 69 | 152 | 194 | 234 | 311 | 314 | 307 | 210 | 174 | 151 | 68 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange—Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| **Total PPAs** | 45 | 46 | 23 | 23 | 38 | 38 | 35 | 32 | 34 | 12 | 21 | 43 |
| **Transmission Capacity Available for Market Purchases** | 203 | 245 | 320 | 285 | 222 | 399 | 313 | 335 | 175 | 290 | 237 | 182 |
| **Existing Resource Subtotal** | **3,190** | **3,190** | **3,354** | **3,291** | **3,571** | **3,785** | **3,684** | **3,420** | **3,120** | **3,160** | **2,979** | **3,119** |
| **Monthly Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **750** | **833** | **1,288** | **1,272** | **886** | **745** | **489** | **510** | **340** | **1,070** | **672** | **508** |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,449) | (2,367) | (2,078) | (2,032) | (2,702) | (3,444) | (3,605) | (3,266) | (2,801) | (2,105) | (2,315) | (2,620) |
| Load Forecast—included EE | 9 | 9 | 11 | 12 | 16 | 13 | 18 | 18 | 20 | 15 | 8 | 9 |
| Load Forecast (95th% w/DSM and EE) | (2,441) | (2,358) | (2,067) | (2,020) | (2,686) | (3,431) | (3,586) | (3,248) | (2,781) | (2,091) | (2,307) | (2,611) |
| Adjustment for EE Potential Study Forecast | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM and EE** | (2,440) | (2,357) | (2,066) | (2,019) | (2,685) | (3,040) | (3,195) | (2,910) | (2,780) | (2,090) | (2,307) | (2,611) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 950 | 900 | 950 | 850 | 1,050 | 1,000 | 1,000 | 800 | 750 | 750 | 650 | 900 |
| Hydro (90th%)—Other | 190 | 195 | 172 | 203 | 291 | 301 | 285 | 208 | 215 | 197 | 185 | 189 |
| **Total Hydro (90th%)** | 1,140 | 1,095 | 1,122 | 1,053 | 1,341 | 1,301 | 1,285 | 1,008 | 965 | 947 | 835 | 1,089 |
| **CSPP (PURPA)** | 66 | 69 | 152 | 194 | 234 | 311 | 314 | 307 | 210 | 174 | 151 | 68 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange—Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| **Total PPAs** | 45 | 46 | 23 | 23 | 38 | 38 | 35 | 32 | 34 | 12 | 21 | 43 |
| **Transmission Capacity Available for Market Purchases** | 202 | 243 | 318 | 284 | 220 | 399 | 313 | 333 | 174 | 289 | 236 | 182 |
| **Existing Resource Subtotal** | 3,187 | 3,188 | 3,351 | 3,291 | 3,575 | 3,790 | 3,684 | 3,418 | 3,120 | 3,160 | 2,973 | 3,117 |
| **Monthly Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | 704 | 799 | 1,254 | 1,247 | 857 | 697 | 429 | 456 | 293 | 1,047 | 641 | 473 |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,561) | (2,458) | (2,164) | (2,107) | (2,798) | (3,585) | (3,760) | (3,405) | (2,916) | (2,182) | (2,391) | (2,699) |
| Load Forecast—included EE | 31 | 32 | 31 | 34 | 40 | 45 | 47 | 46 | 40 | 41 | 31 | 32 |
| Load Forecast (95th% w/DSM and EE) | (2,530) | (2,426) | (2,132) | (2,073) | (2,758) | (3,540) | (3,713) | (3,359) | (2,876) | (2,141) | (2,359) | (2,666) |
| Adjustment for EE Potential Study Forecast | 8 | 9 | 8 | 9 | 11 | 12 | 12 | 12 | 11 | 11 | 8 | 9 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM and EE** | (2,521) | (2,417) | (2,124) | (2,065) | (2,747) | (3,139) | (3,310) | (3,010) | (2,865) | (2,130) | (2,351) | (2,658) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 | 1,020 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 950 | 900 | 950 | 850 | 1,050 | 1,000 | 1,000 | 800 | 750 | 750 | 650 | 900 |
| Hydro (90th%)—Other | 181 | 186 | 172 | 204 | 301 | 309 | 285 | 209 | 216 | 198 | 177 | 177 |
| **Total Hydro (90th%)** | 1,131 | 1,086 | 1,122 | 1,054 | 1,351 | 1,309 | 1,285 | 1,009 | 966 | 948 | 827 | 1,077 |
| **CSPP (PURPA)** | 66 | 69 | 152 | 194 | 234 | 311 | 314 | 307 | 210 | 177 | 153 | 68 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange—Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| **Total PPAs** | **45** | **46** | **23** | **23** | **38** | **38** | **35** | **32** | **34** | **12** | **21** | **43** |
| **Transmission Capacity Available for Market Purchases** | 201 | 242 | 317 | 293 | 226 | 387 | 302 | 332 | 177 | 288 | 236 | 183 |
| **Existing Resource Subtotal** | **3,179** | **3,178** | **3,350** | **3,300** | **3,584** | **3,781** | **3,673** | **3,417** | **3,123** | **3,161** | **2,972** | **3,109** |
| **Monthly Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **657** | **761** | **1,226** | **1,236** | **838** | **643** | **362** | **407** | **258** | **1,031** | **621** | **451** |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,598) | (2,487) | (2,192) | (2,136) | (2,840) | (3,641) | (3,836) | (3,469) | (2,962) | (2,215) | (2,420) | (2,720) |
| Load Forecast—included EE | 48 | 49 | 46 | 50 | 59 | 67 | 70 | 67 | 58 | 60 | 48 | 49 |
| Load Forecast (95th% w/DSM and EE) | (2,550) | (2,438) | (2,146) | (2,087) | (2,780) | (3,574) | (3,766) | (3,402) | (2,904) | (2,154) | (2,373) | (2,671) |
| Adjustment for EE Potential Study Forecast | 7 | 7 | 7 | 7 | 9 | 10 | 10 | 10 | 8 | 9 | 7 | 7 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM and EE** | (2,543) | (2,431) | (2,139) | (2,080) | (2,772) | (3,174) | (3,366) | (3,055) | (2,896) | (2,145) | (2,366) | (2,664) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 889 | 889 | 889 | 889 | 889 | 889 | 889 | 889 | 889 | 889 | 889 | 889 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 950 | 900 | 950 | 850 | 1,050 | 1,000 | 1,000 | 800 | 750 | 750 | 650 | 900 |
| Hydro (90th%)—Other | 181 | 180 | 172 | 205 | 300 | 308 | 285 | 209 | 215 | 198 | 177 | 178 |
| **Total Hydro (90th%)** | 1,131 | 1,080 | 1,122 | 1,055 | 1,350 | 1,308 | 1,285 | 1,009 | 965 | 948 | 827 | 1,078 |
| **CSPP (PURPA)** | 66 | 69 | 154 | 196 | 236 | 316 | 319 | 312 | 213 | 177 | 153 | 68 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 5 | 6 | 7 | 9 | 10 | 11 | 10 | 7 | 4 | 1 | 3 | 4 |
| Clatskanie Exchange—Return | 0 | 0 | (20) | (20) | 0 | 0 | 0 | 0 | 0 | (20) | (20) | 0 |
| **Total PPAs** | **45** | **46** | **23** | **23** | **38** | **38** | **35** | **32** | **34** | **12** | **21** | **43** |
| **Transmission Capacity Available for Market Purchases** | 332 | 374 | 448 | 425 | 359 | 518 | 433 | 463 | 308 | 419 | 366 | 314 |
| **Existing Resource Subtotal** | **3,179** | **3,173** | **3,353** | **3,303** | **3,587** | **3,785** | **3,676** | **3,421** | **3,124** | **3,161** | **2,971** | **3,108** |
| **Monthly Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **636** | **742** | **1,213** | **1,223** | **815** | **611** | **311** | **366** | **229** | **1,015** | **605** | **444** |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,624) | (2,513) | (2,212) | (2,161) | (2,877) | (3,691) | (3,908) | (3,529) | (3,004) | (2,243) | (2,448) | (2,754) |
| Load Forecast—included EE | 61 | 63 | 58 | 63 | 74 | 86 | 90 | 85 | 72 | 76 | 61 | 63 |
| Load Forecast (95th% w/DSM and EE) | (2,562) | (2,450) | (2,153) | (2,098) | (2,803) | (3,606) | (3,819) | (3,444) | (2,932) | (2,168) | (2,387) | (2,691) |
| Adjustment for EE Potential Study Forecast | 8 | 8 | 8 | 8 | 10 | 11 | 12 | 11 | 10 | 10 | 8 | 8 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM and EE** | (2,554) | (2,442) | (2,145) | (2,090) | (2,793) | (3,205) | (3,417) | (3,096) | (2,922) | (2,157) | (2,379) | (2,683) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 950 | 900 | 950 | 850 | 1,050 | 1,000 | 1,000 | 800 | 750 | 750 | 650 | 900 |
| Hydro (90th%)—Other | 175 | 183 | 173 | 205 | 299 | 307 | 285 | 209 | 215 | 198 | 177 | 175 |
| **Total Hydro (90th%)** | 1,125 | 1,083 | 1,123 | 1,055 | 1,349 | 1,307 | 1,285 | 1,009 | 965 | 948 | 827 | 1,075 |
| **CSPP (PURPA)** | 66 | 69 | 154 | 196 | 236 | 316 | 319 | 312 | 213 | 177 | 153 | 68 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **40** | **40** | **36** | **34** | **28** | **27** | **25** | **25** | **30** | **31** | **38** | **39** |
| **Transmission Capacity Available for Market Purchases** | 392 | 433 | 507 | 484 | 417 | 576 | 492 | 521 | 366 | 479 | 425 | 374 |
| **Existing Resource Subtotal** | **3,174** | **3,175** | **3,371** | **3,320** | **3,580** | **3,777** | **3,671** | **3,417** | **3,124** | **3,185** | **2,993** | **3,108** |
| **Monthly Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **620** | **733** | **1,226** | **1,230** | **787** | **572** | **255** | **322** | **202** | **1,028** | **614** | **425** |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,666) | (2,548) | (2,244) | (2,191) | (2,919) | (3,750) | (3,985) | (3,595) | (3,053) | (2,275) | (2,479) | (2,785) |
| Load Forecast—included EE | 75 | 76 | 71 | 76 | 89 | 103 | 109 | 103 | 87 | 91 | 74 | 76 |
| Load Forecast (95th% w/DSM and EE) | (2,591) | (2,472) | (2,173) | (2,116) | (2,830) | (3,647) | (3,876) | (3,492) | (2,966) | (2,184) | (2,405) | (2,708) |
| Adjustment for EE Potential Study Forecast | 10 | 10 | 9 | 10 | 11 | 13 | 14 | 13 | 11 | 12 | 9 | 10 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM and EE** | (2,582) | (2,462) | (2,164) | (2,106) | (2,818) | (3,244) | (3,472) | (3,142) | (2,955) | (2,172) | (2,395) | (2,699) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 950 | 900 | 950 | 850 | 1,050 | 1,000 | 1,000 | 800 | 750 | 750 | 650 | 900 |
| Hydro (90th%)—Other | 183 | 187 | 172 | 205 | 300 | 304 | 284 | 207 | 214 | 197 | 177 | 183 |
| **Total Hydro (90th%)** | 1,133 | 1,087 | 1,122 | 1,055 | 1,350 | 1,304 | 1,284 | 1,007 | 964 | 947 | 827 | 1,083 |
| **CSPP (PURPA)** | 66 | 69 | 154 | 196 | 236 | 316 | 319 | 312 | 213 | 177 | 153 | 68 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | 40 | 40 | 36 | 34 | 28 | 27 | 25 | 25 | 30 | 31 | 38 | 39 |
| **Transmission Capacity Available for Market Purchases** | 391 | 433 | 506 | 484 | 416 | 575 | 489 | 521 | 365 | 478 | 424 | 373 |
| **Existing Resource Subtotal** | **3,181** | **3,179** | **3,370** | **3,320** | **3,580** | **3,773** | **3,667** | **3,416** | **3,122** | **3,184** | **2,992** | **3,114** |
| **Monthly Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **599** | **717** | **1,206** | **1,214** | **761** | **529** | **195** | **275** | **167** | **1,012** | **596** | **415** |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,707) | (2,582) | (2,275) | (2,222) | (2,961) | (3,809) | (4,064) | (3,661) | (3,103) | (2,306) | (2,511) | (2,814) |
| Load Forecast—included EE | 88 | 89 | 83 | 88 | 103 | 120 | 129 | 120 | 101 | 104 | 86 | 89 |
| Load Forecast (95th% w/DSM and EE) | (2,619) | (2,493) | (2,192) | (2,134) | (2,858) | (3,690) | (3,934) | (3,541) | (3,002) | (2,202) | (2,426) | (2,725) |
| Adjustment for EE Potential Study Forecast | 11 | 11 | 11 | 11 | 13 | 15 | 16 | 15 | 13 | 13 | 11 | 11 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM and EE** | (2,608) | (2,482) | (2,181) | (2,122) | (2,845) | (3,284) | (3,528) | (3,188) | (2,989) | (2,189) | (2,415) | (2,713) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 950 | 900 | 950 | 850 | 1,050 | 1,000 | 1,000 | 800 | 750 | 750 | 650 | 900 |
| Hydro (90th%)—Other | 182 | 187 | 172 | 205 | 299 | 303 | 284 | 207 | 214 | 197 | 176 | 183 |
| **Total Hydro (90th%)** | 1,132 | 1,087 | 1,122 | 1,055 | 1,349 | 1,303 | 1,284 | 1,007 | 964 | 947 | 826 | 1,083 |
| **CSPP (PURPA)** | 66 | 69 | 154 | 196 | 236 | 316 | 319 | 312 | 213 | 177 | 153 | 68 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **40** | **40** | **36** | **34** | **28** | **27** | **25** | **25** | **30** | **31** | **38** | **39** |
| **Transmission Capacity Available for Market Purchases** | 390 | 432 | 506 | 484 | 415 | 574 | 488 | 520 | 364 | 477 | 423 | 372 |
| **Existing Resource Subtotal** | **3,179** | **3,178** | **3,370** | **3,319** | **3,578** | **3,771** | **3,666** | **3,415** | **3,120** | **3,182** | **2,990** | **3,113** |
| **Monthly Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **571** | **696** | **1,188** | **1,197** | **734** | **487** | **138** | **226** | **132** | **994** | **576** | **399** |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,755) | (2,621) | (2,312) | (2,257) | (3,007) | (3,871) | (4,147) | (3,731) | (3,155) | (2,342) | (2,552) | (2,849) |
| Load Forecast—included EE | 101 | 101 | 95 | 100 | 117 | 136 | 149 | 137 | 116 | 117 | 98 | 102 |
| Load Forecast (95th% w/DSM and EE) | (2,654) | (2,520) | (2,217) | (2,156) | (2,890) | (3,735) | (3,998) | (3,594) | (3,040) | (2,225) | (2,454) | (2,747) |
| Adjustment for EE Potential Study Forecast | 13 | 13 | 12 | 13 | 15 | 17 | 19 | 17 | 15 | 15 | 12 | 13 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM and EE** | (2,641) | (2,507) | (2,205) | (2,144) | (2,875) | (3,328) | (3,589) | (3,240) | (3,025) | (2,210) | (2,442) | (2,735) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 950 | 900 | 950 | 850 | 1,050 | 1,000 | 1,000 | 800 | 750 | 750 | 650 | 900 |
| Hydro (90th%)—Other | 182 | 181 | 172 | 205 | 299 | 302 | 283 | 206 | 213 | 196 | 175 | 182 |
| **Total Hydro (90th%)** | 1,132 | 1,081 | 1,122 | 1,055 | 1,349 | 1,302 | 1,283 | 1,006 | 963 | 946 | 825 | 1,082 |
| **CSPP (PURPA)** | 66 | 69 | 154 | 196 | 236 | 316 | 319 | 312 | 213 | 177 | 153 | 68 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **40** | **40** | **36** | **34** | **28** | **27** | **25** | **25** | **30** | **31** | **38** | **39** |
| **Transmission Capacity Available for Market Purchases** | 389 | 431 | 506 | 483 | 414 | 573 | 487 | 519 | 364 | 476 | 423 | 372 |
| **Existing Resource Subtotal** | **3,178** | **3,171** | **3,369** | **3,318** | **3,577** | **3,769** | **3,665** | **3,413** | **3,120** | **3,181** | **2,990** | **3,112** |
| **Monthly Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **537** | **664** | **1,164** | **1,175** | **702** | **441** | **76** | **174** | **95** | **971** | **548** | **378** |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2025 | 2/2025 | 3/2025 | 4/2025 | 5/2025 | 6/2025 | 7/2025 | 8/2025 | 9/2025 | 10/2025 | 11/2025 | 12/2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,783) | (2,648) | (2,333) | (2,281) | (3,043) | (3,920) | (4,221) | (3,791) | (3,198) | (2,368) | (2,577) | (2,869) |
| Load Forecast—included EE | 115 | 115 | 108 | 114 | 132 | 153 | 172 | 156 | 132 | 131 | 110 | 115 |
| Load Forecast (95th% w/DSM and EE) | (2,668) | (2,533) | (2,226) | (2,167) | (2,911) | (3,766) | (4,050) | (3,636) | (3,066) | (2,236) | (2,466) | (2,754) |
| Adjustment for EE Potential Study Forecast | 13 | 13 | 13 | 13 | 15 | 18 | 20 | 18 | 15 | 15 | 13 | 13 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM and EE** | (2,655) | (2,519) | (2,213) | (2,154) | (2,896) | (3,359) | (3,640) | (3,281) | (3,051) | (2,221) | (2,454) | (2,741) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 | 835 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 950 | 900 | 950 | 850 | 1,050 | 1,000 | 1,000 | 800 | 750 | 750 | 650 | 900 |
| Hydro (90th%)—Other | 181 | 186 | 171 | 204 | 298 | 301 | 283 | 206 | 212 | 195 | 175 | 181 |
| **Total Hydro (90th%)** | 1,131 | 1,086 | 1,121 | 1,054 | 1,348 | 1,301 | 1,283 | 1,006 | 962 | 945 | 825 | 1,081 |
| **CSPP (PURPA)** | 66 | 69 | 154 | 196 | 236 | 316 | 319 | 312 | 213 | 176 | 153 | 68 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **40** | **40** | **36** | **34** | **28** | **27** | **25** | **25** | **30** | **31** | **38** | **39** |
| **Transmission Capacity Available for Market Purchases** | 390 | 431 | 505 | 483 | 412 | 571 | 486 | 517 | 362 | 476 | 423 | 371 |
| **Existing Resource Subtotal** | **3,178** | **3,176** | **3,368** | **3,318** | **3,574** | **3,766** | **3,663** | **3,411** | **3,117** | **3,180** | **2,989** | **3,110** |
| **Monthly Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **524** | **657** | **1,155** | **1,164** | **678** | **408** | **23** | **130** | **66** | **959** | **535** | **370** |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2026 | 2/2026 | 3/2026 | 4/2026 | 5/2026 | 6/2026 | 7/2026 | 8/2026 | 9/2026 | 10/2026 | 11/2026 | 12/2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,814) | (2,674) | (2,357) | (2,308) | (3,082) | (3,972) | (4,301) | (3,856) | (3,245) | (2,396) | (2,604) | (2,901) |
| Load Forecast—included EE | 133 | 131 | 124 | 130 | 149 | 174 | 199 | 178 | 152 | 148 | 125 | 131 |
| Load Forecast (95th% w/DSM and EE) | (2,682) | (2,542) | (2,233) | (2,178) | (2,933) | (3,798) | (4,102) | (3,678) | (3,093) | (2,248) | (2,479) | (2,769) |
| Adjustment for EE Potential Study Forecast | 11 | 11 | 10 | 11 | 12 | 14 | 16 | 15 | 13 | 12 | 10 | 11 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM and EE** | (2,671) | (2,531) | (2,223) | (2,167) | (2,920) | (3,394) | (3,695) | (3,326) | (3,080) | (2,236) | (2,469) | (2,759) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 950 | 900 | 950 | 850 | 1,050 | 1,000 | 1,000 | 800 | 750 | 750 | 650 | 900 |
| Hydro (90th%)—Other | 181 | 185 | 171 | 204 | 298 | 300 | 282 | 205 | 211 | 195 | 174 | 181 |
| **Total Hydro (90th%)** | 1,131 | 1,085 | 1,121 | 1,054 | 1,348 | 1,300 | 1,282 | 1,005 | 961 | 945 | 824 | 1,081 |
| **CSPP (PURPA)** | 66 | 68 | 153 | 195 | 236 | 316 | 318 | 312 | 212 | 176 | 152 | 68 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **40** | **40** | **36** | **34** | **28** | **27** | **25** | **25** | **30** | **31** | **38** | **39** |
| **Transmission Capacity Available for Market Purchases** | 521 | 562 | 636 | 613 | 543 | 703 | 616 | 648 | 492 | 607 | 554 | 503 |
| **Existing Resource Subtotal** | **3,176** | **3,174** | **3,365** | **3,316** | **3,573** | **3,764** | **3,661** | **3,410** | **3,114** | **3,177** | **2,987** | **3,110** |
| **Monthly Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **(34)** | **0** | **0** | **0** | **0** | **0** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **705** | **843** | **1,342** | **1,649** | **1,153** | **870** | **466** | **584** | **533** | **1,142** | **718** | **552** |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,854) | (2,706) | (2,387) | (2,338) | (3,123) | (4,029) | (4,383) | (3,923) | (3,295) | (2,426) | (2,633) | (2,931) |
| Load Forecast—included EE | 149 | 147 | 139 | 146 | 166 | 194 | 227 | 201 | 172 | 164 | 139 | 147 |
| Load Forecast (95th% w/DSM and EE) | (2,705) | (2,559) | (2,248) | (2,192) | (2,957) | (3,836) | (4,157) | (3,723) | (3,124) | (2,262) | (2,493) | (2,784) |
| Adjustment for EE Potential Study Forecast | 9 | 9 | 8 | 8 | 10 | 11 | 13 | 12 | 10 | 10 | 8 | 9 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM and EE** | (2,696) | (2,551) | (2,240) | (2,184) | (2,947) | (3,434) | (3,753) | (3,374) | (3,114) | (2,252) | (2,485) | (2,776) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 950 | 900 | 950 | 850 | 1,050 | 1,000 | 1,000 | 800 | 750 | 750 | 650 | 900 |
| Hydro (90th%)—Other | 180 | 185 | 170 | 204 | 296 | 298 | 282 | 205 | 210 | 194 | 174 | 181 |
| **Total Hydro (90th%)** | 1,130 | 1,085 | 1,120 | 1,054 | 1,346 | 1,298 | 1,282 | 1,005 | 960 | 944 | 824 | 1,081 |
| **CSPP (PURPA)** | 65 | 68 | 153 | 195 | 236 | 316 | 318 | 312 | 212 | 176 | 152 | 68 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **40** | **40** | **36** | **34** | **28** | **27** | **25** | **25** | **30** | **31** | **38** | **39** |
| **Transmission Capacity Available for Market Purchases** | 520 | 562 | 636 | 612 | 542 | 701 | 615 | 647 | 492 | 607 | 554 | 502 |
| **Existing Resource Subtotal** | **3,174** | **3,173** | **3,365** | **3,314** | **3,570** | **3,761** | **3,659** | **3,408** | **3,113** | **3,177** | **2,986** | **3,109** |
| **Monthly Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **(94)** | **0** | **(1)** | **0** | **0** | **0** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **678** | **823** | **1,325** | **1,631** | **1,123** | **826** | **406** | **534** | **499** | **1,124** | **701** | **534** |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,894) | (2,737) | (2,417) | (2,368) | (3,165) | (4,085) | (4,467) | (3,991) | (3,346) | (2,455) | (2,661) | (2,957) |
| Load Forecast—included EE | 166 | 163 | 155 | 161 | 183 | 213 | 255 | 223 | 192 | 179 | 153 | 162 |
| Load Forecast (95th% w/DSM and EE) | (2,728) | (2,574) | (2,263) | (2,206) | (2,981) | (3,872) | (4,212) | (3,768) | (3,155) | (2,276) | (2,509) | (2,796) |
| Adjustment for EE Potential Study Forecast | 6 | 6 | 6 | 6 | 7 | 8 | 10 | 9 | 7 | 7 | 6 | 6 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM and EE** | (2,721) | (2,568) | (2,257) | (2,200) | (2,974) | (3,474) | (3,812) | (3,422) | (3,147) | (2,269) | (2,503) | (2,789) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 | 703 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 950 | 900 | 950 | 850 | 1,050 | 1,000 | 1,000 | 800 | 750 | 750 | 650 | 900 |
| Hydro (90th%)—Other | 180 | 179 | 170 | 204 | 295 | 296 | 281 | 204 | 209 | 193 | 173 | 181 |
| **Total Hydro (90th%)** | 1,130 | 1,079 | 1,120 | 1,054 | 1,345 | 1,296 | 1,281 | 1,004 | 959 | 943 | 823 | 1,081 |
| **CSPP (PURPA)** | 65 | 68 | 153 | 195 | 236 | 316 | 318 | 312 | 212 | 176 | 152 | 68 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **35** | **35** | **31** | **29** | **23** | **22** | **20** | **20** | **25** | **26** | **33** | **34** |
| **Transmission Capacity Available for Market Purchases** | 520 | 562 | 635 | 612 | 540 | 700 | 614 | 646 | 491 | 607 | 553 | 502 |
| **Existing Resource Subtotal** | **3,169** | **3,163** | **3,358** | **3,309** | **3,562** | **3,753** | **3,653** | **3,401** | **3,106** | **3,171** | **2,979** | **3,104** |
| **Monthly Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **(159)** | **(21)** | **(41)** | **0** | **0** | **0** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **648** | **795** | **1,302** | **1,609** | **1,088** | **779** | **341** | **479** | **459** | **1,102** | **677** | **514** |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2029 | 2/2029 | 3/2029 | 4/2029 | 5/2029 | 6/2029 | 7/2029 | 8/2029 | 9/2029 | 10/2029 | 11/2029 | 12/2029 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,929) | (2,767) | (2,444) | (2,396) | (3,205) | (4,139) | (4,551) | (4,058) | (3,397) | (2,483) | (2,688) | (2,985) |
| Load Forecast—included EE | 184 | 179 | 172 | 178 | 201 | 233 | 286 | 247 | 213 | 195 | 167 | 178 |
| Load Forecast (95th% w/DSM and EE) | (2,745) | (2,588) | (2,273) | (2,218) | (3,004) | (3,906) | (4,265) | (3,811) | (3,183) | (2,288) | (2,521) | (2,807) |
| Adjustment for EE Potential Study Forecast | 3 | 3 | 3 | 3 | 3 | 4 | 5 | 4 | 3 | 3 | 3 | 3 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM and EE** | (2,742) | (2,585) | (2,270) | (2,215) | (3,001) | (3,513) | (3,870) | (3,470) | (3,180) | (2,285) | (2,519) | (2,805) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 950 | 900 | 950 | 850 | 1,050 | 1,000 | 1,000 | 800 | 750 | 750 | 650 | 900 |
| Hydro (90th%)—Other | 179 | 184 | 169 | 203 | 293 | 295 | 281 | 203 | 208 | 192 | 172 | 180 |
| **Total Hydro (90th%)** | 1,129 | 1,084 | 1,119 | 1,053 | 1,343 | 1,295 | 1,281 | 1,003 | 958 | 942 | 822 | 1,080 |
| **CSPP (PURPA)** | 63 | 66 | 151 | 193 | 233 | 313 | 316 | 309 | 209 | 173 | 149 | 65 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **35** | **35** | **31** | **29** | **23** | **22** | **20** | **20** | **25** | **26** | **33** | **34** |
| **Transmission Capacity Available for Market Purchases** | 519 | 561 | 635 | 611 | 539 | 698 | 613 | 645 | 489 | 606 | 553 | 501 |
| **Existing Resource Subtotal** | **2,989** | **2,988** | **3,180** | **3,129** | **3,381** | **3,571** | **3,473** | **3,221** | **2,924** | **2,991** | **2,800** | **2,924** |
| **Monthly Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **(397)** | **(249)** | **(256)** | **0** | **0** | **0** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **448** | **603** | **1,110** | **1,414** | **881** | **559** | **103** | **251** | **244** | **906** | **482** | **319** |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2030 | 2/2030 | 3/2030 | 4/2030 | 5/2030 | 6/2030 | 7/2030 | 8/2030 | 9/2030 | 10/2030 | 11/2030 | 12/2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (2,965) | (2,797) | (2,473) | (2,425) | (3,245) | (4,192) | (4,636) | (4,125) | (3,447) | (2,511) | (2,715) | (3,012) |
| Load Forecast—included EE | 203 | 197 | 189 | 196 | 220 | 253 | 318 | 272 | 237 | 211 | 182 | 195 |
| Load Forecast (95th% w/DSM and EE) | (2,763) | (2,601) | (2,284) | (2,230) | (3,025) | (3,939) | (4,317) | (3,853) | (3,210) | (2,299) | (2,533) | (2,817) |
| Adjustment for EE Potential Study Forecast | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM and EE** | (2,763) | (2,601) | (2,284) | (2,230) | (3,025) | (3,549) | (3,927) | (3,516) | (3,210) | (2,299) | (2,533) | (2,817) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 950 | 900 | 950 | 850 | 1,050 | 1,000 | 1,000 | 800 | 750 | 750 | 650 | 900 |
| Hydro (90th%)—Other | 179 | 183 | 169 | 203 | 293 | 294 | 280 | 203 | 207 | 192 | 172 | 179 |
| **Total Hydro (90th%)** | 1,129 | 1,083 | 1,119 | 1,053 | 1,343 | 1,294 | 1,280 | 1,003 | 957 | 942 | 822 | 1,079 |
| **CSPP (PURPA)** | 63 | 65 | 151 | 193 | 233 | 311 | 314 | 307 | 207 | 171 | 148 | 63 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **35** | **35** | **31** | **29** | **23** | **22** | **20** | **20** | **25** | **26** | **33** | **34** |
| **Transmission Capacity Available for Market Purchases** | 518 | 561 | 634 | 612 | 538 | 698 | 612 | 644 | 489 | 606 | 552 | 501 |
| **Existing Resource Subtotal** | **2,988** | **2,987** | **3,178** | **3,130** | **3,380** | **3,568** | **3,470** | **3,218** | **2,922** | **2,988** | **2,797** | **2,921** |
| **Monthly Deficit** | **0** | **0** | **0** | **0** | **0** | **0** | **(458)** | **(299)** | **(288)** | **0** | **0** | **0** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **New Resource Subtotal** | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| **Monthly Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **425** | **586** | **1,094** | **1,400** | **855** | **519** | **42** | **201** | **212** | **889** | **464** | **304** |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (3,001) | (2,827) | (2,501) | (2,454) | (3,285) | (4,244) | (4,723) | (4,193) | (3,497) | (2,538) | (2,741) | (3,031) |
| Load Forecast—included EE | 222 | 214 | 207 | 213 | 238 | 274 | 353 | 297 | 261 | 227 | 196 | 211 |
| Load Forecast (95th% w/DSM and EE) | (2,780) | (2,613) | (2,294) | (2,241) | (3,047) | (3,971) | (4,370) | (3,896) | (3,237) | (2,311) | (2,545) | (2,820) |
| Adjustment for EE Potential Study Forecast | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM and EE** | (2,780) | (2,613) | (2,294) | (2,241) | (3,047) | (3,581) | (3,980) | (3,559) | (3,237) | (2,311) | (2,545) | (2,820) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 950 | 900 | 950 | 850 | 1,050 | 1,000 | 1,000 | 800 | 750 | 750 | 650 | 900 |
| Hydro (90th%)—Other | 179 | 183 | 169 | 203 | 292 | 292 | 279 | 202 | 206 | 191 | 171 | 179 |
| **Total Hydro (90th%)** | 1,129 | 1,083 | 1,119 | 1,053 | 1,342 | 1,292 | 1,279 | 1,002 | 956 | 941 | 821 | 1,079 |
| **CSPP (PURPA)** | 58 | 55 | 141 | 183 | 222 | 302 | 305 | 298 | 198 | 162 | 137 | 53 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **35** | **35** | **31** | **29** | **23** | **22** | **20** | **20** | **25** | **26** | **33** | **34** |
| **Transmission Capacity Available for Market Purchases** | 518 | 560 | 635 | 611 | 538 | 697 | 611 | 643 | 489 | 605 | 552 | 500 |
| **Existing Resource Subtotal** | **2,983** | **2,976** | **3,169** | **3,119** | **3,368** | **3,556** | **3,459** | **3,207** | **2,911** | **2,977** | **2,786** | **2,910** |
| **Monthly Deficit** | **0** | **0** | **0** | **0** | **0** | **(24)** | **(521)** | **(352)** | **(325)** | **0** | **0** | **0** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engine | 36 | 0 | 0 | 0 | 0 | 36 | 36 | 36 | 36 | 0 | 0 | 36 |
| **New Resource Subtotal** | 236 | 200 | 200 | 500 | 500 | 536 | 536 | 536 | 536 | 200 | 200 | 236 |
| **Monthly Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **439** | **563** | **1,076** | **1,378** | **821** | **512** | **15** | **184** | **211** | **866** | **441** | **326** |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2032 | 2/2032 | 3/2032 | 4/2032 | 5/2032 | 6/2032 | 7/2032 | 8/2032 | 9/2032 | 10/2032 | 11/2032 | 12/2032 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (3,029) | (2,853) | (2,522) | (2,479) | (3,321) | (4,291) | (4,807) | (4,258) | (3,545) | (2,562) | (2,765) | (3,059) |
| Load Forecast—included EE | 240 | 231 | 225 | 230 | 256 | 293 | 387 | 323 | 285 | 242 | 210 | 227 |
| Load Forecast (95th% w/DSM and EE) | (2,788) | (2,623) | (2,297) | (2,248) | (3,065) | (3,998) | (4,420) | (3,935) | (3,260) | (2,320) | (2,555) | (2,832) |
| Adjustment for EE Potential Study Forecast | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM and EE** | (2,788) | (2,623) | (2,297) | (2,248) | (3,065) | (3,608) | (4,030) | (3,598) | (3,260) | (2,320) | (2,555) | (2,832) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 | 527 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 950 | 900 | 950 | 850 | 1,050 | 1,000 | 1,000 | 800 | 750 | 750 | 650 | 900 |
| Hydro (90th%)—Other | 179 | 177 | 169 | 202 | 291 | 290 | 279 | 201 | 205 | 190 | 170 | 179 |
| **Total Hydro (90th%)** | 1,129 | 1,077 | 1,119 | 1,052 | 1,341 | 1,290 | 1,279 | 1,001 | 955 | 940 | 820 | 1,079 |
| **CSPP (PURPA)** | 50 | 53 | 138 | 180 | 221 | 301 | 303 | 297 | 197 | 161 | 137 | 53 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **35** | **35** | **31** | **29** | **23** | **22** | **20** | **20** | **25** | **26** | **33** | **34** |
| **Transmission Capacity Available for Market Purchases** | 517 | 560 | 634 | 611 | 537 | 696 | 610 | 643 | 488 | 605 | 552 | 500 |
| **Existing Resource Subtotal** | **2,974** | **2,968** | **3,165** | **3,116** | **3,364** | **3,552** | **3,456** | **3,205** | **2,908** | **2,975** | **2,785** | **2,909** |
| **Monthly Deficit** | **0** | **0** | **0** | **0** | **0** | **(56)** | **(574)** | **(393)** | **(352)** | **0** | **0** | **0** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2033 Combined Cycle Combustion Turbine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030s Reciprocating Gas Engine | 72 | 0 | 0 | 0 | 0 | 72 | 72 | 72 | 72 | 0 | 0 | 72 |
| **New Resource Subtotal** | 272 | 200 | 200 | 500 | 500 | 572 | 572 | 572 | 572 | 200 | 200 | 272 |
| **Monthly Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (2) | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **458** | **545** | **1,068** | **1,367** | **799** | **516** | **(2)** | **179** | **220** | **855** | **430** | **349** |

Note: Remaining monthly deficit amounts for July 2032, July 2035, and July 2036 are below de minimis amounts and occur near the end of the planning period leaving adequate time to adjust in future planning periods.

# Peak-Hour Load and Resource Balance (continued)

| | 1/2033 | 2/2033 | 3/2033 | 4/2033 | 5/2033 | 6/2033 | 7/2033 | 8/2033 | 9/2033 | 10/2033 | 11/2033 | 12/2033 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (3,066) | (2,879) | (2,550) | (2,507) | (3,359) | (4,343) | (4,894) | (4,325) | (3,596) | (2,587) | (2,790) | (3,089) |
| Load Forecast—included EE | 258 | 247 | 242 | 247 | 272 | 311 | 421 | 347 | 308 | 255 | 222 | 242 |
| Load Forecast (95th% w/DSM and EE) | (2,808) | (2,633) | (2,309) | (2,260) | (3,087) | (4,032) | (4,474) | (3,979) | (3,288) | (2,332) | (2,567) | (2,847) |
| Adjustment for EE Potential Study Forecast | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM and EE** | (2,808) | (2,633) | (2,309) | (2,260) | (3,087) | (3,642) | (4,084) | (3,642) | (3,288) | (2,332) | (2,567) | (2,847) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 352 | 352 | 352 | 352 | 352 | 352 | 352 | 352 | 352 | 352 | 352 | 352 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 950 | 900 | 950 | 850 | 1,050 | 1,000 | 1,000 | 800 | 750 | 750 | 650 | 900 |
| Hydro (90th%)—Other | 178 | 182 | 168 | 200 | 290 | 289 | 278 | 200 | 204 | 189 | 170 | 178 |
| **Total Hydro (90th%)** | 1,128 | 1,082 | 1,118 | 1,050 | 1,340 | 1,289 | 1,278 | 1,000 | 954 | 939 | 820 | 1,078 |
| **CSPP (PURPA)** | 41 | 44 | 130 | 171 | 212 | 292 | 295 | 288 | 188 | 152 | 128 | 44 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **35** | **35** | **31** | **29** | **23** | **22** | **20** | **20** | **25** | **26** | **33** | **34** |
| **Transmission Capacity Available for Market Purchases** | 517 | 559 | 633 | 610 | 535 | 694 | 608 | 641 | 487 | 604 | 551 | 500 |
| **Existing Resource Subtotal** | **2,789** | **2,787** | **2,979** | **2,928** | **3,177** | **3,364** | **3,269** | **3,017** | **2,721** | **2,789** | **2,598** | **2,724** |
| **Monthly Deficit** | **(20)** | **0** | **0** | **0** | **0** | **(279)** | **(815)** | **(624)** | **(567)** | **0** | **0** | **(123)** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2033 Combined Cycle Combustion Turbine | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| 2030s Reciprocating Gas Engine | 72 | 0 | 0 | 0 | 0 | 72 | 72 | 72 | 72 | 0 | 0 | 72 |
| **New Resource Subtotal** | 572 | 500 | 500 | 800 | 800 | 872 | 872 | 872 | 872 | 500 | 500 | 572 |
| **Monthly Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **552** | **654** | **1,171** | **1,468** | **890** | **593** | **57** | **248** | **305** | **957** | **531** | **449** |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2034 | 2/2034 | 3/2034 | 4/2034 | 5/2034 | 6/2034 | 7/2034 | 8/2034 | 9/2034 | 10/2034 | 11/2034 | 12/2034 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (3,108) | (2,912) | (2,582) | (2,537) | (3,400) | (4,398) | (4,985) | (4,396) | (3,652) | (2,613) | (2,816) | (3,117) |
| Load Forecast—included EE | 276 | 262 | 259 | 263 | 288 | 328 | 455 | 371 | 332 | 267 | 234 | 257 |
| Load Forecast (95th% w/DSM and EE) | (2,832) | (2,649) | (2,323) | (2,274) | (3,112) | (4,070) | (4,529) | (4,025) | (3,319) | (2,346) | (2,582) | (2,860) |
| Adjustment for EE Potential Study Forecast | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM and EE** | (2,832) | (2,649) | (2,323) | (2,274) | (3,112) | (3,680) | (4,139) | (3,688) | (3,319) | (2,346) | (2,582) | (2,860) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 352 | 352 | 352 | 352 | 352 | 352 | 352 | 352 | 352 | 352 | 352 | 352 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 950 | 900 | 950 | 850 | 1,050 | 1,000 | 1,000 | 800 | 750 | 750 | 650 | 900 |
| Hydro (90th%)—Other | 177 | 181 | 168 | 200 | 289 | 286 | 278 | 200 | 202 | 188 | 169 | 177 |
| **Total Hydro (90th%)** | 1,127 | 1,081 | 1,118 | 1,050 | 1,339 | 1,286 | 1,278 | 1,000 | 952 | 938 | 819 | 1,077 |
| **CSPP (PURPA)** | 41 | 44 | 130 | 171 | 212 | 292 | 295 | 288 | 188 | 152 | 128 | 44 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **35** | **35** | **31** | **29** | **23** | **22** | **20** | **20** | **25** | **26** | **33** | **34** |
| **Transmission Capacity Available for Market Purchases** | 517 | 559 | 633 | 610 | 535 | 693 | 607 | 640 | 486 | 604 | 551 | 500 |
| **Existing Resource Subtotal** | **2,787** | **2,786** | **2,979** | **2,928** | **3,176** | **3,360** | **3,267** | **3,016** | **2,719** | **2,788** | **2,598** | **2,723** |
| **Monthly Deficit** | **(45)** | **0** | **0** | **0** | **0** | **(320)** | **(872)** | **(672)** | **(601)** | **0** | **0** | **(137)** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2033 Combined Cycle Combustion Turbine | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| 2030s Reciprocating Gas Engine | 72 | 0 | 0 | 0 | 0 | 72 | 72 | 72 | 72 | 0 | 0 | 72 |
| **New Resource Subtotal** | 572 | 500 | 500 | 800 | 800 | 872 | 872 | 872 | 872 | 500 | 500 | 572 |
| **Monthly Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (0) | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **527** | **637** | **1,156** | **1,454** | **864** | **552** | **(0)** | **200** | **271** | **942** | **515** | **435** |

# Peak-Hour Load and Resource Balance (continued)

| | 1/2035 | 2/2035 | 3/2035 | 4/2035 | 5/2035 | 6/2035 | 7/2035 | 8/2035 | 9/2035 | 10/2035 | 11/2035 | 12/2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (3,147) | (2,942) | (2,611) | (2,566) | (3,440) | (4,453) | (5,076) | (4,466) | (3,707) | (2,638) | (2,843) | (3,149) |
| Load Forecast—included EE | 294 | 278 | 276 | 280 | 305 | 345 | 492 | 396 | 357 | 280 | 246 | 272 |
| Load Forecast (95th% w/DSM and EE) | (2,853) | (2,664) | (2,334) | (2,287) | (3,135) | (4,107) | (4,584) | (4,070) | (3,350) | (2,359) | (2,597) | (2,878) |
| Adjustment for EE Potential Study Forecast | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM and EE** | (2,853) | (2,664) | (2,334) | (2,287) | (3,135) | (3,717) | (4,194) | (3,733) | (3,350) | (2,359) | (2,597) | (2,878) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 352 | 352 | 352 | 352 | 352 | 352 | 352 | 352 | 352 | 352 | 352 | 352 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 950 | 900 | 950 | 850 | 1,050 | 1,000 | 1,000 | 800 | 750 | 750 | 650 | 900 |
| Hydro (90th%)—Other | 176 | 181 | 167 | 200 | 287 | 284 | 277 | 199 | 201 | 188 | 168 | 177 |
| **Total Hydro (90th%)** | 1,126 | 1,081 | 1,117 | 1,050 | 1,337 | 1,284 | 1,277 | 999 | 951 | 938 | 818 | 1,077 |
| **CSPP (PURPA)** | 41 | 44 | 130 | 171 | 212 | 292 | 295 | 288 | 188 | 152 | 128 | 44 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **35** | **35** | **31** | **29** | **23** | **22** | **20** | **20** | **25** | **26** | **33** | **34** |
| **Transmission Capacity Available for Market Purchases** | 516 | 559 | 632 | 609 | 534 | 693 | 607 | 640 | 485 | 604 | 550 | 499 |
| **Existing Resource Subtotal** | **2,786** | **2,786** | **2,977** | **2,927** | **3,173** | **3,358** | **3,267** | **3,015** | **2,716** | **2,787** | **2,596** | **2,721** |
| **Monthly Deficit** | **(67)** | **0** | **0** | **0** | **0** | **(359)** | **(928)** | **(718)** | **(634)** | **0** | **(1)** | **(156)** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2033 Combined Cycle Combustion Turbine | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| 2030s Reciprocating Gas Engine | 126 | 0 | 0 | 0 | 0 | 126 | 126 | 126 | 126 | 0 | 0 | 126 |
| **New Resource Subtotal** | 626 | 500 | 500 | 800 | 800 | 926 | 926 | 926 | 926 | 500 | 500 | 626 |
| **Monthly Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (2) | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **559** | **622** | **1,143** | **1,440** | **838** | **567** | **(2)** | **208** | **292** | **928** | **499** | **470** |

Note: Remaining monthly deficit amounts for July 2032, July 2035, and July 2036 are below de minimis amounts and occur near the end of the planning period leaving adequate time to adjust in future planning periods.

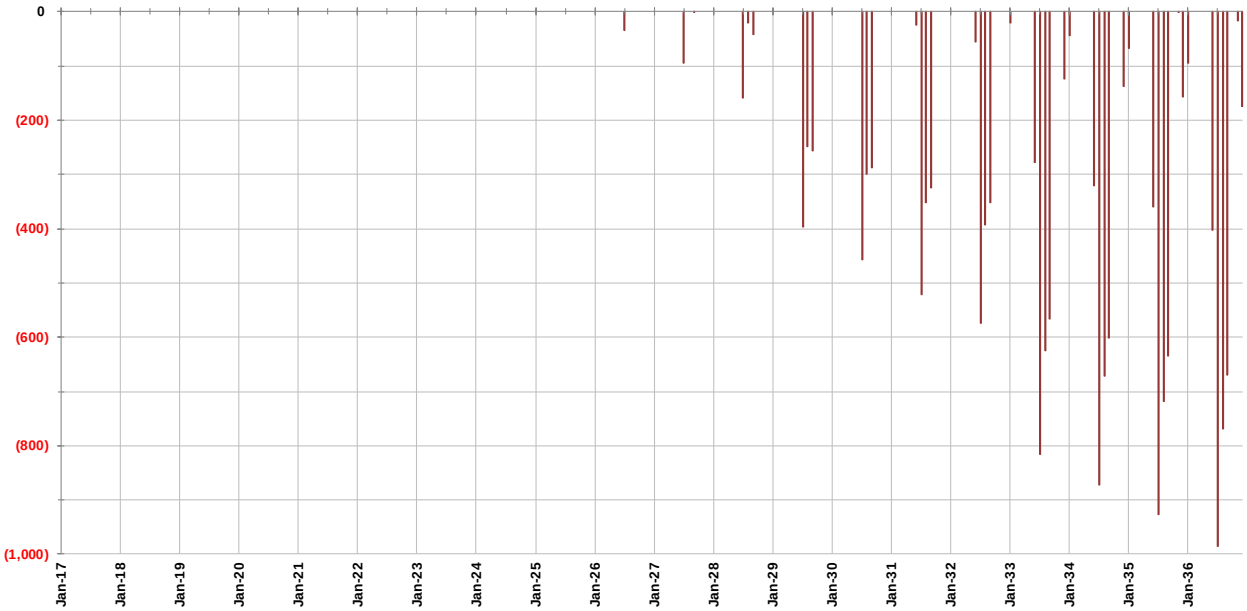
# Peak-Hour Load and Resource Balance (continued)

| | 1/2036 | 2/2036 | 3/2036 | 4/2036 | 5/2036 | 6/2036 | 7/2036 | 8/2036 | 9/2036 | 10/2036 | 11/2036 | 12/2036 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Load Forecast (95th% w/no DSM)** | (3,193) | (2,978) | (2,646) | (2,599) | (3,484) | (4,512) | (5,172) | (4,541) | (3,769) | (2,666) | (2,871) | (3,183) |
| Load Forecast—included EE | 314 | 295 | 296 | 298 | 323 | 364 | 531 | 423 | 384 | 293 | 259 | 288 |
| Load Forecast (95th% w/DSM and EE) | (2,879) | (2,682) | (2,350) | (2,302) | (3,161) | (4,148) | (4,641) | (4,118) | (3,384) | (2,373) | (2,612) | (2,896) |
| Adjustment for EE Potential Study Forecast | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Existing Demand Response | 0 | 0 | 0 | 0 | 0 | 390 | 390 | 337 | 0 | 0 | 0 | 0 |
| **Peak-Hour Forecast w/DSM and EE** | (2,879) | (2,682) | (2,350) | (2,302) | (3,161) | (3,758) | (4,251) | (3,781) | (3,384) | (2,373) | (2,612) | (2,896) |
| Existing Resources | | | | | | | | | | | | |
| **Total Coal** | 352 | 352 | 352 | 352 | 352 | 352 | 352 | 352 | 352 | 352 | 352 | 352 |
| **Total Gas** | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 | 716 |
| Hydro (90th%)—HCC | 950 | 900 | 950 | 850 | 1,050 | 1,000 | 1,000 | 800 | 750 | 750 | 650 | 900 |
| Hydro (90th%)—Other | 175 | 175 | 166 | 200 | 286 | 282 | 276 | 198 | 200 | 187 | 167 | 176 |
| **Total Hydro (90th%)** | 1,125 | 1,075 | 1,116 | 1,050 | 1,336 | 1,282 | 1,276 | 998 | 950 | 937 | 817 | 1,076 |
| **CSPP (PURPA)** | 41 | 44 | 130 | 171 | 212 | 292 | 295 | 288 | 188 | 152 | 128 | 44 |
| **PPAs** | | | | | | | | | | | | |
| Elkhorn Valley Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Raft River Geothermal | 10 | 10 | 9 | 9 | 7 | 8 | 8 | 7 | 9 | 9 | 10 | 10 |
| Neal Hot Springs Geothermal | 25 | 25 | 23 | 20 | 16 | 15 | 12 | 13 | 16 | 17 | 23 | 25 |
| Clatskanie Exchange—Take | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Clatskanie Exchange—Return | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total PPAs** | **35** | **35** | **31** | **29** | **23** | **22** | **20** | **20** | **25** | **26** | **33** | **34** |
| **Transmission Capacity Available for Market Purchases** | 515 | 558 | 631 | 609 | 533 | 692 | 606 | 638 | 485 | 604 | 550 | 499 |
| **Existing Resource Subtotal** | **2,784** | **2,779** | **2,976** | **2,927** | **3,170** | **3,355** | **3,265** | **3,012** | **2,715** | **2,786** | **2,595** | **2,721** |
| **Monthly Deficit** | **(95)** | **0** | **0** | **0** | **0** | **(403)** | **(986)** | **(769)** | **(669)** | **0** | **(17)** | **(175)** |
| **2017 IRP Resources** | | | | | | | | | | | | |
| 2026 Boardman to Hemingway Transmission | 200 | 200 | 200 | 500 | 500 | 500 | 500 | 500 | 500 | 200 | 200 | 200 |
| 2033 Combined Cycle Combustion Turbine | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 | 300 |
| 2030s Reciprocating Gas Engine | 180 | 0 | 0 | 0 | 0 | 180 | 180 | 180 | 180 | 0 | 0 | 180 |
| **New Resource Subtotal** | 680 | 500 | 500 | 800 | 800 | 980 | 980 | 980 | 980 | 500 | 500 | 680 |
| **Monthly Deficit** | 0 | 0 | 0 | 0 | 0 | 0 | (6) | 0 | 0 | 0 | 0 | 0 |
| **Monthly Surplus/Deficit** | **585** | **597** | **1,126** | **1,425** | **809** | **577** | **(6)** | **211** | **311** | **913** | **483** | **505** |

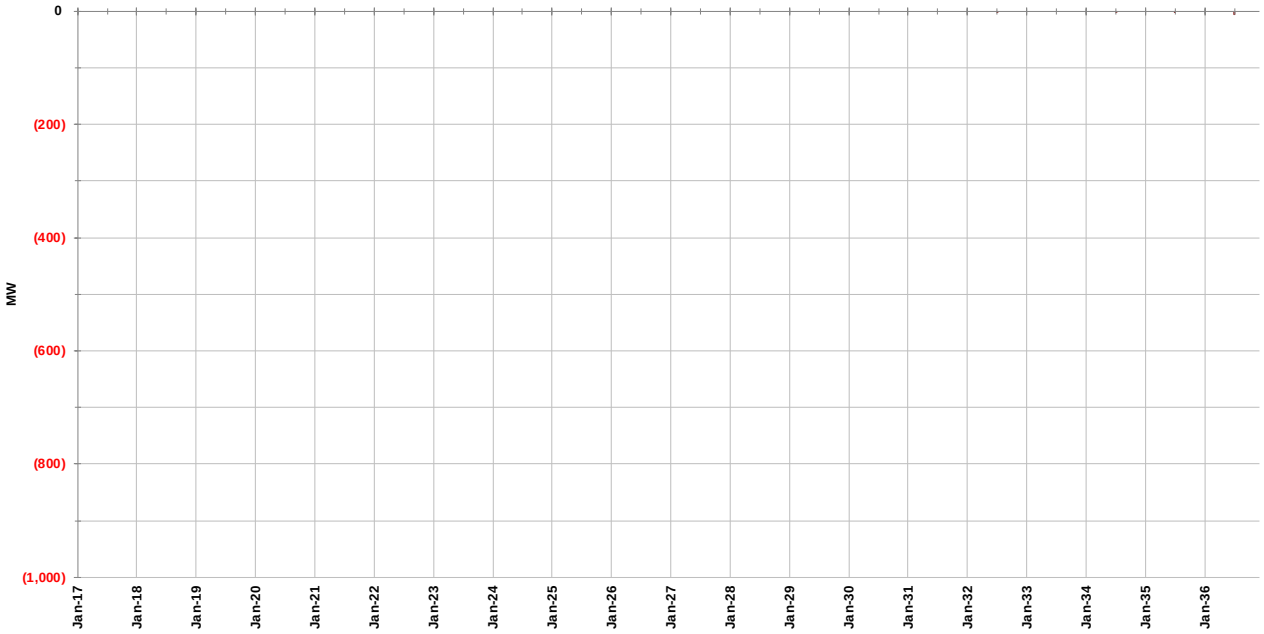
Note: Remaining monthly deficit amounts for July 2032, July 2035, and July 2036 are below de minimis amounts and occur near the end of the planning period leaving adequate time to adjust in future planning periods.

# Peak-Hour Surplus/Deficit Charts

**Peak-hour monthly deficits with existing DSM and existing resources**




**Peak-hour monthly deficits with existing DSM, existing resources, IRP DSM, and IRP resources**



# DEMAND-SIDE RESOURCE DATA

## Cost Effectiveness

Idaho Power considers cost-effectiveness to be the primary screening tool prior to demand-side management (DSM) program implementation. Idaho Power's goal is for all programs to have benefit/cost (B/C) ratios greater than one for the total resource cost (TRC) test, utility cost (UC) test, and participant cost test (PCT) at the program and measure level where appropriate. Each cost-effectiveness test provides a different perspective, and Idaho Power believes each test provides value when evaluating program performance. If a specific measure or program is found to be not cost-effective from each of the three tests. For resource planning Idaho Power primarily uses the total resource cost (TRC) test and the utility cost (UC) tests to determine the cost-effective energy efficiency for inclusion in the IRP. Each energy efficiency program and individual program measures are reviewed annually as part of preparation of an annual report that is submitted to both the Idaho Public Utilities Commission and Public Utilities Commission of Oregon. More information on Idaho Power's programs and cost-effectiveness is included in the *Demand-Side Management 2016 Annual Report* and its *Supplement 1: Cost-Effectiveness,* (idahopower.com/EnergyEfficiency/reports.cfm).

Incorporated into the cost-effectiveness analysis are inputs from various sources that represent the most current and reliable information available. Measure savings, measure life, and participant cost assumptions for prescriptive programs are usually sourced from the Regional Technical Forum (RTF), which is the regional advisory group and technical arm of the Northwest Power and Conservation Council (NPCC). For custom and non-prescriptive programs, annual energy savings can be derived from program evaluations, engineering estimates, or regionally deemed values. Participant costs for non-prescriptive programs are often actual costs from customer-submitted information. Other inputs used in the cost-effectiveness models are obtained from the IRP process, including the financial assumptions along with the value of DSM alternative costs.

For the 2017 IRP, non-energy related benefits (NEB) were included in the cost-effectiveness analysis of the program forecasts. NEB include savings from water savings, deferred maintenance and operational costs, avoided supplemental fuels, and other quantifiable benefits. NEB values from the 2016 portfolio of programs was used in the calculation of cost-effectiveness at the sector level. For a complete list of NEB and sources that Idaho Power currently uses for its program cost-effectiveness, see *Demand-Side Management 2016 Annual Report* and its *Supplement 1: Cost-Effectiveness,* (idahopower.com/EnergyEfficiency/reports.cfm).

The cost-effective analysis methods used at Idaho Power are consistent with published methods and standard practices. Idaho Power relies on the *Electric Power Research Institute End Use Technical Assessment Guide* (TAG) *Understanding Cost-Effectiveness of Energy Efficiency Programs,* and the *California Standard Practice Manual* for the cost-effectiveness methodology. As defined in the TAG and *California Standard Practice Manual*, the TRC and UC tests are most like supply-side cost analysis and provide a useful basis to compare demand-side and supply-side resources.

## Resource Development and Evaluation

When developing energy efficiency programs, Idaho Power uses data and experiences from other companies in the region, or throughout the country, where applicable, to help identify specific program parameters. This is accomplished through discussions with other utilities' program managers and researchers. Idaho Power also uses electric industry research organizations, such as E Source, the Consortium for Energy Efficiency (CEE), American Council for an Energy-Efficient Economy (ACEEE), and the Association of Energy Service Professionals (AESP), to identify similar programs and their results.

All programs are included in an ongoing evaluation schedule where a third-party consultant verifies the claimed savings from the program. Programs are also evaluated to review the program processes to assess the effectiveness of the program delivery. If an evaluation determines that savings are less than claimed or that there is potential for improvement in delivery of the program, then changes can be made based on the recommendations. Recent evaluations from the 2016 program year can be found in the *Demand-Side Management 2016 Annual Report* and its *Supplement 2: Evaluations,* (idahopower.com/EnergyEfficiency/reports.cfm).

## Planning Assumptions and Alternate Costs

All financial assumptions used in the cost-effectiveness analysis for energy efficiency resources included in the 2017 IRP are consistent with the financial assumptions made for supply-side resources, including the discount rate and cost escalation rates. The IRP is also the source of the DSM alternative costs, which is the basis for estimating the value of energy savings and demand reduction resulting from the DSM programs. The DSM alternative energy costs are based on either IRP forecast of fuel costs of a natural gas peaking unit for peak summer hours or future energy prices as determined by the AURORAxmp® Electric Market Model. The avoided capacity resource for peak summer hours is based on a 170 MW natural gas-fired, simple-cycle combustion turbine (SCCT) 35-year levelized cost.

The AURORAxmp® model is an electricity forecasting tool that simulates hourly economic dispatch of supply-side resources considering demand-side, and transmission resources. Idaho Power's planning model forecasts electric market prices throughout southern Idaho and theWestern Electricity Coordinating Council (WECC) region. Idaho Power modeled hourly, marginal electricity costs for the years 2017 through 2036 to estimate the potential system benefit of avoiding future cost production energy. An initial run of DSM Alternative costs is estimated during the preliminary analysis phase of the IRP process. The preliminary runs combined updated planning assumptions including load and natural gas price forecasts run using the preferred resource portfolio from the 2015 IRP. After the selection of the preferred portfolio a final run of marginal prices will be run which, once acknowledged, become the DSM alternative energy prices for energy efficiency valuation until the next IRP analysis is completed and acknowledged.

To simplify cost-effectiveness calculations, the DSM alternative costs are averaged and placed into five pricing categories. The resulting pricing categories include the following:

- Summer On-Peak (SONP)—Average of Idaho Power variable energy and operating costs of a 170 MW SCCT, which is the marginal resource for peak hour load deficits during summertime heavy load hours
- Summer Mid-Peak (SMP)—Average of heavy load prices from June to August (excluding the SONP hours)
- Summer Off-Peak (SOFP)—Average of light load prices from June to August
- Non-Summer Mid-Peak (NSMP)—Average of heavy load prices in January through May and September through December
- Non-Summer Off-Peak (NSOFP)—Average of light load prices in January through May and September through December

The SONP is treated differently than the other four pricing periods when valuing energy efficiency. The estimated levelized capacity cost of a new SCCT is $122 per kW/Year over a 35-year period. The $122 per kW/Year avoided capacity value is spread across the annual SONP hours to value the energy efficiency savings occurring during the hours.

## Forecast and Cost-Effectiveness Data

Table DSM-1 lists the financial assumptions used for the cost-effectiveness analysis.

**Table DSM-1. IRP financial assumptions**

| DSM Analysis Assumptions | |
|---|---|
| **Avoided 35-Year Levelized Capacity Costs** | |
| SCCT | $122/kW/year |
| **Financial Assumptions** | |
| Weighted average cost of capital (2016 year ending after tax) | 6.74% |
| Financial escalation factor | 2.10% |
| **Transmission Losses** | |
| Non-summer secondary losses | 9.60% |
| Summer peak loss | 9.70% |

Table DSM-2 shows the planning results of averaging forward energy prices over the 20-year planning period.

**Table DSM-2. DSM alternate costs by pricing period**

| Year | Summer On-Peak[1] (SONP) | Summer Mid-Peak (SMP) | Summer Off-Peak (SOFP) | Non-Summer Mid-Peak (NSMP) | Non-Summer Off-Peak (NSOFP) | Annual Average[2] |
|---|---|---|---|---|---|---|
| 2017 | $48.14 | $29.55 | $26.33 | $28.28 | $26.47 | $42.76 |
| 2018 | $53.96 | $31.32 | $28.28 | $29.94 | $27.92 | $44.64 |
| 2019 | $54.40 | $32.35 | $29.33 | $30.75 | $28.81 | $45.48 |
| 2020 | $55.59 | $32.56 | $30.53 | $30.75 | $28.99 | $45.73 |
| 2021 | $57.00 | $33.08 | $30.94 | $30.75 | $29.05 | $45.96 |
| 2022 | $57.70 | $33.04 | $31.59 | $30.60 | $28.35 | $45.74 |
| 2023 | $58.80 | $34.20 | $33.75 | $32.99 | $31.92 | $48.29 |
| 2024 | $61.08 | $35.90 | $35.82 | $34.52 | $33.55 | $49.90 |
| 2025 | $63.75 | $36.67 | $36.46 | $35.53 | $34.19 | $50.87 |
| 2026 | $66.15 | $38.74 | $38.40 | $37.98 | $36.43 | $53.21 |
| 2027 | $68.26 | $41.86 | $41.04 | $41.18 | $39.35 | $56.19 |
| 2028 | $71.36 | $45.21 | $44.09 | $44.44 | $42.35 | $59.28 |
| 2029 | $73.79 | $46.30 | $44.94 | $47.07 | $44.23 | $61.38 |
| 2030 | $75.69 | $48.53 | $47.23 | $49.11 | $46.31 | $63.45 |
| 2031 | $77.07 | $50.56 | $48.01 | $51.00 | $48.22 | $65.24 |
| 2032 | $78.34 | $51.91 | $48.94 | $52.49 | $49.82 | $66.69 |
| 2033 | $78.88 | $52.02 | $48.16 | $53.35 | $50.36 | $67.23 |
| 2034 | $78.79 | $52.71 | $47.92 | $53.80 | $51.02 | $67.67 |
| 2035 | $77.22 | $51.71 | $46.89 | $53.08 | $50.46 | $66.90 |
| 2036 | $75.80 | $51.20 | $45.74 | $51.83 | $49.59 | $65.80 |

[1] Estimated average annual variable operations and management costs of a 170 MW capacity SCCT.

[2] Annual average across all hours includes 35 year levelized capacity value of a 170 MW SCCT.

Tables DSM-3 and DSM-4 shows the distribution of the three summer and two non-summer pricing periods across the hours and days of the week and for holidays.

**Table DSM-3. DSM alternate cost summer pricing periods (June 1–August 31)**

| Hour | Sunday | Monday | Tuesday | Wednesday | Thursday | Friday | Saturday | Holiday |
|---|---|---|---|---|---|---|---|---|
| 1 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 2 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 3 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 4 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 5 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 6 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 7 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 8 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 9 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 10 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 11 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 12 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 13 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 14 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 15 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 16 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 17 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 18 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 19 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 20 | SMP | SONP | SONP | SONP | SONP | SONP | SMP | SMP |
| 21 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 22 | SMP | SMP | SMP | SMP | SMP | SMP | SMP | SMP |
| 23 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |
| 24 | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP | SOFP |

**Table DSM-4. DSM alternate cost non-summer pricing periods (September 1–May 31)**

| Hour | Sunday | Monday | Tuesday | Wednesday | Thursday | Friday | Saturday | Holiday |
|---|---|---|---|---|---|---|---|---|
| 1 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 2 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 3 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 4 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 5 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 6 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 7 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 8 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 9 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 10 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 11 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 12 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 13 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 14 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 15 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 16 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 17 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 18 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 19 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 20 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 21 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 22 | NSOFP | NSMP | NSMP | NSMP | NSMP | NSMP | NSMP | NSOFP |
| 23 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |
| 24 | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP | NSOFP |

Tables DSM-5 lists the 20-year cumulative forecasted of average energy (aMW) by customer class and total on-peak reduction potential (MW).

**Table DSM-5. Cumulative existing energy efficiency forecast 2017–2036**
*(aMW w/transmission losses and peak contributions [MW])*

| Year | Residential | Commercial/Industrial/ Special Contracts | Irrigation | Total | On Peak (MW) |
|---|---|---|---|---|---|
| 2017 | 2 | 9 | 2 | 13 | 20 |
| 2018 | 6 | 19 | 3 | 28 | 40 |
| 2019 | 10 | 29 | 5 | 44 | 60 |
| 2020 | 12 | 40 | 6 | 59 | 80 |
| 2021 | 14 | 51 | 8 | 73 | 102 |
| 2022 | 16 | 63 | 9 | 89 | 123 |
| 2023 | 18 | 75 | 11 | 104 | 146 |
| 2024 | 21 | 86 | 12 | 120 | 168 |
| 2025 | 24 | 98 | 14 | 135 | 192 |
| 2026 | 27 | 105 | 15 | 147 | 216 |
| 2027 | 31 | 112 | 17 | 160 | 240 |
| 2028 | 34 | 120 | 19 | 173 | 265 |
| 2029 | 38 | 126 | 20 | 184 | 290 |
| 2030 | 42 | 133 | 22 | 196 | 316 |
| 2031 | 46 | 140 | 23 | 208 | 343 |
| 2032 | 50 | 146 | 25 | 220 | 370 |
| 2033 | 54 | 154 | 26 | 234 | 397 |
| 2034 | 58 | 162 | 28 | 247 | 425 |
| 2035 | 62 | 169 | 29 | 261 | 454 |
| 2036 | 66 | 175 | 31 | 273 | 483 |

Table DSM-6 details the 20-year estimated utility or program administrator costs of the achievable potential energy efficiency forecast by customer class.

**Table DSM-6. Energy Efficiency Total Utility (Program Administrator) Costs 2017–2036 ($000s)**

| Year | Residential | Commercial/Industrial/ Special Contracts | Irrigation | Total |
|---|---|---|---|---|
| 2017 | $3,828 | $12,199 | $1,868 | $17,896 |
| 2018 | $5,718 | $13,638 | $1,916 | $21,273 |
| 2019 | $6,821 | $14,977 | $1,957 | $23,754 |
| 2020 | $3,907 | $15,785 | $1,999 | $21,691 |
| 2021 | $3,998 | $16,350 | $2,032 | $22,380 |
| 2022 | $3,840 | $17,482 | $2,087 | $23,410 |
| 2023 | $4,323 | $18,094 | $2,126 | $24,544 |
| 2024 | $5,690 | $18,174 | $2,167 | $26,031 |
| 2025 | $6,546 | $18,123 | $2,207 | $26,877 |
| 2026 | $8,183 | $11,837 | $2,251 | $22,271 |
| 2027 | $8,832 | $12,546 | $2,328 | $23,706 |
| 2028 | $9,297 | $12,886 | $2,365 | $24,548 |
| 2029 | $9,736 | $11,140 | $2,395 | $23,272 |
| 2030 | $11,500 | $12,028 | $2,472 | $26,001 |
| 2031 | $11,490 | $11,627 | $2,517 | $25,635 |
| 2032 | $11,983 | $12,178 | $2,572 | $26,733 |
| 2033 | $12,696 | $14,815 | $2,627 | $30,138 |
| 2034 | $13,278 | $14,982 | $2,684 | $30,943 |
| 2035 | $13,954 | $14,828 | $2,741 | $31,523 |
| 2036 | $14,616 | $12,726 | $2,800 | $30,142 |
| **20-Year NPV** | **$78,908** | **$157,520** | **$23,828** | **$260,255** |

Table DSM-7 details the 20-year estimated total resource costs of the achievable potential energy efficiency forecast by customer class.

**Table DSM-7. Energy Efficiency Total Resource Costs 2017–2036 ($000s)**

| Year | Residential | Commercial/Industrial/ Special Contracts | Irrigation | Total |
|---|---|---|---|---|
| 2017 | $8,015 | $23,432 | $6,428 | $37,874 |
| 2018 | $12,137 | $26,196 | $6,594 | $44,926 |
| 2019 | $14,548 | $28,767 | $6,733 | $50,048 |
| 2020 | $8,242 | $30,320 | $6,877 | $45,439 |
| 2021 | $8,331 | $31,405 | $6,990 | $46,727 |
| 2022 | $7,887 | $33,579 | $7,180 | $48,647 |
| 2023 | $8,731 | $34,754 | $7,316 | $50,801 |
| 2024 | $11,338 | $34,909 | $7,454 | $53,701 |
| 2025 | $12,891 | $34,811 | $7,595 | $55,296 |
| 2026 | $15,995 | $22,736 | $7,745 | $46,475 |
| 2027 | $17,132 | $24,098 | $8,008 | $49,238 |
| 2028 | $17,896 | $24,751 | $8,138 | $50,784 |
| 2029 | $18,614 | $21,398 | $8,240 | $48,253 |
| 2030 | $21,884 | $23,103 | $8,507 | $53,493 |
| 2031 | $21,758 | $22,333 | $8,661 | $52,753 |
| 2032 | $22,584 | $23,392 | $8,848 | $54,824 |
| 2033 | $23,821 | $28,456 | $9,038 | $61,315 |
| 2034 | $24,816 | $28,776 | $9,233 | $62,825 |
| 2035 | $25,990 | $28,482 | $9,431 | $63,903 |
| 2036 | $27,144 | $24,443 | $9,634 | $61,221 |
| **20-Year NPV** | **$155,425** | **$302,559** | **$81,981** | **$539,964** |

Table DSM-8 shows the cost-effectiveness analysis and levelized cost of saved energy for achievable potential energy efficiency by sector through the IRP planning period.

**Table DSM-8. Total Energy Efficiency Benefits 2017–2036 ($000s)**

| Year | Residential | Commercial/Industrial/ Special Contracts | Irrigation | Total |
|---|---|---|---|---|
| 2017 | $15,350 | $40,747 | $9,459 | $65,555 |
| 2018 | $22,620 | $43,135 | $9,265 | $75,020 |
| 2019 | $25,730 | $44,722 | $8,988 | $79,440 |
| 2020 | $13,491 | $44,331 | $8,668 | $66,490 |
| 2021 | $12,535 | $43,077 | $8,281 | $63,894 |
| 2022 | $10,887 | $43,208 | $8,001 | $62,096 |
| 2023 | $10,996 | $41,986 | $7,673 | $60,655 |
| 2024 | $13,068 | $39,472 | $7,313 | $59,853 |
| 2025 | $13,625 | $36,775 | $6,950 | $57,350 |
| 2026 | $15,557 | $22,459 | $6,613 | $44,629 |
| 2027 | $15,384 | $22,268 | $6,387 | $44,038 |
| 2028 | $14,873 | $21,412 | $6,071 | $42,356 |
| 2029 | $14,345 | $17,333 | $5,751 | $37,428 |
| 2030 | $15,667 | $17,508 | $5,548 | $38,723 |
| 2031 | $14,495 | $15,844 | $5,283 | $35,622 |
| 2032 | $14,017 | $15,555 | $5,057 | $34,629 |
| 2033 | $13,760 | $17,738 | $4,842 | $36,340 |
| 2034 | $13,368 | $15,940 | $4,643 | $33,950 |
| 2035 | $13,038 | $13,930 | $4,447 | $31,415 |
| 2036 | $12,675 | $10,483 | $4,260 | $27,418 |
| **20-Year NPV** | **$295,479** | **$567,923** | **$133,497** | **$996,900** |

**DSM-9. Total energy efficiency cost-effectiveness summary**

| | 2036 Load Reduction (aMW) | Utility Costs ($000s) (20-Year NPV) | Resource Costs ($000s) (20-Year NPV) | Total Benefits ($000s) (20-Year NPV) | TRC: Benefit/ Cost Ratio | TRC Levelized Costs (cents/kWh) |
|---|---|---|---|---|---|---|
| Residential | 66 | $78,908 | $155,425 | $295,479 | 1.9 | 6.7 |
| Industrial/Commercial/ Special Contract | 176 | $157,520 | $302,559 | $567,923 | 1.9 | 3.9 |
| Irrigation | 31 | $23,828 | $81,981 | $133,498 | 1.6 | 6.7 |
| **Total** | **273** | **$260,255** | **$539,964** | **$996,900** | **1.8** | **4.8** |

# SUPPLY-SIDE RESOURCE DATA

## Key Financial and Forecast Assumptions

| Financing Cap Structure and Cost | |
|---|---|
| **Composition** | |
| Debt | 50.04% |
| Preferred | 0.00% |
| Common | 49.96% |
| **Total** | **100.00%** |
| **Cost** | |
| Debt | 5.73% |
| Preferred | 0.00% |
| Common | 10.00% |
| Average Weighted Cost | 7.86% |

| Financial Assumptions and Factors | |
|---|---|
| Plant operating (book) life | Expected Life of the Asset |
| Discount rate (weighted average cost of capital[1]) | 6.74% |
| Composite tax rate | 39.10% |
| Deferred rate | 35.00% |
| General O&M escalation rate | 2.10% |
| Emission adder escalation rate | 3.00% |
| Annual property tax rate (% of investment) | 0.29% |
| Property tax escalation rate | 3.00% |
| Annual insurance premiums (% of investment) | 0.31% |
| Insurance escalation rate | 2.00% |
| AFUDC rate (annual) | 7.72% |

[1] Incorporates tax effects.

| Emission Intensity Rate (lbs per MMBtu by technology) | |
|---|---|
| | **$CO_2$** |
| Small frame SCCT | 125 |
| Large frame SCCT | 118 |
| CCCT 1x1 | 119 |
| Reciprocating engines | 119 |
| Pulverized coal | 210 |

| Fuel Forecast Base Case (Nominal, $ per MMBtu) | | |
|---|---|---|
| **Year** | **Natural Gas** | **Nuclear** |
| 2017 | $2.75 | $0.57 |
| 2018 | $3.28 | $0.58 |
| 2019 | $3.28 | $0.59 |
| 2020 | $3.35 | $0.60 |
| 2021 | $3.45 | $0.61 |
| 2022 | $3.47 | $0.63 |
| 2023 | $3.53 | $0.64 |
| 2024 | $3.71 | $0.65 |
| 2025 | $3.92 | $0.67 |
| 2026 | $4.10 | $0.68 |
| 2027 | $4.26 | $0.70 |
| 2028 | $4.51 | $0.71 |
| 2029 | $4.70 | $0.73 |
| 2030 | $4.83 | $0.74 |
| 2031 | $4.91 | $0.76 |
| 2032 | $4.98 | $0.77 |
| 2033 | $4.98 | $0.79 |
| 2034 | $4.91 | $0.81 |
| 2035 | $4.70 | $0.81 |
| 2036 | $4.51 | $0.82 |
| 2037 | $4.53 | $0.82 |
| 2038 | $4.56 | $0.83 |
| 2039 | $4.59 | $0.83 |
| 2040 | $4.62 | $0.84 |
| 2041 | $4.64 | $0.84 |
| 2042 | $4.67 | $0.85 |
| 2043 | $4.70 | $0.85 |
| 2044 | $4.73 | $0.86 |
| 2045 | $4.76 | $0.87 |
| 2046 | $4.78 | $0.87 |

# Cost Inputs and Operating Assumptions

(All costs in 2017 dollars)

| Supply-Side Resources | Plant Capacity (MW) | Plant Capital ($/kW)[1,3] | Transmission Capital $/kW | Total Capital $/kW | Total Investment $/kW[2] | Fixed O&M $/kW[3] | Variable O&M $/kW | Other $/MWh | Heat Rate Btu/kWh | Economic Life |
|---|---|---|---|---|---|---|---|---|---|---|
| Biomass Indirect—Anaerobic Digester (35 MW) | 35 | 6,522 | 144 | $6,666 | $7,133 | 3 | 16 | 0 | 14,500 | 30 |
| Boardman to Hemingway (250 MW) | 350 | 0 | 734 | $734 | $734 | 0 | 0 | 0 | 0 | 55 |
| Canal Drop Hydro (1 MW) | 1 | 3,753 | 70 | $3,823 | $4,550 | 2 | 0 | 0 | 0 | 75 |
| CCCT (1x1) F Class (300 MW) | 300 | 1,246 | 98 | $1,344 | $1,574 | 1 | 0 | 0 | 6,714 | 30 |
| CCCT (2x1) F Class (550 MW) | 550 | 1,150 | 109 | $1,259 | $1,474 | 1 | 3 | 0 | 6,700 | 30 |
| CHP (35 MW) | 35 | 2,213 | 35 | $2,248 | $2,406 | 4 | 5 | 0 | 6,060 | 40 |
| Demand Response—Additional (25 MW) | 25 | 0 | 0 | $0 | $0 | 51 | 0 | 0 | 0 | 20 |
| Geothermal (30 MW) | 35 | 4,675 | 144 | $4,819 | $5,342 | 18 | 5 | 0 | 0 | 25 |
| Reciprocating Gas Engine (18.8 MW) | 18 | 775 | 112 | $887 | $945 | 1 | 7 | 0 | 8,370 | 40 |
| SCCT—Frame F Class (170 MW) | 170 | 878 | 117 | $995 | $1,060 | 1 | 11 | 0 | 10,300 | 35 |
| Small Modular Nuclear (50 MW) | 50 | 6,126 | 663 | $6,789 | $10,279 | 8 | 2 | 0 | 11,493 | 40 |
| Solar PV—Rooftop C&I (1 MW) | 1 | 2,925 | 0 | $2,925 | $3,040 | 1 | 0 | 1 | 0 | 25 |
| Solar PV—Rooftop Residential (0.005 MW) | 0 | 2,400 | 0 | $2,400 | $2,495 | 2 | 0 | 1 | 0 | 25 |
| Solar PV—Utility Scale 1-Axis Tracking (30 MW) | 30 | 1,375 | 144 | $1,519 | $1,579 | 1 | 0 | 1 | 0 | 25 |
| Storage—Ice Thermal Storage (10 MW) | 10 | 2,000 | 0 | $2,000 | $2,039 | 3 | 0 | 0 | 0 | 20 |
| Storage—Li Battery Residential (10 MW) | 10 | 3,114 | 0 | $3,114 | $3,175 | 4 | 0 | 0 | 0 | 10 |
| Storage—Pumped-Hydro (300 MW) | 300 | 2,352 | 183 | $2,535 | $3,017 | 4 | 0 | 0 | 0 | 50 |
| Storage—V Flow Battery (10 MW) | 10 | 3,736 | 0 | $3,736 | $3,809 | 6 | 0 | 0 | 0 | 10 |
| Storage—Zn Battery (10 MW) | 10 | 2,010 | 0 | $2,010 | $2,049 | 3 | 0 | 0 | 0 | 10 |
| Wind (100 MW) | 100 | 1,475 | 117 | $1,592 | $1,700 | 3 | 0 | 16 | 0 | 25 |

[1] Plant costs include engineering development costs, generating and ancillary equipment purchase, and installation costs, as well as balance of plant construction.

[2] Total Investment includes capital costs and AFUDC.

[3] Fixed O&M excludes property taxes and insurance (separately calculated within the levelized resource cost analysis)

# Transmission Cost Assumptions

## *Cost Assumptions by Supply-Side Resource Type*

| Capacity (MW Rating) | Overnight Transmission Capital Cost/kW[1] | Cost Assumptions Notes | Local Interconnection Assumptions | Backbone Transmission Assumptions |
|---|---|---|---|---|
| Biomass Indirect—Anaerobic Digester | | | | |
| 35 | $144 | Assume distribution feeder locations in the Magic Valley; displaces equivalent MW of portfolio resources in same region. | Assume $3.5 million of distribution feeder upgrades and $1.167 million in substation upgrades. | Assigns Pro-Rata share for transmission upgrades identified for east-of-Boise resources. |
| Geothermal (binary-cycle)—Idaho | | | | |
| 35 | $144 | Assume Raft River area location; displaces equivalent MW of portfolio resources in same region. | Requires 5-mile 138-kV line to nearby station with new 138-kV substation line terminal bay. | Assigns Pro-Rata share for transmission upgrades identified for east-of-Boise resources. |
| Hydro—Canal Drop (Seasonal) | | | | |
| 1 | $70 | Assume Magic Valley location connecting to 46-kV sub-transmission or local feeder. | Assume 4 miles of distribution rebuild at $150 thousand per mile plus $100 thousand in substation upgrades. | No backbone upgrades required. |
| Natural Gas—SCCT Frame F Class (Idaho Power's peaker plants use this technology) | | | | |
| 170 | $117 | Assume Mountain Home location; displaces equivalent MW of portfolio resources in same region. | Assume 2 mi of 230 kV line required to connect to nearby station. | Assigns Pro-Rata share for transmission upgrades identified for east-of-Boise resources. |
| Natural Gas—Reciprocating Gas Engine Wartsila 34SG | | | | |
| 18 | $112 | Assume Mountain Home location; displaces equivalent MW of portfolio resources in same region. | Interconnecting at RTSN 230-kV station. | Assigns Pro-Rata share for transmission upgrades identified for east-of-Boise resources. |
| Natural Gas—CCCT (1x1) F Class with Duct Firing | | | | |
| 300 | $98 | Assume Mountain Home location; displaces equivalent MW of portfolio resources in same region. | Assume 2 miles of 230-kV line required to connect to nearby station. | Assigns Pro-Rata share for transmission upgrades identified for east-of-Boise resources. |
| Natural Gas—CCCT (2x1) F Class | | | | |
| 550 | $109 | Build new facility south of Boise (assume Simco Road area). | New 230-kV switching station with a 22-mile; 230-kV line to Boise Bench Substation and wrap 230-kV DNPR-HRBD line into new station. | Rebuild RTSN-DRAM 230 kV line, BOBN-DRAM 230 kV line, MCRN-BOBN 138 kV line, and replace BOMT-SWPO wave trap. |
| Natural Gas—Combined Heat and Power (CHP) | | | | |
| 35 | $35 | Assumed location in Treasure Valley. | Assume 1 mile tap to existing 138-kV line and new 138-kV source substation. | No backbone upgrades required. |
| Nuclear—Small Modular Reactor (SMR) | | | | |
| 50 | $663 | Assume tie into ANTS 230-kV transmission substation; displaces equivalent MW of portfolio resources east of Boise. | Two 2-mile, 138-kV lines to interconnect to Antelope Substation. New 138-kV terminal at ANTS. | New parallel 55-mile, 230-kV line from Antelope to Brady Substation. New 230-kV terminal at Brady Substation. Assigns Pro-Rata share for transmission upgrades identified for east-of-Boise resources. |
| Pumped Storage—new upper reservoir and generation/pumping plant, pump water from existing lower reservoir to new upper reservoir and run water through new power plant) | | | | |
| 300 | $183 | Assume Anderson Ranch location; displaces equivalent MW of portfolio resources in same region. | 18 mi 230-kV line to connect to RTSN. | Assigns Pro-Rata share for transmission upgrades identified for east-of-Boise resources. |

| Capacity (MW Rating) | Overnight Transmission Capital Cost/kW[1] | Cost Assumptions Notes | Local Interconnection Assumptions | Backbone Transmission Assumptions |
|---|---|---|---|---|
| Solar PV—Utility Scale 1-Axis Tracking | | | | |
| 30 | $144 | Assume Magic Valley location; displaces equivalent MW of portfolio resources in same region. | Assume 1 mile 230 kV line and associated stations equipment. | Assigns Pro-Rata share for transmission upgrades identified for east-of-Boise resources. |
| Wind—Idaho | | | | |
| 100 | $117 | Assume location within 5 miles of Midpoint Substation; displaces equivalent MW of portfolio resources in same region. | Assume 5 mi of 230-kV transmission from MPSN to project site. | Assigns Pro-Rata share for transmission upgrades identified for east-of-Boise resources. |

# Levelized Cost of Energy

**30-Year Levelized Cost of Energy (at stated capacity factors)**

| Supply-Side Resources | Cost of Capital | Non-Fuel O&M[1] | Fuel | Wholesale Energy | Net of Tax Credit/Steam sales/Integration/ Transmission Revenue | Total Cost per MWh | Capacity Factor |
|---|---|---|---|---|---|---|---|
| Biomass Indirect—Anaerobic Digester (35 MW) | $98 | $35 | $0 | $0 | $0 | $133 | 85% |
| Boardman to Hemingway (250 MW) | $18 | $3 | $0 | $28 | -$9 | $39 | 33% |
| Canal Drop Hydro (1 MW) | $140 | $25 | $0 | $0 | $0 | $165 | 33% |
| CCCT (1x1) F Class (300 MW) | $26 | $6 | $28 | $0 | $0 | $59 | 70% |
| CCCT (2x1) F Class (550 MW) | $25 | $7 | $28 | $0 | $0 | $59 | 70% |
| CHP (35 MW) | $33 | $20 | $25 | $0 | -$6 | $71 | 80% |
| Demand Response—Additional (25 MW) | $0 | $706 | $0 | $0 | $0 | $706 | 1% |
| Geothermal (30 MW) | $64 | $47 | $0 | $0 | $0 | $111 | 88% |
| Reciprocating Gas Engine (18.8 MW) | $41 | $18 | $35 | $0 | $0 | $94 | 25% |
| SCCT—Frame F Class (170 MW) | $118 | $36 | $43 | $0 | $0 | $197 | 10% |
| Small Modular Nuclear (50 MW) | $124 | $31 | $8 | $0 | $0 | $163 | 90% |
| Solar PV—Rooftop C&I (1 MW) | $153 | $25 | $0 | $0 | $1 | $179 | 21% |
| Solar PV—Rooftop Residential (0.005 MW) | $126 | $26 | $0 | $0 | $1 | $153 | 21% |
| Solar PV—Utility Scale 1-Axis Tracking (30 MW) | $62 | $12 | $0 | $0 | $1 | $74 | 27% |
| Storage—Ice Thermal Storage (10 MW) | $595 | $147 | $0 | $0 | $0 | $742 | 4% |
| Storage—Li Battery Residential (10 MW) | $400 | $60 | $0 | $0 | $0 | $460 | 14% |
| Storage—Pumped-Hydro (300 MW) | $158 | $57 | $0 | $0 | $0 | $214 | 20% |
| Storage—V Flow Battery (10 MW) | $1,679 | $317 | $0 | $0 | $0 | $1,996 | 4% |
| Storage—Zn Battery (10 MW) | $516 | $92 | $0 | $0 | $0 | $608 | 7% |
| Wind (100 MW) | $64 | $24 | $0 | $0 | $22 | $111 | 28% |

[1] Non Fuel O&M includes fixed and variable costs, property taxes.

**30-Year Levelized Capacity (fixed) Cost per kW/Month**

| Supply-Side Resources | Cost of Capital | Non-Fuel O&M | Fuel | Net of Tax Credit/Steam sales/Integration/ Transmission Revenue | Total Cost per kW |
|---|---|---|---|---|---|
| Biomass Indirect—Anaerobic Digester (35 MW) | $61 | $9 | $0 | $0 | $70 |
| Boardman to Hemingway (250 MW) | $5 | $1 | $0 | -$2 | $4 |
| Canal Drop Hydro (1 MW) | $34 | $6 | $0 | $0 | $40 |
| CCCT (1x1) F Class (300 MW) | $13 | $3 | $0 | $0 | $16 |
| CCCT (2x1) F Class (550 MW) | $13 | $2 | $0 | $0 | $14 |
| CHP (35 MW) | $19 | $7 | $0 | $0 | $26 |
| Demand Response—Additional (25 MW) | $0 | $5 | $0 | $0 | $5 |
| Geothermal (30 MW) | $41 | $26 | $0 | $0 | $67 |
| Reciprocating Gas Engine (18.8 MW) | $7 | $2 | $0 | $0 | $9 |
| SCCT—Frame F Class (170 MW) | $9 | $2 | $0 | $0 | $10 |
| Small Modular Nuclear (50 MW) | $81 | $18 | $0 | $0 | $100 |
| Solar PV—Rooftop C&I (1 MW) | $24 | $4 | $0 | $0 | $27 |
| Solar PV—Rooftop Residential (0.005 MW) | $19 | $4 | $0 | $0 | $23 |
| Solar PV—Utility Scale 1-Axis Tracking (30 MW) | $12 | $2 | $0 | $0 | $14 |
| Storage—Ice Thermal Storage (10 MW) | $17 | $4 | $0 | $0 | $22 |
| Storage—Li Battery Residential (10 MW) | $41 | $6 | $0 | $0 | $47 |
| Storage—Pumped-Hydro (300 MW) | $23 | $8 | $0 | $0 | $31 |
| Storage—V Flow Battery (10 MW) | $49 | $9 | $0 | $0 | $58 |
| Storage—Zn Battery (10 MW) | $26 | $5 | $0 | $0 | $31 |
| Wind (100 MW) | $13 | $5 | $0 | $0 | $18 |

# Peak-Hour Capacity Credit (Contribution to Peak)

## *Solar and Wind Resources*

Peak hour capacity credit (contribution to peak) for new IRP intermittent generation resources:

| New IRP intermittent generation—Peak hour capacity credit | |
|---|---|
| **Resource** | **Peak Hour Capacity Credit** |
| PV solar south orientation | 28.4% |
| PV solar southwest orientation | 45.4% |
| PV solar single-axis tracking | 51.3% |
| Wind | 5.0% |

# Energy Shape—Solar

## *2017 IRP Assumed Solar Capacity Factors*

Total nameplate: 298.3 MW
Total annual capacity factor: 27%

| Hour | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 12:00 AM | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 1:00 AM | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2:00 AM | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 3:00 AM | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 4:00 AM | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 5:00 AM | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 6:00 AM | 0.0 | 0.0 | 0.4 | 0.1 | 8.4 | 15.9 | 9.7 | 0.4 | 0.0 | 0.0 | 0.0 | 0.0 |
| 7:00 AM | 0.0 | 0.6 | 16.2 | 16.6 | 47.7 | 69.8 | 57.7 | 32.9 | 8.7 | 0.3 | 2.4 | 0.0 |
| 8:00 AM | 6.5 | 29.6 | 47.9 | 66.4 | 126.5 | 154.3 | 138.3 | 104.9 | 57.7 | 25.0 | 29.6 | 7.3 |
| 9:00 AM | 34.9 | 90.7 | 108.1 | 142.9 | 203.1 | 229.6 | 225.0 | 194.1 | 144.8 | 84.5 | 65.5 | 37.2 |
| 10:00 AM | 73.0 | 143.8 | 173.4 | 197.6 | 228.2 | 259.5 | 252.5 | 253.0 | 226.2 | 163.0 | 109.9 | 79.5 |
| 11:00 AM | 87.1 | 151.7 | 197.9 | 219.0 | 240.8 | 262.4 | 265.0 | 258.0 | 236.4 | 196.7 | 130.3 | 91.4 |
| 12:00 PM | 84.0 | 148.3 | 199.3 | 228.1 | 243.9 | 272.8 | 260.3 | 263.8 | 235.3 | 196.9 | 129.9 | 88.5 |
| 1:00 PM | 92.4 | 149.0 | 196.4 | 225.6 | 249.1 | 267.5 | 258.1 | 256.0 | 232.5 | 192.2 | 120.1 | 89.4 |
| 2:00 PM | 94.0 | 146.5 | 199.9 | 228.6 | 239.4 | 263.5 | 266.2 | 250.9 | 232.1 | 184.1 | 117.0 | 96.6 |
| 3:00 PM | 93.0 | 153.6 | 193.1 | 230.1 | 242.6 | 254.4 | 264.8 | 249.4 | 226.1 | 187.5 | 111.4 | 87.4 |
| 4:00 PM | 88.2 | 146.3 | 190.2 | 210.6 | 222.8 | 234.5 | 262.9 | 250.2 | 225.0 | 178.4 | 81.7 | 62.0 |
| 5:00 PM | 35.4 | 93.2 | 158.0 | 199.3 | 218.9 | 213.8 | 246.2 | 243.5 | 220.7 | 162.2 | 28.1 | 2.7 |
| 6:00 PM | 0.4 | 16.1 | 108.3 | 180.4 | 189.3 | 196.6 | 221.7 | 222.9 | 178.6 | 82.2 | 9.3 | 0.0 |
| 7:00 PM | 0.0 | 0.0 | 49.5 | 107.2 | 147.1 | 157.8 | 177.8 | 145.7 | 73.3 | 6.3 | 0.0 | 0.0 |
| 8:00 PM | 0.0 | 0.0 | 2.3 | 30.5 | 69.8 | 96.8 | 101.6 | 53.7 | 3.1 | 0.0 | 0.0 | 0.0 |
| 9:00 PM | 0.0 | 0.0 | 0.0 | 0.0 | 2.6 | 17.9 | 14.4 | 1.3 | 0.0 | 0.0 | 0.0 | 0.0 |
| 10:00 PM | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 11:00 PM | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Average | 28.7 | 52.9 | 76.7 | 95.1 | 111.7 | 123.6 | 125.9 | 115.9 | 95.9 | 69.1 | 39.0 | 26.7 |
| MWh per Day | 688.9 | 1269.3 | 1841.0 | 2282.9 | 2680.3 | 2967.1 | 3022.4 | 2781.0 | 2300.6 | 1659.3 | 935.2 | 641.9 |
| Days in Month | 31 | 28 | 31 | 30 | 31 | 30 | 31 | 31 | 30 | 31 | 30 | 31 |
| MWh per Month | 21,355 | 35,541 | 57,070 | 68,488 | 83,088 | 89,013 | 93,695 | 86,211 | 69,019 | 51,438 | 28,057 | 19,898 |
| MWh for year | 702,875 | | | | | | | | | | | |
| Average | 28.7 | 52.9 | 76.7 | 95.1 | 111.7 | 123.6 | 125.9 | 115.9 | 95.9 | 69.1 | 39.0 | 26.7 |

# Idaho Schedule 87/Oregon Schedule 85—Integration Costs for Solar and Wind Resources

## *Solar*

| 0–100 MW Solar Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates* |
| 2016 | 0.04 | 2016 | 0.04 |
| 2017 | 0.04 | 2017 | 0.04 |
| 2018 | 0.04 | 2018 | 0.04 |
| 2019 | 0.05 | 2019 | 0.04 |
| 2020 | 0.05 | 2020 | 0.04 |
| 2021 | 0.05 | 2021 | 0.04 |
| | | 2022 | 0.04 |
| | | 2023 | 0.04 |
| | | 2024 | 0.04 |
| | | 2025 | 0.04 |
| | | 2026 | 0.04 |
| | | 2027 | 0.05 |
| | | 2028 | 0.05 |
| | | 2029 | 0.05 |
| | | 2030 | 0.05 |
| | | 2031 | 0.05 |
| | | 2032 | 0.05 |
| | | 2033 | 0.05 |
| | | 2034 | 0.05 |
| | | 2035 | 0.05 |
| | | 2036 | 0.06 |
| | | 2037 | 0.06 |
| | | 2038 | 0.06 |
| | | 2039 | 0.06 |
| | | 2040 | 0.06 |
| | | 2041 | 0.06 |

*$/MWh

| 101–200 MW Solar Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2016 | 0.19 | 2016 | 0.16 |
| 2017 | 0.20 | 2017 | 0.17 |
| 2018 | 0.20 | 2018 | 0.17 |
| 2019 | 0.21 | 2019 | 0.18 |
| 2020 | 0.21 | 2020 | 0.18 |
| 2021 | 0.22 | 2021 | 0.18 |
| | | 2022 | 0.19 |
| | | 2023 | 0.19 |
| | | 2024 | 0.20 |
| | | 2025 | 0.20 |
| | | 2026 | 0.20 |
| | | 2027 | 0.21 |
| | | 2028 | 0.21 |
| | | 2029 | 0.22 |
| | | 2030 | 0.22 |
| | | 2031 | 0.23 |
| | | 2032 | 0.23 |
| | | 2033 | 0.24 |
| | | 2034 | 0.24 |
| | | 2035 | 0.25 |
| | | 2036 | 0.25 |
| | | 2037 | 0.26 |
| | | 2038 | 0.27 |
| | | 2039 | 0.27 |
| | | 2040 | 0.28 |
| | | 2041 | 0.28 |

*$/MWh

| 201–300 MW Solar Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2016 | 0.41 | 2016 | 0.34 |
| 2017 | 0.42 | 2017 | 0.35 |
| 2018 | 0.43 | 2018 | 0.36 |
| 2019 | 0.44 | 2019 | 0.37 |
| 2020 | 0.44 | 2020 | 0.38 |
| 2021 | 0.45 | 2021 | 0.38 |
| | | 2022 | 0.39 |
| | | 2023 | 0.40 |
| | | 2024 | 0.41 |
| | | 2025 | 0.42 |
| | | 2026 | 0.43 |
| | | 2027 | 0.44 |
| | | 2028 | 0.45 |
| | | 2029 | 0.46 |
| | | 2030 | 0.47 |
| | | 2031 | 0.48 |
| | | 2032 | 0.49 |
| | | 2033 | 0.50 |
| | | 2034 | 0.51 |
| | | 2035 | 0.52 |
| | | 2036 | 0.53 |
| | | 2037 | 0.54 |
| | | 2038 | 0.56 |
| | | 2039 | 0.57 |
| | | 2040 | 0.58 |
| | | 2041 | 0.59 |

*$/MWh

| 301–400 MW Solar Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2016 | 0.64 | 2016 | 0.54 |
| 2017 | 0.65 | 2017 | 0.55 |
| 2018 | 0.67 | 2018 | 0.56 |
| 2019 | 0.68 | 2019 | 0.57 |
| 2020 | 0.70 | 2020 | 0.59 |
| 2021 | 0.71 | 2021 | 0.60 |
| | | 2022 | 0.61 |
| | | 2023 | 0.63 |
| | | 2024 | 0.64 |
| | | 2025 | 0.66 |
| | | 2026 | 0.67 |
| | | 2027 | 0.68 |
| | | 2028 | 0.70 |
| | | 2029 | 0.71 |
| | | 2030 | 0.73 |
| | | 2031 | 0.75 |
| | | 2032 | 0.76 |
| | | 2033 | 0.78 |
| | | 2034 | 0.80 |
| | | 2035 | 0.81 |
| | | 2036 | 0.83 |
| | | 2037 | 0.85 |
| | | 2038 | 0.87 |
| | | 2039 | 0.89 |
| | | 2040 | 0.91 |
| | | 2041 | 0.93 |

*$/MWh

| 401–500 MW Solar Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2016 | 0.84 | 2016 | 0.71 |
| 2017 | 0.86 | 2017 | 0.73 |
| 2018 | 0.88 | 2018 | 0.75 |
| 2019 | 0.90 | 2019 | 0.76 |
| 2020 | 0.92 | 2020 | 0.78 |
| 2021 | 0.94 | 2021 | 0.80 |
| | | 2022 | 0.81 |
| | | 2023 | 0.83 |
| | | 2024 | 0.85 |
| | | 2025 | 0.87 |
| | | 2026 | 0.89 |
| | | 2027 | 0.91 |
| | | 2028 | 0.93 |
| | | 2029 | 0.95 |
| | | 2030 | 0.97 |
| | | 2031 | 0.99 |
| | | 2032 | 1.01 |
| | | 2033 | 1.03 |
| | | 2034 | 1.06 |
| | | 2035 | 1.08 |
| | | 2036 | 1.10 |
| | | 2037 | 1.13 |
| | | 2038 | 1.15 |
| | | 2039 | 1.18 |
| | | 2040 | 1.20 |
| | | 2041 | 1.23 |

*$/MWh

**501–600 MW Solar Capacity Penetration Level**

| Levelized | | Non Levelized | |
|---|---|---|---|
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2016 | 1.01 | 2016 | 0.86 |
| 2017 | 1.03 | 2017 | 0.87 |
| 2018 | 1.06 | 2018 | 0.89 |
| 2019 | 1.08 | 2019 | 0.91 |
| 2020 | 1.10 | 2020 | 0.93 |
| 2021 | 1.13 | 2021 | 0.95 |
| | | 2022 | 0.97 |
| | | 2023 | 1.00 |
| | | 2024 | 1.02 |
| | | 2025 | 1.04 |
| | | 2026 | 1.06 |
| | | 2027 | 1.09 |
| | | 2028 | 1.11 |
| | | 2029 | 1.13 |
| | | 2030 | 1.16 |
| | | 2031 | 1.19 |
| | | 2032 | 1.21 |
| | | 2033 | 1.24 |
| | | 2034 | 1.26 |
| | | 2035 | 1.29 |
| | | 2036 | 1.32 |
| | | 2037 | 1.35 |
| | | 2038 | 1.38 |
| | | 2039 | 1.41 |
| | | 2040 | 1.44 |
| | | 2041 | 1.47 |

*$/MWh

| 601–700 MW Solar Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2016 | 1.12 | 2016 | 0.95 |
| 2017 | 1.15 | 2017 | 0.97 |
| 2018 | 1.17 | 2018 | 0.99 |
| 2019 | 1.20 | 2019 | 1.01 |
| 2020 | 1.22 | 2020 | 1.03 |
| 2021 | 1.25 | 2021 | 1.06 |
| | | 2022 | 1.08 |
| | | 2023 | 1.10 |
| | | 2024 | 1.13 |
| | | 2025 | 1.15 |
| | | 2026 | 1.18 |
| | | 2027 | 1.20 |
| | | 2028 | 1.23 |
| | | 2029 | 1.26 |
| | | 2030 | 1.29 |
| | | 2031 | 1.31 |
| | | 2032 | 1.34 |
| | | 2033 | 1.37 |
| | | 2034 | 1.40 |
| | | 2035 | 1.43 |
| | | 2036 | 1.46 |
| | | 2037 | 1.50 |
| | | 2038 | 1.53 |
| | | 2039 | 1.56 |
| | | 2040 | 1.60 |
| | | 2041 | 1.63 |

*$/MWh

| 701–800 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2016 | 1.17 | 2016 | 0.99 |
| 2017 | 1.20 | 2017 | 1.01 |
| 2018 | 1.22 | 2018 | 1.03 |
| 2019 | 1.25 | 2019 | 1.06 |
| 2020 | 1.28 | 2020 | 1.08 |
| 2021 | 1.30 | 2021 | 1.10 |
| | | 2022 | 1.13 |
| | | 2023 | 1.15 |
| | | 2024 | 1.18 |
| | | 2025 | 1.20 |
| | | 2026 | 1.23 |
| | | 2027 | 1.26 |
| | | 2028 | 1.28 |
| | | 2029 | 1.31 |
| | | 2030 | 1.34 |
| | | 2031 | 1.37 |
| | | 2032 | 1.40 |
| | | 2033 | 1.43 |
| | | 2034 | 1.46 |
| | | 2035 | 1.49 |
| | | 2036 | 1.53 |
| | | 2037 | 1.56 |
| | | 2038 | 1.60 |
| | | 2039 | 1.63 |
| | | 2040 | 1.67 |
| | | 2041 | 1.70 |

*$/MWh

| 801–900 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2016 | 1.16 | 2016 | 0.98 |
| 2017 | 1.19 | 2017 | 1.00 |
| 2018 | 1.21 | 2018 | 1.03 |
| 2019 | 1.24 | 2019 | 1.05 |
| 2020 | 1.27 | 2020 | 1.07 |
| 2021 | 1.30 | 2021 | 1.09 |
| | | 2022 | 1.12 |
| | | 2023 | 1.14 |
| | | 2024 | 1.17 |
| | | 2025 | 1.19 |
| | | 2026 | 1.22 |
| | | 2027 | 1.25 |
| | | 2028 | 1.28 |
| | | 2029 | 1.30 |
| | | 2030 | 1.33 |
| | | 2031 | 1.36 |
| | | 2032 | 1.39 |
| | | 2033 | 1.42 |
| | | 2034 | 1.45 |
| | | 2035 | 1.48 |
| | | 2036 | 1.52 |
| | | 2037 | 1.55 |
| | | 2038 | 1.59 |
| | | 2039 | 1.62 |
| | | 2040 | 1.66 |
| | | 2041 | 1.69 |

*$/MWh

| 901–1,000 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2016 | 1.12 | 2016 | 0.94 |
| 2017 | 1.14 | 2017 | 0.96 |
| 2018 | 1.17 | 2018 | 0.99 |
| 2019 | 1.19 | 2019 | 1.01 |
| 2020 | 1.22 | 2020 | 1.03 |
| 2021 | 1.25 | 2021 | 1.05 |
| | | 2022 | 1.08 |
| | | 2023 | 1.10 |
| | | 2024 | 1.12 |
| | | 2025 | 1.15 |
| | | 2026 | 1.17 |
| | | 2027 | 1.20 |
| | | 2028 | 1.23 |
| | | 2029 | 1.25 |
| | | 2030 | 1.28 |
| | | 2031 | 1.31 |
| | | 2032 | 1.34 |
| | | 2033 | 1.37 |
| | | 2034 | 1.40 |
| | | 2035 | 1.43 |
| | | 2036 | 1.46 |
| | | 2037 | 1.49 |
| | | 2038 | 1.52 |
| | | 2039 | 1.56 |
| | | 2040 | 1.59 |
| | | 2041 | 1.63 |

*$/MWh

| 1,001–1,100 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2016 | 1.06 | 2016 | 0.90 |
| 2017 | 1.08 | 2017 | 0.92 |
| 2018 | 1.11 | 2018 | 0.94 |
| 2019 | 1.13 | 2019 | 0.96 |
| 2020 | 1.16 | 2020 | 0.98 |
| 2021 | 1.18 | 2021 | 1.00 |
| | | 2022 | 1.02 |
| | | 2023 | 1.04 |
| | | 2024 | 1.07 |
| | | 2025 | 1.09 |
| | | 2026 | 1.11 |
| | | 2027 | 1.14 |
| | | 2028 | 1.16 |
| | | 2029 | 1.19 |
| | | 2030 | 1.22 |
| | | 2031 | 1.24 |
| | | 2032 | 1.27 |
| | | 2033 | 1.30 |
| | | 2034 | 1.33 |
| | | 2035 | 1.36 |
| | | 2036 | 1.39 |
| | | 2037 | 1.42 |
| | | 2038 | 1.45 |
| | | 2039 | 1.48 |
| | | 2040 | 1.51 |
| | | 2041 | 1.54 |

*$/MWh

| 1,101–1,200 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2016 | 1.03 | 2016 | 0.87 |
| 2017 | 1.05 | 2017 | 0.89 |
| 2018 | 1.08 | 2018 | 0.91 |
| 2019 | 1.10 | 2019 | 0.93 |
| 2020 | 1.12 | 2020 | 0.95 |
| 2021 | 1.15 | 2021 | 0.97 |
| | | 2022 | 0.99 |
| | | 2023 | 1.01 |
| | | 2024 | 1.04 |
| | | 2025 | 1.06 |
| | | 2026 | 1.08 |
| | | 2027 | 1.11 |
| | | 2028 | 1.13 |
| | | 2029 | 1.16 |
| | | 2030 | 1.18 |
| | | 2031 | 1.21 |
| | | 2032 | 1.23 |
| | | 2033 | 1.26 |
| | | 2034 | 1.29 |
| | | 2035 | 1.32 |
| | | 2036 | 1.35 |
| | | 2037 | 1.37 |
| | | 2038 | 1.41 |
| | | 2039 | 1.44 |
| | | 2040 | 1.47 |
| | | 2041 | 1.50 |

*$/MWh

| 1,201–1,300 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2016 | 1.07 | 2016 | 0.90 |
| 2017 | 1.09 | 2017 | 0.92 |
| 2018 | 1.12 | 2018 | 0.94 |
| 2019 | 1.14 | 2019 | 0.97 |
| 2020 | 1.17 | 2020 | 0.99 |
| 2021 | 1.19 | 2021 | 1.01 |
| | | 2022 | 1.03 |
| | | 2023 | 1.05 |
| | | 2024 | 1.08 |
| | | 2025 | 1.10 |
| | | 2026 | 1.12 |
| | | 2027 | 1.15 |
| | | 2028 | 1.17 |
| | | 2029 | 1.20 |
| | | 2030 | 1.23 |
| | | 2031 | 1.25 |
| | | 2032 | 1.28 |
| | | 2033 | 1.31 |
| | | 2034 | 1.34 |
| | | 2035 | 1.37 |
| | | 2036 | 1.40 |
| | | 2037 | 1.43 |
| | | 2038 | 1.46 |
| | | 2039 | 1.49 |
| | | 2040 | 1.52 |
| | | 2041 | 1.56 |

*$/MWh

| 1,301–1,400 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2016 | 1.24 | 2016 | 1.05 |
| 2017 | 1.27 | 2017 | 1.07 |
| 2018 | 1.30 | 2018 | 1.10 |
| 2019 | 1.33 | 2019 | 1.12 |
| 2020 | 1.36 | 2020 | 1.15 |
| 2021 | 1.39 | 2021 | 1.17 |
| | | 2022 | 1.20 |
| | | 2023 | 1.22 |
| | | 2024 | 1.25 |
| | | 2025 | 1.28 |
| | | 2026 | 1.31 |
| | | 2027 | 1.33 |
| | | 2028 | 1.36 |
| | | 2029 | 1.39 |
| | | 2030 | 1.42 |
| | | 2031 | 1.46 |
| | | 2032 | 1.49 |
| | | 2033 | 1.52 |
| | | 2034 | 1.55 |
| | | 2035 | 1.59 |
| | | 2036 | 1.62 |
| | | 2037 | 1.66 |
| | | 2038 | 1.70 |
| | | 2039 | 1.73 |
| | | 2040 | 1.77 |
| | | 2041 | 1.81 |

*$/MWh

| 1,401–1,500 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2016 | 1.61 | 2016 | 1.36 |
| 2017 | 1.65 | 2017 | 1.39 |
| 2018 | 1.69 | 2018 | 1.42 |
| 2019 | 1.72 | 2019 | 1.46 |
| 2020 | 1.76 | 2020 | 1.49 |
| 2021 | 1.80 | 2021 | 1.52 |
| | | 2022 | 1.55 |
| | | 2023 | 1.59 |
| | | 2024 | 1.62 |
| | | 2025 | 1.66 |
| | | 2026 | 1.70 |
| | | 2027 | 1.73 |
| | | 2028 | 1.77 |
| | | 2029 | 1.81 |
| | | 2030 | 1.85 |
| | | 2031 | 1.89 |
| | | 2032 | 1.93 |
| | | 2033 | 1.97 |
| | | 2034 | 2.02 |
| | | 2035 | 2.06 |
| | | 2036 | 2.11 |
| | | 2037 | 2.15 |
| | | 2038 | 2.20 |
| | | 2039 | 2.25 |
| | | 2040 | 2.30 |
| | | 2041 | 2.35 |

*$/MWh

| 1,501–1,600 MW Solar Capacity Penetration Level** | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2016 | 2.26 | 2016 | 1.91 |
| 2017 | 2.31 | 2017 | 1.95 |
| 2018 | 2.36 | 2018 | 2.00 |
| 2019 | 2.41 | 2019 | 2.04 |
| 2020 | 2.47 | 2020 | 2.09 |
| 2021 | 2.52 | 2021 | 2.13 |
| | | 2022 | 2.18 |
| | | 2023 | 2.23 |
| | | 2024 | 2.28 |
| | | 2025 | 2.33 |
| | | 2026 | 2.38 |
| | | 2027 | 2.43 |
| | | 2028 | 2.48 |
| | | 2029 | 2.54 |
| | | 2030 | 2.59 |
| | | 2031 | 2.65 |
| | | 2032 | 2.71 |
| | | 2033 | 2.77 |
| | | 2034 | 2.83 |
| | | 2035 | 2.89 |
| | | 2036 | 2.95 |
| | | 2037 | 3.02 |
| | | 2038 | 3.09 |
| | | 2039 | 3.15 |
| | | 2040 | 3.22 |
| | | 2041 | 3.29 |

*$/MWh

## Wind

| 0–100 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 0.27 | 2014 | 0.21 |
| 2015 | 0.27 | 2015 | 0.22 |
| 2016 | 0.28 | 2016 | 0.23 |
| 2017 | 0.29 | 2017 | 0.23 |
| 2018 | 0.30 | 2018 | 0.24 |
| 2019 | 0.31 | 2019 | 0.25 |
| | | 2020 | 0.25 |
| | | 2021 | 0.26 |
| | | 2022 | 0.27 |
| | | 2023 | 0.28 |
| | | 2024 | 0.29 |
| | | 2025 | 0.29 |
| | | 2026 | 0.30 |
| | | 2027 | 0.31 |
| | | 2028 | 0.32 |
| | | 2029 | 0.33 |
| | | 2030 | 0.34 |
| | | 2031 | 0.35 |
| | | 2032 | 0.36 |
| | | 2033 | 0.37 |
| | | 2034 | 0.38 |
| | | 2035 | 0.40 |
| | | 2036 | 0.41 |
| | | 2037 | 0.42 |
| | | 2038 | 0.43 |
| | | 2039 | 0.45 |

*$/MWh

| 101–200 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 1.22 | 2014 | 0.98 |
| 2015 | 1.25 | 2015 | 1.00 |
| 2016 | 1.29 | 2016 | 1.04 |
| 2017 | 1.33 | 2017 | 1.07 |
| 2018 | 1.37 | 2018 | 1.10 |
| 2019 | 1.41 | 2019 | 1.13 |
| | | 2020 | 1.16 |
| | | 2021 | 1.20 |
| | | 2022 | 1.24 |
| | | 2023 | 1.27 |
| | | 2024 | 1.31 |
| | | 2025 | 1.35 |
| | | 2026 | 1.39 |
| | | 2027 | 1.43 |
| | | 2028 | 1.48 |
| | | 2029 | 1.52 |
| | | 2030 | 1.57 |
| | | 2031 | 1.61 |
| | | 2032 | 1.66 |
| | | 2033 | 1.71 |
| | | 2034 | 1.76 |
| | | 2035 | 1.81 |
| | | 2036 | 1.87 |
| | | 2037 | 1.93 |
| | | 2038 | 1.98 |
| | | 2039 | 2.04 |

*$/MWh

| 201–300 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 2.78 | 2014 | 2.23 |
| 2015 | 2.87 | 2015 | 2.30 |
| 2016 | 2.95 | 2016 | 2.37 |
| 2017 | 3.04 | 2017 | 2.44 |
| 2018 | 3.13 | 2018 | 2.51 |
| 2019 | 3.23 | 2019 | 2.59 |
| | | 2020 | 2.67 |
| | | 2021 | 2.75 |
| | | 2022 | 2.83 |
| | | 2023 | 2.92 |
| | | 2024 | 3.00 |
| | | 2025 | 3.09 |
| | | 2026 | 3.19 |
| | | 2027 | 3.28 |
| | | 2028 | 3.38 |
| | | 2029 | 3.48 |
| | | 2030 | 3.59 |
| | | 2031 | 3.69 |
| | | 2032 | 3.80 |
| | | 2033 | 3.92 |
| | | 2034 | 4.04 |
| | | 2035 | 4.16 |
| | | 2036 | 4.28 |
| | | 2037 | 4.41 |
| | | 2038 | 4.54 |
| | | 2039 | 4.68 |

*$/MWh

**301–400 MW Wind Capacity Penetration Level**

| Levelized | | Non Levelized | |
|---|---|---|---|
| **On-line Year** | **20-Year Contract Term Levelized Rates*** | **Contract year** | **Non-Levelized Rates** |
| 2014 | 4.95 | 2014 | 3.98 |
| 2015 | 5.10 | 2015 | 4.10 |
| 2016 | 5.26 | 2016 | 4.22 |
| 2017 | 5.41 | 2017 | 4.35 |
| 2018 | 5.58 | 2018 | 4.48 |
| 2019 | 5.74 | 2019 | 4.61 |
| | | 2020 | 4.75 |
| | | 2021 | 4.89 |
| | | 2022 | 5.04 |
| | | 2023 | 5.19 |
| | | 2024 | 5.34 |
| | | 2025 | 5.51 |
| | | 2026 | 5.67 |
| | | 2027 | 5.84 |
| | | 2028 | 6.02 |
| | | 2029 | 6.20 |
| | | 2030 | 6.38 |
| | | 2031 | 6.57 |
| | | 2032 | 6.77 |
| | | 2033 | 6.97 |
| | | 2034 | 7.18 |
| | | 2035 | 7.40 |
| | | 2036 | 7.62 |
| | | 2037 | 7.85 |
| | | 2038 | 8.08 |
| | | 2039 | 8.33 |

*$/MWh

| 401–500 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 7.71 | 2014 | 6.19 |
| 2015 | 7.95 | 2015 | 6.38 |
| 2016 | 8.18 | 2016 | 6.57 |
| 2017 | 8.43 | 2017 | 6.77 |
| 2018 | 8.68 | 2018 | 6.97 |
| 2019 | 8.94 | 2019 | 7.18 |
| | | 2020 | 7.39 |
| | | 2021 | 7.62 |
| | | 2022 | 7.84 |
| | | 2023 | 8.08 |
| | | 2024 | 8.32 |
| | | 2025 | 8.57 |
| | | 2026 | 8.83 |
| | | 2027 | 9.09 |
| | | 2028 | 9.37 |
| | | 2029 | 9.65 |
| | | 2030 | 9.94 |
| | | 2031 | 10.23 |
| | | 2032 | 10.54 |
| | | 2033 | 10.86 |
| | | 2034 | 11.18 |
| | | 2035 | 11.52 |
| | | 2036 | 11.86 |
| | | 2037 | 12.22 |
| | | 2038 | 12.59 |
| | | 2039 | 12.96 |

*$/MWh

**501–600 MW Wind Capacity Penetration Level**

| Levelized | | Non Levelized | |
|---|---|---|---|
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 11.05 | 2014 | 8.87 |
| 2015 | 11.38 | 2015 | 9.13 |
| 2016 | 11.72 | 2016 | 9.41 |
| 2017 | 12.07 | 2017 | 9.69 |
| 2018 | 12.43 | 2018 | 9.98 |
| 2019 | 12.81 | 2019 | 10.28 |
| | | 2020 | 10.59 |
| | | 2021 | 10.91 |
| | | 2022 | 11.23 |
| | | 2023 | 11.57 |
| | | 2024 | 11.92 |
| | | 2025 | 12.28 |
| | | 2026 | 12.64 |
| | | 2027 | 13.02 |
| | | 2028 | 13.41 |
| | | 2029 | 13.82 |
| | | 2030 | 14.23 |
| | | 2031 | 14.66 |
| | | 2032 | 15.10 |
| | | 2033 | 15.55 |
| | | 2034 | 16.02 |
| | | 2035 | 16.50 |
| | | 2036 | 16.99 |
| | | 2037 | 17.50 |
| | | 2038 | 18.03 |
| | | 2039 | 18.57 |

*$/MWh

**601–700 MW Wind Capacity Penetration Level**

| Levelized | | Non Levelized | |
|---|---|---|---|
| **On-line Year** | **20-Year Contract Term Levelized Rates*** | **Contract year** | **Non-Levelized Rates** |
| 2014 | 14.94 | 2014 | 11.99 |
| 2015 | 15.39 | 2015 | 12.35 |
| 2016 | 15.85 | 2016 | 12.72 |
| 2017 | 16.33 | 2017 | 13.10 |
| 2018 | 16.82 | 2018 | 13.50 |
| 2019 | 17.32 | 2019 | 13.90 |
| | | 2020 | 14.32 |
| | | 2021 | 14.75 |
| | | 2022 | 15.19 |
| | | 2023 | 15.65 |
| | | 2024 | 16.12 |
| | | 2025 | 16.60 |
| | | 2026 | 17.10 |
| | | 2027 | 17.61 |
| | | 2028 | 18.14 |
| | | 2029 | 18.68 |
| | | 2030 | 19.24 |
| | | 2031 | 19.82 |
| | | 2032 | 20.42 |
| | | 2033 | 21.03 |
| | | 2034 | 21.66 |
| | | 2035 | 22.31 |
| | | 2036 | 22.98 |
| | | 2037 | 23.67 |
| | | 2038 | 24.38 |
| | | 2039 | 25.11 |

*$/MWh

| 701–800 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 19.38 | 2014 | 15.55 |
| 2015 | 19.96 | 2015 | 16.02 |
| 2016 | 20.56 | 2016 | 16.50 |
| 2017 | 21.17 | 2017 | 17.00 |
| 2018 | 21.81 | 2018 | 17.51 |
| 2019 | 22.46 | 2019 | 18.03 |
| | | 2020 | 18.57 |
| | | 2021 | 19.13 |
| | | 2022 | 19.70 |
| | | 2023 | 20.29 |
| | | 2024 | 20.90 |
| | | 2025 | 21.53 |
| | | 2026 | 22.18 |
| | | 2027 | 22.84 |
| | | 2028 | 23.53 |
| | | 2029 | 24.23 |
| | | 2030 | 24.96 |
| | | 2031 | 25.71 |
| | | 2032 | 26.48 |
| | | 2033 | 27.27 |
| | | 2034 | 28.09 |
| | | 2035 | 28.93 |
| | | 2036 | 29.80 |
| | | 2037 | 30.70 |
| | | 2038 | 31.62 |
| | | 2039 | 32.57 |

*$/MWh

**801–900 MW Wind Capacity Penetration Level**

| Levelized | | Non Levelized | |
|---|---|---|---|
| **On-line Year** | **20-Year Contract Term Levelized Rates*** | **Contract year** | **Non-Levelized Rates** |
| 2014 | 24.34 | 2014 | 19.54 |
| 2015 | 25.07 | 2015 | 20.13 |
| 2016 | 25.83 | 2016 | 20.73 |
| 2017 | 26.60 | 2017 | 21.35 |
| 2018 | 27.40 | 2018 | 21.99 |
| 2019 | 28.22 | 2019 | 22.65 |
| | | 2020 | 23.33 |
| | | 2021 | 24.03 |
| | | 2022 | 24.75 |
| | | 2023 | 25.50 |
| | | 2024 | 26.26 |
| | | 2025 | 27.05 |
| | | 2026 | 27.86 |
| | | 2027 | 28.70 |
| | | 2028 | 29.56 |
| | | 2029 | 30.44 |
| | | 2030 | 31.36 |
| | | 2031 | 32.30 |
| | | 2032 | 33.27 |
| | | 2033 | 34.26 |
| | | 2034 | 35.29 |
| | | 2035 | 36.35 |
| | | 2036 | 37.44 |
| | | 2037 | 38.56 |
| | | 2038 | 39.72 |
| | | 2039 | 40.91 |

*$/MWh

| 901–1,000 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 29.82 | 2014 | 23.94 |
| 2015 | 30.72 | 2015 | 24.66 |
| 2016 | 31.64 | 2016 | 25.40 |
| 2017 | 32.59 | 2017 | 26.16 |
| 2018 | 33.57 | 2018 | 26.94 |
| 2019 | 34.57 | 2019 | 27.75 |
| | | 2020 | 28.59 |
| | | 2021 | 29.44 |
| | | 2022 | 30.33 |
| | | 2023 | 31.24 |
| | | 2024 | 32.17 |
| | | 2025 | 33.14 |
| | | 2026 | 34.13 |
| | | 2027 | 35.16 |
| | | 2028 | 36.21 |
| | | 2029 | 37.30 |
| | | 2030 | 38.42 |
| | | 2031 | 39.57 |
| | | 2032 | 40.76 |
| | | 2033 | 41.98 |
| | | 2034 | 43.24 |
| | | 2035 | 44.54 |
| | | 2036 | 45.87 |
| | | 2037 | 47.25 |
| | | 2038 | 48.66 |
| | | 2039 | 50.12 |

*$/MWh

| 1,001–1,100 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 35.81 | 2014 | 28.74 |
| 2015 | 36.88 | 2015 | 29.60 |
| 2016 | 37.99 | 2016 | 30.49 |
| 2017 | 39.13 | 2017 | 31.41 |
| 2018 | 40.30 | 2018 | 32.35 |
| 2019 | 41.51 | 2019 | 33.32 |
| | | 2020 | 34.32 |
| | | 2021 | 35.35 |
| | | 2022 | 36.41 |
| | | 2023 | 37.50 |
| | | 2024 | 38.63 |
| | | 2025 | 39.78 |
| | | 2026 | 40.98 |
| | | 2027 | 42.21 |
| | | 2028 | 43.47 |
| | | 2029 | 44.78 |
| | | 2030 | 46.12 |
| | | 2031 | 47.51 |
| | | 2032 | 48.93 |
| | | 2033 | 50.40 |
| | | 2034 | 51.91 |
| | | 2035 | 53.47 |
| | | 2036 | 55.07 |
| | | 2037 | 56.72 |
| | | 2038 | 58.43 |
| | | 2039 | 60.18 |

*$/MWh

| 1,101–1,200 MW Wind Capacity Penetration Level | | | |
|---|---|---|---|
| Levelized | | Non Levelized | |
| On-line Year | 20-Year Contract Term Levelized Rates* | Contract year | Non-Levelized Rates |
| 2014 | 42.27 | 2014 | 33.93 |
| 2015 | 43.54 | 2015 | 34.95 |
| 2016 | 44.85 | 2016 | 36.00 |
| 2017 | 46.19 | 2017 | 37.08 |
| 2018 | 47.58 | 2018 | 38.19 |
| 2019 | 49.01 | 2019 | 39.34 |
| | | 2020 | 40.52 |
| | | 2021 | 41.73 |
| | | 2022 | 42.98 |
| | | 2023 | 44.27 |
| | | 2024 | 45.60 |
| | | 2025 | 46.97 |
| | | 2026 | 48.38 |
| | | 2027 | 49.83 |
| | | 2028 | 51.33 |
| | | 2029 | 52.87 |
| | | 2030 | 54.45 |
| | | 2031 | 56.09 |
| | | 2032 | 57.77 |
| | | 2033 | 59.50 |
| | | 2034 | 61.29 |
| | | 2035 | 63.12 |
| | | 2036 | 65.02 |
| | | 2037 | 66.97 |
| | | 2038 | 68.98 |
| | | 2039 | 71.05 |

*$/MWh

# PURPA Reference Data

The following information is provided for PURPA reference purposes.

1. Preferred portfolio: Portfolio P7

## *Resource Portfolio P7*

| Date | Resource | Installed Capacity | Peak-Hour Capacity (MW) |
|---|---|---|---|
| 2026 | B2H | 500, 200* | 500 |
| 2031 | Reciprocating engines | 36 | 36 |
| 2032 | Reciprocating engines | 36 | 36 |
| 2033 | Combined-cycle combustion turbine (1x1) | 300 | 300 |
| 2035 | Reciprocating engines | 54 | 54 |
| 2036 | Reciprocating engines | 54 | 54 |
| Total | | 980 | 980 |

*April–Sep, Oct–Mar transfer capacity

2. Deficiency period under preferred portfolio

   1st capacity deficit = (34) MW July 2026
   1st energy deficit = (143) MW July 2029

3. Intermittent generation integration costs

   See integration cost schedule included in *Appendix C—Technical Appendix*, section *Idaho Schedule 87/Oregon Schedule 85—Integration Costs for Solar and Wind Resources*.

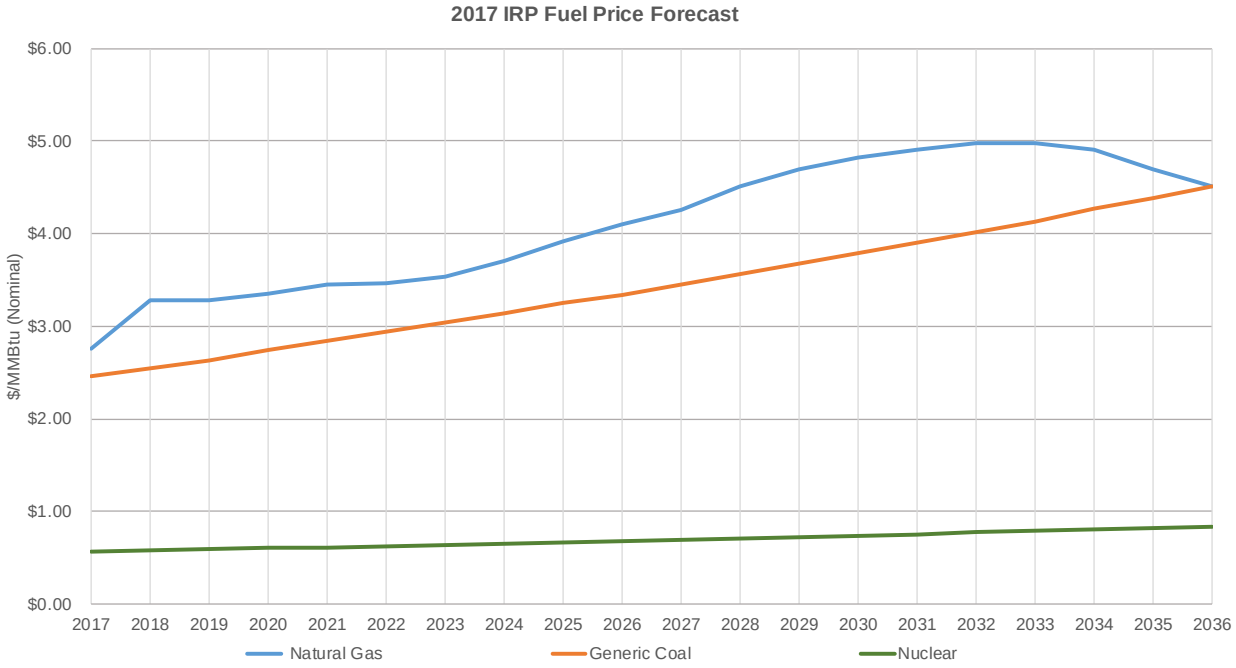
# Renewable Energy Certificate Forecast

| Year | Nominal ($/MWh) |
|---|---|
| 2017 | 4.59 |
| 2018 | 4.86 |
| 2019 | 4.91 |
| 2020 | 5.23 |
| 2021 | 5.55 |
| 2022 | 5.92 |
| 2023 | 6.29 |
| 2024 | 6.67 |
| 2025 | 7.05 |
| 2026 | 7.46 |
| 2027 | 7.85 |
| 2028 | 8.25 |
| 2029 | 8.67 |
| 2030 | 9.08 |
| 2031 | 9.51 |
| 2032 | 9.95 |
| 2033 | 10.40 |
| 2034 | 10.85 |
| 2035 | 11.32 |
| 2036 | 11.79 |

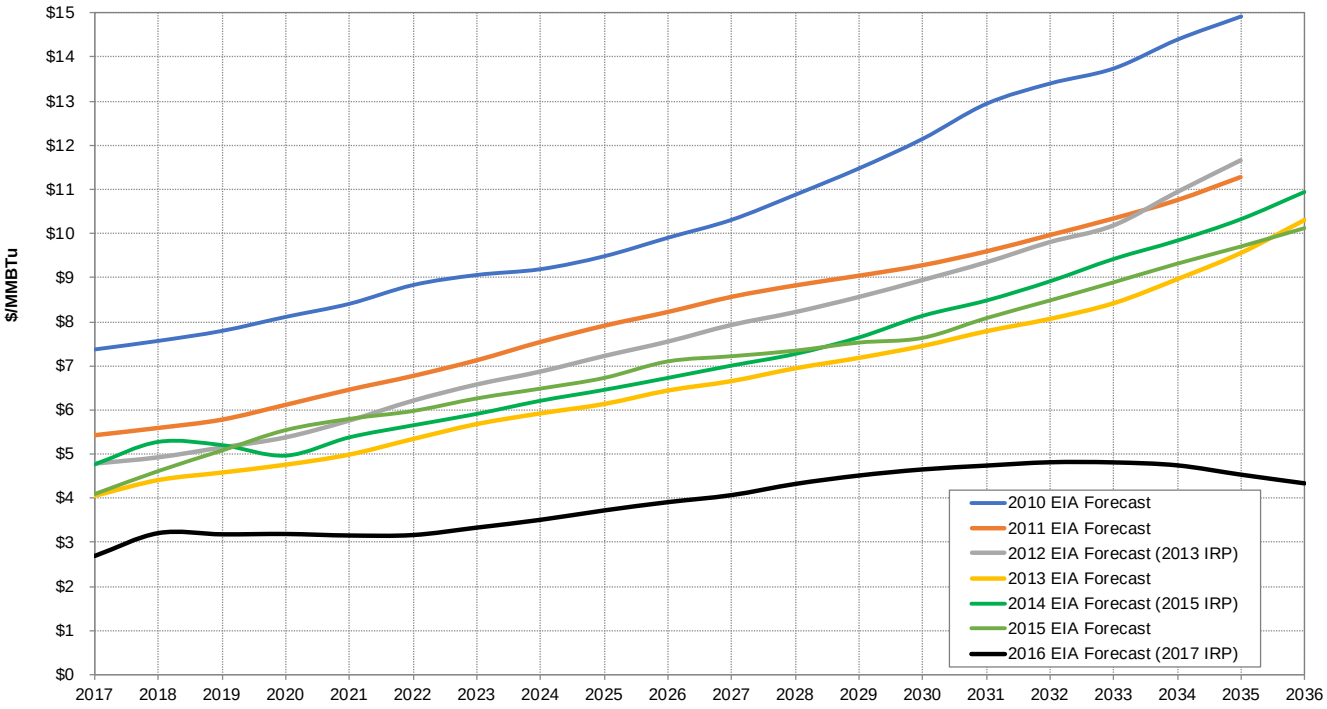
# FUEL PRICE FORECAST

## Natural Gas, Coal, and Nuclear Price Forecast (nominal $/MMBtu)

| Year | Idaho Citygate Natural Gas | Generic Coal | Nuclear |
|---|---|---|---|
| 2017 | $2.75 | $2.46 | $0.57 |
| 2018 | $3.28 | $2.55 | $0.58 |
| 2019 | $3.28 | $2.64 | $0.59 |
| 2020 | $3.35 | $2.74 | $0.60 |
| 2021 | $3.45 | $2.85 | $0.61 |
| 2022 | $3.47 | $2.94 | $0.63 |
| 2023 | $3.53 | $3.04 | $0.64 |
| 2024 | $3.71 | $3.14 | $0.65 |
| 2025 | $3.92 | $3.25 | $0.67 |
| 2026 | $4.10 | $3.34 | $0.68 |
| 2027 | $4.26 | $3.46 | $0.70 |
| 2028 | $4.51 | $3.57 | $0.71 |
| 2029 | $4.70 | $3.67 | $0.73 |
| 2030 | $4.83 | $3.79 | $0.74 |
| 2031 | $4.91 | $3.90 | $0.76 |
| 2032 | $4.98 | $4.02 | $0.77 |
| 2033 | $4.98 | $4.13 | $0.79 |
| 2034 | $4.91 | $4.27 | $0.81 |
| 2035 | $4.70 | $4.39 | $0.82 |
| 2036 | $4.51 | $4.51 | $0.84 |



**EIA Henry Hub Spot Price Forecasts (Nominal Dollars)**



# EXISTING RESOURCE DATA

## Hydroelectric and Thermal Plant Data

| Hydroelectric Power Plans | Nameplate kVA | Nameplate kW | Normal Rating kW[4] | Emergency Rating kW[5] |
|---|---|---|---|---|
| American Falls | 102,600 | 92,340 | 92,340 | 106,190 |
| Bliss | 86,250 | 75,038 | 75,000 | 84,860 |
| Brownlee | 650,444 | 585,400 | 585,400 | 678,040 |
| Cascade | 13,800 | 12,420 | 12,420 | 14,280 |
| C.J. Strike | 90,000 | 82,800 | 82,800 | 95,420 |
| Clear Lake | 3,125 | 2,500[1] | 2,420 | 2,430 |
| Hells Canyon | 435,000 | 391,500 | 391,500 | 449,580 |
| Lower Salmon | 70,000 | 60,000 | 60,000 | 69,140 |
| Malad–Lower | 15,500 | 13,500 | 13,500 | 13,500 |
| Malad–Upper | 9,650 | 8,270 | 8,270 | 8,400 |
| Milner | 62,890 | 59,448 | 59,448 | 61,880 |
| Oxbow | 211,112 | 190,000 | 190,000 | 218,520 |
| Shoshone Falls | 14,900 | 12,500[1] | 12,500 | 12,500 |
| Swan Falls | 28,600 | 27,170 | 24,170[3] | 24,170 |
| Thousand Springs | 11,000 | 8,800[1] | 6,380[2] | 6,380 |
| Twin Falls | 56,175 | 52,897 | 52,561 | 54,170 |
| Upper Salmon “A” | 18,000 | 18,000 | 18,000 | 18,000 |
| Upper Salmon “B” | 18,000 | 16,500 | 16,500 | 16,560 |
| **Total Hydro** | **1,897,046** | **1,709,083** | | |

[1] A power factor rating of 0.8 is assumed on four units (Clear Lake, Shoshone Falls unit 2, and Thousand Springs units 1 and 2) with a total kVA rating of 6,125 kVA on which the nameplate rating is assumed.
[2] The two smaller units, 1 and 2, have nameplate ratings of 1.25 MVA and 1 MW have been taken out of service due to reduced flows from the springs and penstock integrity.
[3] The Swan Falls units have been limited to 24,170 kW as a result of vibration issues.
[4] Normal Rating is the normal kW output of the facility with all units on-line. This rating includes all equipment limitations and may be different than the nameplate rating. To operate at the Normal Rating, appropriate water and ambient conditions must exist and the FERC license requirements permit.
[5] The Emergency Rating is defined as the maximum kW output of the facility with all units on-line. The Emergency Rating is based on manufacturer guidelines, ANSI standards, and limited by auxiliary equipment ratings. To operate at the Emergency Rating, appropriate water conditions must exist and the FERC license requirements permit.
[6] The Shoshone Falls Unit #2 is out of service due to an exciter condition.

| Thermal, Natural Gas, and Diesel Power Plans | Generator Nameplate Rating Gross kVA | Gross kW | Net Dependable Capability (NDC)[6,7] kW | Summer kW | Winter kW |
|---|---|---|---|---|---|
| Bridger (Idaho Power share) | 811,053 | 770,500 | | 707,667 | 707,667 |
| Boardman (Idaho Power share) | 67,600 | 64,199 | | 57,550 | 58,050 |
| Valmy (Idaho Power share) | 315,000 | 283,500 | | 260,000 | 260,000 |
| **Total Thermal** | **1,193,653** | **1,118,199** | | | |
| Bennett Mountain | 192,000 | 172,800 | 164,159 | | |
| Evander Andrews Unit #1 | 199,000 | 179,100 | 170,955 | | |
| Evander Andrews Unit #2 | 51,000 | 45,900 | 45,405 | | |
| Evander Andrews Unit #3 | 51,000 | 45,900 | 45,066 | | |
| Langley Gulch CT | 220,000 | 187,000 | 176,880 | | |
| Langley Gulch ST | 154,650 | 131,452 | 122,765 | | |
| **Total Natural Gas** | **867,650** | **762,152** | | | |
| Salmon Diesel | 6,250 | 5,000 | 5,500 | | |
| **Total IPC Generation** | **3,964,599** | **3,594,434** | | | |

[1] Ratings for coal-fired generators are provided by Idaho Power's thermal partners who operate these plants.

[2] Net Dependable Capacity (NDC) is defined in the NERC Generating Availability Data System (GADS) as Gross Dependable Capacity (GDC) less the unit capacity utilized for that unit's station service or auxiliaries. GDC is the Gross Maximum Capacity (GMC) modified for seasonal limitations over a specified period. The GDC and Maximum Dependable Capacity (MDC) used in previous GADS reports are the same in intent and purpose. GMC is the maximum capacity a unit can sustain over a specified period when not restricted by seasonal or other de-ratings.

[3] Evander Andrews Power Plant is also known to Idaho Power as Danskin Power Plant (DNPR).

[4] Performance test numbers provided by the contractor corrected for the following rating conditions: 90.0 Deg. F, Relative Humidity 20%, Barometric pressure 13.378 psia, Duct Burners ON. Performance numbers were obtained from the Siemens report EC-12087, Thermal performance test results of SGT6-5000F GAs turbine in fuel gas at Langley Gulch, New Plymouth, ID for IPC (Unit # 1—Shop Order Number GT378521)

# Qualifying Facility Data (PURPA)

**Cogeneration and Small Power Production Projects**

**Status as of April 1, 2017.**

| Project | MW | Contract On-line Date | Contract End Date | Project | MW | Contract On-line Date | Contract End Date |
|---|---|---|---|---|---|---|---|
| **Hydro Projects** | | | | | | | |
| Arena Drop | 0.45 | Sep-2010 | Sep-2030 | Little Wood Rvr Res | 2.85 | Feb-1985 | Feb-2020 |
| Baker City Hydro | 0.24 | Sep-2015 | Sep-2030 | Littlewood/Arkoosh | 0.87 | Aug-1986 | Aug-2021 |
| Barber Dam | 3.70 | Apr-1989 | Apr-2024 | Low Line Canal | 7.97 | May-1985 | May-2020 |
| Birch Creek | 0.05 | Nov-1984 | Nov-2019 | Low Line Midway Hydro | 2.50 | Aug-2007 | Aug-2027 |
| Black Canyon #3 | 0.14 | Apr-1984 | Apr-2019 | Lowline #2 | 2.79 | Apr-1988 | Apr-2023 |
| Black Canyon Bliss Hydro | 0.03 | Nov-2014 | Oct-2035 | Magic Reservoir | 9.07 | Jun-1989 | Jun-2024 |
| Blind Canyon | 1.63 | Dec-2014 | Dec-2034 | Malad River | 0.62 | May-1984 | May-2019 |
| Box Canyon | 0.36 | Feb-1984 | Feb-2019 | Marco Ranches | 1.20 | Aug-1985 | Aug-2020 |
| Briggs Creek | 0.60 | Oct-1985 | Oct-2020 | Mile 28 | 1.50 | Jun-1994 | Jun-2029 |
| Bypass | 9.96 | Jun-1988 | Jun-2023 | Mill Creek Hydroelectric | 0.80 | Oct-2011 | Jun-2017 |
| Canyon Springs | 0.13 | Oct-1984 | As delivered | Mitchell Butte | 2.09 | May-1989 | Dec-2033 |
| Cedar Draw | 1.55 | Jun-1984 | Jun-2019 | Mora Drop Small Hydro Fac | 1.85 | Sep-2006 | Sep-2026 |
| Clark Canyon Hydroelectric | 7.55 | Jun-2017 | Estimated | Mud Creek/S&S | 0.52 | Feb-1982 | Jan-2017 |
| Clear Springs Trout | 0.52 | Nov-1983 | Nov-2018 | Mud Creek/White | 0.21 | Jan-1986 | Jan-2021 |
| Crystal Springs | 2.44 | Apr-1986 | Apr-2021 | North Gooding Main | 1.30 | Oct-2016 | Oct-2036 |
| Curry Cattle Company | 0.22 | Jun-1983 | Jun-2018 | Owyhee Dam Cspp | 5.00 | Aug-1985 | May-2033 |
| Dietrich Drop | 4.50 | Aug-1988 | Aug-2023 | Pigeon Cove | 1.89 | Oct-1984 | Oct-2019 |
| Eightmile Hydro Project | 0.36 | Oct-2014 | Oct-2034 | Pristine Springs #1 | 0.13 | May-2005 | May-2015 |
| Elk Creek | 2.00 | May-1986 | May-2021 | Pristine Springs #3 | 0.20 | May-2005 | May-2015 |
| Falls River | 9.10 | Aug-1993 | Aug-2028 | Reynolds Irrigation | 0.26 | May-1986 | May-2021 |
| Fargo Drop Hydroelectric | 1.27 | Apr-2013 | Apr-2033 | Rock Creek #1 | 2.05 | Sep-1983 | Sep-2018 |
| Faulkner Ranch | 0.87 | Aug-1987 | Aug-2022 | Rock Creek #2 | 1.90 | Apr-1989 | Apr-2024 |
| Fisheries Dev. | 0.26 | Jul-1990 | Jul-2040 | Sagebrush | 0.43 | Sep-1985 | Sep-2020 |
| Geo-Bon #2 | 0.93 | Nov-1986 | Nov-2021 | Sahko Hydro | 0.50 | Feb-2011 | Feb-2021 |
| Hailey Cspp | 0.06 | Jun-1985 | Jun-2020 | Schaffner | 0.53 | Aug-1986 | Aug-2021 |
| Hazelton A | 8.10 | Mar-2011 | Mar-2026 | Shingle Creek | 0.22 | Aug-1983 | Aug-2017 |
| Hazelton B | 7.60 | May-1993 | May-2028 | Shoshone #2 | 0.58 | May-1996 | May-2031 |
| Head of U Canal Project | 1.28 | May-2015 | Jun-2035 | Shoshone Cspp | 0.37 | Jun-1982 | Feb-2017 |
| Horseshoe Bend Hydro | 9.50 | Sep-1995 | Sep-2030 | Snake River Pottery | 0.07 | Nov-1984 | Nov-2019 |
| Jim Knight | 0.34 | Jun-1985 | Jun-2020 | Snedigar | 0.54 | Jan-1985 | Jan-2020 |
| Kasel & Witherspoon | 0.90 | Mar-1984 | Mar-2019 | Tiber Dam | 7.50 | Jun-2004 | Jun-2024 |
| Koyle Small Hydro | 1.25 | Apr-1984 | Apr-2019 | Trout-Co | 0.24 | Dec-1986 | Dec-2021 |
| Lateral # 10 | 2.06 | May-1985 | May-2020 | Tunnel #1 | 7.00 | Jun-1993 | Feb-2035 |
| Lemoyne | 0.08 | Jun-1985 | Jun-2020 | White Water Ranch | 0.16 | Aug-1985 | Aug-2020 |
| Little Wood River Ranch II | 1.25 | Jun-2015 | Oct-2035 | Wilson Lake Hydro | 8.40 | May-1993 | May-2028 |
| **Total Hydro Nameplate Rating 155.32 MW** | | | | | | | |

| Thermal Projects | MW | On-line Date | End Date |
|---|---|---|---|
| Simplot Pocatello Cogen | 15.90 | Mar-2013 | Feb-2016 |
| TASCO—Nampa Natural Gas | 2 | Sep-2003 | As Delivered |
| TASCO—Twin Falls Natural Gas | 3 | Aug-2001 | As Delivered |
| **Total Thermal Nameplate Rating 20.90 MW** | | | |

| Project | MW | Contract On-line Date | Contract End Date | Project | MW | Contract On-line Date | Contract End Date |
|---|---|---|---|---|---|---|---|
| **Biomass Projects** | | | | | | | |
| B6 Anaerobic Digester | 2.28 | Aug-2010 | Aug-2020 | Hidden Hollow Landfill Gas | 3.20 | Jan-2007 | Jan-2027 |
| Bannock County Landfill | 3.20 | May-2014 | May-2034 | Pocatello Waste | 0.46 | Dec-1985 | Dec-2020 |
| Bettencourt Dry Creek BioFactory | 2.25 | May-2010 | May-2020 | Rock Creek Dairy | 4.00 | Aug-2012 | Aug-2027 |
| Big Sky West Dairy Digester | 1.50 | Jan-2009 | Jan-2029 | SISW LFGE | 5.00 | Oct-2018 | Estimated |
| Double A Digester Project | 4.50 | Jan-2012 | Jan-2032 | Tamarack CSPP | 5.00 | Jun-1983 | Jun-2018 |
| Fighting Creek Landfill | 3.06 | Apr-2014 | Apr-2029 | | | | |
| **Total Biomass Nameplate Rating 34.45 MW** | | | | | | | |
| **Solar Projects** | | | | | | | |
| American Falls Solar II, LLC | 20.00 | Mar-2017 | Mar-2037 | Murphy Flat Power, LLC | 20.00 | Mar-2017 | Mar-2037 |
| American Falls Solar, LLC | 40.00 | Mar-2017 | Mar-2037 | Open Range Solar Center, LLC | 20.00 | Mar-2017 | Mar-2037 |
| Brush Solar | 2.75 | Oct-2019 | Estimated | Orchard Ranch Solar, LLC | 10.00 | Oct-2016 | Oct-2036 |
| Grand View PV Solar Two | 80.00 | Dec-2016 | Dec-2036 | Railroad Solar Center, LLC | 4.50 | Dec-2016 | Dec-2036 |
| Grove Solar Center, LLC | 6.00 | Oct-2016 | Oct-2036 | Simco Solar, LLC | 20.00 | Mar-2017 | Mar-2037 |
| Hyline Solar Center, LLC | 9.00 | Nov-2016 | Nov-2036 | Thunderegg Solar Center, LLC | 10.00 | Nov-2016 | Nov-2036 |
| ID Solar 1 | 40.00 | Aug-2016 | Jan-2036 | Vale Air Solar Center, LLC | 10.00 | Nov-2016 | Nov-2036 |
| Morgan Solar | 3.00 | Oct-2019 | Estimated | Vale 1 Solar | 3.00 | Oct-2019 | Estimated |
| Mt. Home Solar 1, LLC | 20.00 | Mar-2017 | Mar-2037 | | | | |
| **Total Solar Nameplate Rating 298.25 MW** | | | | | | | |
| **Wind Projects** | | | | | | | |
| Bennett Creek Wind Farm | 21.00 | Dec-2008 | Dec-2028 | Mainline Windfarm | 23.00 | Dec-2012 | Dec-2032 |
| Benson Creek Windfarm | 10.00 | Mar-2017 | Mar-2037 | Milner Dam Wind | 19.92 | Feb-2011 | Feb-2031 |
| Burley Butte Wind Park | 21.30 | Feb-2011 | Feb-2031 | Oregon Trail Wind Park | 13.50 | Jan-2011 | Jan-2031 |
| Camp Reed Wind Park | 22.50 | Dec-2010 | Dec-2030 | Payne's Ferry Wind Park | 21.00 | Dec-2010 | Dec-2030 |
| Cassia Wind Farm LLC | 10.50 | Mar-2009 | Mar-2029 | Pilgrim Stage Station Wind Park | 10.50 | Jan-2011 | Jan-2031 |
| Cold Springs Windfarm | 23.00 | Dec-2012 | Dec-2032 | Prospector Windfarm | 10.00 | Mar-2017 | Mar-2037 |
| Desert Meadow Windfarm | 23.00 | Dec-2012 | Dec-2032 | Rockland Wind Farm | 80.00 | Dec-2011 | Dec-2036 |
| Durbin Creek Windfarm | 10.00 | Mar-2017 | Mar-2037 | Ryegrass Windfarm | 23.00 | Dec-2012 | Dec-2032 |
| Fossil Gulch Wind | 10.50 | Sep-2005 | Sep-2025 | Salmon Falls Wind | 22.00 | Apr-2011 | Apr-2031 |
| Golden Valley Wind Park | 12.00 | Feb-2011 | Feb-2031 | Sawtooth Wind Project | 22.00 | Nov-2011 | Nov-2031 |
| Hammett Hill Windfarm | 23.00 | Dec-2012 | Dec-2032 | Thousand Springs Wind Park | 12.00 | Jan-2011 | Jan-2031 |
| High Mesa Wind Project | 40.00 | Dec-2012 | Dec-2032 | Tuana Gulch Wind Park | 10.50 | Jan-2011 | Jan-2031 |
| Horseshoe Bend Wind | 9.00 | Feb-2006 | Feb-2026 | Tuana Springs Expansion | 35.70 | May-2010 | May-2030 |
| Hot Springs Wind Farm | 21.00 | Dec-2008 | Dec-2028 | Two Ponds Windfarm | 23.00 | Dec-2012 | Dec-2032 |
| Jett Creek Windfarm | 10.00 | Mar-2017 | Mar-2037 | Willow Spring Windfarm | 10.00 | Mar-2017 | Mar-2037 |
| Lime Wind Energy | 3.00 | Dec-2011 | Dec-2031 | Yahoo Creek Wind Park | 21.00 | Dec-2010 | Dec-2030 |
| **Total Wind Nameplate Rating 626.92 MW** | | | | | | | |
| **Total Nameplate Rating 1,135.84 MW** | | | | | | | |

The above is a summary of the Nameplate rating for the CSPP projects under contract with Idaho Power as of April 1, 2017. In the case of CSPP projects, Nameplate rating of the actual generation units is not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy these projects will produce.

# Power Purchase Agreement Data

| Idaho Power Company Power Purchase Agreements Status as of April 1, 2017 | | | Contract |
|---|---|---|---|
| **Project** | **MW** | **On-Line Date** | **End Date** |
| **Wind projects** | | | |
| Elkhorn Wind Project | 101 | December 2007 | December 2027 |
| **Total wind nameplate MW rating** | 101 | | |
| **Geothermal Projects** | | | |
| Raft River Unit 1 | 13 | April 2008 | April 2033 |
| Neal Hot Springs | 22 | November 2012 | November 2037 |
| **Total geothermal nameplate MW rating** | 35 | | |
| **Total nameplate MW rating** | 136 | | |

1. Above is a summary of the nameplate ratings for the Power Purchase Agreements under contract with Idaho Power. Nameplate ratings of the actual generation units are not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource-specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy the projects will produce.
2. Not included in the above table is the energy exchange agreement between Idaho Power and the Clatskanie PUD. Under the exchange, Idaho Power receives energy from the 18-MW power plant at Arrowrock Dam on the Boise River and returns to Clatskanie PUD energy of an equivalent value delivered seasonally. The agreement began in January 2010 and extends through 2020. Idaho Power retains the right to renew the agreement through 2025.

# Flow Modeling

## Models

Idaho Power uses two primary models for forecasting future flows for the IRP. The Snake River Planning Model (SRPM) is used to forecast surface water flows and the Enhanced Snake Plain Aquifer Model (ESPAM) is used to forecast the impact of various aquifer management practices implemented on the Eastern Snake Plain Aquifer (ESPA). The SRPM was updated in late 2012 to include hydrologic conditions for years 1928 through 2009. ESPAM was also updated with the release of ESPAM 2.1 in late 2012. Beginning with the 2009 IRP, Idaho Power began running the SRPM and ESPAM as a combined modeling system. The combined model seeks to maximize diversions for aquifer recharge and system conversions without creating additional model irrigation shortages over a modeled reference condition.

## Model Inputs

The inputs for the 2017 IRP were derived from management practices outlined in an agreement between the Surface Water Coalition and Idaho Groundwater Appropriators (IGWA). The agreement set out specific targets for several management practices that include aquifer recharge, system conversions, and a total reduction in ground water diversions of 240,000 acre feet (acft). The 2017 IRP modeling also recognized ongoing declines in specific reaches and additional surface water from weather modification activities.

Recharge modeled for the 2017 IRP included new recharge diversions that have the capability of completely drying the Snake River below Milner Dam during the winter months. These diversions can have a significant impact to flows downstream of Milner Dam. Recharge diversions increased from 2017 and peaked at close to 249,000 acft in IRP year 2022. In IRP year 2022, approximately 67,000 acft of recharge occurs above American Falls Reservoir and 182,000 acft is diverted at Milner Dam. Recharge diversions are held steady until 2031 when declines in reach gains reduce the amount of water available for recharge operations.

System conversion projects involve the conversion of ground water supplied irrigated land to surface supplied irrigated land. The number of acres modeled and potential water savings was based on data provided by the Idaho Department of Water Resources. The current model assumes a total of 16,687 acres of converted land on the ESPA with a total water savings of 2.0 acre-ft or water per acre of irrigated land (acre-ft/acre). Diversions for conversion projects peak at approximately 33,000 acft. Diversions for conversion projects generally decline after 2021 as declines in reach gains reduces water availability for diversion.

The model accounted for a 240,000 acft decreases in ground water pumping from the Eastern Snake Plain Aquifer (ESPA). The decreases were spread evenly over ground water irrigated lands that are subject to the agreement between the Surface Water Coalition and the IGWA. This reduction in ground water diversions resulted in increased reach gains throughout much of the mid-Snake River.

The goal of the Surface Water Coalition agreement was to provide additional water to those entities diverting Snake River water from Minidoka Dam to Milner Dam. To simulate this delivery of additional water, a new diversion was added to the model. This diversion is not delivered to a specific entity in the model but is designed to simulate additional surface water diversions at Milner. The amount of this diversion was calculated to ensure that surface water diverters would receive water amounting to the 25 percent exceedance of diversions for years 1995 – 2009. These additional diversions were not allowed if either storage water or natural flow were not available in excess of existing modeled diversions. Water was not available in all years to fill these diversions.

Future reach declines were determined using a variety of statistical analyses. Trend data indicate reach gains into American Falls Reservoir and from Milner Dam to Lower Salmon Falls Dam demonstrated a statistically significant decline for the period of 1986 to 2015. On average, reach gains into American Falls Reservoir declined 29 cubic feet per second per year. Reach gains from Milner Dam to Lower Salmon Falls Dam declined on average 28 cubic feet per second per year. Declines in these two reaches met strict, predefined criteria, and were therefore included as inputs into the model.

Weather modification was added to the model at different levels of development. For IRP years 2017 through 2019, weather modification was increased to reflect projected levels of fully built-out programs in Eastern Idaho, the Wood River Valley and the Boise Basin. Beyond IRP year 2019, weather modification levels in these three basins were held constant through the rest of the IRP forecast period. The level of weather modification was held constant at the current level in the Payette River Basin throughout the IRP forecast period.

## Model Results

The combined model allows for the ability to include future management activities, and the resulting reach gains from those management activities into Idaho Power's 2017 IRP. Management activities, such as recharge and system conversions, do not significantly change the total annual volume of water expected to flow through the Hells Canyon Complex, but instead change the timing and location of reach gains within the system. Other future management activities, such as weather modification and a decrease in ground water pumping do directly impact the annual volume of water expected through the Hells Canyon Complex as well as the timing and location of gains within the system.

Overall inflow to Brownlee Reservoir increases from IRP year 2017 through 2018. These increases are a response to increased weather modification in the Upper Snake, Wood and Boise River Basins and increased reach gains resulting from a decrease in pumping on the ESPA. Flows peak in 2018 with the 50 percent exceedance flows into Brownlee Reservoir at just over 11.72 million acre-ft/year. In 2036, those flows have declined to approximately 11.3 million acre-ft/year. For the April through July volume the peak occurs in 2021 with a volume of 5.32 million acre-ft/year. By 2036 the April through July inflow to Brownlee decreases to 5.17 million acre-ft/year. The decline in inflow to Brownlee Reservoir after 2018 is likely due to the increased diversions for recharge, particularly winter time diversions that reduce flow at Milner Dam to zero. April through July volumes continue to increase as new reach gains from recharge and a decline in ground water pumping yield at springs tributary to the Snake River. However, there is a long-term decrease in Snake River flows which is attributable to

declining flows into American Falls and the Milner to Lower Salmon Falls reach. These long-term declines eventually overwhelm any new reach gains from management practices on the ESPA.

## 2017 Model Parameters

| IRP Year | Managed Recharge (acft/yr) | | | Weather Modification (acft/yr) | System Conversions (Ac) | CREP (Ac) | Reach Declines (acft/yr) | |
|---|---|---|---|---|---|---|---|---|
| | Above American Falls | Below American Falls | Total | | | | American Falls Inflows | Below Milner Inflows |
| 2017 | 700 | 56,444 | 57,144 | 888,301 | 16,700 | 240,000 | 167,000 | 161,700 |
| 2018 | 4,900 | 70,748 | 75,648 | 990,779 | 16,700 | 240,000 | 187,700 | 181,900 |
| 2019 | 36,379 | 144,079 | 180,459 | 1,031,541 | 16,376 | 240,000 | 208,500 | 201,400 |
| 2020 | 39,309 | 143,957 | 183,266 | 1,031,541 | 16,574 | 240,000 | 229,300 | 222,400 |
| 2021 | 39,310 | 167,259 | 206,568 | 1,031,541 | 16,700 | 240,000 | 250,100 | 242,600 |
| 2022 | 67,427 | 181,352 | 248,779 | 1,031,541 | 16,490 | 240,000 | 270,900 | 263,100 |
| 2023 | 67,427 | 181,352 | 248,779 | 1,031,541 | 16,490 | 240,000 | 291,900 | 283,000 |
| 2024 | 67,427 | 181,352 | 248,779 | 1,031,541 | 16,490 | 240,000 | 312,800 | 303,200 |
| 2025 | 67,427 | 181,352 | 248,779 | 1,031,541 | 16,490 | 240,000 | 333,400 | 323,300 |
| 2026 | 67,427 | 181,352 | 248,779 | 1,031,541 | 16,490 | 240,000 | 354,300 | 343,900 |
| 2027 | 67,427 | 181,352 | 248,779 | 1,031,541 | 16,490 | 240,000 | 375,500 | 364,000 |
| 2028 | 67,427 | 181,352 | 248,779 | 1,031,541 | 16,490 | 240,000 | 396,100 | 384,200 |
| 2029 | 67,427 | 181,352 | 248,779 | 1,031,541 | 16,490 | 240,000 | 417,000 | 404,400 |
| 2030 | 67,427 | 181,352 | 248,779 | 1,031,541 | 16,490 | 240,000 | 437,900 | 424,600 |
| 2031 | 65,871 | 176,055 | 241,926 | 1,031,541 | 16,238 | 240,000 | 458,600 | 444,600 |
| 2032 | 65,871 | 176,055 | 241,926 | 1,031,541 | 16,238 | 240,000 | 479,600 | 465,000 |
| 2033 | 65,871 | 176,055 | 241,926 | 1,031,541 | 16,238 | 240,000 | 500,600 | 485,100 |
| 2034 | 65,871 | 176,055 | 241,926 | 1,031,541 | 16,238 | 240,000 | 521,300 | 505,300 |
| 2035 | 65,871 | 176,055 | 241,926 | 1,031,541 | 16,238 | 240,000 | 542,200 | 525,600 |
| 2036 | 65,871 | 176,055 | 241,926 | 1,031,541 | 16,238 | 240,000 | 562,900 | 545,300 |

# Hydro Modeling Results (PDR580)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2017** | **2/2017** | **3/2017** | **4/2017** | **5/2017** | **6/2017** | **7/2017** | **8/2017** | **9/2017** | **10/2017** | **11/2017** | **12/2017** | **aMW** |
| Brownlee | HCC* | 308.0 | 348.1 | 344.5 | 453.3 | 399.4 | 415.5 | 251.3 | 162.5 | 221.4 | 184.0 | 144.7 | 240.8 | 289.5 |
| Oxbow | HCC | 126.9 | 150.0 | 156.1 | 199.5 | 163.7 | 168.7 | 106.8 | 74.4 | 100.1 | 85.1 | 66.2 | 102.2 | 125.0 |
| Hells Canyon | HCC | 249.6 | 298.0 | 315.2 | 408.1 | 338.4 | 340.6 | 211.7 | 146.3 | 195.5 | 168.1 | 132.2 | 202.8 | 250.5 |
| American Falls | ROR | 22.6 | 24.1 | 24.4 | 56.2 | 84.4 | 92.5 | 86.7 | 66.3 | 42.4 | 13.6 | – | 10.2 | 43.6 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 47.3 | 47.3 | 42.0 | 55.4 | 48.0 | 41.8 | 35.5 | 28.7 | 37.4 | 38.2 | 36.5 | 40.8 | 41.6 |
| C .J. Strike | ROR | 61.5 | 62.6 | 56.0 | 69.9 | 61.1 | 51.2 | 37.2 | 31.8 | 44.8 | 48.5 | 47.7 | 51.5 | 52.0 |
| Cascade | ROR | 1.5 | 1.5 | 2.5 | 5.9 | 5.4 | 11.6 | 10.4 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 32.9 | 32.9 | 27.9 | 38.5 | 33.7 | 28.1 | 23.1 | 16.2 | 23.7 | 24.5 | 22.8 | 26.3 | 27.6 |
| Milner | ROR | 34.9 | 36.0 | 20.3 | 42.8 | 31.1 | 15.4 | 6.4 | – | – | – | – | 14.7 | 16.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 9.7 | 12.0 | 10.5 |
| Swan Falls | ROR | 19.8 | 20.1 | 18.2 | 22.6 | 19.9 | 16.8 | 13.0 | 11.2 | 15.0 | 15.9 | 15.8 | 17.0 | 17.1 |
| Twin Falls | ROR | 35.1 | 36.0 | 22.6 | 45.5 | 32.0 | 20.1 | 10.7 | – | – | – | 5.9 | 17.8 | 18.8 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.2 | 18.0 | 19.1 | 17.6 | 18.0 | 14.1 | 9.0 | 14.5 | 15.0 | 13.6 | 16.5 | 16.2 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 16.6 | 17.7 | 17.7 | 16.2 | 13.3 | 8.9 | 13.6 | 14.0 | 12.9 | 15.3 | 15.1 |
| **HCC Total** | | **684.5** | **796.1** | **815.8** | **1,060.9** | **901.5** | **924.8** | **569.8** | **383.2** | **516.9** | **437.2** | **343.1** | **545.8** | **665.0** |
| **ROR Total** | | **330.3** | **335.6** | **287.7** | **413.0** | **391.6** | **350.4** | **288.9** | **219.5** | **235.1** | **206.0** | **192.4** | **249.4** | **291.7** |
| **Total** | | **1,014.8** | **1,131.7** | **1,103.5** | **1,473.9** | **1,293.1** | **1,275.2** | **858.7** | **602.7** | **752.0** | **643.2** | **535.5** | **795.2** | **956.6** |

*HCC=Hells Canyon Complex, **ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2018** | **2/2018** | **3/2018** | **4/2018** | **5/2018** | **6/2018** | **7/2018** | **8/2018** | **9/2018** | **10/2018** | **11/2018** | **12/2018** | **aMW** |
| Brownlee | HCC* | 299.6 | 350.8 | 344.3 | 455.2 | 402.9 | 420.5 | 252.0 | 162.6 | 221.9 | 184.2 | 144.8 | 245.5 | 290.4 |
| Oxbow | HCC | 124.0 | 151.4 | 156.7 | 201.8 | 165.2 | 170.7 | 107.1 | 74.5 | 100.3 | 85.3 | 66.3 | 104.2 | 125.6 |
| Hells Canyon | HCC | 244.0 | 300.6 | 316.3 | 412.7 | 341.3 | 344.5 | 212.2 | 146.5 | 196.0 | 168.3 | 132.4 | 206.8 | 251.8 |
| American Falls | ROR | 24.3 | 24.8 | 25.4 | 59.7 | 85.7 | 94.1 | 86.9 | 66.5 | 42.5 | 13.6 | – | 14.5 | 44.8 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 47.4 | 47.6 | 42.5 | 56.0 | 49.2 | 42.4 | 35.7 | 28.5 | 37.5 | 38.3 | 36.8 | 42.6 | 42.0 |
| C .J. Strike | ROR | 61.7 | 63.3 | 56.7 | 72.5 | 62.8 | 52.6 | 37.2 | 31.8 | 45.0 | 48.6 | 47.7 | 53.5 | 52.8 |
| Cascade | ROR | 1.5 | 1.5 | 2.5 | 5.9 | 5.4 | 11.6 | 10.4 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 33.3 | 33.5 | 28.2 | 39.4 | 35.2 | 29.0 | 23.2 | 16.2 | 23.6 | 24.5 | 22.7 | 29.1 | 28.2 |
| Milner | ROR | 36.5 | 36.4 | 22.6 | 45.1 | 35.0 | 18.2 | 6.4 | – | – | – | – | 23.7 | 18.7 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 9.6 | 12.0 | 10.5 |
| Swan Falls | ROR | 19.8 | 20.2 | 18.5 | 23.1 | 20.3 | 17.2 | 13.0 | 11.1 | 15.1 | 16.0 | 15.9 | 17.6 | 17.3 |
| Twin Falls | ROR | 36.9 | 36.3 | 24.3 | 47.8 | 35.3 | 21.8 | 10.7 | – | – | – | 5.9 | 25.3 | 20.4 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 17.7 | 17.7 | 16.8 | 17.7 | 17.7 | 16.2 | 13.3 | 8.9 | 13.6 | 14.0 | 12.8 | 17.2 | 15.3 |
| Upper Salmon 3&4 | ROR | 19.1 | 19.1 | 18.2 | 19.0 | 17.6 | 18.7 | 14.2 | 9.0 | 14.5 | 15.0 | 13.6 | 18.7 | 16.4 |
| **HCC Total** | | **667.6** | **802.8** | **817.3** | **1,069.7** | **909.3** | **935.7** | **571.3** | **383.6** | **518.1** | **437.8** | **343.5** | **556.5** | **667.8** |
| **ROR Total** | | **336.0** | **338.6** | **294.9** | **425.6** | **404.9** | **360.5** | **289.5** | **219.4** | **235.5** | **206.3** | **192.5** | **281.5** | **298.8** |
| **Total** | | **1,003.6** | **1,141.4** | **1,112.2** | **1,495.3** | **1,314.2** | **1,296.2** | **860.8** | **603.0** | **753.6** | **644.1** | **536.0** | **838.0** | **966.5** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

**Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load**

| Resource | Type | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 297.4 | 349.1 | 343.4 | 454.0 | 405.5 | 422.9 | 252.2 | 162.7 | 221.6 | 184.7 | 144.5 | 243.7 | 290.1 |
| Oxbow | HCC | 123.1 | 150.7 | 156.3 | 201.2 | 166.2 | 171.7 | 107.2 | 74.5 | 100.2 | 85.5 | 66.1 | 103.4 | 125.5 |
| Hells Canyon | HCC | 242.2 | 299.1 | 315.5 | 411.5 | 343.3 | 346.4 | 212.4 | 146.6 | 195.6 | 168.7 | 132.0 | 205.2 | 251.5 |
| American Falls | ROR | 24.4 | 25.0 | 22.5 | 60.5 | 86.6 | 95.2 | 87.1 | 66.6 | 42.6 | 13.6 | – | 15.9 | 45.0 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 46.9 | 47.7 | 40.5 | 56.2 | 50.1 | 43.4 | 35.7 | 28.6 | 37.5 | 38.3 | 36.3 | 43.2 | 42.0 |
| C .J. Strike | ROR | 61.4 | 63.1 | 53.9 | 71.3 | 62.9 | 54.4 | 37.3 | 31.9 | 45.0 | 48.7 | 47.1 | 54.3 | 52.6 |
| Cascade | ROR | 1.5 | 1.5 | 2.5 | 5.9 | 5.4 | 11.6 | 10.4 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | |
| Lower Salmon | ROR | 32.8 | 33.1 | 26.0 | 39.5 | 35.5 | 29.3 | 23.2 | 16.3 | 23.6 | 24.5 | 22.4 | 29.6 | 28.0 |
| Milner | ROR | 35.0 | 35.0 | 15.2 | 44.9 | 35.7 | 21.2 | 6.4 | – | – | – | – | 25.3 | 18.2 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 8.5 | 12.0 | 10.4 |
| Swan Falls | ROR | 19.6 | 20.2 | 17.7 | 23.1 | 20.4 | 17.7 | 13.0 | 11.2 | 15.1 | 16.0 | 15.6 | 17.8 | 17.3 |
| Twin Falls | ROR | 35.6 | 35.5 | 18.6 | 47.4 | 35.9 | 24.0 | 10.7 | – | – | – | 4.7 | 27.0 | 20.0 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 17.7 | 17.7 | 15.4 | 17.7 | 17.7 | 16.2 | 13.4 | 8.9 | 13.5 | 14.0 | 12.6 | 17.5 | 15.2 |
| Upper Salmon 3&4 | ROR | 19.2 | 19.1 | 16.5 | 19.0 | 17.6 | 18.9 | 14.2 | 9.0 | 14.4 | 15.0 | 13.3 | 19.1 | 16.3 |
| **HCC Total** | | **662.7** | **798.9** | **815.2** | **1,066.7** | **915.0** | **941.0** | **571.8** | **383.8** | **517.3** | **438.9** | **342.6** | **552.3** | **667.2** |
| **ROR Total** | | **331.9** | **336.1** | **268.0** | **424.9** | **408.5** | **370.6** | **289.9** | **219.9** | **235.4** | **206.4** | **188.0** | **289.0** | **285.2** |
| **Total** | | **994.6** | **1,135.0** | **1,083.2** | **1,491.6** | **1,323.5** | **1,311.6** | **861.7** | **603.7** | **752.7** | **645.3** | **530.6** | **841.3** | **952.4** |

*HCC=Hells Canyon Complex, **ROR= Run of River

**Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load**

| Resource | Type | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 297.8 | 338.0 | 343.4 | 454.2 | 405.7 | 422.7 | 252.1 | 162.5 | 221.2 | 184.7 | 144.4 | 243.7 | 289.2 |
| Oxbow | HCC | 123.3 | 145.9 | 156.3 | 201.2 | 166.4 | 171.6 | 107.1 | 74.4 | 100.0 | 85.4 | 66.1 | 103.4 | 125.1 |
| Hells Canyon | HCC | 242.6 | 289.7 | 315.5 | 411.7 | 343.5 | 346.2 | 212.3 | 146.4 | 195.3 | 168.6 | 131.9 | 205.3 | 250.7 |
| American Falls | ROR | 24.5 | 24.4 | 22.3 | 60.7 | 86.6 | 95.2 | 87.1 | 66.6 | 42.6 | 13.6 | – | 16.1 | 45.0 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 47.0 | 46.2 | 40.5 | 56.3 | 50.2 | 43.4 | 35.7 | 28.5 | 37.4 | 38.3 | 36.3 | 43.3 | 41.9 |
| C .J. Strike | ROR | 61.6 | 61.0 | 53.8 | 71.4 | 63.1 | 54.4 | 37.3 | 31.8 | 44.8 | 48.7 | 47.1 | 54.5 | 52.5 |
| Cascade | ROR | 1.5 | 1.4 | 2.5 | 5.9 | 5.4 | 11.6 | 10.4 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 32.9 | 32.2 | 25.9 | 39.6 | 35.6 | 29.3 | 23.2 | 16.2 | 23.5 | 24.5 | 22.4 | 29.7 | 27.9 |
| Milner | ROR | 35.3 | 34.3 | 15.2 | 45.0 | 35.8 | 21.2 | 6.4 | – | – | – | – | 25.6 | 18.2 |
| Shoshone Falls | ROR | 12.0 | 11.6 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 8.8 | 12.0 | 10.4 |
| Swan Falls | ROR | 19.6 | 19.5 | 17.7 | 23.1 | 20.4 | 17.8 | 13.0 | 11.1 | 15.0 | 16.0 | 15.6 | 17.9 | 17.2 |
| Twin Falls | ROR | 35.8 | 34.7 | 18.6 | 47.5 | 35.9 | 24.0 | 10.7 | – | – | – | 5.2 | 27.3 | 20.0 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 19.2 | 18.4 | 16.5 | 19.0 | 17.6 | 18.9 | 14.2 | 9.0 | 14.4 | 14.9 | 13.3 | 19.2 | 16.2 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.1 | 15.3 | 17.7 | 17.7 | 16.2 | 13.3 | 8.9 | 13.5 | 14.0 | 12.6 | 17.6 | 15.1 |
| **HCC Total** | | **663.7** | **773.6** | **815.2** | **1,067.1** | **915.7** | **940.5** | **571.5** | **383.3** | **516.4** | **438.7** | **342.4** | **552.4** | **665.0** |
| **ROR Total** | | **332.9** | **327.1** | **267.5** | **425.6** | **409.0** | **370.7** | **289.8** | **219.5** | **234.9** | **206.3** | **188.8** | **290.5** | **296.9** |
| **Total** | | **996.6** | **1,100.6** | **1,082.7** | **1,492.7** | **1,324.6** | **1,311.2** | **861.3** | **602.8** | **751.3** | **645.0** | **531.2** | **842.9** | **961.9** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

**Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load**

| Resource | Type | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 296.8 | 348.7 | 343.9 | 454.9 | 406.0 | 422.7 | 252.1 | 162.4 | 216.4 | 184.8 | 144.6 | 242.5 | 289.6 |
| Oxbow | HCC | 122.9 | 150.5 | 156.5 | 201.5 | 166.6 | 171.6 | 107.1 | 74.4 | 99.6 | 85.4 | 66.1 | 102.9 | 125.4 |
| Hells Canyon | HCC | 241.8 | 298.8 | 315.9 | 412.3 | 343.8 | 346.1 | 212.3 | 146.3 | 195.4 | 168.6 | 132.1 | 204.3 | 251.5 |
| American Falls | ROR | 24.6 | 25.2 | 22.3 | 60.3 | 86.6 | 95.2 | 87.1 | 66.6 | 42.6 | 13.6 | – | 15.9 | 45.0 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 46.7 | 47.6 | 40.4 | 56.3 | 50.4 | 43.3 | 35.7 | 28.5 | 37.3 | 38.2 | 36.1 | 43.0 | 42.0 |
| C .J. Strike | ROR | 61.2 | 62.9 | 53.5 | 71.5 | 63.3 | 54.5 | 37.3 | 31.8 | 44.7 | 48.6 | 46.9 | 54.1 | 52.5 |
| Cascade | ROR | 1.5 | 1.5 | 2.5 | 5.9 | 5.4 | 11.6 | 10.4 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 32.6 | 32.9 | 25.7 | 39.7 | 35.8 | 29.3 | 23.2 | 16.2 | 23.4 | 24.4 | 22.3 | 29.5 | 27.9 |
| Milner | ROR | 34.4 | 34.5 | 14.2 | 45.2 | 35.7 | 21.1 | 6.4 | – | – | – | – | 24.8 | 18.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 8.2 | 12.0 | 10.3 |
| Swan Falls | ROR | 19.5 | 20.2 | 17.6 | 23.1 | 20.4 | 17.8 | 13.0 | 11.1 | 15.0 | 16.0 | 15.6 | 17.8 | 17.3 |
| Twin Falls | ROR | 35.1 | 35.1 | 18.1 | 47.7 | 35.9 | 24.0 | 10.7 | – | – | – | 4.5 | 26.5 | 19.8 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.1 | 16.3 | 19.0 | 17.6 | 18.9 | 14.2 | 9.0 | 14.3 | 14.9 | 13.3 | 19.0 | 16.2 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.1 | 17.7 | 17.7 | 16.2 | 13.3 | 8.9 | 13.4 | 13.9 | 12.6 | 17.4 | 15.1 |
| **HCC Total** | | **661.5** | **798.0** | **816.3** | **1,068.7** | **916.4** | **940.4** | **571.5** | **383.1** | **511.3** | **438.8** | **342.8** | **549.7** | **666.5** |
| **ROR Total** | | **330.3** | **334.9** | **264.9** | **425.8** | **409.5** | **370.6** | **289.8** | **219.5** | **234.4** | **205.9** | **187.0** | **287.3** | **296.6** |
| **Total** | | **991.8** | **1,132.9** | **1,081.2** | **1,494.5** | **1,325.9** | **1,311.0** | **861.3** | **602.6** | **745.6** | **644.7** | **529.8** | **837.0** | **963.2** |

*HCC=Hells Canyon Complex, **ROR= Run of River

**Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load**

| Resource | Type | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 298.8 | 351.2 | 343.6 | 441.1 | 407.1 | 422.4 | 251.8 | 162.2 | 215.7 | 184.8 | 144.7 | 244.0 | 288.9 |
| Oxbow | HCC | 123.7 | 151.5 | 156.3 | 195.4 | 167.0 | 171.5 | 107.0 | 74.3 | 99.2 | 85.4 | 66.2 | 103.6 | 125.1 |
| Hells Canyon | HCC | 243.4 | 300.8 | 315.5 | 400.1 | 344.5 | 345.9 | 212.1 | 146.1 | 194.7 | 168.5 | 132.2 | 205.6 | 250.8 |
| American Falls | ROR | 24.6 | 25.7 | 22.7 | 57.8 | 86.7 | 95.2 | 87.1 | 66.5 | 42.5 | 13.6 | – | 16.4 | 44.9 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 47.2 | 48.1 | 40.8 | 52.7 | 50.4 | 43.3 | 35.6 | 28.4 | 37.2 | 38.1 | 36.2 | 43.6 | 41.8 |
| C .J. Strike | ROR | 61.3 | 63.4 | 54.4 | 67.1 | 63.1 | 53.6 | 37.2 | 31.7 | 44.5 | 48.5 | 47.0 | 55.3 | 52.3 |
| Cascade | ROR | 1.5 | 1.5 | 2.5 | 5.9 | 5.4 | 11.6 | 10.4 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 33.0 | 33.4 | 26.3 | 36.5 | 35.8 | 29.3 | 23.1 | 16.1 | 23.3 | 24.3 | 22.4 | 30.0 | 27.8 |
| Milner | ROR | 35.7 | 36.5 | 16.0 | 42.0 | 35.6 | 21.3 | 6.4 | – | – | – | – | 26.4 | 18.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 9.4 | 12.0 | 10.4 |
| Swan Falls | ROR | 19.7 | 20.3 | 17.9 | 21.6 | 20.4 | 17.5 | 13.0 | 11.1 | 14.9 | 15.9 | 15.6 | 18.1 | 17.2 |
| Twin Falls | ROR | 36.2 | 36.7 | 19.3 | 41.1 | 35.8 | 24.1 | 10.7 | – | – | – | 5.7 | 28.0 | 19.8 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.1 | 16.8 | 19.1 | 17.6 | 18.9 | 14.1 | 8.9 | 14.2 | 14.8 | 13.4 | 19.2 | 16.3 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.6 | 17.7 | 17.7 | 16.2 | 13.3 | 8.8 | 13.3 | 13.9 | 12.6 | 17.7 | 15.2 |
| **HCC Total** | | **665.9** | **803.5** | **815.4** | **1,036.6** | **918.5** | **939.8** | **570.9** | **382.6** | **509.5** | **438.7** | **343.1** | **553.2** | **664.8** |
| **ROR Total** | | **333.9** | **340.6** | **271.5** | **400.9** | **409.2** | **369.7** | **289.4** | **218.9** | **233.6** | **205.4** | **189.8** | **294.0** | **296.4** |
| **Total** | | **999.8** | **1,144.1** | **1,086.9** | **1,437.5** | **1,327.8** | **1,309.5** | **860.3** | **601.5** | **743.1** | **644.1** | **532.9** | **847.2** | **961.2** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2023** | **2/2023** | **3/2023** | **4/2023** | **5/2023** | **6/2023** | **7/2023** | **8/2023** | **9/2023** | **10/2023** | **11/2023** | **12/2023** | **aMW** |
| Brownlee | HCC* | 298.6 | 350.6 | 343.4 | 440.8 | 407.4 | 422.0 | 251.5 | 161.8 | 214.7 | 184.8 | 144.6 | 243.7 | 288.7 |
| Oxbow | HCC | 123.6 | 151.3 | 156.2 | 195.3 | 167.1 | 171.3 | 106.9 | 74.1 | 98.7 | 85.4 | 66.1 | 103.5 | 125.0 |
| Hells Canyon | HCC | 243.2 | 300.4 | 315.3 | 399.7 | 344.8 | 345.7 | 211.8 | 145.8 | 193.7 | 168.5 | 132.1 | 205.3 | 250.5 |
| American Falls | ROR | 24.6 | 25.7 | 22.7 | 57.9 | 86.7 | 95.2 | 87.1 | 66.5 | 42.5 | 13.6 | – | 16.4 | 44.9 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 47.2 | 48.0 | 40.8 | 52.7 | 50.4 | 43.2 | 35.5 | 28.3 | 37.0 | 38.0 | 36.2 | 43.5 | 41.7 |
| C .J. Strike | ROR | 61.3 | 63.4 | 54.3 | 67.1 | 63.1 | 53.4 | 37.1 | 31.5 | 44.3 | 48.3 | 46.8 | 55.1 | 52.1 |
| Cascade | ROR | 1.5 | 1.5 | 2.5 | 5.9 | 5.4 | 11.6 | 10.4 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 33.0 | 33.4 | 26.3 | 36.5 | 35.8 | 29.2 | 23.0 | 16.0 | 23.1 | 24.2 | 22.4 | 29.9 | 27.7 |
| Milner | ROR | 35.8 | 36.4 | 15.9 | 42.3 | 35.6 | 21.2 | 6.4 | – | – | – | – | 26.4 | 18.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 9.4 | 12.0 | 10.4 |
| Swan Falls | ROR | 19.7 | 20.3 | 17.8 | 21.6 | 20.4 | 17.5 | 13.0 | 11.1 | 14.9 | 15.9 | 15.6 | 18.1 | 17.2 |
| Twin Falls | ROR | 36.2 | 36.7 | 19.3 | 41.2 | 35.7 | 24.0 | 10.7 | – | – | – | 5.7 | 27.9 | 19.8 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.1 | 16.7 | 19.1 | 17.6 | 18.9 | 14.1 | 8.8 | 14.1 | 14.7 | 13.3 | 19.2 | 16.2 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.5 | 17.7 | 17.7 | 16.2 | 13.2 | 8.8 | 13.2 | 13.8 | 12.6 | 17.7 | 15.2 |
| **HCC Total** | | 665.4 | 802.3 | 814.9 | 1,035.8 | 919.3 | 939.0 | 570.2 | 381.7 | 507.1 | 438.7 | 342.8 | 552.5 | 664.1 |
| **ROR Total** | | 334.0 | 340.4 | 271.0 | 401.4 | 409.1 | 369.1 | 289.0 | 218.4 | 232.8 | 204.8 | 189.5 | 293.5 | 296.1 |
| **Total** | | 999.4 | 1,142.7 | 1,085.9 | 1,437.2 | 1,328.4 | 1,308.1 | 859.2 | 600.1 | 739.8 | 643.5 | 532.3 | 846.0 | 960.2 |

*HCC=Hells Canyon Complex, **ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2024** | **2/2024** | **3/2024** | **4/2024** | **5/2024** | **6/2024** | **7/2024** | **8/2024** | **9/2024** | **10/2024** | **11/2024** | **12/2024** | **aMW** |
| Brownlee | HCC* | 298.3 | 337.4 | 343.1 | 440.6 | 407.3 | 421.5 | 251.2 | 161.4 | 213.2 | 184.9 | 144.6 | 243.8 | 287.3 |
| Oxbow | HCC | 123.5 | 145.6 | 156.0 | 195.2 | 167.1 | 171.1 | 106.7 | 73.9 | 97.9 | 85.3 | 66.1 | 103.5 | 124.3 |
| Hells Canyon | HCC | 243.0 | 289.1 | 315.0 | 399.6 | 344.7 | 345.2 | 211.5 | 145.4 | 192.1 | 168.3 | 131.9 | 205.4 | 249.3 |
| American Falls | ROR | 24.6 | 24.4 | 22.7 | 57.5 | 86.6 | 95.0 | 87.0 | 66.5 | 42.4 | 13.6 | – | 16.2 | 44.7 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 47.1 | 46.3 | 40.7 | 52.6 | 50.4 | 43.0 | 35.5 | 28.2 | 36.9 | 37.9 | 36.1 | 43.4 | 41.5 |
| C .J. Strike | ROR | 61.2 | 61.1 | 54.2 | 67.1 | 63.2 | 53.2 | 37.0 | 31.4 | 44.1 | 48.2 | 46.7 | 54.7 | 51.8 |
| Cascade | ROR | 1.5 | 1.4 | 2.5 | 5.9 | 5.4 | 11.6 | 10.4 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 32.9 | 32.2 | 26.2 | 36.4 | 35.8 | 29.1 | 23.0 | 15.9 | 23.0 | 24.1 | 22.3 | 29.8 | 27.6 |
| Milner | ROR | 35.7 | 34.7 | 15.8 | 42.5 | 35.4 | 21.0 | 6.4 | – | – | – | – | 26.0 | 18.1 |
| Shoshone Falls | ROR | 12.0 | 11.6 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 8.9 | 12.0 | 10.4 |
| Swan Falls | ROR | 19.7 | 19.6 | 17.8 | 21.6 | 20.4 | 17.4 | 12.9 | 11.0 | 14.8 | 15.8 | 15.6 | 17.9 | 17.0 |
| Twin Falls | ROR | 36.2 | 35.0 | 19.2 | 41.3 | 35.6 | 23.8 | 10.7 | – | – | – | 5.3 | 27.5 | 19.5 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 19.2 | 18.4 | 16.7 | 19.1 | 17.6 | 18.8 | 14.0 | 8.8 | 14.0 | 14.6 | 13.3 | 19.2 | 16.1 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.1 | 15.5 | 17.7 | 17.7 | 16.2 | 13.2 | 8.7 | 13.1 | 13.7 | 12.6 | 17.7 | 15.1 |
| **HCC Total** | | **664.8** | **772.0** | **814.1** | **1,035.4** | **919.2** | **937.8** | **569.4** | **380.7** | **503.1** | **438.5** | **342.6** | **552.7** | **660.9** |
| **ROR Total** | | **333.6** | **328.0** | **270.5** | **401.1** | **408.8** | **367.8** | **288.6** | **217.9** | **232.0** | **204.2** | **188.3** | **291.7** | **294.4** |
| **Total** | | **998.4** | **1,100.1** | **1,084.6** | **1,436.5** | **1,328.0** | **1,305.6** | **858.0** | **598.6** | **735.1** | **642.7** | **530.9** | **844.4** | **955.2** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2025** | **2/2025** | **3/2025** | **4/2025** | **5/2025** | **6/2025** | **7/2025** | **8/2025** | **9/2025** | **10/2025** | **11/2025** | **12/2025** | **aMW** |
| Brownlee | HCC* | 297.9 | 348.8 | 342.7 | 440.5 | 407.0 | 420.8 | 250.8 | 161.0 | 211.9 | 184.8 | 144.9 | 243.5 | 287.9 |
| Oxbow | HCC | 123.3 | 150.5 | 155.9 | 195.2 | 166.9 | 170.8 | 106.6 | 73.7 | 97.2 | 85.1 | 66.2 | 103.4 | 124.6 |
| Hells Canyon | HCC | 242.7 | 298.9 | 314.7 | 399.6 | 344.5 | 344.7 | 211.2 | 145.1 | 190.8 | 168.1 | 132.2 | 205.1 | 249.8 |
| American Falls | ROR | 24.6 | 25.2 | 22.6 | 56.7 | 86.6 | 94.8 | 86.9 | 66.4 | 42.3 | 13.5 | – | 15.8 | 44.6 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 47.0 | 47.6 | 40.6 | 52.5 | 50.3 | 42.8 | 35.4 | 28.1 | 36.7 | 37.8 | 36.1 | 43.1 | 41.5 |
| C .J. Strike | ROR | 61.0 | 63.2 | 54.1 | 67.0 | 63.1 | 53.0 | 36.8 | 31.2 | 43.9 | 47.8 | 46.5 | 54.3 | 51.8 |
| Cascade | ROR | 1.5 | 1.5 | 2.5 | 5.9 | 5.4 | 11.6 | 10.4 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 32.6 | 33.0 | 26.0 | 36.3 | 35.7 | 29.0 | 22.9 | 15.8 | 22.8 | 24.0 | 22.2 | 29.6 | 27.5 |
| Milner | ROR | 35.7 | 35.8 | 15.7 | 42.5 | 35.2 | 20.7 | 6.4 | – | – | – | – | 25.3 | 18.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 8.8 | 12.0 | 10.4 |
| Swan Falls | ROR | 19.6 | 20.3 | 17.8 | 21.6 | 20.4 | 17.3 | 12.9 | 11.0 | 14.7 | 15.8 | 15.5 | 17.8 | 17.1 |
| Twin Falls | ROR | 36.2 | 36.2 | 19.1 | 41.4 | 35.4 | 23.6 | 10.7 | – | – | – | 5.2 | 27.0 | 19.6 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.1 | 16.6 | 19.1 | 17.6 | 18.7 | 13.9 | 8.7 | 13.8 | 14.5 | 13.2 | 19.1 | 16.1 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.4 | 17.7 | 17.7 | 16.2 | 13.1 | 8.6 | 13.0 | 13.6 | 12.5 | 17.5 | 15.1 |
| **HCC Total** | | **663.9** | **798.2** | **813.3** | **1,035.3** | **918.3** | **936.3** | **568.6** | **379.8** | **499.9** | **438.0** | **343.3** | **552.0** | **662.2** |
| **ROR Total** | | **332.9** | **337.8** | **269.6** | **400.1** | **408.1** | **366.4** | **287.9** | **217.2** | **230.9** | **203.3** | **187.5** | **288.8** | **294.2** |
| **Total** | | **996.8** | **1,136.0** | **1,082.9** | **1,435.4** | **1,326.4** | **1,302.7** | **856.5** | **597.0** | **730.8** | **641.3** | **530.8** | **840.8** | **956.4** |

*HCC=Hells Canyon Complex, **ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2026** | **2/2026** | **3/2026** | **4/2026** | **5/2026** | **6/2026** | **7/2026** | **8/2026** | **9/2026** | **10/2026** | **11/2026** | **12/2026** | **aMW** |
| Brownlee | HCC* | 297.3 | 348.2 | 342.3 | 440.0 | 407.1 | 420.1 | 250.4 | 160.6 | 210.0 | 185.1 | 145.0 | 243.4 | 287.5 |
| Oxbow | HCC | 123.1 | 150.3 | 155.7 | 195.0 | 166.9 | 170.5 | 106.4 | 73.5 | 96.2 | 85.2 | 66.2 | 103.3 | 124.4 |
| Hells Canyon | HCC | 242.2 | 298.4 | 314.4 | 399.1 | 344.6 | 344.2 | 210.9 | 144.7 | 188.8 | 168.1 | 132.2 | 205.0 | 249.4 |
| American Falls | ROR | 23.9 | 25.2 | 22.5 | 56.7 | 86.5 | 94.7 | 86.9 | 66.4 | 42.3 | 13.5 | – | 15.3 | 44.5 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 46.9 | 47.1 | 40.4 | 52.4 | 50.3 | 42.5 | 35.3 | 27.9 | 36.5 | 37.6 | 36.0 | 42.7 | 41.3 |
| C .J. Strike | ROR | 60.8 | 62.9 | 53.8 | 66.3 | 63.1 | 52.7 | 36.7 | 31.1 | 43.6 | 47.6 | 46.3 | 53.9 | 51.6 |
| Cascade | ROR | 1.5 | 1.5 | 2.5 | 5.9 | 5.4 | 11.6 | 10.4 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 32.3 | 32.9 | 25.9 | 36.2 | 35.7 | 28.9 | 22.8 | 15.7 | 22.7 | 23.8 | 22.2 | 29.2 | 27.4 |
| Milner | ROR | 34.9 | 35.8 | 15.6 | 42.5 | 35.0 | 20.4 | 6.4 | – | – | – | – | 24.5 | 17.9 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 8.8 | 12.0 | 10.4 |
| Swan Falls | ROR | 19.6 | 20.1 | 17.7 | 21.4 | 20.4 | 17.3 | 12.8 | 10.9 | 14.7 | 15.7 | 15.4 | 17.7 | 17.0 |
| Twin Falls | ROR | 35.1 | 36.2 | 18.9 | 41.4 | 35.2 | 23.3 | 10.7 | – | – | – | 5.2 | 26.0 | 19.3 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.1 | 16.5 | 19.1 | 17.6 | 18.6 | 13.9 | 8.6 | 13.7 | 14.4 | 13.2 | 18.8 | 16.1 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.3 | 17.7 | 17.7 | 16.2 | 13.1 | 8.6 | 12.9 | 13.5 | 12.5 | 17.3 | 15.0 |
| **HCC Total** | | **662.6** | **796.9** | **812.4** | **1,034.1** | **918.7** | **934.8** | **567.7** | **378.8** | **494.9** | **438.4** | **343.4** | **551.7** | **661.2** |
| **ROR Total** | | **329.7** | **336.7** | **268.3** | **399.0** | **407.6** | **364.9** | **287.5** | **216.6** | **230.1** | **202.4** | **187.1** | **284.7** | **292.9** |
| **Total** | | **992.3** | **1,133.6** | **1,080.7** | **1,433.1** | **1,326.3** | **1,299.7** | **855.2** | **595.4** | **724.9** | **640.8** | **530.5** | **836.4** | **954.1** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

**Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load**

| Resource | Type | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 296.7 | 347.4 | 342.1 | 439.9 | 407.3 | 419.6 | 249.9 | 160.1 | 208.6 | 185.1 | 145.4 | 241.7 | 287.0 |
| Oxbow | HCC | 122.8 | 149.9 | 155.6 | 194.8 | 167.0 | 170.3 | 106.2 | 73.3 | 95.4 | 85.0 | 66.4 | 102.6 | 124.1 |
| Hells Canyon | HCC | 241.7 | 297.7 | 314.1 | 398.9 | 344.7 | 343.8 | 210.5 | 144.3 | 187.4 | 167.8 | 132.5 | 203.6 | 248.9 |
| American Falls | ROR | 23.6 | 25.1 | 22.1 | 56.6 | 86.4 | 94.6 | 86.9 | 66.3 | 42.2 | 13.5 | – | 14.8 | 44.3 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 46.7 | 47.0 | 40.2 | 52.3 | 50.2 | 42.3 | 35.2 | 27.8 | 36.3 | 37.5 | 35.9 | 42.4 | 41.2 |
| C .J. Strike | ROR | 60.6 | 62.1 | 53.5 | 66.1 | 63.1 | 52.3 | 36.5 | 30.9 | 43.3 | 47.4 | 46.2 | 53.5 | 51.3 |
| Cascade | ROR | 1.5 | 1.5 | 2.5 | 5.9 | 5.4 | 11.6 | 10.4 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 32.2 | 32.8 | 25.8 | 36.1 | 35.6 | 28.6 | 22.7 | 15.5 | 22.5 | 23.7 | 22.1 | 28.7 | 27.2 |
| Milner | ROR | 34.5 | 35.7 | 15.4 | 42.5 | 34.7 | 20.1 | 6.4 | – | – | – | – | 23.0 | 17.7 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 8.8 | 12.0 | 10.4 |
| Swan Falls | ROR | 19.5 | 20.0 | 17.6 | 21.3 | 20.4 | 17.2 | 12.8 | 10.8 | 14.6 | 15.7 | 15.4 | 17.6 | 16.9 |
| Twin Falls | ROR | 34.6 | 36.1 | 18.8 | 41.3 | 35.0 | 23.7 | 10.7 | – | – | – | 5.2 | 24.7 | 19.2 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.2 | 16.4 | 19.1 | 17.6 | 18.4 | 13.8 | 8.5 | 13.6 | 14.3 | 13.1 | 18.3 | 16.0 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 15.2 | 17.7 | 17.7 | 16.2 | 13.0 | 8.5 | 12.8 | 13.5 | 12.4 | 16.9 | 14.9 |
| **HCC Total** | | **661.2** | **795.0** | **811.8** | **1,033.6** | **918.9** | **933.7** | **566.6** | **377.7** | **491.4** | **437.9** | **344.3** | **547.9** | **660.0** |
| **ROR Total** | | **327.9** | **335.4** | **266.7** | **398.3** | **406.8** | **363.7** | **286.9** | **215.7** | **229.0** | **201.9** | **186.6** | **279.2** | **291.5** |
| **Total** | | **989.1** | **1,130.4** | **1,078.5** | **1,431.9** | **1,325.7** | **1,297.4** | **853.5** | **593.4** | **720.3** | **639.8** | **530.9** | **827.1** | **951.5** |

*HCC=Hells Canyon Complex, **ROR= Run of River

**Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load**

| Resource | Type | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 296.0 | 334.6 | 341.9 | 439.6 | 407.7 | 418.8 | 249.4 | 159.6 | 207.2 | 184.9 | 145.2 | 240.4 | 285.4 |
| Oxbow | HCC | 122.6 | 144.3 | 155.4 | 194.6 | 167.1 | 170.0 | 106.0 | 73.1 | 94.7 | 84.9 | 66.2 | 102.0 | 123.4 |
| Hells Canyon | HCC | 241.2 | 286.7 | 313.8 | 398.4 | 345.1 | 343.2 | 210.1 | 143.8 | 185.9 | 167.5 | 132.3 | 202.5 | 247.5 |
| American Falls | ROR | 23.3 | 24.1 | 21.7 | 56.6 | 86.3 | 94.5 | 86.9 | 66.3 | 42.1 | 13.5 | – | 14.2 | 44.1 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 46.6 | 45.2 | 39.7 | 52.2 | 50.1 | 42.1 | 35.0 | 27.7 | 36.1 | 37.3 | 35.8 | 41.9 | 40.8 |
| C .J. Strike | ROR | 60.4 | 59.8 | 53.3 | 65.9 | 63.0 | 52.0 | 36.4 | 30.7 | 43.0 | 47.2 | 46.1 | 53.1 | 50.9 |
| Cascade | ROR | 1.5 | 1.4 | 2.5 | 5.9 | 5.4 | 11.6 | 10.4 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 32.1 | 31.3 | 25.4 | 36.0 | 35.5 | 28.5 | 22.6 | 15.4 | 22.3 | 23.5 | 22.0 | 28.1 | 26.9 |
| Milner | ROR | 34.0 | 34.3 | 15.0 | 42.5 | 34.5 | 19.3 | 6.4 | – | – | – | – | 21.5 | 17.3 |
| Shoshone Falls | ROR | 12.0 | 11.6 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 8.8 | 12.0 | 10.4 |
| Swan Falls | ROR | 19.5 | 19.2 | 17.5 | 21.3 | 20.4 | 17.1 | 12.8 | 10.8 | 14.5 | 15.6 | 15.3 | 17.5 | 16.8 |
| Twin Falls | ROR | 34.3 | 34.8 | 18.2 | 41.3 | 34.8 | 23.5 | 10.7 | – | – | – | 5.2 | 23.3 | 18.8 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 19.2 | 18.5 | 16.1 | 19.1 | 17.6 | 18.3 | 13.7 | 8.4 | 13.5 | 14.2 | 13.1 | 17.8 | 15.8 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.1 | 14.9 | 17.7 | 17.7 | 16.2 | 12.9 | 8.4 | 12.7 | 13.4 | 12.4 | 16.5 | 14.8 |
| **HCC Total** | | **659.8** | **765.6** | **811.1** | **1,032.6** | **919.9** | **932.0** | **565.5** | **376.5** | **487.8** | **437.3** | **343.7** | **544.9** | **656.4** |
| **ROR Total** | | **326.4** | **323.5** | **263.5** | **397.9** | **406.0** | **361.8** | **286.3** | **215.1** | **227.9** | **201.0** | **186.2** | **273.2** | **289.1** |
| **Total** | | **986.2** | **1,089.1** | **1,074.6** | **1,430.5** | **1,325.9** | **1,293.8** | **851.8** | **591.6** | **715.6** | **638.3** | **529.9** | **818.1** | **945.4** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2029** | **2/2029** | **3/2029** | **4/2029** | **5/2029** | **6/2029** | **7/2029** | **8/2029** | **9/2029** | **10/2029** | **11/2029** | **12/2029** | **aMW** |
| Brownlee | HCC* | 295.5 | 344.4 | 341.4 | 440.0 | 411.9 | 417.9 | 249.0 | 159.2 | 205.8 | 185.0 | 145.0 | 238.8 | 286.2 |
| Oxbow | HCC | 122.3 | 148.5 | 154.7 | 193.8 | 168.8 | 169.7 | 105.8 | 72.8 | 93.9 | 84.9 | 66.1 | 101.3 | 123.5 |
| Hells Canyon | HCC | 240.8 | 294.9 | 312.5 | 396.9 | 348.2 | 342.5 | 209.7 | 143.4 | 184.5 | 167.5 | 132.0 | 201.1 | 247.8 |
| American Falls | ROR | 22.9 | 24.9 | 21.3 | 56.4 | 86.3 | 94.5 | 86.8 | 66.1 | 42.0 | 13.4 | – | 13.7 | 44.0 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 46.4 | 46.7 | 39.2 | 52.0 | 50.0 | 42.0 | 34.9 | 27.5 | 35.9 | 37.2 | 35.5 | 41.1 | 40.7 |
| C .J. Strike | ROR | 60.2 | 61.7 | 53.1 | 65.7 | 63.0 | 51.6 | 36.2 | 30.5 | 42.7 | 47.0 | 46.0 | 52.6 | 50.9 |
| Cascade | ROR | 1.5 | 1.5 | 2.5 | 5.9 | 5.4 | 11.6 | 10.4 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 31.9 | 32.3 | 25.0 | 35.9 | 35.4 | 28.3 | 22.5 | 15.3 | 22.2 | 23.4 | 21.9 | 27.4 | 26.8 |
| Milner | ROR | 33.5 | 35.4 | 14.4 | 42.4 | 34.2 | 19.0 | 6.4 | – | – | – | – | 19.3 | 17.1 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 8.8 | 12.0 | 10.4 |
| Swan Falls | ROR | 19.4 | 19.9 | 17.3 | 21.2 | 20.4 | 17.0 | 12.7 | 10.7 | 14.4 | 15.5 | 15.3 | 17.4 | 16.8 |
| Twin Falls | ROR | 34.0 | 35.9 | 17.6 | 41.2 | 34.6 | 23.3 | 10.7 | – | – | – | 5.2 | 21.7 | 18.7 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.2 | 15.8 | 19.1 | 17.6 | 18.1 | 13.6 | 8.3 | 13.3 | 14.1 | 12.9 | 17.3 | 15.7 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.7 | 17.7 | 17.7 | 16.2 | 12.8 | 8.3 | 12.6 | 13.3 | 12.3 | 16.0 | 14.8 |
| **HCC Total** | | **658.6** | **787.8** | **808.6** | **1,030.7** | **928.8** | **930.1** | **564.5** | **375.4** | **484.1** | **437.4** | **343.1** | **541.2** | **657.5** |
| **ROR Total** | | **324.5** | **333.4** | **260.1** | **396.9** | **405.3** | **360.3** | **285.5** | **214.1** | **226.8** | **200.2** | **185.4** | **265.8** | **288.2** |
| **Total** | | **983.1** | **1,121.2** | **1,068.7** | **1,427.6** | **1,334.1** | **1,290.4** | **850.0** | **589.5** | **710.9** | **637.6** | **528.5** | **807.0** | **945.7** |

*HCC=Hells Canyon Complex, **ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2030** | **2/2030** | **3/2030** | **4/2030** | **5/2030** | **6/2030** | **7/2030** | **8/2030** | **9/2030** | **10/2030** | **11/2030** | **12/2030** | **aMW** |
| Brownlee | HCC* | 295.1 | 343.8 | 341.0 | 439.6 | 411.7 | 417.0 | 248.5 | 158.7 | 204.2 | 185.5 | 144.7 | 238.5 | 285.7 |
| Oxbow | HCC | 122.2 | 148.2 | 154.6 | 193.7 | 168.7 | 169.3 | 105.6 | 72.6 | 93.2 | 85.0 | 66.0 | 101.2 | 123.4 |
| Hells Canyon | HCC | 240.5 | 294.4 | 312.1 | 396.5 | 348.1 | 341.8 | 209.3 | 143.0 | 182.8 | 167.7 | 131.8 | 200.9 | 247.4 |
| American Falls | ROR | 22.7 | 24.8 | 21.1 | 56.3 | 86.2 | 94.5 | 86.9 | 66.0 | 41.9 | 13.4 | – | 13.0 | 43.9 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 46.2 | 46.5 | 38.9 | 51.4 | 49.9 | 41.8 | 34.8 | 27.4 | 35.8 | 37.0 | 35.3 | 40.3 | 40.4 |
| C .J. Strike | ROR | 59.9 | 61.5 | 52.8 | 65.5 | 62.9 | 51.3 | 36.0 | 30.3 | 42.5 | 46.8 | 45.6 | 51.7 | 50.6 |
| Cascade | ROR | 1.5 | 1.5 | 2.5 | 5.9 | 5.4 | 11.6 | 10.4 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 31.8 | 32.1 | 24.9 | 35.8 | 35.3 | 28.1 | 22.3 | 15.2 | 22.0 | 23.3 | 21.5 | 26.6 | 26.6 |
| Milner | ROR | 33.2 | 35.3 | 14.1 | 42.2 | 33.9 | 18.7 | 6.4 | – | – | – | – | 17.3 | 16.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 8.5 | 12.0 | 10.4 |
| Swan Falls | ROR | 19.3 | 19.8 | 17.2 | 21.2 | 20.3 | 16.9 | 12.7 | 10.7 | 14.3 | 15.5 | 15.4 | 17.1 | 16.7 |
| Twin Falls | ROR | 33.9 | 35.8 | 17.5 | 41.1 | 34.3 | 23.1 | 10.7 | – | – | – | 4.8 | 19.9 | 18.4 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.2 | 15.7 | 19.1 | 17.6 | 18.0 | 13.5 | 8.2 | 13.2 | 14.0 | 12.6 | 16.7 | 15.6 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.6 | 17.7 | 17.7 | 16.2 | 12.8 | 8.2 | 12.5 | 13.2 | 12.0 | 15.5 | 14.7 |
| **HCC Total** | | **657.8** | **786.4** | **807.7** | **1,029.8** | **928.4** | **928.1** | **563.4** | **374.3** | **480.1** | **438.2** | **342.5** | **540.6** | **656.4** |
| **ROR Total** | | **323.2** | **332.4** | **258.5** | **395.6** | **404.2** | **358.9** | **285.0** | **213.4** | **225.9** | **199.5** | **183.2** | **257.4** | **286.4** |
| **Total** | | **981.0** | **1,118.8** | **1,066.2** | **1,425.4** | **1,332.6** | **1,287.0** | **848.4** | **587.7** | **706.0** | **637.7** | **525.7** | **798.0** | **942.9** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Modeling Results (PDR580) (continued)

**Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load**

| Resource | Type | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 294.7 | 343.1 | 342.7 | 439.2 | 411.3 | 415.6 | 248.0 | 158.2 | 202.5 | 185.4 | 144.8 | 238.2 | 285.3 |
| Oxbow | HCC | 122.0 | 147.9 | 155.3 | 193.5 | 168.5 | 168.8 | 105.4 | 72.4 | 92.2 | 84.8 | 66.0 | 101.0 | 123.2 |
| Hells Canyon | HCC | 240.1 | 293.8 | 313.6 | 396.2 | 347.8 | 340.7 | 208.9 | 142.5 | 181.1 | 167.4 | 131.7 | 200.6 | 247.0 |
| American Falls | ROR | 22.6 | 24.7 | 21.0 | 56.2 | 86.1 | 94.3 | 86.8 | 66.0 | 41.8 | 13.4 | – | 11.7 | 43.7 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 46.0 | 46.4 | 38.7 | 51.0 | 49.8 | 41.8 | 34.7 | 27.2 | 35.6 | 36.9 | 35.1 | 39.3 | 40.2 |
| C .J. Strike | ROR | 59.7 | 61.3 | 52.3 | 65.3 | 62.8 | 51.0 | 35.9 | 30.2 | 42.2 | 46.5 | 45.0 | 50.4 | 50.2 |
| Cascade | ROR | 1.5 | 1.5 | 2.5 | 5.9 | 5.4 | 11.6 | 10.4 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 31.6 | 32.0 | 24.9 | 35.4 | 35.2 | 27.9 | 22.2 | 15.0 | 21.8 | 23.1 | 21.5 | 25.7 | 26.4 |
| Milner | ROR | 33.0 | 35.1 | 14.0 | 40.4 | 33.6 | 18.4 | 6.4 | – | – | – | – | 14.9 | 16.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 9.5 | 12.0 | 10.5 |
| Swan Falls | ROR | 19.3 | 19.7 | 17.2 | 21.1 | 20.3 | 16.8 | 12.7 | 10.6 | 14.3 | 15.4 | 15.2 | 16.7 | 16.6 |
| Twin Falls | ROR | 33.8 | 35.7 | 17.3 | 39.6 | 34.0 | 22.9 | 10.7 | – | – | – | 5.8 | 17.8 | 18.1 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.2 | 15.6 | 19.1 | 17.6 | 17.8 | 13.5 | 8.1 | 13.1 | 13.9 | 12.7 | 16.0 | 15.5 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.6 | 17.7 | 17.7 | 16.2 | 12.7 | 8.2 | 12.4 | 13.1 | 12.0 | 14.9 | 14.6 |
| **HCC Total** | | **656.8** | **784.8** | **811.6** | **1,028.9** | **927.5** | **925.1** | **562.3** | **373.1** | **475.8** | **437.6** | **342.5** | **539.8** | **655.5** |
| **ROR Total** | | **322.2** | **331.5** | **257.3** | **391.1** | **403.2** | **357.4** | **284.5** | **212.7** | **224.9** | **198.6** | **184.3** | **246.7** | **284.5** |
| **Total** | | **979.0** | **1,116.3** | **1,068.9** | **1,420.0** | **1,330.7** | **1,282.5** | **846.8** | **585.8** | **700.7** | **636.2** | **526.8** | **786.5** | **940.0** |

*HCC=Hells Canyon Complex, **ROR= Run of River

**Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load**

| Resource | Type | 1/2032 | 2/2032 | 3/2032 | 4/2032 | 5/2032 | 6/2032 | 7/2032 | 8/2032 | 9/2032 | 10/2032 | 11/2032 | 12/2032 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 294.3 | 330.5 | 342.3 | 438.7 | 410.9 | 414.5 | 247.5 | 157.6 | 200.5 | 185.9 | 145.2 | 236.8 | 283.7 |
| Oxbow | HCC | 121.9 | 142.5 | 155.1 | 193.3 | 168.4 | 168.3 | 105.2 | 72.1 | 91.2 | 84.9 | 66.1 | 100.4 | 122.4 |
| Hells Canyon | HCC | 239.8 | 283.1 | 313.2 | 395.8 | 347.5 | 339.8 | 208.5 | 142.0 | 179.1 | 167.6 | 132.0 | 199.4 | 245.6 |
| American Falls | ROR | 22.5 | 23.8 | 20.8 | 56.0 | 86.0 | 94.2 | 86.8 | 65.9 | 41.7 | 13.5 | – | 10.5 | 43.5 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 45.9 | 44.6 | 38.6 | 50.9 | 49.7 | 41.8 | 34.5 | 27.1 | 35.4 | 36.8 | 34.9 | 38.4 | 39.9 |
| C .J. Strike | ROR | 59.4 | 58.9 | 51.8 | 65.0 | 62.8 | 50.7 | 35.7 | 30.0 | 42.0 | 46.3 | 44.9 | 49.2 | 49.7 |
| Cascade | ROR | 1.5 | 1.4 | 2.5 | 5.9 | 5.4 | 11.6 | 10.4 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 31.5 | 30.7 | 24.7 | 35.2 | 35.1 | 27.7 | 22.1 | 14.9 | 21.6 | 23.0 | 21.3 | 24.9 | 26.1 |
| Milner | ROR | 32.8 | 33.7 | 13.9 | 39.3 | 33.3 | 18.2 | 6.4 | – | – | – | – | 12.6 | 15.8 |
| Shoshone Falls | ROR | 12.0 | 11.6 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 9.5 | 12.0 | 10.4 |
| Swan Falls | ROR | 19.2 | 19.0 | 17.1 | 21.1 | 20.3 | 16.7 | 12.6 | 10.5 | 14.2 | 15.4 | 15.2 | 16.2 | 16.5 |
| Twin Falls | ROR | 33.7 | 34.3 | 17.1 | 38.5 | 33.8 | 22.5 | 10.7 | – | – | – | 5.8 | 15.9 | 17.7 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 19.2 | 18.5 | 15.5 | 19.1 | 17.6 | 17.7 | 13.4 | 8.0 | 12.9 | 13.8 | 12.5 | 15.4 | 15.3 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.1 | 14.5 | 17.7 | 17.7 | 16.2 | 12.6 | 8.1 | 12.3 | 13.0 | 11.9 | 14.4 | 14.4 |
| **HCC Total** | | **656.0** | **756.1** | **810.6** | **1,027.8** | **926.7** | **922.6** | **561.2** | **371.7** | **470.8** | **438.4** | **343.3** | **536.6** | **651.8** |
| **ROR Total** | | **321.2** | **319.8** | **255.7** | **388.1** | **402.4** | **356.0** | **283.7** | **211.9** | **223.8** | **198.1** | **183.5** | **236.8** | **281.7** |
| **Total** | | **977.2** | **1,075.9** | **1,066.3** | **1,415.9** | **1,329.1** | **1,278.6** | **844.9** | **583.6** | **694.6** | **636.5** | **526.8** | **773.4** | **933.6** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2033** | **2/2033** | **3/2033** | **4/2033** | **5/2033** | **6/2033** | **7/2033** | **8/2033** | **9/2033** | **10/2033** | **11/2033** | **12/2033** | **aMW** |
| Brownlee | HCC* | 293.9 | 341.6 | 341.7 | 438.3 | 410.4 | 413.7 | 247.0 | 157.1 | 199.1 | 186.1 | 145.0 | 235.6 | 284.1 |
| Oxbow | HCC | 121.7 | 147.3 | 154.9 | 193.1 | 168.2 | 168.0 | 105.0 | 71.9 | 90.5 | 84.9 | 66.0 | 99.9 | 122.6 |
| Hells Canyon | HCC | 239.5 | 292.6 | 312.8 | 395.4 | 347.1 | 339.2 | 208.1 | 141.6 | 177.7 | 167.6 | 131.8 | 198.4 | 246.0 |
| American Falls | ROR | 22.3 | 24.5 | 20.7 | 54.1 | 85.9 | 94.0 | 86.7 | 65.8 | 41.6 | 13.2 | – | 9.1 | 43.2 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 45.7 | 46.0 | 38.5 | 50.7 | 49.6 | 41.8 | 34.4 | 26.9 | 35.2 | 36.6 | 34.8 | 37.4 | 39.8 |
| C .J. Strike | ROR | 59.1 | 60.1 | 51.4 | 64.1 | 62.7 | 50.4 | 35.5 | 29.8 | 41.7 | 46.1 | 44.8 | 47.8 | 49.5 |
| Cascade | ROR | 1.5 | 1.5 | 2.5 | 5.9 | 5.4 | 11.6 | 10.4 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 31.4 | 31.7 | 24.5 | 35.1 | 35.0 | 27.5 | 22.0 | 14.8 | 21.5 | 22.8 | 21.2 | 24.0 | 26.0 |
| Milner | ROR | 32.7 | 34.8 | 13.5 | 39.1 | 32.9 | 17.7 | 6.4 | – | – | – | – | 10.8 | 15.7 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 9.5 | 12.0 | 10.5 |
| Swan Falls | ROR | 19.1 | 19.4 | 16.9 | 20.8 | 20.3 | 16.4 | 12.5 | 10.5 | 14.1 | 15.3 | 15.2 | 15.8 | 16.4 |
| Twin Falls | ROR | 33.6 | 35.4 | 16.9 | 38.4 | 33.5 | 21.4 | 10.7 | – | – | – | 5.8 | 13.7 | 17.5 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.2 | 15.4 | 19.1 | 17.6 | 17.5 | 13.3 | 7.9 | 12.8 | 13.6 | 12.4 | 14.7 | 15.2 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.4 | 17.7 | 17.7 | 16.2 | 12.6 | 8.0 | 12.1 | 12.9 | 11.8 | 13.8 | 14.4 |
| **HCC Total** | | **655.1** | **781.5** | **809.4** | **1,026.8** | **925.6** | **920.9** | **560.1** | **370.6** | **467.2** | **438.6** | **342.8** | **533.9** | **652.7** |
| **ROR Total** | | **320.1** | **328.5** | **253.9** | **384.4** | **401.3** | **353.2** | **283.0** | **211.1** | **222.7** | **196.8** | **183.0** | **226.4** | **280.4** |
| **Total** | | **975.2** | **1,110.0** | **1,063.3** | **1,411.2** | **1,326.9** | **1,274.1** | **843.1** | **581.7** | **689.9** | **635.4** | **525.8** | **760.3** | **933.1** |

*HCC=Hells Canyon Complex, **ROR= Run of River

| Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2034** | **2/2034** | **3/2034** | **4/2034** | **5/2034** | **6/2034** | **7/2034** | **8/2034** | **9/2034** | **10/2034** | **11/2034** | **12/2034** | **aMW** |
| Brownlee | HCC* | 293.2 | 340.9 | 341.1 | 437.8 | 409.9 | 412.8 | 246.5 | 156.6 | 197.2 | 186.7 | 145.1 | 234.4 | 283.5 |
| Oxbow | HCC | 121.4 | 147.0 | 154.6 | 192.9 | 168.0 | 167.7 | 104.8 | 71.6 | 89.4 | 85.0 | 66.0 | 99.4 | 122.3 |
| Hells Canyon | HCC | 239.0 | 292.0 | 312.2 | 395.0 | 346.7 | 338.5 | 207.7 | 141.2 | 175.7 | 167.8 | 131.8 | 197.4 | 245.4 |
| American Falls | ROR | 22.2 | 24.4 | 20.5 | 53.8 | 85.7 | 93.8 | 86.7 | 65.7 | 41.5 | 13.2 | – | 7.7 | 42.9 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 45.5 | 45.8 | 38.4 | 50.5 | 49.5 | 41.8 | 34.3 | 26.8 | 35.0 | 36.4 | 34.6 | 36.6 | 39.6 |
| C .J. Strike | ROR | 58.9 | 59.9 | 51.1 | 63.2 | 62.6 | 50.1 | 35.4 | 29.6 | 41.5 | 45.8 | 44.6 | 46.9 | 49.1 |
| Cascade | ROR | 1.5 | 1.5 | 2.5 | 5.9 | 5.4 | 11.6 | 10.4 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 31.3 | 31.5 | 24.3 | 35.0 | 34.9 | 27.3 | 21.9 | 14.7 | 21.3 | 22.6 | 21.2 | 23.7 | 25.8 |
| Milner | ROR | 32.6 | 34.6 | 13.3 | 38.9 | 32.6 | 17.2 | 6.4 | – | – | – | – | 8.7 | 15.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 9.4 | 12.0 | 10.4 |
| Swan Falls | ROR | 19.0 | 19.4 | 16.8 | 20.3 | 20.3 | 16.4 | 12.5 | 10.4 | 14.1 | 15.2 | 15.1 | 15.6 | 16.3 |
| Twin Falls | ROR | 33.5 | 35.2 | 16.4 | 38.2 | 33.4 | 21.3 | 10.7 | – | – | – | 5.7 | 11.6 | 17.2 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.2 | 15.2 | 19.1 | 17.6 | 17.4 | 13.2 | 7.8 | 12.7 | 13.5 | 12.4 | 14.5 | 15.2 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.2 | 17.7 | 17.7 | 16.1 | 12.5 | 7.9 | 12.0 | 12.8 | 11.8 | 13.6 | 14.3 |
| **HCC Total** | | **653.6** | **779.9** | **807.9** | **1,025.7** | **924.5** | **919.0** | **559.0** | **369.4** | **462.3** | **439.5** | **342.9** | **531.2** | **651.2** |
| **ROR Total** | | **319.2** | **327.4** | **251.9** | **382.0** | **400.4** | **351.7** | **282.5** | **210.3** | **221.8** | **195.8** | **182.3** | **218.2** | **278.6** |
| **Total** | | **972.8** | **1,107.3** | **1,059.8** | **1,407.7** | **1,324.9** | **1,270.7** | **841.5** | **579.7** | **684.1** | **635.3** | **525.2** | **749.4** | **929.9** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Modeling Results (PDR580) (continued)

**Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load**

| Resource | Type | 1/2035 | 2/2035 | 3/2035 | 4/2035 | 5/2035 | 6/2035 | 7/2035 | 8/2035 | 9/2035 | 10/2035 | 11/2035 | 12/2035 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 292.4 | 340.1 | 340.4 | 437.2 | 408.0 | 411.9 | 246.1 | 156.2 | 195.0 | 187.0 | 145.7 | 233.2 | 282.8 |
| Oxbow | HCC | 121.1 | 146.7 | 154.3 | 192.6 | 167.2 | 167.3 | 104.6 | 71.4 | 88.3 | 85.0 | 66.2 | 98.9 | 122.0 |
| Hells Canyon | HCC | 238.3 | 291.4 | 311.6 | 394.4 | 345.1 | 337.9 | 207.3 | 140.7 | 173.5 | 167.8 | 132.2 | 196.4 | 244.7 |
| American Falls | ROR | 22.0 | 24.2 | 20.0 | 53.7 | 85.6 | 93.6 | 86.7 | 65.7 | 41.4 | 13.2 | – | 6.2 | 42.7 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 45.3 | 45.6 | 38.0 | 49.8 | 49.4 | 41.6 | 34.2 | 26.6 | 34.8 | 36.1 | 34.4 | 36.3 | 39.3 |
| C .J. Strike | ROR | 58.6 | 59.6 | 50.8 | 62.6 | 62.5 | 49.8 | 35.2 | 29.4 | 41.3 | 45.6 | 44.1 | 46.3 | 48.8 |
| Cascade | ROR | 1.5 | 1.5 | 2.5 | 5.9 | 5.4 | 11.6 | 10.4 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 31.2 | 31.3 | 24.1 | 34.7 | 34.8 | 27.3 | 21.8 | 14.5 | 21.1 | 22.5 | 21.1 | 23.7 | 25.7 |
| Milner | ROR | 32.5 | 34.4 | 12.8 | 37.7 | 32.3 | 16.8 | 6.4 | – | – | – | – | 6.5 | 15.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 9.4 | 12.0 | 10.4 |
| Swan Falls | ROR | 18.9 | 19.3 | 16.5 | 20.1 | 20.2 | 16.3 | 12.4 | 10.4 | 14.1 | 15.4 | 15.1 | 15.6 | 16.2 |
| Twin Falls | ROR | 33.4 | 35.0 | 15.7 | 37.2 | 33.2 | 21.1 | 10.7 | – | – | – | 5.7 | 10.4 | 16.9 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 19.2 | 19.2 | 15.1 | 19.1 | 17.6 | 17.3 | 13.1 | 7.7 | 12.5 | 13.4 | 12.3 | 14.5 | 15.1 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.7 | 14.1 | 17.7 | 17.7 | 16.0 | 12.4 | 7.8 | 11.9 | 12.7 | 11.7 | 13.6 | 14.3 |
| **HCC Total** | | **651.8** | **778.2** | **806.3** | **1,024.2** | **920.2** | **917.1** | **558.0** | **368.3** | **456.7** | **439.8** | **344.1** | **528.5** | **649.4** |
| **ROR Total** | | **318.1** | **326.0** | **248.8** | **377.9** | **399.4** | **350.1** | **281.8** | **209.5** | **220.8** | **195.2** | **181.3** | **212.4** | **276.8** |
| **Total** | | **969.9** | **1,104.2** | **1,055.1** | **1,402.1** | **1,319.6** | **1,267.2** | **839.8** | **577.8** | **677.5** | **635.0** | **525.4** | **740.9** | **926.2** |

*HCC=Hells Canyon Complex, **ROR= Run of River

**Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load**

| Resource | Type | 1/2036 | 2/2036 | 3/2036 | 4/2036 | 5/2036 | 6/2036 | 7/2036 | 8/2036 | 9/2036 | 10/2036 | 11/2036 | 12/2036 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 291.5 | 326.6 | 339.6 | 437.1 | 407.1 | 411.0 | 245.6 | 155.6 | 193.9 | 187.2 | 145.7 | 233.2 | 281.2 |
| Oxbow | HCC | 120.7 | 140.9 | 153.8 | 192.3 | 166.8 | 167.0 | 104.3 | 71.2 | 87.7 | 85.0 | 66.2 | 98.9 | 121.2 |
| Hells Canyon | HCC | 237.6 | 279.8 | 310.7 | 393.8 | 344.4 | 337.2 | 206.9 | 140.2 | 172.3 | 167.7 | 132.1 | 196.4 | 243.3 |
| American Falls | ROR | 21.7 | 23.3 | 19.8 | 53.5 | 84.4 | 93.3 | 86.7 | 65.7 | 41.3 | 13.1 | – | – | 41.9 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 45.1 | 43.9 | 37.8 | 49.6 | 49.2 | 41.1 | 34.0 | 26.5 | 34.6 | 35.9 | 34.3 | 36.3 | 39.0 |
| C .J. Strike | ROR | 58.3 | 57.2 | 50.5 | 62.3 | 62.4 | 49.5 | 35.1 | 29.2 | 41.1 | 45.4 | 44.0 | 46.1 | 48.4 |
| Cascade | ROR | 1.5 | 1.4 | 2.5 | 5.9 | 5.4 | 11.6 | 10.4 | 13.3 | 8.8 | 1.9 | 1.4 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 31.0 | 30.1 | 23.9 | 34.4 | 33.9 | 26.9 | 21.7 | 14.4 | 20.9 | 22.3 | 20.8 | 23.7 | 25.3 |
| Milner | ROR | 32.1 | 33.0 | 12.3 | 36.9 | 30.3 | 16.5 | 6.4 | – | – | – | – | 6.1 | 14.5 |
| Shoshone Falls | ROR | 12.0 | 11.6 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 9.4 | 12.0 | 10.4 |
| Swan Falls | ROR | 18.9 | 18.4 | 16.4 | 20.1 | 20.2 | 16.2 | 12.4 | 10.3 | 14.0 | 15.3 | 15.1 | 15.6 | 16.1 |
| Twin Falls | ROR | 33.1 | 33.7 | 15.3 | 36.4 | 31.6 | 20.5 | 10.7 | – | – | – | 5.7 | 10.4 | 16.4 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 19.2 | 18.5 | 14.9 | 19.1 | 17.6 | 17.0 | 13.0 | 7.6 | 12.4 | 13.3 | 12.1 | 14.5 | 14.9 |
| Upper Salmon 3&4 | ROR | 17.7 | 17.1 | 14.0 | 17.7 | 17.7 | 15.8 | 12.3 | 7.7 | 11.8 | 12.6 | 11.6 | 13.6 | 14.1 |
| **HCC Total** | | **649.8** | **747.3** | **804.1** | **1,023.2** | **918.2** | **915.2** | **556.8** | **367.0** | **453.9** | **439.9** | **344.0** | **528.5** | **645.7** |
| **ROR Total** | | **316.4** | **314.5** | **246.6** | **375.3** | **393.4** | **347.1** | **281.2** | **208.8** | **219.8** | **194.2** | **180.5** | **205.6** | **273.6** |
| **Total** | | **966.2** | **1,061.8** | **1,050.7** | **1,398.5** | **1,311.6** | **1,262.3** | **838.0** | **575.8** | **673.6** | **634.1** | **524.5** | **734.1** | **919.3** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Modeling Results (PDR580) (continued)

**Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2017 | 2/2017 | 3/2017 | 4/2017 | 5/2017 | 6/2017 | 7/2017 | 8/2017 | 9/2017 | 10/2017 | 11/2017 | 12/2017 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 257.2 | 286.1 | 251.4 | 319.5 | 385.2 | 258.9 | 237.4 | 155.6 | 175.9 | 190.1 | 148.0 | 200.6 | 238.8 |
| Oxbow | HCC | 108.9 | 121.3 | 111.6 | 135.3 | 159.8 | 108.8 | 100.5 | 71.1 | 80.0 | 84.7 | 66.4 | 84.6 | 102.7 |
| Hells Canyon | HCC | 215.6 | 239.8 | 227.7 | 274.0 | 324.5 | 223.1 | 198.2 | 139.8 | 156.9 | 167.0 | 132.2 | 167.8 | 205.5 |
| American Falls | ROR | – | 5.5 | 11.2 | 38.4 | 73.8 | 90.9 | 87.2 | 63.0 | 35.9 | 10.3 | – | – | 34.7 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.4 | 37.4 | 35.9 | 38.5 | 41.5 | 38.9 | 35.0 | 27.9 | 36.7 | 37.3 | 35.2 | 35.4 | 36.3 |
| C .J. Strike | ROR | 47.4 | 49.4 | 47.7 | 51.6 | 49.1 | 44.7 | 35.6 | 30.8 | 43.6 | 47.0 | 45.4 | 45.4 | 44.8 |
| Cascade | ROR | 1.5 | 1.4 | 1.3 | 1.2 | 2.1 | 7.1 | 7.4 | 12.0 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 22.8 | 23.0 | 21.9 | 24.5 | 27.8 | 27.0 | 22.6 | 15.8 | 23.1 | 23.8 | 22.2 | 22.2 | 23.1 |
| Milner | ROR | 4.8 | 6.1 | 3.6 | 11.4 | 14.4 | 14.7 | 6.4 | – | – | – | – | 1.8 | 5.3 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 7.3 | 9.9 | 10.1 |
| Swan Falls | ROR | 15.5 | 16.0 | 15.8 | 17.1 | 16.2 | 15.1 | 12.6 | 10.8 | 14.7 | 15.6 | 15.3 | 15.3 | 15.0 |
| Twin Falls | ROR | 8.9 | 9.8 | 8.1 | 14.3 | 17.8 | 18.2 | 10.7 | – | – | – | 3.8 | 6.2 | 8.2 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 13.8 | 14.1 | 13.4 | 15.4 | 17.7 | 17.1 | 13.8 | 8.7 | 14.1 | 14.4 | 13.2 | 13.3 | 14.1 |
| Upper Salmon 3&4 | ROR | 13.0 | 13.3 | 12.6 | 14.4 | 16.6 | 15.8 | 13.0 | 8.6 | 13.2 | 13.6 | 12.5 | 12.6 | 13.3 |
| **HCC Total** | | **581.7** | **647.2** | **590.7** | **728.8** | **869.5** | **590.8** | **536.1** | **366.5** | **412.7** | **441.8** | **346.6** | **453.0** | **547.1** |
| **ROR Total** | | **201.9** | **214.2** | **210.7** | **266.2** | **317.7** | **328.2** | **282.8** | **211.7** | **223.5** | **197.9** | **182.3** | **189.4** | **235.5** |
| **Total** | | **783.6** | **861.4** | **801.4** | **995.0** | **1,187.2** | **919.0** | **818.9** | **578.2** | **636.2** | **639.7** | **528.9** | **642.4** | **782.7** |

*HCC=Hells Canyon Complex, **ROR= Run of River

**Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2018 | 2/2018 | 3/2018 | 4/2018 | 5/2018 | 6/2018 | 7/2018 | 8/2018 | 9/2018 | 10/2018 | 11/2018 | 12/2018 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 249.6 | 296.3 | 252.8 | 324.7 | 384.9 | 264.9 | 237.0 | 155.1 | 176.1 | 189.9 | 147.7 | 205.0 | 289.5 |
| Oxbow | HCC | 106.1 | 125.6 | 112.3 | 137.6 | 159.8 | 111.4 | 100.4 | 70.9 | 80.0 | 84.7 | 66.3 | 86.4 | 125.0 |
| Hells Canyon | HCC | 210.2 | 248.2 | 229.0 | 278.4 | 324.4 | 228.0 | 197.9 | 139.3 | 157.0 | 166.9 | 132.0 | 171.4 | 250.5 |
| American Falls | ROR | – | 11.0 | 13.9 | 40.8 | 73.8 | 91.4 | 87.2 | 63.7 | 36.3 | 10.3 | – | – | 43.6 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.4 | 38.6 | 36.7 | 41.6 | 42.0 | 39.1 | 35.1 | 27.9 | 36.8 | 37.3 | 35.3 | 35.3 | 41.6 |
| C .J. Strike | ROR | 47.5 | 50.3 | 48.2 | 52.8 | 49.5 | 45.2 | 35.7 | 31.0 | 43.6 | 47.1 | 45.2 | 45.5 | 52.0 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.2 | 2.1 | 7.1 | 7.4 | 12.0 | 7.3 | 1.5 | 1.3 | 1.4 | 5.5 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 22.8 | 25.3 | 22.6 | 25.6 | 28.2 | 27.2 | 22.7 | 15.8 | 23.1 | 23.9 | 22.1 | 22.2 | 27.6 |
| Milner | ROR | 4.3 | 13.3 | 5.0 | 13.6 | 15.4 | 15.4 | 6.4 | – | – | – | – | – | 16.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 6.6 | 9.4 | 10.5 |
| Swan Falls | ROR | 15.5 | 16.2 | 15.8 | 17.4 | 16.5 | 15.3 | 12.7 | 10.8 | 14.7 | 15.6 | 15.3 | 15.2 | 17.1 |
| Twin Falls | ROR | 8.8 | 16.0 | 9.2 | 16.8 | 18.1 | 18.7 | 10.7 | – | – | – | – | 5.7 | 18.8 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 13.8 | 15.9 | 13.9 | 16.3 | 17.7 | 17.2 | 13.8 | 8.7 | 14.1 | 14.5 | 13.1 | 13.3 | 16.2 |
| Upper Salmon 3&4 | ROR | 13.0 | 14.8 | 13.1 | 15.1 | 16.8 | 16.0 | 13.0 | 8.6 | 13.2 | 13.6 | 12.4 | 12.6 | 15.1 |
| **HCC Total** | | **565.9** | **670.1** | **594.1** | **740.7** | **869.1** | **604.3** | **535.3** | **365.3** | **413.1** | **441.5** | **346.0** | **462.8** | **665.0** |
| **ROR Total** | | **201.3** | **241.0** | **218.9** | **280.6** | **320.8** | **331.3** | **283.2** | **212.6** | **224.0** | **198.2** | **177.4** | **186.5** | **291.7** |
| **Total** | | **767.2** | **911.1** | **813.0** | **1,021.3** | **1,189.9** | **935.6** | **818.5** | **577.9** | **637.1** | **639.7** | **523.4** | **649.3** | **956.6** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

**Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 247.0 | 296.0 | 250.8 | 325.1 | 386.3 | 269.2 | 237.3 | 155.2 | 173.8 | 191.0 | 147.7 | 203.3 | 240.2 |
| Oxbow | HCC | 105.1 | 125.5 | 111.5 | 137.8 | 160.3 | 113.2 | 100.5 | 70.9 | 78.8 | 84.9 | 66.2 | 85.7 | 103.4 |
| Hells Canyon | HCC | 208.1 | 248.0 | 227.4 | 278.9 | 325.5 | 231.5 | 198.2 | 139.5 | 154.6 | 167.4 | 131.9 | 170.0 | 206.8 |
| American Falls | ROR | – | 14.2 | 13.9 | 40.0 | 73.9 | 91.5 | 87.5 | 64.0 | 36.7 | 10.4 | – | – | 36.0 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.0 | 38.9 | 36.8 | 41.5 | 42.3 | 39.1 | 35.1 | 27.9 | 36.8 | 37.3 | 34.7 | 34.7 | 36.8 |
| C .J. Strike | ROR | 46.6 | 51.5 | 47.6 | 53.4 | 50.3 | 45.3 | 35.8 | 31.0 | 43.6 | 47.1 | 44.8 | 45.1 | 45.2 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.2 | 2.1 | 7.1 | 7.4 | 12.0 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 22.2 | 25.9 | 22.2 | 26.2 | 28.4 | 27.2 | 22.7 | 15.8 | 23.1 | 23.9 | 21.7 | 21.7 | 23.4 |
| Milner | ROR | 2.6 | 16.1 | 3.6 | 15.3 | 15.4 | 15.4 | 6.4 | – | – | – | – | – | 6.2 |
| Shoshone Falls | ROR | 11.2 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 5.4 | 8.3 | 9.7 |
| Swan Falls | ROR | 15.3 | 16.4 | 15.7 | 17.6 | 16.7 | 15.4 | 12.7 | 10.9 | 14.6 | 15.6 | 15.2 | 15.3 | 15.1 |
| Twin Falls | ROR | 7.3 | 17.8 | 8.3 | 18.2 | 18.2 | 18.9 | 10.7 | – | – | – | – | 4.5 | 8.7 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 13.4 | 16.3 | 13.6 | 16.7 | 17.7 | 17.2 | 13.8 | 8.7 | 14.0 | 14.5 | 12.8 | 12.9 | 14.3 |
| Upper Salmon 3&4 | ROR | 12.6 | 15.2 | 12.8 | 15.5 | 17.0 | 16.0 | 13.0 | 8.7 | 13.2 | 13.6 | 12.2 | 12.2 | 13.5 |
| **HCC Total** | | **560.2** | **669.5** | **589.7** | **741.8** | **872.1** | **613.9** | **536.0** | **365.6** | **407.2** | **443.3** | **345.8** | **459.0** | **550.3** |
| **ROR Total** | | **194.4** | **251.9** | **215.0** | **285.0** | **322.7** | **331.8** | **283.6** | **213.1** | **224.2** | **198.3** | **174.2** | **182.0** | **239.7** |
| **Total** | | **754.6** | **921.4** | **804.7** | **1,026.8** | **1,194.8** | **945.7** | **819.6** | **578.7** | **631.4** | **641.6** | **520.0** | **641.0** | **790.0** |

*HCC=Hells Canyon Complex, **ROR= Run of River

**Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 247.2 | 296.0 | 250.8 | 325.2 | 387.4 | 269.5 | 237.1 | 155.0 | 173.5 | 190.9 | 147.6 | 203.9 | 240.3 |
| Oxbow | HCC | 105.1 | 125.5 | 111.5 | 137.9 | 160.8 | 113.3 | 100.4 | 70.8 | 78.6 | 84.9 | 66.2 | 86.0 | 103.4 |
| Hells Canyon | HCC | 208.2 | 248.0 | 227.5 | 279.0 | 326.3 | 231.8 | 198.1 | 139.3 | 154.3 | 167.3 | 131.8 | 170.5 | 206.8 |
| American Falls | ROR | – | 14.8 | 13.9 | 40.3 | 73.9 | 91.5 | 87.5 | 64.0 | 36.7 | 10.4 | – | – | 36.1 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.0 | 39.3 | 36.9 | 41.6 | 42.4 | 39.1 | 35.1 | 27.9 | 36.7 | 37.3 | 34.6 | 34.7 | 36.8 |
| C .J. Strike | ROR | 46.6 | 51.5 | 47.7 | 53.5 | 50.5 | 45.2 | 35.8 | 31.0 | 43.4 | 47.0 | 44.8 | 45.1 | 45.2 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.2 | 2.1 | 7.1 | 7.4 | 12.0 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 22.2 | 26.0 | 22.2 | 26.3 | 28.4 | 27.1 | 22.7 | 15.8 | 23.0 | 23.8 | 21.7 | 21.7 | 23.4 |
| Milner | ROR | 2.6 | 17.3 | 3.6 | 15.5 | 15.4 | 15.4 | 6.4 | – | – | – | – | – | 6.4 |
| Shoshone Falls | ROR | 11.2 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 5.4 | 8.3 | 9.7 |
| Swan Falls | ROR | 15.3 | 16.5 | 15.8 | 17.6 | 16.8 | 15.4 | 12.7 | 10.8 | 14.6 | 15.6 | 15.2 | 15.3 | 15.1 |
| Twin Falls | ROR | 7.3 | 18.8 | 8.3 | 18.4 | 18.2 | 19.2 | 10.7 | – | – | – | – | 4.5 | 8.8 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 13.4 | 16.4 | 13.6 | 16.8 | 17.7 | 17.2 | 13.8 | 8.7 | 13.9 | 14.4 | 12.8 | 12.9 | 14.3 |
| Upper Salmon 3&4 | ROR | 12.6 | 15.3 | 12.8 | 15.6 | 17.0 | 15.9 | 13.0 | 8.6 | 13.1 | 13.6 | 12.1 | 12.2 | 13.5 |
| **HCC Total** | | **560.5** | **669.5** | **589.8** | **742.1** | **874.5** | **614.6** | **535.6** | **365.1** | **406.4** | **443.1** | **345.6** | **460.4** | **550.6** |
| **ROR Total** | | **194.4** | **255.5** | **215.3** | **286.2** | **323.1** | **331.8** | **283.6** | **212.9** | **223.6** | **198.0** | **174.0** | **182.0** | **240.0** |
| **Total** | | **754.9** | **925.0** | **805.1** | **1,028.3** | **1,197.6** | **946.4** | **819.2** | **578.0** | **629.9** | **641.1** | **519.6** | **642.4** | **790.6** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

**Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2021 | 2/2021 | 3/2021 | 4/2021 | 5/2021 | 6/2021 | 7/2021 | 8/2021 | 9/2021 | 10/2021 | 11/2021 | 12/2021 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 246.1 | 295.1 | 250.9 | 326.1 | 386.7 | 268.5 | 237.1 | 154.9 | 172.2 | 191.1 | 147.8 | 202.8 | 239.9 |
| Oxbow | HCC | 104.7 | 125.2 | 111.6 | 138.3 | 160.5 | 112.9 | 100.4 | 70.8 | 78.1 | 84.9 | 66.2 | 85.5 | 103.3 |
| Hells Canyon | HCC | 207.3 | 247.3 | 227.6 | 279.7 | 325.9 | 231.0 | 198.1 | 139.2 | 153.1 | 167.3 | 131.9 | 169.6 | 206.5 |
| American Falls | ROR | – | 15.0 | 13.9 | 40.8 | 73.9 | 91.5 | 87.5 | 63.9 | 36.6 | 10.4 | – | – | 36.1 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 35.8 | 39.0 | 36.6 | 41.8 | 42.5 | 39.1 | 35.1 | 27.9 | 36.6 | 37.2 | 34.6 | 34.4 | 36.7 |
| C .J. Strike | ROR | 46.3 | 51.1 | 47.5 | 53.8 | 50.6 | 45.2 | 35.8 | 30.9 | 43.3 | 46.9 | 44.7 | 45.0 | 45.1 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.2 | 2.1 | 7.1 | 7.4 | 12.0 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 22.0 | 25.3 | 22.0 | 26.4 | 28.6 | 27.1 | 22.7 | 15.7 | 22.9 | 23.8 | 21.6 | 21.4 | 23.3 |
| Milner | ROR | 1.7 | 16.2 | 3.5 | 15.6 | 15.4 | 15.4 | 6.4 | – | – | – | – | – | 6.2 |
| Shoshone Falls | ROR | 10.1 | 12.0 | 11.4 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 5.4 | 7.9 | 9.6 |
| Swan Falls | ROR | 15.4 | 16.3 | 15.7 | 17.7 | 16.8 | 15.3 | 12.7 | 10.8 | 14.6 | 15.5 | 15.2 | 15.2 | 15.1 |
| Twin Falls | ROR | 6.3 | 17.9 | 7.4 | 18.5 | 18.2 | 18.9 | 10.7 | – | – | – | – | 4.2 | 8.5 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 13.2 | 15.9 | 13.4 | 16.9 | 17.7 | 17.2 | 13.8 | 8.6 | 13.9 | 14.4 | 12.7 | 12.6 | 14.2 |
| Upper Salmon 3&4 | ROR | 12.5 | 14.8 | 12.7 | 15.7 | 17.1 | 15.9 | 13.0 | 8.6 | 13.1 | 13.5 | 12.1 | 12.0 | 13.4 |
| **HCC Total** | | **558.1** | **667.6** | **590.1** | **744.1** | **873.1** | **612.4** | **535.6** | **364.9** | **403.4** | **443.3** | **345.9** | **457.9** | **549.7** |
| **ROR Total** | | **190.5** | **251.1** | **212.6** | **287.8** | **323.6** | **331.4** | **283.6** | **212.5** | **223.2** | **197.6** | **173.7** | **180.0** | **239.0** |
| **Total** | | **748.6** | **918.7** | **802.7** | **1,031.9** | **1,196.7** | **943.8** | **819.2** | **577.4** | **626.5** | **640.9** | **519.6** | **637.9** | **788.7** |

*HCC=Hells Canyon Complex, **ROR= Run of River

**Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2022 | 2/2022 | 3/2022 | 4/2022 | 5/2022 | 6/2022 | 7/2022 | 8/2022 | 9/2022 | 10/2022 | 11/2022 | 12/2022 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 247.9 | 296.4 | 251.0 | 317.6 | 386.9 | 263.3 | 236.9 | 154.7 | 172.1 | 190.7 | 148.0 | 204.0 | 239.1 |
| Oxbow | HCC | 105.4 | 125.7 | 111.6 | 134.8 | 160.6 | 110.7 | 100.3 | 70.7 | 77.9 | 84.7 | 66.3 | 86.0 | 102.9 |
| Hells Canyon | HCC | 208.8 | 248.4 | 227.6 | 272.9 | 325.9 | 226.7 | 197.9 | 138.9 | 153.0 | 167.0 | 132.1 | 170.7 | 205.8 |
| American Falls | ROR | – | 12.0 | 13.7 | 38.0 | 74.3 | 91.5 | 87.4 | 63.9 | 36.2 | 10.3 | – | – | 35.6 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.1 | 39.2 | 36.3 | 37.2 | 42.3 | 39.0 | 35.0 | 27.8 | 36.5 | 37.2 | 34.7 | 34.9 | 36.4 |
| C .J. Strike | ROR | 46.9 | 51.6 | 47.4 | 50.9 | 50.7 | 45.1 | 35.7 | 30.8 | 43.1 | 46.8 | 44.6 | 45.3 | 44.9 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.2 | 2.1 | 7.1 | 7.4 | 12.0 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 22.4 | 25.3 | 22.1 | 22.9 | 28.6 | 27.0 | 22.6 | 15.6 | 22.7 | 23.7 | 21.6 | 21.8 | 23.0 |
| Milner | ROR | 3.2 | 13.5 | 3.4 | 5.1 | 15.4 | 15.4 | 6.4 | – | – | – | – | – | 5.2 |
| Shoshone Falls | ROR | 11.7 | 12.0 | 11.2 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 5.4 | 8.7 | 9.7 |
| Swan Falls | ROR | 15.4 | 16.7 | 15.7 | 16.9 | 16.9 | 15.3 | 12.7 | 10.8 | 14.5 | 15.5 | 15.2 | 15.3 | 15.1 |
| Twin Falls | ROR | 7.7 | 16.4 | 7.3 | 8.8 | 18.2 | 18.9 | 10.7 | – | – | – | – | 4.9 | 7.7 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 13.5 | 15.9 | 13.5 | 14.2 | 17.7 | 17.2 | 13.7 | 8.6 | 13.8 | 14.3 | 12.7 | 13.0 | 14.0 |
| Upper Salmon 3&4 | ROR | 12.7 | 14.8 | 12.8 | 13.4 | 17.2 | 15.9 | 12.9 | 8.5 | 13.0 | 13.4 | 12.1 | 12.3 | 13.3 |
| **HCC Total** | | **562.1** | **670.5** | **590.2** | **725.3** | **873.4** | **600.7** | **535.1** | **364.3** | **403.0** | **442.4** | **346.4** | **460.7** | **547.8** |
| **ROR Total** | | **196.8** | **245.0** | **211.9** | **248.0** | **324.1** | **331.1** | **283.0** | **212.1** | **222.0** | **197.1** | **173.7** | **183.5** | **235.7** |
| **Total** | | **758.9** | **915.5** | **802.1** | **973.3** | **1,197.4** | **931.8** | **818.1** | **576.4** | **624.9** | **639.5** | **520.1** | **644.2** | **783.5** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

**Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 247.7 | 296.1 | 250.8 | 317.6 | 387.5 | 262.9 | 236.6 | 154.3 | 167.1 | 190.8 | 148.3 | 203.1 | 238.6 |
| Oxbow | HCC | 105.3 | 125.6 | 111.4 | 134.7 | 160.8 | 110.5 | 100.2 | 70.5 | 77.3 | 84.7 | 66.4 | 85.7 | 102.8 |
| Hells Canyon | HCC | 208.6 | 248.0 | 227.4 | 272.7 | 326.4 | 226.4 | 197.6 | 138.6 | 151.5 | 167.0 | 132.3 | 169.9 | 205.5 |
| American Falls | ROR | – | 11.6 | 13.7 | 38.4 | 74.3 | 91.5 | 87.4 | 63.9 | 36.1 | 10.3 | – | – | 35.6 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.1 | 39.3 | 36.2 | 37.2 | 42.4 | 38.9 | 35.0 | 27.7 | 36.3 | 37.1 | 34.6 | 34.8 | 36.3 |
| C .J. Strike | ROR | 46.8 | 51.4 | 47.3 | 51.0 | 50.7 | 45.0 | 35.6 | 30.7 | 42.9 | 46.7 | 44.5 | 45.2 | 44.8 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.2 | 2.1 | 7.1 | 7.4 | 12.0 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 22.3 | 25.4 | 22.0 | 22.9 | 28.7 | 26.9 | 22.5 | 15.5 | 22.6 | 23.6 | 21.5 | 21.7 | 23.0 |
| Milner | ROR | 3.2 | 13.0 | 3.3 | 5.0 | 15.4 | 15.4 | 6.4 | – | – | – | – | – | 5.1 |
| Shoshone Falls | ROR | 11.7 | 12.0 | 11.2 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 5.4 | 8.7 | 9.7 |
| Swan Falls | ROR | 15.4 | 16.8 | 15.7 | 16.9 | 16.9 | 15.2 | 12.6 | 10.7 | 14.5 | 15.5 | 15.2 | 15.3 | 15.1 |
| Twin Falls | ROR | 7.7 | 16.4 | 7.3 | 8.7 | 18.2 | 18.9 | 10.7 | – | – | – | – | 4.9 | 7.7 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 13.5 | 16.0 | 13.5 | 14.2 | 17.7 | 17.1 | 13.7 | 8.5 | 13.7 | 14.2 | 12.7 | 12.9 | 14.0 |
| Upper Salmon 3&4 | ROR | 12.7 | 14.9 | 12.7 | 13.3 | 17.2 | 15.8 | 12.9 | 8.5 | 12.9 | 13.4 | 12.0 | 12.3 | 13.2 |
| **HCC Total** | | **561.6** | **669.7** | **589.6** | **725.0** | **874.7** | **599.8** | **534.4** | **363.4** | **395.8** | **442.5** | **347.0** | **458.7** | **546.9** |
| **ROR Total** | | **196.6** | **244.4** | **211.4** | **248.2** | **324.3** | **330.5** | **282.7** | **211.6** | **221.2** | **196.7** | **173.3** | **183.1** | **235.3** |
| **Total** | | **758.2** | **914.1** | **801.0** | **973.2** | **1,199.0** | **930.3** | **817.1** | **575.0** | **617.0** | **639.2** | **520.3** | **641.8** | **782.2** |

*HCC=Hells Canyon Complex, **ROR= Run of River

**Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 247.4 | 295.8 | 250.5 | 317.4 | 387.7 | 262.4 | 236.2 | 153.9 | 165.7 | 191.1 | 147.9 | 202.1 | 238.2 |
| Oxbow | HCC | 105.2 | 125.4 | 111.3 | 134.6 | 160.9 | 110.3 | 100.1 | 70.3 | 76.5 | 84.8 | 66.2 | 85.2 | 102.6 |
| Hells Canyon | HCC | 208.4 | 247.8 | 227.1 | 272.6 | 326.6 | 226.0 | 197.3 | 138.3 | 150.0 | 167.1 | 131.9 | 169.1 | 205.2 |
| American Falls | ROR | – | 10.8 | 13.6 | 38.6 | 74.3 | 91.5 | 87.3 | 63.7 | 36.1 | 10.3 | – | – | 35.5 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.1 | 38.9 | 36.1 | 37.1 | 42.4 | 38.8 | 34.9 | 27.6 | 36.1 | 37.0 | 34.5 | 34.7 | 36.2 |
| C .J. Strike | ROR | 46.7 | 50.8 | 47.2 | 51.0 | 50.7 | 44.8 | 35.5 | 30.5 | 42.7 | 46.5 | 44.3 | 45.1 | 44.7 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.2 | 2.1 | 7.1 | 7.4 | 12.0 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 22.3 | 25.0 | 21.9 | 22.8 | 28.7 | 26.8 | 22.4 | 15.4 | 22.5 | 23.4 | 21.4 | 21.6 | 22.9 |
| Milner | ROR | 3.2 | 12.5 | 3.2 | 5.0 | 15.4 | 15.4 | 6.4 | – | – | – | – | – | 5.1 |
| Shoshone Falls | ROR | 11.7 | 12.0 | 11.2 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 5.4 | 8.7 | 9.7 |
| Swan Falls | ROR | 15.3 | 16.4 | 15.6 | 16.9 | 16.9 | 15.2 | 12.6 | 10.7 | 14.4 | 15.4 | 15.2 | 15.3 | 15.0 |
| Twin Falls | ROR | 7.7 | 16.4 | 7.3 | 8.6 | 18.2 | 18.9 | 10.7 | – | – | – | – | 4.9 | 7.7 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 13.4 | 15.7 | 13.4 | 14.1 | 17.7 | 17.0 | 13.6 | 8.4 | 13.5 | 14.1 | 12.6 | 12.9 | 13.9 |
| Upper Salmon 3&4 | ROR | 12.7 | 14.6 | 12.6 | 13.3 | 17.2 | 15.8 | 12.8 | 8.4 | 12.8 | 13.3 | 12.0 | 12.2 | 13.1 |
| **HCC Total** | | **561.0** | **669.0** | **588.9** | **724.6** | **875.2** | **598.7** | **533.6** | **362.5** | **392.2** | **443.0** | **346.0** | **456.4** | **545.9** |
| **ROR Total** | | **196.3** | **240.7** | **210.6** | **248.0** | **324.3** | **330.0** | **282.1** | **210.8** | **220.3** | **195.9** | **172.8** | **182.7** | **234.5** |
| **Total** | | **757.3** | **909.7** | **799.5** | **972.6** | **1,199.5** | **928.7** | **815.7** | **573.3** | **612.5** | **638.9** | **518.8** | **639.1** | **780.5** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2025** | **2/2025** | **3/2025** | **4/2025** | **5/2025** | **6/2025** | **7/2025** | **8/2025** | **9/2025** | **10/2025** | **11/2025** | **12/2025** | **aMW** |
| Brownlee | HCC* | 247.1 | 295.6 | 249.8 | 317.4 | 387.8 | 261.9 | 235.8 | 153.5 | 164.1 | 191.2 | 148.2 | 200.7 | 237.8 |
| Oxbow | HCC | 105.1 | 125.3 | 111.0 | 134.6 | 160.9 | 110.1 | 99.9 | 70.1 | 75.6 | 84.7 | 66.3 | 84.6 | 102.3 |
| Hells Canyon | HCC | 208.1 | 247.6 | 226.5 | 272.6 | 326.6 | 225.6 | 197.0 | 137.9 | 148.4 | 166.9 | 132.0 | 167.9 | 204.8 |
| American Falls | ROR | – | 10.5 | 13.5 | 38.7 | 74.3 | 91.5 | 87.3 | 63.6 | 36.1 | 10.3 | – | – | 35.5 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.0 | 38.2 | 36.0 | 37.1 | 42.4 | 38.8 | 34.8 | 27.4 | 36.0 | 36.9 | 34.3 | 34.6 | 36.0 |
| C .J. Strike | ROR | 46.6 | 50.4 | 47.1 | 50.9 | 50.6 | 44.6 | 35.3 | 30.4 | 42.5 | 46.3 | 44.2 | 45.1 | 44.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.2 | 2.1 | 7.1 | 7.4 | 12.0 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 22.2 | 24.8 | 21.9 | 22.8 | 28.7 | 26.7 | 22.3 | 15.3 | 22.3 | 23.3 | 21.3 | 21.6 | 22.8 |
| Milner | ROR | 3.2 | 12.3 | 3.1 | 4.9 | 15.4 | 15.4 | 6.4 | – | – | – | – | – | 5.1 |
| Shoshone Falls | ROR | 11.7 | 12.0 | 11.2 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 5.4 | 8.7 | 9.7 |
| Swan Falls | ROR | 15.3 | 16.2 | 15.6 | 16.9 | 16.9 | 15.2 | 12.6 | 10.6 | 14.3 | 15.4 | 15.1 | 15.3 | 15.0 |
| Twin Falls | ROR | 7.7 | 16.1 | 7.3 | 8.4 | 18.2 | 18.9 | 10.7 | – | – | – | – | 4.9 | 7.7 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 13.3 | 15.5 | 13.4 | 14.1 | 17.7 | 16.9 | 13.5 | 8.3 | 13.4 | 14.0 | 12.5 | 12.8 | 13.8 |
| Upper Salmon 3&4 | ROR | 12.6 | 14.5 | 12.6 | 13.3 | 17.2 | 15.7 | 12.8 | 8.3 | 12.7 | 13.2 | 11.9 | 12.1 | 13.1 |
| **HCC Total** | | **560.3** | **668.5** | **587.3** | **724.6** | **875.3** | **597.6** | **532.7** | **361.5** | **388.0** | **442.8** | **346.5** | **453.2** | **544.9** |
| **ROR Total** | | **195.8** | **238.1** | **210.2** | **247.7** | **324.2** | **329.5** | **281.6** | **210.0** | **219.5** | **195.3** | **172.1** | **182.4** | **233.9** |
| **Total** | | **756.1** | **906.6** | **797.5** | **972.3** | **1,199.4** | **927.1** | **814.3** | **571.5** | **607.5** | **638.1** | **518.6** | **635.6** | **778.7** |

*HCC=Hells Canyon Complex, **ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2026** | **2/2026** | **3/2026** | **4/2026** | **5/2026** | **6/2026** | **7/2026** | **8/2026** | **9/2026** | **10/2026** | **11/2026** | **12/2026** | **aMW** |
| Brownlee | HCC* | 246.6 | 294.0 | 249.8 | 316.6 | 388.2 | 261.3 | 235.4 | 153.1 | 162.4 | 191.2 | 148.3 | 198.8 | 237.1 |
| Oxbow | HCC | 104.9 | 124.7 | 111.0 | 134.2 | 161.1 | 109.9 | 99.7 | 69.9 | 74.7 | 84.6 | 66.3 | 83.8 | 102.1 |
| Hells Canyon | HCC | 207.7 | 246.3 | 226.4 | 271.9 | 327.0 | 225.1 | 196.6 | 137.5 | 146.7 | 166.7 | 132.1 | 166.3 | 204.2 |
| American Falls | ROR | – | 10.1 | 13.4 | 38.8 | 74.3 | 91.5 | 87.3 | 63.5 | 36.0 | 10.2 | – | – | 35.4 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 36.0 | 37.2 | 35.9 | 36.9 | 42.5 | 38.7 | 34.7 | 27.3 | 35.8 | 36.8 | 34.2 | 34.5 | 35.9 |
| C .J. Strike | ROR | 46.5 | 50.0 | 46.9 | 50.8 | 50.6 | 44.5 | 35.2 | 30.2 | 42.2 | 46.1 | 43.9 | 45.0 | 44.3 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.2 | 2.1 | 7.1 | 7.4 | 12.0 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 22.1 | 24.5 | 21.8 | 22.8 | 28.8 | 26.6 | 22.2 | 15.2 | 22.1 | 23.1 | 21.1 | 21.5 | 22.7 |
| Milner | ROR | 3.2 | 12.1 | 2.6 | 4.7 | 15.4 | 15.4 | 6.4 | – | – | – | – | – | 5.0 |
| Shoshone Falls | ROR | 11.7 | 12.0 | 11.2 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 5.4 | 8.7 | 9.7 |
| Swan Falls | ROR | 15.3 | 15.9 | 15.6 | 16.9 | 16.9 | 15.1 | 12.5 | 10.6 | 14.3 | 15.3 | 15.0 | 15.2 | 14.9 |
| Twin Falls | ROR | 7.7 | 15.5 | 7.3 | 8.3 | 18.2 | 18.9 | 10.7 | – | – | – | – | 4.8 | 7.6 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 13.3 | 15.3 | 13.3 | 14.1 | 17.7 | 16.8 | 13.5 | 8.2 | 13.3 | 13.9 | 12.4 | 12.7 | 13.7 |
| Upper Salmon 3&4 | ROR | 12.6 | 14.3 | 12.6 | 13.3 | 17.2 | 15.6 | 12.7 | 8.3 | 12.6 | 13.1 | 11.8 | 12.1 | 13.0 |
| **HCC Total** | | **559.2** | **665.0** | **587.2** | **722.7** | **876.3** | **596.3** | **531.7** | **360.5** | **383.7** | **442.5** | **346.7** | **448.9** | **543.4** |
| **ROR Total** | | **195.6** | **234.5** | **209.1** | **247.2** | **324.4** | **328.9** | **281.1** | **209.4** | **218.5** | **194.4** | **171.2** | **181.8** | **233.0** |
| **Total** | | **754.8** | **899.5** | **796.3** | **969.9** | **1,200.6** | **925.2** | **812.8** | **569.9** | **602.2** | **636.9** | **517.9** | **630.7** | **776.4** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

**Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2027 | 2/2027 | 3/2027 | 4/2027 | 5/2027 | 6/2027 | 7/2027 | 8/2027 | 9/2027 | 10/2027 | 11/2027 | 12/2027 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 246.2 | 289.9 | 249.5 | 316.2 | 387.5 | 260.4 | 234.9 | 152.6 | 160.6 | 191.8 | 148.2 | 196.3 | 236.2 |
| Oxbow | HCC | 104.7 | 123.0 | 110.8 | 134.0 | 160.8 | 109.5 | 99.5 | 69.7 | 73.8 | 84.8 | 66.3 | 82.7 | 101.6 |
| Hells Canyon | HCC | 207.4 | 243.0 | 226.1 | 271.4 | 326.4 | 224.4 | 196.2 | 137.1 | 144.9 | 167.1 | 131.9 | 164.2 | 203.3 |
| American Falls | ROR | – | 9.5 | 13.2 | 38.7 | 74.2 | 91.3 | 87.3 | 63.5 | 35.9 | 10.3 | – | – | 35.3 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 35.9 | 36.7 | 35.5 | 36.8 | 42.5 | 38.6 | 34.5 | 27.2 | 35.6 | 36.6 | 34.1 | 34.4 | 35.7 |
| C .J. Strike | ROR | 46.4 | 49.5 | 46.5 | 50.7 | 51.0 | 44.3 | 35.1 | 30.1 | 42.0 | 45.9 | 43.7 | 44.9 | 44.2 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.2 | 2.1 | 7.1 | 7.4 | 12.0 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 22.1 | 23.6 | 21.7 | 22.8 | 28.8 | 26.5 | 22.1 | 15.1 | 22.0 | 23.0 | 21.0 | 21.4 | 22.5 |
| Milner | ROR | 3.3 | 11.3 | 2.5 | 4.5 | 15.4 | 15.4 | 6.4 | – | – | – | – | – | 4.9 |
| Shoshone Falls | ROR | 11.7 | 12.0 | 11.2 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 5.4 | 8.6 | 9.7 |
| Swan Falls | ROR | 15.2 | 15.8 | 15.4 | 16.8 | 17.0 | 15.1 | 12.5 | 10.5 | 14.2 | 15.3 | 14.9 | 15.2 | 14.8 |
| Twin Falls | ROR | 7.7 | 14.6 | 7.2 | 8.2 | 18.2 | 18.9 | 10.7 | – | – | – | – | 4.8 | 7.5 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 13.2 | 14.6 | 13.2 | 14.1 | 17.7 | 16.7 | 13.4 | 8.2 | 13.2 | 13.8 | 12.3 | 12.7 | 13.6 |
| Upper Salmon 3&4 | ROR | 12.5 | 13.7 | 12.5 | 13.3 | 17.2 | 15.5 | 12.6 | 8.2 | 12.5 | 13.0 | 11.7 | 12.0 | 12.9 |
| **HCC Total** | | **558.3** | **655.9** | **586.4** | **721.6** | **874.6** | **594.3** | **530.6** | **359.4** | **379.3** | **443.7** | **346.4** | **443.2** | **541.1** |
| **ROR Total** | | **195.2** | **228.9** | **207.4** | **246.5** | **324.8** | **328.1** | **280.5** | **208.9** | **217.6** | **193.8** | **170.5** | **181.3** | **232.0** |
| **Total** | | **753.5** | **884.8** | **793.8** | **968.1** | **1,199.4** | **922.4** | **811.1** | **568.3** | **596.9** | **637.5** | **516.9** | **624.5** | **773.1** |

*HCC=Hells Canyon Complex, **ROR= Run of River

**Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2028 | 2/2028 | 3/2028 | 4/2028 | 5/2028 | 6/2028 | 7/2028 | 8/2028 | 9/2028 | 10/2028 | 11/2028 | 12/2028 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 245.0 | 285.9 | 249.0 | 315.9 | 387.5 | 259.9 | 234.5 | 152.1 | 159.4 | 191.7 | 148.3 | 195.6 | 235.4 |
| Oxbow | HCC | 104.2 | 121.3 | 110.5 | 133.8 | 160.7 | 109.2 | 99.3 | 69.5 | 73.2 | 84.6 | 66.3 | 82.4 | 101.2 |
| Hells Canyon | HCC | 206.4 | 239.7 | 225.6 | 271.1 | 326.4 | 223.9 | 195.8 | 136.7 | 143.7 | 166.8 | 132.0 | 163.6 | 202.6 |
| American Falls | ROR | – | 8.1 | 12.9 | 38.6 | 74.2 | 91.0 | 87.3 | 63.2 | 35.9 | 10.3 | – | – | 35.1 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 35.8 | 36.5 | 35.2 | 36.7 | 42.5 | 38.5 | 34.5 | 27.0 | 35.4 | 36.5 | 33.9 | 34.3 | 35.6 |
| C .J. Strike | ROR | 46.3 | 49.1 | 46.1 | 50.6 | 50.9 | 44.1 | 35.0 | 29.9 | 41.7 | 45.7 | 43.5 | 44.7 | 44.0 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.2 | 2.1 | 7.1 | 7.4 | 12.0 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 22.0 | 22.9 | 21.3 | 22.8 | 28.8 | 26.4 | 22.0 | 15.0 | 21.8 | 22.8 | 20.9 | 21.3 | 22.3 |
| Milner | ROR | 3.3 | 6.8 | 2.2 | 4.4 | 15.4 | 15.4 | 6.4 | – | – | – | – | – | 4.5 |
| Shoshone Falls | ROR | 11.7 | 12.0 | 10.0 | 12.0 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 5.4 | 8.6 | 9.6 |
| Swan Falls | ROR | 15.4 | 15.7 | 15.3 | 16.8 | 17.0 | 15.0 | 12.4 | 10.5 | 14.2 | 15.4 | 14.9 | 15.1 | 14.8 |
| Twin Falls | ROR | 7.7 | 10.0 | 6.3 | 8.1 | 18.2 | 18.8 | 10.7 | – | – | – | – | 4.8 | 7.1 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 13.2 | 14.1 | 12.9 | 14.1 | 17.7 | 16.6 | 13.3 | 8.1 | 13.0 | 13.7 | 12.2 | 12.6 | 13.5 |
| Upper Salmon 3&4 | ROR | 12.5 | 13.2 | 12.2 | 13.3 | 17.2 | 15.4 | 12.6 | 8.1 | 12.4 | 12.9 | 11.6 | 12.0 | 12.8 |
| **HCC Total** | | **555.6** | **646.9** | **585.1** | **720.8** | **874.7** | **593.0** | **529.6** | **358.3** | **376.3** | **443.1** | **346.6** | **441.6** | **539.3** |
| **ROR Total** | | **195.1** | **216.0** | **202.9** | **246.0** | **324.7** | **327.0** | **280.1** | **207.9** | **216.6** | **193.2** | **169.8** | **180.7** | **230.0** |
| **Total** | | **750.7** | **862.9** | **788.0** | **966.8** | **1,199.3** | **920.0** | **809.7** | **566.2** | **592.9** | **636.3** | **516.4** | **622.3** | **769.3** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2029** | **2/2029** | **3/2029** | **4/2029** | **5/2029** | **6/2029** | **7/2029** | **8/2029** | **9/2029** | **10/2029** | **11/2029** | **12/2029** | **aMW** |
| Brownlee | HCC* | 244.0 | 281.7 | 248.6 | 315.2 | 387.6 | 259.2 | 234.0 | 151.6 | 158.1 | 191.5 | 148.2 | 195.4 | 234.6 |
| Oxbow | HCC | 103.8 | 119.5 | 110.3 | 133.5 | 160.7 | 109.0 | 99.1 | 69.2 | 72.5 | 84.5 | 66.2 | 82.3 | 100.9 |
| Hells Canyon | HCC | 205.5 | 236.2 | 225.2 | 270.5 | 326.4 | 223.4 | 195.5 | 136.3 | 142.5 | 166.5 | 131.9 | 163.4 | 201.9 |
| American Falls | ROR | – | 5.9 | 12.8 | 38.4 | 74.1 | 90.9 | 87.3 | 63.1 | 35.8 | 10.2 | – | – | 34.9 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 35.7 | 36.4 | 34.9 | 36.5 | 42.5 | 38.3 | 34.3 | 26.9 | 35.2 | 36.3 | 33.7 | 34.2 | 35.4 |
| C .J. Strike | ROR | 46.1 | 48.5 | 45.9 | 50.5 | 50.5 | 43.9 | 34.9 | 29.7 | 41.5 | 45.5 | 43.3 | 44.4 | 43.7 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.2 | 2.1 | 7.1 | 7.4 | 12.0 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 21.9 | 22.9 | 21.2 | 22.8 | 28.7 | 26.3 | 21.9 | 14.9 | 21.6 | 22.7 | 20.7 | 21.1 | 22.2 |
| Milner | ROR | 3.3 | 5.7 | 2.0 | 4.0 | 15.4 | 15.4 | 6.4 | – | – | – | – | – | 4.4 |
| Shoshone Falls | ROR | 11.7 | 12.0 | 9.8 | 11.8 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 5.4 | 7.9 | 9.5 |
| Swan Falls | ROR | 15.4 | 15.7 | 15.2 | 16.8 | 16.8 | 14.9 | 12.4 | 10.4 | 14.1 | 15.4 | 14.8 | 15.1 | 14.8 |
| Twin Falls | ROR | 7.7 | 10.0 | 6.0 | 7.8 | 18.2 | 18.8 | 10.7 | – | – | – | – | 4.3 | 7.0 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 13.1 | 14.0 | 12.8 | 14.1 | 17.7 | 16.5 | 13.2 | 8.0 | 12.9 | 13.6 | 12.1 | 12.4 | 13.4 |
| Upper Salmon 3&4 | ROR | 12.4 | 13.2 | 12.2 | 13.2 | 17.2 | 15.4 | 12.5 | 8.0 | 12.2 | 12.8 | 11.5 | 11.8 | 12.7 |
| **HCC Total** | | **553.3** | **637.4** | **584.1** | **719.2** | **874.7** | **591.6** | **528.6** | **357.1** | **373.1** | **442.5** | **346.3** | **441.1** | **537.4** |
| **ROR Total** | | **194.5** | **211.9** | **201.3** | **244.5** | **323.9** | **326.2** | **279.5** | **207.1** | **215.5** | **192.4** | **168.9** | **178.5** | **228.7** |
| **Total** | | **747.8** | **849.3** | **785.4** | **963.7** | **1,198.6** | **917.8** | **808.1** | **564.2** | **588.6** | **634.9** | **515.2** | **619.6** | **766.1** |

*HCC=Hells Canyon Complex, **ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2030** | **2/2030** | **3/2030** | **4/2030** | **5/2030** | **6/2030** | **7/2030** | **8/2030** | **9/2030** | **10/2030** | **11/2030** | **12/2030** | **aMW** |
| Brownlee | HCC* | 242.8 | 278.3 | 248.3 | 315.1 | 387.1 | 258.6 | 233.5 | 151.1 | 156.7 | 191.7 | 148.6 | 194.9 | 233.9 |
| Oxbow | HCC | 103.2 | 118.1 | 110.1 | 133.4 | 160.6 | 108.7 | 98.9 | 69.0 | 71.8 | 84.5 | 66.4 | 82.1 | 100.6 |
| Hells Canyon | HCC | 204.5 | 233.5 | 224.8 | 270.3 | 326.1 | 222.9 | 195.1 | 135.8 | 141.1 | 166.6 | 132.2 | 163.0 | 201.3 |
| American Falls | ROR | – | – | 11.2 | 37.2 | 74.1 | 90.9 | 87.3 | 63.0 | 35.8 | 10.2 | – | – | 34.1 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 35.3 | 36.3 | 33.9 | 36.4 | 42.5 | 38.2 | 34.2 | 26.7 | 35.0 | 36.1 | 33.6 | 34.1 | 35.2 |
| C .J. Strike | ROR | 46.0 | 47.8 | 45.5 | 50.3 | 50.5 | 43.7 | 34.7 | 29.5 | 41.3 | 45.2 | 43.1 | 44.2 | 43.5 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.2 | 2.1 | 7.1 | 7.4 | 12.0 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 21.8 | 22.8 | 20.8 | 22.8 | 28.6 | 26.1 | 21.8 | 14.7 | 21.5 | 22.5 | 20.6 | 21.0 | 22.1 |
| Milner | ROR | 2.5 | 5.6 | – | 3.8 | 15.1 | 15.4 | 6.4 | – | – | – | – | – | 4.1 |
| Shoshone Falls | ROR | 11.7 | 12.0 | 9.4 | 11.6 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 5.4 | 7.9 | 9.5 |
| Swan Falls | ROR | 15.3 | 15.6 | 15.4 | 16.7 | 16.8 | 14.9 | 12.3 | 10.4 | 14.1 | 15.3 | 14.7 | 15.0 | 14.7 |
| Twin Falls | ROR | 7.7 | 9.9 | 5.7 | 7.6 | 17.9 | 18.7 | 10.7 | – | – | – | – | 4.3 | 6.9 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 13.0 | 14.0 | 12.5 | 14.1 | 17.7 | 16.4 | 13.1 | 7.9 | 12.8 | 13.4 | 12.0 | 12.4 | 13.3 |
| Upper Salmon 3&4 | ROR | 12.3 | 13.2 | 11.9 | 13.2 | 17.1 | 15.3 | 12.4 | 8.0 | 12.1 | 12.7 | 11.4 | 11.8 | 12.6 |
| **HCC Total** | | **550.5** | **629.9** | **583.2** | **718.8** | **873.8** | **590.2** | **527.5** | **355.9** | **369.5** | **442.8** | **347.2** | **440.0** | **535.8** |
| **ROR Total** | | **192.8** | **204.8** | **194.8** | **242.3** | **323.1** | **325.4** | **278.8** | **206.3** | **214.8** | **191.3** | **168.2** | **178.0** | **226.7** |
| **Total** | | **743.3** | **834.7** | **778.0** | **961.1** | **1,196.9** | **915.6** | **806.3** | **562.2** | **584.3** | **634.1** | **515.4** | **618.0** | **762.5** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Modeling Results (PDR580) (continued)

**Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 243.1 | 277.7 | 247.8 | 314.5 | 386.4 | 257.5 | 233.1 | 150.7 | 154.9 | 191.9 | 148.8 | 194.2 | 233.4 |
| Oxbow | HCC | 103.4 | 117.8 | 109.9 | 133.2 | 160.3 | 108.2 | 98.7 | 68.8 | 70.8 | 84.5 | 66.4 | 81.8 | 100.3 |
| Hells Canyon | HCC | 204.8 | 232.9 | 224.4 | 269.8 | 325.5 | 222.0 | 194.7 | 135.4 | 139.3 | 166.6 | 132.3 | 162.5 | 200.8 |
| American Falls | ROR | – | – | 11.0 | 36.8 | 74.1 | 90.8 | 87.3 | 62.9 | 35.8 | 10.2 | – | – | 34.1 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 35.1 | 36.2 | 33.8 | 36.3 | 42.5 | 38.0 | 34.1 | 26.6 | 34.8 | 35.9 | 33.5 | 34.0 | 35.1 |
| C .J. Strike | ROR | 46.0 | 47.4 | 45.2 | 50.2 | 49.9 | 43.5 | 34.6 | 29.3 | 41.0 | 45.0 | 43.3 | 44.1 | 43.3 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.2 | 2.1 | 7.1 | 7.4 | 12.0 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 22.1 | 22.8 | 20.7 | 22.8 | 28.6 | 26.0 | 21.7 | 14.6 | 21.3 | 22.4 | 20.5 | 21.0 | 22.0 |
| Milner | ROR | 4.0 | 7.5 | 1.6 | 3.6 | 14.6 | 14.6 | 6.4 | – | – | – | – | – | 4.4 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 10.0 | 11.4 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 5.4 | 8.6 | 9.6 |
| Swan Falls | ROR | 15.3 | 15.5 | 15.3 | 16.5 | 16.8 | 14.8 | 12.3 | 10.3 | 14.1 | 15.2 | 14.7 | 15.0 | 14.7 |
| Twin Falls | ROR | 8.9 | 10.2 | 6.2 | 7.4 | 17.7 | 18.2 | 10.7 | – | – | – | – | 4.8 | 7.0 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 13.3 | 13.9 | 12.4 | 14.1 | 17.7 | 16.3 | 13.0 | 7.8 | 12.6 | 13.3 | 11.9 | 12.3 | 13.2 |
| Upper Salmon 3&4 | ROR | 12.6 | 13.1 | 11.8 | 13.2 | 17.1 | 15.2 | 12.4 | 7.9 | 12.0 | 12.6 | 11.4 | 11.8 | 12.6 |
| **HCC Total** | | **551.3** | **628.4** | **582.1** | **717.5** | **872.2** | **587.7** | **526.5** | **354.9** | **364.9** | **443.0** | **347.5** | **438.5** | **534.5** |
| **ROR Total** | | **196.5** | **206.2** | **196.5** | **240.9** | **321.8** | **323.2** | **278.4** | **205.5** | **213.8** | **190.5** | **168.1** | **178.9** | **226.7** |
| **Total** | | **747.8** | **834.6** | **778.6** | **958.4** | **1,194.0** | **910.9** | **804.9** | **560.4** | **578.7** | **633.5** | **515.6** | **617.4** | **761.2** |

*HCC=Hells Canyon Complex, **ROR= Run of River

**Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2032 | 2/2032 | 3/2032 | 4/2032 | 5/2032 | 6/2032 | 7/2032 | 8/2032 | 9/2032 | 10/2032 | 11/2032 | 12/2032 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 242.7 | 268.8 | 247.1 | 313.8 | 385.3 | 256.1 | 232.6 | 150.1 | 153.4 | 191.8 | 148.5 | 194.2 | 232.0 |
| Oxbow | HCC | 103.2 | 117.5 | 109.6 | 132.9 | 159.8 | 107.7 | 98.5 | 68.5 | 70.0 | 84.4 | 66.3 | 81.8 | 100.0 |
| Hells Canyon | HCC | 204.5 | 234.1 | 223.7 | 269.2 | 324.7 | 220.9 | 194.3 | 134.9 | 137.8 | 166.3 | 132.0 | 162.4 | 200.4 |
| American Falls | ROR | – | – | 9.6 | 36.6 | 74.1 | 90.8 | 87.2 | 62.5 | 35.7 | 10.2 | – | – | 33.9 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 35.0 | 35.4 | 33.3 | 36.2 | 42.5 | 37.9 | 34.0 | 26.4 | 34.6 | 35.8 | 33.2 | 33.9 | 34.9 |
| C .J. Strike | ROR | 45.8 | 47.0 | 44.9 | 50.0 | 50.0 | 43.3 | 34.4 | 29.1 | 40.8 | 44.8 | 43.1 | 43.9 | 43.1 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.2 | 2.1 | 7.1 | 7.4 | 12.0 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 22.0 | 22.4 | 20.1 | 22.0 | 28.6 | 25.9 | 21.6 | 14.5 | 21.1 | 22.2 | 20.3 | 20.8 | 21.8 |
| Milner | ROR | 4.0 | 5.3 | – | 3.1 | 14.3 | 14.3 | 6.4 | – | – | – | – | – | 4.0 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.8 | 10.7 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 5.4 | 8.6 | 9.5 |
| Swan Falls | ROR | 15.2 | 15.4 | 15.2 | 16.4 | 16.8 | 14.7 | 12.2 | 10.2 | 14.0 | 15.1 | 14.7 | 14.9 | 14.6 |
| Twin Falls | ROR | 8.9 | 9.8 | 5.2 | 6.8 | 17.5 | 18.2 | 10.7 | – | – | – | – | 4.8 | 6.8 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 13.2 | 13.6 | 11.9 | 13.5 | 17.7 | 16.2 | 13.0 | 7.7 | 12.5 | 13.2 | 11.8 | 12.2 | 13.0 |
| Upper Salmon 3&4 | ROR | 12.5 | 12.8 | 11.4 | 12.7 | 17.1 | 15.1 | 12.3 | 7.8 | 11.9 | 12.5 | 11.3 | 11.6 | 12.4 |
| **HCC Total** | | **550.4** | **620.4** | **580.4** | **715.9** | **869.9** | **584.7** | **525.4** | **353.5** | **361.2** | **442.5** | **346.8** | **438.4** | **532.5** |
| **ROR Total** | | **195.8** | **201.3** | **188.9** | **236.6** | **321.4** | **322.2** | **277.7** | **204.3** | **212.8** | **189.7** | **167.2** | **178.0** | **224.7** |
| **Total** | | **746.2** | **821.7** | **769.3** | **952.5** | **1,191.3** | **906.9** | **803.1** | **557.8** | **573.9** | **632.2** | **514.0** | **616.4** | **757.1** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2033** | **2/2033** | **3/2033** | **4/2033** | **5/2033** | **6/2033** | **7/2033** | **8/2033** | **9/2033** | **10/2033** | **11/2033** | **12/2033** | **aMW** |
| Brownlee | HCC* | 242.2 | 267.9 | 246.8 | 313.3 | 385.6 | 255.1 | 232.0 | 149.6 | 151.5 | 192.1 | 148.7 | 193.7 | 231.5 |
| Oxbow | HCC | 103.0 | 117.1 | 109.4 | 132.6 | 159.9 | 107.3 | 98.3 | 68.3 | 69.1 | 84.4 | 66.3 | 81.6 | 99.8 |
| Hells Canyon | HCC | 204.1 | 233.3 | 223.4 | 268.6 | 324.8 | 220.1 | 193.9 | 134.4 | 136.0 | 166.4 | 132.0 | 162.0 | 199.9 |
| American Falls | ROR | – | – | 9.4 | 36.4 | 74.1 | 90.9 | 87.2 | 62.5 | 35.7 | 10.2 | – | – | 33.9 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 34.8 | 35.2 | 33.1 | 36.1 | 42.4 | 37.6 | 33.8 | 26.3 | 34.4 | 35.6 | 33.1 | 33.8 | 34.7 |
| C .J. Strike | ROR | 45.2 | 46.9 | 44.5 | 49.8 | 49.9 | 43.1 | 34.2 | 28.9 | 40.5 | 44.7 | 43.1 | 43.5 | 42.9 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.2 | 2.1 | 7.1 | 7.4 | 12.0 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 21.8 | 21.9 | 19.9 | 21.1 | 28.7 | 25.8 | 21.5 | 14.3 | 20.9 | 22.1 | 20.2 | 20.7 | 21.6 |
| Milner | ROR | 3.3 | 5.1 | – | 2.3 | 14.3 | 14.3 | 6.4 | – | – | – | – | – | 3.8 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.6 | 10.4 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 5.4 | 8.6 | 9.4 |
| Swan Falls | ROR | 15.1 | 15.3 | 15.1 | 16.2 | 16.8 | 14.6 | 12.2 | 10.2 | 13.9 | 15.1 | 14.6 | 14.9 | 14.5 |
| Twin Falls | ROR | 8.5 | 9.4 | 4.8 | 6.6 | 17.5 | 18.2 | 10.7 | – | – | – | – | 4.8 | 6.7 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 13.1 | 13.3 | 11.8 | 12.8 | 17.7 | 16.2 | 12.9 | 7.6 | 12.4 | 13.1 | 11.6 | 12.1 | 12.9 |
| Upper Salmon 3&4 | ROR | 12.4 | 12.5 | 11.3 | 12.1 | 17.2 | 15.0 | 12.2 | 7.7 | 11.8 | 12.4 | 11.2 | 11.6 | 12.3 |
| **HCC Total** | | **549.3** | **618.3** | **579.6** | **714.5** | **870.3** | **582.5** | **524.2** | **352.3** | **356.6** | **442.9** | **347.0** | **437.3** | **531.2** |
| **ROR Total** | | **193.4** | **199.2** | **187.0** | **232.4** | **321.4** | **321.5** | **277.0** | **203.6** | **211.8** | **189.1** | **166.6** | **177.3** | **223.4** |
| **Total** | | **742.7** | **817.5** | **766.6** | **946.9** | **1,191.7** | **904.0** | **801.2** | **555.9** | **568.3** | **632.0** | **513.6** | **614.6** | **754.6** |

*HCC=Hells Canyon Complex, **ROR= Run of River

| Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2034** | **2/2034** | **3/2034** | **4/2034** | **5/2034** | **6/2034** | **7/2034** | **8/2034** | **9/2034** | **10/2034** | **11/2034** | **12/2034** | **aMW** |
| Brownlee | HCC* | 241.8 | 266.9 | 246.7 | 312.2 | 384.9 | 254.4 | 231.6 | 149.1 | 150.1 | 191.9 | 148.8 | 193.2 | 231.0 |
| Oxbow | HCC | 102.9 | 116.6 | 109.3 | 132.1 | 159.6 | 107.0 | 98.1 | 68.0 | 68.3 | 84.3 | 66.4 | 81.4 | 99.5 |
| Hells Canyon | HCC | 203.8 | 232.4 | 223.3 | 267.8 | 324.2 | 219.5 | 193.5 | 134.0 | 134.5 | 166.1 | 132.1 | 161.6 | 199.4 |
| American Falls | ROR | – | – | 9.2 | 35.6 | 74.1 | 90.8 | 87.2 | 62.4 | 35.6 | 10.2 | – | – | 33.8 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 34.7 | 35.2 | 32.9 | 35.7 | 42.5 | 37.4 | 33.7 | 26.1 | 34.2 | 35.4 | 33.0 | 33.7 | 34.5 |
| C .J. Strike | ROR | 45.1 | 46.7 | 44.3 | 48.6 | 49.9 | 42.9 | 34.0 | 28.7 | 40.2 | 44.5 | 43.0 | 43.5 | 42.6 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.2 | 2.1 | 7.1 | 7.4 | 12.0 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 21.7 | 21.8 | 19.8 | 20.9 | 28.5 | 25.3 | 21.4 | 14.2 | 20.8 | 21.9 | 20.0 | 20.6 | 21.4 |
| Milner | ROR | 3.3 | 5.1 | – | – | 14.3 | 14.2 | 6.4 | – | – | – | – | – | 3.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.3 | 7.3 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 5.4 | 8.6 | 9.1 |
| Swan Falls | ROR | 15.1 | 15.2 | 15.0 | 16.0 | 16.8 | 14.6 | 12.1 | 10.1 | 13.8 | 15.1 | 14.6 | 14.8 | 14.4 |
| Twin Falls | ROR | 8.5 | 8.8 | 4.6 | 3.8 | 17.3 | 18.2 | 10.7 | – | – | – | – | 4.8 | 6.4 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 13.0 | 13.1 | 11.7 | 12.6 | 17.7 | 15.8 | 12.8 | 7.5 | 12.2 | 13.0 | 11.5 | 12.0 | 12.7 |
| Upper Salmon 3&4 | ROR | 12.3 | 12.4 | 11.2 | 12.0 | 17.1 | 14.7 | 12.1 | 7.6 | 11.7 | 12.3 | 11.1 | 11.5 | 12.2 |
| **HCC Total** | | **548.5** | **615.9** | **579.3** | **712.1** | **868.6** | **580.9** | **523.2** | **351.1** | **352.8** | **442.3** | **347.3** | **436.2** | **529.9** |
| **ROR Total** | | **192.9** | **197.9** | **185.5** | **221.1** | **321.0** | **319.7** | **276.3** | **202.7** | **210.7** | **188.3** | **166.0** | **176.8** | **221.6** |
| **Total** | | **741.4** | **813.8** | **764.8** | **933.2** | **1,189.7** | **900.6** | **799.5** | **553.8** | **563.5** | **630.6** | **513.3** | **613.0** | **751.4** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Modeling Results (PDR580) (continued)

**Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2035 | 2/2035 | 3/2035 | 4/2035 | 5/2035 | 6/2035 | 7/2035 | 8/2035 | 9/2035 | 10/2035 | 11/2035 | 12/2035 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 241.4 | 265.2 | 246.5 | 312.2 | 384.1 | 253.8 | 231.1 | 148.6 | 148.2 | 192.2 | 148.9 | 192.7 | 230.4 |
| Oxbow | HCC | 102.7 | 115.8 | 109.1 | 132.0 | 159.3 | 106.7 | 97.9 | 67.8 | 67.3 | 84.3 | 66.4 | 81.2 | 99.2 |
| Hells Canyon | HCC | 203.4 | 230.8 | 222.8 | 267.5 | 323.6 | 219.0 | 193.1 | 133.6 | 132.7 | 166.1 | 132.2 | 161.2 | 198.8 |
| American Falls | ROR | – | – | 9.1 | 35.5 | 73.9 | 90.7 | 87.2 | 62.4 | 35.6 | 10.3 | – | – | 33.7 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 34.6 | 34.9 | 32.8 | 35.5 | 42.4 | 37.2 | 33.6 | 26.0 | 34.0 | 35.3 | 32.8 | 33.6 | 34.4 |
| C .J. Strike | ROR | 44.9 | 46.6 | 44.0 | 47.6 | 49.9 | 42.7 | 33.9 | 28.6 | 40.0 | 44.2 | 42.8 | 43.5 | 42.4 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.2 | 2.1 | 7.1 | 7.4 | 12.0 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 21.2 | 21.7 | 19.7 | 20.8 | 28.4 | 25.1 | 21.3 | 14.1 | 20.6 | 21.8 | 19.9 | 20.5 | 21.3 |
| Milner | ROR | 3.3 | 5.1 | – | – | 14.3 | 14.2 | 6.4 | – | – | – | – | – | 3.6 |
| Shoshone Falls | ROR | 12.0 | 12.0 | 8.3 | 6.6 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 5.4 | 8.6 | 9.1 |
| Swan Falls | ROR | 15.1 | 15.2 | 14.9 | 15.9 | 16.8 | 14.5 | 12.1 | 10.0 | 13.8 | 15.0 | 14.5 | 14.8 | 14.4 |
| Twin Falls | ROR | 8.0 | 8.8 | 4.6 | – | 17.3 | 18.2 | 10.7 | – | – | – | – | 4.8 | 6.0 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 12.6 | 13.1 | 11.6 | 12.5 | 17.7 | 15.7 | 12.7 | 7.4 | 12.1 | 12.8 | 11.4 | 11.9 | 12.6 |
| Upper Salmon 3&4 | ROR | 12.0 | 12.4 | 11.1 | 11.9 | 17.0 | 14.6 | 12.1 | 7.5 | 11.6 | 12.2 | 11.0 | 11.4 | 12.1 |
| **HCC Total** | | **547.5** | **611.8** | **578.4** | **711.7** | **867.0** | **579.5** | **522.1** | **350.0** | **348.1** | **442.6** | **347.5** | **435.1** | **528.4** |
| **ROR Total** | | **190.9** | **197.4** | **184.6** | **214.9** | **320.5** | **318.7** | **275.9** | **202.1** | **209.9** | **187.5** | **165.2** | **176.4** | **220.3** |
| **Total** | | **738.4** | **809.2** | **763.0** | **926.6** | **1,187.5** | **898.2** | **798.0** | **552.1** | **558.0** | **630.1** | **512.7** | **611.5** | **748.8** |

*HCC=Hells Canyon Complex, **ROR= Run of River

**Average Megawatt (aMW) 70th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2036 | 2/2036 | 3/2036 | 4/2036 | 5/2036 | 6/2036 | 7/2036 | 8/2036 | 9/2036 | 10/2036 | 11/2036 | 12/2036 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 240.8 | 264.2 | 245.9 | 311.6 | 384.5 | 253.1 | 230.6 | 148.1 | 146.3 | 192.4 | 148.8 | 192.6 | 229.9 |
| Oxbow | HCC | 102.4 | 115.3 | 108.8 | 131.6 | 159.5 | 106.4 | 97.6 | 67.6 | 66.3 | 84.3 | 66.3 | 81.1 | 98.9 |
| Hells Canyon | HCC | 202.9 | 229.9 | 222.2 | 266.8 | 323.8 | 218.4 | 192.6 | 133.1 | 130.9 | 166.1 | 132.0 | 161.1 | 198.3 |
| American Falls | ROR | – | – | 8.9 | 35.5 | 73.9 | 90.7 | 87.2 | 62.2 | 35.6 | 10.3 | – | – | 33.7 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 34.4 | 34.8 | 32.7 | 35.4 | 42.3 | 37.1 | 33.4 | 25.8 | 33.8 | 35.1 | 32.7 | 33.5 | 34.3 |
| C .J. Strike | ROR | 44.2 | 46.4 | 43.7 | 47.5 | 49.9 | 42.6 | 33.7 | 28.4 | 39.7 | 44.0 | 42.7 | 43.4 | 42.2 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.2 | 2.1 | 7.1 | 7.4 | 12.0 | 7.3 | 1.5 | 1.3 | 1.4 | 3.8 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 20.7 | 21.6 | 19.6 | 20.7 | 28.4 | 25.0 | 21.2 | 14.0 | 20.4 | 21.6 | 19.8 | 20.4 | 21.1 |
| Milner | ROR | 2.5 | 5.1 | – | – | 14.3 | 14.2 | 6.4 | – | – | – | – | – | 3.5 |
| Shoshone Falls | ROR | 10.7 | 12.0 | 8.3 | 6.6 | 12.0 | 12.0 | 12.0 | 6.9 | 6.7 | 6.3 | 5.4 | 8.6 | 9.0 |
| Swan Falls | ROR | 15.0 | 15.1 | 14.8 | 15.8 | 16.8 | 14.4 | 12.0 | 10.0 | 13.7 | 14.9 | 14.5 | 14.7 | 14.3 |
| Twin Falls | ROR | 6.8 | 8.8 | 4.6 | – | 17.2 | 18.2 | 10.7 | – | – | – | – | 4.8 | 5.9 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 12.2 | 13.1 | 11.5 | 12.5 | 17.7 | 15.5 | 12.6 | 7.3 | 12.0 | 12.7 | 11.3 | 11.9 | 12.5 |
| Upper Salmon 3&4 | ROR | 11.6 | 12.4 | 11.1 | 11.9 | 17.0 | 14.5 | 12.0 | 7.5 | 11.4 | 12.1 | 10.9 | 11.4 | 12.0 |
| **HCC Total** | | **546.1** | **609.4** | **576.9** | **710.0** | **867.8** | **577.9** | **520.8** | **348.8** | **343.4** | **442.8** | **347.1** | **434.8** | **527.1** |
| **ROR Total** | | **185.3** | **196.9** | **183.7** | **214.5** | **320.3** | **318.0** | **275.1** | **201.3** | **208.8** | **186.6** | **164.7** | **176.0** | **219.3** |
| **Total** | | **731.4** | **806.3** | **760.6** | **924.5** | **1,188.1** | **895.9** | **795.9** | **550.1** | **552.2** | **629.4** | **511.8** | **610.8** | **746.4** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2017** | **2/2017** | **3/2017** | **4/2017** | **5/2017** | **6/2017** | **7/2017** | **8/2017** | **9/2017** | **10/2017** | **11/2017** | **12/2017** | **aMW** |
| Brownlee | HCC* | 221.6 | 195.7 | 231.8 | 225.4 | 272.1 | 167.1 | 222.0 | 141.5 | 131.6 | 192.4 | 148.2 | 178.7 | 194.0 |
| Oxbow | HCC | 93.5 | 83.9 | 99.8 | 96.2 | 115.0 | 72.2 | 93.7 | 64.4 | 59.0 | 83.4 | 65.7 | 78.0 | 83.7 |
| Hells Canyon | HCC | 184.6 | 166.8 | 202.2 | 196.0 | 235.9 | 146.6 | 184.1 | 126.6 | 116.2 | 164.2 | 130.4 | 153.9 | 167.3 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 29.7 | 69.4 | 86.9 | 87.0 | 56.5 | 27.3 | 8.1 | 0.0 | 0.0 | 30.4 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 33.4 | 33.6 | 32.0 | 32.4 | 37.4 | 35.7 | 33.9 | 26.7 | 35.4 | 36.1 | 33.9 | 33.8 | 33.7 |
| C .J. Strike | ROR | 42.0 | 41.9 | 41.0 | 40.9 | 43.1 | 39.0 | 32.4 | 29.5 | 39.1 | 43.1 | 42.7 | 41.7 | 39.7 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.3 | 1.3 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 21.0 | 21.3 | 19.5 | 20.0 | 24.9 | 24.0 | 22.0 | 15.1 | 22.1 | 23.0 | 21.4 | 21.3 | 21.3 |
| Milner | ROR | 1.9 | 3.1 | 0.0 | 0.0 | 8.3 | 8.2 | 6.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.3 |
| Shoshone Falls | ROR | 9.9 | 10.9 | 4.8 | 4.0 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 6.2 | 7.3 | 9.7 | 8.5 |
| Swan Falls | ROR | 14.4 | 14.3 | 14.1 | 14.1 | 14.7 | 13.4 | 11.7 | 10.4 | 13.9 | 14.8 | 14.6 | 14.4 | 13.7 |
| Twin Falls | ROR | 6.1 | 7.0 | 0.0 | 0.0 | 11.1 | 12.0 | 10.3 | 0.0 | 0.0 | 0.0 | 3.7 | 5.9 | 4.7 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 12.4 | 12.8 | 11.5 | 11.9 | 15.7 | 14.8 | 13.3 | 8.1 | 13.3 | 13.8 | 12.6 | 12.6 | 12.7 |
| Upper Salmon 3&4 | ROR | 11.8 | 12.2 | 11.0 | 11.4 | 14.6 | 13.8 | 12.5 | 8.2 | 12.6 | 13.0 | 11.9 | 12.0 | 12.1 |
| **HCC Total** | | **499.7** | **446.4** | **533.8** | **517.6** | **623.0** | **385.9** | **499.8** | **332.5** | **306.8** | **440.0** | **344.3** | **410.6** | **445.0** |
| **ROR Total** | | **180.1** | **184.7** | **162.4** | **193.1** | **281.4** | **290.7** | **275.0** | **198.5** | **204.6** | **187.5** | **175.5** | **178.6** | **209.3** |
| **Total** | | **679.8** | **631.1** | **696.2** | **710.7** | **904.4** | **676.6** | **774.8** | **531.0** | **511.4** | **627.5** | **519.8** | **589.2** | **654.4** |

*HCC=Hells Canyon Complex, **ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2018** | **2/2018** | **3/2018** | **4/2018** | **5/2018** | **6/2018** | **7/2018** | **8/2018** | **9/2018** | **10/2018** | **11/2018** | **12/2018** | **aMW** |
| Brownlee | HCC* | 212.0 | 197.8 | 232.9 | 226.0 | 273.6 | 168.1 | 222.3 | 141.5 | 131.5 | 192.2 | 148.6 | 178.8 | 193.8 |
| Oxbow | HCC | 89.8 | 84.8 | 100.3 | 96.5 | 115.7 | 72.7 | 93.8 | 64.4 | 59.0 | 83.4 | 65.8 | 78.0 | 83.7 |
| Hells Canyon | HCC | 177.5 | 168.5 | 203.1 | 196.5 | 237.1 | 147.5 | 184.3 | 126.7 | 116.2 | 164.1 | 130.7 | 153.9 | 167.2 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 29.6 | 70.0 | 87.7 | 87.1 | 56.5 | 28.5 | 8.7 | 0.0 | 0.0 | 30.7 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 33.3 | 33.5 | 32.0 | 32.5 | 38.1 | 36.3 | 34.0 | 26.9 | 35.4 | 36.2 | 33.7 | 33.7 | 33.8 |
| C .J. Strike | ROR | 42.2 | 42.1 | 41.4 | 41.1 | 43.4 | 39.6 | 32.0 | 29.5 | 39.1 | 43.1 | 42.5 | 41.8 | 39.8 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.3 | 1.3 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 21.1 | 21.3 | 19.4 | 20.1 | 25.6 | 24.4 | 22.0 | 15.1 | 22.1 | 23.0 | 21.2 | 21.2 | 21.4 |
| Milner | ROR | 0.0 | 3.1 | 0.0 | 0.0 | 9.7 | 9.6 | 6.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.4 |
| Shoshone Falls | ROR | 9.2 | 10.8 | 4.2 | 4.0 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 6.2 | 6.6 | 9.1 | 8.3 |
| Swan Falls | ROR | 14.4 | 14.4 | 14.2 | 14.2 | 14.8 | 13.6 | 11.7 | 10.4 | 13.9 | 14.9 | 14.6 | 14.3 | 13.8 |
| Twin Falls | ROR | 5.6 | 6.9 | 0.0 | 0.0 | 12.4 | 12.6 | 10.3 | 0.0 | 0.0 | 0.0 | 0.0 | 5.5 | 4.4 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 12.5 | 12.8 | 11.4 | 12.0 | 16.2 | 15.1 | 13.3 | 8.1 | 13.3 | 13.8 | 12.4 | 12.5 | 12.8 |
| Upper Salmon 3&4 | ROR | 11.9 | 12.1 | 11.0 | 11.5 | 15.1 | 14.1 | 12.6 | 8.2 | 12.6 | 13.0 | 11.8 | 11.9 | 12.2 |
| **HCC Total** | | **479.3** | **451.1** | **536.3** | **519.0** | **626.4** | **388.3** | **500.4** | **332.6** | **306.6** | **439.7** | **345.1** | **410.7** | **444.6** |
| **ROR Total** | | **177.4** | **184.6** | **162.1** | **193.7** | **287.5** | **295.9** | **274.9** | **198.7** | **205.9** | **188.3** | **170.2** | **177.2** | **209.7** |
| **Total** | | **656.7** | **635.7** | **698.4** | **712.7** | **913.9** | **684.2** | **775.3** | **531.3** | **512.4** | **628.0** | **515.3** | **587.9** | **654.3** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

**Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2019 | 2/2019 | 3/2019 | 4/2019 | 5/2019 | 6/2019 | 7/2019 | 8/2019 | 9/2019 | 10/2019 | 11/2019 | 12/2019 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 209.6 | 202.3 | 231.5 | 226.6 | 274.5 | 168.3 | 222.5 | 141.6 | 129.8 | 192.6 | 149.3 | 178.1 | 193.9 |
| Oxbow | HCC | 88.8 | 86.7 | 99.7 | 96.7 | 116.1 | 72.7 | 93.9 | 64.5 | 58.1 | 83.4 | 66.1 | 77.7 | 83.7 |
| Hells Canyon | HCC | 175.5 | 172.3 | 201.9 | 197.0 | 237.9 | 147.6 | 184.5 | 126.8 | 114.6 | 164.1 | 131.2 | 153.3 | 167.2 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 29.4 | 70.0 | 87.7 | 87.1 | 56.2 | 28.7 | 8.8 | 0.0 | 0.0 | 30.7 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.9 | 33.3 | 32.0 | 32.5 | 38.3 | 36.7 | 34.1 | 27.0 | 35.3 | 36.2 | 33.5 | 33.2 | 33.8 |
| C .J. Strike | ROR | 41.4 | 41.5 | 41.5 | 41.4 | 43.8 | 40.6 | 32.1 | 29.6 | 39.0 | 43.1 | 42.0 | 41.3 | 39.8 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.3 | 1.3 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 20.6 | 20.9 | 19.4 | 20.2 | 26.1 | 24.5 | 22.1 | 15.1 | 22.1 | 23.0 | 20.8 | 20.7 | 21.3 |
| Milner | ROR | 0.0 | 0.0 | 0.0 | 0.0 | 10.3 | 10.2 | 6.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.2 |
| Shoshone Falls | ROR | 7.1 | 8.7 | 4.2 | 4.3 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 6.2 | 5.4 | 7.0 | 7.7 |
| Swan Falls | ROR | 14.2 | 14.3 | 14.2 | 14.2 | 14.9 | 13.9 | 11.7 | 10.4 | 13.9 | 14.8 | 14.4 | 14.2 | 13.8 |
| Twin Falls | ROR | 3.7 | 5.1 | 0.0 | 0.0 | 13.0 | 13.1 | 10.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.8 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 12.1 | 12.4 | 11.4 | 12.1 | 16.6 | 15.2 | 13.3 | 8.2 | 13.3 | 13.8 | 12.1 | 12.2 | 12.7 |
| Upper Salmon 3&4 | ROR | 11.5 | 11.8 | 11.0 | 11.6 | 15.4 | 14.2 | 12.6 | 8.2 | 12.6 | 13.0 | 11.6 | 11.6 | 12.1 |
| **HCC Total** | | **473.9** | **461.3** | **533.1** | **520.3** | **628.5** | **388.6** | **500.9** | **332.9** | **302.5** | **440.1** | **346.6** | **409.1** | **444.8** |
| **ROR Total** | | **170.7** | **175.6** | **162.2** | **194.4** | **290.6** | **299.0** | **275.2** | **198.7** | **205.9** | **188.3** | **167.2** | **167.4** | **207.9** |
| **Total** | | **644.6** | **636.9** | **695.3** | **714.7** | **919.1** | **687.6** | **776.1** | **531.6** | **508.3** | **628.4** | **513.8** | **576.5** | **652.7** |

*HCC=Hells Canyon Complex, **ROR= Run of River

**Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2020 | 2/2020 | 3/2020 | 4/2020 | 5/2020 | 6/2020 | 7/2020 | 8/2020 | 9/2020 | 10/2020 | 11/2020 | 12/2020 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 209.7 | 196.6 | 231.5 | 226.7 | 274.9 | 168.1 | 222.4 | 141.5 | 129.4 | 192.5 | 149.2 | 178.0 | 193.4 |
| Oxbow | HCC | 88.8 | 84.3 | 99.7 | 96.8 | 116.2 | 72.7 | 93.9 | 64.4 | 58.0 | 83.3 | 66.0 | 77.6 | 83.5 |
| Hells Canyon | HCC | 175.6 | 167.4 | 201.9 | 197.1 | 238.2 | 147.5 | 184.4 | 126.6 | 114.3 | 164.0 | 131.1 | 153.2 | 166.8 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 29.3 | 70.0 | 87.7 | 87.1 | 56.7 | 28.8 | 8.8 | 0.0 | 0.0 | 30.7 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.9 | 32.1 | 32.0 | 32.5 | 38.2 | 36.2 | 34.0 | 26.9 | 35.2 | 36.1 | 33.4 | 33.3 | 33.6 |
| C .J. Strike | ROR | 41.4 | 40.1 | 41.5 | 41.7 | 44.0 | 40.3 | 32.1 | 29.5 | 38.9 | 43.1 | 41.9 | 41.6 | 39.7 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.3 | 1.3 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 20.6 | 20.1 | 19.4 | 20.2 | 25.9 | 24.5 | 22.0 | 15.1 | 22.0 | 23.0 | 20.7 | 20.7 | 21.2 |
| Milner | ROR | 0.0 | 0.0 | 0.0 | 0.0 | 10.0 | 9.9 | 6.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.2 |
| Shoshone Falls | ROR | 7.2 | 8.4 | 4.2 | 4.3 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 6.2 | 5.4 | 7.0 | 7.6 |
| Swan Falls | ROR | 14.2 | 13.8 | 14.2 | 14.3 | 15.0 | 13.8 | 11.7 | 10.4 | 13.9 | 14.8 | 14.4 | 14.2 | 13.7 |
| Twin Falls | ROR | 3.7 | 4.9 | 0.0 | 0.0 | 12.6 | 13.0 | 10.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.7 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 12.1 | 12.0 | 11.4 | 12.1 | 16.5 | 15.1 | 13.3 | 8.1 | 13.2 | 13.8 | 12.1 | 12.2 | 12.7 |
| Upper Salmon 3&4 | ROR | 11.6 | 11.4 | 11.0 | 11.6 | 15.3 | 14.2 | 12.6 | 8.2 | 12.5 | 13.0 | 11.5 | 11.6 | 12.0 |
| **HCC Total** | | **474.1** | **448.3** | **533.1** | **520.6** | **629.3** | **388.3** | **500.7** | **332.5** | **301.7** | **439.8** | **346.3** | **408.8** | **443.6** |
| **ROR Total** | | **170.9** | **170.3** | **162.2** | **194.7** | **289.7** | **297.6** | **275.0** | **198.9** | **205.5** | **188.2** | **166.8** | **167.8** | **207.3** |
| **Total** | | **645.0** | **618.6** | **695.3** | **715.3** | **919.0** | **685.9** | **775.7** | **531.4** | **507.1** | **628.0** | **513.1** | **576.6** | **650.9** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2021** | **2/2021** | **3/2021** | **4/2021** | **5/2021** | **6/2021** | **7/2021** | **8/2021** | **9/2021** | **10/2021** | **11/2021** | **12/2021** | **aMW** |
| Brownlee | HCC* | 210.0 | 202.6 | 231.5 | 227.1 | 275.5 | 168.1 | 222.4 | 141.4 | 128.7 | 192.7 | 149.4 | 177.0 | 193.9 |
| Oxbow | HCC | 88.9 | 86.8 | 99.7 | 96.9 | 116.5 | 72.7 | 93.9 | 64.3 | 57.7 | 83.4 | 66.2 | 77.2 | 83.7 |
| Hells Canyon | HCC | 175.8 | 172.6 | 202.0 | 197.4 | 238.7 | 147.5 | 184.4 | 126.6 | 113.7 | 164.1 | 131.3 | 152.4 | 167.2 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 29.4 | 69.9 | 87.7 | 87.1 | 56.6 | 28.7 | 8.8 | 0.0 | 0.0 | 30.7 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.8 | 33.0 | 32.2 | 32.6 | 38.2 | 36.2 | 34.0 | 26.9 | 35.1 | 36.1 | 33.4 | 33.0 | 33.6 |
| C .J. Strike | ROR | 41.1 | 41.5 | 41.7 | 41.8 | 44.0 | 40.1 | 32.1 | 29.5 | 38.9 | 43.0 | 41.9 | 41.3 | 39.7 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.3 | 1.3 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 20.4 | 20.6 | 19.5 | 20.3 | 25.9 | 24.4 | 22.0 | 15.0 | 21.9 | 22.9 | 20.7 | 20.5 | 21.2 |
| Milner | ROR | 0.0 | 0.0 | 0.0 | 0.0 | 9.7 | 9.6 | 6.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.1 |
| Shoshone Falls | ROR | 6.0 | 7.6 | 4.2 | 4.3 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 6.2 | 5.4 | 5.9 | 7.4 |
| Swan Falls | ROR | 14.1 | 14.3 | 14.3 | 14.3 | 15.0 | 13.7 | 11.7 | 10.4 | 13.8 | 14.8 | 14.4 | 14.2 | 13.8 |
| Twin Falls | ROR | 0.0 | 4.0 | 0.0 | 0.0 | 12.4 | 12.8 | 10.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.3 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 12.0 | 12.3 | 11.5 | 12.2 | 16.5 | 15.1 | 13.3 | 8.1 | 13.1 | 13.7 | 12.0 | 11.9 | 12.6 |
| Upper Salmon 3&4 | ROR | 11.4 | 11.7 | 11.0 | 11.6 | 15.3 | 14.1 | 12.6 | 8.1 | 12.4 | 12.9 | 11.5 | 11.4 | 12.0 |
| **HCC Total** | | **474.7** | **462.0** | **533.2** | **521.4** | **630.7** | **388.3** | **500.7** | **332.3** | **300.1** | **440.2** | **346.9** | **406.6** | **444.8** |
| **ROR Total** | | **165.0** | **172.6** | **162.9** | **195.2** | **289.1** | **296.6** | **275.0** | **198.6** | **204.9** | **187.8** | **166.7** | **165.4** | **206.6** |
| **Total** | | **639.7** | **634.6** | **696.1** | **716.6** | **919.8** | **684.9** | **775.7** | **530.9** | **504.9** | **628.0** | **513.6** | **572.0** | **651.4** |

*HCC=Hells Canyon Complex, **ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2022** | **2/2022** | **3/2022** | **4/2022** | **5/2022** | **6/2022** | **7/2022** | **8/2022** | **9/2022** | **10/2022** | **11/2022** | **12/2022** | **aMW** |
| Brownlee | HCC* | 210.4 | 202.9 | 231.8 | 224.7 | 275.9 | 167.9 | 222.1 | 141.1 | 128.2 | 192.5 | 149.3 | 178.0 | 193.7 |
| Oxbow | HCC | 89.1 | 86.9 | 99.8 | 95.9 | 116.7 | 72.6 | 93.8 | 64.2 | 57.4 | 83.3 | 66.1 | 77.7 | 83.6 |
| Hells Canyon | HCC | 176.1 | 172.8 | 202.2 | 195.5 | 239.0 | 147.3 | 184.2 | 126.3 | 113.2 | 164.0 | 131.2 | 153.3 | 167.1 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 30.5 | 70.1 | 87.4 | 86.7 | 56.0 | 28.6 | 8.6 | 0.0 | 0.0 | 30.7 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 33.0 | 33.2 | 32.1 | 32.6 | 38.4 | 36.2 | 34.0 | 26.8 | 35.0 | 36.0 | 33.4 | 33.4 | 33.7 |
| C .J. Strike | ROR | 41.7 | 41.7 | 41.6 | 41.2 | 43.9 | 39.1 | 32.0 | 29.4 | 38.8 | 43.0 | 41.8 | 41.8 | 39.7 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.3 | 1.3 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 20.8 | 21.0 | 19.4 | 20.3 | 26.0 | 24.2 | 21.9 | 14.9 | 21.8 | 22.8 | 20.7 | 20.9 | 21.2 |
| Milner | ROR | 0.0 | 0.0 | 0.0 | 0.0 | 9.6 | 9.5 | 6.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.1 |
| Shoshone Falls | ROR | 7.6 | 9.1 | 4.2 | 4.0 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 6.2 | 5.4 | 7.5 | 7.8 |
| Swan Falls | ROR | 14.3 | 14.3 | 14.2 | 14.1 | 15.0 | 13.4 | 11.6 | 10.3 | 13.8 | 14.8 | 14.4 | 14.2 | 13.7 |
| Twin Falls | ROR | 4.0 | 5.5 | 0.0 | 0.0 | 12.3 | 12.6 | 10.3 | 0.0 | 0.0 | 0.0 | 0.0 | 3.9 | 4.1 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 12.2 | 12.5 | 11.4 | 12.2 | 16.6 | 14.9 | 13.2 | 8.0 | 13.0 | 13.6 | 12.0 | 12.3 | 12.7 |
| Upper Salmon 3&4 | ROR | 11.7 | 11.9 | 11.0 | 11.6 | 15.4 | 14.0 | 12.5 | 8.1 | 12.3 | 12.9 | 11.5 | 11.7 | 12.1 |
| **HCC Total** | | **475.6** | **462.6** | **533.8** | **516.1** | **631.6** | **387.8** | **500.1** | **331.6** | **298.8** | **439.8** | **346.6** | **409.0** | **444.4** |
| **ROR Total** | | **172.5** | **176.8** | **162.4** | **195.2** | **289.5** | **294.2** | **274.1** | **197.5** | **204.2** | **187.3** | **166.6** | **172.9** | **207.8** |
| **Total** | | **648.1** | **639.4** | **696.2** | **711.3** | **921.1** | **682.0** | **774.2** | **529.1** | **503.0** | **627.1** | **513.2** | **581.9** | **652.2** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

**Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2023 | 2/2023 | 3/2023 | 4/2023 | 5/2023 | 6/2023 | 7/2023 | 8/2023 | 9/2023 | 10/2023 | 11/2023 | 12/2023 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 210.1 | 203.2 | 231.5 | 224.6 | 276.1 | 167.6 | 221.8 | 140.7 | 126.9 | 192.6 | 148.8 | 178.1 | 193.5 |
| Oxbow | HCC | 89.0 | 87.1 | 99.7 | 95.9 | 116.7 | 72.5 | 93.6 | 64.0 | 56.8 | 83.3 | 65.9 | 77.7 | 83.5 |
| Hells Canyon | HCC | 175.9 | 173.0 | 202.0 | 195.3 | 239.2 | 147.1 | 183.9 | 126.0 | 112.1 | 164.0 | 130.8 | 153.4 | 166.9 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 30.5 | 70.1 | 87.4 | 86.7 | 56.0 | 28.6 | 8.5 | 0.0 | 0.0 | 30.6 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 33.0 | 33.2 | 32.0 | 32.6 | 38.4 | 36.1 | 33.9 | 26.7 | 34.9 | 35.9 | 33.2 | 33.4 | 33.6 |
| C .J. Strike | ROR | 41.6 | 41.6 | 41.5 | 41.2 | 43.9 | 38.9 | 31.9 | 29.2 | 38.8 | 43.0 | 41.7 | 41.7 | 39.6 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.3 | 1.3 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 20.7 | 20.9 | 19.3 | 20.3 | 26.0 | 24.0 | 21.9 | 14.8 | 21.6 | 22.7 | 20.6 | 20.8 | 21.1 |
| Milner | ROR | 0.0 | 0.0 | 0.0 | 0.0 | 9.5 | 9.4 | 6.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.1 |
| Shoshone Falls | ROR | 7.6 | 9.1 | 4.2 | 4.0 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 6.2 | 5.4 | 7.5 | 7.8 |
| Swan Falls | ROR | 14.2 | 14.3 | 14.2 | 14.1 | 15.0 | 13.4 | 11.6 | 10.3 | 13.8 | 14.7 | 14.3 | 14.2 | 13.7 |
| Twin Falls | ROR | 4.0 | 5.5 | 0.0 | 0.0 | 12.2 | 12.4 | 10.3 | 0.0 | 0.0 | 0.0 | 0.0 | 3.9 | 4.0 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 12.2 | 12.5 | 11.4 | 12.1 | 16.5 | 14.8 | 13.2 | 8.0 | 12.9 | 13.6 | 11.9 | 12.2 | 12.6 |
| Upper Salmon 3&4 | ROR | 11.6 | 11.9 | 10.9 | 11.6 | 15.4 | 13.8 | 12.5 | 8.0 | 12.2 | 12.8 | 11.4 | 11.7 | 12.0 |
| **HCC Total** | | **475.0** | **463.3** | **533.2** | **515.8** | **632.0** | **387.2** | **499.3** | **330.7** | **295.8** | **439.9** | **345.5** | **409.2** | **443.9** |
| **ROR Total** | | **172.1** | **176.6** | **162.0** | **195.1** | **289.2** | **293.1** | **273.9** | **197.0** | **203.7** | **186.8** | **165.9** | **172.6** | **207.3** |
| **Total** | | **647.1** | **639.9** | **695.2** | **710.9** | **921.2** | **680.3** | **773.2** | **527.7** | **499.5** | **626.7** | **511.4** | **581.8** | **651.2** |

*HCC=Hells Canyon Complex, **ROR= Run of River

**Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2024 | 2/2024 | 3/2024 | 4/2024 | 5/2024 | 6/2024 | 7/2024 | 8/2024 | 9/2024 | 10/2024 | 11/2024 | 12/2024 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 209.8 | 193.2 | 231.2 | 224.4 | 276.3 | 167.3 | 221.5 | 140.3 | 125.5 | 192.3 | 149.2 | 177.9 | 192.4 |
| Oxbow | HCC | 88.9 | 82.8 | 99.6 | 95.8 | 116.8 | 72.3 | 93.5 | 63.9 | 56.2 | 83.1 | 66.0 | 77.6 | 83.0 |
| Hells Canyon | HCC | 175.7 | 164.6 | 201.7 | 195.2 | 239.3 | 146.8 | 183.6 | 125.6 | 110.9 | 163.6 | 131.0 | 153.1 | 165.9 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 30.4 | 70.1 | 87.4 | 86.7 | 56.0 | 28.5 | 8.5 | 0.0 | 0.0 | 30.6 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.9 | 32.0 | 31.9 | 32.6 | 38.5 | 36.1 | 33.8 | 26.6 | 34.7 | 35.7 | 33.1 | 33.3 | 33.4 |
| C .J. Strike | ROR | 41.5 | 40.2 | 41.4 | 41.2 | 43.9 | 38.8 | 31.8 | 29.1 | 38.7 | 42.9 | 41.6 | 41.4 | 39.4 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.3 | 1.3 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 20.7 | 20.1 | 19.3 | 20.2 | 26.0 | 23.8 | 21.8 | 14.7 | 21.5 | 22.6 | 20.5 | 20.7 | 21.0 |
| Milner | ROR | 0.0 | 0.0 | 0.0 | 0.0 | 9.3 | 9.2 | 6.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.1 |
| Shoshone Falls | ROR | 7.6 | 8.8 | 4.2 | 4.0 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 6.2 | 5.4 | 7.5 | 7.7 |
| Swan Falls | ROR | 14.2 | 13.8 | 14.2 | 14.1 | 15.0 | 13.3 | 11.6 | 10.2 | 13.8 | 14.7 | 14.3 | 14.2 | 13.6 |
| Twin Falls | ROR | 4.0 | 5.3 | 0.0 | 0.0 | 12.0 | 12.3 | 10.3 | 0.0 | 0.0 | 0.0 | 0.0 | 3.9 | 4.0 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 12.1 | 12.0 | 11.3 | 12.1 | 16.5 | 14.6 | 13.1 | 7.9 | 12.8 | 13.5 | 11.9 | 12.2 | 12.5 |
| Upper Salmon 3&4 | ROR | 11.6 | 11.4 | 10.9 | 11.6 | 15.4 | 13.7 | 12.4 | 8.0 | 12.1 | 12.7 | 11.3 | 11.6 | 11.9 |
| **HCC Total** | | **474.4** | **440.7** | **532.5** | **515.4** | **632.4** | **386.4** | **498.6** | **329.8** | **292.5** | **439.0** | **346.2** | **408.6** | **441.4** |
| **ROR Total** | | **171.8** | **171.0** | **161.7** | **194.9** | **288.9** | **292.1** | **273.4** | **196.5** | **203.1** | **186.2** | **165.5** | **172.0** | **206.4** |
| **Total** | | **646.2** | **611.7** | **694.2** | **710.3** | **921.3** | **678.5** | **772.0** | **526.3** | **495.6** | **625.2** | **511.7** | **580.6** | **647.8** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2025** | **2/2025** | **3/2025** | **4/2025** | **5/2025** | **6/2025** | **7/2025** | **8/2025** | **9/2025** | **10/2025** | **11/2025** | **12/2025** | **aMW** |
| Brownlee | HCC* | 209.6 | 195.7 | 230.9 | 224.2 | 276.4 | 167.0 | 221.0 | 139.9 | 124.1 | 192.2 | 149.1 | 177.5 | 192.3 |
| Oxbow | HCC | 88.8 | 83.9 | 99.4 | 95.7 | 116.9 | 72.2 | 93.3 | 63.7 | 55.5 | 83.0 | 65.9 | 77.4 | 83.0 |
| Hells Canyon | HCC | 175.4 | 166.8 | 201.4 | 195.0 | 239.4 | 146.5 | 183.3 | 125.3 | 109.6 | 163.4 | 130.9 | 152.9 | 165.8 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 30.3 | 69.8 | 87.3 | 86.7 | 56.0 | 28.4 | 8.4 | 0.0 | 0.0 | 30.6 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.8 | 33.0 | 31.8 | 32.5 | 38.5 | 36.0 | 33.7 | 26.5 | 34.5 | 35.6 | 33.0 | 33.2 | 33.4 |
| C .J. Strike | ROR | 41.4 | 41.5 | 41.2 | 41.1 | 44.0 | 38.6 | 31.6 | 28.9 | 38.6 | 42.8 | 41.5 | 41.3 | 39.4 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.3 | 1.3 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 20.5 | 20.7 | 19.2 | 20.2 | 25.9 | 23.6 | 21.7 | 14.6 | 21.3 | 22.4 | 20.3 | 20.6 | 20.9 |
| Milner | ROR | 0.0 | 0.0 | 0.0 | 0.0 | 9.2 | 9.1 | 6.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.1 |
| Shoshone Falls | ROR | 7.6 | 9.1 | 4.2 | 4.0 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 6.2 | 5.4 | 7.5 | 7.8 |
| Swan Falls | ROR | 14.2 | 14.2 | 14.2 | 14.1 | 15.0 | 13.3 | 11.5 | 10.2 | 13.8 | 14.6 | 14.2 | 14.1 | 13.6 |
| Twin Falls | ROR | 4.0 | 5.5 | 0.0 | 0.0 | 11.9 | 12.3 | 10.3 | 0.0 | 0.0 | 0.0 | 0.0 | 4.0 | 4.0 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 12.0 | 12.4 | 11.3 | 12.1 | 16.5 | 14.4 | 13.0 | 7.8 | 12.7 | 13.4 | 11.8 | 12.1 | 12.5 |
| Upper Salmon 3&4 | ROR | 11.5 | 11.8 | 10.8 | 11.5 | 15.3 | 13.6 | 12.3 | 7.9 | 12.0 | 12.6 | 11.3 | 11.5 | 11.8 |
| **HCC Total** | | **473.8** | **446.4** | **531.7** | **514.9** | **632.7** | **385.7** | **497.6** | **328.9** | **289.2** | **438.6** | **345.9** | **407.8** | **441.1** |
| **ROR Total** | | **171.2** | **175.8** | **161.2** | **194.5** | **288.3** | **291.1** | **272.7** | **195.9** | **202.2** | **185.4** | **164.9** | **171.5** | **206.2** |
| **Total** | | **645.0** | **622.2** | **692.9** | **709.4** | **921.0** | **676.8** | **770.3** | **524.8** | **491.4** | **624.0** | **510.8** | **579.3** | **647.3** |

*HCC=Hells Canyon Complex, **ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2026** | **2/2026** | **3/2026** | **4/2026** | **5/2026** | **6/2026** | **7/2026** | **8/2026** | **9/2026** | **10/2026** | **11/2026** | **12/2026** | **aMW** |
| Brownlee | HCC* | 209.2 | 192.4 | 230.5 | 223.9 | 276.5 | 166.8 | 220.7 | 139.5 | 121.6 | 192.7 | 149.5 | 177.1 | 191.7 |
| Oxbow | HCC | 88.6 | 82.4 | 99.2 | 95.5 | 116.9 | 72.1 | 93.2 | 63.4 | 54.4 | 83.1 | 66.1 | 77.3 | 82.7 |
| Hells Canyon | HCC | 175.1 | 164.0 | 201.1 | 194.7 | 239.5 | 146.4 | 183.0 | 124.9 | 107.4 | 163.5 | 131.2 | 152.5 | 165.3 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 30.3 | 69.5 | 87.0 | 86.7 | 56.0 | 28.1 | 8.3 | 0.0 | 0.0 | 30.5 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.7 | 32.9 | 31.7 | 32.5 | 38.3 | 35.7 | 33.6 | 26.3 | 34.3 | 35.4 | 32.9 | 33.1 | 33.3 |
| C .J. Strike | ROR | 41.1 | 41.5 | 41.1 | 41.0 | 44.0 | 38.4 | 31.5 | 28.8 | 38.6 | 42.7 | 41.5 | 41.2 | 39.3 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.3 | 1.3 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 20.4 | 20.6 | 19.1 | 20.1 | 25.9 | 23.4 | 21.6 | 14.5 | 21.1 | 22.3 | 20.2 | 20.6 | 20.8 |
| Milner | ROR | 0.0 | 0.0 | 0.0 | 0.0 | 9.2 | 9.1 | 6.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.1 |
| Shoshone Falls | ROR | 7.6 | 9.2 | 4.2 | 4.0 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 6.2 | 5.4 | 7.5 | 7.8 |
| Swan Falls | ROR | 14.1 | 14.1 | 14.2 | 14.1 | 15.0 | 13.2 | 11.5 | 10.1 | 13.7 | 14.6 | 14.2 | 14.1 | 13.6 |
| Twin Falls | ROR | 4.0 | 5.5 | 0.0 | 0.0 | 11.9 | 12.3 | 10.3 | 0.0 | 0.0 | 0.0 | 0.0 | 4.0 | 4.0 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 12.0 | 12.3 | 11.2 | 12.0 | 16.5 | 14.4 | 13.0 | 7.7 | 12.5 | 13.3 | 11.7 | 12.0 | 12.4 |
| Upper Salmon 3&4 | ROR | 11.4 | 11.7 | 10.8 | 11.5 | 15.3 | 13.5 | 12.3 | 7.8 | 11.9 | 12.5 | 11.2 | 11.5 | 11.8 |
| **HCC Total** | | **472.9** | **438.8** | **530.8** | **514.1** | **632.9** | **385.3** | **496.9** | **327.8** | **283.3** | **439.3** | **346.8** | **406.9** | **439.7** |
| **ROR Total** | | **170.5** | **175.4** | **160.8** | **194.2** | **287.8** | **289.9** | **272.4** | **195.2** | **201.2** | **184.7** | **164.5** | **171.2** | **205.6** |
| **Total** | | **643.4** | **614.2** | **691.6** | **708.3** | **920.7** | **675.2** | **769.3** | **523.0** | **484.5** | **624.0** | **511.3** | **578.1** | **645.3** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Hydro Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2027** | **2/2027** | **3/2027** | **4/2027** | **5/2027** | **6/2027** | **7/2027** | **8/2027** | **9/2027** | **10/2027** | **11/2027** | **12/2027** | **aMW** |
| Brownlee | HCC* | 208.8 | 192.0 | 230.1 | 223.6 | 276.5 | 166.7 | 220.2 | 139.0 | 120.2 | 192.6 | 149.4 | 176.8 | 191.3 |
| Oxbow | HCC | 88.5 | 82.3 | 99.1 | 95.4 | 116.9 | 72.0 | 93.0 | 63.2 | 53.7 | 83.0 | 66.0 | 77.1 | 82.5 |
| Hells Canyon | HCC | 174.8 | 163.7 | 200.7 | 194.5 | 239.5 | 146.3 | 182.6 | 124.5 | 106.2 | 163.4 | 131.1 | 152.2 | 165.0 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 30.3 | 69.5 | 86.9 | 86.7 | 56.0 | 27.8 | 8.2 | 0.0 | 0.0 | 30.4 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.6 | 32.7 | 31.7 | 32.5 | 38.2 | 35.3 | 33.4 | 26.2 | 34.1 | 35.3 | 32.7 | 33.0 | 33.1 |
| C .J. Strike | ROR | 41.0 | 41.5 | 41.0 | 40.9 | 44.0 | 38.1 | 31.3 | 28.6 | 38.4 | 42.5 | 41.4 | 41.2 | 39.2 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.3 | 1.3 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 20.2 | 20.5 | 19.0 | 20.1 | 25.8 | 23.3 | 21.5 | 14.4 | 21.0 | 22.2 | 20.1 | 20.5 | 20.7 |
| Milner | ROR | 0.0 | 0.0 | 0.0 | 0.0 | 8.6 | 8.6 | 6.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.0 |
| Shoshone Falls | ROR | 7.7 | 9.2 | 4.2 | 4.0 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 6.2 | 5.4 | 7.6 | 7.8 |
| Swan Falls | ROR | 14.1 | 14.1 | 14.1 | 14.1 | 15.0 | 13.1 | 11.4 | 10.1 | 13.6 | 14.5 | 14.1 | 14.1 | 13.5 |
| Twin Falls | ROR | 4.1 | 5.5 | 0.0 | 0.0 | 11.4 | 12.3 | 10.3 | 0.0 | 0.0 | 0.0 | 0.0 | 4.0 | 4.0 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 11.8 | 12.2 | 11.1 | 12.0 | 16.4 | 14.3 | 12.9 | 7.6 | 12.4 | 13.1 | 11.6 | 12.0 | 12.3 |
| Upper Salmon 3&4 | ROR | 11.3 | 11.6 | 10.7 | 11.5 | 15.2 | 13.4 | 12.2 | 7.7 | 11.8 | 12.4 | 11.1 | 11.4 | 11.7 |
| **HCC Total** | | **472.1** | **438.0** | **529.9** | **513.5** | **632.9** | **385.0** | **495.8** | **326.7** | **280.0** | **439.0** | **346.5** | **406.1** | **438.8** |
| **ROR Total** | | **170.0** | **174.9** | **160.3** | **194.1** | **286.3** | **288.2** | **271.6** | **194.6** | **200.1** | **183.8** | **163.8** | **171.0** | **204.9** |
| **Total** | | **642.1** | **612.9** | **690.2** | **707.6** | **919.2** | **673.2** | **767.4** | **521.3** | **480.1** | **622.8** | **510.3** | **577.1** | **643.7** |

*HCC=Hells Canyon Complex, **ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2028** | **2/2028** | **3/2028** | **4/2028** | **5/2028** | **6/2028** | **7/2028** | **8/2028** | **9/2028** | **10/2028** | **11/2028** | **12/2028** | **aMW** |
| Brownlee | HCC* | 208.4 | 185.0 | 228.1 | 223.2 | 276.6 | 166.4 | 219.7 | 138.6 | 118.1 | 193.0 | 149.6 | 176.4 | 190.3 |
| Oxbow | HCC | 88.3 | 79.3 | 98.2 | 95.3 | 117.0 | 71.9 | 92.8 | 63.0 | 52.7 | 83.1 | 66.1 | 76.9 | 82.0 |
| Hells Canyon | HCC | 174.5 | 157.8 | 199.1 | 194.2 | 239.6 | 146.1 | 182.2 | 124.1 | 104.3 | 163.5 | 131.2 | 151.9 | 164.0 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 30.3 | 69.3 | 86.8 | 86.7 | 56.0 | 27.7 | 8.2 | 0.0 | 0.0 | 30.4 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.5 | 31.5 | 31.6 | 32.5 | 37.8 | 34.9 | 33.3 | 26.1 | 33.9 | 35.1 | 32.6 | 32.9 | 32.9 |
| C .J. Strike | ROR | 40.9 | 40.0 | 40.9 | 40.8 | 44.0 | 37.9 | 31.2 | 28.4 | 38.2 | 42.4 | 41.3 | 41.1 | 38.9 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.3 | 1.3 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 20.1 | 19.7 | 18.9 | 20.0 | 25.6 | 23.2 | 21.4 | 14.3 | 20.8 | 22.0 | 19.9 | 20.4 | 20.5 |
| Milner | ROR | 0.0 | 0.0 | 0.0 | 0.0 | 8.3 | 8.2 | 6.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.9 |
| Shoshone Falls | ROR | 7.7 | 8.9 | 4.2 | 4.0 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 6.2 | 5.4 | 7.6 | 7.7 |
| Swan Falls | ROR | 14.1 | 13.7 | 14.1 | 14.0 | 15.0 | 13.0 | 11.4 | 10.0 | 13.5 | 14.4 | 14.1 | 14.1 | 13.5 |
| Twin Falls | ROR | 4.1 | 5.3 | 0.0 | 0.0 | 11.1 | 11.9 | 10.3 | 0.0 | 0.0 | 0.0 | 0.0 | 4.0 | 3.9 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 11.7 | 11.7 | 11.0 | 11.9 | 16.2 | 14.2 | 12.8 | 7.5 | 12.3 | 13.0 | 11.5 | 11.9 | 12.1 |
| Upper Salmon 3&4 | ROR | 11.2 | 11.1 | 10.6 | 11.4 | 15.1 | 13.3 | 12.2 | 7.7 | 11.7 | 12.3 | 11.0 | 11.4 | 11.6 |
| **HCC Total** | | **471.2** | **422.0** | **525.4** | **512.7** | **633.2** | **384.4** | **494.7** | **325.7** | **275.0** | **439.6** | **346.9** | **405.2** | **436.3** |
| **ROR Total** | | **169.5** | **169.4** | **159.8** | **193.6** | **284.6** | **286.3** | **271.2** | **194.0** | **199.0** | **183.0** | **163.2** | **170.6** | **203.7** |
| **Total** | | **640.7** | **591.4** | **685.2** | **706.3** | **917.8** | **670.7** | **765.9** | **519.7** | **474.0** | **622.6** | **510.1** | **575.8** | **640.0** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2029** | **2/2029** | **3/2029** | **4/2029** | **5/2029** | **6/2029** | **7/2029** | **8/2029** | **9/2029** | **10/2029** | **11/2029** | **12/2029** | **aMW** |
| Brownlee | HCC* | 208.0 | 191.3 | 227.6 | 222.8 | 276.7 | 165.6 | 219.2 | 138.1 | 116.2 | 192.9 | 149.7 | 175.9 | 190.3 |
| Oxbow | HCC | 88.1 | 81.9 | 98.0 | 95.1 | 117.0 | 71.6 | 92.6 | 62.8 | 51.9 | 83.0 | 66.1 | 76.7 | 82.1 |
| Hells Canyon | HCC | 174.2 | 163.1 | 198.7 | 193.9 | 239.6 | 145.4 | 181.8 | 123.6 | 102.7 | 163.3 | 131.3 | 151.5 | 164.1 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 30.3 | 69.0 | 86.8 | 86.7 | 56.0 | 27.5 | 8.4 | 0.0 | 0.0 | 30.4 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.4 | 32.5 | 31.5 | 32.4 | 37.7 | 34.6 | 33.2 | 25.9 | 33.7 | 34.9 | 32.4 | 32.8 | 32.8 |
| C .J. Strike | ROR | 40.8 | 41.3 | 40.4 | 40.5 | 43.9 | 37.7 | 31.0 | 28.2 | 37.9 | 42.2 | 41.1 | 40.9 | 38.8 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.3 | 1.3 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 20.0 | 20.2 | 18.8 | 19.9 | 25.3 | 23.0 | 21.3 | 14.2 | 20.6 | 21.9 | 19.8 | 20.3 | 20.4 |
| Milner | ROR | 0.0 | 0.0 | 0.0 | 0.0 | 8.3 | 8.2 | 6.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.9 |
| Shoshone Falls | ROR | 7.7 | 9.1 | 4.2 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 6.2 | 5.4 | 7.6 | 7.8 |
| Swan Falls | ROR | 14.1 | 14.1 | 14.1 | 14.0 | 15.0 | 13.0 | 11.3 | 9.9 | 13.4 | 14.4 | 14.1 | 14.1 | 13.5 |
| Twin Falls | ROR | 4.1 | 5.4 | 0.0 | 0.0 | 11.1 | 11.8 | 10.3 | 0.0 | 0.0 | 0.0 | 0.0 | 4.0 | 3.9 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 11.6 | 12.0 | 11.0 | 11.9 | 16.1 | 14.0 | 12.7 | 7.4 | 12.1 | 12.9 | 11.4 | 11.8 | 12.1 |
| Upper Salmon 3&4 | ROR | 11.1 | 11.4 | 10.6 | 11.4 | 14.9 | 13.2 | 12.1 | 7.6 | 11.6 | 12.2 | 10.9 | 11.3 | 11.5 |
| **HCC Total** | | **470.3** | **436.3** | **524.3** | **511.8** | **633.3** | **382.6** | **493.6** | **324.5** | **270.7** | **439.2** | **347.1** | **404.1** | **436.5** |
| **ROR Total** | | **169.0** | **173.6** | **159.1** | **193.0** | **283.5** | **285.2** | **270.5** | **193.2** | **197.8** | **182.5** | **162.5** | **170.0** | **203.3** |
| **Total** | | **639.3** | **609.9** | **683.4** | **704.8** | **916.8** | **667.8** | **764.1** | **517.7** | **468.5** | **621.7** | **509.6** | **574.1** | **639.8** |

*HCC=Hells Canyon Complex, **ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2030** | **2/2030** | **3/2030** | **4/2030** | **5/2030** | **6/2030** | **7/2030** | **8/2030** | **9/2030** | **10/2030** | **11/2030** | **12/2030** | **aMW** |
| Brownlee | HCC* | 207.6 | 190.8 | 227.2 | 222.2 | 276.7 | 164.9 | 218.8 | 137.6 | 114.5 | 192.9 | 149.9 | 175.5 | 189.9 |
| Oxbow | HCC | 87.9 | 81.8 | 97.8 | 94.8 | 117.0 | 71.2 | 92.4 | 62.5 | 51.1 | 82.9 | 66.2 | 76.5 | 81.8 |
| Hells Canyon | HCC | 173.8 | 162.7 | 198.3 | 193.4 | 239.7 | 144.8 | 181.4 | 123.2 | 101.1 | 163.1 | 131.4 | 151.2 | 163.7 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 30.9 | 69.0 | 86.4 | 86.7 | 56.1 | 27.4 | 8.3 | 0.0 | 0.0 | 30.4 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.3 | 32.4 | 31.4 | 32.3 | 37.7 | 34.4 | 33.1 | 25.8 | 33.6 | 34.8 | 32.3 | 32.7 | 32.7 |
| C .J. Strike | ROR | 40.8 | 41.1 | 40.3 | 40.3 | 43.9 | 37.5 | 30.8 | 28.0 | 37.7 | 42.1 | 40.9 | 40.8 | 38.7 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.3 | 1.3 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 19.9 | 20.2 | 18.7 | 19.9 | 25.3 | 22.8 | 21.2 | 14.0 | 20.5 | 21.7 | 19.7 | 20.2 | 20.3 |
| Milner | ROR | 0.0 | 0.0 | 0.0 | 0.0 | 8.2 | 8.1 | 6.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.9 |
| Shoshone Falls | ROR | 7.7 | 9.1 | 4.2 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 6.2 | 5.4 | 7.6 | 7.8 |
| Swan Falls | ROR | 14.1 | 14.1 | 14.1 | 13.9 | 15.0 | 12.9 | 11.2 | 9.9 | 13.4 | 14.3 | 14.1 | 14.0 | 13.4 |
| Twin Falls | ROR | 4.1 | 5.4 | 0.0 | 0.0 | 11.0 | 11.6 | 10.3 | 0.0 | 0.0 | 0.0 | 0.0 | 4.0 | 3.9 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 11.6 | 11.9 | 10.9 | 11.8 | 16.0 | 13.9 | 12.7 | 7.3 | 12.0 | 12.8 | 11.3 | 11.7 | 12.0 |
| Upper Salmon 3&4 | ROR | 11.1 | 11.4 | 10.5 | 11.3 | 14.9 | 13.1 | 12.0 | 7.5 | 11.5 | 12.1 | 10.8 | 11.2 | 11.5 |
| **HCC Total** | | **469.3** | **435.3** | **523.3** | **510.4** | **633.4** | **380.9** | **492.6** | **323.3** | **266.6** | **438.9** | **347.5** | **403.2** | **435.4** |
| **ROR Total** | | **168.8** | **173.2** | **158.6** | **193.0** | **283.2** | **283.6** | **269.9** | **192.6** | **197.1** | **181.7** | **161.9** | **169.4** | **202.7** |
| **Total** | | **638.1** | **608.5** | **681.9** | **703.4** | **916.6** | **664.5** | **762.5** | **515.9** | **463.7** | **620.6** | **509.4** | **572.6** | **638.1** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Modeling Results (PDR580) (continued)

**Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2031 | 2/2031 | 3/2031 | 4/2031 | 5/2031 | 6/2031 | 7/2031 | 8/2031 | 9/2031 | 10/2031 | 11/2031 | 12/2031 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 207.2 | 190.4 | 226.7 | 221.8 | 276.7 | 164.4 | 218.3 | 137.1 | 113.9 | 192.3 | 149.6 | 177.7 | 189.7 |
| Oxbow | HCC | 87.7 | 81.6 | 97.6 | 94.7 | 117.0 | 71.0 | 92.2 | 62.3 | 50.8 | 82.6 | 66.0 | 77.5 | 81.8 |
| Hells Canyon | HCC | 173.5 | 162.4 | 197.9 | 193.0 | 239.7 | 144.4 | 181.0 | 122.7 | 100.6 | 162.7 | 131.1 | 153.0 | 163.5 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 31.1 | 68.8 | 86.6 | 86.5 | 56.0 | 27.4 | 8.3 | 0.0 | 0.0 | 30.4 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.3 | 32.4 | 31.6 | 32.2 | 37.7 | 34.2 | 33.0 | 25.6 | 33.4 | 34.6 | 32.1 | 32.7 | 32.7 |
| C .J. Strike | ROR | 41.0 | 41.0 | 40.6 | 40.1 | 43.8 | 37.3 | 30.7 | 27.9 | 37.4 | 42.0 | 40.8 | 40.6 | 38.6 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.3 | 1.3 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 19.9 | 20.1 | 18.7 | 19.8 | 25.2 | 22.6 | 21.1 | 13.9 | 20.3 | 21.6 | 19.5 | 20.1 | 20.2 |
| Milner | ROR | 0.0 | 0.0 | 0.0 | 0.0 | 8.1 | 8.0 | 6.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.9 |
| Shoshone Falls | ROR | 7.7 | 9.2 | 4.2 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 6.2 | 5.4 | 7.6 | 7.8 |
| Swan Falls | ROR | 14.1 | 14.1 | 14.1 | 13.9 | 15.0 | 12.9 | 11.2 | 9.8 | 13.3 | 14.2 | 14.1 | 14.0 | 13.4 |
| Twin Falls | ROR | 4.1 | 5.5 | 0.0 | 0.0 | 10.8 | 11.3 | 10.3 | 0.0 | 0.0 | 0.0 | 0.0 | 4.0 | 3.8 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 11.6 | 11.9 | 10.8 | 11.8 | 15.9 | 13.7 | 12.6 | 7.2 | 11.9 | 12.7 | 11.2 | 11.7 | 11.9 |
| Upper Salmon 3&4 | ROR | 11.1 | 11.3 | 10.5 | 11.3 | 14.8 | 12.9 | 12.0 | 7.4 | 11.4 | 12.0 | 10.7 | 11.2 | 11.4 |
| **HCC Total** | | **468.4** | **434.4** | **522.2** | **509.5** | **633.4** | **379.8** | **491.5** | **322.1** | **265.3** | **437.6** | **346.7** | **408.2** | **434.9** |
| **ROR Total** | | **169.0** | **173.1** | **159.0** | **192.8** | **282.3** | **282.4** | **269.3** | **191.8** | **196.0** | **181.0** | **161.2** | **169.1** | **202.2** |
| **Total** | | **637.4** | **607.5** | **681.2** | **702.3** | **915.7** | **662.2** | **760.8** | **513.9** | **461.3** | **618.6** | **507.9** | **577.3** | **637.2** |

*HCC=Hells Canyon Complex, **ROR= Run of River

**Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2032 | 2/2032 | 3/2032 | 4/2032 | 5/2032 | 6/2032 | 7/2032 | 8/2032 | 9/2032 | 10/2032 | 11/2032 | 12/2032 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 206.6 | 183.4 | 226.3 | 221.4 | 276.8 | 163.8 | 217.8 | 136.5 | 113.8 | 190.2 | 149.7 | 176.5 | 188.6 |
| Oxbow | HCC | 87.5 | 78.6 | 97.4 | 94.5 | 117.0 | 70.8 | 91.9 | 62.1 | 50.8 | 81.7 | 66.1 | 77.0 | 81.3 |
| Hells Canyon | HCC | 173.0 | 156.4 | 197.6 | 192.7 | 239.7 | 143.8 | 180.6 | 122.2 | 100.6 | 160.9 | 131.2 | 152.0 | 162.6 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 31.1 | 68.4 | 86.4 | 86.5 | 56.0 | 27.2 | 8.3 | 0.0 | 0.0 | 30.3 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.2 | 31.2 | 31.6 | 32.1 | 37.6 | 33.9 | 32.8 | 25.5 | 33.2 | 34.4 | 32.0 | 32.6 | 32.4 |
| C .J. Strike | ROR | 40.9 | 39.4 | 40.5 | 39.8 | 43.8 | 37.1 | 30.6 | 27.7 | 37.1 | 41.8 | 40.5 | 40.5 | 38.3 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.3 | 1.3 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 19.8 | 19.3 | 18.6 | 19.7 | 24.9 | 22.2 | 21.0 | 13.8 | 20.1 | 21.4 | 19.4 | 20.0 | 20.0 |
| Milner | ROR | 0.0 | 0.0 | 0.0 | 0.0 | 7.8 | 7.7 | 6.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.8 |
| Shoshone Falls | ROR | 7.7 | 8.9 | 4.2 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 6.2 | 5.4 | 7.6 | 7.7 |
| Swan Falls | ROR | 14.1 | 13.5 | 14.0 | 13.8 | 14.9 | 12.8 | 11.1 | 9.8 | 13.2 | 14.2 | 14.0 | 14.0 | 13.3 |
| Twin Falls | ROR | 4.1 | 5.3 | 0.0 | 0.0 | 10.5 | 11.0 | 10.3 | 0.0 | 0.0 | 0.0 | 0.0 | 4.0 | 3.8 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 11.5 | 11.4 | 10.8 | 11.7 | 15.7 | 13.4 | 12.5 | 7.1 | 11.7 | 12.6 | 11.0 | 11.6 | 11.7 |
| Upper Salmon 3&4 | ROR | 11.1 | 10.9 | 10.4 | 11.2 | 14.7 | 12.7 | 11.9 | 7.3 | 11.2 | 11.9 | 10.6 | 11.1 | 11.3 |
| **HCC Total** | | **467.1** | **418.5** | **521.3** | **508.6** | **633.5** | **378.4** | **490.3** | **320.8** | **265.2** | **432.8** | **347.0** | **405.5** | **432.4** |
| **ROR Total** | | **168.6** | **167.5** | **158.6** | **192.0** | **280.5** | **280.1** | **268.6** | **191.2** | **194.7** | **180.2** | **160.3** | **168.6** | **200.9** |
| **Total** | | **635.7** | **585.9** | **679.9** | **700.6** | **914.0** | **658.5** | **758.9** | **512.0** | **459.9** | **613.0** | **507.3** | **574.1** | **633.3** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Modeling Results (PDR580) (continued)

**Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2033 | 2/2033 | 3/2033 | 4/2033 | 5/2033 | 6/2033 | 7/2033 | 8/2033 | 9/2033 | 10/2033 | 11/2033 | 12/2033 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 206.4 | 189.5 | 225.8 | 221.1 | 276.4 | 163.2 | 217.3 | 136.0 | 113.8 | 188.0 | 149.9 | 175.9 | 188.6 |
| Oxbow | HCC | 87.4 | 81.2 | 97.2 | 94.4 | 116.9 | 70.5 | 91.7 | 61.8 | 50.8 | 80.8 | 66.1 | 76.7 | 81.3 |
| Hells Canyon | HCC | 172.8 | 161.7 | 197.2 | 192.5 | 239.4 | 143.4 | 180.2 | 121.8 | 100.6 | 159.1 | 131.3 | 151.5 | 162.6 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 30.1 | 68.4 | 85.9 | 86.6 | 56.0 | 27.1 | 8.2 | 0.0 | 0.0 | 30.2 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 32.0 | 32.2 | 31.5 | 32.1 | 37.6 | 33.8 | 32.7 | 25.3 | 33.0 | 34.3 | 31.8 | 32.4 | 32.4 |
| C .J. Strike | ROR | 40.8 | 40.7 | 40.4 | 39.3 | 43.8 | 36.9 | 30.4 | 27.5 | 36.9 | 41.6 | 40.3 | 40.3 | 38.2 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.3 | 1.3 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 19.7 | 19.9 | 18.5 | 19.7 | 24.9 | 22.1 | 20.9 | 13.6 | 19.9 | 21.3 | 19.3 | 19.9 | 20.0 |
| Milner | ROR | 0.0 | 0.0 | 0.0 | 0.0 | 7.7 | 7.6 | 6.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.8 |
| Shoshone Falls | ROR | 7.7 | 9.2 | 4.2 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 6.2 | 5.4 | 7.6 | 7.8 |
| Swan Falls | ROR | 14.0 | 14.0 | 14.0 | 13.6 | 14.9 | 12.8 | 11.1 | 9.7 | 13.1 | 14.1 | 13.9 | 13.9 | 13.3 |
| Twin Falls | ROR | 4.1 | 5.5 | 0.0 | 0.0 | 10.5 | 10.9 | 10.3 | 0.0 | 0.0 | 0.0 | 0.0 | 4.0 | 3.8 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 11.4 | 11.7 | 10.7 | 11.7 | 15.7 | 13.3 | 12.4 | 7.0 | 11.6 | 12.4 | 10.9 | 11.5 | 11.7 |
| Upper Salmon 3&4 | ROR | 10.9 | 11.2 | 10.3 | 11.2 | 14.6 | 12.6 | 11.8 | 7.3 | 11.1 | 11.8 | 10.6 | 11.0 | 11.2 |
| **HCC Total** | | **466.6** | **432.4** | **520.2** | **508.0** | **632.7** | **377.1** | **489.2** | **319.6** | **265.2** | **427.9** | **347.3** | **404.1** | **432.5** |
| **ROR Total** | | **167.8** | **172.0** | **158.1** | **190.3** | **280.3** | **278.8** | **268.1** | **190.4** | **193.6** | **179.3** | **159.6** | **167.8** | **200.5** |
| **Total** | | **634.4** | **604.4** | **678.3** | **698.3** | **913.0** | **655.9** | **757.3** | **510.0** | **458.8** | **607.2** | **506.9** | **571.9** | **633.0** |

*HCC=Hells Canyon Complex, **ROR= Run of River

**Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load**

| Resource | Type | 1/2034 | 2/2034 | 3/2034 | 4/2034 | 5/2034 | 6/2034 | 7/2034 | 8/2034 | 9/2034 | 10/2034 | 11/2034 | 12/2034 | aMW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Brownlee | HCC* | 206.3 | 189.1 | 225.4 | 220.8 | 275.9 | 162.6 | 216.8 | 135.5 | 113.7 | 186.2 | 149.7 | 175.4 | 188.1 |
| Oxbow | HCC | 87.4 | 81.0 | 97.0 | 94.3 | 116.7 | 70.3 | 91.5 | 61.6 | 50.8 | 80.0 | 66.0 | 76.5 | 81.1 |
| Hells Canyon | HCC | 172.7 | 161.3 | 196.8 | 192.2 | 239.0 | 142.9 | 179.8 | 121.3 | 100.6 | 157.6 | 131.1 | 151.1 | 162.2 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 30.9 | 68.4 | 85.1 | 86.6 | 56.0 | 26.6 | 8.1 | 0.0 | 0.0 | 30.1 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 31.8 | 32.0 | 31.4 | 31.8 | 37.6 | 33.6 | 32.6 | 25.2 | 32.8 | 34.1 | 31.6 | 32.3 | 32.2 |
| C .J. Strike | ROR | 40.4 | 40.5 | 40.3 | 39.2 | 43.5 | 36.4 | 30.4 | 27.3 | 36.6 | 41.4 | 40.1 | 40.2 | 38.0 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.3 | 1.3 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 19.5 | 19.8 | 18.3 | 19.6 | 24.7 | 21.9 | 20.8 | 13.5 | 19.7 | 21.1 | 19.1 | 19.8 | 19.8 |
| Milner | ROR | 0.0 | 0.0 | 0.0 | 0.0 | 7.5 | 7.4 | 6.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.8 |
| Shoshone Falls | ROR | 7.7 | 9.2 | 4.2 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 6.2 | 5.4 | 7.6 | 7.8 |
| Swan Falls | ROR | 13.9 | 13.9 | 13.9 | 13.6 | 14.8 | 12.6 | 11.0 | 9.7 | 13.0 | 14.2 | 13.9 | 13.9 | 13.2 |
| Twin Falls | ROR | 4.1 | 5.5 | 0.0 | 0.0 | 10.2 | 10.7 | 10.3 | 0.0 | 0.0 | 0.0 | 0.0 | 4.0 | 3.7 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 11.2 | 11.6 | 10.6 | 11.6 | 15.6 | 13.1 | 12.3 | 6.9 | 11.5 | 12.3 | 10.8 | 11.4 | 11.6 |
| Upper Salmon 3&4 | ROR | 10.8 | 11.1 | 10.3 | 11.1 | 14.5 | 12.4 | 11.7 | 7.2 | 11.0 | 11.7 | 10.5 | 11.0 | 11.1 |
| **HCC Total** | | **466.4** | **431.4** | **519.2** | **507.3** | **631.6** | **375.8** | **488.1** | **318.4** | **265.1** | **423.8** | **346.8** | **403.0** | **431.4** |
| **ROR Total** | | **166.6** | **171.2** | **157.5** | **190.4** | **279.0** | **276.1** | **267.6** | **189.8** | **192.1** | **178.5** | **158.8** | **167.4** | **199.6** |
| **Total** | | **633.0** | **602.6** | **676.7** | **697.7** | **910.6** | **651.9** | **755.7** | **508.2** | **457.2** | **602.3** | **505.6** | **570.4** | **631.0** |

*HCC=Hells Canyon Complex, **ROR= Run of River

# Modeling Results (PDR580) (continued)

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2035** | **2/2035** | **3/2035** | **4/2035** | **5/2035** | **6/2035** | **7/2035** | **8/2035** | **9/2035** | **10/2035** | **11/2035** | **12/2035** | **aMW** |
| Brownlee | HCC* | 206.2 | 188.6 | 224.8 | 220.5 | 275.6 | 162.1 | 216.3 | 135.0 | 113.7 | 183.7 | 150.2 | 175.0 | 187.6 |
| Oxbow | HCC | 87.3 | 80.8 | 96.8 | 94.1 | 116.5 | 70.0 | 91.3 | 61.4 | 50.8 | 78.9 | 66.2 | 76.3 | 80.9 |
| Hells Canyon | HCC | 172.6 | 160.9 | 196.4 | 192.0 | 238.7 | 142.4 | 179.4 | 120.9 | 100.6 | 155.4 | 131.4 | 150.7 | 161.8 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 30.9 | 68.4 | 84.9 | 86.6 | 56.0 | 26.4 | 8.1 | 0.0 | 0.0 | 30.1 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 31.7 | 31.9 | 31.3 | 31.7 | 37.4 | 33.4 | 32.4 | 25.0 | 32.5 | 33.9 | 31.4 | 32.1 | 32.1 |
| C .J. Strike | ROR | 40.3 | 40.4 | 40.1 | 39.1 | 43.0 | 35.7 | 30.3 | 27.1 | 36.3 | 41.2 | 39.9 | 40.0 | 37.8 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.3 | 1.3 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 19.4 | 19.7 | 18.2 | 19.5 | 24.5 | 21.7 | 20.7 | 13.4 | 19.5 | 20.9 | 19.0 | 19.7 | 19.7 |
| Milner | ROR | 0.0 | 0.0 | 0.0 | 0.0 | 7.2 | 7.1 | 6.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.7 |
| Shoshone Falls | ROR | 7.7 | 9.2 | 4.2 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 6.2 | 5.4 | 7.6 | 7.8 |
| Swan Falls | ROR | 13.9 | 13.9 | 13.9 | 13.6 | 14.7 | 12.5 | 11.0 | 9.6 | 13.0 | 14.1 | 13.8 | 13.8 | 13.2 |
| Twin Falls | ROR | 4.1 | 5.5 | 0.0 | 0.0 | 10.1 | 10.6 | 10.3 | 0.0 | 0.0 | 0.0 | 0.0 | 4.0 | 3.7 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 11.2 | 11.5 | 10.5 | 11.5 | 15.4 | 13.0 | 12.2 | 6.8 | 11.3 | 12.2 | 10.7 | 11.3 | 11.5 |
| Upper Salmon 3&4 | ROR | 10.8 | 11.1 | 10.2 | 11.1 | 14.4 | 12.3 | 11.7 | 7.1 | 10.9 | 11.6 | 10.4 | 10.9 | 11.0 |
| **HCC Total** | | **466.1** | **430.3** | **518.0** | **506.6** | **630.8** | **374.5** | **487.0** | **317.3** | **265.1** | **418.0** | **347.8** | **402.0** | **430.3** |
| **ROR Total** | | **166.3** | **170.8** | **156.9** | **190.0** | **277.3** | **274.1** | **267.1** | **189.0** | **190.8** | **177.6** | **158.0** | **166.6** | **198.7** |
| **Total** | | **632.4** | **601.1** | **674.9** | **696.6** | **908.1** | **648.6** | **754.1** | **506.3** | **455.9** | **595.6** | **505.8** | **568.6** | **629.0** |

*HCC=Hells Canyon Complex, **ROR= Run of River

| Average Megawatt (aMW) 90th Percentile Water, 70th Percentile Load | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Resource** | **Type** | **1/2036** | **2/2036** | **3/2036** | **4/2036** | **5/2036** | **6/2036** | **7/2036** | **8/2036** | **9/2036** | **10/2036** | **11/2036** | **12/2036** | **aMW** |
| Brownlee | HCC* | 205.4 | 181.7 | 224.5 | 220.2 | 275.6 | 161.5 | 215.8 | 134.5 | 113.6 | 174.7 | 149.7 | 174.9 | 186.0 |
| Oxbow | HCC | 87.0 | 77.8 | 96.6 | 94.0 | 116.5 | 69.8 | 91.1 | 61.1 | 50.8 | 78.1 | 66.0 | 76.3 | 80.4 |
| Hells Canyon | HCC | 172.0 | 155.0 | 196.1 | 191.7 | 238.7 | 141.9 | 179.0 | 120.4 | 100.6 | 153.5 | 131.0 | 150.6 | 160.9 |
| American Falls | ROR | 0.0 | 0.0 | 0.0 | 31.2 | 68.4 | 84.8 | 86.4 | 55.6 | 26.3 | 8.1 | 0.0 | 0.0 | 30.1 |
| 1,000 Springs | ROR** | 6.2 | 6.3 | 6.1 | 6.1 | 6.1 | 5.9 | 5.9 | 6.1 | 6.2 | 6.3 | 6.2 | 6.2 | 6.1 |
| Bliss | ROR | 31.6 | 30.7 | 31.2 | 31.6 | 37.2 | 33.3 | 32.3 | 24.9 | 32.3 | 33.7 | 31.3 | 32.0 | 31.8 |
| C .J. Strike | ROR | 39.9 | 38.8 | 40.0 | 39.0 | 42.7 | 35.0 | 30.3 | 26.9 | 36.1 | 40.9 | 39.7 | 39.8 | 37.4 |
| Cascade | ROR | 1.4 | 1.4 | 1.3 | 1.3 | 1.5 | 4.2 | 7.0 | 10.3 | 6.3 | 1.3 | 1.3 | 1.3 | 3.2 |
| Clear Lake | ROR | 1.9 | 1.9 | 1.8 | 1.8 | 1.8 | 1.7 | 1.7 | 1.8 | 1.8 | 1.9 | 1.9 | 1.9 | 1.8 |
| Lower Malad | ROR | 11.3 | 11.4 | 12.2 | 12.3 | 13.4 | 12.0 | 12.1 | 12.4 | 13.0 | 13.0 | 11.5 | 11.4 | 12.2 |
| Lower Salmon | ROR | 19.3 | 19.0 | 18.1 | 19.4 | 24.4 | 21.6 | 20.5 | 13.2 | 19.3 | 20.8 | 18.8 | 19.6 | 19.5 |
| Milner | ROR | 0.0 | 0.0 | 0.0 | 0.0 | 6.7 | 6.6 | 6.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.6 |
| Shoshone Falls | ROR | 7.7 | 8.9 | 4.2 | 3.9 | 12.0 | 12.0 | 12.0 | 6.5 | 6.5 | 6.2 | 5.4 | 7.6 | 7.7 |
| Swan Falls | ROR | 13.8 | 13.3 | 13.9 | 13.5 | 14.6 | 12.3 | 10.9 | 9.5 | 12.9 | 14.0 | 13.7 | 13.8 | 13.0 |
| Twin Falls | ROR | 4.1 | 5.3 | 0.0 | 0.0 | 9.8 | 10.5 | 10.3 | 0.0 | 0.0 | 0.0 | 0.0 | 4.0 | 3.7 |
| Upper Malad | ROR | 6.5 | 6.6 | 7.0 | 7.2 | 7.5 | 7.0 | 6.9 | 7.0 | 7.2 | 7.0 | 6.4 | 6.4 | 6.9 |
| Upper Salmon 1&2 | ROR | 11.1 | 11.1 | 10.4 | 11.5 | 15.4 | 12.9 | 12.1 | 6.7 | 11.1 | 12.1 | 10.6 | 11.2 | 11.4 |
| Upper Salmon 3&4 | ROR | 10.7 | 10.7 | 10.1 | 11.0 | 14.3 | 12.2 | 11.6 | 7.0 | 10.7 | 11.5 | 10.3 | 10.8 | 10.9 |
| **HCC Total** | | **464.4** | **414.5** | **517.2** | **505.9** | **630.8** | **373.2** | **485.9** | **316.0** | **265.0** | **406.3** | **346.7** | **401.8** | **427.3** |
| **ROR Total** | | **165.4** | **165.4** | **156.4** | **189.8** | **275.7** | **272.1** | **266.3** | **187.8** | **189.6** | **176.7** | **157.2** | **166.0** | **197.4** |
| **Total** | | **629.8** | **579.9** | **673.6** | **695.7** | **906.5** | **645.3** | **752.2** | **503.8** | **454.6** | **583.0** | **503.9** | **567.8** | **624.7** |

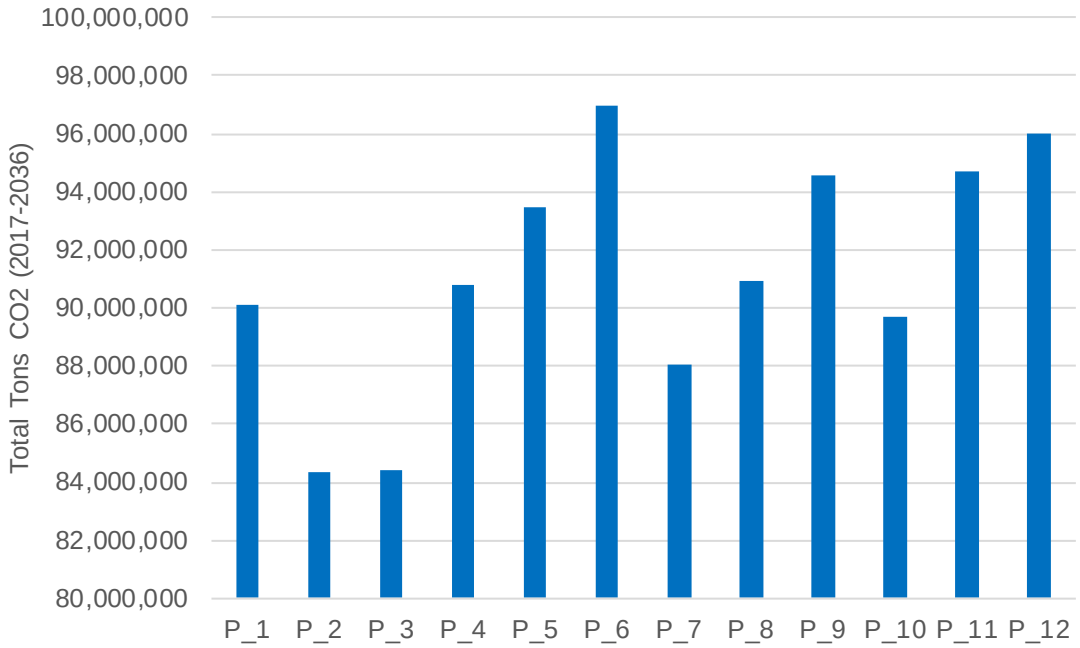
*HCC=Hells Canyon Complex, **ROR= Run of River

# PORTFOLIO ANALYSIS, RESULTS, AND SUPPORTING DOCUMENTATION

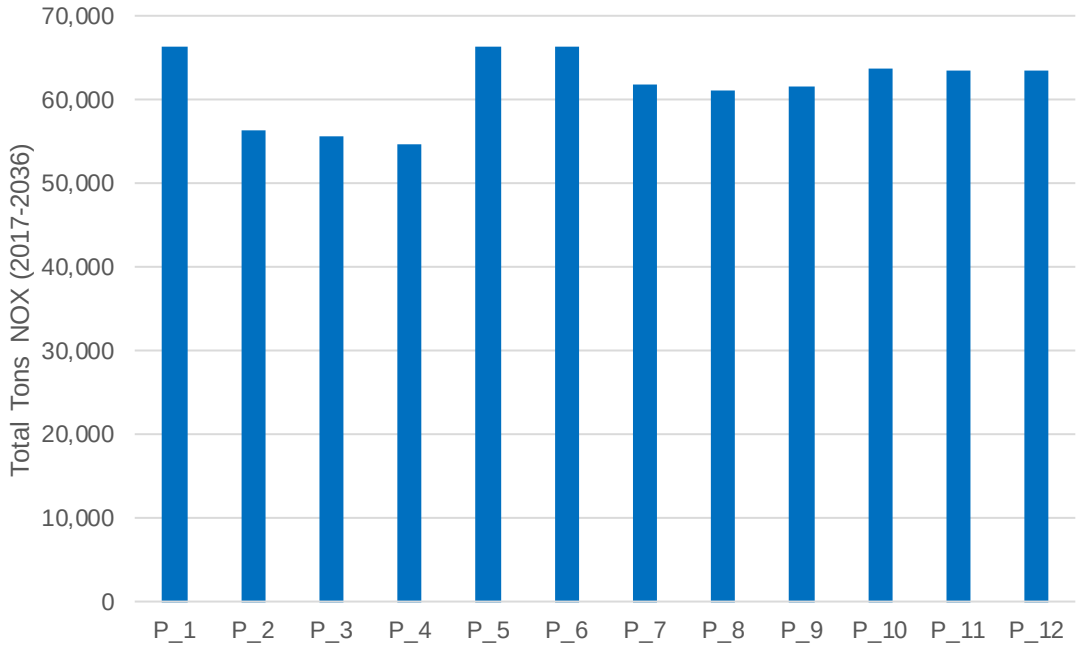
## Portfolio Emissions

### *IPC Emissions*

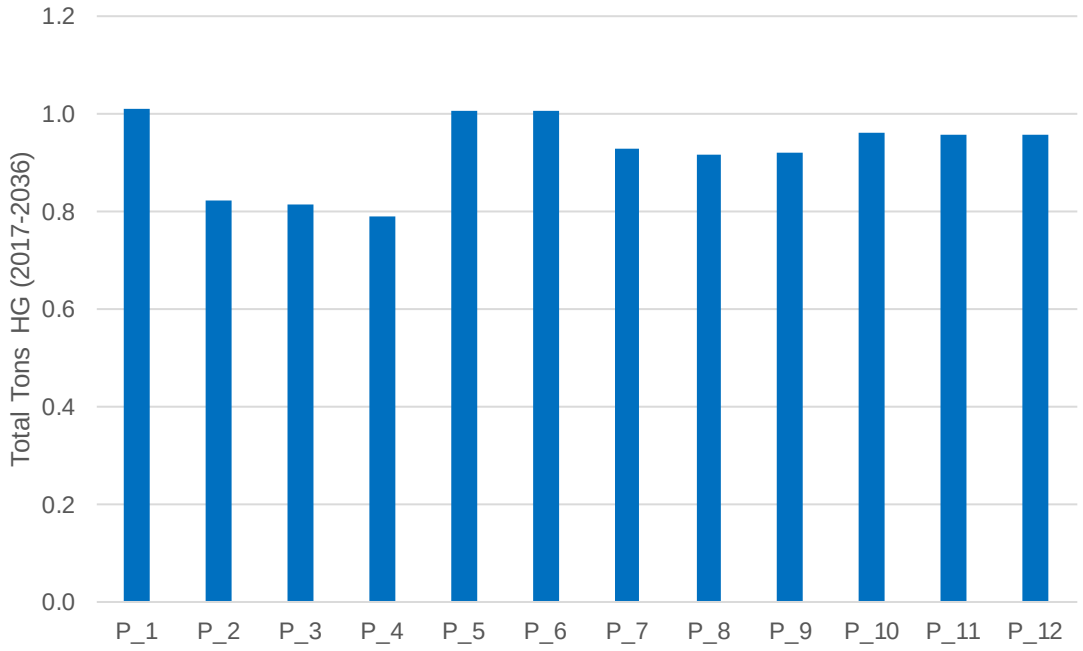
#### $CO_2$ Emission



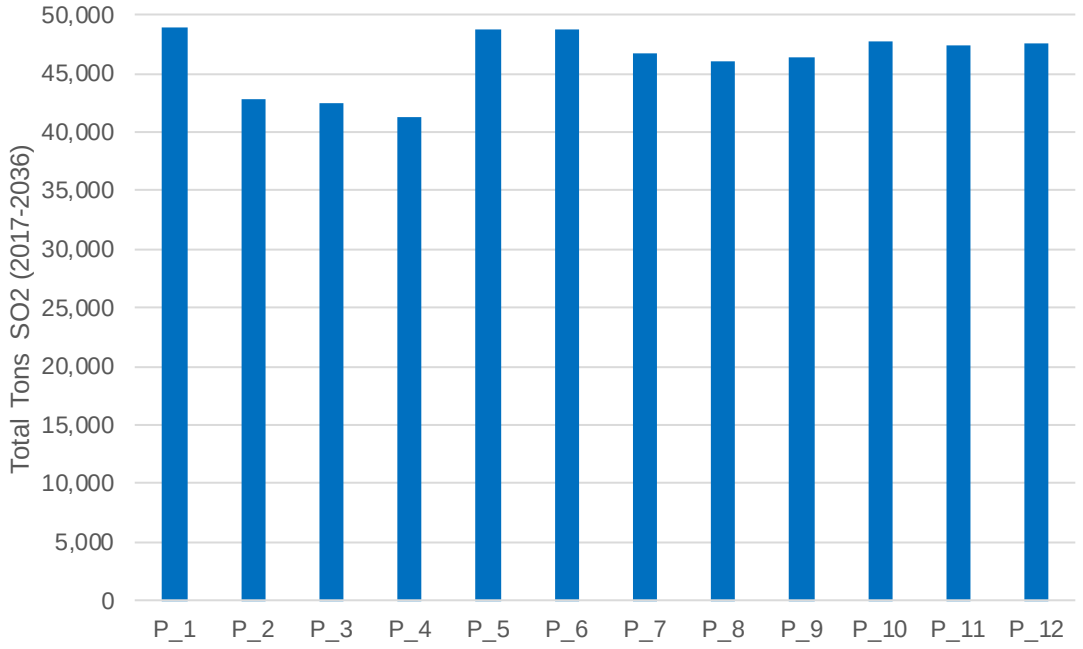

#### NOx Emission



## HG Emission




## $SO_2$ Emission



# COMPLIANCE WITH STATE OF OREGON IRP GUIDELINES

## Guideline 1: Substantive Requirements

a. All resources must be evaluation on a consistent and comparable basis.
   - All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power - or gas purchases, transportation, and storage - and demand side options which focus on conservation and demand response.
   - Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.
   - Consistent assumptions and methods should be used for evaluation of all resources.
   - The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.

**Idaho Power response:**

Supply-side and purchased resources for meeting the utility's load are discussed in *Chapter 3. Idaho Power Today—Existing Supply-side Resources*; demand-side options for are discussed in *Chapter 5. Demand-Side Resources*; and transmission resources are discussed in *Chapter 6. Transmission Planning—Existing Transmission System*.

New resource options including fuel types, technologies, lead times, in-service dates, durations and locations are described in *Chapter 4. Future Supply-side Generation and Storage Resources*, *Chapter 5. Demand-Side resources*, *Chapter 6. Transmission Planning*, and *Chapter 7. Planning Period Forecasts*.

The consistent modeling method for evaluating new resource options is described in *Chapter 7. Planning Period Forecasts—Resource Cost Analysis* and *Chapter 9. Modeling Analysis and Result—Planning Case Portfolio Analysis*.

The WACC rate used to discount all future resource costs is stated in *Chapter 9. Modeling Analysis and Results* Table 9.1 Financial Assumptions.

b. Risk and uncertainty must be considered.
   - At a minimum, utilities should address the following sources of risk and uncertainty:
     1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.
     2. Natural gas utilities: demand (peak, swing and baseload), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.
   - Utilities should identify in their plans any additional sources of risk and uncertainty.

**Idaho Power response:**

Electric utility risk and uncertainty factors (load, NG and water conditions) for resource portfolios are considered in *Chapter 9b Modeling Analysis and Results—Stochastic Risk Analysis*. Plant forced outages are modeled in Aurora on a unit basis and is shown in the Technical Appendix, *Existing Resource Data—Hydroelectric and Thermal Plant Data*.

Additional sources of risk and uncertainty are discussed in *Chapter 9. Modeling Analysis and Results*.

c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.
   - The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being

included in rates over the long term, which extends beyond the planning horizon and the life of the resource.

- Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.
- To address risk, the plan should include, at a minimum:
  a. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.
  b. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.
- The utility should explain in its plan how its resource choices appropriately balance cost and risk.

**Idaho Power response:**

The IRP methodology and the planning horizon of 20 years are discussed in *Chapter 1. Summary—Introduction*.

Modeling analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases is discussed in *Chapter 9. Modeling Analysis and Results*.

The discussion of cost variability and extreme outcomes, including bad outcomes is discussed in *Chapter 9. Modeling Analysis and Risk*. Idaho Power's Risk Management Policy regarding physical and financial hedging is discussed in *Chapter 1a. Summary—Introduction*.

Idaho Power's plan is presented in *Chapter 1g. Summary—Action Plan* and in more detail in *Chapter 10. Preferred Portfolio and Action Plan.*

d. The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.

**Idaho Power response:**

Long-run public interest issues are discussed in *Chapter 2. Political, Regulatory, and Operational Issues*.

## Guideline 2: Procedural Requirements

a. The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.

**Idaho Power response:**

The IRP Advisory Council meetings are open to the public. A roster of the IRP Advisory Council members along with meeting schedules and agendas is provided in the Technical Appendix, *IRP Advisory Council*.

b. While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.

**Idaho Power response:**
Idaho Power makes public extensive information relevant to its resource evaluation and action plan in its plan. This information is discussed in IRP Advisory Council meetings and found throughout the 2017 IRP, the 2017 Load and Sales Forecast and in the 2017 Technical Appendix.

c. The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.

**Idaho Power response:**
Idaho Power provided copies to members of the IRPAC on Thursday, May 11, 2017. The company requested for comments to be provided no later than Friday, June 12, 2017.

## Guideline 3: Plan Filing, Review, and Updates

a. A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.

**Idaho Power response:**
The OPUC acknowledged Idaho Power's 2015 IRP on April 28, 2016 in Order 16-160. The Idaho Power 2017 IRP will be filed by June 30, 2017.

b. The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.

**Idaho Power response:**
Idaho Power will schedule a public meeting at the OPUC following the June 30, 2017 filing of the 2017 IRP.

c. Commission staff and parties should complete their comments and recommendations within six months of IRP filing.

**Idaho Power response:**
No response needed.

d. The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.

**Idaho Power response:**
No response needed.

e. The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.

**Idaho Power response:**
No response needed.

f. Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.

**Idaho Power response:**
In Order No. 16-160, the OPUC waived for Idaho Power the requirement to file an annual update to the 2015 IRP.

g. Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:
   - Describes what actions the utility has taken to implement the plan;
   - Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and
   - Justifies any deviations from the acknowledged action plan.

**Idaho Power response:**
No response needed.

## Guideline 4: Plan Components

At a minimum, the plan must include the following elements:

a. An explanation of how the utility met each of the substantive and procedural requirements;

**Idaho Power response:**
Idaho Power provides information on how the company met each requirement in a table is presented in the Technical Appendix and will be provided to the OPUC staff in an informal letter.

b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;

**Idaho Power response:**
High-growth scenarios at the 90th and 95th percentile levels for peak hour, and at the 70th and 90th percentile levels for energy are provided in *Chapter 7. Planning Period Forecasts*. Stochastic load risk analysis is discussed in *Chapter 9. Modeling Analysis and Results—Stochastic Risk Analysis*. Major assumptions are discussed in *Chapter 7. Planning Period Forecasts* and *Chapter 9a. Modeling Analysis and Results—Planning Case Portfolio Analysis*.

c. For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;

**Idaho Power response:**
Peaking capacity and energy capability for each year of the plan for existing resources is discussed in *Chapter 7. Planning Period Forecasts*. Detailed forecasts are provided in the Technical Appendix, *Sales and Load Forecast Data* and *Chapter 10. Existing Resource Data*, and *Chapter 5. Load and Resource Balance Data*. Identification of capacity and energy needed to bridge the gap between expected loads and resources is discussed in *Chapter 8. Portfolios*.

d. For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;

**Idaho Power response:**
Not applicable.

e. Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;

**Idaho Power response:**
Supply-side resources are discussed in *Chapter 4. Future Supply-Side Generation and Storage Resources*. Demand-side resources are discussed in Chapter 5-Demand-Side Resources. Resource costs are discussed in *Chapter 7. Planning Period Forecasts – Resource Costs* and presented in the Technical Appendix, *Supply-Side Resource Data Levelized Cost of Energy*. Demand-side resources and their levelized costs and technologies are covered in *Chapter 5. Demand-Side Resources* and in the Technical Appendix, *Demand-Side Resource Data*.

f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;

**Idaho Power response:**
Resource reliability is covered in *Chapter 9. Modeling Analysis and Results*

g. Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;

**Idaho Power response:**

Key Assumptions including the natural gas price forecast are discussed in *Chapter 7. Planning Period Forecasts* and in the Technical Appendix, *Key Financial and Forecast Assumptions*. Environmental compliance costs are addressed in the Technical Appendix, *Portfolio Analysis, Results and supporting Documentation–Portfolio Emissions*. Compliance alternatives to SCR installation at Jim Bridger Units 1 and 2 are considered using portfolios with varying retirement dates of Jim Bridger Units 1 and 2 and are discussed in *Chapter 8 Portfolios*.

h. Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;

**Idaho Power response:**

Resource portfolios considered for the 2017 IRP are described in *Chapter 8. Portfolios*. Resource portfolios were developed using resources from the resource stack provided in *Chapter 7. Planning Period Forecasts—Resource Cost Analysis* and with guidance from the IRP Advisory Council and public participants.

i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;

**Idaho Power response:**

Evaluation of the portfolios over a range of risks and uncertainties is discussed in *Chapter 9. Modeling Analysis and Results*.

j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;

**Idaho Power response:**

Portfolio cost, risk results, interpretations and the selection of the preferred portfolio are provided in *Chapter 9. Modeling Analysis and Results*.

k. Analysis of the uncertainties associated with each portfolio evaluated;

**Idaho Power response:**

The quantitative and qualitative uncertainties associated with each portfolio are evaluated in *Chapter 9. Modeling Analysis and Results*.

l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers

**Idaho Power response:**

The preferred resource portfolio is identified in *Chapter 10. Preferred Portfolio and Action Plan*.

m. Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and

**Idaho Power response:**
Portfolio risk associated with the successful permitting to operate Jim Bridger Units 1 and 2 beyond their regional haze compliance dates without installation of SCR retrofits is discussed in *Chapter 9 Modeling Analysis and Results*.

n. An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.

**Idaho Power response:**
An action plan is provided in *Chapter 1. Summary—Action Plan* and in *Chapter 10 Preferred Portfolio and Action Plan.*

## Guideline 5: Transmission

Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.

**Idaho Power response:**
The fuel transportation and electric transmission required for each resource being considered is presented in the Technical Appendix, *Cost Inputs and Operating Assumptions*. Transmission assumptions for supply-side resources considered are included in *Chapter 6. Transmission Planning—Transmission assumptions in IRP portfolios*. Transportation for natural gas is discussed in *Chapter 7. Planning Period Forecasts—Natural Gas Price Forecast*.

## Guideline 6: Conservation

a. Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.

**Idaho Power response:**
Applied Energy Group (AEG) conducted a study for the 2017 IRP and is described in *Chapter 5 Demand-Side Resources*.

b. To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.

**Idaho Power response:**
A forecast for energy efficiency effects in five-year blocks is provided in Cha*pter 5. Demand-Side Resources—Committed EE forecast*. Detailed monthly forecast values are a line item in the Technical Appendix, *Load and Resource Balance Data.*

c. To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:
   - Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and
   - Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.

**Idaho Power response:**

Treatment of third party market transformation savings was provided by the Northwest Energy Efficiency Alliance (NEEA) and is discussed in *Chapter 5. Demand-Side Resources*. NEEA savings are included as savings to meet targets because of the overlap of NEEA initiatives and IPC's most recent potential study.

## Guideline 7: Demand Response

Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).

**Idaho Power response:**

Demand response resources are evaluated in *Chapter 5. Demand-Side Resources*. Additional demand response above baseline levels is considered in select portfolios and discussed in *Chapter 5. Demand-Side Resources—Additional DR*.

## Guideline 8: Environmental Costs

Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide (CO2), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential CO2 regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.

**Idaho Power response:**

Compliance with existing environmental regulation is discussed in *Chapter 9. Modeling Analysis and Results—Qualitative Risk Analysis*. Emissions for each portfolio is shown in the Technical Appendix, *Portfolio Analysis, Results, and Supporting Documentation*.

## Guideline 9: Direct Access Loads

An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.

**Idaho Power response:**

Idaho Power does not have any customers served by alternative electricity suppliers and Idaho Power has no direct access loads.

## Guideline 10: Multi-state Utilities

Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.

**Idaho Power response:**

Idaho Power's analysis was performed on an integrated-system basis discussed in *Chapter 9. Modeling Analysis and Results*. Idaho Power will file the 2017 IRP in both the Idaho and Oregon jurisdictions.

## Guideline 11: Reliability

Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.

**Idaho Power response:**

The capacity planning margin is discussed in *Chapter 9. Modeling Analysis and Results—Capacity Planning Margin* followed by the discussion of flexible resource needs assessment at *Chapter 9g. Modeling Analysis and Results—Flexible Resource Needs Assessment* and the loss of load probabilities at *Chapter 9h. Modeling Analysis and Results—LOLE*.

## Guideline 12: Distributed Generation

Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.

**Idaho Power response:**

Idaho Power evaluated utility scale solar PV combined with reciprocating engines as resource options in four portfolios. In four other portfolios, reciprocating engines were paired with CCCT gas turbines. These portfolios are discussed in *Chapter 8. Portfolios.*

Other distributed generation technologies were evaluated in *Chapter 7. Planning Period Forecasts—Resource Cost Analysis*. Utility-scale solar and reciprocating engines were selected for further portfolio analysis based on their low-cost, scalability, and efficiency. As shown in our load and resource balance, resource need is beyond the immediate action plan. While utility scale solar and reciprocating engines are currently the low-cost choices, these future energy needs will continually be reevaluated.

## Guideline 13: Resource Acquisition

a. An electric utility should, in its IRP:
   - Identify its proposed acquisition strategy for each resource in its action plan.

- Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.
- Identify any Benchmark Resources it plans to consider in competitive bidding.

**Idaho Power response:**

Idaho Power continues to evaluate resource ownership along with other supply options. Idaho Power conducts its resource acquisition and competitive bidding processes consistent with the guidelines established by Oregon in Order No. 14-149 issued on April 30, 2014.

Idaho Power discusses asset ownership in *Chapter 10b. Preferred Portfolio and Action Plan—Action Plan (2017–2020).*

Idaho Power's action plan includes ongoing permitting, planning studies, and regulatory filings associated with the Boardman to Hemingway transmission line.

b. Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.

**Idaho Power response:**

Not applicable.

# COMPLIANCE WITH EV GUIDELINES

## Guideline 1: Forecast the Demand for Flexible Capacity

Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period;

**Idaho Power response:**

A discussion of the 2017 IRP's analysis for the flexibility guideline is provided in *Chapter 9. Modeling Analysis and Results—Flexible Resource Needs Assessment*.

## Guideline 2: Forecast the Supply for Flexible Capacity

Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period;

**Idaho Power response:**

A discussion of the 2017 IRP's analysis for the flexibility guideline is provided in *Chapter 9. Modeling Analysis and Results—Flexible Resource Needs Assessment*.

## Guideline 3: Evaluate Flexible Resources on a Consistent and Comparable Basis

In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis.

**Idaho Power response:**

The adoption rate of EVs is discussed in Appendix A Sales and Load Forecast, *Company System Load—Electric Vehicles*

# STATE OF OREGON ACTION ITEMS REGARDING IDAHO POWER'S 2015 IRP

## Action Item 1: B2H Transmission Line

Idaho Power will continue the ongoing permitting, planning studies and regulatory filings.

**Idaho Power response:**

Discussion specific to B2H is found in *Chapter 6. Transmission Planning—Boardman to Hemingway.* Portfolio design for the 2017 IRP provides a comparison of portfolios having B2H as a resource to portfolios not having B2H. A tabulation of resource portfolios with respect to B2H inclusion is provided in *Chapter 8. Portfolios*.

## Action Item 2: Gateway West Transmission Line

Idaho Power will continue the ongoing permitting, planning studies and regulatory filings.

**Idaho Power response:**

Discussion specific to Gateway West is found in Chapter 6e. Transmission Planning—Gateway West.

## Action Item 3: Energy Efficiency

Idaho Power will continue the pursuit of cost-effective energy efficiency—the forecast reduction for the 2015–2019 programs is 84 average megawatts (MW) for energy demand and 126 MW for peak demand.

**Idaho Power response:**

Discussion specific to energy efficiency is found in *Chapter 5. Demand-Side Resources*. All portfolios contain achievable energy efficiency. The monthly forecast is provided in the Technical Appendix, *Load and Resource Balance Data*.

## Action Item 4: Section 111(d)

Idaho Power will coordinate with government agencies on implementation planning for Section 111 (d).

**Idaho Power response:**

All portfolios meet current regulatory requirements. Portfolio Emissions are shown in the Technical Appendix, *Portfolio Emissions Graphs*.

## Action Item 5: Shoshone Falls License Amendment

Idaho Power will file to amend the FERC license regarding the 50-MW expansion.

**Idaho Power response:**
In April 2017, Idaho Power filed with FERC to amend the FERC's July 2010 License Order which authorized Idaho Power to upgrade the Shoshone Falls hydroelectric project changing the approved installed capacity from 50MW to 3.2MW.

## Action Item 6: Jim Bridger Unit 3

Idaho Power will complete the installation of selective catalytic reduction (SCR) emission-control technology.

**Idaho Power response:**
Installation of selective catalytic reduction emission-control technology was completed on Jim Bridger Unit 3 in November 2015.

## Action Item 7: Shoshone Falls Upgrades Study

Idaho Power will study options for smaller upgrades ranging in size up to approximately 4MW.

**Idaho Power response:**
In early 2016, Idaho Power explored a variety of smaller upgrade options. The most cost effective option was to replace units 1 and 2 with a single 3.2 MW unit.

## Action Item 8: Jim Bridger Unit 4

Idaho Power will complete installation of SCR emission-control technology.

**Idaho Power response:**
Installation of selective catalytic reduction emission-control technology was completed on Jim Bridger Unit 3 in November 2016.

## Action Item 9: North Valmy Units 1 and 2

Idaho Power will continue to work with NV Energy to synchronize depreciation dates and determine if a date can be established to cease coal-fired operations.

**Idaho Power response:**
In October and November 2016, Idaho Power filed applications with the IPUC an OPUC, respectively, requesting authorization to accelerate depreciation for the North Valmy coal-fired power plant. The approved settlement stipulations in both Idaho and Oregon agreed to an early shutdown of year-end 2019 for Unit 1 and year-end 2025 for Unit 2.

## Action Item 10: Shoshone Falls 2017 Upgrade

Idaho Power will commence construction of a smaller upgrade.

**Idaho Power response:**
The upgrade of Shoshone Falls is currently scheduled from May 2018 through June 2019

## Action Item 11: Jim Bridger Units 1 and 2

Idaho Power will evaluate the installation of SCR technology for units 1 and 2 at Jim Bridger in the 2017 IRP.

**Idaho Power response:**
The 2017 IRP focuses on evaluating the installation of SCR technology for units 1 and 2 at Jim Bridger. The discussion of portfolios is in Chapter 8 Portfolios and the results are in *Chapter 9. Modeling Analysis and Results*. The preferred portfolio and action plan, discussed in Chapter 10 does not include the installation of SCR equipment; rather it contemplates early shut down for the units in lieu of installing the SCRs.

## Action Item 12: Shoshone Falls 2019 On-Line Date

Idaho Power will place the smaller upgrade on-line.

**Idaho Power response:**
The upgrade of Shoshone Falls is currently scheduled from May 2018 through June 2019.

## Other Issues

Selection of Preferred Portfolio—Staff agrees with Idaho Power's position that the Commission should acknowledge Idaho Power's 2015 IRP Action Plan.

**Idaho Power response:**
No action needed.

Qualitative Risk Analysis: Staff recommends Idaho Power include a more systematic evaluation of the qualitative benefits of the resource portfolios in the 2017 IRP.

**Idaho Power response:**
Qualitative Risk Analysis is evaluated in *Chapter 10d. Modeling Analysis and Results—Qualitative Risk Analysis*.

2015 IRP Update Waiver: Staff agrees and recommends the Commission waive Idaho Power's obligation to file a 2015 IRP Update.

**Idaho Power response:**
No action needed.

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# 2017 IRP

## APPENDIX D: B2H SUPPLEMENT




DECEMBER • 2017

## SAFE HARBOR STATEMENT

This document may contain forward-looking statements, and it is important to note that the future results could differ materially from those discussed. A full discussion of the factors that could cause future results to differ materially can be found in Idaho Power's filings with the Securities and Exchange Commission.

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# 2017 IRP

## APPENDIX D: B2H SUPPLEMENT

# ACKNOWLEDGEMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan (IRP) every two years. Idaho Power expects that the experience gained over the next few years will likely modify the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the 2017 IRP. Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council and other concerned citizens and customers.

It takes approximately one year for a dedicated team of individuals at Idaho Power to prepare the IRP. The Idaho Power team is comprised of individuals that represent many departments within the company. The IRP team members are responsible for preparing forecasts, working with the advisory council and the public, and performing all the analyses necessary to prepare the resource plan.

Idaho Power looks forward to continuing the resource planning process with customers, public-interest groups, regulatory agencies, and other interested parties. You can learn more about the Idaho Power resource planning process at idahopower.com.

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# EXECUTIVE SUMMARY

The Boardman to Hemingway Transmission Line Project (B2H) is a planned 500-kilovolt (kV) transmission project that would span between the Hemingway 500-kV substation near Marsing, Idaho, and the proposed Longhorn Substation near Boardman, Oregon. Once operational, B2H will provide Idaho Power increased access to reliable, low-cost market energy purchases from the Pacific Northwest. Idaho Power's planned capacity interest in B2H will increase the availability of capacity and energy of the Pacific Northwest market by 500 megawatts (MW) during the summer months, when energy demand from Idaho Power's customers is at its highest. B2H (including early versions of the project) has been a cost-effective resource identified in each of Idaho Power's integrated resource plans (IRP) since 2006 and continues to be a cornerstone of Idaho Power's 2017 IRP preferred resource portfolio. In the 2017 IRP, as has been the case in prior IRPs, the B2H project is not simply evaluated as a transmission line, but rather as a *resource* that will be used to serve Idaho Power load. That is, the B2H project, and the market purchases it will facilitate, is evaluated in the same manner as a new combined-cycle gas plant, or a new utility-scale solar complex.

As a resource, the B2H project is demonstrated to be the most cost-effective method of serving projected customer demand. In the 2017 IRP, B2H was identified as the least-cost and least-risk resource to serve peak-hour load deficits forecast to occur beginning in 2026. As can be seen in Table 9.3, page 111 of the 2017 IRP, the four lowest-cost resource portfolios (P1, P4, P7, and P10) each included B2H. The information presented in Table 9.3 also indicates that the next lowest-cost portfolio that does not include B2H had a present-value portfolio cost of approximately $147 million dollars greater than Idaho Power's preferred resource portfolio, P7. When compared to other individual resource options, B2H is also the least-cost option in terms of both capacity cost and energy cost. B2H is expected to have a capacity cost that is 71 percent lower than either a combined-cycle gas plant or utility-scale solar alternatives.[1] B2H is also expected to have a levelized cost of energy that is 22 percent lower than a combined-cycle gas plant and 38 percent lower than utility-scale solar.[2] As a resource alone, B2H is the lowest-cost alternative to serve Idaho Power's customers in Oregon and Idaho. As a transmission line, B2H also offers incremental ancillary benefits and additional operational and resource integration flexibility.

In addition to being the least-cost, lowest-risk resource to meet Idaho Power' resource needs, the B2H project has received national recognition for the benefits it will provide. The B2H

[1] 2017 IRP, page 87, Figure 7.5.

[2] 2017 IRP, page 89, Figure 7.6.

Footnotes continued on the next page.

project was selected by the Obama administration as one of seven nationally significant transmission projects that, when built, will help increase electric reliability, integrate new renewable energy into the grid, create jobs, and save consumers money. Most recently, B2H was acknowledged as complementing the Trump Administration's America First Energy Plan, which addresses all forms of domestic energy production. In a November 17, 2017, United States (US) Department of the Interior press release,[3] B2H was held up as "a Trump Administration priority focusing on infrastructure needs that support America's energy independence…" The release went on to say, "This project will help stabilize the power grid in the Northwest, while creating jobs and carrying low-cost energy to the families and businesses who need it…" The benefits B2H is expected to bring to the region and nation have been recognized across both major political parties.

Under a 2012 B2H Permit Funding agreement, Idaho Power is allocated a 21.2-percent project interest, with PacifiCorp and Bonneville Power Administration (BPA) subscribed for the remainder of the line's capacity. The agreement will allow Idaho Power customers to benefit from the project's economies of scale and from load diversity between the project co-participants. While Idaho Power's 21.2-percent share would provide for an annual average of 350 MW of west-to-east import capacity, the agreement is structured to provide Idaho Power with 500 MW of import capacity during the summer months, when Idaho Power experiences peak demand, and 200 MW of import capacity in the winter months, when the load-serving need is less.

The total cost estimate for the B2H project is $1 to $1.2 billion dollars, which includes Idaho Power's allowance for funds used during construction (AFUDC). Co-participant AFUDC is not included in this estimate range. The total cost estimate includes a 20 percent contingency for unforeseen expenses. In the 2017 IRP, Idaho Power assumes a 21.2-percent share of the direct expenses, plus its entire AFUDC cost, which equates to approximately $258 million in B2H project expenses. Idaho Power also included costs for local interconnection upgrades totaling $16 million. The 2017 IRP was the first year for which the B2H route was relatively certain, resulting in a more accurate cost estimate compared to prior IRPs.

Idaho Power is the project manager for the permitting phase of the B2H project. The B2H project achieved a major milestone nearly 10 years in the making with the release of the Bureau of Land Management (BLM) Record of Decision (ROD) on November 17, 2017. The BLM ROD formalized the conclusion of the siting process at the federal level, as required by the *National Environmental Policy Act of 1969* (NEPA). The BLM ROD provides the ability to site the B2H project on BLM-administered land.

[3] blm.gov/press-release/doi-announces-approval-transmission-line-project-oregon-and-idaho

For the State of Oregon permitting process, Idaho Power submitted the amended application for Site Certificate to the Oregon Department of Energy in summer 2017. Oregon's Energy Facility Siting Council (EFSC) is tasked with establishing siting standards for energy facilities in Oregon and ensuring certain transmission line projects, including B2H, meet those standards.[4] Before Idaho Power can begin construction on B2H, it must obtain a Site Certificate from EFSC. The Oregon EFSC process is a standards-based process based on a fixed site boundary. For a linear facility, like a transmission line, the process requires the transmission line boundary be established (a route selected) and fully evaluated to determine if the project meets established standards. Idaho Power must demonstrate a need for the project before EFSC will issue a Site Certificate authorizing the construction of a transmission line (non-generating facility). Idaho Power's demonstration of need is based on the least-cost plan rule, for which the requirements can be met through a commission acknowledgement of the resource in the company's IRP.[5] In this case, Idaho Power seeks to satisfy EFSC's least-cost plan rule requirement through an acknowledgement of its 2017 IRP.

As of the date of this report, Idaho Power expects the Oregon Department of Energy (ODOE) to issue a Draft Proposed Order in 2018 and a Final Order and Site Certificate in 2020. To achieve an in-service date in the mid-2020s, preliminary construction activities must commence in parallel to EFSC permitting activities. Preliminary construction activities include, but are not limited to, geotechnical explorations, detailed ground surveys, sectional surveys, right-of-way (ROW) acquisition activities, and detailed design and construction bid package development. After the Oregon permitting process and preliminary construction activities conclude, construction activities can commence.

This B2H 2017 IRP Appendix D provides context and details that support evaluating this transmission line project as a supply-side resource, explores (qualitatively and quantitatively) many of the ancillary benefits offered by the transmission line, and considers the risks and benefits of owning a transmission line connected to a market hub in contrast to direct ownership of a traditional generation resource.

[4] See generally Oregon Revised Statute (ORS) 469.300-469.563, 469.590-469.619, and 469.930-469.992.

[5] OAR 345-023-0020(2).

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# RESOURCE NEED EVALUATION

## Capacity Needs

The entire Integrated Resource Plan (IRP) process is predicated on defining a need for resources in the future to serve projected customer demand.

The IRP analysis begins by developing a monthly load forecast, which incorporates the future electricity needs of our customers. The load forecast consists of both average monthly (energy) and monthly peak-hour (capacity) conditions. The existing Idaho Power resources (generating, demand side management [DSM], and transmission) are evaluated against the load forecast. The load less the available resources determines the load and resource balance. Times where the load exceeds the resources defines the need for resources to reliably serve our customers.

All resources on Idaho Power's system are considered in the load and resource balance, including hydro, gas, coal, existing cogeneration and small-power producer (CSPP) contracts, existing power purchase agreements (PPA) (including the *Public Utility Regulatory Policies Act of 1978* [PURPA]), and available import transmission capacity. All supply-side resources, all DSM and EE programs, and transmission import capacity are summed and subtracted from the appropriate load forecast—either peak hour or average monthly. If the result of load is greater than resources is, Idaho Power's system is resource insufficient and the need for a resource is established.

As detailed in Idaho Power's 2017 IRP, Idaho Power has a peak-demand capacity deficit in the year 2026. The Jim Bridger unit retirement evaluations in the 2017 IRP can accelerate the capacity deficit date depending on the retirement date assumptions.

Refer to Chapter 7 of Idaho Power's 2017 IRP for more information on the planning period forecasts and establishment of need.

## IRP Guideline Language—Transmission Evaluated on Comparable Basis

In Order No. 07-002, the Public Utility Commission of Oregon (OPUC) adopted guidelines regarding integrated resource planning.[6]

> Guideline 5: Transmission. Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation *and electric transmission facilities as resource options*, taking into account their value

[6] apps.puc.state.or.us/orders/2007ords/07-002.pdf

for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.

## Boardman to Hemingway as a Resource

The Boardman to Hemingway Transmission Line Project (B2H) is one of the most cost-effective IRP resources Idaho Power has considered and proven through successive IRPs. When evaluating and comparing alternative resources, two major cost considerations exist: 1) the capacity cost of the project (fixed costs) and 2) the energy cost of the project (variable costs). The 2017 IRP details the results of each component of the various portfolios in Table 9.3 of the IRP. Capital costs are derived through cost estimates to install the various projects. Energy costs are calculated through a detailed modeling analysis, using the AURORA software. Energy prices are derived based on inputs into the model, such as gas price, coal price, nuclear price, hydro conditions, etc.

Illustrating the difference between capacity and energy, a diesel generator may have a very low cost to install; however, the cost of diesel fuel and the maintenance required would be significant. Alternatively, a utility-scale solar plant will have almost no energy cost; the fuel to run the plant—the sun—is free. However, in the case of a solar plant, the capacity cost to install the plant is quite expensive. The installed capacity needed to ensure the solar is available during the Idaho Power peak is even larger.

### *Capacity Costs*

Exploring the capacity costs of different resources, page 73 of the 2017 IRP *Appendix C—Technical Appendix* details the total capital cost per kilowatt (kW) for many various resources. This capital-cost data feeds into Table 9.3 of the main IRP report. Data from the technical appendix is copied into Table 1 below for illustrative purposes. Note that solar costs have been updated from those reported in the IRP with capital costs from the November 2017 Lazard energy cost report.[7] The capital costs for B2H in the table below reflect the inclusion of local interconnection costs for B2H, and consequently also differ from the per-kW cost reported in the IRP technical appendix. The local interconnection costs for B2H were included in portfolio cost modeling performed for the IRP.

**Table 1. Total capital $/kW for select resources considered in the 2017 IRP**

| Resource Type | Total Capital $/kW | Total Capital $/kw—peak | Depreciable Life |
|---|---|---|---|
| B2H | $783* | $548** | 55 years |
| Combined-cycle combustion turbine (CCCT) (1x1) F Class (300 megawatts [MW]) | $1,344 | $1,344 | 30 years |

[7] Lazard's Levelized Cost of Energy Analysis—Version 11.0, November 2017.

| | | | |
|---|---|---|---|
| Simple-cycle combustion turbine —Frame F Class (170 MW) | $995 | $995 | 30 years |
| Reciprocating Gas Engine | $887 | $887 | 30 years |
| Solar Photovoltaic (PV)— Utility-Scale 1-Axis | $1,382 | $2,692 | 25 years |

* Utilizes the B2H 350-MW average capacity

** Utilizes the B2H 500-MW average capacity

The B2H total capital cost per kilowatt at peak is 62 percent of the cost of the next lowest-cost resource. Additionally, B2H, as a transmission line, will depreciate over 55 years compared to 30 years for a gas plant or 25 years for a solar plant. The low up-front cost and slower depreciation further reduces the cost impact to Idaho Power's customers. Finally, the B2H cost estimate includes a 20 percent contingency, whereas none of the other resources evaluated in the 2017 IRP include a cost contingency. The summation of these factors suggest B2H is the lowest capital-cost resource by a substantial margin.

## *Energy Cost*

B2H provides Idaho Power with more capacity to the Pacific Northwest to purchase power from the Mid-Columbia (Mid-C) trading hub. Market power in the summer months is generally a function of the price of natural gas. Idaho Power, in a B2H future, would therefore pay a slight premium for market power compared to a future in which Idaho Power owned its own combined-cycle gas plant. This slight premium is reflected in the 2017 IRP by comparing the energy costs of B2H and the non-B2H gas portfolios: P1 and P3, P4 and P6, P7 and P9, and P10 and P12. In each of these cases, the B2H portfolio has a higher energy cost than the non-B2H portfolio. Higher energy costs for B2H portfolios are due to the following:

- Idaho Power will pay a slight premium to Pacific Northwest entities for purchased power (selling entities must recover some of their fixed costs).

- P3, P6, P9, and P12 include Idaho Power constructing power plants rather than B2H. In these portfolios, Idaho Power would have the opportunity to sell excess energy to the market and generate revenue to offset costs.

- Idaho Power must purchase transmission service (transmission wheeling) from a Pacific Northwest entity (likely Bonneville Power Administration [BPA]) to transmit the purchased power to the edge of Idaho Power's system at Longhorn Substation (once B2H is built). If Idaho Power and BPA can complete an asset swap, these transmission wheeling costs may be avoided, which would reduce the energy cost component of B2H portfolios. Refer to Appendix D-4 for the Memorandum of Understanding (MOU) relating to the potential Idaho Power–BPA asset swap.

The B2H portfolios' capacity costs are so low that capacity installation savings far outweigh the additional energy costs, leading B2H portfolios to be the lowest-cost option for Idaho Power's customers.

# Market Overview

## *Power Markets*

A power market hub is an aggregation of transaction points (often referred to as bus points or buses). Hubs create a common point to buy and sell energy, creating one transaction point for bilateral transactions. Hubs also create price signals for geographical regions.

Six characteristics of successful electric trading markets include the following:

1. The geographic location is a natural supply/demand balancing point for a particular region with adequate available transmission.
2. Reliable contractual standards exist for the delivery and receipt of the energy.
3. There is transparent pricing at the market with no single player nor group of players with the ability to manipulate the market price.
4. Homogeneous pricing exists across the market.
5. Convenient tools are in place to execute trades and aggregate transactions.
6. Most importantly, there is a critical mass of buyers and sellers that respond to the five characteristics listed above and actively trade the market on a consistent basis. This is the definition of liquidity, which is clearly the most critical requirement of a successful trading hub.

## *Mid-C Market*

The Mid-C electric energy market hub is a hub where power is transacted both physically and financially (derivative). Power is traded both physically and financially in different blocks: long term, monthly, balance-of-month, day ahead, and hourly. Much of the activity for balance-of-month and beyond is traded and cleared through a clearing exchange, the Intercontinental Exchange (ICE). For short-term transactions, such as day-ahead and real time (hourly), trades are made primarily between buyers and sellers negotiating price, quantity, and point of delivery over the phone (bilateral transactions). In the Pacific Northwest, most of the price negotiations begin with prices displayed for Mid-C on the ICE trading platform.

The Mid-C market exhibits all six characteristics of a successful electric trading market discussed above. Figure 1 shows the relative volume of energy in the Northwest.

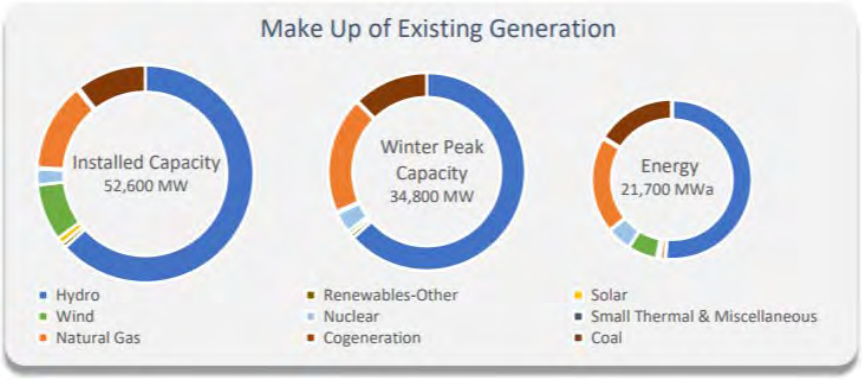



**Figure 1. Northwest regional forecast (Source: 2017 PNUCC)[8]**

In the western US, the other major market hubs are California–Oregon Border (COB), Four Corners (Arizona–New Mexico border), Mead (Nevada), Mona (Utah), Palo Verde (Arizona), and SP15 (California). The Mid-C market is very liquid. In 2017, on a day-ahead trading basis, daily average trading volume during heavy-load hours during June and July ranged from nearly 40,000 megawatt-hours (MWh) to over 51,000 MWh. When combining heavy-load hours with light-load hours, on a day-ahead trading basis, the monthly volumes for June and July were each approximately 2,000,000 MWhs. These volumes are in addition to month-ahead trading volumes. Mid-C is by far the highest volume market hub in the west; frequently, Mid-C volumes are greater than the other hubs combined.

The following market participants transact regularly at Mid-C. Additionally, numerous other independent power producers trade at Mid-C.

- Avista Utility
- BPA
- Chelan County Public Utility District (PUD)
- Douglas County PUD
- Eugene Electric Board
- Idaho Power
- PacifiCorp
- Portland General Electric

[8] pnucc.org/system-planning/northwest-regional-forecast

- Powerex
- Puget Sound Energy
- Seattle City Light
- Tacoma City Light

Energy traded at Mid-C is not necessarily physically generated in the Mid-Columbia River geographic area. For instance, Powerex is a merchant of BC Hydro in British Columbia and frequently buys and sells energy at Mid-C. A trade at Mid-C requires that transmission is available to deliver the energy to Mid-C. Transmission wheeling charges must be accounted for when transacting at Mid-C. Sellers at Mid-C must pay necessary transmission charges to deliver power to Mid-C, and buyers must pay necessary transmission charges to deliver power to load.

## *Mid-C and Idaho Power*

Historically, Idaho Power wholesale energy transactions have correlated well with the Mid-C hub due to Idaho Power's proximity to the market hub and because it is the most liquid hub in the region. Energy at Mid-C can be delivered to, or received from, Idaho Power through a single transmission wheel through the BPA or Avista. Additionally, long-term monthly price quotes are readily available for Mid-C, making it an ideal basis for long-term planning.

Idaho Power uses the market to balance surplus and deficit positions between generation resources and customer demand, and to take advantage of price differences across the region. For example, when market purchases are more cost-effective than generating energy within Idaho Power's generation fleet, Idaho Power customers benefit from lower net power supply cost through purchases instead of Idaho Power fuel expense. Idaho Power customers also benefit from the sale of surplus energy. Surplus energy sales are made when Idaho Power's resources are greater than Idaho Power customer demand and when the incremental cost of these resources are below market prices. Idaho Power customers benefit from these surplus energy sales as offsets to net power supply costs through the power cost adjustment (PCA).

In 2017, Idaho Power averaged approximately 55,000 MWh of Mid-C purchases in June and July. As stated previously, the average monthly volumes at Mid-C, on a day-ahead basis, were approximately 2,000,000 MWh. Based on these averages, Idaho Power's purchases represented less than 3 percent of the total market volumes in June and July. At 3 percent of total market volume on average in June and July, Idaho Power represents a very small fraction of the Mid-C volume during the months when Idaho Power relies on Mid-C the most.

The Mid-C market could be used more to economically serve Idaho Power customers, but Idaho Power's ability to transact at Mid-C is limited due to transmission capacity constraints between the Pacific Northwest and Idaho. In other words, sufficient transmission capacity is currently

unavailable during certain times of the year for Idaho Power to procure cost-effective resources from Mid-C for its customers, even though generation supply is available at the market.

### *Modeling of the Mid-C Market in the IRP*

As part of the IRP analysis, Idaho Power uses the AURORA to derive energy prices at the Mid-C market. Energy prices are derived based on inputs into the model, such as gas price, coal price, nuclear price, hydro conditions, etc. Refer to Chapter 9 of the 2017 IRP for more information on AURORA and modeling.

Energy purchases from the market require transmission to wheel the energy from the source to the utility purchasing the energy. Purchases from the Mid-C market would need to be wheeled across the BPA system to get the energy to the proposed Longhorn Substation near Boardman, Oregon.

Transmission wheeling rates and wheeling losses are included in the AURORA database and are part of the dispatch logic within the AURORA modeling. AURORA economically dispatches generating units, which can be located across any system in the West. All market energy purchases modeled in Aurora include these additional transmission costs and are included in all portfolios and sensitivities.

## B2H Comparison to Other Resources

The 2017 IRP provides an in-depth analysis of the B2H project compared to alternative resource options. Table 2 summarizes some of the high-level differences between B2H and other notable resource options.

**Table 2. High-level differences between resource options**

| | B2H | Reciprocating Engines | CCCT | Lithium batteries | 1-axis solar PV |
|---|---|---|---|---|---|
| Intermittent renewable | | | | | ✓ |
| Dispatchable capacity providing | ✓ | ✓ | ✓ | ✓ | |
| Non-dispatchable (coincidental) capacity providing | | | | | ✓ |
| Balancing, flexibility providing | ✓ | ✓ | ✓ | ✓ | |
| Energy providing | ✓ | ✓ | ✓ | ✓ | ✓ |
| Variable costs (primary variable cost driver) | Mid-C market | Natural gas | Natural gas | Mid-C market | No variable costs |
| Capital costs | $450/on-peak kW | $775/kW | $1,250/kW | $1,750/kW | $2,500/on-peak kW |
| Fuel price risk | | ✓ | ✓ | | |
| Wholesale power market price risk | ✓ | | | ✓ | |
| Other | Expanded access to market (Mid-C) providing abundant clean, renewable energy, highly reliable (low forced outage), as long-lived resources promote stability in customer rates, benefit to regional grid | Scalable (modeled generators 18.8-MW nameplate), relatively short-lead resource | Relatively short-lead resource with recent construction experience | Nascent, uncertainty related to performance (e.g., # of lifetime cycles), potential grid benefit depending on resource siting, scalable and potential for geographic dispersion | Renewable, clean, scalable (modeled plants 30-MW nameplate) |

Notes:

1. Idaho Power's 2016 solar integration study suggests modest impacts from solar intermittency. Study based on synthetic solar data. Actual production from currently on-line solar projects will be reviewed in 2018 to verify study findings.
2. Solar is not dispatchable but tends to produce at fairly high levels during periods of high customer demand (on-peak capacity factor or contribution to peak equal to 51.3 percent of installed capacity).
3. Lithium battery is a net energy consumer (roundtrip efficiency = 86 percent). Lithium battery provides energy during heavy load hours or other high energy demand/high energy value periods; battery recharge costs tied primarily to Mid-C market costs or variable costs of Idaho Power's system resources during light load hours.
4. B2H capital-cost estimate includes a 20-percent contingency. Lithium battery capital costs are on a declining trend; 2017 Lazard reporting projects 10 percent per year annual rate of capital cost decline. Solar capital cost decline slowing. B2H and solar capital costs are expressed in terms of $/on-peak kW, where on-peak kW for B2H are based on 500-MW summer capacity and for solar is based on on-peak capacity equal to 51 percent of installed capacity.

## Idaho Power's Transmission System

Idaho Power's transmission system is a key element to providing reliable, responsible, fair-priced energy services. A map of Idaho Power's transmission system is shown in Figure 6.1 on page 58 of the 2017 IRP and in Figure 2. Transmission lines facilitate the delivery of economic resources and allow resources to be sited where most cost effective. In most instances,

the most economic/best location for resources is not immediately next to major load centers (i.e., hydro along the Columbia River, wind in Wyoming, solar in the desert southwest). For much of its history, Idaho Power has taken advantage of resources outside of its major load pockets to economically serve its customers. The existing transmission lines between Idaho Power and the Pacific Northwest have been particularly valuable. Idaho Power has maximized its use of the transmission path between Idaho and the Pacific Northwest. Additional transmission capacity is required to access incremental resources to meet projected peak demand. The B2H project is the mechanism to increase capacity between the Pacific Northwest and Idaho Power's service area.

Transmission lines are constructed and operated at different operating voltages depending on purpose, location, and distance. Idaho Power operates transmission lines at 138 kV, 161 kV, 230 kV, 345 kV, and 500 kV. Idaho Power also operates sub-transmission lines at 46 kV and 69 kV, but these voltages will not be discussed further in this appendix; the focus of this appendix is on higher voltage transmission lines used for moving bulk electricity. The higher the voltage, the greater the capacity of the line, but also the greater the construction cost and physical size requirements.

The utility industry often compares transmission lines to roads and highways. Typically, lower-voltage transmission lines (138 kV) are used to facilitate delivery of energy to substations to serve load, like a two-lane highway. Much like roads and highways can become congested, so can transmission lines. High-voltage lines are used to facilitate the bulk delivery of power, sometimes referred to as backbone transmission. Depending on the capacity needs, economics, distance (higher voltages result in less losses for longer distances), and intermediate substation requirements, either 230-kV, 345-kV, or 500-kV transmission lines are used. A 230- or 345-kV line can be compared to a multi-lane interstate, whereas a 500-kV line can be compared to a major (6+ lane) freeway used to move as many vehicles as possible.

## Transmission Capacity Between Idaho Power and the Pacific Northwest

Idaho Power owns 1,280 MW of transmission capacity between the Pacific Northwest transmission system and Idaho Power's transmission system. Of this capacity, 1,200 MW are on the Idaho to Northwest path (Western Electricity Coordinating Council [WECC] Path 14), and 80 MW are on the Montana–Idaho path (WECC Path 18). A transmission path is one or more transmission lines that collectively transmit power to/from similar geographic areas. The Idaho to Northwest transmission path is comprised of three 230-kV lines, one 500-kV transmission line, and one 115-kV transmission line. The capacity limit on the path is established through a WECC rating process based on equipment overload ratings resulting from the loss of the most critical element on the transmission system. Collectively, these lines between Idaho and the Northwest have a transfer capacity rating that is greater than the individual rating of each line

but less than the sum of the individual capacity ratings of each line based on reliability limits. Figure 2 shows an overview of Idaho Power's transmission system.

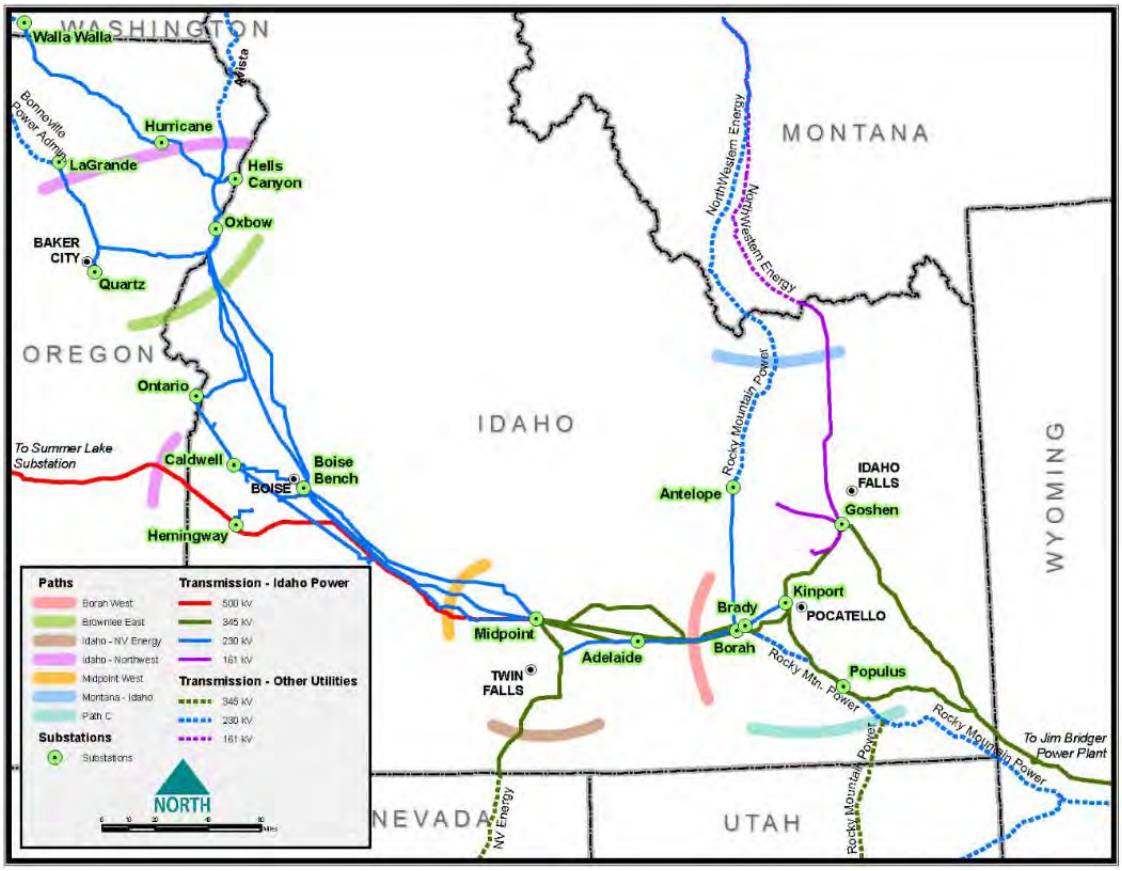



**Figure 2. Idaho Power transmission system map**

Table 3 details the capacity allocation between the Pacific Northwest and Idaho Power in 2017. The shaded rows represent capacity amounts that can be used to serve Idaho Power's native load. Although Idaho Power owns 1280 MW of transmission capacity between the Pacific Northwest and Idaho Power's system, after all other uses are accounted for, Idaho Power was only able to use 307 MW to serve Idaho Power's native load in 2017. Idaho Power used 361 MW to serve BPA or PacifiCorp network load on Idaho Power's system, 282 MW were allocated to transmission reserve margin (TRM), and 330 MW were allocated to capacity benefit margin (CBM).

**Table 3. Pacific Northwest to Idaho Power import transmission capacity from the 2016 transmission forecast**

| Firm Transmission Usage (Pacific Northwest to Idaho Power) | Capacity (July MW) |
|---|---|
| BPA Load Service (Network Customer) | 360 |
| Boardman Generation | 60 |
| Fighting Creek (PURPA) | 4 |

| | |
|---|---|
| Pallette Load (PacifiCorp—Network Customer) | 1 |
| TRM | 282 |
| CBM | 330 |
| **Subtotal** | **1,037** |
| Pacific Northwest Purchase (Idaho Power Load Service) | 243 |
| **Total** | **1,280** |

TRM is transmission capacity that Idaho Power sets aside as unavailable for firm use, for the purposes of grid reliability. Idaho Power's TRM methodology, approved by the Federal Energy Regulatory Commission (FERC) in 2002, requires Idaho Power to set aside transmission capacity based on the average loopflow on the Idaho to Northwest path. In the west, electrical power is scheduled through a contract-path methodology, which means if 100 MW is purchased and scheduled over a path, that 100 MW is decremented from the path's total availability. Physics dictate the actual power flow over the path (based on the path of least resistance), so actual flows don't always follow contract-path schedules. This unscheduled flow is sometimes referred to as loopflow. The average adverse loopflow across the Idaho to Northwest path during the month of July is 282 MW, which is equal to Idaho Power's TRM in July. Idaho Power reserves TRM to ensure a safe and reliable transmission system.

CBM is transmission capacity Idaho Power sets aside as unavailable for firm use, for the purposes of recovering from severe unexpected generation outages. Reserve generation capacity is critical to being able to recover from unexpected outages. CBM allows a utility to reduce the amount of reserve generation capacity on its system by providing transmission availability to another market, such as the Pacific Northwest, which is rich with surplus capacity necessary for emergency conditions. Idaho Power's 330 MW of CBM is based on Idaho Power's share of the unplanned loss of two Jim Bridger units. The loss of two Jim Bridger units results in the removal of over 1,000 MW of generation in Wyoming, leaving Idaho Power and PacifiCorp searching to replace approximately 330 MW and 670 MW, respectively. Recovering from such an event, especially during peak summer load, can be extremely difficult without access to Pacific Northwest generation capacity, hence the reserve margin.

## *Montana–Idaho Path Utilization*

To utilize Idaho Power's share of the Montana–Idaho 80 MW of capacity, Idaho Power must purchase transmission service from either Avista or BPA. This transmission system connects the purchased resource in the Pacific Northwest to Idaho Power's transmission system. Avista or BPA transmits, or wheels, the power across their transmission system and delivers the power to Idaho Power's transmission system. The Montana–Idaho path is identified in Figure 2 above.

### *Idaho to Northwest Path Utilization*

To utilize Idaho Power's share of the Idaho to Northwest capacity, Idaho Power must purchase transmission service from Avista, BPA, or PacifiCorp. Table 4 details a typical summer allocation of the Idaho to Northwest capacity:

**Table 4. The Idaho to Northwest Path (WECC Path 14) summer allocation**

| Transmission Provider | Idaho to Northwest Allocation (Summer West to East) (MW) |
|---|---|
| Avista (to Idaho Power) | 340 |
| BPA (to Idaho Power) | 350 |
| PacifiCorp (to Idaho Power) | 510 |
| **Total Capability to Idaho Power** | **1,200*** |

* During times of very low generation at Brownlee, Oxbow, and Hells Canyon hydro plants, the Idaho to Northwest path total capability can increase to as much as 1,340 MW; low generation at these power plants does not correspond with Idaho Power's system peak.

Avista, BPA and PacifiCorp share an allocation of capacity on the western side of the Idaho to Northwest path, and Idaho Power owns 100 percent of the capacity on the eastern side of the Idaho to Northwest path. For Idaho Power to transact across the path and serve customer load, Idaho Power's Load Servicing Operations must purchase transmission service from Avista, BPA, or PacifiCorp to connect the selling entity, via a contract transmission path, to Idaho Power.

Construction of B2H will add 1,050 MW of capacity to the Idaho to Northwest path in the west-to-east direction, of which Idaho Power will own 500 MW in the summer months (April–September), and 200 MW in the winter months (January–March and October–December). A total breakdown of capacity rights of the B2H permitting co-participants can be found in the Project Co-Participants section of this report. The Idaho to Northwest path is identified in Figure 2 above.

## Regional Planning—Studies and Conclusions

The Northern Tier Transmission Group (NTTG) and Columbia Grid are regional planning organizations that are organized and operate in compliance with FERC orders 890 and 1000. The purpose of these organizations is to consolidate each member's local transmission plans and determine a regional plan that can meet the needs of the combined member footprint in a more efficient or cost-effective manner. The NTTG and Columbia Grid develop transmission plans biennially.

B2H is a committed project in the most recent Columbia Grid 10-year plan, and it is part of the projects compromising the NTTG 2014–2015 Biennial Plan and the soon-to-be-published NTTG 2016–2017 Biennial Plan. The identified need for the B2H project in these regional planning organizations is based on transmission needs submitted by BPA, Idaho Power, and PacifiCorp.

At NTTG, all member utilities submit their load forecasts, generation forecasts, and transmission needs. NTTG studies the members' transmission footprints to determine the more efficient or cost-effective plan to meet those needs.

B2H has been, and remains, an integral part of NTTG's 10-year plan. NTTG's analysis indicated B2H is the most cost-effective and efficient project to meet the needs of the NTTG footprint.

Appendix D-5 contains the latest NTTG materials. For the most recent updates related to Idaho Power's regional planning organization, please refer to the NTTG website at nttg.biz/.

# THE B2H PROJECT

## Project History

The B2H project originated from Idaho Power's 2006 IRP. The 2006 IRP specified 285 MW of additional transmission capacity, increasing Idaho Power's connection to the Pacific Northwest power markets, as a resource in the preferred resource portfolio. A project had not been fully vetted at that time but was described as a 230-kV transmission line between McNary Substation and Boise. After the initial identification in the 2006 IRP, Idaho Power evaluated numerous capacity upgrade alternatives. Considering distance, cost, capacity, losses, and substation termination operating voltages, Idaho Power determined a new 500-kV transmission line between the Boardman, Oregon, area and the proposed Hemingway 500-kV substation would be the most cost-effective method of increasing capacity. Refer to Appendix D-1 for more information on the upgrade options considered.

Transmission capacity, especially at 500 kV, can be described as "lumpy" because capacity increments are relatively large between the different transmission operating voltages. In the 2009 IRP, Idaho Power assumed 425 MW of capacity, which was 50 percent of the assumed total rating. Idaho Power's long-standing preference was to find a partner or partners to construct B2H with to take advantage of economies of scale. In the 2011 IRP, Idaho Power assumed 450 MW of capacity. In 2012, Idaho Power achieved two major milestones: 1) PacifiCorp and BPA officially joined the B2H project as permitting co-participants and 2) Idaho Power received a formal capacity rating for the B2H project via the WECC Path Rating Process (more on this process in preceding section). In the 2013 IRP, Idaho Power began to use the negotiated capacity from the permitting agreement: 500 MW in the summer and 200 MW in the winter, a yearly average of 350 MW, for a cost allocation of 21 percent of the total project. Idaho Power used the same 21.2 percent interest in the 2015 and 2017 IRPs.

## Public Participation

The B2H project has involved considerable stakeholder involvement over the last 10 years. Idaho Power has hosted and participated in over 250 public and stakeholder meetings with an

estimated 3,000+ participants. After approximately a year of public scoping in 2008, Idaho Power paused the federal and state review process and initiated a year-long comprehensive public process to gather more input. This community advisory process (CAP) took place in 2009 and 2010. The four objectives and steps of the CAP were as follows:

1. Identify community issues and concerns.
2. Develop a range of possible routes that address community issues and concerns.
3. Recommend proposed and alternate routes.
4. Follow through with communities during the federal and state review processes.

Through the CAP, Idaho Power hosted 27 Project Advisory Team meetings, 15 public meetings, and 7 special topic meetings. In all, nearly 1,000 people were involved in the CAP, either through Project Advisory Team activities or public meetings. Additionally, numerous meetings with individuals and advocacy groups were held during and after the process.

Ultimately, the route recommendation from the CAP was the route Idaho Power brought into the *National Environmental Policy Act of 1969* (NEPA) process as the proponent-recommended route. The NEPA process included additional opportunities for public comment at major milestones, and Idaho Power worked with landowners and communities along the way. Ultimately, the route selected through the NEPA process was based on the Bureau of Land Management's (BLM) analysis and public input. For more information on the CAP, including the final report[9], and Idaho Power's initial scoping activities, visit the documents section[10] on the B2H website.

Throughout the BLM's NEPA process, including development of the Draft Environmental Impact Statement (EIS), issued Dec. 19, 2014, and prior to the Final EIS, issued Nov. 22, 2016, Idaho Power worked with landowners, stakeholders and jurisdictional leaders on route refinements and to balance environmental impacts with impacts to farmers and ranchers. For example, Idaho Power met with the original "Stop Idaho Power" group in Malheur County to help the group effectively comments and seek change from the BLM when the Draft EIS indicated a preference for a route across Stop Idaho Power stakeholder lands. BLM's decision was modified, and the route moved away from an area of highly valued agricultural lands in the Final EIS almost two years later.

[9] boardmantohemingway.com/documents/CAP%20Report-Final-Feb%202011.pdf

[10] boardmantohemingway.com/documents.aspx

Idaho Power worked with landowners in the Baker Valley, near the National Historic Oregon Trail Interpretive Center (NHOTIC), to move an alternative route along fence lines to minimize impacts to irrigated farmland, where practicable. This change was submitted by the landowners and included in the BLM's Final EIS and ROD (issued Nov. 17, 2017). Another change in Baker County was in the Burnt River Canyon and Durkee area, where Idaho Power worked with the BLM and affected landowners to find a more suitable route than what was initially preferred in the Draft EIS. Idaho Power is still working with landowners and local jurisdictional leaders to microsite in these areas to minimize impacts.

Unfortunately, the route preferences of Idaho Power and the local communities aren't always reflected in the BLM's Agency Preferred route. For example, Idaho Power had worked in the Baker County area to propose a route on the backside of the NHOTIC (to the east) to minimize visual impacts, and in the Brogan area, to avoid landowner impacts. However, both route variations went through priority sage grouse habitat and were not adopted in BLM's Agency Preferred route.

However, Idaho Power worked with Umatilla County, local jurisdictional leaders and landowners to identify a new route through the entire county, essentially moving the line further south and away from residences, ranches, and certain agriculture. This southern route variation through Umatilla County was included the BLM's Agency Preferred route.

At the urging of local landowners along Bombing Range Road in Morrow County, Idaho Power has been working with local jurisdictional leaders, delegate representatives, farmers, ranchers, and other interested parties to gain the Navy's consideration of an easement along the eastern edge of the Boardman Bombing Range. This cooperative effort with the local area has benefited the Project, providing an approach that meets the interests and common good for all in the area. Idaho Power is still working with the Navy to obtain that easement, but all indications point to receiving an authorization from the Navy in 2018.

Finally, in Union County Idaho Power worked with local jurisdictional leaders, stakeholder groups, such as the Glass Hill Coalition and some members of StopB2H (prior to that group's formation) to identify new route opportunities. The Union County B2H Advisory Commission agreed to submit a route proposal to the BLM that followed existing high-voltage transmission lines, which was later identified as the Millcreek Alternative. At the same time, Idaho Power met with a large landowner to adjust the Morgan Lake Alternative route to minimize impacts to the landowners. Idaho Power understood that both the Mill Creek and Morgan Lake route variations were favored over BLM's Agency Preferred Alternative (Glass Hill Alternative) by landowners, the Glass Hill Coalition, several stakeholders, and the Confederated Tribe of the Umatilla Indian Reservation due to concerns of impacts on areas that had no prior development. Idaho Power continued support of the community-favored routes in its amended preliminary Application for

Site Certificate. Idaho Power will work with Union County and local stakeholders to determine the route preference between the Morgan Lake and Millcreek alternatives.

## Project Activities

Below is a summary of notable activities by year since project inception. For more information about any of the activities, please visit the B2H website.

### *2006*

Idaho Power files its IRP with a transmission line to the Pacific Northwest identified in the preferred resource portfolio.

### *2007*

Idaho Power analyzes the capacity and cost of different transmission line operating voltages and determines a new 500-kV transmission line to be the most cost-effective option to increase capacity and meet customer needs. Idaho Power files a Preliminary Draft Application for Transportation and Utility Systems and Facilities on Federal Lands. Idaho Power scopes routes.

### *2008*

Idaho Power submits application materials to the BLM. Idaho Power submits a Notice of Intent to the EFSC. The BLM issues a Notice of Intent to prepare an EIS; officially initiating the BLM-led federal NEPA process. Idaho Power embarks on a more extensive public outreach program to determine the transmission line route.

### *2009*

Idaho Power pauses NEPA and EFSC activities to work with community members throughout the route as part of the CAP to identify a proposed route that would be acceptable to both Idaho Power and the public. Forty-nine routes and/or route segments were considered through CAP.

### *2010*

The CAP concludes. Idaho Power resubmits a proposed route to the BLM based on input from the CAP. The BLM re-initiates the NEPA scoping process and solicits public comments. Idaho Power publishes its B2H Siting Study. Idaho Power files a Notice of Intent with EFSC.

### *2011*

Additional public outreach resulted in additional route alternatives submitted to the BLM. The Obama Administration recognizes B2H as one of seven national priority projects[11].

[11] boardmantohemingway.com/documents/RRTT_Press_Release_10-5-2011.pdf

### 2012

The ODOE conducts informational meetings and solicits comments. The ODOE issues a Project Order outlining the issues and regulations Idaho Power must address in its Application for Site Certificate. Additional public outreach and analysis resulted in route modifications and refinements submitted to the BLM. Idaho Power issues a Siting Study Supplement. Idaho Power conducts field surveys for the EFSC application. WECC adopts a new Adjacent Transmission Circuits definition with a separation distance of 250 feet, which would later modify routes in the EIS process. Idaho Power receives a formal capacity rating from WECC.

### 2013

Public meetings are held. Idaho Power submits its Preliminary Application for Site Certificate to the ODOE. The BLM releases preliminary preferred route alternatives and works on a Draft EIS.

### 2014

The BLM issues a Draft EIS identifying an Agency Preferred Alternative. The 90-day comment period opens. Idaho Power conducts field surveys for EFSC application.

### 2015

The BLM hosts open houses for the public to learn about the Draft EIS, route alternatives, environmental analysis. The BLM reviews public comments. Idaho Power notifies the BLM of a preferred termination location, Longhorn Substation. Idaho Power submits an application to the Navy for an easement on the Naval Weapons System Training Facility in Boardman.
Idaho Power conducts field surveys for the EFSC application.

### 2016

Idaho Power submits a Draft Amended Application for Site Certificate to the ODOE for review. The BLM issues a Final EIS identifying an environmentally preferred route alternative and an Agency Preferred route alternative. Idaho Power incorporates the Agency Preferred route alternative into the EFSC application material. Idaho Power collaborates with local area stakeholders in Morrow County to find a routing solution on Navy-owned land. Idaho Power submits a revised application to the Navy. Idaho Power conducts field surveys for the EFSC application.

### 2017

Idaho Power submits an Amended Application for Site Certificate to the ODOE. The BLM issues a ROD.

For a detailed list of project activities by year, please refer to Appendix D-2.

## Route History

As stated previously, the B2H project was first identified in the 2006 IRP. At that time, the transmission line was contemplated as a line between Boise and McNary. The project evolved into a 500-kV line between the Boardman area and the Hemingway Substation. Several northern terminus substations were considered over the years, including the Boardman coal plant 500-kV yard, the proposed Grassland Substation to be constructed by Portland General Electric to integrate the then-proposed Carty Plant, and the proposed Longhorn Substation, which at the time was proposed by BPA to integrate wind onto the BPA 500-kV transmission system. During scoping, a considerable number of routes were considered to connect Hemingway and the Boardman area. Figure 3 is a snapshot of a number of routes considered early on during the CAP process (2009 timeframe). Numerous alternatives were considered, including routes through Idaho and through central Oregon. This large number of routes was further refined during the CAP process.

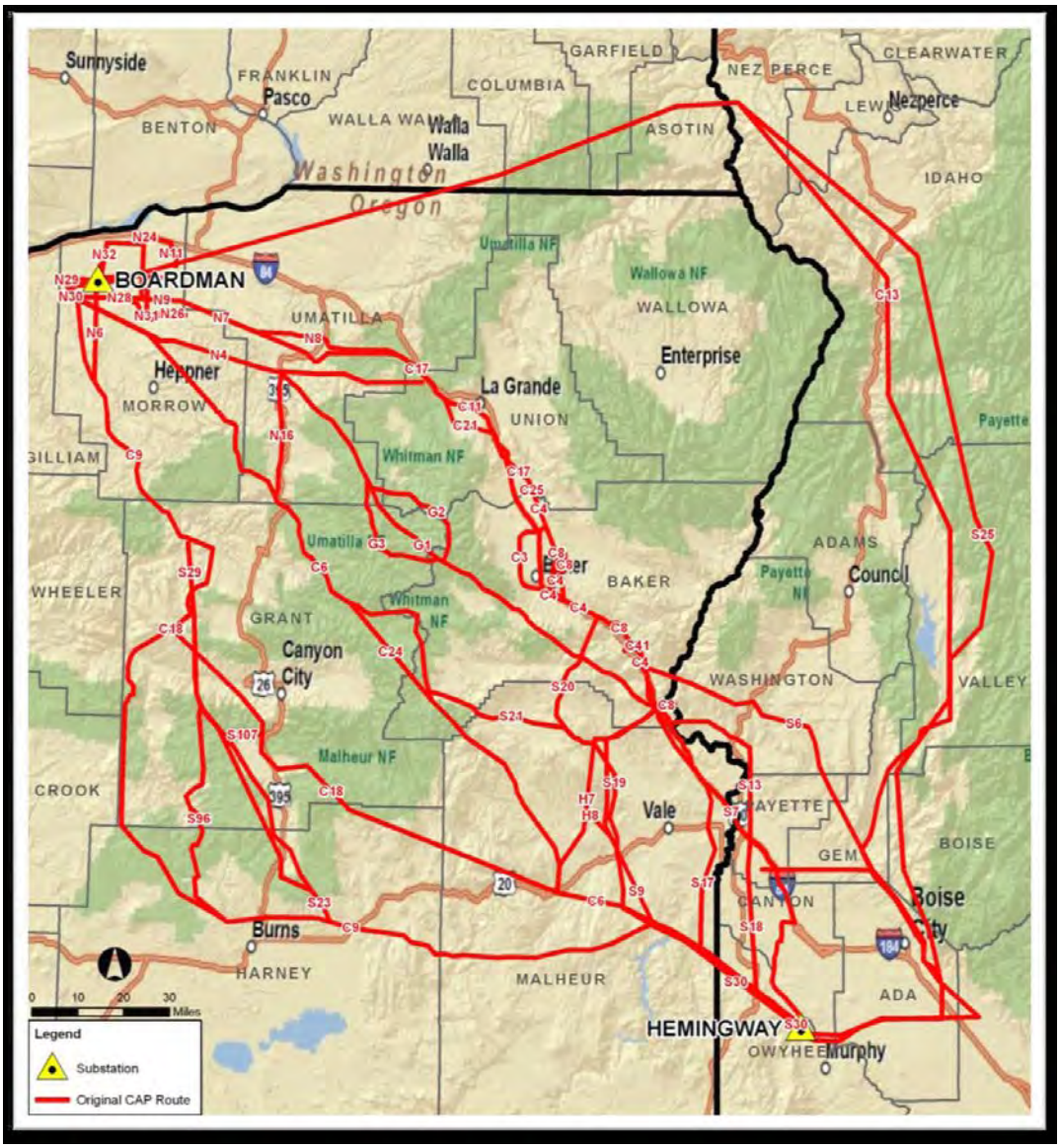



**Figure 3. Routes developed by the CAP advisory teams (2009 timeframe)**

The CAP process resulted in Idaho Power submitting the route shown in Figure 4 as the company's proposed route in the BLM-led NEPA process.

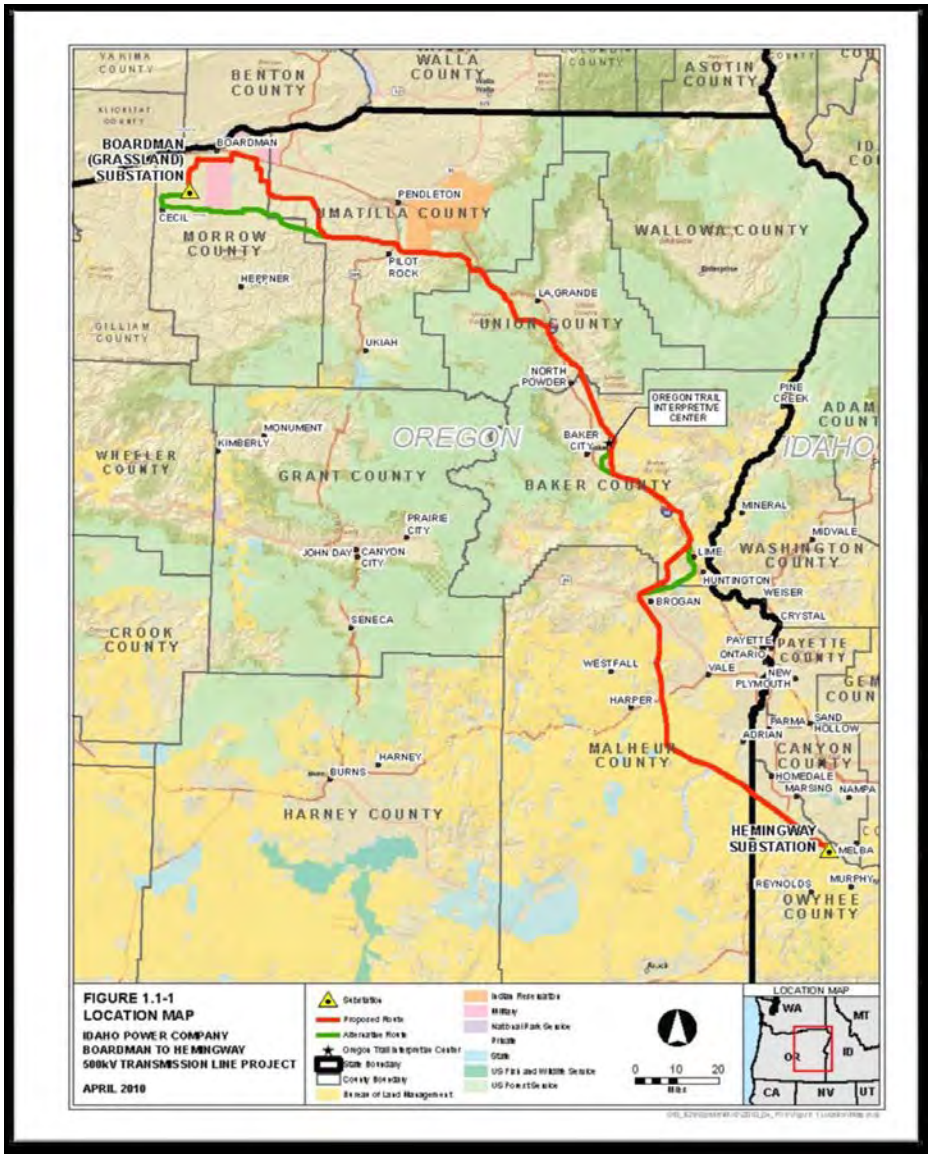



**Figure 4. B2H proposed route resulting from the CAP process (2010 timeframe)**

The BLM considered Idaho Power's proposed route, along with a number of other reasonable alternative routes, in the NEPA process. Figure 5 shows the route alternatives and variations considered in the BLM's November 2016 Final EIS.

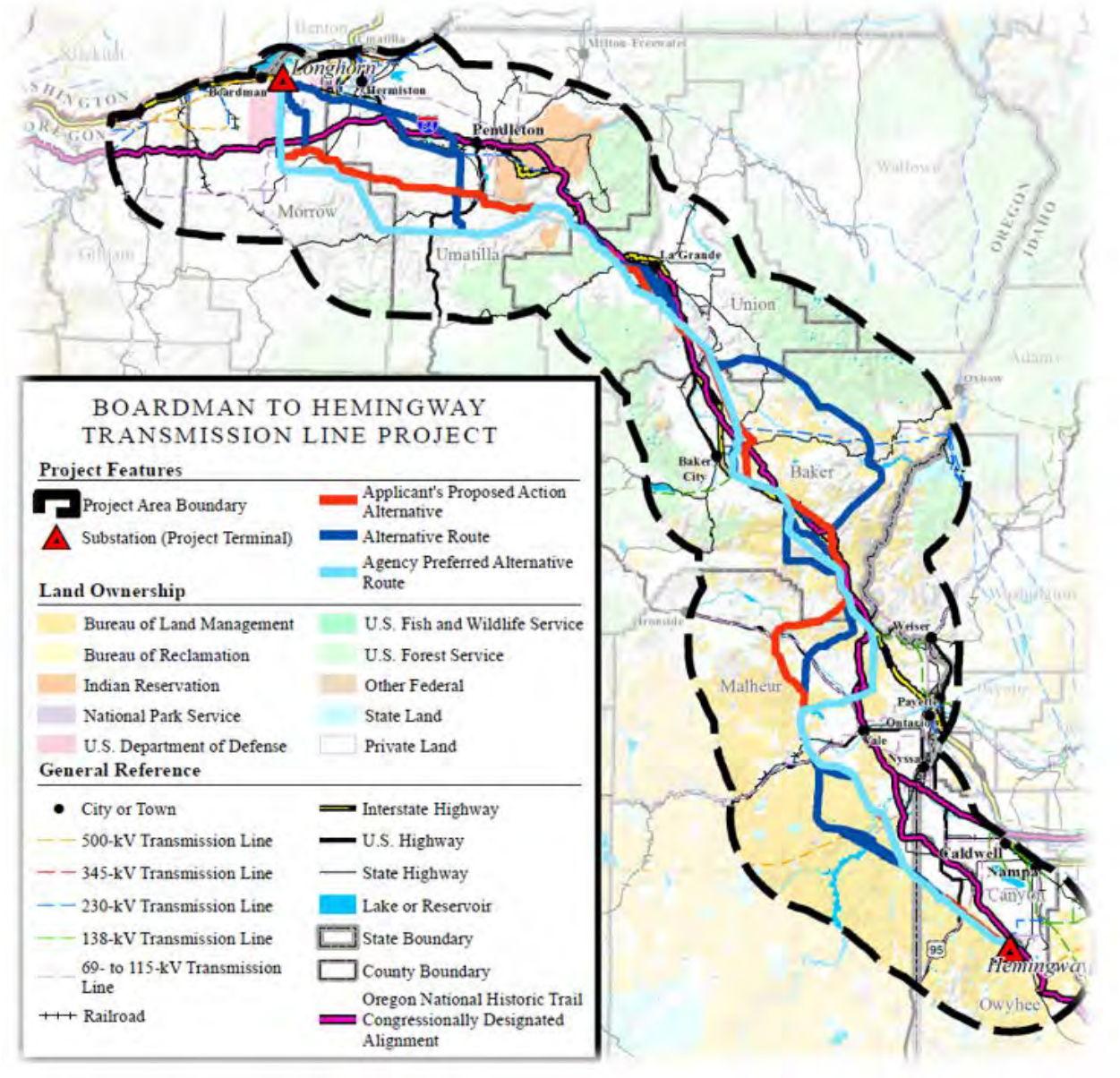



**Figure 5. BLM final EIS routes**

The conclusion of the BLM-led NEPA process, the BLM's ROD, resulted in a singular route—the BLM's Agency Preferred route. The 293.4-mile approved route will run across 100.3 miles of federal land (managed by the BLM, the U.S. Forest Service [USFS], the Bureau of Reclamation, and the U.S. Department of Defense), 190.2 miles of private land, and 2.9 miles of state lands. Figure 6 shows the BLM's Agency Preferred route.

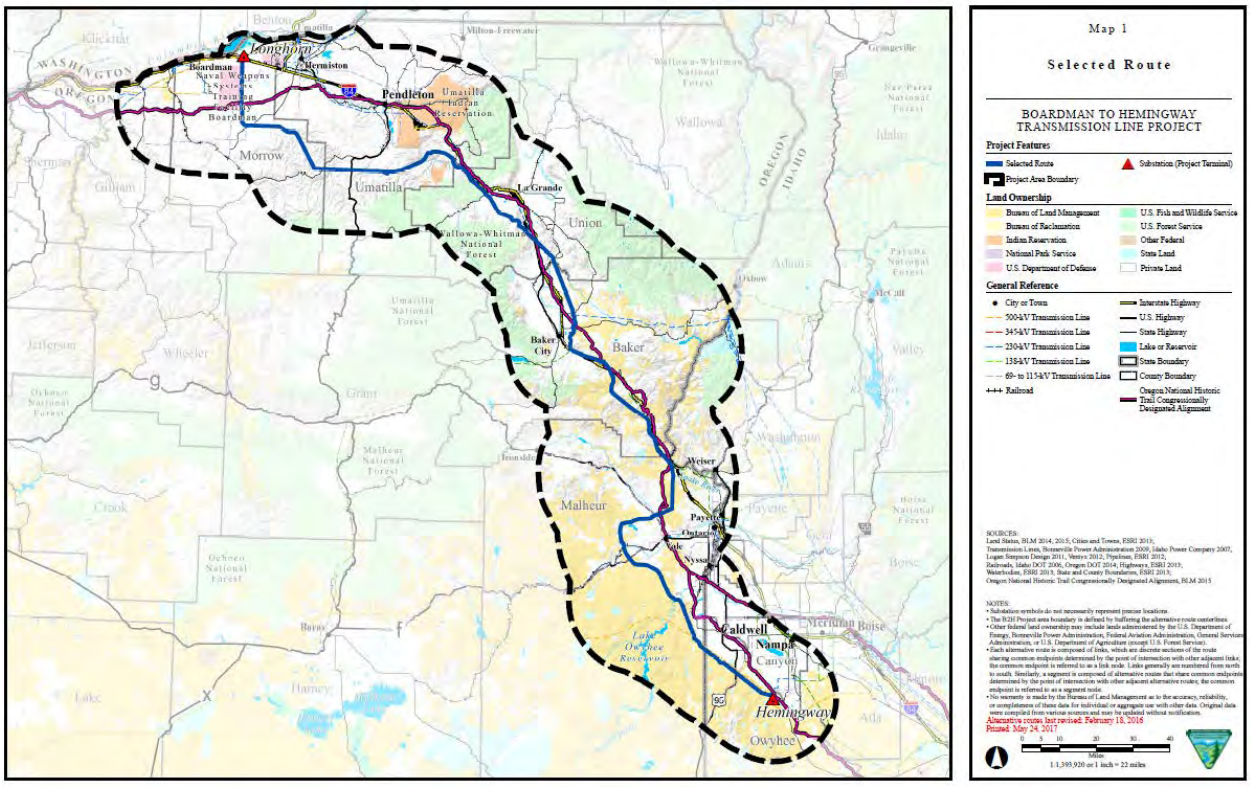



**Figure 6. BLM Agency Preferred route from the 2017 BLM ROD**

As discussed previously, the BLM-led NEPA process and the EFSC process are distinct processes. Idaho Power submitted its Amended Application for Site Certificate to the ODOE in summer 2017. The route Idaho Power submitted to the ODOE as part of the Application for Site Certificate is very similar to the BLM's Agency Preferred route, except for a small section of private property west of La Grande. The BLM's Agency Preferred route in this area was a surprise to Idaho Power and seemingly all stakeholders in the area. The section the BLM chose was not the county's stated preference, nor was it the variation Idaho Power had worked with a large local landowner to modify to minimize impacts to his property.

At the time of EFSC application finalization (which was prior to the Final EIS release), Idaho Power did not feel as if there was a stakeholder consensus preference between the County's preferred route and the modified route west of the City of La Grande. Therefore, Idaho Power brought both alternatives into the EFSC application. Idaho Power intends to continue to work with the community to finalize which of the two variations in this area will be constructed.

Figure 7 shows the route Idaho Power submitted in its 2017 EFSC Application for Site Certificate.

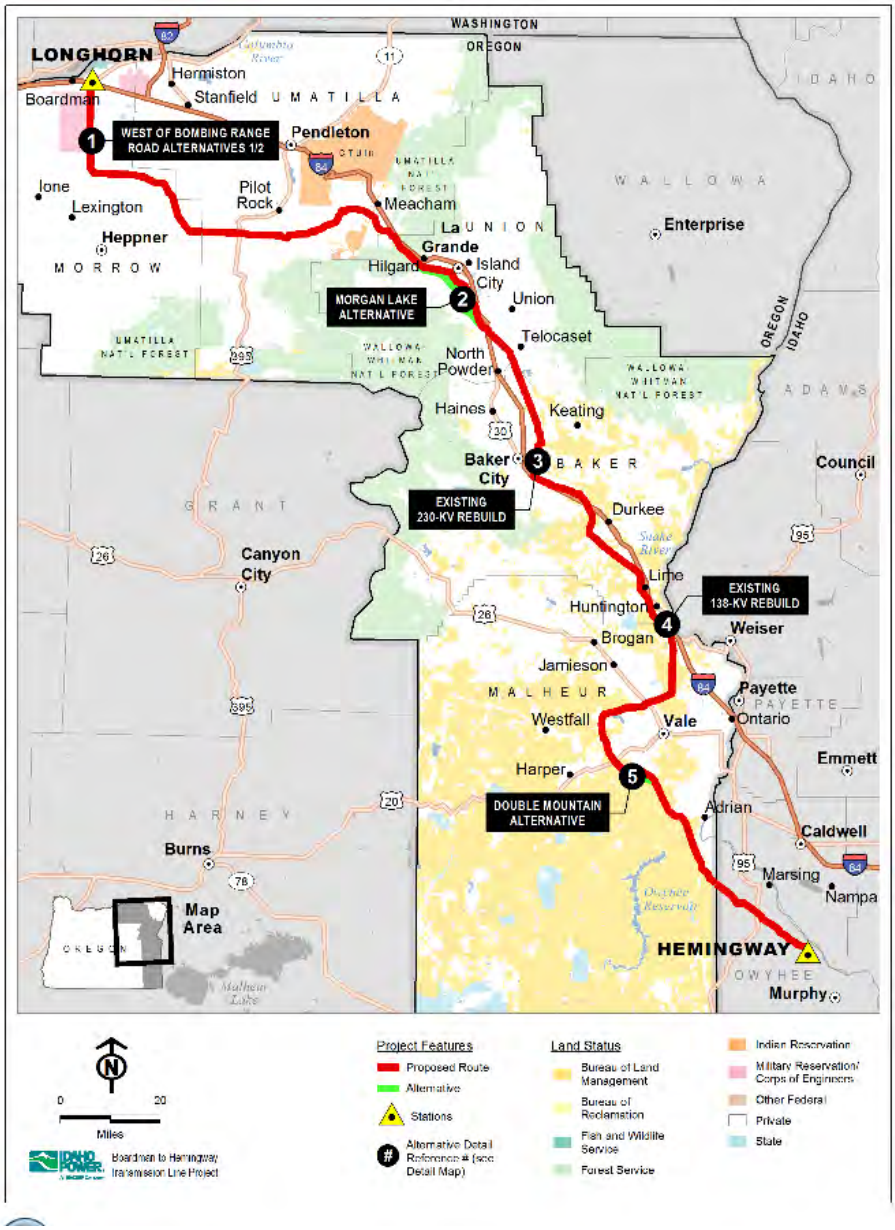



**Figure 7. B2H route submitted in 2017 EFSC Application for Site Certificate**

## B2H Capacity Interest

Per the terms of the Joint Permit Funding Agreement (see Appendix D-3), each co-participant (funder) is assigned a permitting interest based on the annual weighted capacity expressed in the project. The permitting interest is determined by the sum of a funder's eastbound capacity interest and westbound capacity interest, divided by the total of all eastbound and westbound capacity interest. Table 5 details the capacity interest of each funder.

**Table 5. B2H joint permit funding capacity interests by funder**

| | Capacity Interest (West-to-East) | Capacity Interest (East-to-West) | Ownership % |
|---|---|---|---|
| **Idaho Power** | 350 MW (Average)<br>500 MW (Summer)<br>200 MW (Winter) | 0 MW | 21.2% |
| **PacifiCorp** | 300 MW | 600 MW | 54.5% |
| **BPA** | 400 MW (Average)<br>250 MW (Summer)<br>550 MW (Winter) | 0 MW | 24.2% |
| **Unallocated** | 0 MW | 400 MW | |

Idaho Power's capacity interest is seasonally shaped, with 500 MW of eastbound capacity from April through September and 200 MW of eastbound capacity from January through March and October through December. BPA's capacity interest is seasonally shaped with 250 MW of eastbound capacity from April through September and 550 MW of eastbound capacity from January through March and October through December. PacifiCorp's capacity is constant throughout the year. The sum of the capacity interest in the east-to-west direction is less than the rating (1,000 MW), so the unallocated capacity is divided among the funders based on their respective percentage permitting interest.

The seasonal capacity shaping is a great benefit for Idaho Power's customers, and one of the reasons why the B2H project is such a competitive and cost-effective option in the IRP process. Idaho Power is effectively purchasing 500 MW of capacity (peak summer need) at a cost based on 350 MW of capacity.

## Capacity Rating—WECC Rating Process

Idaho Power coordinated with other utilities in the Western Interconnection via a peer-reviewed process known as the WECC Path Rating Process. Through the WECC Path Rating Process, Idaho Power worked with other western utilities to determine the maximum rating (power flow limit) across the transmission line under various stresses, such as high winter or high summer peak load, light load, high wind generation, and high hydro generation on the bulk power system. Based on industry standards to test reliability and resilience, Idaho Power simulated various outages, including the outage of B2H, while modeling these various stresses to ensure the power grid was capable of reliably operating with increased power flow. Through this process, Idaho Power also ensured the B2H project did not negatively impact the ratings of other transmission projects in the Western Interconnection. Idaho Power completed the WECC Path Rating Process in November 2012 and achieved a WECC Accepted Rating of 1,050 MW in the west-to-east direction and 1,000 MW in the east-to-west direction. The B2H project, when constructed, will add significant reliability, resilience, and flexibility to the Northwest power grid.

## B2H Design

B2H is routed and designed to withstand catastrophic events, including, but not limited to, the following:

- Lightning
- Earthquake
- Fire
- Wind/tornado
- Ice
- Landslide
- Flood
- Direct physical attack

The following sections provide more information about the design of the B2H transmission line and address each of the catastrophic events listed above.

### Transmission Line Design

The details below are not inclusive of every design aspect of the transmission line but provide a brief overview of the design criteria. The B2H project will be designed and constructed to meet or exceed all required safety and reliability criteria.

The basic purpose of a transmission line is to move power from one substation to another for eventual distribution of electricity to end users. The basic components of a transmission line are the structures/towers, conductors, insulators, foundations to support the structures, and shield wires to prevent lighting from striking conductors. See Figure 8 for a cross-section of a transmission line.

For a single-circuit transmission line, such as B2H, power is transmitted via three-phase conductors (a phase can also have multiple conductors, called a bundle configuration). These conductors are typically comprised of a steel core to give the conductor tensile strength and reduce sag and of aluminum outer strands. Aluminum is used because of its conductive properties, and it provides the ability to move more power using a smaller amount of material.

Shield wires, typically either steel or aluminum, and occasionally including fiber optic cables inside for communication between substation equipment, are the highest wires on the structure. Their main purpose is to protect the phase conductors from a lightning strike.

Structures are designed to support the phase conductors and shield wires and keep them safely in the air. For the B2H project, structures were chosen to be steel lattice tower structures,

which provide an economical means to support large conductors for long spans over long distances. The typical structure height for B2H is 135 feet tall (structure height will vary depending on location) with a structure located roughly every 1,200 feet on average. The tower height and span length were optimized to minimize ground impacts and material requirements; taller structures could allow for longer spans (less structures on average per mile) but would be costlier due to material requirements. Again, the B2H tower and conductors were engineered to maximize benefits and minimize costs and impacts.

Foundations are the support mechanism that bind the structures to the earth and safely keep the phase conductors and shield wires in the air. For the B2H project, the foundations at each lattice tower structure are planned to be concrete-drilled pier shafts. A cylindrical hole will be drilled at each tower footing of adequate diameter and depth to support the loads applied to the structure from the shield wires and phase conductors. The loads applied to structures via shield wires and conductors are discussed in further detail below.

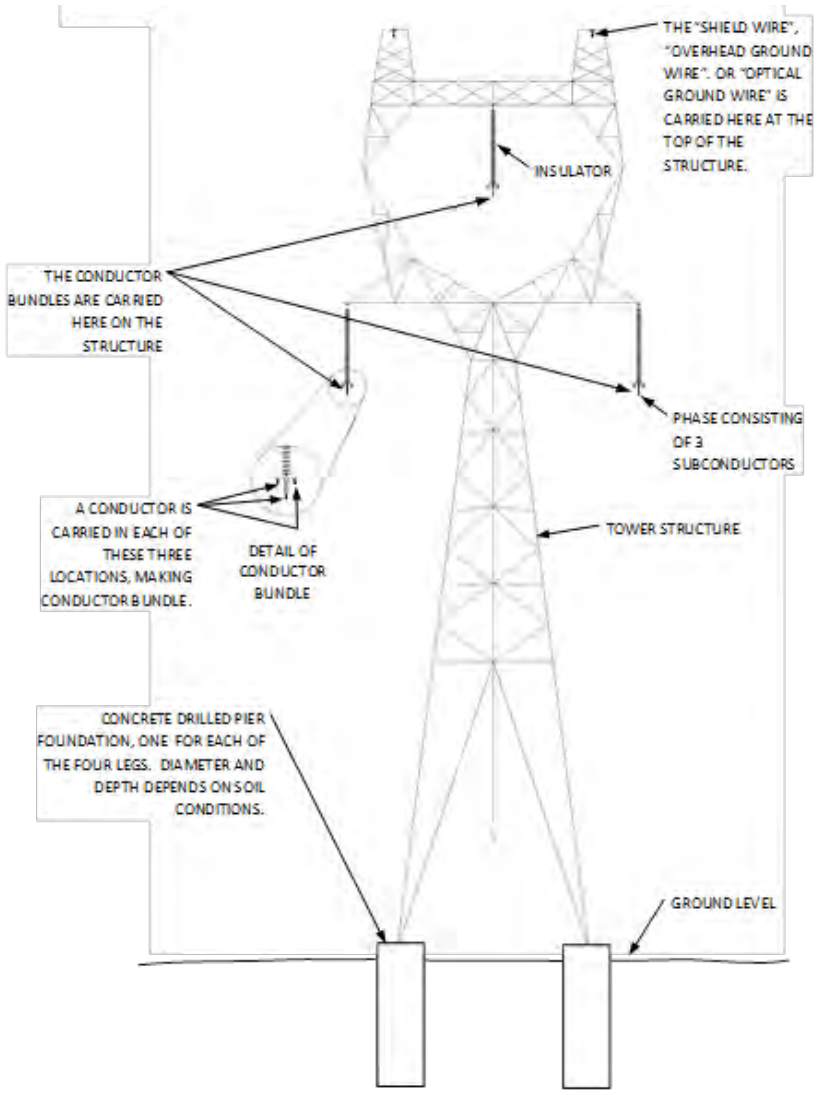



**Figure 8. Transmission tower components**

## Transmission Line Structural Loading Considerations

Reliability and resiliency are designed into transmission lines. Overhead transmission lines have been in existence for over 100 years, and many codes and regulations govern the design and operation of transmission lines. Safety, reliability, and electrical performance are all incorporated into the design of transmission lines. Idaho Power's EFSC application includes an exhaustive list of standards. Several notable standards are as follows:

- American Concrete Institute 318—*Building Code Requirements for Structural Concrete*
- American National Standards Institute (ANSI) standards (for material specs)
- American Society of Civil Engineers (ASCE) Manual No.74—*Guidelines for Electrical Transmission Line Structural Loading*

- National Electrical Safety Code (NESC)
- Occupational Safety and Health Administration (OSHA) 1910.269 April 11, 2014 (for worker safety requirements)
- National Fire Protection Association (NFPA) 780—*Guide for Improving the Lightning Performance of Transmission Lines*

NESC provides for minimum guidelines and industry standards for safeguarding persons from hazards arising from the construction, maintenance, and operation of electric supply and communication lines and equipment. The B2H project will be designed, constructed, and operated at standards that meet, and in most cases, exceed, the provisions of NESC.

Physical loads induced onto transmission structures and foundations supporting the phase conductors and shield wires for the B2H project are derived from three phenomena: wind, ice, and tension. Under certain conditions, ice can build up on phase conductors and shield wires of transmission lines. When transverse wind loading is also applied to these iced conductors, it can produce structural loading on towers and foundations far greater than normal operating conditions produce. Design weather cases for the B2H project exceed the provisions in the NESC. As an example, for a high wind case, NESC recommends 90 miles per hour (mph) winds. The criteria proposed for this project is 100 mph wind on the conductors and 120 mph wind on the structures. There are multiple loading conditions that will be incorporated into the design of the B2H project, including unbalanced longitudinal loads, differential ice loads, broken phase conductors, broken sub-phase conductors, heavy ice loads, extreme wind loads, extreme ice and wind loads, construction loads, and full dead-end structure loads.

### Transmission Line Foundation Design

The 500-kV single-circuit lattice steel structures require a foundation for each leg of the structure. The foundation diameter and depth shall be determined during final design and are dependent on the type of soil or rock present. The foundations will be concrete pier foundations designed to comply with the allowable bearing and shear strengths of the soil where placed. Soil borings shall be taken at key locations along the project route, and subsequent soil reports and investigations shall govern specific foundation designs as appropriate.

Common industry practices design transmission line structures to withstand wind and ice loads of NESC or greater, and are accepted as more stringent than the potential loads resulting from ground motion due to earthquakes. The 2017 NESC Rule 250A4 observes the structure capacity obtained by designing for NESC wind and ice loads at the specified strength requirements is sufficient to resist earthquake ground motions. Additionally, ASCE Manual No. 74 states transmission structures need not be designed for ground-induced vibrations caused by earthquake

motion; historically, transmission structures have performed well under earthquake events,[12, 13] and transmission structure loadings caused by wind/ice combinations and broken wire forces exceed earthquake loads.

### Lightning Performance

The B2H project is in an area that historically experiences 20 lightning storm days per year.[14] This is relatively low compared to other parts of the US. The transmission line will be designed to not exceed a lightning outage rate of one per 100 miles per year. This will be accomplished by proper shield wire placement and structure/shield wire grounding to adequately dissipate a lightning strike on the shield wires or structures if it were to occur. The electrical grounding requirements for the project will be determined by performing ground resistance testing throughout the project alignment, and by designing adequately sized counterpoise or using driven ground rods with grounding attachments to the steel rebar cages within the caisson foundations as appropriate.

### Earthquake Performance

Experience has demonstrated that high-voltage transmission lines are very resistant to ground-motion forces caused by earthquake, so much so that national standards do not require these forces be directly considered in the design. However, secondary hazards can affect a transmission line, such as landslides, liquefaction, and lateral spreading. The design process considers these geologic hazards using multiple information streams throughout the siting and design process. The current B2H route evaluated geologic hazards using available electronic (geographic information system [GIS]) data, such as fault lines, areas of unstable and/or steep soils, mapped and potential landslide areas, etc. Towers located in potential geologic hazards are investigated further to determine risk. Additional analysis may include field reconnaissance to gauge the stability of the area and subsurface investigation to determine the soil strata and depth of hazard. At the time of this report, no high-risk geologic hazard areas have been identified. If, during the process of final design, an area is found to be high risk, the first option would be to micro-site—route around or span over the hazard. If avoidance is not feasible, the design team would seek to stabilize the hazard. Engineering options for stabilization include designing an array of sacrificial foundations above the tower foundation to anchor the soil or improving the subsurface soils by injecting grout or outside aggregates into the ground. If the geotechnical

[12] Risk Assessment of Transmission System under Earthquake Loading. J.M. Eidinger, and L. Kemper, Jr. Electrical Transmission and Substation Structures 2012, Pg. 183-192 © ASCE 2013.

[13] Earthquake Resistant Construction of Electric Transmission and Telecommunication Facilities Serving the Federal Government Report. Felix Y. Yokel. Federal Emergency Management Agency (FEMA). September 1990.

[14] USDA RUS Bulletin 1751-801.

investigation determines the problematic soils are relatively shallow, the tower foundations can be designed to pass through the weaker soils and embed into competent soils.

### Wildfire

The transmission line steel structures are constructed of non-flammable materials, so wildfires do not pose a physical threat to the transmission line itself. However, heavy smoke from wildfires in the immediate area of the transmission line can cause flashover/arcing between the phase conductors and electrically grounded components. Standard operation is to de-energize transmission lines when fire is present in the immediate area of the line. Transmission lines generally remain in-service when smoke is present from wildfires not in the immediate vicinity of the transmission line. Alternatively, solar PV is susceptible to smoke, which can move into areas even if fires are not in the immediate vicinity of the solar generation. For example, the forest fires in the Pacific Northwest in 2017 caused much smoke along the proposed B2H corridor and in the Pacific Northwest in general. The B2H line would likely still operate for the fires not in the immediate area, whereas solar PV would likely operate at a much-reduced capacity while heavy smoke is covering the area.

### Wind Gusts/Tornados

Tornados are unlikely along the B2H route. As noted in the Transmission Line Structural Loading Considerations section above, the B2H transmission line is designed to withstand extreme wind loading combined with ice loading.

### Ice

Ice formation around the phase conductors and around the shield wires can add a substantial amount of incremental weight to the transmission line, putting extra force on the steel structures and foundations. As described in the Transmission Line Structural Loading Considerations section above, the B2H transmission line is designed to withstand heavy ice loading combined with heavy wind loading.

### Landslide

The siting and design process considers geologic hazards, such as landslides, liquefaction, and lateral spreading. See the Earthquake Performance section above. Through the siting and design process, steep, unstable slopes are avoided, especially where evidence of past landslides is evident. During the preliminary construction phase, geotechnical surveys and ground surveys (light detection and ranging [LiDAR] surveys) help verify potentially hazardous conditions. If a potentially hazardous area cannot be avoided, the design process will seek to stabilize the area.

### Flood

The identification and avoidance of flood zones was incorporated into the siting process and will be further incorporated into the design process. Foundations and structures can be designed to withstand flood conditions.

### Direct Physical Attack

A direct physical attack on the B2H transmission line will remove the line's ability to deliver power to customers. In the case of a direct attack, B2H is fundamentally no different than any other supply-side resource should a direct physical attack occur on a specific resource. However, because the B2H project is connected to the transmission grid, a direct physical attack on any specific generation site in the Pacific Northwest or Mountain West region will not limit B2H's ability to deliver power from other generation in the region. In this context, B2H provides additional ability for generation resources to serve load if a physical attack were to occur on a specific resource or location within the region and therefore increases the resiliency of the electric grid as a whole.

If a direct physical attack were to occur on the B2H transmission line and force the line out of service, the rest of the grid would adjust to account for the loss of the line. Per the WECC facility rating process, the B2H capacity rating is such that an outage of the B2H line would not overload any other system element beyond equipment emergency ratings. Idaho Power also keeps a supply of emergency transmission towers that can be very quickly deployed to replace a damaged tower allowing the transmission line to be quickly returned to service.

### B2H Design Conclusions

As evidenced in this section, the B2H project is designed to withstand a wide range of physical conditions and extreme events. Because transmission lines are so vital to our electrical grid, design standards are stringent. B2H will adhere to, and in most cases, exceed, the required codes or standards observed for high voltage transmission line design. This approach to the design, construction, and operation of the B2H project will establish utmost reliability for the life of the transmission line. Additionally, as discussed in the Direct Physical Attack section, transmission lines add to the resiliency of the grid by providing additional paths for electricity should one or more generation resources or transmission lines experience a catastrophic event.

# PROJECT CO-PARTICIPANTS

## PacifiCorp and BPA Needs

PacifiCorp and BPA are co-participants on the B2H project (also referred to as funders). Collectively, Idaho Power, PacifiCorp, and BPA represent a very large electric service footprint in the western US. The fact that three large utilities have each identified the value of the B2H

project indicates the regional significance of the project and the value the project brings to customers throughout the West. Idaho Power, PacifiCorp, and BPA have worked closely to assign the capacity rights of the project to correlate with each party's needs. More information about PacifiCorp's and BPA's needs and interest in the B2H project can be found in the following sections.

## PacifiCorp

PacifiCorp is a locally managed, wholly owned subsidiary of Berkshire Hathaway Energy Company. PacifiCorp is a leading western US energy services provider and the largest grid owner/operator in the West, serving 1.8 million retail customers in six western states. PacifiCorp is comprised of two business units: Pacific Power (serving Oregon, Washington, and California) and Rocky Mountain Power (serving Utah, Idaho, and Wyoming). Visit pacificorp.com for more information.

PacifiCorp has invested in the permitting of the B2H project because of the strategic value of the B2H corridor, which connects the Pacific Northwest to the Intermountain West. The existing transmission path between the two regions is fully used during key operating periods. As a potential owner in the project, PacifiCorp would be able to use its bidirectional capacity to increase reliability and efficiency for its customers. The following is a list of additional B2H benefits identified for PacifiCorp.

- **Customers**: PacifiCorp continues to invest to meet customers' needs, making only critical investments now to ensure future reliability, security, and safety. The B2H project is identified as an investment that will ensure future reliability, security, and safety for PacifiCorp customers.

- **Renewables**: PacifiCorp continues to grow their renewable resources and transition to a lower-carbon future. The B2H project has been identified as a strategic project to facilitate PacifiCorp's use of renewable resources across their two balancing authority areas.

- **EIM**: PacifiCorp was a leader in implementing the western energy imbalance market (EIM). The real-time market helps optimize the electric grid, lowering costs, enhancing reliability, and more effectively integrating resources. PacifiCorp believes the B2H project will help advance the objectives of the EIM, benefitting PacifiCorp customers and the broader region.

- **Regional Benefit**: PacifiCorp, as a member of the regional planning entity Northern Tier Transmission Group (NTTG), supports the conclusion that the B2H project is as a cost-effective project providing regional solutions to identified regional needs.

- **Balancing Area Consolidation**: PacifiCorp operates/controls two balancing areas in the West. After the addition of B2H and portions of Gateway West, more transmission capacity will exist between PacifiCorp's two balancing areas, providing the ability to increase operating efficiencies. B2H will provide PacifiCorp 300 MW of additional west-to-east capability and 600 MW of east-to-west capability to move resources between PacifiCorp's two balancing authority areas.

### *BPA*

BPA is a nonprofit federal power marketing administration based in the Pacific Northwest. BPA provides approximately 28 percent of the electric power used in the Pacific Northwest, which has-an estimated population of over 13 million people. BPA also operates and maintains about three-fourths of the high-voltage transmission in its service area. BPA's area includes Idaho, Oregon, Washington, western Montana, and small parts of eastern Montana, California, Nevada, Utah, and Wyoming. For more information, visit bpa.gov.

Similar to the Idaho Power IRP process for identifying cost-effective service alternatives, BPA identified the B2H project plus associated asset exchange as its top priority for pursuit for serving customers in southeast Idaho. BPA's load and resource mix in southeast Idaho results in a net winter peak demand that exceeds the summer peak demand. BPA's winter peak load couples well with Idaho Power's summer peak load to allow for seasonal shaping of the B2H capacity. Seasonal shaping of capacity would allow BPA to own 550 MW of B2H capacity in the winter and 250 MW of capacity in the summer, dramatically increasing the cost-effectiveness of the project for BPA customers. A recent analysis performed by BPA continues to support the B2H project plus the asset exchange as its top priority for pursuit. For more information about the southeast Idaho load service analysis, visit bpa.gov.[15]

As a federal agency, BPA has responsibilities to comply with NEPA and consider the environmental impacts of its actions, such as participating in transmission line construction. To that end, BPA was a cooperating agency in the development of the B2H EIS and continues to coordinate with the BLM and other federal agencies. BPA will ensure an appropriate environmental review has been conducted on any BPA-proposed action associated with the project and plans to prepare a ROD to the B2H EIS as appropriate and in accordance with the B2H project's permitting schedule.

## Co-Participant Expenses Paid to Date

Approximately $92 million, including allowance for funds used during construction (AFUDC), have been expended on the B2H project through September 30, 2017. Pursuant to the terms of

[15] Southeast Idaho Load Service analysis: bpa.gov/transmission/CustomerInvolvement/SEIdahoLoadService/Pages/default.aspx

the joint funding arrangements, Idaho Power has received approximately $48 million of that amount as reimbursement from the project participants as of September 30, 2017. Idaho Power has accrued in receivables approximately $18 million more that will be billed by Idaho Power in the future to the project co-participants for expenses Idaho Power has incurred, for a total amount reimbursable by co-participants of $66 million. Co-participants are obligated to reimburse Idaho Power for their share of any future project permitting expenditures incurred by Idaho Power.

## Co-Participant Agreements

Idaho Power, BPA, and PacifiCorp (collectively, the funders) entered a Joint Permit Funding Agreement on January 12, 2012, with the intent to be joint owners of the B2H line. The Joint Permit Funding Agreement provides for the permitting (state and federal), siting, and acquisition of right-of-way (ROW) over public lands. A copy of the Joint Permit Funding can be found in Appendix D-3.

Related to the project, but not specific to the B2H permitting activities, the B2H co-participants entered into an MOU on January 12, 2012, to 1) explore alternatives to establish BPA eastern Idaho load service from Idaho Power and PacifiCorp's Hemingway Substation and 2) consider whether to replace certain transmission arrangements involving existing assets with joint ownership transmission arrangements and other alternative transmission arrangements pursuant to definitive agreements mutually satisfactory to the co-participants. In other words, in conjunction with the project, the parties agreed to explore cost-effective methods to serve customers by jointly owning facilities other than the B2H project. A copy of the MOU can be found here or in Appendix D-4.

# Cost

## Cost Estimate

The total cost estimate for the B2H project is $1 to $1.2 billion dollars, which includes Idaho Power's allowance for funds used during construction (AFUDC). Co-participant AFUDC is not included in this estimate range. The total cost estimate includes a 20-percent contingency for unforeseen expenses.

In IRP modeling, Idaho Power assumes a 21.2-percent share of the direct expenses, plus its entire AFUDC cost, which equates to approximately $258 million. Idaho Power also included costs for local interconnection upgrades totaling $16 million. The 2017 IRP was the first year for which the B2H route was relatively certain. In prior years, the estimate was based on uncertain route and terminus location information.

## Transmission Line Estimate

Idaho Power has contracted with HDR to serve as the B2H project's third-party owners' engineer and prepare the B2H transmission line cost estimate. HDR has extensive industry experience, including experience serving as an owner's engineer for BPA for the last seven years. HDR has prepared a preliminary transmission line design that locates every tower and access road needed for the project. HDR used utility industry experience and current market values for materials, equipment, and labor to arrive at the B2H estimate. Material quantities and construction methods are well understood because the B2H project is utilizing BPA's standard tower and conductor design for 500-kV lines. BPA has used the proposed towers and conductor on hundreds of miles of lines currently in-service. HDR was the owner's engineer on recent BPA projects, so HDR is also familiar with the BPA towers and conductor the B2H project is using.

## Substation Estimates

Idaho Power prepared the substation cost estimate for the Hemingway Substation, and BPA prepared the Longhorn Substation estimate. Idaho Power used experience designing and constructing the Hemingway Substation in 2013. The Hemingway Substation is designed to accommodate the B2H line terminal in the future. New equipment must be ordered and installed, but no station expansion will be required. The Longhorn Substation is a station proposed by BPA near Boardman, Oregon. BPA owns the land for the Longhorn Substation, but the station has yet to be constructed. BPA proposed the Longhorn Substation to integrate certain wind projects in the immediate area. BPA has extensive experience designing and constructing substations.

## Calibration of Cost Estimates

The B2H estimate was reviewed and approved by BPA and PacifiCorp. BPA and PacifiCorp both have recent transmission line construction projects to calibrate against. The recent projects included the following:

- BPA: Lower Monumental–Central Ferry 500-kV line (38 miles, in-service 2015)
- BPA: Big Eddy–Knight 500-kV line (39 miles, in-service 2016)
- PacifiCorp: Sigurd to Red Butte 345-kV line (160 miles, in-service 2015)
- PacifiCorp: Mona to Oquirrh 500-kV line (100 miles, in-service 2013)

Additionally, in early 2017 Idaho Power visited with NV Energy and Southern California Edison to learn from each company's recent experience constructing 500-kV transmission lines in the West. As part of the discussions with each company, Idaho Power calibrated cost estimates and resource requirements.

The two projects were as follows:

- NV Energy: ON Line project (235 miles, 500 kV, in-service 2014)
- Southern California Edison: Devers to Palo Verde (150 miles, 500 kV, in-service 2013)

### Costs Incurred to Date

Approximately $92 million, including AFUDC, has been expended on the Boardman-to-Hemingway project through September 30, 2017. Refer to the Co-Participant Expenses Paid to Date section for co-participant reimbursements. The $92 million incurred through September 30, 2017, is included in the $1 to $1.2 billion total estimate. Idaho Power's share of the costs incurred to-date is included B2H IRP portfolio modeling.

### Cost-Estimate Conclusions

The cost estimate for B2H has been thoroughly vetted. Idaho Power used third-party contractors with industry experience, relied on PacifiCorp and BPA recent transmission line construction experience, and benchmarked against multiple recent high-voltage transmission line investments in the West to arrive at the B2H construction cost estimate. Material quantities and construction methods are well understood because the B2H project is using BPA's standard tower and conductor design for 500-kV lines. As a conservative measure, Idaho Power has added a 20 percent contingency to cover any unanticipated expenses. As a reminder, Idaho Power's IRP analysis escalates all resource costs at a 2.1-percent inflation rate into the future so future labor and material cost escalations are accounted for in B2H IRP portfolio modeling.

## Transmission Revenue

The B2H transmission line project is modeled in AURORA as additional transmission capacity available for Idaho Power energy purchases from the Pacific Northwest. In general, for new supply-side resources modeled in the IRP process, surplus sales of generation are included as a cost offset in the AURORA portfolio modeling. However, historically, additional transmission wheeling revenue has not been quantified for transmission capacity additions. For the 2017 IRP, Idaho Power modeled the additional transmission wheeling revenue for the B2H project. After the B2H line is in-service, the cost of Idaho Power's share of the transmission line will go into Idaho Power's transmission rate base as a transmission asset. Idaho Power's transmission assets are funded by native-load customers, network customers, and transmission wheeling customers based on a ratio of each party's usage of the transmission system. In the IRP modeling, the estimated incremental transmission wheeling revenue from non-native-load customers was modeled as an annual revenue credit for B2H portfolios.

In the B2H analysis, Idaho Power chose to conservatively assume that third-party use (network customers and transmission wheeling customers) across Idaho Power's transmission system would remain static following the construction of B2H. Idaho Power's FERC transmission rate is calculated as follows:

$$Transmission\ Rate = \frac{Transmission\ Costs\ (\$)}{Transmission\ Usage\ (MW * year)}$$

Per the formula above, since transmission costs will go up following the installation of B2H, and transmission usage is assumed to remain the same, Idaho Power's transmission rate will increase. Idaho Power's *existing* transmission customers will pay this higher transmission rate, resulting in incremental transmission revenue to Idaho Power.

As a specific example, based on current third-party long-term usage, Idaho Power forecasts 611 MW of third-party long-term transmission wheeling customers. Idaho Power also forecasts 250 average MW of network customers for a combined total of 861 MW usage. For each $1,000 per MW per year increase to the transmission rate (transmission costs in the equation above), Idaho Power will gain about $861,000 in transmission revenue. B2H will increase Idaho Power's rate by over $6,000 per MW per year.

An alternative way to understand the FERC transmission rate, and B2H's impact, is to look at the transmission system from a total load prospective. Native load, network load, and transmission customers must pay their respective share based on their usage of the system. Native load and network load usage is measured in peak MW (averaged by month), and transmission customer usage is measured by reservation amount. The total transmission usage in 2026 is forecast to be approx. 3,900 MW (including Idaho Power's native load usage); therefore, the 861 MW of network load and transmission customer usage results in approximately 22 percent of the total transmission system usage. As such, non-Idaho Power customers are estimated to pay about 22 percent of the costs associated with B2H.

This transmission revenue will offset the cost of B2H for retail customers. In a similar manner, other portfolios include revenues from market sales of newly installed supply resources, which act to offset costs in those portfolios. This section provides a high-level explanation of the workings of Idaho Power's FERC transmission rate. When determining the annual transmission revenue credit for B2H portfolios, Idaho Power ran a full corporate financial model, including rate of return, depreciation expense, operation and maintenance (O&M), etc.

Idaho Power believes short-term usage of the Idaho Power transmission system by third parties could substantially increase because additional capacity is created, further reducing Idaho Power customer rates. However, to be conservative, Idaho Power assumed there would be no increased short-term or long-term third-party transmission usage and only applied the higher transmission rate to the existing usage.

## Potential BPA and Idaho Power Asset Swap

Corresponding with the construction of B2H, Idaho Power and BPA are working to complete an asset swap that would allow Idaho Power to directly access the Mid-C market and avoid a BPA transmission wheeling charge. Such a swap would result in lower purchased-power prices for

Idaho Power's customers. In return, BPA would be able to directly serve their load in southeastern Idaho and avoid an Idaho Power wheeling charge. As part of the 2017 IRP analysis, Idaho Power conservatively assumed there would be a wheeling charge to access Mid-C resources across B2H. If an asset swap were to take place, the cost of energy in B2H portfolios would be further reduced and make B2H an even more attractive project. Refer to Appendix D-4 for the MOU relating to the potential Idaho Power–BPA asset swap.

# BENEFITS

High-voltage transmission lines, such as B2H, are used to serve customer demand and to move energy between major markets hubs in the Western Interconnection. If the existing western US were to be overlaid with thousands of new miles of high-voltage transmission lines, the entire WECC could be optimized such that all customers would be served with the most economic resources at all times of the year. The long-term need for new supply-side resources would greatly diminish due to the vast diversity of the loads and resources across the Western Interconnection. Such a grid, of course, is economically infeasible, but projects such as B2H are being developed to allow economic resources to be shared between regions. The existing transmission grid is not perfect and many areas of the transmission grid are congested. Transmission congestion causes both economic and reliability issues.

## Capacity

High-voltage transmission lines provide many significant benefits to the Western Interconnection. The most significant benefit of the B2H project is the capacity benefit of the transmission line. Idaho Power is developing the B2H project to create capacity to serve peak customer demand. The capacity benefit is described in more detail in the Resource Need section.

The Pacific Northwest is a winter peaking region. Pacific Northwest utilities continue to install and build generation capacity to meet winter peak regional needs. Idaho Power operates a system with a summer peak demand. Idaho Power's peak occurs in the late June/early July timeframe, which aligns well with spring hydro runoff conditions when the Pacific Northwest is flush with surplus power capacity. The existing transmission system between the Pacific Northwest and Idaho Power is constrained. Constructing B2H will alleviate this constraint and add 1,050 MW of transfer capability between the Pacific Northwest and Idaho Power. Both the Pacific Northwest and Idaho Power will significantly benefit from the addition of transmission capacity between the regions. The Pacific Northwest has already built the power plants and would benefit from selling energy to Idaho Power. Idaho Power needs resources to serve peak load, and a transmission line to existing, underutilized power plants is much more cost effective than building a new power plant.

## Avoid Constructing New Resources (and Potentially Carbon-Emitting Resources

In the early days of the electric grid, utilities built individual power plants to serve their local load. Utilities quickly realized that if they interconnected their systems with low-cost transmission, the resulting diversity of load reduced their need to build power plants. Utilities also realized transmission allowed them to build and share larger, more cost-effective and more efficient power plants. The same opportunities exist today. In fact, B2H is being developed to take advantage of existing diversity.

Table 6 illustrates peak-load estimates, by utility and season, for 2026. The shading represents winter-peaking utilities. As seen in the table, there is significant diversity of load between the regions. The Maximum (MW) column illustrates the minimum amount of generating capacity that would be required if each region were to individually plan and construct generation to meet their own peak load need: 69,000 MW. When all regions plan together, the total generating capacity can be reduced to 63,800 MW, a nearly 10 percent reduction. Transmission connections between the regions, such as B2H, are the key to sharing installed generation capacity.

**Table 6. 2026 peak load estimates—illustration of load diversity between western regions**

| Region | Summer Peak (MW) | Winter Peak (MW) | Maximum (MW) |
|---|---|---|---|
| Avista | 2,200 | 2,400 | 2,400 |
| BPA | 9,200 | 11,000 | 11,000 |
| British Columbia | 10,300 | 13,100 | 13,100 |
| Chelan | 600 | 800 | 800 |
| Grant | 900 | 900 | 900 |
| Idaho Power | 3,800 | 2,800 | 3,800 |
| Nevada | 9,000 | 6,500 | 9,000 |
| Northwestern Energy | 2,000 | 1,900 | 2,000 |
| PacifiCorp—East | 9,500 | 7,900 | 9,500 |
| PacifiCorp—West | 3,600 | 4,000 | 4,000 |
| Portland General | 4,000 | 4,100 | 4,100 |
| Puget Sound | 4,000 | 5,400 | 5,400 |
| Seattle City | 1,500 | 1,900 | 1,900 |
| Tacoma | 800 | 1,100 | 1,100 |
| **Total** | **61,400** | **63,800** | **69,000** |

Note: 2026 regional peak load data extracted from the WECC TEPPC 2026 Common Case.

Load diversity occurs seasonally, as illustrated in Table 6, but it also occurs sub-seasonally and daily. An additional major variable in the Northwest is hydroelectric generation diversity. Over the winter, water accumulates in the mountains through snowpack. As this snow melts, water

flows through the region's hydroelectric dams, and northwest utilities generate a significant amount of power. During the spring runoff, generation capacity available in the Pacific Northwest can be significantly higher than generation capacity available during the winter, or even during late summer. Idaho Power is fortunate to have a peak load that is coincident with the late spring / early summer hydro runoff. Idaho Power's peak load occurs in late June/early July, when hot weather causes major air-conditioning load coincident with agricultural irrigation/pumping load. Idaho Power's time window for a significant peak is quite short, with agricultural irrigation/pumping load starting to ramp down by mid-July.

Utilities have an obligation to serve customer load. This means that utilities are planning to meet peak load needs. As discussed previously, transmission congestion can cause utilities to build additional generation to serve load. Due to transmission congestion, utilities may be unable to leverage their transmission system to access dormant generation already constructed by their neighbors. The B2H project is an alternative to building new supply-side resources. As demonstrated in the 2017 IRP, the portfolios that are the most cost-effective other than B2H are portfolios with natural gas generation. In this case, B2H is an alternative to building a carbon-emitting supply-side resource.

## Improved Economic Efficiency

Transmission congestion causes power prices on opposite sides of the congestion to diverge. Transmission congestion is managed by dispatching less economically efficient resources to ensure the transmission system is operating securely and reliably. Congestion can have a significant cost. During peak summer conditions, the Idaho to Northwest path in the west-to-east direction becomes constrained and power prices in Idaho and to the east will generally be high, while power prices in the Pacific Northwest will be depressed due to a surplus of power availability without adequate transmission capacity to move the power out of the region. The construction of B2H will alleviate much of this constraint and create a win–win scenario where generators in the Pacific Northwest will be able to gain further value from their existing resource, and load-serving entities in the Mountain West region will be able to meet load service needs at a lower cost. The reverse situation could be true as well—the Pacific Northwest could benefit from economical resources from the Mountain West region during certain times of the years.

## Renewable Integration

Transmission capacity is critical to the integration of renewable generation that, at times, is curtailed due to a lack of transmission capacity to move the energy to load. Transmission is a facilitator for future generation development.

## Grid Reliability/Resiliency

Transmission grid disturbances do occur. B2H will increase the robustness and reliability of the regional transmission system by adding additional high-capacity bulk electric facilities designed with the most up-to-date engineering standards. Major 500-kV transmission lines, such as B2H, substantially increase the grid's ability to recover from major unexpected disturbances. Unexpected disturbances are difficult to predict, but below are a few examples of disturbances whose impacts would be reduced with the addition of B2H:

1. Loss of the Hemingway–Summer Lake 500-kV line with heavy west-to-east power transfer into Idaho. The loss of the Hemingway–Summer Lake 500-kV transmission line, the only 500-kV connection between the Pacific Northwest and Idaho Power, during peak summer load is one of the worst possible contingencies the Idaho Power transmission system can experience. Once Hemingway–Summer Lake 500-kV disconnects, the transfer capability of the Idaho to Northwest path is reduced by over 700 MW in the west-to-east direction. After the addition of B2H, there will be two major 500-kV connections between the Pacific Northwest and Idaho Power. The Hemingway–Summer Lake 500-kV outage would become much less severe to Idaho Power's transmission system.

2. Loss of the Hemingway–Summer Lake 500-kV line with heavy east-to-west power transfer out of Idaho to the Pacific Northwest. In this disturbance, an existing remedial action scheme (power system logic used to protect power system equipment) will disconnect over 1,000 MW of generation at the Jim Bridger Power Plant to reduce path transfers and protect bulk transmission lines and apparatus. Due to the magnitude of the generation loss, recovery from this disturbance can be extremely difficult. After the addition of B2H, this enormous amount of generation shedding will no longer be required. With two 500-kV lines between Idaho and the Pacific Northwest, the loss of one can be absorbed by the other.

3. Loss of a single 230-kV transmission tower in the Hells Canyon area. Idaho Power owns two 230-kV transmission lines, co-located on the same transmission towers, that connect Idaho to the Pacific Northwest. Because these lines are on a common tower, Idaho Power must consider the simultaneous loss of these lines as a realistic planning event. Historically, such an outage did occur on these lines in 2004 during a day with high summer loads. By losing these lines, Idaho Power's import capability was dramatically reduced, and Idaho Power was forced to rotate customer outages for several hours due to a lack of resource availability. After the addition of B2H, the impact of this outage would be substantially reduced.

## Resource Reliability

Transmission unavailability and unexpected forced outages have historically been a fraction of a traditional generation resource. Availability, and contribution to resource adequacy on the power grid, vary significantly by resource type. The North American Electric Reliability Corporation (NERC) has historically tracked transmission availability through a Transmission Availability Data System (TADS) and generation availability through a Generation Availability Data System (GADS) in North America. A telling sign of the reliability of a resource is the equivalent forced outage rate (EFOR). The EFOR is calculated based on the amount of time a transmission line, or generator, is either de-rated, or forced out of service while needed. De-rating a generator would be considered a partial outage, based on the de-rate amount as a percentage of the total capacity.

Table 7 provides the NERC TADS data for different transmission operating voltages. From the NERC TADS data, a 300-mile, 500-kV transmission line (B2H) would be expected to have an outage rate of 0.4 percent. Stated differently, the B2H transmission line is expected to have 99.6 percent availability.

**Table 7. NERC—AC transmission circuit sustained outage metrics**

| Voltage Class | Circuit Miles | No. of Circuits | No. of Outages | Total Outage Time (hr) | Frequency (SCOF) (per 100 CM per yr) | Frequency (SOF) (per circuit per yr) | MTTR or Mean Outage Duration (hr) |
|---|---|---|---|---|---|---|---|
| 200–299 kV | 103,558 | 4,477.5 | 876 | 14,789.6 | 0.8459 | 0.1956 | 16.9 |
| 300–399 kV | 56,791 | 1,623.6 | 394 | 19,766.8 | 0.6938 | 0.2427 | 50.2 |
| 400–599 kV | 32,184 | 594.7 | 141 | 3,957.9 | 0.4381 | 0.2371 | 28.1 |
| 600–799 kV | 9,451 | 110.0 | 28 | 342.4 | 0.2963 | 0.2545 | 12.2 |
| All Voltages | 201,985 | 6,805.8 | 1,439 | 38,856.7 | 0.7124 | 0.2114 | 27.0 |

By comparison, Table 8, lists the average EFOR for traditional fossil fuel power plants (coal, oil, gas, etc.) and the average EFOR for gas power plants.

**Table 8. NERC forced-outage rate information for a fossil or gas power plant**

| Generation Type | Unit Size | EFOR |
|---|---|---|
| Fossil (general) | All Sizes | 7.96% |
| Fossil (general) | 100–199 MW | 7.49% |
| Fossil (general) | 200–299 MW | 5.85% |
| Gas | All Sizes | 9.61% |
| Gas | 1–99 MW | 9.72% |
| Gas | 100–199 MW | 6.85% |

A transmission line with an EFOR of less than 1 percent, on the high end, is significantly more reliable than a power plant, which has an EFOR of 7 to 10 percent. A transmission line, of

course, requires a resource to source the line and serve load. However, the resources purchased at the end of the transmission line can be purchased as firm, whereby the seller must be able to supply the generation no-matter what (which may require purchasing someone else's generation if the primary unit experiences an outage). Therefore, if the resource is purchased as firm, the purchased resource would have an EFOR consistent with the transmission line, which is much more reliable than traditional supply-side generation. In the management of cost and risk, B2H will provide Idaho Power's operators additional flexibility when managing the Idaho Power resource portfolio.

## Reduced Electrical Losses

During peak summer conditions, with heavy power transfers on the Pacific Northwest and Idaho Power transmission systems, the addition of the B2H project is expected to reduce electrical losses by more than 100 MW in the Western Interconnection. This is a considerable savings for the region; 100 MW of generation, that customers ultimately pay for, does not need produced to supply losses alone.

Losses on the power system are caused by electrical current flowing through energized conductors, which in turn create heat. Losses are equal to the electrical current squared times the resistance of the transmission line:

$$Electrical\ Losses = Current^2 \times Resistance$$

From the electrical losses equation above, if the current doubles, the electrical losses will increase by a factor of four. By constructing the B2H line, less efficient (i.e., lower voltage) transmission lines with very large transfers are relieved, reducing the electrical current through these lines and dramatically reducing the losses due to heat.

## Flexibility

Advances in technology are pushing certain existing generation resources toward economic obsolescence. Any supply-side resource alternative could face the same economic obsolescence in the future. B2H is an alternative to constructing a new supply-side resource and therefore, reduces the risk of technological obsolescence. B2H will facilitate the transfer of any generation technology, ensuring Idaho Power customers always have access to the most economic resources, regardless of the resource type.

B2H capacity, when not used by B2H owners, will be available (for purchase) to other parties to make economic interstate west-to-east and east-to-west power transfers for more efficient regional economic dispatch. This provides a regional economic benefit to utilities around Idaho Power that is not factored into the analysis. Specifically, the B2H project will make additional capacity available for Pacific Northwest utilities to sell energy to southern and eastern markets in the West, and for Pacific Northwest utilities to purchase energy from southern and eastern

markets to meet their winter peak load service needs (southern and eastern WECC entities are mostly summer peaking). Idaho Power customers benefit from any third-party transmission purchases as the incremental transmission revenue acts to offset retail customer costs.

The existing electric system is heavily used. Because the system is so heavily used, new transmission line infrastructure, like B2H, creates additional operational flexibility. B2H will increase the ability to take other system elements out of service to conduct maintenance and will provide additional flexibility to move needed resources to load when outages occur on equipment.

## EIM

Idaho Power views the regional high-voltage transmission system as critical to the realization of EIM benefits, and the expansion of this transmission system (i.e., B2H) facilitates the realization of these benefits. As fluctuations in supply and demand occur for EIM participants, the market system will automatically find the best resource(s) from across the large-footprint EIM region to meet immediate power needs. This activity optimizes the interconnected high-voltage system as market systems automatically manage congestion, helping maintain reliability while also supporting the integration of intermittent renewable resources and avoiding curtailing excess supply by sending it to where demand can use it.

Idaho Power notes that EIM participation does not alter its obligations as a balancing authority (BA) required to comply with all regional and national reliability standards. Participation in the western EIM does not change NERC or WECC responsibilities for resource adequacy, reserves, or other BA reliability-based functions for a utility.

### *B2H Complements All Resource Types*

Utility-scale resource installations allow economies of scale to benefit customers in the form of lower cost per watt. For instance, residential rooftop solar is growing in popularity, but the economics of rooftop solar are outweighed by the economics of utility-scale solar installation.[16] Large transmission lines allow the most economical resources to be sited in the most economical locations. As an example, single-axis tracking utility-scale solar in Salem, Oregon, is expected to have a capacity factor of approximately 15 percent (where the capacity factor is the amount of time the system generates over the course of a year). Comparatively, the same single-axis tracking utility-scale solar system in Boise, Idaho, has a capacity factor of approximately 19 percent[17]. If solar system prices are assumed to be equivalent in Salem and Boise, a Boise

[16] The National Renewable Energy Laboratory (NREL) estimates the cost of residential rooftop solar (PV) is approximately 2.5 times the cost of utility-scale solar on a $/Watt basis (NREL, U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017).

[17] NREL, System Advisory Model

installation would generate over 30 percent more energy over the course of the year. Transmission lines provide the ability to move the most economical resources around the region.

Idaho Power views transmission lines like B2H as a complement to any resource type that allows access to the least-cost and most efficient resource, as well as regional diversity, to benefit all customers in the West.

# B2H Benefits to Oregon

## *Economic and Tax Benefits*

The B2H project will result in positive economic impacts for eastern Oregon communities in the form of new jobs, economic support associated with infrastructure development (i.e., lodging and food), and increased annual tax benefits to each county for project-specific property tax dollars. The annual tax benefit for the non-BPA owned portion of the line is shown in Table 9 below. BPA, as a federal entity, does not pay taxes, so BPA's 25 percent project interest is excluded from the estimates. Idaho Power anticipates the project will add about 500 construction jobs, which will provide a temporary increase in spending at local businesses.

**Table 9. Projected annual B2H tax expenditures by county**

| Oregon County | Property Tax (excluding BPA's 25% ownership interest) |
|---|---|
| Morrow | $270,295 |
| Umatilla | $569,656 |
| Union | $629,410 |
| Baker | $1,778,282 |
| Malheur | $893,567 |
| **Total Oregon Tax Benefit** | **$4,141,210** |

## *Local Area Electrical Benefits*

The B2H project will add 1,050 MW of additional transmission connectivity between the BPA and Idaho Power systems. Currently, the transmission connections between BPA and Idaho Power are fully used for existing customer commitments. Idaho Power currently serves customers in Owyhee County, Idaho, and Malheur County and portions of Baker County in Oregon. PacifiCorp, through Pacific Power, serves portions of Umatilla County. BPA provides transmission service to local cooperatives in the remainder of the project area in Morrow, Umatilla, Union, and Baker counties. Below is a summary of how these areas will benefit directly from B2H.

La Grande and Baker City are served by the Oregon Trails Electric Cooperative (OTEC). Portions of Morrow County and Umatilla County are served by Umatilla Electric Cooperative (UEC) and Columbia Basin Electric Cooperative (CBEC). OTEC, UEC, and CBEC pay BPA's

network transmission rate to receive power and transmission service from the BPA system. If BPA finds less expensive solutions to meet service obligations to customers in southeast Idaho and Wyoming, costs are kept low for other BPA customers, including OTEC, UEC, and CBEC. In other words, BPA customers in Oregon benefit by finding a low-cost solution for customers in Idaho and Wyoming. BPA's financial analysis to date has projected that a share of the B2H project with asset exchange appears the most cost-effective, long-term solution to serve customers in southeast Idaho and eastern Wyoming. Correspondingly, OTEC, UEC, and CBEC customers would also benefit from this cost-effective solution.

The B2H project provides economic development opportunities. The cost of power is a major factor in economic development and, as discussed previously, B2H, as a low-cost resource alternative, will keep power costs low compared to more expensive alternatives.

Capacity must be available on the existing system for additional economic development to take place. In Union and Umatilla counties, BPA's McNary–Roundup–La Grande 230-kV line has limited ability to serve additional demand in the Pendleton and La Grande areas but is currently capable of meeting the 10-year load forecast. The B2H project will increase the transfer capability through eastern Oregon by 1,050 MW. This capacity will provide a significant regional benefit to the entire Northwest and specifically benefit load service to eastern Oregon and southern Idaho. It is possible this added capacity resulting from the B2H project could be used to serve additional demand in Union and Umatilla counties.

Portions of Baker County are served by Idaho Power, from Durkee to the east. BPA currently provides energy to OTEC, which serves Baker City via transmission connections between the Northwest and Idaho Power's transmission system. At this point, the existing transmission connections between the Northwest and Idaho Power are fully used for existing load commitments, with very little ability to meet load growth requirements. The B2H project will increase the transmission connectivity between the Northwest and Idaho Power by 1,050 MW, which will allow BPA to serve additional demand in Baker City.

Finally, additional transmission capacity can create opportunities for new energy resources, which can add to the county tax base and create new jobs.

## RISK

Risk is inherent in any infrastructure development project. The sections below address various risks associated with the B2H project. Combining the analysis below with the risk analysis conducted in the 2017 IRP, Idaho Power believes B2H is the lowest-risk resource to meet Idaho Power' resource needs.

## Capital-Cost Risk

The capital-cost estimate for the B2H project has been well vetted. See the Cost section for an explanation of how the B2H project cost estimate was determined. Idaho Power's share of the B2H project is $274 million, including Idaho Power's AFUDC and local interconnection costs. For illustrative purposes, Figure 9 compares total portfolio costs for the 2017 IRP 20-year planning horizon. To determine the fixed costs associated with each portfolio, costs for each resource are levelized over the asset life, and costs beyond 2036 are not included in the analysis. The information from Figure 9 was extracted directly from the IRP Table 9.3.

The B2H project has considerable capital-cost bandwidth. The least-cost B2H portfolio (Portfolio 7) outperforms the least-cost B2H-alternative portfolio (Portfolio 9) by a 2017 net present value (NPV) of $147 million. Note that the B2H estimate already includes 20-percent capital-cost contingency. No other resources evaluated in IRP portfolios include a contingency. Based on NPV analysis over the 20-year planning horizon, Idaho Power's cost share of the B2H project could more than double, and the least-cost B2H portfolio would still be more cost-effective than the least-cost B2H-alternative portfolio.

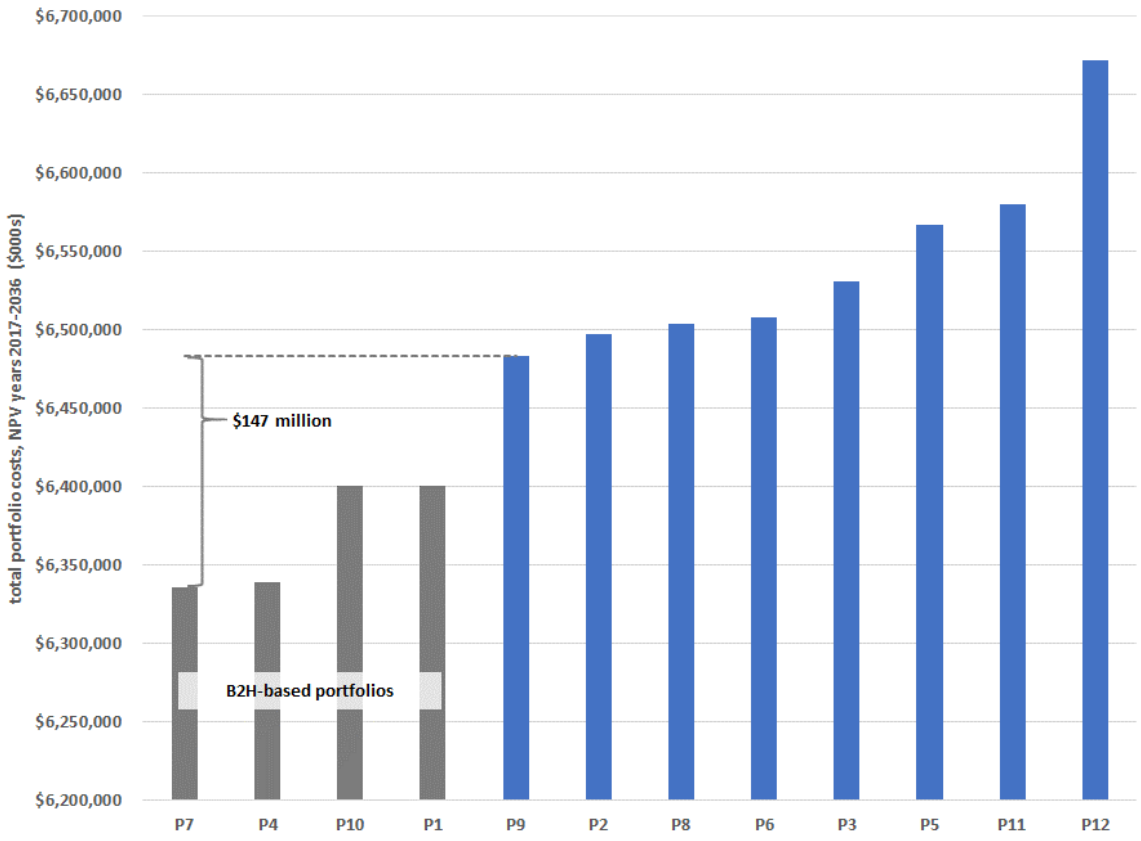



**Figure 9. Comparison of total portfolio costs from 2017 IRP (Table 9.3 in 2017 IRP)**

## Market Price Risk

The cost of dispatching gas-fired generation typically sets the market price of power at Mid-C. A stochastic risk analysis was conducted on all 2017 Idaho Power IRP portfolios, with natural gas prices ranging up to 400 percent of the planning case. Refer to IRP Table 9.4 and Table 9.5 for more information. The natural gas stochastic risk analysis in the 2017 IRP is a market price stochastic analysis because natural gas prices set the energy market prices. Figure 10 below shows three stochastic iterations comparing natural gas prices and Mid-C market prices. The solid lines represent Mid-C energy hub prices, and the dotted lines represent Sumas hub natural gas prices; the natural gas prices and market prices are very closely correlated.

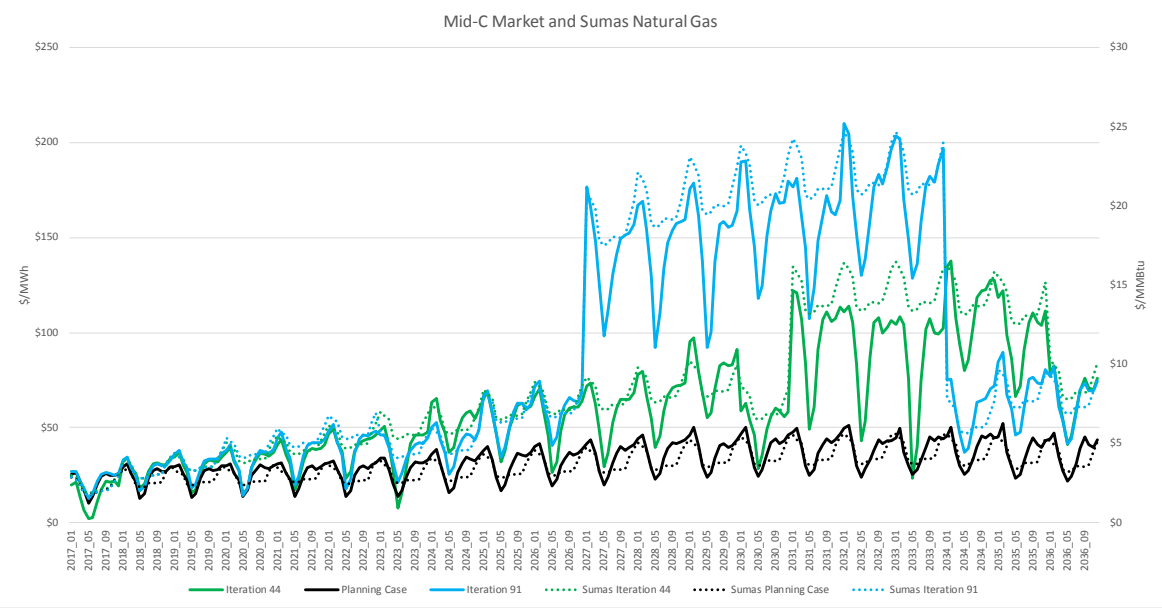



**Figure 10. Correlation between Mid-C market prices and natural gas prices**

Based on the correlation of natural gas prices and market prices, market price risk analysis was considered for the B2H project in Idaho Power's 2017 IRP. Results of the stochastic analysis show B2H portfolios remain the low-cost portfolios for all natural gas price sensitivities, except a 400 percent price sensitivity. However, Idaho Power believes a 400 percent energy market price increase is unlikely because a 400 percent increase in natural gas prices, along with the associated increase in energy prices, would likely result in the development of alternative resources in place of natural gas (that is, developers of more cost-effective resources would take advantage of financial opportunities if market prices increased 400 percent due to natural gas costs).

## Liquidity and Market Sufficiency Risk

The Pacific Northwest is a winter peaking region. Pacific Northwest utilities continue to install and build generation capacity to meet winter peak regional needs. Idaho Power operates a system

with a summer peak. Idaho Power's peak occurs in the late June/early July timeframe. The Idaho Power summer peak aligns with the Mid-C hydro runoff conditions when the Pacific Northwest is flush with surplus power capacity. The existing transmission system between the Pacific Northwest and Idaho Power is constrained. Constructing B2H will alleviate this constraint and add 1,050 MW of total transfer capability between the Pacific Northwest and the Intermountain West region. The Pacific Northwest and Idaho Power will significantly benefit from the addition of transmission capacity between the regions. The Pacific Northwest has constructed power plants to meet winter needs and would benefit from selling energy to Idaho Power in the summer. Idaho Power needs generation capacity to serve summer peak load, and a transmission line to existing underutilized power plants is much more cost-effective than building a new power plant.

See the Market Overview section of this appendix for more information about the Mid-C market hub liquidity. Based on the risk assessment, Idaho Power believes sufficient market liquidity exists.

The following data points will address the market sufficiency risk.

### *Data Point 1. Peak Load Analysis from Table 6*

Referencing Table 6 from the Benefits section above, British Columbia and other utilities in the Pacific Northwest have forecast 2026 winter peaks that exceed their forecast 2026 summer peaks by a combined 7,600 MW. Given the difference in seasonal peaks, coupled with Columbia runoff hydro conditions aligning with Idaho Power's summer peak, resource availability in the Pacific Northwest during Idaho Power's summer peak is likely.

### *Data Point 2. Pacific Northwest Power Supply Adequacy Assessment for 2022—Northwest Power Conservation Council Report*

The Northwest Power and Conservation Council (NWPCC) recently studied the Northwest power system to determine resource adequacy using a five-year forecast. In July 2017, the NWPCC published their 2022 Assessment.[18] The report suggests the Northwest must install 400 MW of new effective capacity by 2021 to meet the NWPCC standard.

The NWPCC, through their analysis, attempted to quantify resource adequacy through a loss-of-load probability (LOLP) analysis. In Figure 11 below, a higher LOLP indicates worse performance (more customer risk), and a lower LOLP indicates better performance. Idaho Power's peak load occurs in a narrow window in the late June/early July timeframe. Figure 11 illustrates the Northwest has a 0 percent LOLP for the June and July months. This indicates that

[18] nwcouncil.org/media/7491213/2017-5.pdf

the Northwest will continue to have sufficient resources available for Idaho Power to purchase and deliver to Idaho Power customers across the B2H line.

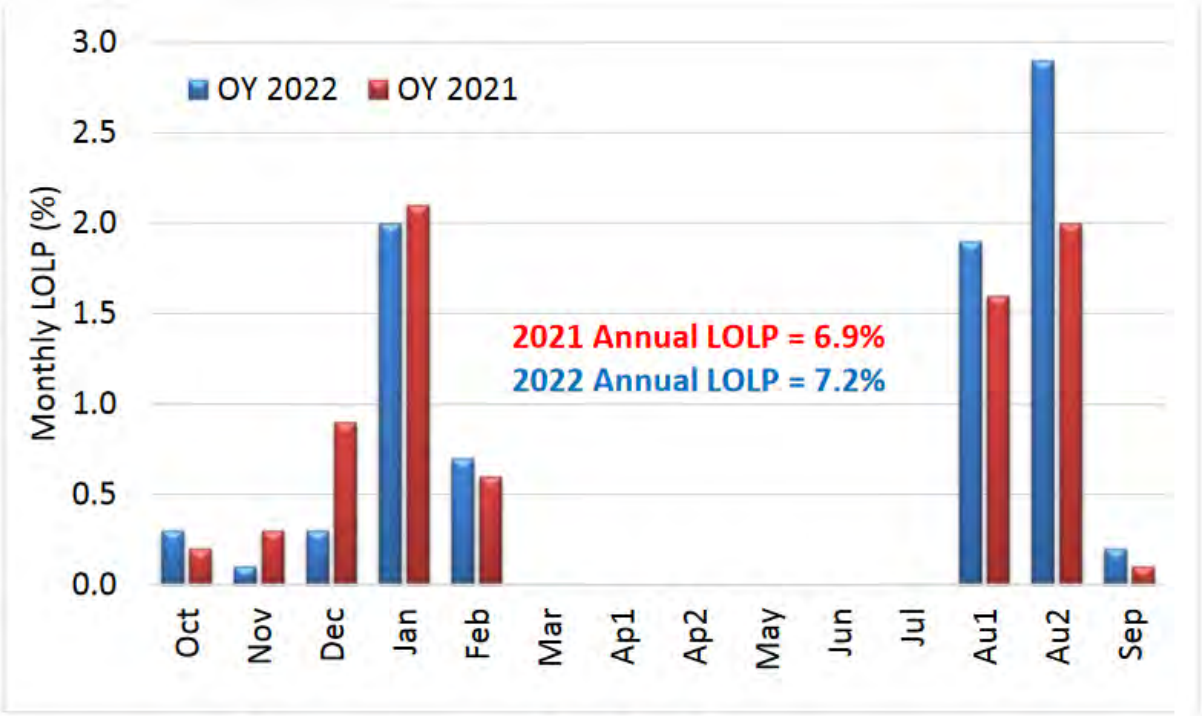



**Figure 11. 2021–22 LOLP by month (Source: NWPCC northwest analysis)**

Evaluating Figure 11 further, the NWPCC information suggests the Northwest region, as a whole, must add resources to address deficiencies in the winter and late summer. Resource additions to address these needs will further increase resource availability in late June/early July. This argument is further stressed in Data Point 3.

## *Data Point 3: 2016 Pacific Northwest Loads and Resources Study—BPA*

The Pacific Northwest Loads and Resources Study[19], commonly called "The White Book," is BPA's annual publication of the federal system and the Pacific Northwest regions loads and resources for the upcoming 10-year period.

Data detailing whether Pacific Northwest resources will be available to purchase post-2025 can be found in the 2016 Pacific Northwest Loads and Resources Technical Appendix, Volume 2,

[19] bpa.gov/power/pgp/whitebook/2016/index.shtml

Footnotes continued on the next page.

Capacity Analysis[20]. This appendix evaluates the Pacific Northwest resource and generation balance to determine a monthly surplus/deficit for the next 10 years. Given the importance of hydro generation in the Pacific Northwest, BPA makes a conservative assumption that there will be a water year equivalent to 1937, one of the worst water years on record.

The BPA capacity metrics are defined as follows:

- **120-Hour Capacity**—Calculated by averaging the generation forecasts from the six highest heavy load hours per day, five days per week, for four weeks per month (6 x 5 x 4 = 120 hours).

- **1-Hour Capacity**—Calculated using the highest single one-hour generation per month.

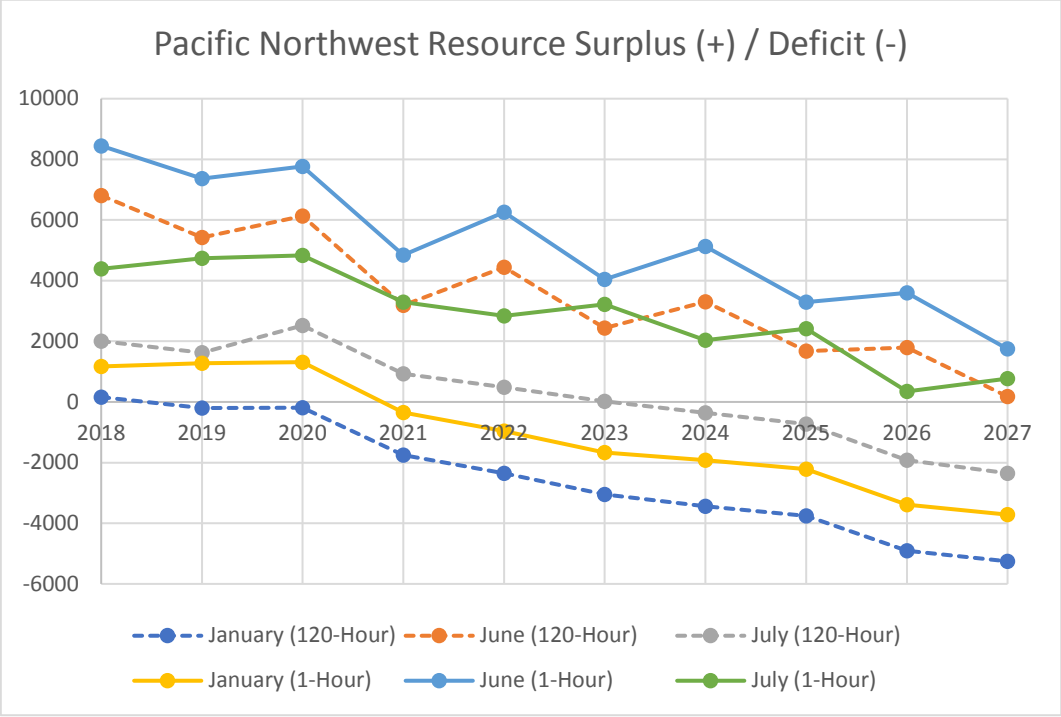



**Figure 12. January, June, and July forecast Pacific Northwest resource surplus/deficit (Source: 2016 BPA White Book)[21]**

Exploring Figure 12 further, Table 10 below lists the critical 2027 data points.

[20] bpa.gov/power/pgp/whitebook/2016/2016-WBK-Technical-Appendix-Volume%20-2-Capacity-Analysis-20161222.pdf

[21] bpa.gov/power/pgp/whitebook/2016/2016-WBK-Technical-Appendix-Volume%20-2-Capacity-Analysis-20161222.pdf

**Table 10. 2027 data points from Figure 12**

| Month | 120-Hour Capacity (MW) | 1-Hour Capacity (MW) |
|---|---|---|
| January | -5,255 | -3,716 |
| June | 177 | 1,748 |
| July | -2,349 | 770 |

Assuming a critical water year equivalent to 1937, BPA forecasts a 2027 January deficit of 5,255 MW in the 120-hour capacity evaluation and a deficit of 3,716 MW in the one-hour capacity evaluation. July is much better than January; BPA forecasts a 2027 deficit of 2,349 MW in the 120-hour capacity evaluation and a surplus in the 1-hour capacity evaluation. BPA forecasts a surplus for June in both the 120-hour and 1-hour capacity evaluations.

Several BPA considerations are built into the analysis:

- Analysis includes a 1,000+ MW export to Canada (summer and winter). In practice, at peak, Canada is typically exporting to the Northwest.
- Renewables are assumed to have a capacity factor near zero.
- California solar exports to the Pacific Northwest are zero.
- Analysis includes committed generation retirements. There are no assumptions for replacement generation.

Given BPA's analysis, Idaho Power believes there will be sufficient resources in the future based on the following:

- Northwest utilities will need to address their severe January deficit. Adding resources to address this deficit will improve the July deficit. A similar argument was made in Data Point 2.
- Canada generally exports 1,000+ MW over summer peak, rather than importing over 1,000 MW per BPA assumptions in the analysis. This reduces the July deficit to almost zero.
- Solar resources should have a summer capacity factor (should not be zero). Idaho Power assumed a 51-percent summer capacity factor in the 2017 IRP for potential Idaho Power utility-scale solar resources.
- All signs point to California exporting solar output to the Pacific Northwest, especially if renewable portfolio standards (RPS) increase.

The 2016 Pacific Northwest Loads and Resources Study can be found on BPA's website.

### *Data Point 4: Northwest and California Renewable Portfolio Standards*

The adoption of more aggressive RPS goals by states such as Oregon, California, and Washington will drive policy-driven resource additions. The RPS goals will also likely result in the addition of dispatchable flexible ramping resources, such as the recently constructed Port Westward 2 power plant installed by Portland General Electric.

### *Market Sufficiency and Liquidity Conclusions*

Based on the analysis summarized above and in the Markets section of this report, Idaho Power believes there will be sufficient resources in the future to source the B2H transmission line. Also, because the market balances supply and demand based on a market clearing price, liquidity risk can be modeled in economic terms. Should demand be greater than supply at the Mid-C energy hub in the future, market hub prices would reflect the scarcity accordingly (higher prices). As discussed in the Market Price Risk section, a sensitivity analysis conducted in the 2017 IRP indicates B2H remains the low-cost resource portfolio over a wide range of market price sensitivities.

## Co-Participant Risks

Idaho Power, BPA, and PacifiCorp, collectively referred to as co-participants or funders, are fully engaged in permitting activities but have not yet entered into construction and operating agreements. Per the 2012 Joint Funding Agreement, Idaho Power has 60 days following the publication of the BLM ROD to issue a Notice of Completion (Notice), which triggers the commencement of construction negotiations. The funders are allotted two 180-day periods (360 days total), following receipt of the Notice, to negotiate one or more definitive development and construction agreements. The BLM ROD was published on November 17, 2017. Idaho Power, PacifiCorp, and BPA have been in negotiations regarding a possible amendment to the Joint Funding Agreement that would clarify ongoing payment terms, update the milestone schedule, and modify construction agreement triggers and negotiation durations.

The funders may withdraw from the Joint Permitting Agreement at any time and for no reason, and the withdrawing funder(s) shall pay all costs up to the last day of the month of withdrawal. If one or more of these funders does not move forward with construction, withdrawals from the project, all rights, title, and interest will be transferred to the remaining funder(s) such that the remaining funder(s) shall have 100 percent of the permitting interest in the permitting project. The remaining funders may then seek other funder(s) and/or proceed with construction.

Although funder commitments are not a guarantee at this point, Idaho Power believes other parties may have interest in potential ownership in the project should one or more of the funders decide not to move forward with construction. At least one additional party was involved in the

original negotiations that ultimately lead to the current three-party 2012 Joint Funding Agreement. Additionally, Idaho Power has been approached by at least one entity that may have interest in the B2H project. Any consideration of additional project co-participants would be discussed and agreed on by current funders.

Changes in ownership structure could change cost allocation percentages. Refer to the Capital-Cost Risk section of this appendix for more information about capital-cost risk. For any potential changes in ownership structure, Idaho Power will evaluate the potential ownership cost and capacity allocation, and assuming cost-effective for Idaho Power customers, would request approval from the Oregon and Idaho public utility commissions for any modification in ownership.

## Siting Risk

Siting any new infrastructure projects comes with siting risk. The BLM ROD, which was released on November 17, 2017, was a significant milestone in the B2H project development and greatly minimized siting risk. It provided the project authorization to cross BLM land and provided the BLM Agency Preferred alternative for the remainder of the route. The USFS and Navy will tier off of the BLM's analysis to conclude their NEPA processes. The State of Oregon EFSC process is the next major step to ensure siting risk is minimized for privately owned land in Oregon.

## Schedule Risk

As of the date of this appendix, Idaho Power has schedule scenarios for B2H in-service dates in 2024 or later. At a high level, activities prior to energization are permitting, co-participant agreements, preliminary construction, and material procurement and construction.

The B2H project is currently in the permitting phase of the project. For federal permitting, the B2H project recently achieved the biggest schedule milestone to date with the release of BLM's ROD on November 17, 2017. The ROD formalized the BLM-led NEPA process and established a BLM Agency Preferred route on public and private property. The USFS ROD and a Navy ROD and easement are the next major federal permitting milestones. At this point, neither the USFS ROD nor Navy ROD are expected to be critical path schedule activities.

For the State of Oregon permitting process, the B2H project also achieved a considerable milestone in summer 2017 with the submittal of the amended Application for Site Certificate to the ODOE. The ODOE is expected to issue a Draft Proposed Order in 2018 and a Final Order and Site Certificate in 2020. The EFSC permitting process is a critical path schedule activity. Schedule risk exists for the EFSC permitting process if the ODOE does not issue a Site Certificate by late 2020.

With the receipt of the BLM ROD and submittal of the amended Application for Site Certificate, which is expected to be deemed complete in the near future, sufficient route certainty exists to begin preliminary construction activities. Assuming co-participant agreements are in place, the current B2H schedule plans to commence preliminary construction activities prior to the receipt of a Site Certificate to achieve an in-service date in the mid-2020s. The B2H co-participants have not formally decided on the contracting method for the project, so the preliminary construction and construction schedule activities remain preliminary until contracts are in place.

Idaho Power believes schedule flexibility exists if the EFSC process is delayed. For instance, certain schedule activities could be condensed by employing more resources or certain activities. Additionally, certain schedule activities could overlap if planned appropriately, such as ROW acquisition and construction.

Currently, Idaho Power believes there is sufficient schedule flexibility to achieve a 2026 in-service date. Idaho Power, BPA, and PacifiCorp plan to negotiate construction agreements in 2018, which should provide additional clarity to the schedule.

## Catastrophic Event Risk

As detailed in B2H Design section, the B2H transmission line is designed to withstand a variety of extreme weather conditions and catastrophic events. Like most infrastructure, the B2H project is susceptible to direct physical attack. However, unlike some other supply-side resources, B2H adds to the resiliency of the electrical grid by providing additional capacity to transfer energy throughout the region should a physical attack or other catastrophic event occur elsewhere on the system. Additionally, Idaho Power also keeps a supply of emergency transmission towers that can be quickly deployed to replace a damaged tower, allowing the transmission line to be quickly returned to service.

# PROJECT ACTIVITIES

## Schedule Update

### *Permitting*

The B2H projected achieved a major milestone with the release of the BLM ROD on November 17, 2017. The BLM ROD formalized the conclusion of the siting process and federally required NEPA. The BLM ROD provides the B2H project the ability to site the project on BLM-administered land. The BLM-led NEPA process took nearly 10 years to complete and involved extensive stakeholder input. Refer to the Project History and Route History sections of this report for more information on project history and public involvement. The next steps in the federal permitting process include a USFS ROD and Navy ROD; both are expected in 2018. Both the USFS and Navy will use the BLM's environmental analysis.

For the State of Oregon permitting process, Idaho Power submitted the amended application for Site Certificate to the ODOE in summer 2017. As of the date of this report, Idaho Power expects the ODOE to issue a Draft Proposed Order in 2018 and a Final Order and Site Certificate in 2020.

The NEPA and EFSC processes are very distinct permitting processes and not necessarily designed to work simultaneously. At a high level, the NEPA EIS process evaluates reasonable alternatives to determine the best alternative (the Agency Preferred Alternative) at the end of the process. Comparative analysis is conducted at a "desktop" level. Information is brought into the process on a phased-approach. Detailed analysis must be conducted on the final route prior to construction, generally once final design is complete.

The Oregon EFSC process is a standards-based process based on a fixed site boundary. For a linear facility, like a transmission line, the process requires the transmission line boundary to be established (a route selected) and fully evaluated to determine if the project meets established standards. The practical effect of the EFSC standards-based process required the NEPA process be far enough along to conduct field studies and other technical analysis to comply with standards. Idaho Power conducted field surveys and prepared the EFSC application in parallel with the NEPA process. The EFSC application is lengthy. Idaho Power estimates the application submitted in 2017 was roughly 17,000 pages long.

### *Post-Permitting*

To achieve an in-service date in the mid-2020s, preliminary construction activities must commence parallel to EFSC permitting activities. Preliminary construction activities include, but are not limited to, the following:

- Geotechnical explorations
- Detailed ground surveys
- Sectional surveys
- ROW acquisition activities
- Detailed design
- Construction bid package development and construction contractor selection

After the Oregon permitting process and preliminary construction activities conclude, construction activities can commence. Construction activities include, but are not limited to, long-lead material acquisition, transmission line construction, and substation construction. The preliminary construction activities must commence several years prior to construction.

The material acquisition and construction activities are expected to take 3 to 4 years. The specific timing of each of the preliminary construction and construction activities will be coordinated with the project co-participants.

## CONCLUSIONS

This B2H 2017 IRP appendix provides context and details that support evaluating the B2H transmission line project as a supply-side resource, explores (qualitatively and quantitatively) many of the ancillary benefits offered by the transmission line, and considers the risks and benefits of owning a transmission line connected to a market hub in contrast to direct ownership of a traditional generation resource.

As discussed in this report, once operational, B2H will provide Idaho Power increased access to reliable, low-cost market energy purchases from the Pacific Northwest. B2H (including early versions of the project) has been a cost-effective resource identified in each of Idaho Power's Integrated Resource Plans (IRP) since 2006 and continues to be a cornerstone of Idaho Power's 2017 IRP preferred resource portfolio. In the 2017 IRP, B2H was identified as the least-cost and least-risk resource to serve peak-hour load to resource deficits that are forecast to occur beginning in 2026. When compared to other individual resource options, B2H is also the least-cost option in terms of both capacity cost and energy cost. B2H is expected to have a capacity cost that is 71 percent lower than either a combined-cycle gas plant or utility-scale solar alternatives.[22] B2H is also expected to have a levelized cost of energy that is 22 percent lower than a combined-cycle gas plant and 38 percent lower than utility-scale solar.[23]

B2H project brings additional benefits beyond cost-effectiveness. The B2H project will increase the efficiency, reliability, and resiliency of the electric system by creating an additional pathway for energy to move between major load centers in the West. The B2H project also provides the flexibility to integrate any resource type and move existing resources during times of congestion, benefiting customers throughout the region. Idaho Power believes B2H provides value to the system beyond any individual resource because it enhances the flexibility of the existing system and facilitates the delivery of cost-effective resources not only to Idaho Power customers, but also to customers throughout the Pacific Northwest and Mountain West regions.

The company must demonstrate a need for the project before EFSC will issue a Site Certificate authorizing the construction of a transmission line. The need demonstration can be met through a commission acknowledgement of the resource in the company's IRP.[24] In this case, Idaho Power

[22] 2017 IRP, Page 87, Figure 7.5.

[23] 2017 IRP, Page 89, Figure 7.6.

[24] OAR 345-023-0020(2).

seeks to satisfy EFSC's least-cost plan rule's requirement through an acknowledgement of its 2017 IRP.

## Appendix D-1. Transmission line alternatives to the proposed B2H 500-kV transmission line

**Table D-1**

Comparison of Transmission Line Capacity Scenarios—New Lines from Longhorn to Hemingway

| Scenario | Line Capacity[1] | Potential Path 14 West-East Increase[2] | Losses on New Circuit(s)[3] |
|---|---|---|---|
| a. Longhorn to Hemingway 230 kV single circuit | 956 MW | 525 MW | 10.8% |
| b. Longhorn to Hemingway 230 kV double circuit | 1,912 MW | 915 MW | 9.5% |
| c. Longhorn to Hemingway 345 kV single circuit | 1,434 MW | 730 MW | 6.6% |
| d. Longhorn to Hemingway 500 kV single circuit | 3,214 MW | 1,050 MW | 4.2% |
| e. Longhorn to Hemingway 500 kV—two separate lines | 6,428 MW | 2,215 MW | 3.7% |
| f. Longhorn to Hemingway 500 kV double circuit | 6,428 MW | 1,235 MW | 2.9% |
| g. Longhorn to Hemingway 765 kV single circuit | 4,770 MW | 1,200 MW | 2.4% |

[1] Line Capacity is the thermal rating of the assumed conductors and does not account for system limitations of voltage, stability, or reliability requirements.

[2] Potential Rating is based upon study results to date to meet reliability design requirements for the WECC ratings processes, not including simultaneous interaction studies.

[3] Estimated Losses are percent losses for the new line at the Potential Rating loading level. Annual energy losses are dependent on total system loss reductions. All of the scenarios would likely yield a total system loss reduction for the flow levels above.

**Table D-2**

Comparison of Transmission Line Capacity Scenarios – Rebuild Existing Lines to the Northwest

| Scenario | Line Capacity[1] | Potential Path 14 Increase[2] | Losses on New Circuit(s)[3] | Length of Line/ New ROW[4] |
|---|---|---|---|---|
| h. Replace Oxbow-Lolo 230 kV with Hatwai - Hemingway 500 kV | 3,214 MW | 430 MW W-E<br>675 MW E-W | 3.8% | 255 Miles/136 Miles |
| i. Replace Oxbow-Lolo 230 kV with Hatwai - Hemingway 500 kV - No double circuiting with existing lines | 3,214 MW | 710 MW W-E<br>745 MW E-W | 4.1% | 255 Miles/167 Miles |
| j. Replace Walla Walla to Brownlee 230 kV with Sacajawea Tap-Hemingway 500 kV | 3,214 MW | 400 MW W-E<br>675 MW E-W | 3.5% | 288 Miles/150 Miles |
| k. Replace Walla Walla to Pallette 230 kV with Sacajawea Tap-Hemingway 500 kV - No double circuiting with existing lines | 3,214 MW | 720 MW W-E<br>730 MW E-W | 3.8% | 288 Miles/181 Miles |
| l. Build double circuit 500 kV/230 kV line from McNary to Quartz. Build 500kV from Quartz to Hemingway. | 3,214 MW | 765 MW W-E<br>870 MW E-W | 3.9% | 298 Miles/168 Miles |

[1] Line Capacity is the thermal rating of the assumed conductors and does not account for system limitations of voltage, stability, or reliability requirements.

[2] Potential Rating is based upon study results to date to meet reliability design requirements for the WECC ratings processes, not including simultaneous interaction studies.

[3] Estimated Losses are percent losses for the new line at the Potential Rating west-east loading level. Annual energy losses are dependent on total system loss reductions. All of the scenarios would likely yield a total system loss reduction for the flow levels above.

[4] In addition to utilizing existing 230 kV right-of-way (“ROW”), each of the scenarios above will require new ROW to be obtained.

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**Appendix D-2. Detailed list of notable project milestones**

- June, 2006 – Idaho Power files the 2006 IRP – Transmission line between Boise and Pacific Northwest identified in preferred resource portfolio (this transmission line eventually became the Boardman to Hemingway project)
- December 19, 2007 – Idaho Power Completes the B2H Preliminary Plan of Development
- 2008 – Idaho Power files the 2008 IRP Update
- August 28, 2008 – Idaho Power submits Notice of Intent to EFSC to submit an Application for Site Certificate.
- September 12, 2008 – Notice of Intent published in the Federal Register for BLM to prepare an Environmental Impact Statement for B2H
- April 10, 2009 – Public Scoping Report for B2H EIS completed by Tetra Tech
- December 30, 2009 – Idaho Power files the 2009 IRP – B2H Project identified in preferred resource portfolio
- June 2010 – Idaho Power completes the B2H Preliminary Plan of Development
- July 2010 – Idaho Power submits a NOI to apply for a Site Certificate for B2H to ODOE
- August 2010 – Idaho Power completes the B2H Siting Study
- August 2010- February 2011 – Idaho Power completes the Community Advisory Process
- February 2011 – Idaho Power completes a Revised Plan of Development for B2H
- June 30, 2011 – Idaho Power files the 2011 IRP – B2H Project identified in preferred resource portfolio
- October 5, 2011 – Obama administration recognizes B2H as one of seven national priority projects that when built, will help increase electric reliability, integrate new renewable energy into the grid, create jobs and save consumers money. See news release.
- November 2011 – Idaho Power completes a Revised Plan of Development for B2H
- January 12, 2012 – Idaho Power, BPA and PacifiCorp enter into Joint Permit Funding Agreement
- March 2, 2012 – ODOE issues a Project Order for B2H

- June 2012 – Idaho Power completes a Supplemental Siting Study for B2H
- October 2, 2012 – BPA identifies B2H as the best option for meeting load growth in southeastern Idaho
- November 27, 2012 – Idaho Power receives formal capacity rating from Western Electricity Coordinating Council (WECC)
- February 28, 2013 – Idaho Power submits Preliminary Application for Site Certificate to Oregon Department of Energy
- June 28, 2013 – Idaho Power files the 2013 IRP
- December 19, 2014 – Draft EIS and Land-use Plan Amendments Published in Federal Register
- December 22, 2014 – ODOE issues amended Project Order for B2H
- June 22, 2015 – Idaho Power submits easement application to Navy to site on Naval Weapons System Training Facility Boardman (aka "Bombing Range")
- June 30, 2015 – Idaho Power files the 2015 IRP – B2H Project identified in the preferred resource portfolio
- November 25, 2016 – BLM issues the Final EIS for B2H
- November 18, 2016 – Idaho Power submits revised application to Navy, updating the route on Navy property based on collaborative routing solution
- January 20, 2017 – Donald Trump inaugurated as 45th President of the United State
- June 29, 2017 – Idaho Power submits electronic version of Amended Preliminary Application for Site Certification to ODOE
- June 30, 2017 – Idaho Power files the 2017 Integrated Resource Plan (IRP) – B2H Project identified in the preferred resource portfolio
- July 19, 2017 – Idaho Power submits hard copies of Amended Preliminary Application for Site Certification to ODOE.
- November 17, 2017 – BLM issues a Record of Decision (ROD) for the B2H. The Record of Decision was signed by the Assistant Secretary of Lands and Minerals, U.S. Department of Interior.

**Appendix D-3. B2H funding agreement**

See the attached document.

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**Execution Copy**
**BPA Contract Number 12TX-15583**

# BOARDMAN TO HEMINGWAY TRANSMISSION PROJECT JOINT PERMIT FUNDING AGREEMENT

This Boardman to Hemingway Transmission Project Joint Permit Funding Agreement (the "Agreement") is entered into this 12th day of January, 2012 (the "Effective Date"), by and between Idaho Power Company, an Idaho corporation ("Idaho Power"), PacifiCorp, an Oregon corporation ("PAC"), and the Bonneville Power Administration ("BPA"), a United States government power marketing administration. Idaho Power, PAC, and BPA are hereinafter sometimes individually referred to as a "Funder" and collectively as the "Funders."

## RECITALS

WHEREAS, Idaho Power, PAC, and BPA have independent obligations to plan for and expand their respective transmission systems to provide safe, reliable and cost-effective service to their native load customers, network customers, and/or eligible customers;

WHEREAS, Idaho Power, PAC and BPA recognize the potential to fulfill their respective service obligations through the development of certain new transmission facilities;

WHEREAS, the proposed Boardman to Hemingway Transmission Project is a 500 kV single circuit transmission line located from the vicinity of Boardman, Oregon to the existing Hemingway substation near Melba, Idaho (as further described in Exhibit A, the "Boardman to Hemingway Transmission Project"), that if constructed could assist Idaho Power, PAC, and BPA in fulfilling their respective service obligations;

WHEREAS, Idaho Power, PAC, and BPA recognize that obtaining appropriate and necessary Governmental Authorizations and completing other necessary work is an essential component to developing the Boardman to Hemingway Transmission Project;

WHEREAS, Idaho Power, PAC, and BPA desire to support and contribute funds, with the intent to be joint owners subject to the terms of this Agreement, to the processes associated with obtaining the necessary Governmental Authorizations and completing other necessary work to develop, permit, site, and acquire Rights-of-Way over public lands for the Boardman to Hemingway Transmission Project;

WHEREAS, Idaho Power, PAC, and BPA are entering into this Agreement for the purposes of providing the definitive terms and conditions by which Idaho Power, PAC, and BPA will jointly support and contribute funds, with the intent to be joint owners subject to the terms of this Agreement, to permit, site and acquire Rights of Way over public lands for the development of Boardman to Hemingway Transmission Project;

WHEREAS, Idaho Power has submitted applications to the United States Department of Interior, Bureau of Land Management ("BLM"), serving as the lead permitting agency under the

National Environmental Policy Act ("NEPA"), to obtain authorizations for the Boardman to Hemingway Transmission Project to cross federal lands. The United States Forest Service, United States Department of the Navy and the United States Bureau of Reclamation are cooperating agencies with the BLM in preparing an Environmental Impact Statement ("EIS") for the Boardman to Hemingway Transmission Project;

WHEREAS, Idaho Power has submitted its notice of intent to apply for an energy facility site certificate with the Oregon Department of Energy, Energy Facility Siting Council, to construct the portions of the Boardman to Hemingway Transmission Project located in the State of Oregon;

WHEREAS, Idaho Power, PAC, and BPA intend for the express purpose of this Agreement to facilitate the successful completion of the Project Permitting Objectives (as further defined herein);

WHEREAS, Idaho Power and PAC recognize that, although BPA is entering into this Agreement, BPA has certain obligations and responsibilities under NEPA and other federal laws that it must fulfill before it can make a decision concerning whether to participate in the development and construction of the Boardman to Hemingway Transmission Project, and BPA intends to be a cooperating agency under NEPA on the Environmental Impact Statement being prepared by the BLM and other federal agencies to facilitate completion of BPA's obligations and responsibilities under NEPA;

WHEREAS, Idaho Power and PAC acknowledge that BPA is considering various transmission and other alternatives to meet its service obligations in eastern Idaho and that BPA's decision whether to participate in the development and construction of the Boardman to Hemingway Transmission Project may be based on BPA's evaluation of such alternatives;

WHEREAS, upon the completion of the Project Permitting Objectives, any of the Funders that decide to proceed with the development and construction of the Boardman to Hemingway Transmission Project intend to negotiate in good faith further agreement(s) for the purposes of providing the definitive terms and conditions by which such Funders may jointly design, engineer, procure, construct, commission, own and operate the Boardman to Hemingway Transmission Project (the "Definitive Development and Construction Agreements"); and

WHEREAS, nothing in this Agreement shall affect any other existing or proposed projects, expansions, or developments that are not a part of this Agreement.

NOW, THEREFORE, in consideration of the promises and the mutual covenants and agreements herein contained, the adequacy of which is hereby acknowledged, Idaho Power, PAC, and BPA agree as follows:

## ARTICLE I
## DEFINITIONS; RULES OF INTERPRETATION

1.1 Definitions. As used in this Agreement, the following capitalized terms have the meanings specified in this Section 1.1:

"Advance Contribution" has the meaning set for in Section 4.2(a).

"Affected Party" has the meaning set forth in Section 9.1.

"Affiliate" means, with respect to a Person, each other Person that, directly or indirectly, controls, is controlled by or is under common control with, such designated Person; provided, however, that in the case of PAC "Affiliate" includes MidAmerican Energy Holdings Company and its direct and indirect subsidiaries. For the purposes of this definition, "control" (including with correlative meanings, the terms "controlled by" and "under common control with"), as used with respect to any Person, shall mean (a) the direct or indirect right to cast at least fifty percent (50%) of the votes exercisable at an annual general meeting (or its equivalent) of such Person or, if there are no such rights, ownership of at least fifty percent (50%) of the equity or other ownership interest in such Person, or (b) the right to direct the policies or operations of such Person.

"Agreement" has the meaning set forth in the Preamble.

"Bankrupt" means, with respect to any Person, that such Person: (a) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy, insolvency, reorganization or similar law, or has any such petition filed or commenced against it, (b) makes an assignment or any general arrangement for the benefit of creditors, (c) otherwise becomes insolvent (however evidenced), (d) has a liquidator, administrator, receiver, trustee, conservator or similar official appointed with respect to it or any substantial portion of its property or assets, or (e) is generally unable to pay its debts as they fall due.

"BLM" has the meaning set forth in the Recitals.

"Boardman to Hemingway Transmission Project" has the meaning set forth in the Recitals.

"BPA" has the meaning set forth in the Preamble.

"Business Day" means any day other than Saturday, Sunday and any day which is not a federal holiday or a day on which banking institutions in New York, New York are authorized or obligated by Governmental Requirements to close.

"Claims" has the meaning set forth in Section 11.1.

"Commercially Reasonable Efforts" means the level of effort that a reasonable electric utility would take in light of the then known facts and circumstances to accomplish the required action at a then commercially reasonable cost (taking into account the benefits to be gained thereby).

"Completion Funding Payment" has the meaning set forth in Section 3.1(a)(ii) and Exhibit B.

"Completion Notice" has the meaning set forth Section 3.3(a).

"Defaulting Funder" has the meaning set forth in Section 8.1.

"Dispute" has the meaning set forth in Section 13.1.

"Dispute Notice" has the meaning set forth in Section 13.2.

"Disputing Party" has the meaning set forth in Section 13.2.

"Definitive Development and Construction Agreements" has the meaning set forth in the Recitals.

"Effective Date" has the meaning set forth in the Preamble.

"Environmental Impact Statement" has the meaning set forth in the Recitals.

"Event of Default" has the meaning set forth in Section 8.1.

"Executives" has the meaning set forth in Section 13.3(a).

"FERC" means the Federal Energy Regulatory Commission.

"Final Environmental Impact Statement" means the Final Environmental Impact Statement for the Boardman to Hemingway Transmission Project.

"Force Majeure" has the meaning set forth in Section 9.1.

"Funders" has the meaning set forth in the Preamble.

"Funding Committee Representative" has the meaning set forth in Section 3.2(b).

"Funding Invoice" has the meaning set forth in Section 3.1(b)(i).

"Final Expense True-Up" has the meaning set forth in Section 3.1(b)(iii) and Exhibit B.

"Good Utility Practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, would have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(d).

"Governmental Authority" means any federal, state, local or municipal governmental body; any governmental, quasi-governmental, regulatory or administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority or power, including FERC, NERC or any regional reliability council; or any court or governmental tribunal, in each case, having jurisdiction over any Funder (whether as Funder or as Permitting Project Manager) or any of its Affiliates or the development, permitting, siting, acquisition of Rights-of Way, or preliminary design of the Boardman to Hemingway Transmission Project.

"Governmental Authorizations" means any license, permit, order, approval, filing, waiver, exemption, variance, clearance, entitlement, allowance, franchise, or other authorization from or by a Governmental Authority.

"Governmental Requirements" means all laws, statutes, ordinances, rules, regulations, codes, and similar acts or promulgations or other legally enforceable requirements of any Governmental Authority.

"Idaho Power" has the meaning set forth in the Preamble.

"Joint Defense Agreement" has the meaning set forth in Section 11.1.

"Joint Defense Agreement Notice" has the meaning set forth in Section 11.2.

"Manager" has the meaning set forth in Section 13.3(a).

"Mandatory Payments" has the meaning set forth in Section 3.1(a) and Exhibit B.

"Negotiations End Date" has the meaning set forth in Section 3.3(b).

"NEPA" means the National Environmental Policy Act, as the same may be amended from time to time.

"NERC" means the North American Electric Reliability Corporation.

"Non-Defaulting Funders" means a Funder(s) that is not a Defaulting Funder(s).

"Non-Permitting Project Manager Funders" means PAC and BPA.

"Notice of Payment" has the meaning set forth in Section 3.1(b)(ii).

"PAC" has the meaning set forth in the Preamble.

"Person" means an individual, partnership, corporation, limited liability company, joint venture, association, trust, unincorporated organization, Governmental Authority, or other form of entity

"Permit Funding Committee" has the meaning set forth in Section 3.2.

"Permit Funding Payment Schedule" has the meaning set forth in Section 3.1(a)(iii) and Exhibit B.

"Permitting Interest" means, with respect to each of the Funders, their Permitting Interest as set forth in Exhibit D.

"Permitting Project" has the meaning set forth in Section 2.1.

"Permitting Project Manager" means Idaho Power.

"Private Property Interest" has the meaning set forth in Section 2.1.

"Project Costs" has the meaning set forth in Section 3.1(d)

"Project Cost Records" has the meaning set forth in Section 3.1(d).

"Project Permitting Objectives" has the meaning set forth in Section 2.2.

"Project Permitting Timetable" has the meaning set forth in Section 2.2.

"Purchase and Sale Date" has the meaning set forth in Section 3.3(c).

"Purchase and Sale End Date" has the meaning set forth in Section 3.3(c).

"Purchasing Funder" has the meaning set forth in Section 3.3(c).

"Representatives" means, in respect of a Funder or Permitting Project Manager, the directors, officers, shareholders, partners, members, employees, agents, consultants, contractors or other representatives of such Funder or Permitting Project Manager.

"Response Notice" has the meaning set forth in Section 3.3(c).

"Rights-of-Way" means all rights-of-way, easements, grants and other interests on which the Boardman to Hemingway Transmission Project is or will be constructed that are owned or to be owned by Funders or their Affiliates. Private Property Interests are expressly excluded from this Agreement.

"Selling Funder" has the meaning set forth in Section 3.3(c).

"Subchapter K" has the meaning set forth in Section 14.4(b).

"Term" has the meaning set forth in Section 6.1.

"WECC Rating Process" has the meaning set forth in Section 3.3(a)(iii)(A).

"Withdrawal Date" has the meaning set forth in Section 7.2(a).

"Withdrawal Payment" has the meaning set forth in Section 7.2(a).

"Withdrawing Funder" has the meaning set forth in Section 7.1.

1.2 Interpretation. The following rules of interpretation and construction shall apply in this Agreement:

(a) The masculine shall include the feminine and neuter.

(b) References to "Articles," "Sections" and "Exhibits" shall be to articles and sections of and exhibits to this Agreement.

(c) The Exhibits and Schedule 2.2 attached hereto are incorporated in and are intended to be a part of this Agreement.

(d) This Agreement was negotiated and prepared by Idaho Power, PAC, and BPA with the advice and participation of counsel. Idaho Power, PAC, and BPA have agreed to the wording of this Agreement and none of the provisions hereof shall be construed against one Funder on the ground that such Funder is the author of this Agreement or any part hereof.

(e) Each reference in this Agreement to any agreement or document or a portion or provision thereof shall be construed as a reference to the relevant agreement or document as amended, supplemented or otherwise modified from time to time with the written approval of Idaho Power, PAC, and BPA.

(f) Each reference in this Agreement to Governmental Requirements and to terms defined in, and other provisions of, Governmental Requirements shall be references to the same (or a successor to the same) as amended, supplemented or otherwise modified from time to time.

(g) The term "day" shall mean a calendar day, the term "month" shall mean a calendar month, and the term "year" shall mean a calendar year. Whenever an event is to be performed, a period commences or ends, or a payment is to be made on or by a particular date and the date in question falls on a day which is not a Business Day, the event shall be performed, or the payment shall be made, on the next succeeding Business Day; provided, however, that all calculations shall be made regardless of whether any given day is a Business Day and whether any given period ends on a Business Day.

(h) Each reference in this Agreement to a Person includes its successors and permitted assigns; and each reference to a Governmental Authority includes any Governmental Authority succeeding to its functions and capacities.

(i) In this Agreement, the words "include," "includes" and "including" are to be construed as being at all times followed by the words "without limitation." References to "or" shall be deemed to be disjunctive but not necessarily exclusive.

(j) The words "hereof," "herein" and "hereunder" and words of similar import when used in this Agreement shall, unless otherwise specified, refer to this Agreement as a whole and not to any particular provision of this Agreement.

## ARTICLE II
## THE PERMITTING PROJECT

2.1 Joint Permitting. The Funders desire to jointly fund and support, with the intent to be joint owners pursuant to this Agreement, the process of obtaining Governmental Authorizations and completing other necessary work directly related to the siting, permitting, preliminary designing and acquiring Rights-of-Way for the Boardman to Hemingway Transmission Project (collectively, the "Permitting Project"), in accordance with the terms of this Agreement. The planning, design, procurement, and acquisition of private rights of way, private easements, private licenses, and similar private property interests are expressly excluded from this Agreement ("Private Property Interests"). Neither the Funders nor the Permitting Project Manager shall acquire Private Property Interests for the Boardman to Hemingway Transmission Project without the written agreement, not to be unreasonably withheld, of the then current Funders. Idaho Power, BPA, and PAC will define the terms of any acquisition of Private Property Interests by

amending this Agreement in accordance with Section 14.7, entering into a separate agreement expressly for the purpose of acquiring Private Property Interests, or through the incorporation of Private Property Interests into one or more Definitive Development and Construction Agreements. The Funders intend the terms of the acquisition of Private Property Interests to be consistent with the Permitting Interests established in Exhibit D to this Agreement.

2.2 Project Permitting Objectives and Timetable. The objectives (the "Project Permitting Objectives") and timetable (the "Project Permitting Timetable") that Idaho Power, PAC, and BPA desire to achieve with respect to the Permitting Project pursuant to this Agreement are set forth in Schedule 2.2. Idaho Power, PAC and BPA agree to use Commercially Reasonable Efforts to achieve the Project Permitting Objectives and Project Permitting Timetable in accordance with Schedule 2.2.

## ARTICLE III
## FUNDERS & PERMIT FUNDING COMMITTEE

3.1 Funders' Rights & Obligations.

(a) Payment Obligations. Subject to the provisions of Article VII and after the Effective Date:

(i) Each Funder is required to pay the mandatory funding payments as set forth in Exhibit B (the "Mandatory Payments"). Any payment made by a Funder will accrue interest, per annum, on behalf of the Funder calculated in accordance with Idaho Power's AFUDC rate to be credited to the Funder. Any credit shall be included in the funding invoice provided pursuant to Section 3.1(b)(i) and, as applicable, Section 3.1(b)(iii).

(ii) A Funder may elect, but is not required, to pay the final funding payment as set forth in Exhibit B (the "Completion Funding Payment"). A Funder that does not elect to pay the Completion Funding Payment set forth in Exhibit B consistent with Sections 3.1(b)(ii) and a Funder that pays such Completion Funding Payment but does not pay the Final Expense True-Up payment consistent with Section 3.1(b)(iii), shall be deemed a Withdrawing Funder under Article VII of this Agreement.

(iii) A Funder may, in its sole and absolute discretion, elect to make any of the Mandatory Payments or the Completion Funding Payment, in whole or in part, in advance of the date due identified in the Permit Funding Payment Schedule set forth in Exhibit B, in accordance with Section 3.1(b). In the event a Funder elects to make an early payment which includes an

AFUDC accumulation component, accumulation of AFUDC will cease upon receipt of the payment by the Permitting Project Manager.

(b) Method of Payment. All payments required under the terms of this Agreement shall be made to an account or accounts designated by the Permitting Project Manager to which payment is owed by electronic transfer in immediately available funds in the lawful currency of the United States. The Permitting Project Manager shall invoice the payments set forth in Exhibit B of this Agreement as follows:

(i) Mandatory Payments. The Permitting Project Manager shall deliver to the Funders an invoice ("Funding Invoice") ten (10) days in advance of each of the Mandatory Payment dates as set forth in Exhibit B. The invoice shall provide a sufficient level of detail describing the activities to be performed by the Permitting Project Manager, as requested by the receiving Funder. With the exception of Mandatory Payment 1 which is due twenty (20) days after the Effective Date, Funders shall tender payments to the Permitting Project Manager within forty (40) days of receipt of the Funding Invoice. Any payment past due will accrue interest, per annum, calculated in accordance with Section 3.1(a)(i). The failure of the Permitting Project Manager to timely deliver an invoice shall not relieve any Funder of its payment obligations in respect to the Mandatory Payments or Completion Funding Payment shown on such invoice.

(ii) Completion Funding Payment. The Permitting Project Manager shall provide the Funders with written notice of the expected date of completion of the Project Permitting Objectives and an invoice for the Completion Funding Payment within sixty (60) days after the publication of a Final Record of Decision by the BLM in the *Federal Register* for the Boardman to Hemingway Transmission Project (the "Final Payment Invoice"). The Final Payment Invoice shall provide a sufficient level of detail describing the activities performed or to be performed by the Permitting Project Manager, as requested by the receiving Funder. The Funders shall provide written notice to the Permitting Project Manager of its intent to pay the Completion Funding Payment within twenty (20) days from receipt of the Final Payment Invoice for the Completion Funding Payment (the "Notice of Payment"). Any Funder who fails to issue a Notice of Payment within such twenty (20) day period or issues a Notice of Payment within such twenty (20) day period but fails to tender payment to the Permitting Project Manager within forty (40) days of the Notice of Payment shall be deemed a Withdrawing Funder pursuant to Article VII, provided,

however, that Idaho Power may not withdraw from this Agreement pursuant to Article VII. The Funders electing to make the Completion Funding Payment shall tender payment to the Permitting Project Manager within forty (40) days of the Notice of Payment.

(iii) Final Expense True-Up Payment. Except where a Funder has withdrawn from this Agreement pursuant to Article VII, the Permitting Project Manager shall deliver to the Funders an invoice one hundred and eighty (180) days following the Notice of Payment relating to a Completion Funding Payment to include a final true up payment as provided in Exhibit B (the "Final Expense True-Up"). The Final Expense True-Up payment shall include all cost adjustments to Mandatory Payments 1, 2 and 4 approved by the Permit Funding Committee and not previously paid by the Funders to the Permitting Project Manager and any credit for any accrued interest not previously received by the Funders pursuant to Section 3.1(a)(i). The invoice shall provide the Funders sufficient level of detail describing the activities performed by the Permitting Project Manager, as requested by the receiving Funder. The Funders shall tender payment to the Permitting Project Manager within thirty (30) days of receipt of the invoice. The failure by the Permitting Project Manager to timely deliver an invoice shall not relieve any Funder of its payment obligations in respect to the Final Expense True-Up payment shown on such invoice. Any true up associated with a Funder's withdrawal from the Agreement is subject to Article VII. In the case of any overpayment by the Non-Permitting Project Manager Funders, the Permitting Project Manager shall promptly return the amount of the overpayment to the Non-Permitting Project Manager Funder, together with interest for the period from the date of overpayment until such amount has been paid, calculated in the manner prescribed for calculating interest in Section 3.1(a).

(c) Disputed Amounts. If a Funder disputes any portion of any amount described in Exhibit B, the Funder shall pay its total amount of the invoice when due, and, if actually known at the time by the Funder, identify the disputed amount and state that the disputed amount is being paid under protest. Any disputed amount shall be resolved pursuant to the provisions of Article XIII. If it is determined pursuant to Article XIII that an overpayment or underpayment has been made by the Funder or any amount allocated to a Funder on an invoice is incorrect, then (i) in the case of any overpayment by a Funder, the Permitting Project Manager shall promptly return the amount of the overpayment (or credit the amount of the overpayment on the next invoice) to the Funder; and (ii) in the case of an underpayment by the Funder, the Funder shall promptly pay the amount of the

underpayment to the Permitting Project Manager (in each case, together with interest for the period from the date of overpayment, underpayment, or incorrect allocation, until such amount has been paid or credited against a future invoice calculated in the manner prescribed for calculating interest in Section 3.1(a)).

(d) Audit Rights. Each Funder may, at its cost, at any time during normal business hours and with reasonable prior notice to the Permitting Project Manager and the other Funders, of not less than ten (10) Business Days, but not more often than twice in any twelve (12) month period, inspect and audit the books and records of the Permitting Project Manager and any of its Affiliates (and the Permitting Project Manager shall secure such rights for the Permitting Project Manager from its Affiliates) relating: (1) to the determination of the payments set forth in Exhibit B for which the Funders are responsible under this Agreement, including the costs set forth in Exhibit C (the "Project Costs"), within twelve (12) months prior to the date of the audit notice; and (2) directly related to and involved in formulating the Mandatory Payments, Completion Funding Payment, and any applicable true up payment pursuant to this Agreement ("Project Costs Records"). Audit findings shall be provided to each Funder to this Agreement. If any audit discloses that, during such twelve (12)-month period, an overpayment or underpayment of Project Costs has been made by the Funders or the amount of any Project Costs allocated to the Funders on an invoice is incorrect, then such overpayment, underpayment or incorrect amount shall be resolved pursuant to Article XIII. The Funders requesting the audit shall reimburse one hundred percent (100%) of all reasonable costs and expenses (including internal costs and expenses) incurred by or on behalf of the Permitting Project Manager and any of its Affiliates in complying with the provisions of this Section 3.1(d), provided, however, that such Funders shall not be required to reimburse any such costs if the audit determines that Funders, in combination, have made more than Twenty-Five Thousand Dollars ($25,000) in overpayments of Project Costs or more than Twenty-Five Thousand Dollars ($25,000) in Project Costs have been incorrectly allocated to Funders.

(e) Access. The Permitting Project Manager shall, to the extent possible under any Rights-of-Ways, provide each Funder and its designees reasonable access to the Boardman to Hemingway Transmission Project sites to permit the Funders and their designees to inspect the development, preliminary design, siting, Rights-of-Way acquisition and permitting of the Boardman to Hemingway Transmission Project, provided that (i) the Funders and their designees do not interfere with the development, preliminary designing, siting, Rights-of-Way acquisition and permitting of the Boardman to Hemingway Transmission Project or any portion thereof or pose a safety hazard; (ii) the Funders and their designees comply with

any requirements of any Rights-of-Ways applicable to the Boardman to Hemingway Transmission Project; and (iii) the Funders and their designees performing the inspection comply with the Permitting Project Manager's or any other contractor's safety and security rules, notice of which the Permitting Project Manager shall provide to the Funders.

3.2 Permit Funding Committee.

(a) Scope and Authority. The Permit Funding Committee shall consider, evaluate and take action with respect to mutually resolving the following matters: (1) any and all changes in the scope or schedule of the Permitting Project that directly affect the cost of the Mandatory Payments, Completion Funding Payment or the costs otherwise associated with the Permitting Project; (2) any and all proposed cost adjustments to the Mandatory Payments, Completion Funding Payment or costs otherwise described in Exhibit B; (3) any and all technical specifications and other matters related to the Permitting Project; (4) requests from and provide guidance to the Permitting Project Manager from time to time as necessary or when requested relating to the advancement of the Project Permitting Objectives and Project Timetable, or the Permitting Project; (5) general development of policy and strategy with respect to the Permitting Project; and (6) any and all direct or indirect effects of the development of other regional transmission projects (including project schedule and location of potential interconnection points), including, but not limited to, the Cascade Crossing Project and Gateway West Project, on the development and permitting of the Boardman to Hemingway Transmission Project.

(b) Membership. The Permit Funding Committee shall be comprised of a representative of each Funder (each a "Funding Committee Representative"). Each Funder's Funding Committee Representative shall be a senior level representative or designee with authority to consider and act to resolve issues that arise between or among the Funders.

(c) Permitting Project Manager. The Permitting Project Manager shall inform the Permit Funding Committee and the Funding Committee Representatives through formal and informal communication, of the ongoing progress and matters that impact the Governmental Authorizations or other necessary work relating to the Permitting Project. The Permitting Project Manager shall confer and communicate with the Permit Funding Committee and Funding Committee Representatives as to the matters described in Section 3.2(a) or as otherwise provided in this Agreement.

(d) Funding Committee Meetings. The Permit Funding Committee will meet at least monthly, in person or telephonically, or as deemed necessary by the Funding Committee Representatives. Any Funding Committee Representative may request a meeting of the Permit Funding Committee at any time and for any reason. The Permitting Project Manager shall provide the Permit Funding Committee with regular statements, at least monthly, regarding the Permitting Project that include future expense projections.

(e) Funding Committee Procedures. The Funding Committee Representatives shall work in good faith to consider, evaluate and make best efforts to mutually resolve any issues that are raised before the Permit Funding Committee. If the Funding Committee Representatives are unable to mutually resolve any issue, they shall refer the matter to the Executives that have the authority to settle the issue. If the Executives are unable to mutually resolve the issue, the Funders may move to dispute resolution as set forth in Article XIII. All communications and writings exchanged between and/or among the Permitting Project Manager, Funding Committee Representatives, and Executives in connection with the Permit Funding Committee shall be treated as Confidential Information in accordance with Article XII.

(f) Joint Working Groups. Joint working groups may be established by the Permit Funders Committee on an ad hoc basis when the need arises to advance certain specific tasks related to the Permitting Project and the Boardman to Hemingway Transmission Project, including, but not limited to, consultation on technical specifications and other matters related to the Permitting Project.

(g) Committee Conversion. Within sixty (60) days after one or more Funders tenders Mandatory Payment 3 and the Completion Funding Payment set forth in Exhibit B, the Funders shall amend this Agreement, or enter into a new agreement, that establishes a committee structure that is consistent with the Permitting Interests of the Funders.

3.3 Future Agreements

(a) Negotiation Process

(i) Completion Notice. Unless this Agreement is terminated pursuant to Article VI, the Permitting Project Manager shall provide the Funders with written notice within sixty (60) days following the publication of a Final Record of Decision by the BLM in the *Federal Register* for the Boardman to Hemingway Transmission Project (the "Completion Notice") of the expected date of completion of the Project Permitting Objectives.

Notwithstanding the foregoing, any Funder may commence negotiations pursuant to this Section 3.3 for reaching Definitive Development and Construction Agreements at any time by providing written notice of its desire to do so to the other Funders pursuant Section 14.10.

(ii) Negotiation Period. Upon receipt of the Completion Notice, the Funders shall meet, subject to Section 3.3(a)(iii), to negotiate one or more Definitive Development and Construction Agreements for up to one hundred eighty (180) days (the "Negotiation Period"). Upon the termination of the Negotiation Period, the Funders may agree to extend the Negotiation Period for an additional period not to exceed one hundred eighty (180) days.

(iii) Negotiations. During the Negotiation Period, the Funders will attempt, to the greatest extent possible, but subject to the other provisions of this Section 3.3(a)(iii), to keep the Definitive Development and Construction Agreements consistent with the terms and conditions of this Agreement, including the Permitting Interests set forth in Exhibit D, as may be amended from time to time by mutual agreement of the Funders pursuant to Section 14.7. In negotiating the Definitive Development and Construction Agreement the Funders shall also consider the following:

(A) Path Rating. The Funders acknowledge and agree that the Permitting Interest set forth in Exhibit D may be impacted by the WECC Three Phase Project Rating Process (the "WECC Rating Process") and that each Funder's Permitting Interest is subject to the results of the WECC Rating Process. Subject to the outcome of the WECC Rating Process, the Funders may, using the Permitting Interests set forth in Exhibit D as a baseline for allocation, mutually agree to further negotiate, revise, or adjust the Permitting Interest set forth in Exhibit D for purposes of negotiating Definitive Development and Construction Agreements, including adjustments to Mandatory Payments, the Completion Funding Payment or the Final Expense True-Up paid pursuant to this Agreement. The Funders shall cooperate and support each other in the WECC Rating Process in a manner consistent with Section 4.5.

(B) Alternative Analysis. BPA is considering various transmission and other alternatives to meet their service obligations in eastern Idaho. BPA's decision whether to participate in and timing associated with participation in the development and construction of the

Boardman to Hemingway Transmission Project may be based on BPA's evaluation of such alternatives.

(C) BPA NEPA Requirements. BPA has certain obligations and responsibilities under NEPA and other applicable Governmental Requirements that must be fulfilled before it can make a definitive decision concerning whether to participate in development and construction of the Boardman to Hemingway Transmission Project. Nothing in this Agreement shall be construed as obligating or committing BPA to enter into the Definitive Development and Construction Agreement before the NEPA review process for the Boardman to Hemingway Transmission Project has been completed and BPA has made a decision regarding how to proceed. Additionally, PAC's participation in the Boardman to Hemingway Transmission Project may be impacted by the schedule and design specifications of the Cascade Crossing Project and/or the Gateway West Project. As a result, or for other reasons, BPA or PAC may decide not to proceed further and to withdraw from this Agreement in accordance with Article VII at any time.

(D) Additional Materials. The Funders may request the Permitting Project Manager or other Funders to make available, and the Permitting Project Manager or other Funders will make available, on mutually agreed to terms (such agreement not to be unreasonably withheld) additional information related to the design, engineering, construction, or procurement of materials related to the Boardman to Hemingway Transmission Project that are not part of this Agreement.

(b) Negotiation Termination. Any negotiations pursuant to this Section 3.3 shall automatically terminate, unless the Negotiation Period is extended as provided in Section 3.3(a)(ii) (the "Negotiations End Date").

(c) Transfer of Interest. Following the Negotiations End Date and notwithstanding Article V herein, to the extent a Definitive Development and Construction Agreement is not executed, any Funder who has made all payments pursuant to Exhibit B may issue a written notice to proceed with the development and construction of the Boardman to Hemingway Transmission Project to the other Funders (the "Notice to Proceed"). Notwithstanding anything to the contrary in Article VII, within thirty (30) days of the receipt of the Notice to Proceed, each Funder shall notify the other Funders whether it does or does not desire to proceed with the development and construction of the Boardman to Hemingway

Transmission Project (each a "Response Notice"). Within two (2) years of receipt of the last Response Notice (the "Purchase and Sale End Date") the Funders who desire to proceed with the development and construction of the Boardman to Hemingway Transmission Project (each a "Purchasing Funder") shall purchase and the Funders who do not desire to proceed with the development and construction of the Boardman to Hemingway Transmission Project (each a "Selling Funder") shall sell all of the Selling Funder's rights, title, and interests in and to the Permitting Project, including all reports, studies, and Governmental Authorizations, Rights of Way, and any other property whatsoever of whatever nature and kind, whether real or personal, tangible or intangible, acquired or perfected by the Permitting Project Manager for the benefit of the Funder(s) pursuant to the terms of this Agreement. Purchasing Funders shall select the date for the purchase and sale (the "Purchase and Sale Date") which shall occur before the Purchase and Sale End Date, written notice of which they shall provide to the Selling Funders. On the Purchase and Sale Date, the Purchasing Funders shall pay immediately available funds pro-rata (based on their Permitting Interest after giving effect to the sale) and the Selling Funders shall receive the aggregate amount of all payments made pursuant to Exhibit B. The Funders shall execute such agreements and documents as may be reasonably required to facilitate the purchase and sale contemplated pursuant to this Section 3.3 (c).

(d) If two or more Purchasing Funders remain pursuant to Section 3.3(c), the Purchasing Funders shall meet to negotiate one or more Definitive Development and Construction Agreements pursuant to Sectiond 3.3(a)(ii), (a)(iii), (b), (c) and (d).

(e) In the event no Funder has issued a Notice to Proceed, the Funders retain their respective right, title and interest in the Permitting Project pursuant to this Agreement.

3.4 Other Projects. Nothing in this Agreement shall preclude a Funder from taking any action (or having its Affiliates take any action) with respect to any other transmission project, including a transmission project that may compete with the Permitting Project.

## ARTICLE IV
## PERMITTING PROJECT MANAGER

4.1 Appointment of Permitting Project Manager.

(a) Appointment. The Funders hereby appoint Idaho Power, and Idaho Power hereby accepts appointment, to serve as Permitting Project Manager of the Permitting

Project and will perform the obligations of the Permitting Project Manager expressly set forth in this Agreement, in accordance with the terms and conditions of this Agreement.

(b) Duty. The Funders agree that the Permitting Project Manager shall not have any obligations, responsibilities or duties to the Funders other than as are expressly provided for in this Agreement.

4.2 Authority of Permitting Project Manager.

(a) Role of Permitting Project Manager. The Permitting Project Manager shall administer and oversee the Permitting Project and shall be responsible for the day to day activities involved in advancing the Permitting Project to achieve the Project Permitting Objectives and Project Permitting Timetable, including the responsibility for obtaining all required Governmental Authorizations, siting, and Rights-of-Way acquisition relating to the Boardman to Hemingway Transmission Project. The Permitting Project Manager will advance funds in anticipation of receiving the Mandatory Payments from Funders, as necessary, to fulfill the Permitting Project Objectives ("Advance Contributions"). Idaho Power's Advance Contributions will accrue interest, per annum, calculated in accordance with Idaho Power's AFUDC rate. The Advance Contributions and accrued AFUDC will be reimbursed as part of the Funder's Mandatory Payments 2 or 4 as set forth in Exhibit B, as applicable. The Permitting Project Manager shall not collect payments other than those described in Exhibit B or as approved by the Permit Funding Committee. The Permitting Project Manager will exercise or enforce all benefits, rights and remedies under this Agreement for the benefit of the Funders pro rata (in accordance with their respective Permitting Interests) and without adverse distinction or undue discrimination between or against the Funder's respective Permitting Interests. In furtherance and not in limitation of the immediately preceding sentence, the Permitting Project Manager agrees to transfer, assign, distribute, pay over or otherwise make available to the Non-Permitting Project Manager Funders, the Non-Permitting Project Manager Funder's pro rata share (based on its respective Permitting Interests) in any payments or proceeds obtained pursuant to this Agreement.

(b) Communication. The Permitting Project Manager shall have the duty to communicate the status of the Permitting Project, including the Project Permitting Objectives, on a regular basis with the Permitting Funding Committee in a manner consistent with Section 3.2(c).

(c) Reporting. The Permitting Project Manager shall be responsible for preparing and distributing monthly reports to the Permitting Project Committee (or less

frequently if mutually required by the Permit Funding Committee) regarding (i) Project Costs paid and projected to be incurred, and, to the extent necessary, recommend to the Permit Funding Committee adjustments to the Permit Funding Schedule to satisfy expected Project Costs to be incurred in relation to the Project Permitting Objectives and (ii) activity and progress with respect to achieving the Project Permitting Objectives and the Project Permitting Timetable. The Permitting Project Manager shall be responsible for preparing and distributing reports to the Permit Funding Committee at such other times as any material change occurs or is contemplated that affects the achievement of the Project Permitting Objectives.

(d) Project Coordination. Notwithstanding anything to the contrary contained in this Agreement, the Permitting Project Manager shall work diligently, consult with and obtain the express written approval of the Funders with respect to the location, technical design and engineering specifications relating directly to the interconnection point of the Boardman to Hemingway Transmission Project and the proposed Cascade Crossing Project and Gateway West Project.

4.3 Funder's Ownership Interests.

(a) Perfection of Existing Ownership Interests. Commencing on the Effective Date of this Agreement, the Permitting Project Manager will take all necessary and reasonable action, unless prohibited by applicable Governmental Requirements, to perfect and vest, on behalf and in the name of the Funders, in accordance with the Funders' Permitting Interest set forth in Exhibit D, an undivided ownership interest as tenants-in-common in all right, title, and interest in all reports, studies, Governmental Authorizations (including permits) and other property of whatever nature and kind, whether real or personal, tangible or intangible, purchased or acquired prior to the Effective Date by or on behalf of the Permitting Project Manager or Idaho Power for the Boardman to Hemingway Transmission Project, including all Governmental Authorizations and Rights-of-Way required for the Boardman to Hemingway Transmission Project and acquired by Idaho Power hereunder.

(b) Perfection of Future Ownership Interests. Following the Effective Date of this Agreement, the Permitting Project Manager shall acquire, unless prohibited by applicable Governmental Requirements, on behalf and in the name of the Funders, in accordance with the Funders' respective Permitting Interests set forth in Exhibit D, an undivided ownership interest as tenants-in-common in all right, title, and interest in all reports, studies, Governmental Authorizations (including permits) and other property of whatever nature and kind, whether real or personal,

tangible or intangible, for the Boardman to Hemingway Transmission Project, including all Governmental Authorizations and Rights-of-Way required for the Boardman to Hemingway Transmission Project and acquired by the Permitting Project Manager hereunder. The Funders and the Permitting Project Manager agree that any reports, studies and Governmental Authorizations shall be issued in the names of all Funders. Notwithstanding any provision to the contrary contained in this Agreement, the Permitting Project Manager shall make all applications for Government Authorizations, and shall obtain all such Government Authorizations, reports, and studies, in the name of the Funders, to the extent permitted by applicable Governmental Requirements. In the event a Governmental Authorization, report or study is not issued in the name of all Funders, the Funders and Permitting Project Manager agree to take all necessary and reasonable actions to perfect and vest, on behalf and in the name of the Funders, in accordance with the Funders' respective Permitting Interests, an undivided ownership interest as tenants-in-common in all right, title and interest in all such Governmental Authorizations, reports, and studies.

(c) Forfeiture of Ownership Interests. In the event any Funder elects not to make all of the payments set forth in Exhibit B, or otherwise withdraws from this Agreement pursuant to Article VII, the Withdrawing Funder shall convey to the remaining Funders all right, title, and interest in this Agreement, as well as all right title and interest in all reports, studies, Governmental Authorizations (including permits), Rights of Way, and any other property whatsoever of whatever nature and kind, whether real or personal, tangible or intangible, acquired or perfected by the Permitting Project Manager for the benefit of the Funders pursuant to the terms of this Agreement pursuant to Section 7.2. If and to the extent the right, title, or interest in any permit or Governmental Authorization is by its terms or pursuant to applicable law not assignable, the Withdrawing Funder shall execute such reasonable agreements, licenses, or other instruments as shall be deemed reasonably necessary by the remaining Funders to otherwise convey all use and enjoyment of the Withdrawing Party's right, title, and interest in such permit or Governmental Authorization.

4.4 Standard of Work. The Permitting Project Manager shall perform all of its obligations under this Agreement as an independent contractor and in accordance with Good Utility Practice and applicable Governmental Requirements and Governmental Authorizations and without adverse distinction among the Funders.

4.5 Assistance. Each Funder shall cooperate with the Permitting Project Manager promptly, as and when reasonably requested by the Permitting Project Manager, to assist the Permitting Project Manager in the performance of its duties, responsibilities and

obligations under this Agreement, including executing and delivering from time to time such additional documents, certificates or instruments, and taking such additional actions, as may be reasonably requested by the Permitting Project Manager. Each Funder shall bear its own costs for providing such cooperation and assistance as requested by the Permitting Project Manager unless all of the Funders agree otherwise in writing. Each Funder shall provide internal personnel, services, know how, intellectual property or other internal resources as may be reasonably necessary or appropriate to carry out the intent of and to perform the Funders' and Permitting Project Manager's obligations under this Agreement or as all of the Funders may otherwise agree to in writing; provided however, to the extent the Permitting Project Manager desires to use for the purposes of this Agreement services of a Funder that are the subject of a separate agreement, such Funder shall consent, in its sole and absolute discretion, to such use and be reimbursed by the other Funders and the Permitting Project Manager as mutually agreed to by all the Funders. No Funder (other than Idaho Power in its role as Permitting Project Manager) shall have the right to invoice the other Funders for the costs or expenses associated with the utilization of internal personnel, services, know how intellectual property or other internal resources necessary or appropriate to carry out the intent of and to perform its obligations under this Agreement, unless otherwise agreed upon in writing by the Funders. Nothing in this Agreement shall preclude a Funder from exercising any rights expressly granted it under this Agreement or taking any action (or having its Affiliates take any action) with respect to any other transmission project, including any such project that may compete with the Permitting Project. The Permitting Project Manger shall request assistance under this Section 4.5 without adverse distinction of the Funders.

4.6 Remedies.

(a) Notwithstanding any provision to the contrary contained in this Agreement, the Permitting Project Manager shall not have any liability to the Non-Permitting Project Manager Funders in connection with the performance of its covenants and obligations under this Agreement, provided, however, the Permitting Project Manager shall be liable for any direct actual damages resulting from its own negligence or breach of this Agreement. The Funders agree that each Funder has a duty to mitigate any damages and shall use Commercially Reasonable Efforts to minimize any damages it may incur as a result of the Permitting Project Manager's failure to perform or breach of any of its covenants or obligations under this Agreement.

(b) The Funders and the Permitting Project Manager acknowledge that the obligations and covenants performed by the Permitting Project Manager hereunder are unique and that the Non-Permitting Project Manager Funders will be irreparably injured should such obligations and covenants not be performed in accordance with the

terms and conditions of this Agreement. Consequently, the Non-Permitting Project Manager Funders will not have an adequate remedy at law if the Permitting Project Manager shall fail to perform its obligations and covenants hereunder. The Non- Permitting Project Manager Funders shall have the right, in addition to any other remedy available under this Agreement, to specific performance of the Permitting Project Manager's obligations and covenants hereunder, and the Funders and the Permitting Project Manager agree not to take a position in any proceeding arising out of this Agreement to the effect that the Non-Permitting Project Manager Funder has an adequate remedy at law.

4.7 Injury to Third Parties. Idaho Power and PAC shall be responsible for obtaining and maintaining during the Term insurance covering their respective legal liabilities to third persons or the property of third persons related to their respective obligations under this Agreement in amounts consistent with Good Utility Practice and any applicable Governmental Requirements. Insurance coverage required by this Section 4.7 for Idaho Power and PAC may be through a carrier or self-insured, or any combination of carrier insured and self-insured. BPA shall be responsible for injury or damage to third persons or the property of third parties related to its obligations under this Agreement and caused by BPA in accordance with the provisions of the Federal Tort Claims Act.

## ARTICLE V
## TRANSFER OF RIGHTS AND INTERESTS; ASSIGNMENT

5.1 Prohibited Transfers and Assignments. Except as provided in Section 3.3(c) and Section 5.2, no Funder may, without the express written consent of the other Funders (such consent not to be unreasonably withheld, conditioned or delayed) sell, assign, transfer, convey or otherwise dispose of, directly, in whole or in part, any of its rights, titles or interest in and to (a) this Agreement including its rights, duties and obligations hereunder, or (b) the Permitting Project. Any sale, assignment, transfer, conveyance or other disposition in violation of this Article V shall be null and void.

5.2 Permitted Assignments and Transfers. Notwithstanding anything to the contrary contained in this Agreement, Section 5.1 shall not restrict:

(a) the right of any Funder to transfer voluntarily (and without the consent of the other Funders) all of its Permitting Interest in the Permitting Project and all of its rights, titles and interests in and to this Agreement (including all of its rights and obligations in this Agreement as Permitting Project Manager, if any) in connection with any sale, merger or other transfer of substantially all of such Funder's electric transmission facilities as an operating entity; provided, however, that the effectiveness of such assignment shall be conditioned upon the assignee

agreeing in writing to assume all of the rights and obligations of the assigning Funder under this Agreement (including all of its rights and obligations in this Agreement as Permitting Project Manager, if any) as of the effective date of assignment;

(b) the right of any Funder to transfer voluntarily (and without the consent of the other Funders) all of its Permitting Interest in the Permitting Project and all of its rights, titles and interests in and to this Agreement (including all of its rights and obligations in this Agreement as Permitting Project Manager, if any) to an Affiliate of the Funder; provided, however, that the effectiveness of such assignment shall be conditioned upon the assignee agreeing in writing to assume all of the rights and obligations of the assigning Funder under this Agreement (including all of its rights and obligations in this Agreement as Permitting Project Manager, if any) as of the effective date of assignment;

(c) the right of any Funder to transfer voluntarily all of its Permitting Interest in the Permitting Project and all of its rights, titles and interest in and to this Agreement (including all of its rights and obligations in this Agreement as Permitting Project Manager, if any) to a third party that is financially and technically capable of performing the transferring Funder's (and, Permitting Project Manager's, if any) obligations under this Agreement; provided that: (i) the other Funders approve, in their sole discretion, such transfer, and (ii) the other Funders are offered the right of first refusal to purchase such Permitting Interest and all of the transferring Party' rights, titles and interests in and to this Agreement (including all of its rights and obligations in this Agreement as Permitting Project Manager, if any) at the amounts set forth in the Permitting Funding Schedule; provided, however, that the effectiveness of such assignment shall be conditioned upon the third-party purchaser agreeing in writing to assume all of the rights and obligations of the assigning Funder under this Agreement (including all of its rights and obligations in this Agreement as Permitting Project Manager, if any) as of the effective date of assignment.

5.3 Release. Upon any assignment or transfer pursuant to this Section 5.2, no Funder transferring or assigning its right, title and interest in this Agreement and the Permitting Project shall have any further obligations or responsibilities under this Agreement.

## ARTICLE VI
## TERM

6.1 Term. The term of this Agreement ("Term") shall commence on the Effective Date and shall continue in full force and effect until the successful completion of the duties and obligations under this Agreement in accordance with the terms of this Agreement, unless

terminated earlier as set forth in this Article VI. Notwithstanding the foregoing, this Agreement shall terminate not later than January 1, 2022.

6.2 Early Termination.

(a) The Term of this Agreement shall terminate effective upon the occurrence of any of the following:

(i) Withdrawal of two (2) Funders, if there are three (3) Funders at the time, or one (1) Funder, if there are only two (2) Funders at the time, in each case, pursuant to Article VII;

(ii) the mutual written consent of the Funders; or

(iii) The effective date of a separate written agreement among all of the then current Funders which by its terms supersedes this Agreement.

(b) If this Agreement is terminated pursuant to this Section 6.2, then, except as for those provisions that are expressly intended to survive termination pursuant to this Agreement, this Agreement shall terminate and become void and of no further force and effect, without further action by any Funder, provided that no Funder shall be relieved from any of its obligations or liabilities hereunder accruing prior thereto.

(c) If this Agreement is terminated pursuant to Section 6.2(a)(i), then the Non-Withdrawing Funder may, in its sole and absolute discretion, proceed with the Permitting Project.

## ARTICLE VII
## WITHDRAWAL

7.1 Withdrawal. PAC or BPA may withdraw from this Agreement at any time and for any reason, or for no reason, subject to the limitations of this Article VII (a "Withdrawing Funder"). Idaho Power shall have no right to withdraw from this Agreement under any circumstance or at any time, including if it is a Defaulting Funder pursuant to Article VIII. A Withdrawing Funder shall provide reasonable prior written notice to the other Funders of its intent to withdraw from this Agreement ("Notice of Withdrawal"), and the Notice of Withdrawal shall specify the effective date of withdrawal, which in no event shall be less than five (5) Business Days after the date of delivery of the Notice of Withdrawal.

7.2 Effect of Withdrawal. The Withdrawing Funder's withdrawal from this Agreement shall be subject to the following:

(a) Withdrawal will become effective as of the last day of the month the Withdrawing Funder provides its Notice of Withdrawal ("Withdrawal Date"). As of the Withdrawal Date, the Withdrawing Funder shall be obligated to pay the Permitting Project Manager any outstanding Mandatory Payments identified in Exhibit B, including a true up that shall include all cost adjustments to Mandatory Payments 1, 2 and 4 approved by the Funding Committee and not previously paid by the Withdrawing Funder as of the Withdrawal Date and any credit for any accrued interest pursuant to Section 3.1(a)(i) (the "Withdrawal Payment"). The Permitting Project Manager shall invoice, in a manner consistent with Section 3.1(b), the Withdrawing Funder for the Withdrawal Payment within one hundred twenty (120) days following the Withdrawal Date.

(b) Except as otherwise provided in Article III of this Agreement, effective as of the Withdrawal Date, a Withdrawing Funder shall forfeit and transfer to the remaining Funders all of its right, title and interest in: (i) the Permitting Project, including all Governmental Authorizations, and amounts paid to the Permitting Project Manager through the Withdrawal Date; (ii) all Rights-of-Way issued by the BLM and other federal agencies (including any other permits, licenses, options, permissions); and (iii) any and all reports and studies. The Withdrawing Funder's Permitting Interest (including all project investments associated therewith) shall be allocated to the remaining Funders at no cost to the remaining Funders, such that the remaining Funders shall have 100% of the Permitting Interest in the Permitting Project.

(c) The Withdrawing Funder shall execute such documents and instruments as may be reasonably requested by the remaining Funders in connection with the withdrawal, including as may be necessary to evidence the Withdrawing Funder's relinquishment of its rights, titles and interest in the Permitting Project; provided, however, that the remaining Funders shall not be obligated to pay or reimburse the Withdrawing Funders for any Project Costs or the Withdrawal Payment paid to the Permitting Project Manager through the Withdrawal Date or to otherwise compensate the Withdrawing Funder for its rights, titles and interest in the Project.

## ARTICLE VIII
## EVENT OF DEFAULT

8.1 Event of Default. Each of the following events shall constitute an event of default ("Event of Default") by the defaulting Funder, including the Permitting Manager Funder, (a "Defaulting Funder"):

(a) Subject to Section 3.1(b)(ii), the failure to make, when due, any payment required pursuant to this Agreement, if such failure is not remedied within ninety (90) days after written notice thereof from a Non-Defaulting Funder;

(b) any material representation or warranty made by a Defaulting Funder herein that is false or misleading in any material respect when made, unless (i) the fact, circumstance or condition that is the subject of such representation or warranty is made true within thirty (30) days after notice thereof from a Non-Defaulting Funder, provided that if the fact, circumstance or condition that is the subject of such representation or warranty reasonably cannot be corrected within such thirty (30) day period, then the Defaulting Funder shall have an additional period of time (not to exceed sixty (60) days) in which to correct the fact, circumstance or condition that is the subject of such representation or warranty so long as the Defaulting Funder commences good faith activities to correct the fact, circumstance or condition that is the subject of such representation or warranty during the initial 30-day cure period and continues thereafter to utilize Commercially Reasonable Efforts to effect a cure, and (ii) (A) such cure removes any adverse effect on the Non-Defaulting Funders of such fact, circumstance or condition being otherwise than as first represented, or (B) such fact, circumstance or condition being otherwise than as first represented does not materially adversely affect the Non-Defaulting Funders;

(c) a transfer, assignment or other disposition of its interest in this Agreement or its Permitting Interest in the Permitting Project, in each case, in violation of Article V;

(d) the failure to perform or breach of any material covenant or obligation set forth in this Agreement (other than provided for in this Section 8.1), if such failure is not remedied within thirty (30) days after written notice thereof from a Non-Defaulting Funder, provided that if such failure or breach cannot reasonably be cured within thirty (30) days, then the Defaulting Funder shall have an additional period of time (not to exceed ninety (90) days) in which to cure such failure or breach so long as the Defaulting Funder commences good faith activities to cure the failure or breach during the initial 30-day cure period and thereafter continues to utilize Commercially Reasonable Efforts to effect a cure; or

(e) the Defaulting Funder or the Permitting Project Manager becomes Bankrupt.

8.2 Cure by Non-Defaulting Funders. If a Defaulting Funder fails to cure an Event of Default, then the Non-Defaulting Funders may, individually or together, in their respective sole discretion, attempt to cure the Event of Default, provided that the

Defaulting Funder shall reimburse the Non-Defaulting Funders for all costs and expenses incurred by or on behalf of the Non-Defaulting Funders pursuant to this Section 8.2.

8.3 Remedies.

(a) If an Event of Default occurs and is continuing, then each of the Non-Defaulting Funders shall be entitled to exercise any of its remedies provided for in this Agreement and any of its remedies at law or in equity, including recovery from the Defaulting Funder of any damages suffered as a result of the Event of Default, subject to Section 11.6. The Non-Defaulting Funders shall use Commercially Reasonable Efforts to mitigate any damages suffered as a result of the Event of Default.

(b) If an Event of Default by BPA or PAC occurs and is not cured as provided in this Article VIII, then BPA or PAC, as the Defaulting Funder, shall be deemed to be a Withdrawing Funder under and subject to the terms of Article VII.

(c) The Funders acknowledge that the obligations and covenants performed by Idaho Power (as a Funder and Permitting Project Manager) hereunder are unique. If an Event of Default by Idaho Power occurs and is not cured as provided in this Article VIII, BPA and PAC shall have the right, in addition to any other remedy available under this Agreement, at law, or in equity, to seek specific performance of Idaho Power's obligations and covenants hereunder, and the Non-Defaulting Funders agree not to take a position in any proceeding arising out of this Agreement to the effect that the Non-Defaulting Funders have an adequate remedy at law.

## ARTICLE IX
## FORCE MAJEURE

9.1 Force Majeure Defined. For purposes of this Agreement, "Force Majeure" means an event or circumstance beyond the reasonable control of, and without the fault or negligence of, a Funder or Permitting Project Manager claiming Force Majeure ("Affected Party"), which, despite the exercise of reasonable diligence, cannot be or be caused to be prevented, avoided or removed by such Affected Party including, to the extent satisfying the above requirements, acts of God; earthquake; abnormal weather condition; hurricane; flood; lightning; high winds; drought; peril of the sea; explosion; fire; war (declared or undeclared); military action; sabotage; riot; insurrection; civil unrest or disturbance; acts of terrorism; economic sanction or embargo; civil strike, work stoppage, slow-down, or lock-out that are of an industry or sector-wide nature and that are not directed solely or specifically at the Affected Party; the binding order of any Governmental Authority, provided that the Affected Party has in good faith reasonably

contested such order; the failure to act on the part of any Governmental Authority, provided that such action has been timely requested and diligently pursued; unavailability of equipment, supplies or products, but only to the extent caused by Force Majeure; failure of equipment, provided that the equipment has been operated and maintained in accordance with Good Utility Practice; and transportation delays or accidents, but only to the extent otherwise caused by Force Majeure; provided, however, that neither insufficiency of funds, financial inability to perform nor changes in market conditions shall constitute Force Majeure.

9.2 Effect of Force Majeure.

(a) If an Affected Party is rendered wholly or partly unable to perform its obligations under this Agreement or its performance is delayed because of Force Majeure, such Affected Party shall be excused from, and shall not be liable for, whatever performance it is unable to perform or delayed in performing due to the Force Majeure to the extent so affected, provided that:

(i) The Affected Party, as soon as reasonably practical after the commencement of the Force Majeure, gives the other Funders (s) and/or the Project Manager prompt written notice thereof, including a description of the particulars of the Force Majeure;

(ii) The suspension of performance is of no greater scope and of no longer duration than is required by the Force Majeure; and

(iii) The Affected Party uses Commercially Reasonable Efforts to overcome and remedy its inability to perform as soon as reasonably practical after the commencement of the Force Majeure.

(b) Notwithstanding anything in this Article IX to the contrary, no payment obligation arising under this Agreement prior to the date of an event of Force Majeure shall be excused by such event of Force Majeure.

(c) Whenever an Affected Party is required to commence or complete any action within a specified period and is prevented or delayed by Force Majeure from commencing or completing such action within the specified period, such period shall be extended by an amount equal to the duration of such event of Force Majeure occurring or continuing during such period.

## ARTICLE X
## REPRESENTATIONS AND WARRANTIES

10.1 Representations and Warranties of Idaho Power. Idaho Power represents and warrants to PAC and BPA as of the Effective Date as follows:

(a) It is duly formed, validly existing and in good standing under the laws of the jurisdiction of its formation.

(b) It has all requisite corporate power necessary to own its assets and carry on its business as now being conducted or as proposed to be conducted under this Agreement.

(c) It has all necessary corporate power and authority to execute and deliver this Agreement and to perform its obligations under this Agreement, and the execution and delivery of this Agreement and the performance by it of this Agreement have been duly authorized by all necessary corporate action on its part.

(d) The execution and delivery of this Agreement and the performance by it of this Agreement do not: (i) violate its organizational documents; (ii) violate any Governmental Requirements applicable to it; or (iii) result in a breach of or constitute a default of any material agreement to which it is a party.

(e) This Agreement has been duly and validly executed and delivered by it and constitutes its legal, valid and binding obligation enforceable against it in accordance with its terms, except as the same may be limited by bankruptcy, insolvency or other similar laws affecting creditors' rights generally and by principles of equity regardless of whether such principles are considered in a proceeding at law or in equity.

(f) All material Governmental Authorizations required by Governmental Requirements to have been obtained by it prior to the date hereof in connection with the due execution and delivery of, and performance by it of its obligations under, this Agreement, have been duly obtained or made and are in full force and effect.

10.2 Representations and Warranties of PAC. PAC represents and warrants to BPA and Idaho Power as of the Effective Date as follows:

(a) It is duly formed, validly existing and in good standing under the laws of the jurisdiction of its formation.

(b) It has all requisite corporate power necessary to own its assets and carry on its business as now being conducted or as proposed to be conducted under this Agreement.

(c) It has all necessary corporate power and authority to execute and deliver this Agreement and to perform its obligations under this Agreement, and the execution and delivery of this Agreement and the performance by it of this Agreement have been duly authorized by all necessary corporate action on its part.

(d) The execution and delivery of this Agreement and the performance by it of this Agreement do not: (i) violate its organizational documents; (ii) violate any Governmental Requirements applicable to it; or (iii) result in a breach of or constitute a default of any material agreement to which it is a party.

(e) This Agreement has been duly and validly executed and delivered by it and constitutes its legal, valid and binding obligation enforceable against it in accordance with its terms, except as the same may be limited by bankruptcy, insolvency or other similar laws affecting creditors' rights generally and by principles of equity regardless of whether such principles are considered in a proceeding at law or in equity.

(f) All material Governmental Authorizations required by Governmental Requirements to have been obtained by it prior to the date hereof in connection with the due execution and delivery of, and performance by it of its obligations under, this Agreement, have been duly obtained or made and are in full force and effect.

10.3 Representations and Warranties of BPA. BPA represents and warrants to PAC and Idaho Power as of the Effective Date as follows:

(a) It is duly formed, validly existing and in good standing under the laws of the jurisdiction of its formation.

(b) It has all requisite statutory and administrative power necessary to own its assets and carry on its business as now being conducted or as proposed to be conducted under this Agreement.

(c) It has all necessary statutory and administrative power and authority to execute and deliver this Agreement and to perform its obligations under this Agreement, and the execution and delivery of this Agreement and the performance by it of this Agreement have been duly authorized by all necessary statutory or administrative action on its part.

(d) The execution and delivery of this Agreement and the performance by it of this Agreement do not: (i) violate its organizational documents; (ii) violate any Governmental Requirements applicable to it; or (iii) result in a breach of or constitute a default of any material agreement to which it is a party.

(e) This Agreement has been duly and validly executed and delivered by it and constitutes its legal, valid and binding obligation enforceable against it in accordance with its terms, except as the same may be limited by bankruptcy, insolvency or other similar laws affecting creditors' rights generally and by principles of equity regardless of whether such principles are considered in a proceeding at law or in equity.

(f) All material Governmental Authorizations required by Governmental Requirements to have been obtained by it prior to the date hereof in connection with the due execution and delivery of, and performance by it of its obligations under, this Agreement, have been duly obtained or made and are in full force and effect.

## ARTICLE XI
## COMMON DEFENSE & LIMITATION OF LIABILITY

11.1 Common Defense. The Funders shall, at such time as specified in this Section 11, enter into a Joint Defense Agreement that is consistent with applicable Governmental Requirements and that provides for the common defense, as well as payment for the common defense, including actual damages, for any and all suits, actions, liabilities, legal proceedings, claims, demands, losses, costs and expenses of whatsoever kind or character ( including reasonable attorneys' fees and expenses of third parties) of third parties, for injury or death of persons or physical loss of or damage to property of persons (other than of the Funders or the Permitting Project Manager) arising from the performance by the Permitting Project Manager of its obligations under this Agreement ("Claims"); provided, however, that the Funders shall not be obligated to enter into a Joint Defense Agreement or otherwise be responsible for any Claims arising from the Permitting Project Manager's own negligence or willful misconduct in connection with the performance of its obligations under this Agreement. The Joint Defense Agreement shall set forth the terms under which the Funders shall provide a common defense for the Claims described in this Section 11.1, including, but not limited to, the retention of appropriate legal counsel, advisors, and experts and the resolution of any such Claims. Each Funder shall contribute under the Joint Defense Agreement, in proportion to its Permitting Interest set forth in Exhibit D, or as otherwise mutually agreed to by the Funders in writing, to such common defense.

11.2 Notice and Participation. The Permitting Project Manager shall give the other Funders prompt written notice of any Claim upon the receipt of actual knowledge or information by the Permitting Project Manager of a Claim (the "Joint Defense Agreement Notice"). Upon the issuance of the Joint Defense Agreement Notice, the Funders and Permitting Project Manager shall use all Commercially Reasonable Efforts to agree to the terms of and enter into a Joint Defense Agreement consistent with the provisions of this Section 11 as soon as practicable. Except as otherwise provided in Section 11.1, during such period as the Funders shall not be a party to a Joint Defense Agreement but a Joint Defense Agreement Notice or Joint Defense Agreement Notices shall have been delivered, each of the Funders shall contribute funds and otherwise support the common defense of the Claims that are the subject of such Joint Defense Agreement Notice, in proportion to its Permitting Interest set forth in Exhibit D or as otherwise mutually agreed to by the Funders in writing, and during such period all costs incurred by or on behalf of the Permitting Project Manager for the defense or resolution of any such Claims (including, but not limited to, actual damages to be paid to resolve such Claims and reasonable attorneys' fees and costs) shall be considered Project Costs and payable to the Permitting Project Manager in proportion to the Funders' Permitting Interest set forth in Exhibit D and pursuant to the terms of this Agreement.

11.3 Control of Defense Prior to Joint Defense Agreement. After delivery of a Joint Defense Agreement Notice but before the Funders have entered into a Joint Defense Agreement, the Permitting Project Manager shall have the right to assume the defense of the Claim, with counsel designated by the Permitting Project Manager and reasonably satisfactory to the Funders, and contest or, with or without the prior consent of the Funders, settle such Claim, provided that the Permitting Project Manager shall not settle any Claim with respect to which it has sought or is entitled to seek recovery pursuant to Section 11.1 unless it has obtained the prior written consent of the Funders.

11.4 Failure to Provide Timely Joint Defense Agreement Notice. The Funders shall have no obligation to enter into a Joint Defense Agreement for any Claim for which a Joint Defense Agreement Notice is not timely provided, but only to the extent that such failure to give such notice materially and prejudicially impairs the ability of the Funders to jointly defend the applicable Claim. To the extent that failure to provide a timely Joint Defense Agreement Notice materially and prejudicially impairs a Funder's ability to jointly defend the applicable Claim, the Permitting Project Manager shall not be entitled to recover any costs incurred by or on behalf of the Permitting Project Manager in respect of such Claim as such Claim shall not be considered a Project Cost.

11.5 Survival of Obligation. The duty to provide for the common defense and enter into a Joint Defense Agreement shall continue in full force and effect for a period of one year after the expiration or termination of this Agreement, unless a Funder withdraws pursuant to Article VII in which case the duties and obligations under Sections 11.1 and 11.2 shall

not apply to the Withdrawing Funder for any Claim where it receives the Joint Defense Agreement Notice after the Notice of Withdrawal.

11.6 Limitation on Liability.

(a) In the case of breach or default by a Funder or Permitting Project Manager hereunder for which an express remedy or measure of damages is provided, such express remedy or measure of damages shall be the sole and exclusive remedy, and the Funder's or Permitting Project Manager's liability shall be limited as set forth in such provision and all other remedies or damages at law or in equity are hereby irrevocably waived, unless the provision in question provides that the express remedies are in addition to other remedies that may be available. Unless otherwise provided in this Agreement, if no remedy or measure of damages is expressly provided herein (and a remedy or damages is otherwise permitted), then the Funder's or Permitting Project Manager's liability shall be limited to direct actual damages only, and such direct actual damages shall be the sole and exclusive remedy and all other remedies or damages at law or in equity are hereby irrevocably waived.

(b) Notwithstanding any provision in this Agreement to the contrary, no Funder, whether in its capacity as Funder or Permitting Project Manager, shall be liable under this Agreement in any action at law or in equity, whether based on contract, tort or strict liability or otherwise, for any special, incidental, indirect, exemplary, punitive or consequential damages or losses, including any loss of revenue, income, profits or investment opportunities, loss of the use of equipment, or the cost of temporary equipment or services, provided that any Claims shall not be excluded under this Section 11.6(b) as special, incidental, indirect, exemplary, punitive or consequential damages or losses.

## ARTICLE XII
## PROPRIETARY INFORMATION

12.1 Disclosure of Proprietary Information Prohibited. The Funders agree that all information exchanged in connection with this Agreement (but not this Agreement) shall be treated as "Confidential Information" subject to the terms and conditions of the Nondisclosure Agreement, dated March 15, 2010, between the Funders (the "Confidentiality Agreement"), the provisions of which are incorporated herein by reference.

12.2 Publicity. Each Funder shall provide reasonable advance notice to, and shall consult with, the other Funders of any planned press release, public statement or meeting with the public or Governmental Authorities by such Funder in which discussion of the Permitting Project is expected to be a material part, provided that nothing herein shall prevent, limit, or delay any Funder from making any disclosure required by Governmental

Requirements or Governmental Authorizations. Each Funder shall provide notice to the other Funders as promptly as possible of the nature and content of any significant unplanned communications about the Permitting Project with the public or with Governmental Authorities. Notwithstanding the foregoing, when the information provided at a meeting is part of a previously agreed to public affairs plan or otherwise previously approved for disclosure by the Funders, notice of each such meeting or communication is not required.

## ARTICLE XIII
## DISPUTE RESOLUTION

13.1 Exclusive Procedure. Any dispute, controversy or claim arising out of or relating to this Agreement or the breach, interpretation, termination, performance or validity of this Agreement (each, a "Dispute") shall be resolved pursuant to the procedures of this Article XIII.

13.2 Dispute Notices. If a Dispute arises between the Funders or between the Permitting Project Manager and the Non-Permitting Project Manager Funders, then any Funder or Permitting Project Manager to such Dispute (each, a "Disputing Party") may provide written notice thereof to the other Disputing Parties, including a detailed description of the subject matter of the Dispute (the "Dispute Notice"). Any Disputing Party may seek a preliminary injunction or other provisional judicial remedy to the extent allowed by law if such action is necessary to prevent irreparable harm or preserve the status quo, in which case the Disputing Party nonetheless will continue to pursue resolution of the Dispute pursuant to this Article XIII.

13.3 Informal Dispute Resolution.

(a) The Disputing Parties shall make a good faith effort to resolve the Dispute by prompt negotiations between and/or among each Disputing Party's representative so designated in writing to the other Disputing Party or Disputing Parties (each a "Manager"). If the Managers are not able to resolve the Dispute within thirty (30) days after the date of the Dispute Notice, they shall refer the matter to the designated senior officers of the Disputing Parties (the "Executives"), who shall have authority to settle the Dispute. If the Executives are not able to resolve the Dispute within sixty (60) days after the date of the Dispute Notice, then the Dispute shall be resolved pursuant to Section 13.4.

(b) All communications and writings exchanged between and/or among the Disputing Parties in connection with these negotiations shall be confidential and shall not be used or referred to in any subsequent binding adjudicatory process between the

Disputing Parties, either with respect to the current Dispute or any future Dispute between the Funders and/or the Permitting Project Manager.

13.4 Remedies. If any Dispute arising under this Agreement cannot be resolved as provided in Section 13.3, then any Disputing Party may, in its sole discretion, pursue any available remedy at law or equity.

13.5 Continued Performance. During the pendency of any Dispute, each Funder and the Permitting Project Manager shall continue to perform all of its respective obligations under this Agreement.

## ARTICLE XIV
## MISCELLANEOUS

14.1 Counterparts. This Agreement may be executed in counterparts, each of which shall be considered an original, but all of which together shall constitute the same instrument. Electronic transmission of any signed original document, and retransmission of any signed electronic transmission, shall be the same as delivery of an original. At the request of any Funder or the Permitting Project Manager, the other Funders or Permitting Project Manager, as applicable, will confirm electronically transmitted signatures by signing an original document.

14.2 Headings. The Article and Section headings used in this Agreement (including headings used in any Exhibits attached hereto) are for convenience of reference only and shall not affect the construction of the Agreement or limit the scope of the particular provisions to which they refer.

14.3 Waiver. No waiver by any Funder of any breach or default by any other Funder or the Permitting Project Manager of its obligations herein shall be construed as a waiver of any other breach or default whether of a like kind or different nature. Any delay by a Funder, less than any applicable statutory period of limitations, in asserting or enforcing any rights or remedies under this Agreement shall not be deemed a waiver of such rights or remedies. Failure of any Funder or Permitting Project Manager to enforce any provision hereof shall not be construed to waive such provision, or to affect the validity of this Agreement or any part hereof, or the right of any Funder thereafter to enforce each and every provision hereof.

14.4 Relationship of Funders.

(a) Several and not Joint. The covenants, obligations, and liabilities of the Funders are intended to be several and not joint or collective, and nothing herein contained shall be construed to create an association, joint venture, trust or partnership, or to impose a trust or partnership covenant, obligation or liability on or with regard to

any of the Funders. Each Funder shall be individually responsible for its own covenants, obligations and liabilities as herein provided. No Funders shall be under the control of, or shall be deemed to control, the other Funders. No Funder shall have a right or power to bind any other Funder without such other Funder's express written consent.

(b) No Partnership. None of the provisions of this Agreement shall be deemed to constitute a partnership among or between the Funders and none of the Funders shall have any authority to bind the other Funders in any way, and the Funders agree that the arrangement contemplated by this Agreement shall be excluded from subchapter K of the U.S. Internal Revenue Code of 1986, as amended ("Subchapter K"). Idaho Power and PAC agree to report their respective Permitting Interest of any items of income, deductions and credits of the arrangement contemplated by this Agreement in a manner consistent with the exclusion of such arrangement from Subchapter K beginning with the taxable year which includes the Effective Date.

(c) Additional Funders. This Agreement may be amended to include one or more additional parties as Funders upon mutual written agreement of the then current Funders.

14.5 Severability. In the event that any provision of this Agreement or the application thereof becomes or is declared by a court of competent jurisdiction to be illegal, void or unenforceable, the remainder of this Agreement will continue in full force and effect and the application of such provision to other persons or circumstances will be interpreted so as reasonably to effect the intent of Idaho Power, PAC, and BPA. The Funders and Permitting Project Manager further agree to replace such illegal, void or unenforceable provision of this Agreement with a valid and enforceable provision that will achieve, to the maximum extent possible, the economic, business and other purposes of such illegal, void or unenforceable provision.

14.6 Binding Effect. Upon execution by all Funders, this Agreement shall be binding upon each of the Funders and the Permitting Project Manager and their respective successors and permitted assigns. This Agreement is null and void unless it is executed by all Funders.

14.7 Amendments. This Agreement shall not be modified, amended, supplemented or otherwise changed in any respect except by a written document signed by the Funders and the Permitting Project Manager.

14.8 No Third Party Beneficiary. This Agreement is for the exclusive benefit of the Funders and the Permitting Project Manager, and is not intended to nor shall be construed to

confer upon or give to any Person (other than the Funders and the Permitting Project Manager) any rights or remedies under or by reason of this Agreement or any transaction contemplated herein.

14.9 Entire Agreement. This Agreement, including the Exhibits and Schedule 2.2 attached hereto, constitutes the entire agreement of the Funders and the Permitting Project Manager with respect to the transactions contemplated by this Agreement and supersedes all prior agreements (other than the Confidentiality Agreement), oral or written, with respect thereto.

14.10 Notices.

(a) Except as otherwise provided herein, any notice, demand, request or other communication required or permitted to be given pursuant to this Agreement shall be in writing and signed by the Funder or Permitting Project Manager giving such notice, demand, request or other communication and shall be hand delivered or sent by certified mail, return receipt requested, or overnight courier to the other Funders and/or Permitting Project Manager at the address set forth below:

If to Idaho Power

| | |
|---|---|
| (as Funder or Permitting Project Manager) | Idaho Power Company<br>1221 West Idaho Street<br>Boise, ID 83702<br>Attn: Manager, Delivery Projects<br>Telephone: 208-388-2741 |
| With a copy to: | Idaho Power Company<br>1221 West Idaho Street<br>Boise, ID 83702<br>Attn: Legal Department<br>Telephone: 208-388-2300 |

If to PAC

| | |
|---|---|
| (as Funder) | PacifiCorp<br>825 NE Multnomah Street, Ste. 1600<br>Portland, OR 97232<br>Attn: Vice President, Transmission<br>Telephone: 503-813-6712 |

| | |
|---|---|
| With a copy to: | PacifiCorp<br>825 NE Multnomah Street, Ste. 1800<br>Portland, OR 97232<br>Attn: Legal Department<br>Telephone: 503-813-5854 |
| If to BPA | |
| (as Funder) | Bonneville Power Administration<br>5411 NE Highway 99<br>Vancouver, WA 98663<br>Attn: Senior Vice President,<br>Transmission Services<br>Telephone: 360-418-2122 |
| With a copy to: | Bonneville Power Administration<br>905 NE 11th Avenue<br>Portland, OR 97232<br>Attn: Office of General Counsel<br>Telephone: 503-230-4201 |

(b) Each Funder and the Permitting Project Manager shall have the right to change the place to which any notice, demand, request or other communication shall be sent or delivered by similar notice sent in like manner to the other Funder(s) and Permitting Project Manager. The effective date of any notice, demand, request or other communication issued pursuant to this Agreement shall be when: (i) delivered to the address of the Funders or Permitting Project Manager personally, by messenger, by a nationally or internationally recognized overnight delivery service or otherwise; or (ii) received or rejected by the Funders or Permitting Project Manager, if sent by certified mail, return receipt requested, in each case, addressed to the Funders or Permitting Project Manager at its address and marked to the attention of the person designated above (or to such other address or person as a Funders or Permitting Project Manager may designate by notice to the Funders and/or Permitting Project Manager effective as of the date of receipt by such Funders).

14.11 Choice of Law. This Agreement shall be governed by and construed in accordance with the laws of the State of Idaho, without giving effect to conflicts of laws principles. Notwithstanding the foregoing, for so long as BPA is a Funder, this Agreement shall be governed and construed in accordance with the laws of the United States.

14.12 Further Assurances. Each Funder and the Permitting Project Manager agrees to execute and deliver from time to time such additional documents, and to take such additional actions, as may be reasonably required by the other Funders or the Permitting Project Manager to give effect to the purposes and intent hereof.

14.13 Conflict of Interest. Nothing in this Agreement shall prohibit any Funder or the Permitting Project Manager from engaging in or possessing any interest in other projects or business ventures of any nature and description, independently or with others.

**[SIGNATURE PAGE TO FOLLOW]**

IN WITNESS WHEREOF, the Funders hereto have caused this Boardman to Hemingway Transmission Project Joint Permit Funding Agreement to be executed by their respective authorized representatives on the day and year first above written.

IDAHO POWER COMPANY,
as Funder and Permitting Project Manager

By _____

Date 1/12/12

PACIFICORP,
as Funder

By _____

Date _____

BONNEVILLE POWER ADMINISTRATION,
as Funder

By _____

Date _____

IN WITNESS WHEREOF, the Funders hereto have caused this Boardman to Hemingway Transmission Project Joint Permit Funding Agreement to be executed by their respective authorized representatives on the day and year first above written.

IDAHO POWER COMPANY,
as Funder and Permitting Project Manager

By _____

Date _____

PACIFICORP,
as Funder

By _____

Date _____

BONNEVILLE POWER ADMINISTRATION,
as Funder

By Brian Schuster

Date 1/12/12

IN WITNESS WHEREOF, the Funders hereto have caused this Boardman to Hemingway Transmission Project Joint Permit Funding Agreement to be executed by their respective authorized representatives on the day and year first above written.

IDAHO POWER COMPANY,
as Funder and Permitting Project Manager

By _____

Date _____

PACIFICORP,
as Funder

By _____

Date 1/12/12

BONNEVILLE POWER ADMINISTRATION,
as Funder

By _____

Date _____

Exhibit A

Description of Boardman to Hemingway Transmission Project

The development, siting, and acquisition of permits and Rights-of-Way over public land, construction, operation, and maintenance of a single circuit 500kV overhead electric transmission line and facilities beginning near Boardman, Oregon, and terminating near Melba, Idaho

.

Exhibit B

Permit Funding Schedule

The cost allocation of the Payment Schedule is determined by each Funder's Permitting Interest as of the Effective Date, which shall be calculated using the methodology described in Exhibit D.

Table B.1. Permit Funding Payment Schedule

| Payment | Type | Idaho Power Amount | BPA Amount | PAC Amount | Date |
|---|---|---|---|---|---|
| 1 | Mandatory Payment | $1,608,839 | $ 1,838,673 | $4,137,015 | Due Twenty (20) days following the Effective Date |
| 2 | Mandatory Payment | $1,608,839 | $ 1,838,673 | $4,137,015 | 10/1/2012 |
| 3 | Mandatory Payment* | $2,255,155 | $ 2,577,320 | $5,798,969 | 3/1/2013 |
| 4 | Mandatory Payment | $804,420 | $ 919,337 | $2,068,508 | 10/1/2013 |
| 5 | Completion Funding Payment* | $3,945,498 | $ 4,509,141 | $10,145,567 | Due One hundred twenty (120) days following publication of Final BLM Record of Decision in the *Federal Register* |
| 6 | Final Expense True-up | TBD | TBD | TBD | Two hundred ten (210) days following Notice of Payment |

* The payment amounts shown for Mandatory Payments 3 and Completion Funding Payment 5 include estimated AFUDC accruals. The actual invoice may differ from the amount shown based on the actual monthly AFUDC accrued during the period.

Exhibit C

Project Costs

Project Costs are included as part of the payments set forth in Exhibit B. Project Costs associated with Governmental Authorizations and other necessary work include as relating to the Permitting Project, but are not limited to:

i. Governmental Authorization costs;

ii. NEPA compliance activity;

iii. public involvement activity;

iv. reasonable attorney's fees;

v. third party contractor work for EIS development and support of the Boardman to Hemingway Transmission Project, including, but not limited to, the NEPA process;

vi. Preliminary design and engineering work in support of the Boardman to Hemingway Transmission Project, including, but not limited to, the NEPA process;

vii. Any other costs approved by the Permit Funding Committee associated with services to be coordinated by the Permitting Project Manager (and not provided for above), as set forth in this Agreement; and

viii. Overheads incurred by the Permitting Project Manager for the Permitting Project will be calculated at a 10% rate.

Exhibit D

Permitting Interest Work Paper

Each Funder is assigned a Permitting Interest based on the annual weighted capacity expressed in the Permitting Project. The Permitting Interest is determined by the sum of a Funder's eastbound capacity interest and westbound capacity interest, divided by the total of all Funders' eastbound and westbound capacity interests.

**Table 1: Boardman to Hemingway Weighted Interest**

| | Total Requested Capacity (MW) | Idaho Power Capacity Interest (MW) | BPA Capacity Interest (MW) | PacifiCorp Capacity Interest (MW) |
|---|---|---|---|---|
| **West to East** | **1050** | 350* | 400* | 300 |
| **East to West** | **600** | 0 | 0 | 600 |
| **Permitting Interest** | | 21.21% | 24.24% | 54.55% |

* Seasonally shaped capacity.

The capacity interests are based on:

- Idaho Power's capacity interest is seasonally shaped with 500 MW of eastbound capacity during the months of April through September and 200 MW of eastbound capacity during the months of January through March and October through December.
- BPA's capacity interest is seasonally shaped with 250 MW of eastbound capacity during the months of April through September and 550 MW of eastbound capacity during the months of January through March and October through December.
- PacifiCorp's capacity interest is constant throughout the entire calendar year.
- The sum of all Permitting Interest will equal one hundred percent.
- The sum of capacity interest may or may not equal the total rated capacity of project.

Additional Considerations:

- If the capacity interests are less than the total rated capacity of the Boardman to Hemingway Transmission Project, the unallocated capacity will be divided among the Funders based on the Funders Permitting Interest.
- The total rated capacity of the Boardman to Hemingway Transmission Project is subject to the results of the WECC Rating Process.

**Assumed B2H Ratings and Unassigned Capacity**

| | Assumed Rating (MW) | Unallocated Capacity (MW) |
|---|---|---|
| **West to East** | 1050 | 0 |
| **East to West** | 1000 | 400 |

**Allocation of Unassigned Capacity**

| | Percentage | Allocation of W-E Unassigned Capacity (MW) | Allocation of E-W Unassigned Capacity (MW) |
|---|---|---|---|
| **IPCO** | 21.21% | 0 | 85 |
| **BPA** | 24.24% | 0 | 97 |
| **PAC** | 54.55% | 0 | 218 |

Schedule 2.2

Project Permitting Objectives and Timetable

- National Environmental Policy Act (NEPA) – BLM Lead Agency
  - BLM Publishes Draft Environmental Impact Statement – Q1 of 2013
  - BLM Publishes Final Environmental Impact Statement – Q2 of 2014
  - BLM issues Record of Decision – Q4 of 2014
  - BLM issues Notice to Proceed – Q4 of 2014
- Oregon Energy Facility Siting Council (EFSC)
  - File preliminary Application for Site Certificate (ASC) – Q4 of 2012
  - File Complete ASC – Q2 of 2013
  - EFSC issues Proposed Order & Notice of Contested Case – Q3 of 2013
  - EFSC issues Final Order Issuing Site Certificate & Site Certificate Review – Q2 of 2014
  - EFSC issues Final Site Certificate – Q1 of 2015
  - EFSC issues Notice to Proceed – Q2 of 2015

**Appendix D-4. B2H MOU**

See the attached document.

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# MEMORANDUM OF UNDERSTANDING

This Memorandum of Understanding (this "MOU") is entered into as of January 12th, 2012 (the "Effective Date"), by and among PacifiCorp, an Oregon corporation ("PacifiCorp"), Idaho Power Company, an Idaho corporation ("Idaho Power"), and the Bonneville Power Administration, a United States government power marketing agency ("BPA"). PacifiCorp, Idaho Power and BPA are sometimes referred to in this MOU individually as a "Party" and, collectively, as the "Parties".

## RECITALS

A. PacifiCorp owns and operates facilities for the transmission of electric power and energy in interstate commerce ("PacifiCorp Transmission System");

B. BPA owns and operates facilities for the transmission of electric power and energy in interstate commerce ("BPA Transmission System");

C. Idaho Power owns and operates facilities for the transmission of electric power and energy in interstate commerce ("Idaho Power Transmission System");

D. The PacifiCorp Transmission System, BPA Transmission System and the Idaho Power Transmission System, are sometimes referred to in this MOU individually as a "Transmission System" and, collectively, the "Transmission Systems;"

E. PacifiCorp, BPA and Idaho Power each have an independent obligation or authority to plan for and expand their respective Transmission Systems based upon the needs of their native load customers, network customers, and eligible customers that agree to expand the Transmission System;

F. The Parties are considering whether to permit and construct new transmission projects in the West, including, but not limited to, jointly owning the proposed Boardman to Hemingway Transmission Project, which is a 500kV single circuit transmission line that is proposed to run from Boardman, Oregon to Melba, Idaho that if constructed could assist Idaho Power, PacifiCorp, and BPA in fulfilling their respective service obligations;

G. The Parties desire to (i) explore alternatives to establish eastern Idaho load service from Hemingway in exchange for similar service from the BPA Transmission System and (ii) consider whether to replace certain transmission arrangements involving existing assets with joint ownership transmission arrangements and other alternative transmission arrangements pursuant to definitive agreements mutually satisfactory to the Parties (collectively, the "Definitive Agreements");

H. Idaho Power and PAC acknowledge that BPA is considering various transmission and other alternatives to meet its service obligations in eastern Idaho, including alternatives that would involve Open Access Transmission Service, and that BPA's decision whether to participate

in development and construction of the Boardman to Hemingway Transmission Project may be based on BPA's evaluation of such alternatives; and

I. The Parties are entering into this MOU to set forth a process by which the Parties will negotiate in good faith to attempt to reach mutually satisfactory agreement on the terms and conditions of the Definitive Agreements.

**NOW THEREFORE**, the Parties agree as follows:

1. Effective Date; Term.

(a) This MOU shall become effective on January 12th 2012 (the "Effective Date").

(b) This MOU shall remain in effect until December 31, 2014, at which time it will terminate (the "Termination Date"), unless one of the following occurs:

(i) All Parties execute and deliver each of the Definitive Agreements before the Termination Date, in which case the Termination Date shall be the date that the last Definitive Agreement is fully executed;

(ii) The Parties, by mutual written agreement, agree to extend the Termination Date, in which case the Termination Date shall be a mutually agreed date after December 31, 2014;

(iii) The Parties, by mutual written agreement, agree that the MOU will be terminated before December 31, 2014, in which case the Termination Date shall be a mutually agreed date before December 31, 2014; or

(iv) Two Parties exercise their unilateral right to withdraw from this MOU pursuant to Section 2, in which case the Termination Date shall be thirty (30) days after the second withdrawing Party provides written notice of withdrawal.

(c) Upon termination, this MOU shall have no further force or effect, provided that the rights and obligations set forth in Sections 3(f) and 4 shall survive the termination of this MOU and remain in full force and effect.

2. Unilateral Withdrawal Rights.

Any Party may withdraw from this MOU at any time, for any reason whatsoever or for no reason, after thirty (30) days written notice to the other Parties of the intent to do so.

3. Responsibilities of the Parties.

(a) During the term of this MOU, the Parties meet regularly (either by teleconference or in person), proceed diligently and in good faith to negotiate mutually satisfactory terms of the Definitive Agreements and all such other agreements and documents necessary to fully document the transactions contemplated by the Definitive Agreements by no later than December 31, 2014. The Parties seek to meet the following milestones:

(i) By no later than January 15, 2012, the Parties commence regular meetings to discuss the subject matters described in Exhibit A hereto;

(ii) By no later than March 31, 2012, the Parties identify scenarios and any potential assets, the methodology for valuing capacity and assets, and any required criteria or conditions for execution of Definitive Agreements to achieve the alternatives described in Exhibit A.

(iii) By no later than September 30, 2012, BPA informs Idaho Power and PacifiCorp whether it intends to pursue a plan of service for its eastern Idaho load service requirements that would require the availability of project(s) contemplated herein.

(b) Each Party shall select a senior-level representative (each, a "Representative") to be responsible for coordinating activities under this MOU. Each Party commits to provide its Representative with the support and resources necessary to further the purposes of this MOU.

(c) Any Party would be free to use the rights granted it by another Party under a Definitive Agreement for any legitimate transmission service permitted by its respective OATT, provided, however, that rights granted under a Definitive Agreement would not include any additional rights to receive transmission service that would require use of any portion of the other's system not specifically acknowledged in a Definitive Agreement.

(d) Based on the information currently known to the Parties, it is proposed that negotiations of the Definitive Agreements include the alternatives set forth in Exhibit A. Exhibit A sets forth the Parties' current general understanding with respect to these alternatives, but is not intended to represent a binding agreement or final contractual language, or to address every provision which the Parties may wish to incorporate into the Definitive Agreements.

(e) Each of the Parties acknowledges and agrees that each other Party's decision to proceed with the Definitive Agreements and any other decision with respect to the Definitive Agreements is within such Party's sole and absolute discretion.

(f) The Parties agree that all information exchanged in connection with this MOU (but not this MOU) shall constitute, and be treated by the Parties as, "Confidential Information" subject to the terms and conditions of that certain Nondisclosure Agreement, dated as of March 15, 2010, between the Parties (the "Confidentiality Agreement"), the provisions of which are incorporated herein by reference.

4. General Provisions.

(a) This MOU is not a binding or enforceable contract but is instead an understanding that broadly states the expected responsibilities and objectives of the Parties.

(b) Nothing in this MOU shall limit, repeal, or in any manner modify the existing legal rights, privileges, and duties of each of the Parties as provided by agreement (including the Confidentiality Agreement), statute or any other law or applicable court or regulatory decision. Further, the concepts contemplated by this MOU and any Definitive Agreements, if any, are intended to be consistent with applicable statutes, rules, orders, regulations or other similar requirements or obligations.

(c) Each of the Parties acknowledges and agrees that no Party shall be liable to the other Parties for any claim, loss, cost, liability, damage or expense, including any direct damage or any special, indirect, exemplary, punitive, incidental or consequential loss or damage (including any loss of revenue, income, profits or investment opportunities or claims of third party customers), arising out of or directly or indirectly related to a Party's decision to terminate this MOU, the other Parties' performance or failure thereof under this MOU, or any other decision with respect to proceeding or not proceeding with the Definitive Agreements.

(d) This MOU may not be amended except in writing signed by the Parties.

(e) Any waiver on the part of a Party to this MOU of any provision or condition of this MOU must be in writing signed by each Party to be bound by such waiver, shall be effective only to the extent specifically set forth in such writing and shall not limit or affect any rights with respect to any other or future circumstance.

(f) This MOU is for the sole and exclusive benefit of the Parties and shall not create a contractual relationship with, or cause of action in favor of, any third party.

(g) Nothing in this MOU will be deemed to establish any right or provide a basis for any action, either legal or equitable, by any person or class of persons against the United States, its departments, agencies, instrumentalities or entities, or its officers or employees, challenging a government action or failure to act.

(h) Nothing in this MOU will be construed as limiting or affecting in any way the authority or responsibility of the Parties to perform within their authorities, and nothing in this MOU shall be construed as committing the Parties to take any action concerning the items identified in Exhibit A before they have complied with all applicable statutes and regulations such as the National Environmental Policy Act ("NEPA").

(i) Each Party shall be solely responsible for and shall pay its own costs and expenses incurred by it in connection with the negotiation of this MOU, the Definitive Agreements and all other agreements, documents and instruments related hereto and thereto, including all legal fees and expenses and expenses associated with such Party's own due diligence activities.

(j) Whenever this MOU requires or provides that (i) a notice be given by a Party to another Party or (ii) a Party's action requires the approval or consent of the other Parties, such notice, consent or approval shall be given in writing and shall be given by personal delivery, by recognized overnight courier service, or by certified mail (return receipt requested), postage prepaid, to the recipient thereof at the address given for such Party as set forth below, or to such other address as may be designated by notice given by any Party to the other Parties in accordance with the provisions of this Section 4(j):

If to PacifiCorp:

PacifiCorp
825 NE Multnomah Street, Suite 1600
Portland, OR 97232
Attention: Vice President Transmission Services
Fax No.: (503) 813-6893

If to Idaho Power:

Idaho Power
1221 West Idaho Street
Boise, Idaho 83702
Attention: Manager Delivery Planning
Fax No.: 208-388-6647

If to BPA:

Bonneville Power Administration
5411 NE Highway 99
Vancouver, Washington 98663
Attention: Senior Vice President, Transmission Service
Fax No.: 360 418-8433

Each notice, consent or approval shall be conclusively deemed to have been given (A) on the day of the actual delivery thereof, if given by personal delivery or overnight delivery, and (B) date of delivery shown on the receipt, if given by certified mail (return receipt requested).

Each Party shall have the right to change the place to which any notice, demand, request or other communication shall be sent or delivered by similar notice sent in like manner to the other Parties.

(k) This MOU may be executed in one or more counterparts (including by facsimile or a scanned image), each of which when so executed shall be deemed to be an original, and all of which shall together constitute one and the same instrument.

(l) Nothing contained in this MOU shall be construed as creating a corporation, company, partnership, association, joint venture or other entity, nor shall anything contained in this MOU be construed as creating or requiring any fiduciary relationship between the Parties. No Party shall be responsible hereunder for the acts or omissions of the other Party. Nothing herein shall preclude a Party from taking any action (or have its affiliates take any action) with respect to any other transmission project, including any such project that may compete with the Project.

(m) Unless otherwise expressly provided, for purposes of this MOU, the following rules of interpretation shall apply:

(i) any reference in this MOU to gender includes all genders, and the meaning of defined terms applies to both the singular and the plural of those terms;

(ii) the insertion of headings are for convenience of reference only and do not affect, and will not be utilized in construing or interpreting, this MOU;

(iii) all references in this MOU to any "Section" are to the corresponding Section of this MOU unless otherwise specified;

(iv) words such as "herein," "hereinafter," "hereof," and "hereunder" refer to this MOU (including the Exhibits to this MOU) as a whole and not merely to a subdivision in which such words appear unless the context otherwise requires; and

(v) the word "including" or any variation thereof means "including, without limitation" and does not limit any general statement that it follows to the specific or similar items or matters immediately following it.

**[SIGNATURE PAGE TO FOLLOW]**

IN WITNESS WHEREOF, each of the Parties has caused its duly authorized officer to execute this Memorandum of Understanding as of the date first above written.

**PACIFICORP**

By: _____
Name:
Title:

**IDAHO POWER COMPANY**

By: _____
Name:
Title: EVP & COO

**BONNEVILLE POWER ADMINISTRATION**

By: _____
Name:
Title:

IN WITNESS WHEREOF, each of the Parties has caused its duly authorized officer to execute this Memorandum of Understanding as of the date first above written.

**PACIFICORP**

By: _____
Name: PATRICK REITEN
Title: PRESIDENT/COO

**IDAHO POWER COMPANY**

By: _____
Name:
Title:

**BONNEVILLE POWER ADMINISTRATION**

By: _____
Name:
Title:

IN WITNESS WHEREOF, each of the Parties has caused its duly authorized officer to execute this Memorandum of Understanding as of the date first above written.

**PACIFICORP**

By: _____
Name:
Title:

**IDAHO POWER COMPANY**

By: _____
Name:
Title:

**BONNEVILLE POWER ADMINISTRATION**

By: Brian Silverstein
Name: Brian Silverstein
Title: Senior Vice-President, Transmission Services

EXHIBIT A

PRELIMINARY ALTERNATIVES FOR NEGOTIATION

This Exhibit A identifies the preliminary alternatives to be explored in negotiations under this MOU of the Definitive Agreements. The preliminary alternatives described in this Exhibit A are intended to be consistent with and subject to (i) all applicable statutory and governmental obligations of the Parties, including, as relating to PacifiCorp and Idaho Power, state and Federal Energy Regulatory Commission rules, regulations and orders; (ii) stakeholder and customer interests; and (iii) the Western Electricity Coordinating Council Three-phase rating process.

The Parties envision that PacifiCorp and Idaho Power may agree to jointly purchase and sell assets to achieve the objectives of the alternatives described in this Exhibit A. Any purchase and sale of existing assets between PacifiCorp and Idaho Power may involve some or all of the assets currently defined in existing contracts between Idaho Power and PacifiCorp, including, but not limited to, the Second Restated and Amended Transmission Facilities Agreement, Restated Transmission Service Agreement and the Agreement for Interconnection and Transmission Services. The service arising from any alternative may or may not be contingent upon the timing or physical construction of new assets.

Alternative 1:

- BPA would obtain a network service option from the Hemingway substation to the existing BPA service points in eastern Idaho. Idaho Power would sell and PacifiCorp would acquire Idaho Power's existing assets necessary to provide BPA's long-term load service.

- The Parties' intent is to minimize potential rate pancakes.

- BPA would work to plan an amount of BPA Transmission System capacity sufficient to enable PacifiCorp and Idaho Power to utilize their capacity shares (up to 650 MW in total) of the Boardman to Hemingway transmission project pursuant to standard OATT terms and conditions.

Alternative 2:

- Idaho Power and PacifiCorp, in combination, would provide BPA 600 MW of firm eastbound ownership rights of assets or other terms and conditions associated with the combined systems of Idaho Power and PacifiCorp in southern Idaho for the primary purpose of serving the BPA service points in eastern Idaho.

- BPA would provide to PacifiCorp and Idaho Power equivalent value of capacity rights, ownership rights of assets or other terms and conditions associated with the BPA Transmission System to the western terminus of the Boardman to Hemingway

Transmission Project, or other interconnection points jointly determined by the Parties. Such rights would originate at BPA's NW Market Hub (Mid-C) unless alternatives can be accommodated to serve load elsewhere over the BPA Transmission System.

- To achieve the objectives described in Alternative 2, the Parties would evaluate and consider interim measures and final approaches, including but not limited to the joint ownership of portions of the Gateway West Project, with BPA's minimum eastbound firm ownership rights of 250 MW, combined with the balance of ownership rights on a combination of Idaho Power and PacifiCorp's existing systems, as required to establish ownership rights from the Hemingway substation to BPA's existing eastern Idaho load points.

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**Appendix D-5. NTTG studies**

See the attached document.

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# NTTG 2016-2017

# REVISED DRAFT FINAL

# REGIONAL TRANSMISSION PLAN

# Draft 09.01.17

Note: this is a draft report and may change as a result of stakeholder comments or edits by NTTG

**Date, 2017**

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# Executive Summary

Would it be more efficient or cost-effective to meet future transmission needs in the Northern Tier Transmission Group (NTTG) footprint through a regional planning framework rather than the aggregate of local planning processes[1]? The 2015-2017 NTTG Regional Transmission Plan (RTP) poses this question and seeks to answer it. Developed in accord with NTTG Transmission Providers' Attachment K, which includes FERC Order 1000 regional and interregional transmission planning requirements, the plan analyzes whether NTTG's transmission needs in 2026 could best be satisfied with projects of a regional or interregional scope.

To arrive at a conclusion, NTTG used a two-year process of identifying transmission requirements and performing reliability and economic analyses on several collections of transmission projects, or plans: the prior (2014-2015) RTP, an Initial RTP[2] made up of projects from the prior RTP and projects included in the Full Funders' Local Transmission Plans, and a number of Change Case plans. A Null Change Case, which tests the NTTG footprint's current transmission system stressed by the addition of loads and resources projected for 2026-27, showed that the NTTG system performed acceptably in only one of seven stressed conditions studied. All the other conditions suffered performance issues that required correction.

A technical study found that the 2014-2015 prior RTP, which included two Non-Committed Projects (Boardman to Hemingway and portions of Energy Gateway), was not fully reliable with the 2026-27 load and resource projections. The study then evaluated 23 Change Cases that explored ways to reliably meet the transmission system needs through various combinations of the Non-Committed Projects in the Initial RTP or three proposed Interregional Transmission Projects, or both.

Reliability analyses narrowed the potentially acceptable solutions to the Initial RTP. These Change Cases were created to explore the relationship of a build-out of wind generation in Wyoming to meet NTTG load with its impact on the transmission system west of Wyoming and a potential expansion of the transmission system (i.e., the Gateway West and Gateway South projects). The study also examined three Interregional Transmission Projects as Alternative Projects to determine whether these projects would yield a more efficient or cost-effective regional transmission plan for NTTG and as a part of interregional coordination and planning. The analysis found, however, that none of the Interregional Transmission Projects could replace or enhance the Non-Committed Projects more efficiently or cost effectively to satisfy NTTG's regional transmission needs.

Subsequent economic analyses identified one of the Change Cases as the more-efficient or cost-effective case. Known in the study as Change Case 23, this case includes Boardman to Hemingway, Gateway South, portions of Gateway West, and the Antelope projects.

[1] NTTG's regional transmission planning process is not intended to be a replacement for local transmission or resource planning.

[2] Terms are capitalized to be consistent with Attachment K. All capitalized terms are defined in the glossary.

Stakeholder input on the RTP was accepted and evaluated throughout the biennial planning cycle. NTTG posted the Draft RTP in December 2016 (Quarter 4) for stakeholder comment and the Draft Final RTP in Quarter 6 for public comment. The Planning Committee will vote to recommend submittal of the RTP to the NTTG Steering Committee in Quarter 7. Steering Committee approval of the RTP will be requested in Quarter 8.

## The Northern Tier Transmission Group

The Northern Tier Transmission Group (NTTG) was formed in 2007 to promote effective planning and use of the multi-state electric transmission system within the Northern Tier footprint. NTTG provides a forum where all interested stakeholders, including transmission providers, customers and state regulators, can participate in planning, coordinating and implementing a robust transmission system.

NTTG fulfills requirements of the Federal Energy Regulatory Commission (FERC) Order 1000 for each public utility transmission provider to participate in a regional transmission planning process that produces a regional transmission plan and, if appropriate, includes a regional cost-allocation method.

NTTG evaluates transmission projects that move power across the regional bulk electric transmission system, serving load in its footprint and delivering electricity to external markets. The transmission providers belonging to Northern Tier serve more than 4 million retail

customers with more than 29,000 miles of high-voltage transmission lines. These




Figure 1. Map of western North America showing NTTG members' transmission lines.

members provide service across much of Utah, Wyoming, Montana, Idaho and Oregon, and parts of Washington and California.

NTTG works with other entities—the Western Electricity Coordinating Council (WECC) for reliability planning and neighboring Planning Regions (e.g., ColumbiaGrid, WestConnect and California Independent System Operator (CAISO)) for interregional project coordination.

### Participating Utilities

Deseret Power Electric Cooperative
Idaho Power
Montana Alberta Tie Ltd. (MATL)
NorthWestern Energy
PacifiCorp
Portland General Electric
Utah Associated Municipal Power Systems (UAMPS)

## Purpose of the Plan

The NTTG Regional Transmission Plan (RTP) aims to produce, if possible, a more efficient or cost-effective regional plan to transmit energy compared with a plan that rolls up the local Transmission Providers' transmission plans and other Change Case transmission plans studied. This study process complies with FERC Order No. 1000, Attachment K—Regional Planning Process. This planning cycle marks the first time that NTTG implemented FERC Order 1000 interregional project coordination with the other western regional transmission planning organizations.

## Plan Development Process

The Regional Transmission Plan is developed through a two-year process:

1) Identification of the transmission requirement for the NTTG footprint, derived from the data submissions

2) Reliability analysis and evaluation of the Initial RTP and Alternative Projects (including interregional projects) through Change Cases

3) Economic analysis and evaluation comparing the annualized incremental costs of the Initial RTP and the two most-efficient Change Cases

4) Selection of the project or projects that yield a regional transmission plan that is more efficient or cost-effective than the other regional transmission plans studied

5) Any projects that were submitted for the purposes of cost allocation and selected into the RTP will go through the cost allocation process if they are deemed to be eligible for cost allocation.

## Biennial Cycle

NTTG follows a two-year, eight-quarter planning cycle to produce the 10-year Regional Transmission Plan. In the first step, the Planning and Cost Allocation Committees pre-qualify[3] Transmission Developers who properly submit their transmission project to be considered for regional cost allocation (should the sponsor's project be selected in the Regional Transmission Plan for cost allocation). The biennial cycle includes steps to collect, evaluate and analyze transmission and non-transmission data, produce and publish a draft plan, gather stakeholder and public input, update the plan and complete the cycle with the publishing of a RTP.




**Figure 2. NTTG uses an eight-quarter biennial planning cycle.**

## Biennial Study Plan

The Biennial Study Plan outlines the process that NTTG follows to develop its 10-year RTP. It provides the framework to guide plan development. It also describes NTTG's process to determine if a properly submitted Interregional Transmission Project (ITP) would yield a transmission plan that is a more cost-effective or efficient solution to NTTG's regional transmission needs.

The NTTG Planning Committee manages the study plan. The Planning Committee establishes the Technical Work Group (TWG) subcommittee to develop the study plan. The TWG also performs the necessary technical evaluations for the RTP and assesses any projects, including ITPs, submitted to NTTG. TWG members are NTTG Planning Committee members or their

[3] A project sponsor must have their project pre-qualified before the beginning of the 2016-2017 biennial planning cycle (i.e., the last quarter of the prior planning cycle) pursuant to Attachment K, Section Pre-Qualification for Cost Allocation.

designated technical representatives. They have access to and expertise in power-flow analysis for power systems or production-cost modeling, or both.

Developed during Quarter 2 of the biennial planning cycle, the study plan establishes the:

- Study methodology and criteria
- Study assumptions based on the loads, resources, point-to-point transmission requests, desired flows, constraints and other technical data submitted in Quarter 1 and updated in Quarter 5 of the regional planning cycle
- Software analysis tools
- 2026 production-cost-model database and hours to be selected for reliability analysis
- Evaluation criteria for reliability and transmission service obligations
- Capital cost, energy losses and reserve-sharing metric calculations
- Public policy requirements and considerations

The study plan was posted for stakeholder comment, recommended for approval by the Planning Committee and approved by the Steering Committee during Quarter 2 of the biennial cycle. Due to data submission changes provided in Quarter 5, the study plan was revised in Quarter 6. Any differences between what is stated in the study plan and the process stated in Attachment K of the NTTG FERC Order 1000 defer to Attachment K.

## Study Methodology

To determine the more efficient or cost-effective transmission plan, the TWG subcommittee conducted reliability and economic studies in accordance with the 2016-2017 Study Plan. The Study Plan and ultimately the RTP reflect the Full Funder's Attachment K requirements to satisfy its transmission needs. NTTG's regional transmission planning does not investigate local transmission planning or generation decisions related to integrated resource planning. Rather, NTTG's methodology uses a regional perspective to question the Initial RTP's roll-up of Non-Committed regional transmission project(s) to identify, if possible, a regional transmission plan that is more efficient or cost effective than the aggregated Full Funder's transmission plans. In conducting its regional studies, NTTG uses regional transmission and non-transmission alternatives (if any) to honor the local transmission needs. As part of the study, NTTG assumed that the local existing and new generation additions have (or will have) firm transmission rights to move their power from the generator to load. NTTG's reliability studies did not re-dispatch existing generation down to relieve congestion such that the new generation additions could move their power to load without potentially creating congestion.

The reliability studies used production-cost modeling and power-flow studies. The production-cost and power-flow models represent data for the western interconnection load, resource and transmission topology. In developing the data for these two models, NTTG started with a WECC production cost model (version TEPPC CC1.3) and WECC power-flow model (version 25hs1a) and modified the modeling data in NTTG's footprint for its regional studies. For the studies including one or more interregional transmission project that relied on increased wind

generation within NTTG's footprint (e.g., adding new wind resource in Wyoming), NTTG adjusted generation levels down in the region receiving the power. The goal of the adjustments was to ensure western interconnection load and resource balance. NTTG consulted with the planning region receiving the power (i.e., California ISO) for their generation reductions.

The results of the production-cost modeling were used to identify seven hours of high stress on the transmission system. These seven hours were then subjected to reliability analysis using a power-flow model. The input and output data for these selected hours were transferred from the production-cost model (i.e., GridView) to a power-flow model (i.e., PowerWorld) to perform the technical reliability analysis. By taking these steps, a consistent set of analysis tools can be engaged to evaluate the reliability performance.

Next, economic studies employed the Attachment K's three metrics—capital-related costs, energy losses, and reserves—to analyze Change Case plans that were deemed reliable to further determine the cost effectiveness of the NTTG transmission plan.

### Production-Cost Modeling

The TWG examined 8,760 hours of data using GridView[4] production-cost software to establish stressed conditions within the NTTG footprint. To set the stressed conditions, TWG used and modified a dataset from the Transmission Expansion Planning Policy Committee (TEPPC) of the Western Electricity Coordinating Council (WECC). The TEPPC case included a representation of the load, generation and transmission topology of the WECC interconnection-wide transmission system 10 years into the future.

The study plan identified seven stressed conditions that affect the NTTG area for study. After all hours of data were run through the GridView production-cost program, the results were analyzed and the hours representative of the seven stressed conditions were identified. For a more detailed discussion of the conditions and hours, see the section on stress-conditioned case study results.

### Power-Flow Cases

For the next step in the process, the TWG used PowerWorld[5] simulation software to convert the production-cost model for the seven stressed hours into power-flow cases. Each of the stressed cases was then reviewed by the TWG to ensure that the case met steady-state system performance criteria (no voltage issues or thermal overloads). Bubble diagrams showing the inter-area flows for each of the stressed cases are included in the Draft Final RTP, available on the NTTG website.

[4] GridView is a registered ABB product

[5] PowerWorld is a registered trademark of PowerWorld Corp.

## Data Submission

Information flows in to NTTG during quarters 1 and 5 of the biennial cycle. Transmission Providers and stakeholders may supply data on forecasted firm energy obligations and commitments required to support the transmission system within the NTTG footprint. The data may include load forecasts, resources, transmission topology, transmission service and public policy requirements submissions. Regional transmission projects submitted in Quarter 1 are shown in Table LMJ and include those from the prior Regional Transmission Plan, Full Funder Local Transmission Plans (LTP), Sponsored Projects, unsponsored projects and Merchant Transmission Developer projects. No projects that were eligible for cost allocation were submitted into NTTG's 2016-17 regional planning process.

**JANUARY 2016 DATA SUBMITTAL – TRANSMISSION ADDITIONS BY 2026**

| Sponsor | From | To | Voltage | Circuit | Type | Regionally Significant[6] | Committed | Projects |
|---|---|---|---|---|---|---|---|---|
| Deseret G&T | Bonanza | Upalco | 138 kV | 2 | LTP | No | No | New Line |
| Idaho Power | Hemingway | Boardman/ Longhorn | 500 kV | 1 | LTP & pRTP | Yes | No | B2H Project |
| | Hemingway | Bowmont | 230 kV | 2 | LTP | Yes | No | New Line (associated with Boardman to Hemingway) |
| | Bowmont | Hubbard | 230 kV | 1 | LTP | Yes | No | New Line (associated with Boardman to Hemingway) |
| | Cedar Hill | Hemingway | 500 kV | 1 | LTP | Yes | No | Gateway West Segment #9 (joint with PacifiCorp East) |
| | Cedar Hill | Midpoint | 500 kV | 1 | LTP | Yes | No | Gateway West Segment #10 |
| | Midpoint | Borah | 500 kV | 1 | LTP | Yes | No | (convert existing from 345 kV operation) |
| | King | Wood River | 138 kV | 1 | LTP | No | No | Line Reconductor |
| | Willis | Star | 138 kV | 1 | LTP | No | No | New Line |
| Enbridge | SE Alberta | | DC | 1 | LTP | Yes | No | MATL 600 MW Back to Back DC Converter |
| PacifiCorp East | Aeolus | Clover | 500 kV | 1 | LTP & pRTP | Yes | No | Gateway South Project – Segment #2 |
| | Aeolus | Anticline | 500 kV | 1 | LTP & pRTP | Yes | No | Gateway West Segments 2&3 |
| | Anticline | Jim Bridger | 500 kV | 1 | LTP & pRTP | Yes | No | 345/500 kV Tie |
| | Anticline | Populus | 500 kV | 1 | LTP & pRTP | Yes | No | Gateway West Segment #4 |
| | Populus | Borah | 500 kV | 1 | LTP | Yes | No | Gateway West Segment #5 |
| | Populus | Cedar Hill | 500 kV | 1 | LTP | Yes | No | Gateway West Segment #7 |
| | Antelope | Goshen | 345 kV | 1 | LTP | Yes | No | Nuclear Resource Integration |
| | Antelope | Borah | 345 kV | 1 | LTP | Yes | No | Nuclear Resource Integration |
| | Windstar | Aeolus | 230 kV | 1 | LTP & pRTP | Yes | No | Gateway West Segment #1W |
| | Oquirrh | Terminal | 345 kV | 2 | LTP | Yes | Yes | Gateway Central |

[6] Regionally significant transmission projects are generally those that effect transfer capability between areas of NTTG. Projects that are mainly for local load service are not regionally significant. Projects that are not regionally significant will be placed into all change cases and not tested for impact on the Regional Transmission Plan. The future facilities submitted in the LTP's will be removed in the Null Case

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Cedar Hill | Hemingway | 500 kV | 1 | LTP | Yes | No | Gateway West Segment #9 (joint with Idaho Power) |
| **PacifiCorp West** | Wallula | McNary | 230 kV | 1 | LTP | Yes | Yes | Gateway West Segment A |
| **Portland General** | Blue Lake | Gresham | 230 kV | 1 | LTP | No | No | New Line |
| | Blue Lake | Troutdale | 230 kV | 1 | LTP | No | No | Rebuild |
| | Blue Lake | Troutdale | 230 kV | 2 | LTP | No | No | New Line |
| | Horizon | Springville Jct | 230 kV | 1 | LTP | No | No | New Line (Trojan-St Marys-Horizon) |
| | Horizon | Harborton | 230 kV | 1 | LTP | No | No | New Line (re-terminates Horizon Line) |
| | Trojan | Harborton | 230 kV | 1 | LTP | No | No | Re-termination to Harborton |
| | St Marys | Harborton | 230 kV | 1 | LTP | No | No | Re-termination to Harborton |
| | Rivergate | Harborton | 230 kV | 1 | LTP | No | No | Re-termination to Harborton |
| | Trojan | Harborton | 230 kV | 2 | LTP | No | No | Re-termination to Harborton |

**Table LMJ**

## Forecasted Loads

Participating load-serving entities provide forecasts of loads for balancing authority areas internal to the NTTG footprint. These loads are generally the same as those found in the participants' official load forecasts (such as those in integrated resource plans) and are similar to those provided to the Load and Resource Subcommittee of the WECC Planning Coordination Committee. Chart CCC summarizes the load forecast used in the 2016-2017 planning cycle.

[Chart CCC: 2026 forecasted loads: bar graph to be created from Table 1, below, January 2016-2017 Data Submittal – Load Comparison, on page 8 of DFRTP, v2.6.]

| SUBMITTED BY: | 2015 Actual Peak Demand (MW) | 2024 Summer Load Data Submitted in 2014-15 (MW) | 2026 Summer Load Data Submitted in Q1 2016 (MW) | 2026 Summer Load Data Submitted in Q5 2017 (MW) | Difference (MW) 2024-2026 |
|---|---|---|---|---|---|
| **Idaho Power** | 3,730 | 4,193 | 4,346 | 4,340 | 147 |
| **NorthWestern** | 1,790 | 1,774 | 1,992 | 1,992 | 218 |
| **PacifiCorp** | 12,634 | 14,002 | 13,414 | 13,414 | -588 |
| **Portland General** | 3,958 | 3,933 | 3,885 | 3,874 | -59 |
| **TOTAL*** | 22,112 | 23,902 | 23,637 | 23,620 | -282 |
| * | * Loads for Deseret G&T and UAMPS are included in PacifiCorp East | | | | |

NTTG received 3,200 MW of proposed new generation resources from its funding Transmission Providers for consideration in the RTP. Figure 3 displays these incremental resources within the

NTTG footprint and compares submissions from the prior RTP with submissions for quarters 1 and 5 of the current cycle.

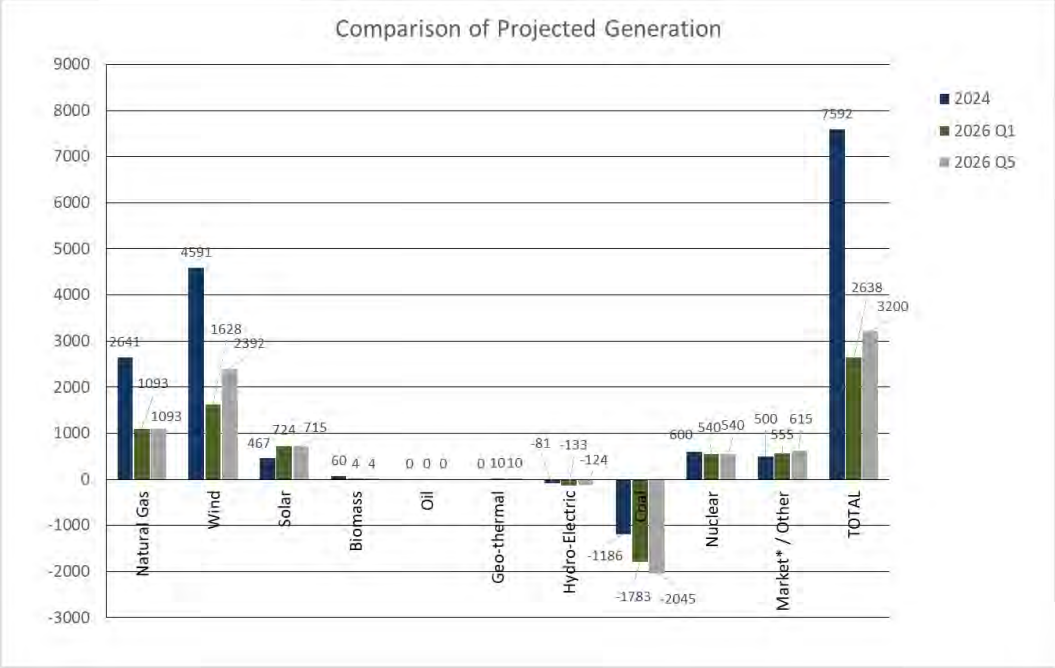



**Figure 3. Comparison of forecasted resources**

In Quarter 5, Northwestern submitted 550 MW of new Montana wind generation. Also PacifiCorp indicated that its recently submitted integrated resource plan increased the amount of Wyoming wind power from 887 MW to 1,100 MW. As shown in Figure 3, the total resource forecast of 3,200 MW submitted this cycle was reduced by 392 MW, or 12.25 percent, from the 3,592 MW forecast in 2024. Following the Quarter 1 data submittal, the owners of the Colstrip 1 and 2 coal-fired plants announced a plan to retire the units before 2026. The owners of the Valmy 1 and 2 coal plants in Nevada also plan to decommission the plants by 2025, a decade earlier than originally planned. Both sets of retirements were assumed in the 2016-2017 studies and are reflected in Quarter 5 values shown in Figure 3.

In the 2014-15 study cycle, Power Company of Wyoming (PCW) submitted 3,000 MW of wind resources associated with the TransWest Express project. PCW asked that those resources not be included in the NTTG 2014-15 Regional Plan. Those resources, to serve loads outside the NTTG footprint in California, have been submitted with an Interregional Transmission Project in the 2016-17 study cycle.

In support of the proposed transmission additions or upgrades, NTTG received four firm transmission-service-obligation submissions (contractual requirements to provide service)—two each from Idaho Power and PacifiCorp. These are shown in the following map. [Reference Report 2.6 Table 4. Map will need to be created. Use the map from page 9 of the 2014-15 RTP

as a guide. Two vectors West to East across ID-Northwest to Boise area and to Idaho Falls area, another vector North to South from Arco to Utah, and a fourth vector east to west from Wyoming.]

| Submitted by | MW | Start Date | POR | POD |
|---|---|---|---|---|
| Idaho Power | 500/200 | 2021 | Northwest | IPCo |
| | 250/550 | 2022 | LGBP | BPASEID |
| PacifiCorp East | 540 | 2024 | Antelope | Network |
| | 1100 | 2026 | Miners / Point of Rocks | Network |

**Table 4 – Transmission Service Obligations**

## Public Policy Consideration Scenario Requests

In Quarter 1, Renewable Northwest (RNW) and the Northwest Energy Coalition (NWEC) jointly submitted a Public Policy Consideration request for a scenario analysis study. The group asked NTTG to study a faster phase-out of coal plants while developing utility-scale renewable resources and replacing Colstrip units 1, 2 and 3 with either wind only or a combination of wind and natural gas combustion.

Members of the TWG and representatives from RNW and NWEC reviewed the request and agreed to some modifications. These modifications, and the associated study assumptions, are documented in the NTTG 2016-2017 Study Plan, Attachment 3 of the Draft Final RTP.

The study results suggested that a replacement of wind or a combination of wind and gas for coal may be feasible. This study, however, neither constituted a path study nor conveyed or implied transmission rights. Additional analysis would be required to understand the full impacts of coal plant decommissioning.

Public Policy Considerations are considered to be relevant factors not established by local, state or federal laws or regulations. The results of PPC analysis may inform the RTP but do not result in the inclusion of additional projects in the RTP.

A full report of the study can be found in Appendix D of the NTTG 2016-2017 Draft Final RTP.

## Regional Economic Study Requests

NTTG received no regional economic study requests.

## Initial Regional Transmission Plan Development

The starting point for the biennial planning process was development of the Initial RTP. This exercise used a bottom-up approach to merge the projects in the prior RTP (2014-2015) and

the Full Funding Transmission Providers' local transmission plans into a single regional transmission plan. Next, the TWG analyzed the Initial RTP through Change Case plans, which included or excluded Non-Committed regional projects and Interregional Transmission Projects. These Change Case plans helped to determine whether Alternative Projects could be added or substituted, or if one or more Non-Committed Projects could be deferred, or both, to yield a regional transmission plan more efficient or cost effective than the Initial RTP. The results of this analysis led to the formation of the Draft RTP.

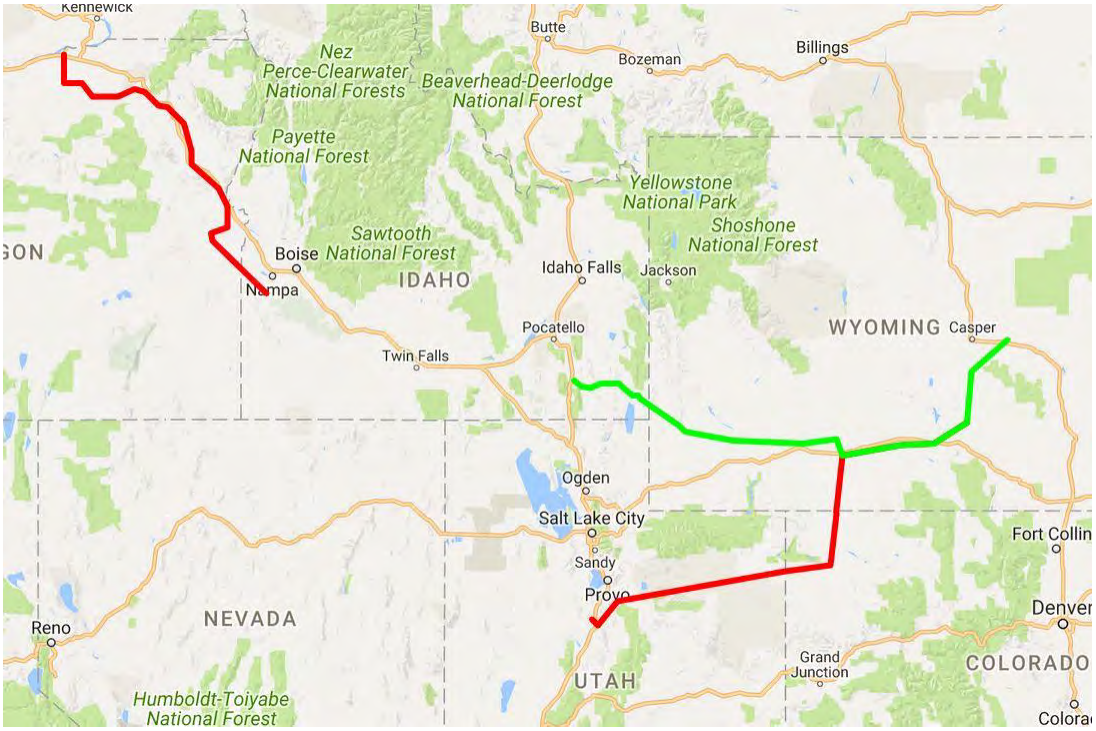



**Figure 4. The red and green lines represent the projects comprising the prior RTP from 2014-2016. These include Boardman to Hemingway, in the northwest sector of the above map, and an Alternative Project with four transmission elements across four states.**

The following Non-Committed regional projects comprised the Initial RTP:

- Boardman to Hemingway (Longhorn-Hemingway) 500 kV (red)
- Gateway West
    - Windstar-Aeolus 230 kV (green)
    - Aeolus-Anticline (Jim Bridger) 500 kV (green)
    - Anticline-Populus 500 kV (green)
    - Populus-Borah 500 kV (blue)
    - Populus- Cedar Hill 500 kV (green)
    - Cedar Hill-Hemingway 500 kV (green)
    - Cedar Hill- Midpoint 500 kV (green)
    - Borah-Midpoint 345 to 500 kV conversion (dark green)

- Midpoint-Hemingway #2 500 kV (blue)

- Gateway South
  - Aeolus-Clover 500 kV (red)
- Antelope
  - Goshen-Antelope 345 kV (red)
  - Antelope-Borah 345 kV (red)

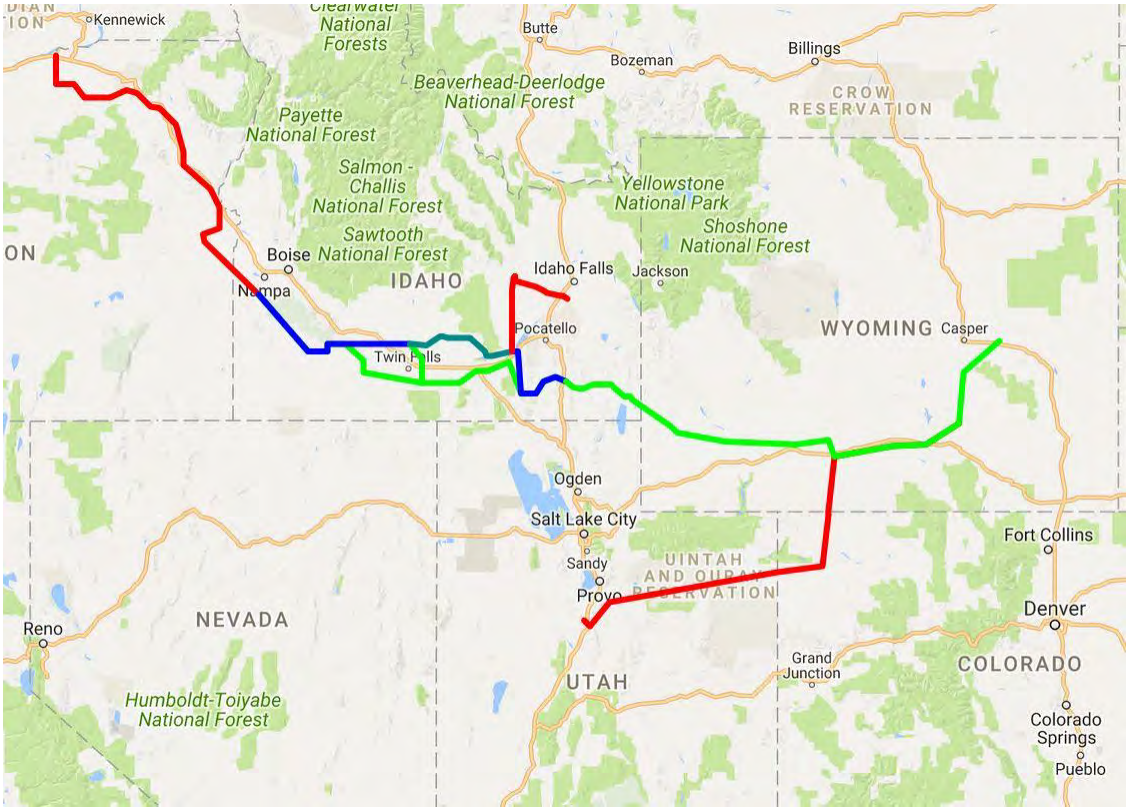



**Figure 5. Map showing Non-Committed regional projects comprising the 2016-2017 Initial RTP.**

## Interregional Project Coordination

As part of interregional coordination, NTTG and the other regional entities in the Western Interconnection collaborate during their transmission planning processes to coordinate their interregional transmission planning data. These coordination efforts inform each planning region's transmission plans. A properly submitted Interregional Transmission Project is evaluated as an Alternative Project in NTTG's regional planning process. The set of uncommitted projects (regional, interregional or both) that results in the more efficient or cost-effective regional transmission plan forms the basis of NTTG's Regional Transmission Plan.

| SUMMARY OF Q1-2016 INTERREGIONAL PROJECTS SUBMITTED TO NTTG | | | | | | |
|---|---|---|---|---|---|---|
| Project Name | Company | Relevant Planning Region(s) | Termination From | Termination to | Status | In Service Date |
| Cross-Tie Transmission Project | TransCanyon, LLC | NTTG, WC | Clover, UT | Robinson Summit, NV | Conceptual | 2024 |
| SWIP-North | Great Basin Transmission LLC | NTTG, WC | Midpoint, ID | Robinson Summit, NV | Permitted | 2021 |
| TransWest Express Transmission Project | TransWest Express, LLC | NTTG, WC and CAISO | Sinclair, WY | Boulder City, NV | Conceptual | 2020 |

Table X. Three Interregional Transmission Projects were submitted for consideration during formation of the Initial RTP in Quarter 1 of the biennial cycle.

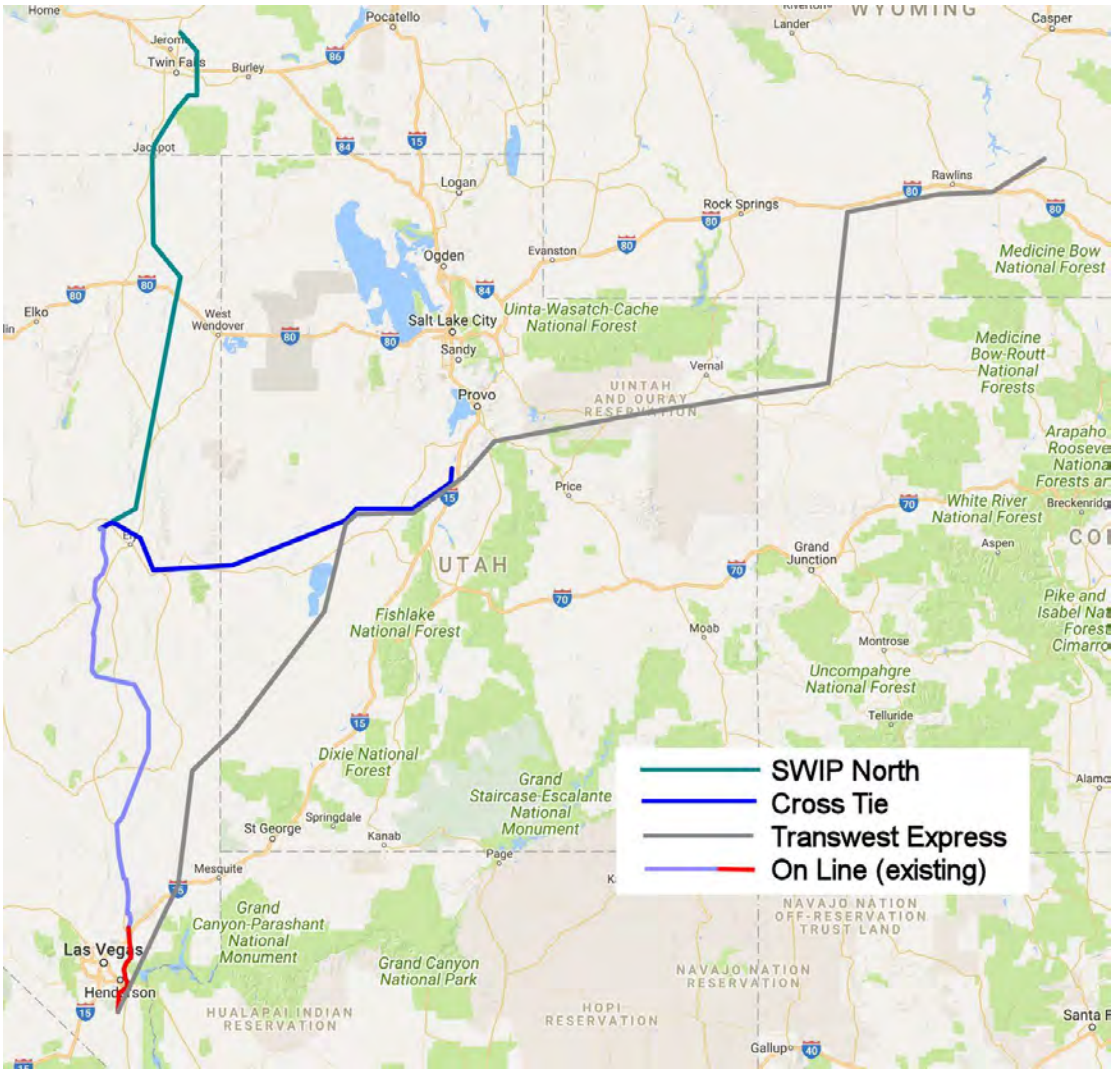



Figure 6. Three Interregional Transmission Projects were evaluated during the planning cycle.

**Southwest Intertie Project (SWIP).** Great Basin Transmission, LLC (GBT), an affiliate of LS Power, submitted the 275-mile northern portion of the Southwest Intertie Project (SWIP) as an ITP. SWIP-North would connect the Midpoint 500-kV substation in NTTG's planning area to the Robinson Summit 500-kV substation in the WestConnect area with a 500-kV single-circuit AC transmission line. The SWIP is expected to have a bi-directional WECC-approved path rating of approximately 2,000 MW. If GBT is selected to build SWIP-North, development, final design and construction activities could be completed to support energizing the project within an estimated 36-42 months.

**Cross-Tie Transmission Line.** TransCanyon submitted the 213-mile Cross-Tie Transmission Line for consideration as an ITP. TransCanyon proposes to build a 1500-MW, 500-kV high-voltage alternating current (HVAC) line between central Utah and east-central Nevada. The line would connect PacifiCorp's proposed 500-kV Clover substation with the existing 500-kV Robinson Summit substation. TransCanyon expects the project to be in-service by the end of 2024.

**TransWest Express Transmission Project.** TransWest proposed a 730-mile, phased 1,500/3,000 MW, ±600 kV, high-voltage direct current (HVDC) transmission system with terminals in south-central Wyoming and southeastern Nevada. The federal Bureau of Land Management and Western Area Power Administration published the Final Environmental Impact Statement (FEIS) for the TWE Project in May 2015.

## Stress-conditioned Case Study Results

### Stressed Hours for Study with Production-Cost Modeling

The TWG used GridView production-cost software to review 8,760 hours of data to identify stressed conditions within the NTTG footprint. A case representing the year 2026 was obtained from the WECC TEPPC. This case included a representation of the load, generation and transmission topology of the WECC interconnection-wide transmission system 10 years in the future. The TWG identified corrections to the data needed to align with data submitted in the first quarter of the biennial planning cycle. TWG shared these changes with the other regional planning entities and WECC to include in their future studies. The TWG then agreed to use this modified TEPPC case in creating the stressed cases discussed below.

After processing all 8,760 hours through the production-cost program, the TWG analyzed the data and identified seven stressed conditions to study:

- High NTTG summer peak
- High NTTG winter peak
- High Montana-Northwest (Path 8) flows
- High southern Idaho import (Idaho-Northwest Eastbound)
- High southern Idaho-Northwest export (Idaho-Northwest westbound)
- High NE-SE (Path Tot2) flows
- Other conditions the might warrant transmission system reinforcement

| Stressed Condition | Date | Hour | TWG Label |
|---|---|---|---|
| **Max. NTTG Summer Peak** | July 22, 2026 | 16:00 | A |
| **Max. NTTG Winter Peak** | December 8, 2026 | 19:00 | B |
| **Max. MT to NW** | September 10, 2026 | Midnight | C |
| **High Southern Idaho Import** | June 11,2026 | 14:00 | D1 |
| **High Southern Idaho Export** | September 17, 2026 | 2:00 | D2 |
| **High Tot2 Flows** | November 11, 2026 | 17:00 | E |
| **High Wyoming Wind** | September 17, 2026 | 2:00 | F |

**Table XYZ – Hours Selected from 2026 WECC TEPPC Case to Represent Different NTTG System Stresses**

High Summer Peak (NTTG Case A)

- 24,100 MW load
- 17,851 MW resources
- -6,250 import
- 4 p.m., July 22, 2026

This case showed a need to import energy during high summer air-conditioning loads. The transmission projects in the Initial RTP performed reasonably well; however, system performance proved inadequate without transmission system additions by 2026 to meet NTTG's summer peak load. This case accounted for wind resources of 2,175 MW to check the performance of the set of projects comprising the Draft RTP.

High Winter Peak (NTTG Case B)

- 22,468 MW load
- 19,261 MW resources
- -3,208 MW import
- 7 p.m., Dec. 8, 2026

A few local system violations occurred when tested against the transmission projects comprising the Initial RTP. This case puts\ less stress on the NTTG system than did the summer peak. This case also accounted for wind resources of 2,175 MW to check the performance of the Draft RTP projects.

High Montana-NW (Path 8) Flows (NTTG Case C)

- 13,097 MW load
- 12,138 MW resources

- -959 MW import
- 12:00 midnight, Sept. 10, 2026

This case tested transmission system capabilities with high electricity flows from Montana to the Northwest. This scenario was used for the public policy consideration study, which analyzed the impact of an accelerated phase-out of Colstrip units 1, 2 and 3 with either wind only or a combination of wind and gas. See the Public Policy Consideration Scenario Requests section for results of the study.

High Southern Idaho Import (NTTG Case D1)

- 16,382 MW load
- 9,159 MW resources
- -7,223 MW import
- 2 p.m., June 11, 2026

Under conditions with the eastbound path from the Northwest to Idaho operating at a 2,244 MW deficit, and the NTTG system importing 7,223 MW, the NTTG transmission topology could not import enough power to support load service obligations in southern Idaho. With the addition of transmission projects comprising the Initial RTP, however, the NTTG system would perform well, with a few local violations.

High Southern Idaho Export ( NTTG Case D2)

- 11,935 MW load
- 14,683 MW resources
- 2,748 MW export
- 2 a.m., Sept 17, 2026

In this export scenario, with the Idaho to Northwest Path 8 flow at 3,391 MW, the existing NTTG system would be incapable of supporting expected transfers and meeting transmission requirements in 2026. Adding in the projects from the Initial RTP, the system performed well, with one contingency that caused a series cap bank to overload. That bank, however, has reached the end of its useful life and is likely to be replaced before 2026.

High NE-SE (Path Tot2) flows (NTTG Case E)

- 16,625 MW load
- 16,620 MW resources
- 5 MW export
- 5 p.m., Nov. 11, 2026

This case evaluated the performance of the Interregional Transmission Projects in supporting transfers between regions. These additional interregional transfers were not identified in Q1 to meet or defer NTTG's 2026 footprint resource requirements. The case showed near balance in the NTTG footprint between loads and resources, with a small 5 MW import, along with a Tot2

flow of 1,566 MW. This case accounted for wind resources of 2,175 MW to check the performance of the Draft RTP.

High Wyoming wind production (NTTG Case F)

- 11,935 MW load
- 15,015 MW resources
- 3,081 MW export
- 2 a.m., Sept. 17, 2026

This case, as others, was studied at the 2,175-MW wind level, which includes the addition of 1,100 MW of wind capacity. The added wind generation in the Wyoming area worsened reliability issues observed in Wyoming and confirmed the need for additional transmission to use these resources to their fullest extent. The RTP addresses these reliability concerns and relieves the transmission constraints.

## Development of Change Cases

For each of the seven stress-conditioned cases, the TWG prepared a Null Change Case and analyzed reliability results. The Null case represents roughly today's transmission topology made to serve loads and resource requirements in 2026. Only the Heavy Winter case performed acceptably. All the other conditions revealed performance issues that required varying degrees of correction, with the heavy summer case needing the least correction and the high Wyoming wind case needing the most. In instances where the transmission system was not adequately stressed to historical norms, the TWG slightly modified system conditions to ensure that the transmission system was studied under reasonably stressed conditions.

## Change Case Results

To efficiently study the wide range of potential combinations of Non-Committed Projects, the TWG proposed a Change Case matrix in the study plan. Once the stressed power-flow cases had been selected and developed, the TWG modified the matrix to better reflect the recommended analysis. The TWG provided stakeholders with the opportunity for input on whether a particular combination of uncommitted regional or interregional projects should be analyzed. No comments were received. The matrix was subsequently vetted through the Planning Committee and the Steering Committee.

Table XX, below, is the Change Case matrix used by the TWG.

| Case | B2H* | Gateway S* | Gateway W* | Antelope Projects | SWIP N | Cross-Tie | TWE | Case(s): |
|---|---|---|---|---|---|---|---|---|
| null | | | | | | | | A B D1 D2 F |
| pRTP | X | X | D | | | | | A B D1 D2 F |
| iRTP | X | X | X | X | | | | A B D1 D2 E F |
| CC1 | X | | | | | | | A B D1 D2 F |
| CC2 | | X | | X | | | | A D2 E F |
| CC3 | | X | X | | | | | A D1 D2 E F |
| CC4 | X | | X | X | | | | A D1 D2 E F |
| CC5 | | | | | | | X | A B D1 D2 F |
| CC6 | | | | | | X | | A B D1 D2 F |
| CC7 | | | | | X | | | A B D1 D2 F |
| CC8 | | | | | | | X | E+RPS |
| CC9 | | X | | | | | X | E+RPS |
| CC20 | | X | X | | | | X | E+RPS |
| CC10 | | | | | | X | | E+RPS |
| CC11 | | X | | | | X | | E+RPS |
| CC18 | | X | X | | | X | | E+RPS |
| CC12 | | | | | X | | | E+RPS |
| CC13 | | | X | | X | | | E+RPS |
| CC19 | | X | X | | X | | | E+RPS |
| CC14 | | X | X | | X | X | | E+RPS |
| CC15 | | | X | | X | | X | E+RPS |
| CC16 | | X | | | | X | X | E+RPS |
| CC17 | | X | X | | X | X | X | E+RPS |
| CC21 | X | X | A | X | | | | D2 F |
| CC22 | X | X | B | X | | | | D2 F |
| CC23 | X | X | C | X | | | | F |

* B2H and Alternate P in the pRTP are similar to B2H, Gateway S and Gateway W in the 2016-17 Q1 data submittals

| | |
|---|---|
| | The change case does not include the non-Committed Project |
| X | The change case includes the non-Committed Project |
| A | Gateway West without Midpoint-Hemingway #2 and Cedar Hill-Midpoint |
| B | Gateway West without Borah-Midpoint Uprate and Populus-Borah |
| C | Gateway West without Midpoint-Hemingway #2, Cedar Hill-Midpoint and Populus-Borah |
| D | Gateway West without Midpoint-Hemingway #2, Cedar Hill-Midpoint, Populus-Cedar Hill-Hemingway, Populus-Borah and Midpoint-Borah Uprate |
| | The change case was run with and without B2H |

**Figure 7. Change Case matrix used in the development of the RTP.**

In all, the TWG performed more than 100 reliability studies on more than 410 contingencies. To better communicate the results of these studies, the TWG created heat maps, which present a

weighted[7] graphical performance of a Change Case on a specific flow condition. A full heat map analysis of the Change Cases is included in the final Draft RTP.

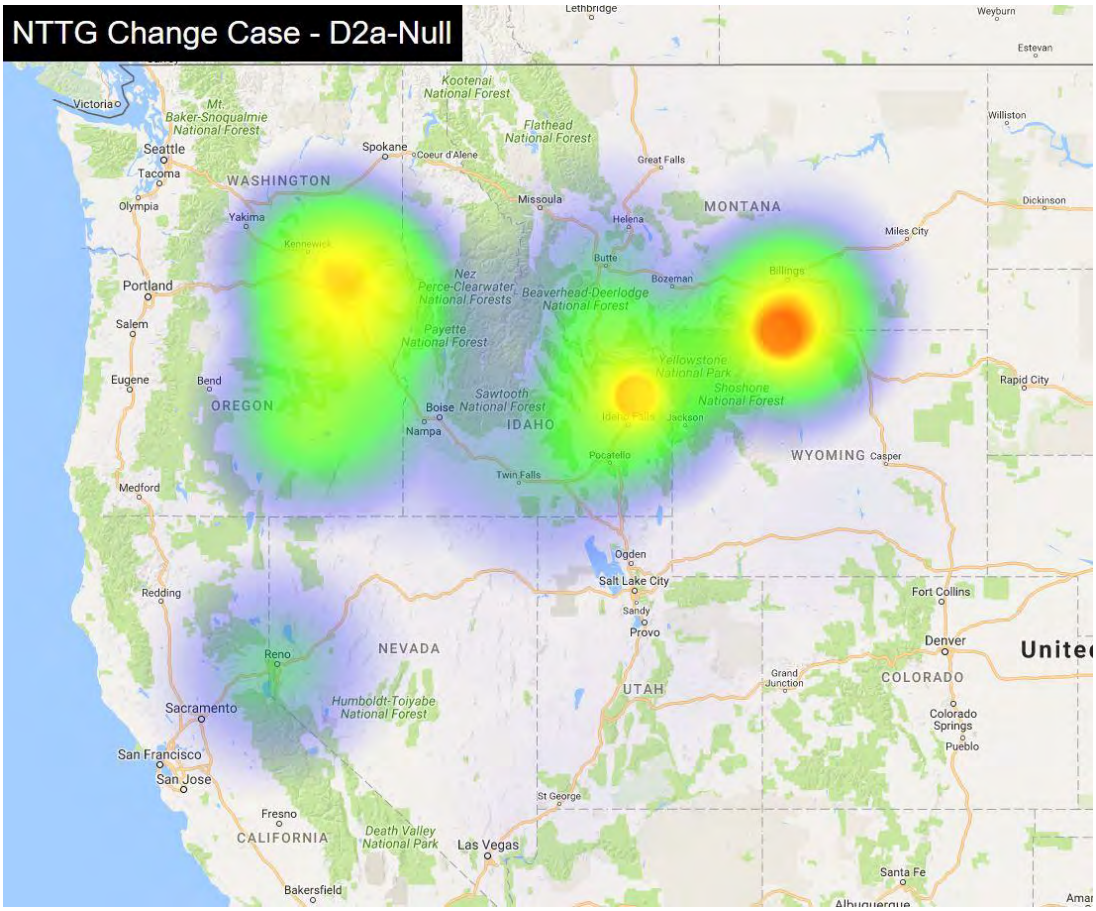



**Figure 8. Heat map of the D2-Null Case**

Figure 8, for example, shows the general location where performance issues (e.g., an overloaded transmission line) occurred for a contingency. The accumulation of overloads and voltage issues are represented by the color spectrum from blue to red, or "cooler" to "hotter." These violations occur when transmission systems cannot handle anticipated transfers across that area's transmission lines. In particular, this heat map, using existing Wyoming wind resources dispatched at about 600 MW, indicates that transmission additions are necessary to integrate the projected wind resources.

[7] High voltage conditions had a weighting of 1; Low voltage conditions had a weighting of 3; and overloads of branches had a weighting of 5. For example, a zone in which 10 contingencies caused an overload of one branch in that zone would receive a total weight of 50 (i.e., 10 x 5), which would then be translated into a color on the map. A blue color represents a weighted total of about 10, green is a count up to 30, yellow is a count up to 50 and red is for a weighted count exceeding about 70.

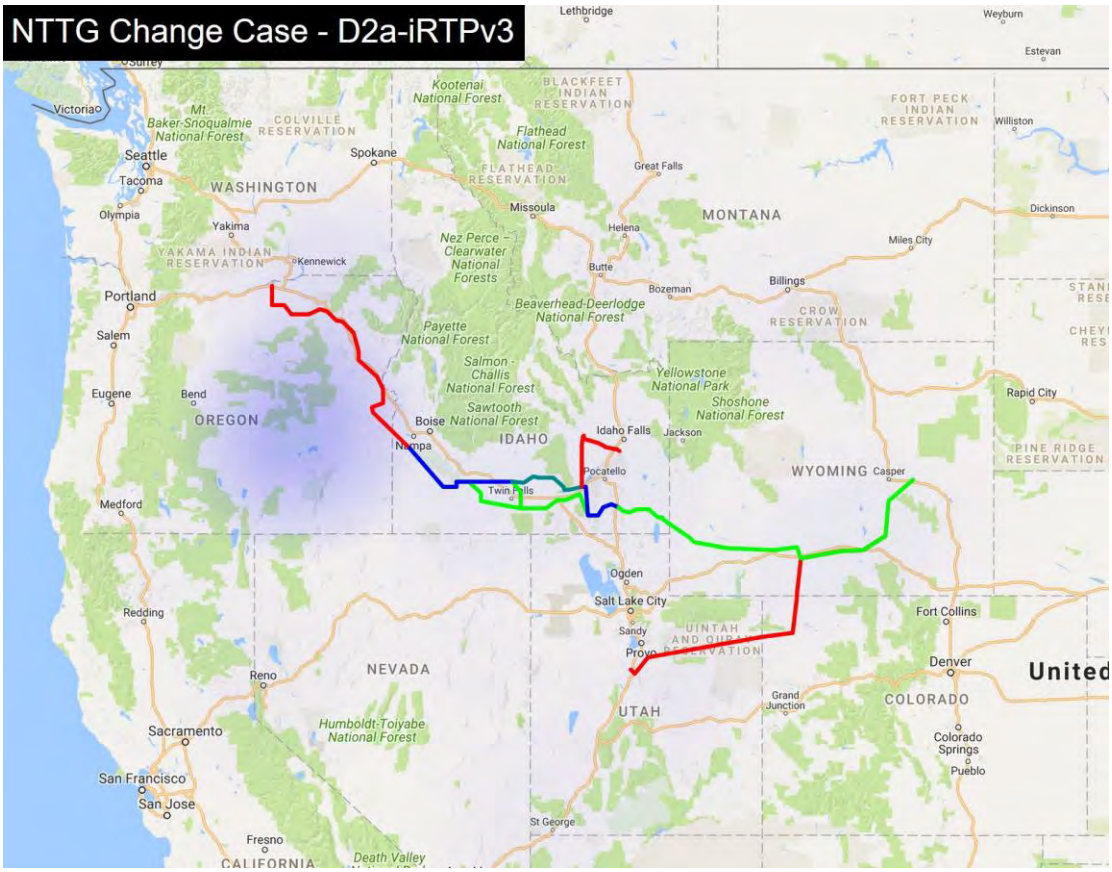



Figure 9. Heat map of the High Southern Idaho export case with the Initial RTP facilities included

The heat map in Figure 9 shows how the addition of the Initial RTP projects produced a dramatic improvement of transmission performance when compared with the Null Case.

### High Southern Idaho Import Case

Combining the Boardman to Hemingway project with the Gateway West and Gateway South Non-Committed Projects eliminated violations in flow conditions visible in the Null Case. Change Case 3 tested whether Gateway West or Gateway South, or both, could replace or compare with the Boardman-to-Hemingway line. They couldn't. The projects contained in the prior RTP also failed to alleviate the violations.

### High Southern Idaho Export Case

Adding the Boardman-to-Hemingway project relieved stress across the Idaho-Northwest cutplane, but significant issues remained east of Hemingway. Adding the eastern portion of Gateway West and Gateway South outlined in the prior RTP eliminated the performance issues in Wyoming and between Idaho and Montana, but those additions increased the stress across southern Idaho. The Initial RTP and Change Cases 21 and 23 resolved these issues.

### High Wyoming Wind Case

Without significant reinforcements, the transmission system in Wyoming could not handle both existing and future planned wind resources while maintaining all other Wyoming area generating resources at their typical high capability in an export scenario.

With wind production at the 1,300-MW level in the Null Case (no new transmission supporting 2026 loads), the system performed poorly. Nor did the projects in the prior RTP solve problems. Adding the Initial RTP projects resolved all violations except for a series capacitor bank. That bank has reached the end of its useful life, however, and is due for replacement.

In Quarter 6, the case was tested to see if Change Cases 1 through 4 would support the increased level of Wyoming wind. The Null Case (no new transmission) was unable to be solved with wind above 1,800 MW. Testing Change Case 4 required adding the Aeolus-Anticline 500-kV line to eliminate a number of contingencies that failed to solve in Wyoming. Change Case 23, which is essentially Change Case 4a with Gateway South added, performed well with Wyoming wind modeled at 2,175 MW.

### Interregional Transmission Projects

Change Cases 5 through 20 tested whether the three Interregional Transmission Projects (ITP)—alone, in combination with other ITPs or in combination with the Non-Committed Projects—could satisfy NTTG's transmission needs on a regional or interregional basis more efficiently or cost effectively than through local planning processes. The ITPs were added to the null cases without any additional resources to serve NTTG load beyond those resources identified in the Quarter 1 and Quarter 5 data submittals. The ITPs did not provide the NTTG footprint with regional benefits, the testing showed, either by significantly reducing performance issues or by displacing NTTG Non-Committed Projects.

The Initial RTP also was analyzed to determine whether it would be capable of supporting the interregional resource transfers proposed by the ITPs. Given the relatively long distances of the ITPs, the local integration performance issues identified in Wyoming were solvable.

## Reliability Conclusions

Based on the above study results, the TWG concluded that both Change Cases 21 and 23 and the Initial RTP satisfy NTTG reliability criteria. In Quarter 5, the TWG tested Change Case 23 and the wind resource additions at various load and flow levels on the Heavy Summer, Heavy Winter, High Tot2 and High Wyoming wind cases. The TWG study found the NTTG area would be reliably served in the year 2026 only by including the following Non-Committed regional projects:

- Boardman to Longhorn (formerly Hemingway)
- The Energy Gateway projects including segments:
    - Windstar-Aeolus 230 kV
    - Aeolus-Clover 500 kV
    - Aeolus-Anticline 500 kV
    - Anticline-Populus 500 kV
    - Populus-Cedar Hill-Hemingway 500 kV

- Antelope Transmission Project including:
  - Antelope – Borah 345 kV
  - Antelope – Goshen 345 kV
  - Antelope 345/230 kV transformers and interconnection facilities

The ITPs were evaluated to determine whether one or more of them could defer or replace NTTG's Non-Committed Projects. The TWG concluded that none of the ITPs solved NTTG's reliability performance issues and, thus, were included in the final NTTG RTP.

## Economic Evaluations

To determine whether the Initial RTP or a Change Case transmission plan was more cost effective, the TWG used three economic metrics, as determined in the Biennial Study Plan. The three metrics—capital-related costs, power flow losses and reserves—and results are discussed below.

### Capital-related Cost Metric

Development of the capital-related cost metric required three steps. The first step validated the capital cost of the Project Sponsor's Q1 submitted project. The second step used those results to estimate the annual capital-related costs. The third step levelized the net present value annual capital-related costs for the Initial RTP and the Change Case plans.

### Energy-loss Metric

The energy-loss metric captures the change in energy generated, based on system topology, to serve a given amount of load. A reduction in losses for a Change Case would represent a benefit, since less energy would be required to serve the same load. The two Change Cases with fewer Gateway West transmission segments—Change Cases 21 and 23—had losses higher than, or in some cases equal to, the Initial RTP. Losses were higher in the two Change Cases because the electrical flows in the Initial RTP were redistributed to fewer lines. From a loss perspective alone, the Initial RTP case had fewer losses and as such was the more efficient case.

### Reserve Metric

The reserve metric evaluates the opportunities for two or more parties to save money by sharing a generating resource that would be enabled by transmission. The metric is a 10-year look at the increased load and generation additions in the NTTG footprint and the incremental transmission additions that may be included in the Draft RTP.

In the study cycle, the TWG analyzed Gateway West, Gateway South, Boardman to Hemingway, SWIP North and the Cross-Tie projects. To evaluate these projects, the NTTG footprint was segmented into five zones, and a sixth external zone was included to study the SWIP North and the Cross-Tie projects. The six zones produced 122 viable sharing combinations. Of those, the analysis of the annual net savings over each theoretical participant's standalone alternative suggested that only 34 viable combinations were economic.

Note that this metric includes generation capital costs in its evaluation and, as such, may only be appropriate for cost allocation purposes. It should not drive the selection of a Draft RTP. Whether these cost savings warrant jointly sharing the costs of reserve capacity is up to the parties to decide.

For the NTTG metric analysis, the Initial RTP and the two alternative Change Cases each supported viable economic combinations. Since these Change Cases could contain the same benefit value, the Change in Reserve metric did not factor into the Draft RTP selection decision.

### Economic Metric Analysis Conclusion

The sum of the annual capital-related cost metric, loss metric (monetized) and reserve metric (monetized) yielded an incremental cost for the Initial RTP and the Change Case plans. The set of projects with the lowest incremental cost, after adjustment by the plan's effects on neighboring regions—Change Case 23 (see Figure 10, below)—was then incorporated into the Draft RTP. Note that the incremental cost was computed as the levelized annual capital-related cost, minus NTTG loss benefit, minus monetized reserve benefit.




**Figure 10. Change Case 23, comprising Boardman to Hemingway, Gateway South, portions of Gateway West, and the Antelope projects, produced the lowest incremental cost.**

## Planning Process Flow Map (Coming)

## Final Regional Transmission Plan

Based on the study assumptions and reliability and economic conclusions discussed above, the more efficient or cost-effective plan is Change Case 23. Change Case 23 is a staged variant of the Initial RTP. For the transfers submitted in Quarter 1 and Quarter 5, the facility segments shown in Figure 11, below, were not necessary for the transfers studied in the Change Cases. These segments would likely be necessary at higher transfer levels.

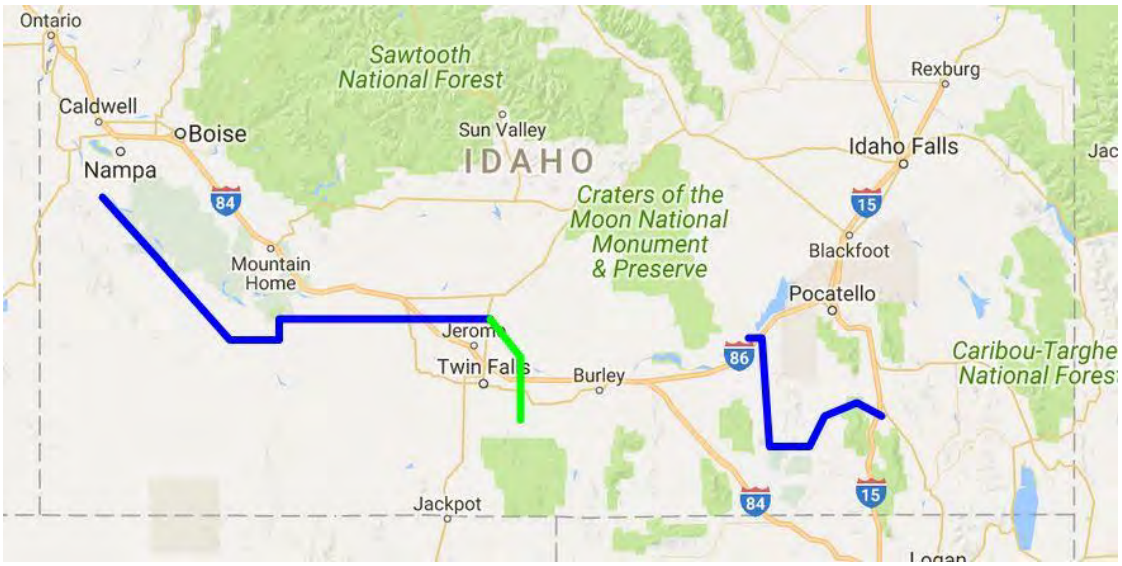



**Figure 11. These transmission line segments from the Initial RTP were not included in the final RTP.**

NTTG's final Draft RTP emerged after a rigorous reliability analysis of the NTTG Transmission Providers' rollup of their local area plans and assumption of Non-Committed regional transmission projects, augmented with stakeholder Interregional Transmission Projects. This technical analysis was followed by an economic metric analysis that selected NTTG's more efficient and cost-effective regional transmission plan, shown below in Figure 12.

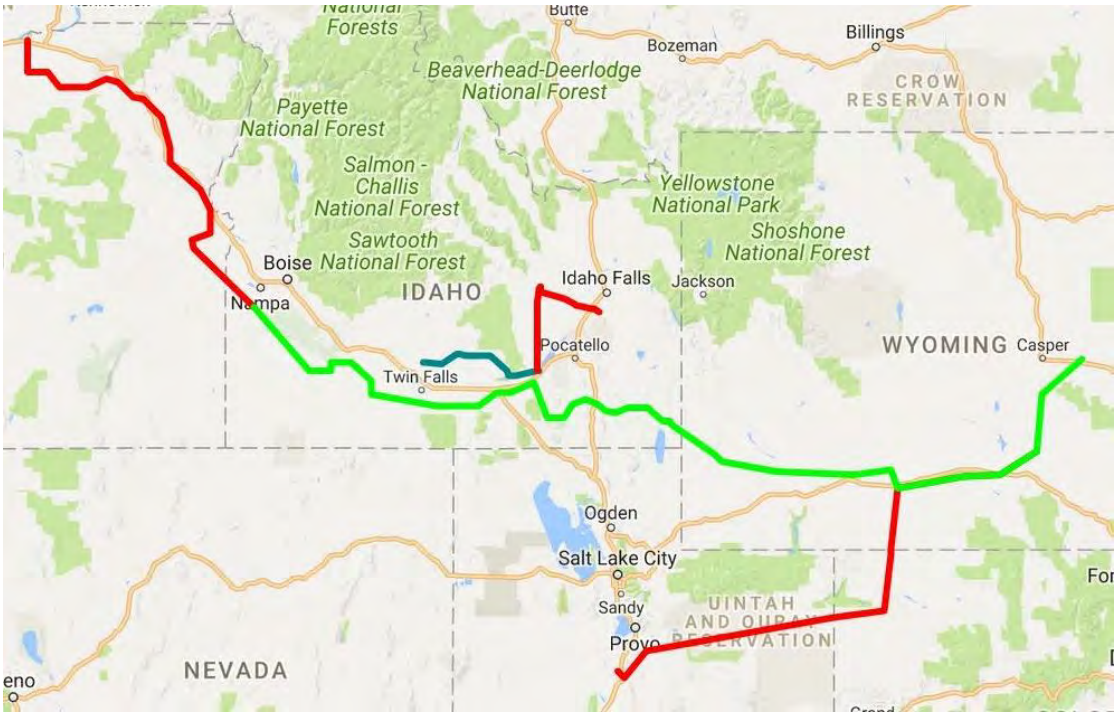



**Figure 12. These projects comprise NTTG's final RTP. See the legend for the identity of individual projects.**

Legend for Fig. 12

Red in upper left: Boardman to Hemingway

Green: Gateway West

Red at bottom: Gateway South Gate

Dark green in middle: Gateway West—upgrade of existing line from 345 kv to 500 kv

Red at center: Antelope projects

## Cost Allocation

The SWIP-North project sponsors were the only project sponsors to request cost allocation; however, they failed to comply with the requirement to submit pre-qualification data by Oct. 31, 2015. As a result, no projects that were eligible for cost allocation were submitted into NTTG's 2016-17 regional planning process.

## Next Steps

Publication of the NTTG Regional Transmission Plan completes the two-year planning process begun in January 2016. The 2016-2017 NTTG RTP identified a need for new transmission capacity to serve forecasted load in 10 years. The plan also identified a set of transmission

projects known in this report as Change Case 23 as the more efficient or cost-effective transmission plan to meet that need. While the RTP is not a construction plan, it provides valuable regional insight and information for all stakeholders (including developers) to consider and use in their respective decision-making processes.

The next biennial regional transmission planning cycle for NTTG started October 1, 2017 and will culminate with the publication of the 2018-2019 RTP in December 2019.

## NTTG 2016-2017 Regional Transmission Plan Supporting Materials

The supporting materials referenced in this report have been posted on the NTTG website and can be found using the following link:

https://www.nttg.biz/site/index.php?option=com_docman&view=list&slug=2016-2017-nttg-planning-cycle&Itemid=31

A list and link to each of the individual supporting documents is also provided below:

1. Amended Quarter 6 NTTG 2016-17 Biennial Study Plan Approved 08.02.17
2. Stakeholder Comments on NTTG 2016-2017 Draft Study Plan & NTTG Response - FINAL 07-13-2016
3. NWEC & RNW Comments Submitted on NTTG 2016-2017 Draft Study Plan
4. NTTG 2016-2017 Draft Final Regional Transmission Plan - 06-30-2017
5. 2016-2017 NTTG Public Policy Consideration Scenario Report
6. Draft NTTG Study Report for 2016-2017 PPC Scenario For Stakeholder Comment

## Glossary

Note: This Glossary is for the benefit of readers and neither supplements nor modifies any defined terms contained in any entity's filed Open Access Transmission Tariff (OATT), including the Attachment K to that tariff. To the extent that a term diverges from any entity's OATT, defer to the OATT.

**Alternative Project** Alternative Project refers to Sponsored Projects, projects submitted by stakeholders, projects submitted by Merchant Transmission Developers and unsponsored projects identified by the Planning Committee (if any).

**Change Case** A Change Case is a scenario where one or more of the Alternative Projects is added to or replaces one or more Non-Committed projects in the Initial RTP. The deletion or deferral of a Non-Committed Project in the Initial RTP without including an Alternative Project can also be a Change Case.

**Committed Project** A Committed Project is a project that has all permits and rights of way required for construction, as identified in the submitted development schedule, by the end of Quarter 1 of the current regional planning cycle.

**Draft Regional Transmission Plan** Draft Regional Transmission Plan refers to the version of the Regional Transmission Plan that is produced by the end of Quarter 4 and presented to stakeholders for comment in Quarter 5.

**Draft Final Regional Transmission Plan** Draft Final Regional Transmission Plan refers to the version of the Regional Transmission Plan that is produced by the end of Quarter 6, presented to stakeholders for comment in Quarter 7 and presented, with any necessary modifications, to the Steering Committee for adoption in Quarter 8.

**Initial Regional Transmission Plan** Initial Regional Transmission Plan comprises projects included in the prior Regional Transmission Plan and projects included in the Full Funders Local Transmission Plans and accounts for future generation additions and deletions (e.g., announced coal retirements).

**Interregional Transmission Project** An Interregional Transmission Project is a proposed new transmission project that would directly interconnect electrically to existing or planned transmission facilities in two or more planning regions and that is submitted into the regional transmission planning processes of all such planning regions.

**Merchant Transmission Developer** Merchant Transmission Developer refers to an entity that assumes all financial risk for developing and constructing its transmission project. A Merchant Transmission Developer recovers the costs of constructing the proposed transmission project through negotiated rates instead of cost-based rates.

**Non-Committed Project** A project that is not a Committed Project

**Sponsored Project** A Sponsored Project is a project proposed by a Project Sponsor.

# ATTACHMENT N-6
# ORDER NO. 10-392 IN DOCKET LC 50

ORDER NO. 10-392
ENTERED 10/11/10

# BEFORE THE PUBLIC UTILITY COMMISSION

# OF OREGON

LC 50

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|---|---|
| In the Matter of<br><br>IDAHO POWER COMPANY<br><br>2009 Integrated Resource Plan. | ORDER |

DISPOSITION: PLAN ACKNOWLEDGED WITH REQUIREMENTS

## I. INTRODUCTION

Idaho Power Company (Idaho Power or Company) seeks acknowledgement of its 2009 Integrated Resource Plan (IRP). This filing is in accordance with Public Utility Commission of Oregon (Commission) Order No. 07-002, as corrected by Order No. 07-047,[1] which requires all regulated energy utilities operating in Oregon to engage in integrated resource planning.

We acknowledge Idaho Power's 2009 IRP and its preferred portfolio as presenting the best combination of expected costs and associated risks and uncertainties for the Company and its customers, and as satisfying the procedural and substantive requirements of this Commission. At the same time, we recognize that the assumptions for several key factors remain uncertain. For this reason, we require that Idaho Power perform further analyses in its 2011 IRP consistent with our discussion below.[2]

### A. Requirements for Integrated Resource Planning

The Commission requires regulated energy utilities to prepare integrated resource plans within two years of acknowledgment of the last plan. Utilities must involve the Commission and the public in their planning process prior to resource decision-making.

Substantively, the Commission requires that energy utilities: (1) evaluate resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) make the primary goal of the process to select a portfolio of resources with the best combination of

[1] The Commission originally adopted least-cost planning in Docket No. UM 180, *See* Order No. 89-507 (Apr 20, 1989). The Commission updated the least-cost planning process in 2007 in Docket No. UM 1056. *See* Order No. 07-002 (Jan 8, 2007).

[2] The original due date for the filing of the Company's 2009 IRP was June 2009. That date was extended by Commission order to December 2009. The Company will file its 2011 IRP in June 2011.

expected costs and associated risks and uncertainties for the utility and its customers; and (4) create a plan that is consistent with the long-run public interest as expressed in state and federal energy policies.[3]

**B. Effect of Acknowledgement of an IRP on Future Ratemaking Actions**

The Commission's role in reviewing an IRP is to determine whether the IRP meets the substantive and procedural guidelines in Order Nos. 89-507 and 07-002. The Commission generally does not address the need for specific resources, but rather determines whether the utility has proposed a portfolio of resources to meet its energy demand that presents the best combination of cost and risk.[4] Commission acknowledgement of an IRP means only that the Commission finds that the utility's preferred portfolio is reasonable at the time of acknowledgement.[5]

In Order No. 89-507, the Commission described its role in reviewing and acknowledging a utility's least-cost plan:

> The establishment of Least-Cost Planning in Oregon is not intended to alter the basic roles of the Commission and the utility in the regulatory process. The Commission does not intend to usurp the role of utility decision-maker. Utility management will retain full responsibility for making decisions and for accepting the consequences of the decisions. Thus, the utilities will retain their autonomy while having the benefit of the information and opinion contributed by the public and the Commission.
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> * * * * *
>
> Acknowledgment of a plan means only that the plan seems reasonable to the Commission at the time the acknowledgment is given. As is noted elsewhere in this order, favorable rate-making treatment is not guaranteed by acknowledgment of a plan.[6]

This order does not constitute a determination on the ratemaking treatment of any resource acquisitions or other expenditures undertaken in accordance with Idaho Power's 2009 IRP. As a legal matter, the Commission must reserve judgment on all ratemaking issues. Notwithstanding these legal requirements, we consider the integrated resource planning process to complement the ratemaking process. In ratemaking proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions that are consistent with acknowledged integrated

[3] *See* Order No. 07-002.
[4] *See id.* at 25.
[5] *See id.* at 16.
[6] *See* Order No. 89-507 at 6, 11. The Commission affirmed these principles in Docket UM 1056. *See* Order No. 07-002 at 24.

resource plans. A utility is also expected to explain actions they take that are inconsistent with Commission-acknowledged plans.

## C. Idaho Power's 2009 IRP

The Commission's IRP Guidelines state that a utility must file its IRP two years from the date of acknowledgement of the previous plan. Idaho Power received acknowledgement of its 2006 IRP on September 12, 2007.[7] Due to substantial changes in economic conditions and permitting delays for the Boardman to Hemingway 500 kV transmission project (B2H Project or Boardman to Hemingway), the Company requested a delay in its September 12, 2009 filing deadline. On May 26, 2009, the Commission approved Idaho Power's motion to delay its filing of the 2009 IRP until December 2009.[8] On December 30, 2009, Idaho Power filed its 2009 IRP.

This is Idaho Power's first plan under the Commission's newly adopted Guidelines.[9] In developing its 2009 plan, Idaho Power worked with an IRP advisory group comprised of major stakeholders representing the environmental community, major industrial customers, irrigation customers, state legislators, Commission representatives, and others.

Idaho Power's 2009 IRP analyses the potential cost of carbon emissions in two ways: cap-and-trade and carbon tax adders. While Idaho Power modeled both a cap-and-trade system and carbon tax adders in future scenarios, the Company primarily focuses on cap-and trade as the most likely regulatory outcome. The Company's analysis uses the Waxman-Markey Bill[10] as the basis for its assumptions on emission targets and allowances.

Idaho Power uses the AURORAxmp (AURORA) market model as the primary tool for determining future resource operations and to estimate the portfolio cost for the twenty-year IRP. Using the AURORA model, the Company performed a quantitative risk analysis of the following variables: third-party transmission subscription; renewable energy credit prices; natural gas prices; carbon emission costs; load growth; and conservation. Additionally, Idaho Power performed a qualitative risk analysis that looked at carbon regulation, technology, market risk, and resource siting.

For the first time, Idaho Power bifurcated the required twenty-year planning period into two ten-year planning periods—2010 through 2019 and 2020 through 2029. The Company believes that this approach prevents near-term decision making from being unduly influenced by resource decisions in the second ten-year planning period.

In the first ten-year planning period (2010 through 2019), Idaho Power examines four resource portfolios, classified as Solar, Gas Peaker, Gas Peaker and B2H,

[7] *See* Order No. 07-394 (Docket No. LC 41).
[8] *See* Order No. 09-183 (Docket No. UM 1428).
[9] *See* Order No. 07-002.
[10] The Waxman-Markey Bill, named after its authors, Representatives Henry A. Waxman of California and Edward J. Markey of Massachusetts, was introduced as an energy bill in the 111th United States Congress. The bill was approved by the House of Representatives on June 26, 2009.

and B2H. The labeling of these portfolios defines the type of supply-side resource that would be used to meet Idaho Power's forecasted energy and capacity deficits. Originally evaluated in the Company's 2006 IRP, and common to all resource portfolios as "committed" resources, are (1) the Langley Gulch combined-cycle combustion turbine (CCCT), (2) up to 150 megawatts (MW) of wind generation, and (3) two 20 MW increments of geothermal energy coming on-line in 2012 and 2016.

In the second ten-year planning period (2020 through 2029), Idaho Power examines five resource portfolios. Idaho Power uses its preferred portfolio for the first ten-year planning period as the basis for designing the second period portfolios. The load forecast for the second planning period is relatively flat. The primary driver for new resources in the second period is carbon emission reductions due to coal curtailment, as identified in the Waxman-Markey Bill.

New energy efficiency programs included in the 2009 IRP are forecast to reduce annual load by 127 average MW (MWa) by the year 2029. This reduction represents a 53 percent increase over the measures included in the Company's 2006 IRP. New and expanded demand response programs are expected to reduce peak summer load by 323 MW by the year 2012, once the programs mature. This reduction represents significant growth over the 2006 IRP when demand response programs were estimated to provide only 78 MW of peak reduction by 2026. All estimated reductions in load due to energy efficiency and demand response programs are included in Idaho Power's 2009 load forecast.

Using an August 2009 load forecast, Idaho Power projects peak-hour load will grow at an average annual rate of 53 MW or 1.5 percent. Average system load is forecasted to grow by 13 MWa or 0.64 percent on an average annual basis over the twenty-year planning period. Idaho Power projects that its system will become short on capacity in 2013 and, on an energy basis, the system begins to experience a short position by 2014.[11]

Based on its analysis, Idaho Power selected "Portfolio 1-4 Boardman to Hemingway" as its preferred portfolio for the 2010-2019 planning period and "Portfolio 2-4 Wind and Peakers" as its preferred portfolio for the 2020-2029 planning period. The selection of these portfolios as the Preferred Portfolio for the twenty-year study is based on the Company's conclusion that the portfolios present the best combination of expected cost and associated risks.

The Company requests acknowledgement of an Action Plan to implement its Preferred Portfolio. The Action Plan includes the following items:

2010 Irrigation Peak Rewards program increases to 220 MW
FlexPeak Management program increases to 40 MW

[11] Idaho Power uses a 70th percentile water conditions and 70th percentile average load conditions for energy planning purposes. For peak-hour capacity planning, Idaho Power uses 90th percentile water conditions and 95th percentile peak-hour load.

2011 Irrigation Peak Rewards program increases to 250 MW
FlexPeak Management program increases to 45 MW

2012 Wind project on-line 150 MW
Langley Gulch CCCT on-line 300 MW
Geothermal Project on-line 20 MW

2013 Boardman to Hemingway construction begins
Shoshone Falls Upgrade Project construction begins

2015 Shoshone Falls Upgrade Project on-line 49 MW
Boardman to Hemingway completed for market purchases of 250 MW

2016 Geothermal Project on-line 20 MW

2017 Boardman to Hemingway capacity for market purchases of 175 MW

Finally, Idaho Power believes that the flexibility to adjust to changes during the present period of uncertainty regarding carbon regulation is very important.

## II. DISCUSSION

### A. Load Forecast

*1. Parties' Positions*

During a public comment hearing in Ontario, Oregon, on April 20, 2010, many commentators argued that the load forecast in Idaho Power's 2009 IRP is too high. Some of the reasons cited for this conclusion are: (1) the Company should not have included new large load customers; (2) the Company did not consider more recent load information in its forecast; and (3) based on historical housing start data, a more protracted economic recovery will occur than assumed by Idaho Power. Commentators believe that the Company over-projected its short-term load growth, making the Boardman to Hemingway transmission line appear necessary when, in fact, it is not needed in the time period specified by the Company.

In its reply comments, Idaho Power refutes all of the commentators' claims regarding its load forecast. The Company states that its forecast contains the most recent information available at the time the filing was prepared and, compared to the Northwest Power and Conservation Council (NPCC) forecast, Idaho Power's forecast is conservatively low. According to Commission Staff's comments, the NPCC's Sixth Power Plan average load forecast grows at an annual average rate of 1.96 percent, while Idaho Power's forecast grows at 1.4 percent over the twenty-year planning period. For peak-hour load, the NPCC forecast grows at an annual average rate of 2.13 percent, while Idaho Power forecasts its peak-hour load to grow at 2.02 percent.

Regarding the inclusion of large load customers in its forecast, Idaho Power states that large loads are developed through direct input from each of the Company's large load customers. These forecasted customer loads reflect the recession and other operational impacts on future energy use.

In its final comments, Staff agrees with the Company. After reviewing Idaho Power's analyses, Staff believes that the Company has conservatively forecasted its average-energy and peak-hour load, taking into consideration the recent economic downturn. But Staff notes that for the 2019 through 2029 planning period, Idaho Power forecasts average energy to grow at a rate of only 0.1 percent per annum, and peak-hour load growth of only 0.9 percent per annum. Staff is concerned that these growth rates may be too low, especially when the rate of growth in demand-side management (DSM) is projected to slow over this time period.

The inclusion of a customer response to potential price increases due to proposed carbon legislation is a contributing factor to relatively flat growth rates in the second ten-year planning period. Staff finds the customer response to projected price increases associated with carbon regulation to be an interesting change in the Company's forecasting methodology. Staff recommends that the Company provide further description of this analysis in future IRP planning cycles, including the regression coefficients and estimated price responsiveness of each customer class. In its final comments, Idaho Power supports Staff's recommendation.

In its final comments, the Oregon Department of Energy (ODOE) supports Idaho Power's load forecast estimates in its 2009 IRP. ODOE also supports the Staff comments associated with Idaho Power's load forecast and reiterates Staff's concerns about the load growth forecast beyond 2019.

*2. Resolution*

We agree with Staff's conclusion that Idaho Power's first ten-year load forecast is reasonable. We agree with Staff and ODOE that the projected load growth for the second ten-year period seems low. We adopt Staff's recommendation and require Idaho Power to justify its load forecast for the second ten-year period in future IRPs.

We also adopt Staff's recommendation that Idaho Power provide estimates of the price sensitivity for each of its customer classes and document the analyses underpinning those estimates in its next IRP planning cycle.

## B. Preferred Portfolio for the First Ten-Year Planning Period and the Boardman to Hemingway Transmission Project

*1. Parties' Positions*

Idaho Power selected Portfolio 1-4 (Boardman to Hemingway) as its preferred portfolio for the 2010-2019 planning period. In comments on the IRP, Staff and intervening

parties primarily focus on the selection of Portfolio 1-4 as the preferred portfolio versus the other portfolios and, more specifically, the inclusion of the Boardman to Hemingway transmission project. In its analysis, Staff examined the portfolio assumptions associated with the B2H Project, such as capital cost assumptions and third-party subscriptions. Staff evaluated the Company's approach to these variables and their robustness under changing circumstances (for example, higher construction costs or lower third-party subscription rates).

Staff notes that very few interstate transmission projects have been constructed in the region over the last 30 years. It is only recently that utilities in the west have proposed and started to build these large transmission projects, such as Gateway West, the Southwest Intertie, and others. Due to the more recent interest by utilities and consortiums in building these projects, Staff was unable to obtain a reliable set of benchmark data to compare to Idaho Power's cost assumptions and subscription rates. In addition, Staff notes that the cost components of an interstate transmission project can vary widely depending on the type of terrain and right-of-way costs. Thus, rather than attempting to compare these components side-by-side to another project, Staff examined how much these assumptions would have to change in order to make the Portfolio 1-4 no longer the best combination of cost and risk. Idaho Power refers to this analysis as the "tipping point."

Staff discusses at length the Company's analysis of a break-even point, or tipping point, with Portfolio 1-2 (Gas Peaker)—the next best alternative to Portfolio 1-4—to understand the sensitivity of the change in cost within the first ten-year planning period. This analysis demonstrates that Portfolio 1-4 is so robust that capital cost could vary by up to 40 percent and subscription rates could change by 15 percent before the portfolio hits the break-even point with the next best alternative.

In support of its subscription rate assumptions, Idaho Power states that there is significant demand for transmission capacity on its Idaho-Northwest transmission path. Idaho Power states that it is aware of over 4,000 MW of transmission requests on the existing transmission path, with only 133 MW of those requests being granted through 2007 due to limited transmission capacity. The Company claims that it is currently reviewing active transmission requests for the B2H Project. The Company states in its reply comments that it has entered into an agreement with PacifiCorp to negotiate the joint ownership and development of the B2H Project.

Even with a change in cost, Staff states that the Company's analysis also includes additional quantitative and qualitative risk measures that must be taken into consideration. According to Staff, Portfolio 1-4 scored higher than all the alternative portfolios in the Company's risk analyses. The different types of risk modeled in Idaho Power's 2009 IRP are renewable energy credit prices, natural gas prices, carbon emission costs, load growth, and lower conservation. Additionally, Idaho Power performed a qualitative risk analysis that looked at carbon regulation, technology, market risk, and resource siting. Therefore, the Boardman to Hemingway capital costs and subscription estimates would have to vary by more than 40 percent and 15 percent respectively to change

the selection of the Portfolio 1-4 as the preferred portfolio for the 2010 through 2019 planning period.

In conclusion, Staff recommends that the Company continue to evaluate the B2H Project in its 2011 IRP. This on-going analysis of the B2H Project should include updated estimates of construction costs, documentation of progress the Company has made towards securing equity partners, and quantitative estimates of third-party subscription on the Boardman to Hemingway transmission line and future wheeling revenues. Staff additionally recommends that the Commission require that Idaho Power provide third-party documentation in support of the Company's construction cost estimates.

Staff's recommendation for further analysis of third-party subscription and the associated wheeling revenues is based on a concern that the active transmission requests referred to by Idaho Power in its 2009 IRP may not materialize, leaving Idaho Power customers liable for paying for an unused transmission line. Given these concerns, Staff initially recommended that the Commission's acknowledgement of the Boardman to Hemingway action item be conditioned on Idaho Power providing further analysis of these issues in its annual IRP update and next IRP.

In their final comments, ODOE and Idaho Power support Staff's recommendation for further information and analyses on the B2H Project in future IRP planning cycles. Idaho Power also agreed with Staff that if there are significant deviations from the IRP assumptions on issues such as construction costs, equity ownership, and subscription rates, then the Company must explain these deviations in its 2011 IRP. But given that Staff found the Company's estimates to be reasonable at this time, Idaho Power argues that conditional acknowledgment is not necessary. The Company agreed to provide additional analyses of the B2H Project, as prescribed in the eight conditions of Staff's proposed final order.

At the Commission public meeting on September 7, 2010, Staff revised its original recommendation for conditional acknowledgement and agreed with Idaho Power that, with the Company's commitment to continue to analyze and assess the B2H Project as an uncommitted resource, acknowledgement with requirements is a reasonable recommendation that meets the goals of Staff's proposed final order.

Finally, Staff discussed the future ratemaking treatment of the B2H Project. Staff reaffirmed that the Company will be required to compare its actual results with its IRP estimates. If the comparison shows significant deviations from its IRP assumptions, then the Company must provide an adequate explanation for why this project was the right resource as compared to an alternative.

In its opening comments, Renewable Northwest Project (RNP) urges the Commission to acknowledge Portfolio 1-3 (Gas Peaker and B2H) as the preferred portfolio for the first ten-year planning period. RNP states that it believes that the Company's commitment to 150 MW of wind energy and 40 MW of geothermal, coupled with the Boardman to Hemingway transmission line, will foster the growth of new renewable energy

resources in the Northwest. Staff agrees with the latter half of RNP's statement, but points out that Idaho Power's preferred portfolio, Portfolio 1-4, also includes the Company's commitment to 150 MW of wind energy and 40 MW of geothermal. Therefore, Staff believes that Portfolio 1-4 meets RNP's goals.

In reply comments, RNP supported Staff's conclusions associated with Portfolio 1-3, and agreed with Staff that the Company's Portfolio 1-4 will also foster the growth of new renewable resources in the Northwest.

Commentators at the April 20, 2010 public comment hearing focused on the need for the B2H Project. Specifically, commentators believe that building a natural gas plant and additional purchased power are preferable to the Boardman to Hemingway transmission line, and that the line should not be built to accommodate third-party wheeling requests.

Idaho Power refutes each of these claims. First, Idaho Power notes the robustness of Portfolio 1-4 as compared to the other portfolios. Second, Idaho Power refutes the possibility of additional purchased power due to its limited transmission capacity during peaking time on existing transmission paths. Third, Idaho Power states that all wheeling requests on the proposed B2H Project will offset costs associated with building the project, which in turn will reduce its customers' rates. In addition, Idaho Power states that it is bound by federal law to provide wheeling services on a non-discriminatory basis, which requires the Company to construct a transmission system that will ensure reliable and economic service to transmission customers.

*2. Resolution*

As Staff notes, the dearth of recent transmission development and the case-specific nature of any transmission project make it difficult to vet key assumptions that will determine the cost to Idaho Power's retail customers of the B2H Project. But our concern about this uncertainty is tempered by risk analyses showing that the "B2H portfolio" (Portfolio 1-4) is the best portfolio for customers over a range of capital costs and third-party subscription levels. Accordingly, we consider it reasonable to proceed with the B2H Project based on the information available now and acknowledge it as part of the Company's 2009 IRP.

We also adopt Staff's recommendation that Idaho Power be required to update its B2H Project assumptions (for example, construction cost estimates, equity partnership estimates, third-party subscription estimates, and wheeling revenues) in its 2011 IRP. We always expect utilities to update their assessments of previously acknowledged projects that are still in the planning or development stages at the time of an IRP acknowledgement. We make this updating requirement explicit for the B2H Project because of current uncertainty about underlying assumptions. We expect the Company to provide a thorough update of its B2H Project assumptions and its risk analysis in the 2011 IRP, with the understanding that the Commission's acknowledgment of the 2011 IRP will depend on the outcome of that updated analysis.

Finally, we reiterate that at the time of ratemaking any utility is required to show that its investment was a prudent decision. Given the inherent risk associated with a transmission facility and the possibility of escalating costs and delays in permitting, the Company will need to address any significant changes in construction cost, equity partnership, or expected third-party subscription and how these factors influenced the Company's decision to continue with the project.

## C. Preferred Portfolio for the Second Ten-Year Planning Period and the Consolidated Preferred Portfolio

### *1. Parties' Positions*

Idaho Power chose Portfolio 2-4 (Wind and Peakers) for the second ten-year planning period. Portfolio 2-4 consists of five single cycle combustion turbine (SCCT) gas resources with a combined capacity of 1,400 MW, two wind facilities with a combined capacity of 200 MW, and 100 MW of market purchases on PacifiCorp's proposed Gateway West transmission project. Idaho Power states that these resources represent a strategy of adding wind resources sufficient to provide energy and renewable energy credits (REC) along with simple-cycle natural gas plants to provide peaking capacity and operating reserves necessary to integrate wind generation.

In its final comments, Staff noted that the load forecast for the second ten-year planning period is relatively flat. The Company stated that the primary driver for new resources in the second period is the carbon emission reductions, due to coal curtailment, identified in the Waxman-Markey Bill. In its comments, RNP lauded Idaho Power for developing a resource portfolio that allows for considerable curtailment of the Company's coal-fired generation. RNP believes that Idaho Power's IRP strategy appropriately accounts for the costs, risks, and environmental concerns associated with future limits on greenhouse gas emissions.

Staff agrees with RNP and believes that Idaho Power complied with Guideline 8 of the Commission's IRP guidelines by modeling the carbon emission future that it believed was most likely to occur. But Staff cites the need for additional analysis, including the end-effects and costs of the retirement of a coal facility. Staff recommends that the Commission require that Idaho Power examine coal curtailment and the costs associated with coal plant retirement.

In its opening comments, RNP expressed concern that the portfolios rely too heavily on natural gas-fired resources. Staff agrees that Portfolio 2-4 relies too heavily on gas in the second ten-year planning period. Staff's primary concern, however, was not the concentration of gas in the second planning period, but the type of gas resource modeled. Because the primary reason for additional resources in the second ten-year planning period was due to modeled coal curtailment, Staff believes it is unreasonable for the Company to choose multiple SCCTs versus one or two CCCTs.

Staff and RNP believe that the Company needs to consider expanding the number of portfolios it considers in the second ten-year planning period. Staff notes that an IRP is designed to take into consideration a broad array of portfolio options. For the second ten-year planning period and the consolidated Preferred Portfolio, Staff discussed the design of Idaho Power's five alternative portfolios. Staff notes that the Company designed the five portfolios for the second ten-year planning period based on the selection of Portfolio 1-4 for the first ten-year planning period, which limits the resource options considered by Idaho Power.

Staff believes that building portfolios is a learning process examining multiple futures, and this learning process should not be overlooked. Staff believes that more than five portfolios should be developed for the second ten-year planning period. Staff therefore recommends that the Commission require Idaho Power to develop significantly more portfolios for the second ten-year planning period for its next IRP. In addition, Staff recommends that Idaho Power be required to provide a review of the benefits of a CCCT versus a SCCT, looking at variables such as cost effectiveness, operation and maintenance costs, and overall system benefit. In its final comments, Idaho Power supported Staff's recommendation.

In its final comments, ODOE also recognized the need for Idaho Power to develop more portfolios and suggested that the Company should consider uncertainty in its future analyses.

As part of the carbon cost evaluation, Staff recommends that Idaho Power be required to look at the likelihood of Environmental Protection Agency (EPA) regulations on air quality, fly ash, and water for all of its generation facilities. Staff believes the Company needs to include the operational impacts of these possible regulations for future consideration. In its final comments, Idaho Power supported Staff's recommendation.

*2. Resolution*

We support Idaho Power's selection of Portfolio 2-4 for the second ten-year planning period and the overall selection of the Preferred Portfolio. While we recognize the speculative nature of the second half of the planning period, we agree with Staff's conclusion that much can be learned from analyzing more portfolios and resource options. We therefore adopt Staff's recommendation and direct the Company to consider more portfolios, including those needed to evaluate the benefits of a CCCT versus a SCCT, in its next IRP cycle. We also direct the Company to include an analysis of potential EPA or other federal and state environmental policies that may affect Idaho Power's generation portfolio.

**D. Demand-Side Management and Energy Efficiency Programs.**

*1. Parties' Positions*

Several commentators at the April 20, 2010 public comment hearing argued that Idaho Power has been deficient in seeking energy savings. Commentators suggested that Idaho Power's energy efficiency efforts lag behind the regional goals established by the NPCC's Sixth Power Plan. They further asserted that the Company could supplant the need for the Boardman to Hemingway transmission line with increased DSM efforts.

Idaho Power responded to these remarks in its reply comments by explaining how they treat DSM in the planning process and by comparing the Company's efforts to the goals set by the NPCC. Idaho Power explains that prior to evaluating the need for traditional resources, the Company includes all cost-effective energy efficiency from existing and new programs in its load and resource balance. In other words, the Idaho Power gives first priority to obtaining cost-effective conservation. The Company then compares its efforts to the goals set by the NPCC. According to Idaho Power, in 2009 it exceeded the goals in NPCC's Fifth Power Plan by approximately 30 percent. Idaho Power also states that it is working aggressively to meet the goals set in the Sixth Power Plan.

In its final comments, Staff echoed the sentiments of Idaho Power and believes that the Company has explored and included all cost-effective DSM and energy efficiency programs in its 2009 IRP. In addition, Staff states that the Company has made great strides with its energy efficiency and DSM measures as compared to the Company's 2006 IRP.

*2. Resolution*

Idaho Power's existing and new energy efficiency programs are forecasted to reduce average annual system loads by 189 MWa by the year 2019 and 383 MWa by 2029. We agree with Staff that Idaho Power is running a reasonable set of programs to capture all cost-effective conservation. We also support the Company in its efforts to refine and improve upon its programs.

We find that Idaho Power cannot rely on additional cost-effective conservation in lieu of a supply-side resource to meet its summer capacity needs and maintain a reliable system. On a monthly basis, after counting energy efficiency savings, the Company forecasts a resource deficit of 155 MWa during July 2019. On a peak hour basis, after counting savings from existing and new energy efficiency programs and new demand response programs, the Company forecasts summertime capacity deficits as large as 471 MW during 2019. We concur with Staff and Idaho Power that a supply-side resource is required to meet these forecasted capacity deficits.

## E. Policy Issues

### *1. Parties' Positions*

In its opening comments, RNP did not agree with Idaho Power's recommendation to sell its RECs from its renewable energy projects until the Company is required to use the RECs to comply with a federal Renewable Energy Standard (RES). RNP believes Idaho Power should be retaining RECs in preparation for compliance with a future federal RES.

In its final comments, Staff notes that the Idaho Public Utilities Commission accepted Idaho Power's REC management plan filing on June 11, 2010.[12] This REC management plan is consistent with Idaho Power's IRP. In its reply comments, Idaho Power explained that its REC management strategy will benefit customers of Idaho Power in two ways. First, customers' rates will be reduced due to REC sales revenue. Second, the Company plans to continue to acquire and hold long-term contract rights to own RECs to meet future federal RES.

In addition, RNP supported the development of a solar pilot project in Idaho Power's service territory. RNP stated that it would like to participate in a stakeholder workshop with Idaho Power to explore options for a solar pilot project. In response to Staff final comments, RNP generally supported Staff's conclusions.

### *2. Resolution*

We agree with Idaho Power's conclusion that its REC management strategy is in the best interest of customers, will reduce rates, and will provide the ability to meet future RES standards.

More recently, Idaho Power has participated in the pilot project for a solar feed-in tariff in Oregon. We believe Idaho Power's participation and introduction of the solar feed-in tariff fulfills RNP's request to develop a solar pilot project in Idaho Power's service territory.[13]

## F. General Issues

### *1. Parties' Positions*

In final comments, Staff noted several deficiencies in Idaho Power's narrative description of its 2009 IRP. Staff believes that Idaho Power should provide a more thorough explanation of the Company's selection of the Preferred Portfolio. Staff believes that Idaho Power failed to provide an adequate narrative of how the Preferred Portfolio performed in the risk analysis individually and comparatively to the other portfolios. Staff therefore recommended that the Commission require Idaho Power to devote specific chapters in its next IRP explaining the selection of its Preferred Portfolio in greater detail and as compared

[12] *See* Idaho Public Utilities Commission Case No. IPC-E-08-24, Order No. 32002.
[13] *See* Docket No. UM 1452.

to an alternative portfolio. Staff believes this narrative should include an explanation of the relative performance of each portfolio within each of the modeled risk measures, including charts and matrices showing the relative ranking of each portfolio using cost and risk metrics. Finally, Staff recommended that Idaho Power should be required to provide an explanation of how each portfolio performed with regard to the qualitative measures the Company considered in its selection process.

Staff also pointed out that Idaho Power's risk analysis consisted of modeling risk variables, such as load growth, in only one direction—high. In its Technical Appendix the Company did not model low load growth scenarios, low subscription rates, or low natural gas prices. Staff recommends the Company model the full range of possible futures for its risk variables, including both the high and low side, in the next IRP. In response to Staff's final comments, Idaho Power agrees with Staff's recommendations.

*2. Resolution*

We support Staff's recommendation regarding Idaho Power's next IRP cycle. As stated in Order No. 07-002, the Commission guidelines incorporate what we minimally expect from an IRP.[14] We always urge the utility to provide more, rather than less, information, especially given the increasing complexity of the planning process.

## III. CONCLUSION

Idaho Power Company's 2009 Integrated Resource Plan, as highlighted in this order, reasonably adheres to the principles of resource planning established in Order No. 07-002 and is acknowledged with the following requirements:

1. Idaho Power Company will file its next integrated resource plan no later than June 30, 2011.

2. In its 2011 Integrated Resource Plan, Idaho Power Company will treat the Boardman to Hemingway transmission project as an uncommitted resource and will update its project analysis, including progress the Company has made towards securing equity partners, updated estimates of construction costs, and quantitative estimates of third-party subscription on the Boardman to Hemingway transmission line and future wheeling revenues. In addition, Idaho Power Company will provide third-party documentation in support of its construction cost estimates.

3. In its next planning cycle, Idaho Power Company will analyze coal curtailment and the costs associated with coal plant retirement.

[14] *See* Order 07-002 at 12.

4. In its next planning cycle, Idaho Power Company will develop significantly more portfolios for the second ten-year planning period, including portfolios designed to evaluate the benefits of a combined cycle combustion turbine gas resource versus multiple single cycle combustion turbine gas resources.

5. In its next planning cycle, Idaho Power Company, will analyze any potential Environmental Protection Agency, state, and other federal agency regulations associated with air quality, fly ash, and water that may affect the Company's generation facilities. These results will be included in the Company's 2011 Integrated Resource Plan.

6. In its 2011 Integrated Resource Plan, Idaho Power Company will provide a more robust justification for its load forecast for the second ten-year planning period. In addition, Idaho Power will provide additional analysis and a description of its estimated price response related to future carbon regulation for each customer class in its next IRP planning cycle.

7. In its 2011 Integrated Resource Plan, Idaho Power Company will devote specific chapters in the Plan to explaining the selection of the Preferred Portfolio in greater detail and as compared to an alternative portfolio. This narrative will include an explanation of the relative performance of each portfolio within each of the modeled risk measures, including charts and matrices showing the relative ranking of each portfolio using cost and risk metrics. Idaho Power Company will provide an explanation of how each portfolio performed using the qualitative measures the Company considered in its selection process.

8. In the 2011 Integrated Resource Plan, Idaho Power Company will model the full range of possible futures for its updated risk variables. Idaho Power Company will model both a high and low future for each variable.

At the Commission's September 7, 2010 public meeting, Idaho Power Company agreed to perform all of the above analyses in its 2011 Integrated Resource Plan and understood that the Commission's acknowledgement of Idaho Power's 2011 Integrated Resource Plan will be based upon the results of the updated analyses.[15]

[15] For further details regarding Idaho Power's adherence to the Commission's Guidelines in Order No. 07-002, *see* Staff Final Comments, Appendix A: Adherence of the Plan to Integrated Resource Planning Guidelines (July 9, 2010).

## IV. ORDER

IT IS ORDERED that:

1. The 2009 Integrated Resource Plan filed by Idaho Power Company on December 30, 2009, is acknowledged with the requirements set forth in this order.

2. Idaho Power Company will file its next Integrated Resource Plan no later than June 30, 2011.

Made, entered, and effective OCT 11 2010.

**Ray Baum**
Chairman

**John Savage**
Commissioner

**Susan K. Ackerman**
Commissioner

# ATTACHMENT N-7
# ORDER NO. 12-177 IN DOCKET LC 53

ORDER NO. 12 177

ENTERED MAY 21 2012

# BEFORE THE PUBLIC UTILITY COMMISSION

# OF OREGON

LC 53

| | |
|---|---|
| In the Matter of<br><br>IDAHO POWER COMPANY<br><br>2011 Integrated Resource Plan. | ORDER |

DISPOSITION: INTEGRATED RESOURCE PLAN ACKNOWLEDGED WITH CONDITIONS AND EXCEPTIONS

## I. INTRODUCTION

Idaho Power Company (Idaho Power) seeks acknowledgment of its 2011 Integrated Resource Plan (IRP). The Company submitted the IRP to meet the requirement that all regulated energy utilities operating in Oregon engage in integrated resource planning.[1] We acknowledge the company's 2011 IRP with conditions and exceptions.

## II. BACKGROUND

We require each regulated energy utility to prepare and file an IRP within two years after acknowledgment of a utility's last IRP. Substantively, we require that energy utilities: (1) evaluate resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) make the primary goal of the process selecting a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers; and (4) create an action plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.[2]

We acknowledge a utility's IRP to the extent the plan satisfies our procedural and substantive requirements, and the plan is deemed reasonable at the time of acknowledgement. Acknowledgment does not constitute a determination of the prudency of any resource acquisitions or other expenditures made by the utility pursuant to the plan. As a legal matter, we must reserve judgment on all rate-making issues.[3] Nonetheless, we consider the integrated resource planning process to complement the rate-making process. In rate-making proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions which are consistent with acknowledged IRP action plans. Utilities will also be

[1] *See* Order Nos. 89-507, 07-002, and 07-047.
[2] *See* Order No. 07-002.
[3] *See* Order No. 07-002 at 24.

expected to explain actions they take which may be inconsistent with Commission-acknowledged plans.

## III. PROCEDURAL HISTORY

Idaho Power filed its 2011 IRP on June 30, 2011. A prehearing conference was held July 29, 2011, and the schedule adopted. Petitions to intervene were granted on behalf of Renewable Northwest Project (RNP), Portland General Electric Company (PGE), the Oregon Department of Energy (ODOE), Move Idaho Power, and Stop Idaho Power. The Citizens' Utility Board of Oregon (CUB) intervened by right.

On September 20, 2011, Idaho Power presented its IRP to the Commission at a public meeting. A technical workshop was held for parties on September 20, 2011. Staff and intervenor initial comments were filed October 18, 2011. Company reply comments were filed November 8, 2011. Staff's final comments and a proposed order were filed December 6, 2011. Company and intervenor comments in reply to Staff's final comments were filed January 3, 2012. Staff's report and its final proposed order were filed on January 24, 2012. This matter was taken up for Commission action at a public meeting on February 14, 2012.

## IV. DISCUSSION

### A. 2011 IRP Overview

Its 2011 IRP is Idaho Power's tenth resource plan filed to meet the requirements and guidelines established by this Commission and the Idaho Public Utilities Commission. In its filing Idaho Power assumed that, during the planning period (2011 through 2030), it will continue to be responsible for acquiring resources sufficient to serve all of its retail customers in its Oregon and Idaho service areas as a vertically integrated company. In developing its plan, Idaho Power worked with its IRP Advisory Council, which is comprised of major stakeholders representing the environmental community, major industrial customers, irrigation customers, state legislators, public utility commission representatives, and others. Following the filing of its final plan, Idaho Power presented the IRP at public meetings in various cities within its service area.

Idaho Power expects the number of customers in its service area to increase from about 492,000 in 2010 to over 650,000 by 2030. The IRP expected-case load forecast projects peak-hour load will grow 69 megawatts (MW) annually (1.8 percent), and average-system load will increase annually 29 average megawatts (aMW) (1.4 percent) over the 20-year term. In 2011, Idaho Power's demand response programs are expected to reduce peak-hour load by 330 MW. Two resources identified in the 2009 IRP are considered committed resources in the 2011 IRP: (1) the 300 MW Langley Gulch combined cycle combustion turbine that is expected to be available in the summer of 2012; and (2) a 49 MW upgrade of the Shoshone Falls Hydroelectric Project in 2015.

Idaho Power divided its 20-year planning period into two 10-year segments. In the first 10-year period, the company examined nine resource portfolios. Each portfolio was designed to substantially meet the energy and capacity deficits identified in the resource balance. For the second 10-year period, Idaho Power analyzed the preferred resource portfolio from the initial 10-year period coupled with each of the 10 portfolios considered for the second period.

In addition to those committed resources (Langley Gulch and the Shoshone Falls upgrade), the preferred resource portfolio includes 450 MW of market purchases beginning in 2016, with the completion of the Boardman to Hemingway transmission line. The total west-to-east transfer capacity reserved on Boardman to Hemingway by Idaho Power is expected to be 450 MW. For the second 10-year period the preferred portfolio adds a mixture of renewable resources along with natural gas-fired baseload and peaking resources.

## B. Objections to Idaho Power's 2011 IRP

Staff and other parties raised numerous issues and provided considerable commentary on certain aspects and elements of the original action items in Idaho Power's IRP Action Plan. We also expressed concerns with aspects of the plan at the public meeting held on February 14, 2011. Those issues, and our resolution of them, are as follows:

### *1. Evaluation of Environmental Compliance Costs for Existing Coal-Fired Plants (Action Item 11)*

Idaho Power does not wholly own or operate any coal plants, but does have a significant ownership interest in three large plants (Boardman, North Valmy, and Jim Bridger). As reported by CUB, these plants provide 41 percent of Idaho Power's total generation. CUB points out that the owners of these three plants likely will face increasing costs to comply with clean air regulations in the coming years.

CUB and RNP are not satisfied with Idaho Power's analysis of the possible environmental compliance costs associated with ownership and operation of these plants. CUB suggests that Idaho Power be required to conduct a unit-by-unit evaluation of its clean air investment costs (similar to that conducted by PGE for its Boardman plant) before the IRP provisions relating to coal plant investment are considered for acknowledgement. CUB recommends that the Commission withhold acknowledgment of the IRP until Idaho Power completes a study of its coal investment compliance costs and the parties have had the opportunity to review and comment on the study. RNP also recommends that the Commission require Idaho Power to analyze the costs and risks of maintaining its coal plants (including carbon costs and environmental regulations) before the company commits to significant investments.

Idaho Power responds that because the amount of any environmental compliance costs is "highly speculative" at this time, any analysis of the costs would be highly speculative as

well. The company argues that the Commission should acknowledge its 2011 IRP, and require that Idaho Power conduct the environmental costs analysis in future IRP filings.

Staff shares CUB's and RNP's concerns about future environmental compliance costs, but agrees with Idaho Power that the company should provide the requested analysis in its 2011 IRP Update. Staff proposes an additional Action Item 11 to address this future requirement.

*Resolution*

As discussed at the public meeting, we share the concerns raised by CUB and RNP regarding Idaho Power's failure to perform a comprehensive study of the possible costs and consequences of environmental regulations associated with the company's partial ownership of three coal plants. Accordingly, we acknowledge Staff's proposed Action Item 11, but not any other IRP provision relating to new investments in coal plants until Idaho Power completes a study of its coal investment compliance costs and other parties have had the opportunity to comment on the study.

### *2. Boardman to Hemingway Transmission (Action Item 7)*

RNP supports acknowledgment of the Boardman to Hemingway (B2H) transmission project as the primary resource in Idaho Power's near-term portfolio. Staff recommends we acknowledge Action Item 7 requiring Idaho Power to continue to make progress on the B2H transmission project between now and the completion of the company's 2013 IRP. CUB notes, however, that closure of one or more coal plants would open up capacity on existing transmission lines and could cause changes to the design and location of new lines.

*Resolution*

We share CUB's concern that coal cost study results will have implications for Idaho Power's transmission line use and plans, but acknowledge Action Item 7 requiring the company to continue to make progress on the B2H transmission project as an uncommitted resource.

### *3. Conservation Voltage Reduction (Action Item 4)*

Staff notes the "promising beginnings" for conservation voltage reduction (CVR) measures reported by Idaho Power. Staff points out, however, that the Company shows no further CVR measures in either its IRP or its Appendix B on Demand-Side Management.

*Resolution*

We are convinced that there is an untapped CVR resource and that this resource is cost effective. We direct the addition of a CVR action item as follows:

> Action Item 4 – Conservation Voltage Reduction – The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The company will propose an action plan in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's load-resource balance forecasts.

### *4. Demand Response (Action Item 3)*

In this IRP cycle Idaho Power switched from an "all cost-effective DSM" approach to "need-based" approach. Based on its analysis comparing the costs of energy saved from demand response to the cost of owning and operating a simple cycle combustion turbine (SCCT), Idaho Power derived an optimal amount of demand response for its system. Staff believes that the Company should pursue all cost-effective demand response through existing programs and consider new programs as applicable. Staff believes Idaho Power should pursue the maximum amount of demand response that (1) is less costly on a kW basis than a supply-side resource, and (2) up to the company's system capacity deficit amount.

*Resolution*

Staff proposed no change to this IRP action item. We accept Staff's proposal that during the preparation of its 2013 IRP, Idaho Power will convene a meeting of its IRP Advisory Council to address demand response, where Staff intends to work with the parties to develop a demand response approach in the best interest of ratepayers.

### *5. Energy Efficiency (Action Items 1 and 2)*

Staff recommends acknowledgment of Idaho Power's Action Items 1 and 2, and recommends the Company continue to pursue all cost-effective demand side management as the lowest cost resource for customers.

*Resolution*

We agree with Staff that Idaho Power should continue to pursue all cost-effective demand side management. No revision to these action items is required.

### *6. Alternative Portfolio (Action Items 8 and 9)*

RNP urges the Commission to consider alternatives to acknowledging Idaho Power's alternative resource portfolio (which is comprised solely of SCCT plants). RNP recommends the Commission give demand side management and solar photovoltaic resources time to ripen. Staff recommends the Commission not acknowledge the alternative portfolio, because there are existing mechanisms in the IRP process to deal with unforeseen circumstances.

*Resolution*

We agree with Staff that there are existing mechanisms in the IRP process to address unforeseen circumstances and do not find a need to acknowledge an alternative resource portfolio. We clarify, however, that the non-acknowledgment of the Alternative Portfolio Action Items 8 and 9 is not due to a flaw or failure in the IRP.

### *7. Long Term Action Items (Action Item 12)*

In its Action Plan, Idaho Power included action items for the 2021 through 2030 time period. Because the IRP Guidelines focus on actions over the next two to four years, Staff recommends that these long-term action items not be acknowledged as part of this IRP.

*Resolution*

We agree with Staff that the desired focus in the IRP is on actions over the next two to four years. We decline to acknowledge the long-term action items contained in Action Item 12.

### *8. Load Forecast*

Staff is concerned that Idaho Power's assumptions of average energy growth and peak-hour load growth are too high. Staff's concerns are based on the lingering economic conditions, plus shifts occurring in the demand/supply balance, conservation, and environmental regulation.

*Resolution*

We agree with Staff that the 2011 IRP Update and the 2013 IRP need to be based on an updated load forecast that reflects current conditions. We concur that it is appropriate to include an allowance for new large loads in the load forecast only if there is a signed energy service agreement, and the load forecast is based on specific supporting documentation.

### *9 Risk Analysis*

Staff is troubled by aspects of Idaho Power's stochastic risk analyses, as contrasted with the more conventional approaches used by other Oregon utilities. With the approach used by Idaho Power, an adverse combination of two or more unfavorable risk factors will never be "sampled," because only one risk factor is allowed to depart from its base value for any one "draw." Staff also recommends the company include hydro generation variability as a risk factor for its next IRP cycle, in light of Idaho Power's significant reliance on hydroelectric generation.

*Resolution*

We adopt Staff's recommendation that the 2013 IRP risk analysis should include hydroelectric generation variability. We agree with Staff's goal of working toward collaborative improvement of Idaho Power's stochastic risk analysis. At least one of the 2013 IRP meetings of the IRP Advisory Committee should focus on this subject.

### *10. Wind Integration Study*

RNP noted that Idaho Power is conducting a wind integration study internally. It encouraged the company to look for ways to lower its costs of wind integration, to seek independent technical review of its study, and to provide stakeholders the chance to provide meaningful feedback.

*Resolution*

We agree that Idaho Power should seek independent technical review of its wind integration study and allow stakeholders the opportunity to provide feedback before the study results are incorporated into the company's next IRP. Accordingly, we direct Idaho Power to form a wind integration study technical review committee that is fully engaged in the process. We also direct Idaho Power to establish a schedule for workshops, providing full opportunity for stakeholder involvement.

### *11. Solar Photovoltaic Analysis*

RNP encourages Idaho Power to evaluate the performance of solar photovoltaic projects as a class, not simply as single projects. The geographic distribution of the projects could have a significant effect of smoothing the short-term variability of single projects.

*Resolution*

We agree with RNP that Idaho Power should evaluate the performance of the solar photovoltaic projects as a class, as consistent with the goals of the pilot program.

### *12. Adherence of Plan to Integrated Resource Planning Guidelines*

Intervenors and Staff agree that Idaho Power's 2011 IRP filing did not comply with IRP Guidelines 1(c) and 4(g),[4] because the company failed to provide a comprehensive evaluation of the compliance of its existing coal fired generation resources with new, draft, and anticipated environmental regulations. Without that evaluation, it was not possible to determine whether any of the candidate resource portfolios met the specified standard.

In response to that deficiency, in its September 20, 2011 IRP presentation to the Commission, Idaho Power presented a "very high-level" evaluation of a range of costs that could potentially result if certain environmental regulations were implemented. According to the company, the existing coal-fired resources would still be less expensive than replacement natural gas generation resources, even if the company were required to spend the estimated amounts to comply with the potential federal environmental regulations.

Staff also noted that Idaho Power did not comply with IRP Guidelines 4(a) and 4(n), because the company did not explain how the utility met each substantive and procedural requirement, nor provide a concise listing of action items for all resources and resource related activities.

*Resolution*

We note Idaho Power's high-level presentation about environmental compliance costs, and expect more detailed information to be provided in the company's coal study. We agree with Staff that future Idaho Power IRPs should include: (1) an explanation of how the utility met each substantive and procedural requirement, and (2) a concise listing of action items for all resources and resource related activities, with each action item numbered.

[4] IRP Guideline 1(c) prescribes the primary goal of the IRP to be the selection of a portfolio of resources with the best combination of cost and risk for the utility and its customers. IRP Guideline 4(g) requires the utility to identify key assumptions about the future, including future enviromnental compliance costs.

## IV. ORDER

IT IS ORDERED that the 2011 Integrated Resource Plan filed by Idaho Power Company is acknowledged with conditions and exceptions contained in this order, with the action items and recommendations summarized in Appendix A .

This order memorializes the decision of the Public Utility Commission of Oregon made and effective at a public meeting held on February 14, 2012.

Dated this 21 day of May, 2012, at Salem, Oregon.

**John Savage**
Commissioner

**Susan K. Ackerman**
Commissioner

**Stephen M. Bloom**
Commissioner

# Appendix A
# Adopted Action Items and Recommendations for Future IRPs

Idaho Power 2011 Integrated Resource Plan (IRP)

Action Items:

Near-Term Action Plan (2011-2020)

Demand-Side Resource Action Items

Action Item 1 - Current Portfolio Energy Efficiency - In 2015, the forecast reduction for 2011–2015 programs will be 69 aMW; by the year 2020, the reduction across all customer classes increases to 133 aMW. By the end of the IRP planning horizon in 2030, 191 aMW of reduction is forecast to come from the current energy efficiency portfolio, with 80 percent of that reduction coming from programs serving commercial and industrial customers.

Action Item 2 - New Portfolio Energy Efficiency - In 2015, the new and expanded energy efficiency programs will reduce average loads by 13 aMW; in 2020, average loads will be reduced by 25 aMW. The full 20-year capacity of the program additions and changes is 42 aMW of average demand reduction.

Action Item 3 - Demand Response - The levels of demand response determined for the 2011 IRP analysis is 330 MW for summer 2011, 310 MW in 2012 when the Langley Gulch plant comes on line, and 315 MW in 2013 and 2014. In 2015, the demand response level used in the IRP analysis is 321 MW and then 351 MW from 2016 through the end of the planning period.

Action Item 4 – Conservation Voltage Reduction - The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The Company will propose an action item in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's load-resource balance forecasts.

Supply-Side Resource Action Items (Preferred Portfolio)

Action Item 5 - Solar - Issue a request for proposal (RFP) before the end of 2011 to design and construct a 500-kW–1-MW solar PV resource to be located in Idaho Power's service area. Evaluate proposals by mid-2012, and if a successful bidder is identified, file a request with the IPUC for a CPCN. If approved, have the facility on line as early as the end of 2012.

This solar resource will satisfy the State of Oregon's Solar PV Pilot Program requirement to build a 500-kilovolt (kV) solar PV project. Continue working with the OPUC to determine if this facility would have to be built in Oregon, which may impact the structure of the RFP.

Action Item 6 - Power Purchase Agreements - Complete 83 MW in market purchase from the east side of Idaho Power's system. The purchase is necessary to cover a summer peak-hour deficit in 2015 that exists before the Boardman to Hemingway line becomes available in 2016.

Action Item 7 - Transmission – Continue to make progress on the Boardman to Hemingway transmission project between now and the completion of the 2013 IRP, and plan to begin work on permitting and initial designs shortly after the completion of the 2013 IRP.

As the Company proceeds with the B2H project, its project assumptions (for example, construction cost estimates, equity partnership estimates, third-party subscription estimates, and wheeling revenues) will be updated and analyzed in the 2013 IRP.

~~Supply-Side Resource Action Items (Alternative Portfolio)~~

~~Action Item 8 - Solar – as described for preferred portfolio Action Item 5.~~

~~Action Item 9 - Simple Cycle Combustion Turbine – 170 MW in 2015, 170 MW in 2017, and 94 MW in 2019. If the Boardman to Hemingway transmission project is delayed, begin the acquisition process for the 2015 SCCT as early as 2012.~~

Other Action Items

Action Item 10 - Renewable Energy Certificate Management - As detailed in the REC Management Plan, continue selling RECs in the near term until they are needed to meet a federal RES.

Action Item 11 - Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants

In its next IRP Update, Idaho Power will include an Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants. The Evaluation will investigate whether there is flexibility in the emerging environmental regulations that would allow the Company to avoid early compliance costs by offering to shut down individual units prior to the end of their useful lives. The Company will also conduct further plant specific analysis to determine whether this tradeoff would be in the ratepayers' interest.

~~Long-Term Action Plan (2021-2030)~~

~~Action Item 12 – Long-Term Action Items – as outlined in IRP Table 10.2~~

Recommendations for future Idaho Power IRPs:

1. During preparation of the 2013 IRP, there be an Integrated Resource Plan Advisory Council (IRPAC) meeting specifically focused on demand response. Staff will participate in that meeting, and work with the Company and parties to develop a demand response approach that is in the best interest of ratepayers.

2. Base the 2011 IRP Update and the 2013 IRP on an updated load forecast that, as accurately as possible, reflects current conditions.

3. Related to the new large load issue, include an allowance for new large loads in the load forecast only if there is a signed energy service agreement. Further, include an allowance for new large loads in the load and resource balance, but the new large load must be based on specific supporting documentation.

4. Toward the goal of working collaboratively to improve of the stochastic risk analysis, at least one 2013 IRP IRPAC meeting should be set aside to focus on this subject. Further, the 2013 IRP risk analysis should include hydroelectric generation variability. In the risk analysis focused IRPAC meeting, the Company should vet its approach to including hydroelectric generation variability in the 2013 IRP risk analysis.

5. Form a wind integration study technical review committee as soon as possible. The committee is recommended to be fully engaged to review and offer suggestions for improvement of the Company's proposals for analytical methods and data used in the study. In addition, establish as soon as possible, a schedule for workshops providing full opportunity for stakeholder involvement and progress reviews. Finally, in the Company's next wind integration study look for ways in which diversity and flexible balancing resources could lower its cost of integrating intermittent resources.

6. Include in future IRPs an explanation of how the utility met each substantive and procedural requirement, as required by Guideline 4(a).

7. Include in future IRPs an action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, as required by IRP Guideline 4(n).

8. Include in future IRPs a concise listing of action items for all resources and resource related activities, with each action item numbered.

# ATTACHMENT N-8
# ORDER NO. 14-253 IN DOCKET LC 58

ORDER NO. 14 253

ENTERED JUL 08 2014

# BEFORE THE PUBLIC UTILITY COMMISSION

# OF OREGON

LC 58

| | |
|---|---|
| In the Matter of<br>IDAHO POWER COMPANY,<br>2013 Integrated Resource Plan | ORDER |

DISPOSITION: PLAN ACKNOWLEDGED IN PART AND AS REVISED

## I. INTRODUCTION

Idaho Power Company is a public utility operating in Oregon and is subject to the Commission's jurisdiction and requirements regarding integrated resource planning. Idaho Power's 2011 Integrated Resource Plan (IRP) was acknowledged with exceptions and guidance for its next IRP in Order No. 12-177. Idaho Power now seeks acknowledgment of its 2013 IRP.

We require each regulated energy utility to prepare and file an IRP within two years of acknowledgment of the utility's last plan. In the IRP, an energy utility must: (1) evaluate resources on a consistent and comparable basis; (2) consider risk and uncertainty; (3) aim to select a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers; and (4) create a plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies.[1]

Once a utility completes a plan, we review for adherence to the procedural and substantive requirements outlined in Order No. 89-507. We generally acknowledge the plan—that is, find it reasonable based on the information available at that time—or return it to the utility with comments.[2] We may also decline to acknowledge specific action items if we question whether the utility's proposed resource decision presents the least cost and risk option for its customers.

We reaffirm our long-standing view that decisions made in IRP proceedings do not constitute ratemaking. Decisions whether to allow a utility to recover from its customers the costs associated with new resources may only be made in a rate proceeding. Acknowledgment of an IRP, however, is relevant to subsequent examination of whether a

[1] Order No. 07-002.
[2] *Id.* at 2.

utility's resource investment is prudent and should be recovered from ratepayers. As we have previously stated:

> Consistency of resource investments with least-cost planning principles will be an additional factor that the Commission will consider in judging prudence. When a plan is acknowledged by the Commission, it will become a working document for use by the utility, the Commission, and any other interested party in a rate case or other proceeding before the Commission[.] Consistency with the plan may be evidence in support of favorable rate-making treatment of the action, although it is not a guarantee of favorable treatment.[3]

Just as acknowledgment does not guarantee favorable ratemaking, a decision to not acknowledge an action item does not constitute a preliminary determination of imprudence. The purpose of the IRP process is to provide the utility with the information and opinion of stakeholders and the Commission based on information presented by the utility. The question of whether a specific investment made by a utility in its planning process was prudent will be fairly examined in a subsequent rate case proceeding.

## II. DISCUSSION

We conclude Idaho Power satisfies all the procedural guidelines and all but one of the substantive guidelines for IRP planning. Idaho Power did not comply with the IRP Guideline regarding flexible capacity adopted in Order No 12-013.

We acknowledge the short-term action items in Idaho Power's Action Plan, except for the investment in selective catalytic reduction emissions technology at Jim Bridger Units 3 and 4.[4] In addition, we acknowledge two additional action items recommended by Staff that relate to energy efficiency. We do not acknowledge the remaining action items, which are for the most part outside the two-to-four year action plan period.[5]

## III. IDAHO POWER'S IRP

During the 20-year planning period, Idaho Power expects that the number of its customers will increase by about 8,400 each year, from approximately 500,000 in 2012 to 670,000 in 2032. Idaho Power's expected-case load forecast predicts that summer-peaking hour load requirements will grow at about 55 MW per year, and that the average-energy requirements will grow at 21 aMW per year. Idaho Power's load and resource balance analysis, which accounts for forecast load growth and generation from all of the company's existing resources and planned purchases, shows no energy deficits through the planning period. Idaho Power's analysis shows a capacity deficit starting in 2016 and monthly peak-hour deficit positions growing steadily in magnitude and the number of months affected. By July 2032, the capacity deficits are approximately 870 MW.

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[3] *Id.* at 24, *quoting* Order No. 89-507 at 7.
[4] *See* Appendix A.
[5] *See* Guideline 4(n).

Idaho Power identifies as its major resource addition the Boardman to Hemingway transmission line (B2H) with market purchases. The company's preferred portfolio also includes demand response, continued operations at the Jim Bridger and North Valmy coal facilities after investment in emission-control technology, and the continued operation of Idaho Power's other existing supply-side resources.

Guideline 4(n) requires the utility to include an action plan with resource activities the utility intends to undertake over the next two to four years. Idaho Power includes the following activities in its 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&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 – 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 |

## IV. DISCUSSION

In this order, we first address Idaho Power's Action Plan, discussing the comments filed by participants[6] and specific IRP Guidelines as appropriate. We then address issues raised by the participants or that we identify related to Idaho Power's compliance with the IRP Guidelines and our order regarding Idaho Power's 2011 IRP that are not discussed in connection with our review of the Action Plan.

[6] Renewable Northwest (RNW), the Citizens' Utility Board of Oregon (CUB), the Oregon Department of Energy (ODOE), and Staff of the Public Utility Commission (Staff) filed opening and reply comments regarding Idaho Power's IRP, and Idaho Power filed two rounds of comments in response. In addition, a resident of Idaho, John Weber, forwarded comments to Staff, which Staff forwarded to the Administrative Hearings Division for inclusion in the record.

## A. Transmission

### *1. Boardman to Hemingway*

Currently, the Boardman to Hemingway transmission project (B2H) is envisioned as a single-circuit 500 kV transmission line approximately 300 miles long between northeast Oregon and southwest Idaho. Idaho Power states that it has entered into a joint funding agreement with PacifiCorp and the Bonneville Power Administration to pursue permitting the project, under which Idaho Power is the permitting project manager.

Idaho Power proposes the following actions for the Boardman to Hemingway transmission project:

| | |
|---|---|
| *2013-2018* | *Boardman to Hemingway – Ongoing permitting, planning studies, and regulatory filings* |
| *2018* | *Boardman to Hemingway – Transmission line complete and in service* |

#### *a. Participants' Comments*

RNW supports investment in B2H because it would provide Idaho Power not only with transmission to a liquid market, enabling the company to access low-cost resources to meet capacity and energy needs, but to also generate revenue by selling energy to other regional utilities. RNW also contends B2H will provide environmental benefits by enabling Idaho Power to reach renewable energy resource zones, thereby facilitating renewable energy resources.

Staff recommends acknowledgement of ongoing permitting, planning studies, and regulatory filings for B2H. Staff notes that B2H is included in five of the nine portfolios modeled in the 2013 IRP. The preferred portfolio and the next lowest "total costs portfolios" include B2H. Staff finds that the IRP analysis regarding B2H supports acknowledgment of ongoing permitting, planning studies, and regulatory filings.

Staff recommends, however, that we decline to acknowledge B2H "Transmission line complete and in-service" in 2018. Staff reports that the estimated in-service date for B2H has moved from 2018 (the year noted in Idaho Power's IRP) to 2020 (the year reported in the company's reply comments). Staff concludes this action item is now well beyond the two-to-four year period prescribed in the IRP Guidelines.

With respect to Idaho Power's activities that occur between the our order in this docket and Idaho Power's 2015 IRP, Staff asks to be apprised of any (1) updated project plan incorporating changes related to Bureau of Land Management delays and Energy Facilities Siting Council developments; (2) final agreement regarding allocation of construction costs between project participants; and (3) significant regulatory decisions that impact the project schedule or costs. Staff also asks that the company to further explore whether B2H would significantly impact wind generation curtailment during

periods of low demand as well as the impact of B2H on resource integration costs in general.

In its first round of comments, Idaho Power asserts that Staff's recommendation to acknowledge only the permitting activities of B2H and not the construction phase of the project is inconsistent with the our past acknowledgment of B2H and is unnecessary to ensure continued analysis of this project. In its final comments, Idaho Power states that it is only requesting acknowledgment of specific action items scheduled to occur within the next four years (which excludes the construction of B2H), but does ask that we acknowledge the 2013 IRP in its entirety, which includes B2H in its preferred portfolio.

*b. Commission Resolution*

We acknowledge ongoing permitting, planning studies, and regulatory filings for B2H. As Staff notes, the analysis in the IRP supports these planned near-term activities. We anticipate additional analysis regarding B2H in Idaho Power's 2015 IRP before acknowledging other actions related to B2H.

We decline to acknowledge completion of B2H because it is well beyond the two-to-four year period for action items specified by the IRP Guidelines. Further, we disagree with any suggestion that declining to acknowledge the construction of B2H is inconsistent with our previous acknowledgment of certain activities (*e.g.*, permitting) related to this resource or inconsistent with previous orders acknowledging IRPs based on a preferred portfolio that includes B2H. Our acknowledgment of an IRP is based on our conclusion that it complies with our guidelines and that the plan seems reasonable based on information known at the time.

*2. Gateway West*

Gateway West is a multi-segment, multi-year, joint transmission project of Idaho Power and PacifiCorp/Rocky Mountain Power to build and operate approximately 1000 miles of new transmission lines from Wyoming to the Hemingway Substation near Melba, Idaho. The project timeline indicates line segments in service between 2019 and 2023. Idaho Power has a one-third interest in some, but not all, of the segments to be located in Idaho and sole interest in one segment.

Idaho Power asks for acknowledgment of the following action item related to Gateway West:

*2013* *Gateway West – Ongoing permitting, planning studies, and regulatory filings*

Idaho Power reports that the Gateway West and B2H projects 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 a population center in Utah. Idaho Power states that Gateway West will benefit customers by (1) relieving transmission constraints on certain transmission paths allowing Idaho Power to move additional energy between the east and west sides of the system; (2) providing the option

to locate future generation resources east of the Treasure Valley load center; and (3) providing future load service to the Magic Valley from the Cedar Hill Substation. Idaho Power does not request acknowledgment of Gateway West as a supply side resource. Instead, the company asserts that Gateway West is reasonable to address transmission system constraints and provide for future least cost resource development.

*a. Participants' Comments*

RNW supports investment in Gateway West because it will provide the same benefits that B2H will provide—that is, access to low-cost resources, access to regions where renewable resources could be sited, and reliability.

CUB recommends that we not acknowledge Gateway West as presented. CUB notes that Gateway West is a large project composed of a number of segments that can be analyzed individually. CUB asserts that Idaho Power should narrow its request and seek acknowledgment only of the segments of Gateway West that it can demonstrate are cost effective for Idaho Power's customers.

Staff concludes that, although there is insufficient information to support acknowledgment of the construction of Gateway West, we should acknowledge the permitting-related activities that must occur prior to construction. For purposes of Idaho Power's next IRP, however, Staff recommends that the company include an analysis of the historical and projected power flows for the portions of the Gateway West project in which Idaho Power has an interest in order to demonstrate the need and specific constraint-related benefits.

*b. Commission Resolution*

We acknowledge ongoing permitting, planning studies, and regulatory filings for Gateway West. However, as CUB notes, the project is composed of multiple segments that can and should be analyzed individually. Moreover, Idaho Power has an ownership interest in relatively few of the segments and must demonstrate the need and specific constraint-related benefits for each segment in which it holds an interest before we will consider acknowledgment of the project's construction.

## B. Pollution Control Investments in Coal Resources

### *1. Idaho Power's Analysis*

IRP Guideline 8, as modified by Order No. 08-339, contains four requirements related to environmental costs. Under this guideline, the utility must model a base case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide ($CO_2$), nitrogen oxides, sulfur oxides, and mercury emissions. The utility must also develop several compliance scenarios ranging from the present $CO_2$ level to the upper reaches of credible proposals by governing entities. Then, the utility must estimate, under each of the compliance scenarios, the present value of revenue requirement (PVRR) cost and risk measures in its preferred portfolio and alternate portfolios. Guideline 8 directs the utility to identify the $CO_2$ emission cost adder level

that triggers the selection of a portfolio that is substantially different from the preferred portfolio. In addition, Guideline 8 requires utilities develop a portfolio to achieve voluntary carbon emission reduction targets set forth in Oregon law.

*a. Participants' Comments*

RNW asserts that Idaho Power's analysis of its coal resources failed to meet IRP Guideline 8 because the company did not (1) model natural gas conversions of the Jim Bridger Units 3 and 4 boilers; (2) model a range of pollution control costs; and (3) account for recent direction from President Obama's Administration that may reduce the cost competitiveness of existing coal resources. RNW asserts that investing in coal units is generally not reasonable under scenarios with low natural gas costs or stringent $CO_2$ regulation or both.

CUB also criticizes Idaho Power's analysis, and contends the company failed to consider all possible scenarios. CUB proposes a four-part, Boardman-style analysis that (1) allows potential pollution controls under different scenarios; (2) compares the broader range of pollution control scenarios to alternative investments, such as repowering with natural gas, building a CCCT, or relying on front office transactions; (3) investigates whether there is a plausible scenario for a phase-out that is at a lower cost than either of the two options; and (4) analyzes whether committing to close a plant at the end of its depreciable life would reduce pollution control costs.

Staff voices a concern similar to CUB's regarding Idaho Power's failure to consider a range of early shutdown scenarios. Staff notes that Idaho Power compared the cost of early shutdown and no controls against other alternatives, but did not model a range of early shut-down scenarios, *e.g.*, smaller pollution control investment in exchange for shutdowns at different points in time, which Staff expected would be done. Like CUB, Staff recommends that future coal analysis consider alternative dates for pollution control equipment, shut down, or other alternatives such as gas conversion.

Staff concludes that Idaho Power's analysis is sufficient to comply with the IRP Guidelines, as well as our direction, provided in 2012, to evaluate whether there is flexibility in the emerging environmental regulations that would allow the company to avoid early compliance costs by offering to shut down individual units prior to the end of their useful lives.

Idaho Power responds that its modeling complies with Guideline 8. Idaho Power notes that it modeled three levels of carbon adders to evaluate the potential impact of carbon emissions regulations in its coal study and in the IRP. In addition, Idaho Power explains it created an alternate portfolio in which the North Valmy units are converted to a gas-fired plant and Jim Bridger Units 3 and 4 are replaced with combined cycle combustion turbines (CCCTs). Idaho Power points out that President Obama's announcement regarding $CO_2$ regulation was issued the same month Idaho Power filed its IRP and that Idaho Power could not account for the announcement without delaying the filing of the 2013 IRP. And, Idaho Power asserts the June 2013 Presidential Memorandum concerned regulations for new power plants and none are included in the company's IRP.

*b. Commission Resolution*

We conclude that Idaho Power's IRP complies with IRP Guideline 8, but as discussed below, is not sufficient to provide a basis to support acknowledgment of selective catalytic reduction emission-control technology (SCR) at Jim Bridger Units 3 and 4. Guideline 8 does not require Idaho Power to model every feasible alternative scenario, but requires the company to determine the PVRR costs and risk measures of a "set of reasonable alternative portfolios" assuming a range of different compliance scenarios. Although Idaho Power did not model a scenario in which both North Valmy units and Bridger Units 3 and 4 were converted to natural gas facilities, as RNW believes should have been done, Idaho Power did model a scenario in which North Valmy is converted to natural gas and Bridger Units 3 and 4 are replaced with CCCTs (portfolio 6). In addition, although Idaho Power did not build a compliance scenario that specifically accounts for the June 2013 Presidential Memorandum, Idaho Power did test its portfolios against a range of carbon compliance futures including a carbon adder in the planning case of $14.64 per ton beginning in 2018 and escalating three percent annually, and a carbon adder in the high case of $35 per ton beginning in 2018 and escalating nine percent annually.

The carbon adder was modeled at three levels: low ($0), planning, and high. Idaho Power did not model a distribution of values, as was done with gas prices, load, and hydro in the stochastic analysis. Instead, one-third of the simulations were drawn from each carbon adder level. The company's analysis showed the preferred portfolio 2 and the non-coal portfolio 6 would switch places at a carbon adder of $45 in 2018. We find the alternative portfolios selected by Idaho Power and the range of compliance futures sufficient to satisfy the requirements of Guideline 8.

We share CUB's and Staff's concern regarding the limited nature of Idaho Power's early retirement scenarios analysis. Even though Idaho Power may have technically complied with the action item from Order No. 12-177, we expected that Idaho Power would model a broader range of early shutdown scenarios. We expect Idaho Power to engage fully with Staff and stakeholders in a timely manner to design coal investment analyses for future IRPs to ensure more robust consideration of early shutdown as a compliance option.

Also, we direct Idaho Power to work with stakeholders to explore options for how it plans to model and perform analysis in the 2015 IRP in order to comply with the applicable emissions requirements of §111(d) of the Clean Air Act.

***2. North Valmy Unit 1***

North Valmy is a coal-fired plant consisting of two generating units located in Nevada. Idaho Power is a 50 percent owner of North Valmy. After adjusting for routine scheduled maintenance and estimated forced outages, the annual energy generating capability of Idaho Power's share of the plant is approximately 220 aMW. Idaho Power plans on the continued operation of North Valmy Unit 1 throughout the 20-year planning period of the 2013 IRP and both units of North Valmy are included in Idaho Power's preferred portfolio.

Idaho Power proposes the following action for North Valmy Unit 1 to comply with federal Mercury Air Toxics Standards (MATS):

*2013* *North Valmy Unit 1 – Commit to the installation of dry sorbent injection emission-control technology*

*a. Participants' Comments*

CUB is concerned because Idaho Power's preferred portfolio includes North Valmy with an end-of-life date that CUB fears is too far in the future. CUB notes that the end-of-life date for North Valmy is at or beyond the end of the 20-year planning period in Idaho Power's preferred portfolio but that the co-owner of North Valmy, Nevada Energy, has announced plans to close the plant in 2025.

Idaho Power responds that it modeled North Valmy consistently with its current expectation of the end-of-life date. Idaho Power asserts that Nevada Energy cannot close the plant early without Idaho Power's consent, which it has not given. Also, Idaho Power modeled two portfolios that included a shortened end-of-life date for North Valmy and replacement of lost energy with other resources. These portfolios were higher cost than the preferred portfolio.

Staff recommends acknowledgment of DSI installation. Staff finds that because the cost of the investment is so small, there is no tipping point in the modeled scenarios at which it is more cost-effective to shut down North Valmy rather than invest in DSI.

*b. Commission Resolution*

We acknowledge installation of DSI at North Valmy Unit 1. We find as Staff did that the relatively low cost of the investment leads to the conclusion that the DSI investment and continued operation of North Valmy is the least cost/least risk alternative given the information that is currently available.

We do not share CUB's concern regarding how Idaho Power included North Valmy in its preferred portfolio. First, shortening the life of North Valmy would not change the result of Idaho Power's analysis; installing DSI would still be the least cost/least risk alternative. Second, future events may lead to a shortened operating life for North Valmy, but whether they will is not certain. Idaho Power reasonably relied on the results of modeling based on the assumption North Valmy will operate as Idaho Power currently expects, rather than an assumption based on events that may, or may not, transpire.

***3. Jim Bridger Units 3 and 4***

Jim Bridger is a coal-fired plant consisting of four generating units located in Wyoming. Idaho Power owns one-third of the plant, or 771 MW. The Environmental Protection Agency (EPA) submitted a final rule on January 10, 2014, requiring the installation of selective catalytic reduction emission-control technology (SCR) at Bridger Units 3 and 4 by December 31, 2015 and December 31, 2016, respectively. Idaho Power's application to the Idaho Public Utilities Commission (IPUC) for a Certificate of Public Convenience

and Necessity states that Idaho Power's cost before AFUDC is estimated to be approximately $118 million.

Idaho Power proposes the following action for Jim Bridger Units 3 and 4:

*2013* — *Jim Bridger Units 3 and 4 – Commit to the installation of selective catalytic reduction emission-control technology*

*a. Participants' Comments*

CUB and RNW recommend that we not acknowledge pollution control investments at Jim Bridger Units 3 and 4, contending additional analysis is needed. Specifically, CUB asserts that Idaho Power should analyze the effect that different early retirement dates would have on the need for pollution controls at Bridger Units 3 and 4 to inform whether the currently planned investment is cost-effective. CUB notes that a shorter life may reduce the controls needed (and therefore costs), making early retirement of coal plants more cost-effective than other options. RNW adds that Idaho Power did not adequately analyze conversion to natural gas or a sufficient range of future $CO_2$ compliance costs. Also, RNW believes that investing in coal units is generally not reasonable under scenarios with low natural gas costs or stringent $CO_2$ regulation or both.

Idaho Power disagrees with RNW's and CUB's conclusions regarding its analysis for Bridger Units 3 and 4, noting that it examined a range of options including early shutdown and conversion to natural gas, and that its analysis shows that installation of SCR at Bridger Units 3 and 4 is the least cost option for the majority of the alternate carbon and natural gas scenarios it modeled.

Staff recommends we acknowledge installation of SCR at Bridger Units 3 and 4. Staff concludes that Idaho Power's coal study demonstrates that the SCR investments are the lowest cost compared to the alternatives analyzed under planning case assumptions and in the majority of the carbon and gas sensitivities. In addition to reviewing the coal study, Staff constructed an independent spreadsheet analysis of the impact of a range of gas and carbon prices on the economics of the SCR investments, which confirmed the coal study results.

*b. Commission Resolution*

Based on the information we have at this time, we decline to acknowledge Idaho Power's action item related to Bridger Units 3 and 4. Our decision regarding these investments is inextricably tied to our decision regarding the same investments in the docket opened to address PacifiCorp's IRP, docket LC 57. In that docket, we did not acknowledge the investments for Bridger Units 3 and 4 for four interrelated reasons.

First, some of the alternatives modeled by PacifiCorp suggest that the installation of SCR at Bridger Units 3 and 4 is not the lowest cost resource option. Second, there were gaps in the analyses conducted by PacifiCorp. Third, some of the questions raised by Staff and other participants on the merit of retaining or retiring the units were not fully fleshed out, while others are more appropriately addressed in a rate proceeding. Finally, PacifiCorp,

the managing utility, is proceeding with the investments, which calls into question the appropriateness of addressing the investments in a planning docket.

We recognize that Idaho Power conducted its own analysis of whether installing SCR at Bridger Units 3 and 4 is the least cost and least risk option. However, Idaho Power's analysis does not persuade us to reach a resolution in this docket that differs from that in docket LC 57, at least in part because of deficiencies in Idaho Power's analysis. More specifically, Idaho Power did not (1) analyze a full range of reasonable scenarios; (2) consider a wider range of resource replacement options as PacifiCorp; or (3) evaluate an adequate range of natural gas price sensitivities.

Idaho Power is proceeding with the investments. We will undertake a fair and thorough investigation of the prudence of the SCR investments when Idaho Power seeks rate recovery. Our decision to not acknowledge them in this docket does not prejudge the prudence of the investments for purposes of rate recovery.

## C. Demand Response

Idaho Power proposes the following near-term action related to demand response:

*2016-2017* *Have demand response capacity available to satisfy deficiencies up to approximately 150 MW*

### *a. Participants' Comments*

Staff notes that both the Oregon and Idaho commissions recently issued orders approving stipulations regarding the redesign of Idaho Power's demand response programs for 2014 and beyond. Those stipulations provide that the annual value of demand response is equal to the levelized annual cost of the minimum size deferred resource, or 170 MW. Therefore, Staff recommends changing this action item to read: "Have demand response capacity available to satisfy deficiencies up to approximately ~~150 MW~~ 170 MW beginning in 2014, and increasing as needed through 2017."

Staff also recommends that the company update its assessment of demand response availability based on summer 2014 program participation and other relevant factors by the end of 2014. In addition, Staff recommends that the Energy Efficiency Advisory Group review any revisions to the resource assessment, along with other relevant factors.

RNW supports Idaho Power's continuation of its demand response program to meet the company's capacity needs.

### *b. Commission Resolution*

We agree that revising the near-term demand response action item as recommended by Staff is appropriate in light of recently concluded dockets in Oregon and Idaho regarding demand response. We acknowledge the action item as revised by Staff. We also expect that Idaho Power will follow Staff's recommendation regarding updating its assessment of demand response availability in 2014.

## D. Long-term Action Items

Idaho Power's Action Plan includes the following long-term activities:

| | |
|---|---|
| *2019* | *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* |
| *2024-2032* | *Demand Response – Have demand response capacity available to satisfy deficiencies in 50 MW increments up to approximately 370 MW* |

### *a. Participants' Comments*

Both Staff and CUB note, and Idaho Power acknowledges, that Idaho Power's Action Plan includes long-term action items in addition to the short-term action items typically presented in an IRP action plan. Staff and CUB recommend that we not acknowledge action items occurring beyond a two-to-four year period. In response, Idaho Power states that it does not seek acknowledgment of the long-term items.

### *b. Commission Resolution*

Although Idaho Power states it does not seek acknowledgment of these long-term action items, they remain part of the company's IRP. For this reason, we believe it is necessary to address them. We do not acknowledge these action items because, as Staff and CUB note, the purpose of an action plan is to identify specific near-term actions that the company plans to take to meet its resource needs.[7] We generally do not acknowledge action items planned to occur more than four years in the future.[8]

## D. Analysis of IRP

### *1. Wind Resources*

#### *a. Participants' Comments*

Several participants raise concerns related to wind resources. RNW asserts that Idaho Power's IRP underestimates the capacity factor of modern wind turbines and includes an unsupported and unreasonably high wind integration rate.

Staff and RNW raise concerns about Idaho Power's wind integration study (WIS), and the company's use of the technical review committee (TRC) we recommended the

[7] *See* Order No. 12-177.
[8] *Id.*

company form to improve such studies.[9] Staff notes that it anticipated more involvement of the TRC and recommends that Idaho Power engage with the TRC for future IRPs. RNW adds that Idaho Power's WIS based the size of the required balancing reserve on the difference between the day-ahead forecast and actual generation, which increased the assumed balancing reserves and costs. RNW notes that the TRC we required in Order No. 12-177 flagged this methodological assumption as a significant concern. Staff shares RNW's concern, and has reservations about using the study results in future filings.

In response to RNW's concern regarding overstated costs, Idaho Power notes the cost difference between the National Renewable Energy Laboratory (NREL) report and its costs comes from the conversion of 2009 dollars to 2013 dollars, the common base for the IRP's comparison of resource costs. In response to RNW's concern regarding the size of the balancing reserves, Idaho Power states that it chose to base the assumption on the day-ahead forecast because balancing reserves based on the hour-ahead forecast "would too often translate to a risky reliance on the wholesale energy market."

In response to RNW's concern regarding the average capacity factor, Idaho Power asserts that the NREL reports that Class 3 resources have an average capacity factor of 33 percent—a percentage Idaho Power adjusted downward to account for lower capacity factors of Class 2 resources. Idaho Power also asserts that its actual observations support the 26 percent average capacity factor used in the WIS and IRP.

In response to Staff's and RNW's concern regarding the role of the TRC, Idaho Power notes that we directed the company to form the committee in February 2012, nearly a year after the company had begun work on the WIS. Idaho Power announced the formation of the committee at an April 2012 workshop, but by this time the study was complete and the company was presenting preliminary study results.

*b. Commission Resolution*

We appreciate that Idaho Power responded quickly to our recommendation but are disappointed the TRC did not prove to be an effective mechanism for stakeholders to engage with Idaho Power regarding the analytical methodology of the WIS. Using the TRC to review and provide comments on the analytical methodology and results is not what we envisioned when making our 2012 recommendation. But, we recognize that our recommendation came late in Idaho Power's process, limiting the opportunity for TRC input.

We continue to recommend use of a TRC in connection with wind integration studies. The TRC could be an effective mechanism for stakeholders to engage with the company regarding the analytical methodology underlying the study and expect Idaho Power to engage with the TRC at the outset of any future study.

Regarding RNW's specific complaints regarding the WIS, we note that RNW does not urge us to disregard the WIS for the purpose of judging the reasonableness of Idaho Power's IRP, but cautions against using the WIS to determine avoided cost prices in a

[9] *Id.* at Appendix A at 3.

future proceeding. Our acknowledgment of Idaho Power's IRP has no effect on the validity of the WIS during any proceeding to establish avoided cost prices for variable wind resources. We do note, however, that effective engagement between stakeholders and utilities regarding the study methodology and inputs would likely lessen disagreements in any proceeding in which the accuracy of the study is at issue.

### 2. *Capacity Contribution of Solar and Other Resources*

#### a. *Participants' Comments*

ODOE recommends certain changes to how Idaho Power examines capacity credits for solar, wind, and hydro resources, and how the company models orientation of flat-plate solar PV systems.

Idaho Power disagrees with ODOE's specific recommendation regarding the capacity contribution, but recognizes that solar resources are unique and that its analysis must address numerous considerations such as tracking systems, resource orientation, and materials. Idaho Power states it seeks to attribute the proper capacity credit to distributed solar PV and has initiated an IRP Advisory Council distributed solar PV workgroup to address the cost and capacity credit of distributed solar PV in the 2015 IRP. Idaho Power states that it anticipates the workgroup will address topics such as panel orientation and tracking systems. Idaho Power also states that it is analyzing integration of large-scale solar PV projects and working on this topic with members of its Solar Integration Study Technical Review Committee.

#### b. *Commission Resolution*

We appreciate Idaho Power's willingness to work on the issues identified by ODOE for its next IRP. We hope Idaho Power will work directly with ODOE. In any event, we expect to see results of Idaho Power's work in its 2015 IRP.

### 3. *Gas Price Forecasts*

#### a. *Participants' Comments*

Staff comments on three aspects of Idaho Power's natural gas price forecasts used in the IRP. Staff expresses concerns regarding the symmetric adjustments to the base case forecast, the escalation of the Energy Information Administration (EIA) reference case gas price forecast, and the high correlation between natural gas prices and wholesale electricity prices in the company's modeling. Staff identifies gas price forecasts as an issue to be analyzed during the development of the 2015 IRP. The company responds that its stochastic inputs are reasonable and that it will consider alternatives to deriving high and low gas price scenarios for future IRPs.

#### b. *Commission Resolution*

We anticipate that these analytical issues will be raised by Staff and addressed during the planning process for the 2015 IRP.

### 4. *Flexibility Guideline*

In our investigation of matters related to electric vehicle charging, we adopted our Staff's recommendation to add an IRP guideline to require utilities to incorporate planning for flexible capacity in IRPs.[10] Utilities must forecast the balancing reserves needed at different time intervals to respond to variation in load and intermittent renewable generation over the 20-year planning period and to forecast the availability of balancing reserves at different time intervals. In planning to fill any gap between the demand and supply of flexible capacity, utilities must also evaluate all resource options on a consistent and comparable basis.

#### *a. Participants' Comments*

RNP asserts that Idaho Power's IRP does not comply with the IRP Guidelines because it does not forecast the demand for and supply of flexible capacity, or evaluate flexible resources on a consistent and comparable basis. RNW suggests that future IRPs should quantify the existing supply of flexible resources across multiple time scales, quantify the amount of reserves associated with each supply-side resource, and expand types of demand for flexible resources, *e.g.*, need to meet hourly ramps of load and other variable resources.

Idaho Power responds that its 2013 IRP did, in fact, include much of the flexibility analysis that RNW asserts is lacking. Idaho Power notes that a pumped storage hydro project was modeled as a resource alternative and as a tool to assist in the integration of wind resources. Idaho Power asserts that this modeling captured the flexibility and peaking capacity of the pumped storage hydro project and helped to integrate the variable wind generation into the system, and captured market arbitrage opportunities.

Staff recognizes that the company provided qualitative analysis that shows it is unlikely Idaho Power will need additional flexible capacity over the 20-year planning horizon, but agrees with RNW that the guideline asks for quantitative analysis of the size and timing of the flexible capacity resource balance. Staff recommends that Idaho Power substantially expand its analysis in the 2015 IRP. Staff is willing to work with Idaho Power and other stakeholders to help develop the quantitative analysis.

#### *b. Commission Resolution*

We find that Idaho Power's IRP does not comply with the Flexible Resources Guideline. Idaho Power did not submit the required analysis of demand and supply of balancing reserves disaggregated across multiple timescales. We expect the company to use the recommendations of both RNW and Staff to provide a compliant and more robust analysis regarding flexible resources in its 2015 IRP.

[10] Order No. 12-013 at16-18.

### 5. *Conservation Voltage Reduction*

Staff states that Idaho Power failed to include the required assessment of the available cost effective conservation voltage reduction (CVR) in its service area. Staff explains that we directed the assessment in our review of Idaho Power's 2012 IRP:

> The next IRP filed by Idaho Power will include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in its service area. The company will propose an action item in its 2013 IRP related to this resource. The planned energy savings and reduced peak demand will be incorporated into Idaho Power's load-resource balance forecasts.[11]

We agree that Idaho Power's 2013 IRP failed to include this assessment, and direct the company to provide this assessment in its 2015 IRP.

In the interim, we direct our Staff to conduct the independent CVR and Volt/Var Ampere Reactive control programs we ordered in Idaho Power's 2013 Annual Smart Grid Report.[12] Staff should conduct the analysis within the next six months and report the results of the analysis to us at a public meeting.

### 6. *Energy Efficiency*

Although Idaho Power's IRP contains specific energy efficiency targets as part of its plan, the company does not include those amounts in the Action Plan. Staff proposes two action items to address energy efficiency:

| | | |
|---|---|---|
| *2013-2017* | *Energy Efficiency* | *The forecast reduction for 2013 to 2017 programs will be 69 aMW* |
| *2013-2017* | *Energy Efficiency* | *The incremental energy efficiency savings for 2013 to 2017 will reduce energy loads by 38 aMW* |

We adopt Staff's proposed additions to the Action Plan.

### 7. *NEEA*

Idaho Power plans to curtail funding to the Northwest Energy Efficiency Alliance (NEEA) in the next five-year funding cycle. Idaho Power explains that it has asked NEEA to operate under an alternative funding model that would allow Idaho Power's funds to be directed toward the costs of activities that Idaho Power believes are most valuable to its customers. Idaho Power supports the concept of optional programs in NEEA's 2015-2019 Business Plan in which funders could choose to participate and fund certain programs or opt out of them altogether.

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[11] Order No. 12-177 at 5.
[12] Order No. 13-481 at 1-2.

*a. Participants' Comments*

CUB and Staff are concerned with Idaho Power's proposal to curtail funding to NEAA. Staff believes that NEAA is one of Idaho Power's most cost effective energy investments. Staff notes that NEEA is a compact between over 100 Northwest utilities and efficiency organizations that creates value for its supporters by broad market intervention and energy efficiency market development. NEEA's activities have resulted in the development of an energy efficiency products and practices pipeline to the region that benefits Idaho Power's and the region's ratepayers.

*b. Commission Resolution:*

We do not know Idaho Power's final decision about continued participation in NEEA. However, we are dismayed by the possibility that Idaho Power's approach could undermine support for regional market transformation. We agree with Staff's observations of the importance of NEEA. We believe that market transformation is an integral part of an effective energy efficiency strategy to lower cost and risk to ratepayers. Based on our analysis and our continued oversight of funding to NEEA from Oregon ratepayers, we believe that NEEA is capturing cost-effective energy efficiency over the long run and expanding opportunities for cost-effective energy efficiency in the future. For those programs Idaho Power opts out of, we expect Idaho Power will acquire commensurate savings from equivalent services at a cost equal to or less than what NEEA could provide.

## D. Recommendations For Idaho Power's 2015 IRP

In Order No. 12-177, we reminded Idaho Power that IRP Guideline 4(n) requires utilities to include in an IRP action plan the resource activities the utility plans to undertake over the next two to four years to acquire the identified resources. We also recommended that Idaho Power's future IRPs include a "concise listing of action items for all resources and resource related activities, with each action item numbered."[13]

Idaho Power did include an action plan with resource activities it plans to take in the next two to four years, but the plan also includes longer-term actions. We clarify that, in future IRPs, Idaho Power should limit its Action Plan to activities it plans to undertake in the next two to four years. Idaho Power may compile other lists of activities planned for an extended period, as it has done in this IRP, but we recommend the company create and identify the action plan activities for which it requests specific acknowledgment. Again, we recommend that the company number each of these action items to facilitate our review.

## E. IRP Update

Staff sought delays in these proceedings to facilitate our review of resource action items presented for acknowledgment in both PacifiCorp's IRP and Idaho Power's IRP.

[13] Order No. 12-177 at 8.

As a result of this delay, Idaho Power's annual update to its 2013 IRP, which is due no later than 12 months after acknowledgment. However, Idaho Power must file its 2015 IRP with the Idaho Public Utilities Commission no later than June 2015. Idaho Power intends to file an IRP in Oregon at the same time it files in Idaho.

Given that Idaho Power will file its next IRP with the Idaho commission by June 2015, we waive the requirement that Idaho Power file an annual update to this IRP. This waiver addresses only a routine IRP update, and we expect Idaho Power to file an IRP update if it anticipates a significant deviation from its acknowledged 2013 IRP in the manner required by IRP Guideline 3(f).

## V. ORDER

IT IS ORDERED that the 2013 Integrated Resource Plan filed by Idaho Power Company is acknowledged in part consistent with the terms of this order.

Made, entered, and effective JUL 08 2014.

**Susan K. Ackerman**
Chair

**John Savage**
Commissioner

**Stephen M. Bloom**
Commissioner

# Appendix A

**Acknowledged Action Plan Items**

| 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 |
| 2016-2017 | Have demand response capacity available to satisfy deficiencies up to approximately 170 MW beginning in 2014, and increasing as needed through 2017 |
| 2013-2017 | Energy efficiency – The forecast reduction for 2013 to 2017 programs will be 69 aMW |
| 2013-2017 | The incremental energy efficiency savings for 2013-2017 will reduce energy loads by 38 aMW |
| 2013-2015 | CVR – Include an assessment of the available cost-effective conservation voltage reduction (CVR) resource potential in service area and an action item related to this resource in the next IRP. Incorporate the planned energy savings and reduced peak demand into load-resource balance forecasts. |

# ATTACHMENT N-9
# ORDER NO. 16-160 IN DOCKET LC 63

ORDER NO. 16 160

ENTERED: APR 28 2016

# BEFORE THE PUBLIC UTILITY COMMISSION

# OF OREGON

LC 63

| | |
|---|---|
| In the Matter of<br><br>IDAHO POWER COMPANY,<br><br>2015 Integrated Resource Plan. | ORDER |

DISPOSITION: STAFF'S RECOMMENDATION ADOPTED AS REVISED

This order memorializes our decision made at the March 24, 2016 Special Public Meeting regarding Idaho Power Company's 2015 Integrated Resource Plan (IRP). At the meeting, we adopted Commission Staff's recommendation to acknowledge Idaho Power's 2015 IRP, as revised by Staff's presentation during the meeting. As we stated at the close of the meeting, our decision to not acknowledge certain action items was based on procedural reasons rather than the merits of the action items.

The Staff Report with its initial recommendation is attached as Appendix A. During the public meeting, Staff made the following revisions to this initial recommendation:

*Action Items 5, 7, 10, and 12* – Staff recommends that we not acknowledge these items. Staff explains that these actions are better suited for evaluation in a general rate case as they relate to a facility upgrade that no longer is forecast to meet any resource need.

*Action Items 6 and 8* – Staff recommends that we not acknowledge these items. Staff recommends that we wait and review these actions in a general rate case as they relate to installation of emission-control technology that is already completed or is significantly underway.

*Action Item 11* – Staff recommends that we not acknowledge this item. Staff reasons that the act of evaluating installing emission-control technology is outside the usual scope of IRP acknowledgement and suggests we wait and address the outcome of the evaluation (rather than the decision itself to evaluate).

For the convenience of the parties, we attach, as Appendix B, a list summarizing all of the action items and our decision as to each item.

## ORDER

IT IS ORDERED that the 2015 Integrated Resource Plan, filed by Idaho Power Company, is acknowledged consistent with the terms of this order and the attached Appendices A & B.

Dated this 28 day of April, 2016, at Salem, Oregon.

**Susan K. Ackerman**
Chair

**John Savage**
Commissioner

**Stephen M. Bloom**
Commissioner

ORDER NO. 16 160

**ITEM NO.1**

**PUBLIC UTILITY COMMISSION OF OREGON**
**STAFF REPORT**
**PUBLIC MEETING DATE: March 24, 2016**

**REGULAR** X **CONSENT** ____ **EFFECTIVE DATE** **Upon Commission's Approval**

**DATE:** March 8, 2016

**TO:** Public Utility Commission

**FROM:** Michael Breish MB

**THROUGH:** Jason Eisdorfer and Aster Adams

**SUBJECT:** IDAHO POWER COMPANY: (Docket No. LC 63) Acknowledgement of the 2015 Integrated Resource Plan.

**STAFF RECOMMENDATION:**

Staff recommends the Commission acknowledge Idaho Power Company's (Idaho Power or Company) 2015 Integrated Resource Plan (IRP) with certain recommendations.

**DISCUSSION:**

**Procedural History**

Idaho Power filed its 2015 IRP on June 30, 2015. The Company's filing included the IRP and three appendices.[1] Gail Carbiener, a member of the public, filed initial comments on October 22, 2015. Commission Staff (Staff) and the Citizen's Utility Board (CUB) filed initial comments on November 25, 2015. Idaho Power filed reply comments on December 30, 2015. Mr. Carbiener filed his final comments on January 8, 2016, and CUB and Staff filed final comments on January 22, 2016. Idaho Power filed final reply comments on February 19, 2016.

Idaho Power held 12 IRP Advisory Council (IRPAC) meetings leading up to the submission of the 2015 IRP. IRPAC members represent various public agencies, public and private enterprises, and advocacy groups. The IRPAC covers aspects of the IRP development, particularly on the resource stack, resource portfolio considerations and

[1] The appendices are the "Sales and Load Forecast," the "DSM Annual Report," and the "Technical Report."

risk analyses. The IRPAC played an integral role this year in discussing matters related to the Environmental Protection Agency Clean Power Plan (CPP), promulgated pursuant to the Clean Air Act, Section 111(d) (Section 111(d)), as well as distributed energy resource integration. Staff appreciated the open and involved stakeholder process that Idaho Power dedicates time and energy into in order to fulfill the public input component of the Company's IRP process.

Staff discusses the comments by the parties and the Company, referencing the near-term action plan, long-term planning aspects of the preferred portfolio, and other IRP issues. The original IRP action plan is set forth in Attachment A to this memo.

**General Description of the IRP**

Idaho Power's IRP presents an analysis that considers costs, risks, and uncertainties of various resource portfolios designed to sufficiently satisfy system load, reliability, and flexibility needs over the next 20 years. Idaho Power analyzed 23 resource portfolios under seven different CPP scenarios as well as three variables in a stochastic analysis.[2] Not only was this a significant increase in the number of portfolios provided with previous IRPs, but the diversity of resource considerations within those portfolios increased as well.

Of critical importance in the 2015 IRP are the fates of Idaho Power's two remaining coal-fired generating plants, North Valmy located in Nevada and Jim Bridger located in Wyoming. Because Idaho Power's 2015 IRP was published at the time of only the draft Section 111(d) rules, Idaho Power's analysis reflects the Company's best assumption of what the final Section 111(d) rule may be. Staff addresses final Section 111(d) considerations later in this report.

With a peak-hour capacity deficit first occurring in 2025 under the Company's preferred portfolio, the 2015 IRP action plan features no additional planned generation. Beyond the ongoing processes related to the Boardman-to-Hemingway (B2H) and Gateway West transmission lines, the only significant actions in the 2015 IRP Action Plan relate to completion and consideration of emissions technology on Jim Bridger units and an upgrade of the Shoshone Falls generation station.

**Compliance with Commission IRP Guidelines**

In its Final Comments, Staff asserted that Idaho Power was not compliant with IRP Guidelines 1 and 12 due to aspects of the Company's residential and commercial solar photovoltaic (PV) resource consideration and calculation. Staff believed that Idaho

[2] These three variables were natural gas prices, customer load, and hydroelectric variability.

Power's inclusion of the fixed costs of a customer-owned and financed resource in the Company's supply-side resource stack was inconsistent with Guideline 1. Guideline 1, part 1, states that "all resources must be evaluated on a consistent and comparable basis." Staff found that since the fixed costs of a residential or commercial solar PV system are not directly borne by the Company unlike other supply-side resources, the results "are inherently inconsistent and incomparable and do not reflect the realities of customer-owned resources."[3] Because of this inconsistency in fixed costs burden, Staff concluded that Idaho Power did not comply with Guideline 12, which states that "electric utilities should evaluate distributed generation technologies on par with other supply-side resources...." Staff further concluded in its Final Comments that it "does not want to punish but rather create an opportunity to determine a more realistic analysis of this new class of supply-side resource."[4]

In its Final Comments, the Company disagreed with Staff's assertions, building on its response made in its Reply Comments. There, Idaho Power argued that "the inclusion of capital costs associated with resource construction is consistent with the treatment for other resources considered in the IRP, thus allowing meaningful cost comparisons between resources."[5] Additionally, Idaho Power stated that excluding a supply-side resource's fixed costs would "lead to uneconomic resource procurement and inefficient deployment of capital on the part of Idaho Power and its customers."[6]

Idaho Power expanded on these points in its Final Comments. There the Company explained that its methodology is predicated on the flow of both costs and benefits to all customers. Idaho Power believes this approach to be reasonable, in part because, though the Company does not directly incur the fixed costs, the customer who owns the PV system will eventually recover its fixed cost investment. Furthermore, the analysis of distributed solar PV's total resource cost, which the Company utilizes for all resources including energy efficiency, enables reasonable comparisons of resources' respective values. Therefore, the Company's approach is consistent with the treatment of other resources.

Staff appreciates Idaho Power's effort in addressing its concerns regarding the consideration of distributed solar PV systems. Idaho Power indicates it is open to exploring the possibility of modeling refinements in its 2017 IRP.[7] Staff appreciates this because additional opportunities for incorporating distributed PV solar system benefits exist. Staff believes that once the resource value of solar is established in

[3] Staff's Final Comments, at page 1, Docket No. LC 63, January 22, 2016.
[4] Ibid., at page 2.
[5] Idaho Power's Reply Comments, at page 19, Docket No. LC 63, December 30, 2015.
[6] Ibid.
[7] Idaho Power's Final Comments, at page 7, Docket No. LC 63, February 19, 2016.

Docket No. UM 1716, the conversation regarding different approaches to modeling distributed solar PV resources at the IRPAC will be appropriate.

Staff also asserted in its Final Comments that Idaho Power was noncompliant with Guideline 4, part I, which states that a utility's IRP must select "a portfolio that represents the best combination of cost and risk for the utility and its customers."[8] Idaho Power's selection of preferred portfolio P6(b) is neither least-cost nor least-risk. However, the Company states that consideration of qualitative risks results in the Company selecting P6(b) as the preferred portfolio.

As Staff discusses later in this memo, without a comprehensive and balanced assessment of every portfolio's qualitative risks, Staff cannot make an informed determination on whether a particular portfolio is least-cost, least-risk when qualitative risks are a deciding factor. Though Idaho Power is correct in pointing out that the Commission only acknowledges a utility's Action Plan, Staff notes that a short-term Action Plan is ultimately derived from a resource plan that achieves long-run cost-risk optimality.[9] Therefore, concerns regarding mid-term and long-term action items should not be dismissed.

| Staff is satisfied that the Company has adequately met the IRP guidelines. |
|---|

**Compliance with Previous IRP Order No. 14-253**

In issuing Order No. 14-253, the Commission accepted Idaho Power's 2013 IRP with several directives and recommendations. These are listed below along with Staff's conclusions about Idaho Power's respective compliance.

Pollution Control Investments in Coal Resources

The Commission directed Idaho Power "to work with stakeholders to explore options for how it plans to model and perform analysis in the 2015 IRP in order to comply with the applicable emissions requirements §111(d) of the Clean Air Act."[10] Staff finds that Idaho Power satisfied the first component of this directive by holding an inclusive and engaging stakeholder process (i.e. the IRP Advisory Council). Idaho Power presented the considerations and analyses of the Company's Coal Study Working Group at the

[8] Commission Order No. 07-002, Appendix A, at page 5, Docket No. UM 10, January 8, 2007.
[9] Commission Order No. 14-253, at page 12, Docket No. LC 58, July 8, 2014.
[10] Ibid., at page 8.

September 2014 IRPAC meeting. Additionally, Idaho Power welcomed and incorporated coal plant retirement date suggestions from IRPAC members.

Staff also finds that Idaho Power satisfied the second component of this directive. To address uncertainty surrounding Section 111(d) and the joint ownership of Idaho Power's coal plants, Idaho Power analyzed 23 portfolios that contain various retirement dates for those facilities. Additionally, Idaho Power conducted a Section 111(d) sensitivity on the 23 resource portfolios that consisted of seven different scenarios split into mass-based or rate-based. However, these analyses were conducted prior to the finalization of Section 111(d) rules. Due to this temporal issue, Staff will recommend additional analyses in Idaho Power's 2015 IRP update.

Gas Price Forecasts

Though not an explicit directive, Staff mentions the Commission's expectation that Idaho Power would address stakeholders' concerns regarding three aspects of the Company's natural gas price forecast.[11] Staff finds that Idaho Power sufficiently addressed the concerns by utilizing Energy Information Administration data for high and low cases as well as the nominal forecast prices. The Company also verified that the implied heat rate, which verifies the relationship between natural gas prices and wholesale electricity prices, aligns with the historical correlation.[12]

Conservation Voltage Reduction (CVR)

Idaho Power was directed to include a CVR assessment in the 2015 IRP after failing to do so in the 2013 IRP. CVR efforts currently progressing at Idaho Power under the "CVR Enhancements Project" should be completed by 2016. Through its *2014 and 2015 Smart Grid Reports*, the Company has kept Staff and the Commission abreast of the renewed evaluation and possible integration of CVR into distribution system operations.

Idaho Power did not include a CVR assessment due to the ongoing nature of the project, but did include a description of the current project on page 48 of the IRP. Staff recommends the Commission delay action on CVR until Staff has been able to review the Company's analysis in the CVR Enhancements Project report to be filed September 1, 2016.

[11] The three issues were " the symmetric adjustments to the base case forecast, the escalation of the Energy Information Administration's reference case gas price forecast, and the high correlation between natural gas prices and wholesale electricity prices in the company's modeling. "*See* Commission Order No. 14-253, at page 14, Docket No. LC 58, July 8, 2014.
[12] Idaho Power's 2015 IRP, Appendix C, at page 215, Docket No. LC 63, June 30, 2015.

Action Plan Limits

The Commission stated that Idaho Power should limit its Action Plan to activities it plans to undertake in the next two to four years as well as enumerate them for ease of analysis. Idaho Power has done so.

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| Staff is satisfied that the Company has adequately addressed all of the Commission's directives set forth in Order 14-253. |

**Action Item Discussion**

The Company offered the following Action Items for the time period 2015-2019.

Action Item #1 – B2H Transmission Line

*Idaho Power will continue the ongoing permitting, planning studies and regulatory filings.*

Mr. Carbiener expressed concerns about the increasing costs of the B2H line as well as the Company's presentation of the viability of portfolios that do not contain B2H. Additionally, Mr. Carbiener discussed how a tipping point analysis of the costs of B2H would be helpful in considering alternative resources.

Staff notes that the Commission acknowledged the same actions for B2H in Order No. 14-253.[13]

The only major development to occur since the 2014 IRP is the Bureau of Land Management's (BLM) issuance of the draft Environmental Impact Statement (EIS), which includes the agency's initial analysis on the proposed and alternate routes of the B2H line.[14] Idaho Power expects the BLM to issue a final EIS in 2016.

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| Staff recommends acknowledgment of Action Item #1. |

[13] Ibid., at page 5.
[14] BLM's *Draft Environmental Impact Statement and Land Use Plan Amendments for the Boardman to Hemingway Transmission Line Project, DOI-BLM-OR-V000-2012-016-EIS,* December 19, 2014.

Action Item #2 – Gateway West Transmission Line

*Idaho Power will continue the ongoing permitting, planning studies and regulatory filings.*

No parties commented on this Action Item.

Staff notes that the Commission acknowledged the same actions for B2H in Order No. 14-253.[15]

Staff recommends acknowledgment of Action Item #2.

Action Item #3 – Energy Efficiency

*Idaho Power will continue the pursuit of cost-effective energy efficiency – the forecast reduction for the 2015-2019 programs is 84 average megawatts (MW) for energy demand and 126 MW for peak demand*

CUB expressed concern that Idaho Power is underestimating the forecasted achievable energy efficiency potential that the Company can acquire. At the core of CUB's concern was Idaho Power's pursuit of achievable, cost-effective energy efficiency, which the Company historically has exceeded annually. CUB believes opportunities exist for Idaho Power to meet more of its projected load growth through energy efficiency, including offering more programs, increasing the Company's energy efficiency marketing, and implementing a "more aggressive (energy efficiency) policy."[16] Staff highlights the fact that Idaho Power's energy efficiency target for the five year period from 2015 to 2019 is 22 percent higher than the five-year window in the 2013 IRP.

Staff recommends acknowledgment of Action Item #3.

Action Item #4 – Section 111(d)

*Idaho Power will coordinate with government agencies on implementation planning for Section 111(d).*

[15] Ibid., at page 6.
[16] CUB's Initial Comments, at page 7, Docket No. LC 63, November 25' 2015.

Staff analyzed and discussed the results of Idaho Power's Section 111(d) sensitivity analyses in its Initial and Reply Comments. Because the 2015 IRP was published prior to the release of the final Section 111(d) rules, Staff expects Idaho Power will continue to work with the co-owners of the North Valmy and Jim Bridger Coal-fired generation stations as states develop Section 111(d) compliance plans.

Staff recommends acknowledgment of Action Item #4, and proposes the following additional recommendations:

- Analyze alternative Section 111(d) compliance paths' impacts on Idaho Power's respective liabilities in North Valmy and Jim Bridger generation stations with stochastic analysis for each compliance path.
- Calculate the cost of compliance with these paths for Idaho Power, and the impact of these costs upon Idaho Power's ratepayers.

Action Item #5 – Shoshone Falls License Amendment

*Idaho Power will file to amend the FERC license regarding the 50-MW expansion.*

No parties commented on this action item.

Staff recommends acknowledgment of Action Item #5.

Action Item #6 – Jim Bridger Unit 3

*Idaho Power will complete the installation of selective catalytic reduction (SCR) emission-control technology.*

No parties commented on this action item.

Staff recommends acknowledgment of Action Item #6.

Action Item #7 – Shoshone Falls Upgrades Study

*Idaho Power will study options for smaller upgrades ranging in size up to approximately 4 MW.*

No parties commented on this action item.

Staff recommends acknowledgment of Action Item #7.

Action Item #8 – Jim Bridger Unit 4

*Idaho Power will complete installation of SCR emission-control technology.*

No parties commented on this action item.

Staff recommends acknowledgment of Action Item #8.

Action Item #9 – North Valmy Units 1 and 2

*Idaho Power will continue to work with NV Energy to synchronize depreciation dates and determine if a date can be established to cease coal-fired operations.*

Mr. Carbiener suggested Idaho Power include additional portfolios that mirror Nevada Power's 2013 IRP 2021 modeled shut down date for North Valmy.

Staff raised concerns regarding the forecasted shut down dates of the North Valmy plant in the Company's preferred portfolio compared to other portfolios that have lower cost and risk. However, all shut down dates considered in Idaho Power's resource portfolios occur beyond the four-year window of the 2015 IRP, so Staff discusses this matter further below.

Staff recommends acknowledgment of Action Item #9.

Action Item #10 – Shoshone Falls 2017 Upgrade

*Idaho Power will commence construction of a smaller upgrade.*

Idaho Power in its Final Comments provided clarifying and additional information regarding the planned upgrades and maintenance of the Shoshone Falls facility that

enables Staff to retract its initial recommendation of non-acknowledgement. The upgrade of the Shoshone Falls facility is necessary for continued reliable operations.[17]

| Staff recommends acknowledgment of Action Item #10. |
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Action Item #11 – Jim Bridger Units 1 and 2

*Idaho Power will evaluate the installation of SCR technology for units 1 and 2 at Jim Bridger in the 2017 IRP.*

Staff noted in its Final Comments that when Idaho Power models Section 111(d) compliance paths, it should fully consider Jim Bridger scenarios that are informed by considerations and possible decisions of the co-owner PacifiCorp. Staff addresses matters related to Jim Bridger in recommendations made under Action Item #4.

| Staff recommends acknowledgment of Action Item #11. |
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Action Item # 12 – Shoshone Falls 2019 On-Line Date

*Idaho Power will place the smaller upgrade on-line.*

Similar to Action Item #10, Staff initially recommended non-acknowledgement of this Action Item in its Final Comments. However, Idaho Power provided clarifying information that led Staff to retract that recommendation.

| Staff recommends acknowledgment of Action Item #12. |
|---|

**Other Issues**

Selection of Preferred Portfolio

Staff and CUB challenged Idaho Power's selection of portfolio P6(b) as the Company's preferred portfolio due to the its higher cost, higher risk, and higher Section 111(d) compliance cost compared to alternative resource portfolios. The Company responded

[17] Idaho Power's Final Comments, at page 7, Docket No. LC 63, February 19, 2016.

that in addition to the relatively small differences in cost for the portfolios that Staff and CUB contended were quantitatively supported, portfolio P6(b) minimized qualitative risks.

Idaho Power also correctly identified that the Commission in its review of a utility's IRP will only consider items set forth in the utility's short-term Action Plan.[18] The portfolios that Staff and CUB argued were more appropriate choices share the same four-year Action Plan as the Company's preferred portfolio. From this, the Company argues the Commission should acknowledge the Company's IRP.

Staff reiterates its observation made in its Final Comments: an Action Plan is only justified by the long-term resource plan. Despite similar or even identical Action Plans, they are otherwise irrelevant if not considered in the broader context of a cost-risk optimal long-term resource plan.

Staff agrees with Idaho Power's position that the Commission should acknowledge Idaho Power's 2015 IRP Action Plan.

Qualitative Risk Analysis

Both CUB and Staff raised concerns over the Company's reliance on qualitative risks to support the selection of portfolio P6(b) as the preferred portfolio despite four lower-cost, lower-risk alternatives. In particular, Staff raised concerns regarding the Section 111(d), "regulatory" resource commitment, PURPA, and DSM implementation qualitative risks. Though Idaho Power further clarified some of Staff's concerns in its Reply Comments, Staff believes that some of these lower-cost, lower-risk portfolios also afford the same qualitative risk benefits the Company attributes to preferred portfolio P6(b). Because of the lack of comprehensive evaluation of qualitative risks of all other portfolios besides the preferred portfolio, Staff recommends Idaho Power pursue a systematic evaluation of all portfolios' qualitative risks. This evaluation must be balanced and consistent in its comparisons in order to support future preferred portfolios. Despite this concern, Staff appreciates Idaho Power's broader assessment in assessing qualitative risks.

| Staff recommends Idaho Power include a more systematic evaluation of the qualitative benefits of the resource portfolios in the 2017 IRP. |
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[18] Commission Order No. 14-253, at page 12, Docket No. LC 58, July 8, 2014.

2015 IRP Update Waiver

In its final comments, Staff recommended that Idaho Power provide updated Section 111(d) and existing coal unit considerations in the 2015 IRP Update. Idaho Power replied in its Final Comments that, though it plans to comply with Staff's recommendations regarding additional analyses, doing so in the 2015 IRP Update would be inefficient. The Company notes that the 2017 IRP is due only three months after the planned 2015 IRP Update filing. Because the analyses requested by Staff are substantial and therefore more suited for a complete IRP cycle rather than an IRP Update, Idaho Power recommends the Commission waive its obligation to file a 2015 IRP Update.

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| Staff agrees and recommends the Commission waive Idaho Power's obligation to file a 2015 IRP Update. |

**PROPOSED COMMISSION MOTION:**

Idaho Power's 2015 IRP be acknowledged with the following recommendations by Staff as contained in this report and summarized in Attachment A to this report.

## ATTACHMENT A

| Action Item | Description | Staff Recommendation |
|---|---|---|
| 1 | B2H – ongoing permitting, planning studies, and regulatory filings | Acknowledge |
| 2 | Gateway West – ongoing permitting, planning studies, and regulatory filings | Acknowledge |
| 3 | Pursuit of cost-effective energy efficiency | Acknowledge |
| 4 | Implementation planning for Section 111(d) | Acknowledge with Recommendations |
| 5 | Shoshone Falls license amendment | Acknowledge |
| 6 | Jim Bridger 3 – Complete SCR installation | Acknowledge |
| 7 | Shoshone Falls upgrade study | Acknowledge |
| 8 | Jim Bridger 4 – Complete SCR installation | Acknowledge |
| 9 | North Valmy – NV Energy collaboration | Acknowledge |
| 10 | Shoshone Falls 2017 upgrade | Acknowledge |
| 11 | Jim Bridger 1 & 2 – SCR evaluation | Acknowledge |
| 12 | Shoshone Falls 2019 on-line date | Acknowledge |

**Recommendations**

In addition to acknowledgement of the Action Plan items, Staff recommends that the Commission direct the Company to:

- Analyze alternative Section 111(d) compliance paths' impacts on Idaho Power's respective liabilities in North Valmy and Jim Bridger generation stations with stochastic analysis for each compliance path in the 2017 IRP.
- Calculate the cost of compliance with these paths for Idaho Power, and the impact of these costs upon Idaho Power's ratepayers.
- Include a more systematic evaluation of the qualitative benefits of the resource portfolios that Idaho Power analyzes in the 2017 IRP.

APPENDIX B

## 1. Action Items

| Action Item | Resource | Description | Disposition |
|---|---|---|---|
| 1 | B2H Transmission | Ongoing permitting, planning studies, and regulatory filings | ***Acknowledged*** |
| 2 | Gateway West Transmission | Ongoing permitting, planning studies, and regulatory filings | ***Acknowledged*** |
| 3 | Energy Efficiency | Continue the pursuit of cost-effective energy efficiency | ***Acknowledged*** |
| 4 | N/A | Coordinate with government agencies on implementation planning for Clean Air Act Section 111(d) | ***Acknowledged*** |
| 5 | Shoshone Falls Hydro | File to amend FERC license regarding 50-MW expansion | Not Acknowledged |
| 6 | Jim Bridger Unit 3 | Complete installation of selective catalytic reduction (SCR) emission-control technology | Not Acknowledged |
| 7 | Shoshone Falls Hydro | Study options for a smaller upgrade ranging in size up to approximately 4 MW | Not Acknowledged |
| 8 | Jim Bridger Unit 4 | Complete installation of SCR emission-control technology | Not Acknowledged |
| 9 | North Valmy Units 1 & 2 | Continue to work with NV Energy to synchronize depreciation dates and determine if a date can be established to cease coal-fired operations | ***Acknowledged*** |
| 10 | Shoshone Falls Hydro | Commence construction of smaller upgrade | Not Acknowledged |
| 11 | Jim Bridger Units 1 & 2 | Evaluate the installation of SCR technology in the 2017 IRP | Not Acknowledged |
| 12 | Shoshone Falls Hydro | On-line date for smaller upgrade during first quarter of 2019 | Not Acknowledged |

## 2. Recommendations

a. Analyze alternative Section 111(d) compliance paths' impacts on Idaho Power's respective liabilities in North Valmy and Jim Bridger generation stations with stochastic analysis for each compliance path in the 2017 IRP.
b. Calculate the cost of compliance with these paths for Idaho Power, and the impact of these costs upon Idaho Power's ratepayers.
c. Include a more systematic evaluation of the qualitative benefits of the resource portfolios that Idaho Power analyzes in the company's 2017 IRP.

# ATTACHMENT N-10
# ORDER NO. 18-176 IN DOCKET LC 68

ORDER NO. 18 176

ENTERED MAY 23 2018

# BEFORE THE PUBLIC UTILITY COMMISSION

# OF OREGON

LC 68

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|---|---|
| In the Matter of<br>IDAHO POWER COMPANY,<br>2017 Integrated Resource Plan. | ORDER |

DISPOSITION: 2017 IRP ACKNOWLEDGED WITH MODIFICATIONS AND EXCEPTIONS

This order memorializes our decision, made and effective at the April 10, 2018 Regular Public Meeting, concerning Idaho Power Company's 2017 Integrated Resource Plan (IRP). We acknowledge all but two of the action items proposed in Idaho Power's revised action plan. Although our acknowledgement includes Idaho Power's Boardman to Hemingway (B2H) related action items, we note that our acknowledgement is limited to our interpretation of IRP standards specific to the Public Utility Commission, and does not interpret or apply the standard of any other state or federal agency.

## I. INTRODUCTION

The central feature of Idaho Power's 2017 IRP is the B2H project. The B2H project has been identified as part of the preferred resource portfolio in Idaho Power's 2009, 2011, 2013, and 2015 IRPs. Several groups formed to oppose this project and, along with many individual interested citizens, participated actively and constructively in this IRP process. Many groups and individuals are concerned about the land use and environmental impacts of B2H and share a preference for demand-side and distributed, clean energy alternatives to B2H. It is our view that the robust participation of citizen groups and individuals has supported a better and fuller understanding of the issues associated with the B2H project and other IRP issues. Although we acknowledge Idaho Power's selection of the B2H project as a least cost, least risk resource to meet the needs of its customers, we remain grateful for the hard work, dedication, knowledge, and passion of all stakeholders in this process.

## II. IRP PROCESS

### A. Purpose

The objective of the IRP is to ensure an adequate and reliable supply of energy at the least cost to the utility and customers in a manner consistent with the long-run public interest.[1] The IRP provides extensive opportunity for the provision of broad input from a range of stakeholders, and public participation and input is a central goal of the IRP. This input, along with IRP guideline requirements that ensure a detailed and wide-ranging review of resource options, technology advancements, pricing scenarios and risk profiles are intended to test the conclusions of the utility. The IRP process is intended to be iterative. Where weakness or issues are identified, stakeholder participation can help identify alternatives and improvements to the plan. Utilities should respond proactively to the concerns of stakeholders, and consider alternatives.

Ultimately, an acknowledged plan will become a working document for use by the utility, the Commission, and other interested parties in Commission proceedings.[2] We have noted in recent IRP decisions that during a time of considerable electric utility industry flux IRPs should serve to allow for course corrections as industry evolution comes into greater focus.[3]

### B. Timing and Content

We require regulated energy utilities to prepare and file IRPs within two years of acknowledgement of the utility's last plan.[4] The IRP process uses a 20-year planning period. Oregon's IRP guidelines include thirteen elements. Summarized, the elements include the following key components:

- Identification of capacity and energy needs to bridge the gap between expected loads and resources
- Identification and estimated costs of all supply-side and demand-side resource options
- Construction of a representative set of resource portfolios
- Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties

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[1] *In the Matter of the Investigation into Least-Cost Planning for Resource Acquisitions by Energy Utilities in Oregon*, Docket No. UM 180, Order No. 89-507 at 2 (Apr 20, 1989).
[2] *Id.* at 7.
[3] *In the Matter of Portland General Electric Company, 2016 Integrated Resource Plan, Docket No. LC 66,* Order No. 17-386 at 2 (Oct 9, 2017).
[4] OAR 860-027-0400(3).

- Selection of a portfolio that represents the best combination of cost and risk and risk for the utility and its customers
- Creation of an Action Plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies

The primary outcome of the IRP process is the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and the customers, that the Commission deems reasonable after the presentation of the plan and review by Staff and stakeholders.

## C. Action Plan

An important product of the IRP process is an action plan. Where new resources are needed to meet system needs, the action plan will include these resource acquisitions. The action plan identifies the preferred portfolio of supply-side and demand-side resources to meet this need and identifies the steps the company will take within the next four years to deliver needed resources. Different resources require different steps to move forward with procurement. Transmission in particular requires more development lead time than other supply-side resources.

## D. Acknowledgement

Our acknowledgement of an IRP means that the Commission finds that the utility's preferred portfolio is reasonable at the time of acknowledgement.[5] We may decline to acknowledge specific action items if we are not satisfied that the proposed resource decision presents the least cost and risk option for customers. We may provide the utility an opportunity to revise the IRP before issuing an acknowledgement order.[6]

Acknowledgment is not a guarantee of cost recovery, nor is consistency with an acknowledged plan a requirement for recovery of resource costs in rates. Acknowledgment provides guidance for later ratemaking proceedings, which are the forum for the Commission to make its ultimate decision to approve or disapprove a resource procurement as prudent and recoverable in customer rates. Consistency with an acknowledged plan may be used as evidence in support of favorable ratemaking treatment, but the utility still must demonstrate that its actions remained reasonable, particularly in light of any material changes in the facts, circumstances and assumptions that supported IRP acknowledgment.

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[5] *In the Matter of Public Utility Commission of Oregon, Investigation into Integrated Resource Planning* Requirements, Docket NO. UM 1056, Order No. 07-002 at 16 (Jan 8, 2007).
[6] OAR 860-027-0400(6).

## III. IDAHO POWER'S 2017 IRP

### A. Previous Idaho Power IRPs

As noted, Idaho Power's IRP process has consistently identified the B2H project as part of its preferred portfolio since 2009, and we have previously recognized action items related to the planning of B2H as reasonable and have encouraged the company to continue its efforts to move forward with the project. We declined to acknowledge construction of B2H once in the past, but did so solely because Idaho Power requested acknowledgement of planned construction activity outside of the four year action plan period.[7]

### B. Projected Resource Needs and Portfolio Modeling

Idaho Power identifies summer peak capacity needs in the 2026 timeframe. The company has access to adequate capacity supply prior to this period. Load is expected to grow by an average of 0.09 percent annually, while peak capacity needs are expected to grow by 1.4 percent annually, according to the company.

For its 2017 IRP, Idaho Power utilized a "factorial design approach." This design was intended to inform the IRP's Action Plan with regard to Selective Catalytic Reduction equipment (SCR) investments for Jim Bridger units one and two, and review the B2H transmission line. The result of this approach was the development of twelve portfolio options, using four SCR investment scenarios for Jim Bridger and three resource portfolio constructions. The non-B2H alternatives included a natural gas generation portfolio and a natural gas and solar generation portfolio. Previous Idaho Power IRPs reviewed more portfolio options. In 2015, Idaho Power compared 23 resource portfolios.

### C. Preferred Portfolio

Of the twelve portfolio options, Idaho Power concludes that portfolio seven provides the best combination of costs and risks for customers. This portfolio includes the following resources: B2H with an in service date in 2026, reciprocating engines in 2031 and 2032, a 300 MW CCCT in 2033, and reciprocating engines in 2035 and 2036. Due to the long lead-times associated with transmission line development, Idaho Power requests acknowledgement of B2H construction activity in its 2017 IRP to meet its 2026 capacity need.

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[7] *In the Matter of Idaho Power Company, 2013 Integrated Resource* Plan, Docket No. LC 58, Order No. 14-253 at 5 (Jul 8, 2014).

### *1. Transmission*

The B2H Transmission project involves permitting, constructing, operating, and maintaining a new single-circuit 500-kV transmission line approximately 300 miles long between the proposed Longhorn Station near Boardman, Oregon, and the existing Hemingway Substation in southwest Idaho. Idaho Power states that this project will provide the lowest cost, lowest risk capacity resource to meet identified needs commencing in 2026. Idaho Power plans to meet capacity needs through market purchases facilitated by the development of the line.

Idaho Power also plans to conduct ongoing permitting, planning studies and regulatory filings for the Gateway West transmission project. Gateway West is a joint project between Idaho Power and PacifiCorp to build and operate new transmission lines running from the planned Windstar substation in Wyoming to the Hemingway substation in Idaho. The line is in the permitting stage, and Idaho Power characterizes Gateway West as complementary to the B2H project.

### *2. Coal*

Idaho Power owns 50 percent, or 284 MW, of the North Valmy coal-fired power plant in Nevada. NV Energy is the operator of the facility and owns the other 50 percent. The plant has two units. Idaho Power plans to exit its share of North Valmy Unit 1 at year-end 2019. Idaho Power identified likely economic benefits associated with a 2019 shutdown of Unit 1 as opposed to the 2025 shutdown date planned in the 2015 IRP. North Valmy units are assumed to be replaced with market purchases imported across the Idaho-Nevada path. Idaho Power plans to exit its share of North Valmy Unit 2 at year-end 2025.

Idaho Power owns one-third (771 MW) of the Jim Bridger coal-fired power plant. PacifiCorp owns two-thirds of the facility and is its operator. The company proposes Jim Bridger unit 1 and 2 retirements at year-end 2028 and year-end 2032, respectively, provided it obtains regulatory approvals allowing it to continue operation without installing SCRs. Previous IRPs had called for the evaluation of SCRs at the units. Idaho Power proposes to work with a variety of regulators and the co-owners of the facility to achieve these retirement dates without SCR installation.

Idaho Power owns 10 percent, of 64.2 MW of the Boardman coal-fired power plant. Portland General Electric (PGE) owns 90 percent of the facility and is its operator. Idaho Power plans to coordinate with PGE to achieve cessation of coal-fired operations at the Boardman coal plant by year-end 2020 and subsequent decommissioning and demolition of the unit. PGE has reached an agreement with Oregon Department of Environmental

Quality and the Environmental Protection Agency to cease coal-fired operations at the facility.

### *3. Demand Side Management*

Idaho Power will continue the pursuit of what it has identified as cost-effective energy efficiency and demand response resources. By 2036, Idaho Power plans to acquire 390 MW of committed peak summer capacity through demand response and expects a reduction in annual loads from energy efficiency of 273 MWa. Energy efficiency is expected to reduce peak load by 483 MW by 2036. The company states that demand-side resources are the first selected resource in each IRP, and the no supply-side generation resource is considered until all future cost-effective, achievable potential energy efficiency and forecasted demand response is accounted for and credited against future loads. Long-term savings estimates declined between the 2015 and 2017 IRPs, due to an anticipated drop in residential savings.

### *4. Natural Gas*

The preferred portfolio includes several natural gas resource additions later in the planning period. Portfolio seven includes the acquisition of 36 MW reciprocating engines in 2031 and 2032, one 300 MW Combined-Cycle Combustion Turbine (CCCT) addition in 2033, and 36 MW reciprocating engines in 2035 and 2036.

## IV. DISCUSSION

We focus our discussion on Idaho Power's proposed action items and one other issue, a waiver request from Idaho Power. For each issue, we describe the action item, briefly summarize some intervenors' comments, and explain our resolution. Idaho Power's proposed action plan identifies steps to be taken within the next four years.

Idaho Power's action plan includes pursuit of cost-effective energy efficiency in conjunction with stakeholder and regional groups, preparation for participation in the western Energy Imbalance Market (EIM) beginning in April 2018, involvement as a stakeholder in CAA Section 111(d) proceedings or alternative regulations constraining carbon emissions, early retirement of Valmy units 1 and 2, early retirement for Jim Bridger units 1 and 2, and investigation of solar PV contribution to peak using loss of load probability (LOLP) analysis for use in the 2019 IRP. The B2H short-term action plan is 2017 to 2026. All other action plan items are in the 2017 to 2021 timeframe.

Idaho Power has also requested a waiver of IRP guideline 3(f), which would relieve the company of the obligation to file an IRP update within one year of IRP acknowledgement.

## A. B2H Transmission Project

The B2H project incorporates action items five and six, in which Idaho Power plans to conduct ongoing permitting, planning studies, and regulatory filings for the B2H transmission line and conduct preliminary construction activities, acquire long-lead materials (action item five), and construct the B2H project (action item six).

### *1. Comments*

According to Staff, B2H has been demonstrated to show important regional benefits and is part of the lowest cost, lowest risk portfolio of resources. Staff considers that in several prior IRPs, Commission Staff performed analysis of the need and justification for the transmission line. Staff notes that the Commission has found the project reasonable in numerous past IRP decisions.

Initially, Staff considered B2H to be inadequately supported by the filed IRP. In response, Idaho Power assembled and submitted Appendix D which focused largely on the B2H project. Staff found that Appendix D delivered a thorough account of the history of the B2H project, the associated reliability and capacity benefits, a detailed account of public participation, and other important material. Staff considered Appendix D to be a responsive and persuasive submission by the company that helped Staff ultimately support acknowledgement of B2H.

The Stop B2H Coalition (Stop B2H) argues that Idaho Power already has sufficient transmission capacity and that the line is not needed for transmission purposes. Stop B2H asserts that transmission should not be treated as a generation resource, and that transmission is less reliable and flexible than other resources because it relies on market purchases. Idaho Power and Staff contend the opposite; that B2H will provide the flexibility to purchase power in many different time frames (years, months, a day, an hour, or within the hour). Idaho Power states that B2H will allow more flexibility to access various generation, including newer renewable resources. Staff and Idaho Power agree that our IRP guidelines as written do encourage the consideration of transmission as a supply resource.

Stop B2H presents a series of arguments asserting that the cost of B2H is likely to be much higher than outlined by the company and the benefits far less extensive. Stop B2H argues that market purchases are a poor strategy for meeting capacity needs. Staff and the

company identify this reliance on market as a strength. Staff believes that one of the central merits of the B2H proposal is that is connects a major power hub (the Mid-C market), which Staff contends is highly liquid, to loads in the Intermountain West.

All stakeholders recognize that Idaho Power has been open and welcoming of public comment and participation throughout this IRP process, and in the many public forums in which B2H was discussed and considered. In its Appendix D to the IRP, Idaho Power highlights that it has participated in over 250 public and stakeholder meetings on the project, with an estimated attendance of over 3,000 people.

Commission Staff states that it has participated in forums and events on B2H with interested members of the public. Commission Staff notes that it was involved in the Commission open houses that occurred in Malheur and Baker Counties, dating back to 2009, and at which the B2H project was discussed with citizens.

Staff points out that the B2H project has been included in numerous regional studies by the Northern Tier Transmission Group, the Western Electricity Coordinating Council (WECC), Columbia Grid, and others. Staff highlights that B2H has been listed as a "Foundational Transmission Project" by WECC's Subregional Planning Group, a committee formed to create interconnection-wide transmission plans for western interconnection. Idaho Power contends that B2H is required for both its west-to-east and east-to-west capacity to meet regional needs.

Stakeholders have repeatedly referenced risks related to Idaho Power's minority share of the capacity of the line and the need for significant participation from other utilities to construct the project. Idaho Power responds that it has an active permitting agreement with its current co-participants. Idaho Power also stated that, should a co-participant drop out, Idaho Power would evaluate other potential partnerships and, if necessary, reevaluate its own participation in the project. ODOE notes that the Energy Facility Siting Council (EFSC) siting process includes risk safeguards for construction and non-performance of partners. Before Idaho Power can begin construction of B2H, it must obtain a Site Certificate from EFSC.

The Lewis and Clark Trail Heritage Foundation asserts that B2H does not adequately protect natural, cultural, and historic resources. Gail Carbiener also argues that the B2H project will disrupt and harm the Oregon Trail. Idaho Power states that trail impacts will be appropriately considered as part of the EFSC siting process, and that B2H will work to minimize trail impacts. Staff believes that Idaho Power has reasonably sought to address landowner concerns and worked with the BLM towards a feasible route minimizing impacts to communities, the Oregon Trail, and public and private land.

Citizens Advocating for Common Sense state that ODOE's processes are too industry friendly and strongly opposes acknowledgement. In addition to formal filed comments, many informal comments were submitted to Staff and the Commission. These comments almost uniformly expressed strong opposition to the construction of the B2H project. Many argue that reliance on traditional resources like large-scale transmission is counter to significant changes in the utility industry, and that distributed resources and other solutions should be prioritized over larger, more centralized resources. Along these lines, some comments urge delay of acknowledgement to the 2019 IRP. Idaho Power states that acknowledgement cannot be delayed, if the project is to move forward with permitting expeditiously and be constructed in time to help the company meet the anticipated 2026 capacity shortfall.

Several parties, including Staff, present objections to Idaho Power's chosen factorial modeling. Like these other parties, CUB objects to Idaho Power's failure to use a capacity expansion model, but does not object to Idaho Power's selection of portfolios including B2H.

Staff asserts that B2H presents a unique case because Idaho Power's analysis of B2H as a least cost, least risk resource to meet customer needs identified in this IRP is also supported by the extensive vetting of the project in prior years and the regional benefits that are associated with it. Rather than locking in costs, Staff sees the resource as flexible, allowing market power purchases without committing to a single technology and remaining flexible to accommodate future changes in technology. Staff argues that while not ideal, the portfolio analysis presented by Idaho Power is sufficient to determine that portfolio seven represents the best combination of costs and risk of the twelve analyzed.

### *2. Resolution*

We acknowledge B2H Action Item 5 to conduct ongoing permitting, planning studies, and regulatory filings for the B2H transmission line, as well as Action Item 6 to conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project. We clarify that this determination is limited to our IRP standards and that, in acknowledging these action items, we do not interpret or apply the standards of any other state or federal agency. Through our acknowledgement we find that these action items are reasonable components of Idaho Power's resource plan based on the information available at this time.

Our acknowledgement of Action Item 6 is based on our finding of its reasonableness, according to the information we possess today, in the context of Idaho Power's entire IRP. Our decision does not mean that Action Item 6 is the only possible option for meeting Idaho Power's resource needs, simply means that we are satisfied that it is the

least cost, least risk resource for meeting the demonstrated resource needs of Idaho Power's customers. We recognize that there may be other ways of meeting the capacity needs identified in this IRP that may not have the same impacts to eastern Oregon as B2H. In this proceeding, however, we do not find that any such alternatives have been demonstrated to be lower cost and lower risk, based on the information presented.

Our acknowledgement of Action Item 6 is not a final determination of prudence and does not guarantee favorable ratemaking treatment. The IRP process is designed to provide the utility with guidance from Staff, stakeholders, and the Commission based on the utility's submitted plan. We have long held that consistency with an acknowledged plan may be evidence in support of favorable ratemaking treatment, but the utility still must demonstrate that its actions remained reasonable, particularly in light of any material changes in the facts, circumstances and assumptions that supported IRP acknowledgment.

We are encouraged by the extensive participation of citizens in this case, many of which are motivated by sincere concerns over impacts to the land which will be created by this project. We are bound by state laws and legal precedent that directs us to exclude from our inquiry many of these concerns, however, and we note that energy facility siting impact issues are appropriately reviewed in other state or federal proceedings.

Our decision is supported by the fact that B2H has been prioritized over multiple portfolios in different IRPs using numerous different modeling concepts and reflecting many different assumptions. While presence in numerous IRPs is not determinative for our acknowledgement judgement, it is indicative to us of sustained value that has remained robust across industry and market changes to date. In each of these portfolios, B2H has proven to be a low-cost resource that provides considerable value to the system. While we are sensitive to the arguments that the utility industry is in flux, and that technological changes are impacting the system in unanticipated ways, we have not seen information presented as part of this IRP process indicating that large-scale transmission resources will not be an important part of future utility systems. We recognize that B2H has the potential to create significant regional benefits and could represent a tool for allocating and moving a diverse set of new low-carbon resources across the west.

Transmission must be developed with very long lead times. Because circumstances may change in the future, and new information may be presented at a later date, the ultimate development of the B2H project is not a foregone conclusion. We agree with Staff that a host of changed circumstances could require Idaho Power to reevaluate its course, including but not limited to significant changes in co-participant shares and commitments, project costs, load needs, power market liquidity and depth, and capabilities and costs of alternative technologies. Idaho Power should be prepared for

such reevaluation and to change course should such information or circumstances emerge.

Based on what we know today, however, we find that the plan to construct the B2H project is reasonable and should be acknowledged subject to the conditions outlined in Staff's memo.

**B. Gateway West**

Action Item 8 concerns Gateway West. Idaho Power plans to conduct ongoing permitting, planning studies, and regulatory filings.

Staff recommends acknowledgement of this action item, but notes that it is important for the Commission to understand how the Gateway West series of projects relate to the B2H project. Staff recommends that the company update the Commission on the status of Gateway West beyond what has been presented in the 2017 IRP.

We acknowledge Action Item 8, and adopt Staff's recommendation.

**C. North Valmy Unit 1**

With Action Item 3, Idaho Power includes a commitment to plan and coordinate with NV Energy an exit from coal-fired operations of North Valmy Unit 1 by year-end 2019. Idaho Power also plans to assess import dependability from Northern Nevada.

Staff and Sierra Club recommend acknowledging this action item. Throughout the comment period, Staff had several requests for clarification on the analysis and rationale behind the decision to exit North Valmy Unit 1 in 2019. Idaho Power responded to these requests, explaining the status of its exit negotiations.

We acknowledge this action item.

**D. North Valmy Unit 2**

In Action Item 11, Idaho Power communicates its plans to coordinate with NV Energy the company's exit from coal-fired operations of North Valmy Unit 2 by year-end 2025. This retirement date is consistent with Idaho Power's 2015 IRP. In November of 2016, Idaho Power requested, and we approved, the accelerated depreciation of both Valmy units with a corresponding increase in rates.

We adopt Staff's recommendation to acknowledge this action item.

## E. Jim Bridger

With Action Item 4, Idaho Power will plan and negotiate with PacifiCorp and regulators to achieve early retirement dates of year-end 2028 for Jim Bridger Unit 2 and year-end 2032 for Jim Bridger Unit 1.

### *1. Comments*

Staff recommends against acknowledgement of this action item. Staff notes that the company considered a 2023 Jim Bridger retirement date in its 2015 IRP, and that this retirement date was not part of any 2017 IRP analysis. Staff also argues that the company has not demonstrated that its plan to not install SCRs at the facilities in 2021 and 2022 is feasible.

Sierra Club also opposes acknowledgement, and argues that there is a lack of discussion and analysis of the economic status of the Jim Bridger plants, and that operation until 2028 and 2032 without SCR represents an illegal plan under current regulatory requirements. Sierra Club recommends that Idaho Power economically model alternative retirement dates.

ODOE recommends the company take a deeper look at carbon price increases as part of the 2019 IRP. Sierra Club also argues that the company must install SCRs by 2021-2022 or shut the facilities down.

CUB is not certain Idaho Power's chosen Bridger retirement date is the least-cost option, because the differences in the cost of portfolios with earlier retirement dates are not statistically significant.

Idaho Power responds that the chosen retirement dates are consistent with those adopted by the majority owner, PacifiCorp. Idaho Power sees its decision not to install SCRs as consistent with its stated objective to transition away from coal-fired resources. Idaho Power asserts that it will not agree to any operational plan for the facility that is illegal, and that it will work with the appropriate regulators to pursue the action item as outlined in the IRP.

### *2. Discussion*

We decline to acknowledge this action item. We agree with Staff and other stakeholders that Idaho Power has not demonstrated that the retirement dates outlined in the action plan are supported by sufficiently robust or compelling economic analysis. In addition,

although we do not expect Idaho Power to provide information at the level necessary to secure environmental regulatory approvals, we do expect a better demonstration that the company has a viable path forward under currently applicable emission control regulations. The paucity of information on the alternative paths forward is particularly concerning because, under current regulations, installation of SCR is required within the four-year action plan window for this IRP.

**F. Boardman**

Action Item 7 commits Idaho Power to continue to coordinate with Portland General Electric (PGE) to achieve cessation of coal-fired operations at the Boardman coal plant by year-end 2020 and the subsequent decommissioning and demolition of the unit. Staff recommends acknowledgement of this action item, noting that it is consistent with previous Commission orders that allow early closure of the Boardman coal plant.

We acknowledge this action item.

**G. Demand Side Management**

With Action Item 9, Idaho Power proposes to continue the pursuit of cost-effective energy efficiency.

Staff recommends acknowledgement of this action item with conditions that Idaho Power undertake greater studies of residential savings opportunities and update its transmission and distribution system deferral calculations. Stop B2H argues that Idaho Power has achieved less energy efficiency than other utilities, and argues that the company could do significantly more to achieve demand reduction through more investment in energy efficiency. Stop B2H argues that reductions in peak demand brought on through increased energy efficiency could obviate the near-term need for new transmission facilities. Stop B2H contends that Idaho Power should act to deploy advanced metering infrastructure. Sierra Club argues that Idaho Power's energy efficiency potential is understated, because it's planning uses achievable potential, and Idaho Power has historically out-performed those achievable potential estimates.

We acknowledge Action Item 9, and adopt Staff's recommended conditions.

**H. EIM**

Idaho Power has begun participating in the EIM effective April 2018, and the company requests acknowledgement of this activity through Action Item 1.

Staff does not recommend acknowledgement of this action item. Staff states that it is not appropriately included as an action item, and add that the company did not provide an adequate discussion of costs, risks and value of EIM participation. Idaho states that it included EIM participation in its action plan for informational purposes only.

We view this action item as informational only and therefore decline to acknowledge it.

## I. Solar Investigation

Idaho Power's calculated contribution to peak of solar energy has been derived from a settlement in docket UM 1719. That docket required the company to conduct a loss-of-load study, which the company expects to complete in the near term.

Staff recommends acknowledgement of this action item.

We acknowledge this action item.

## J. Stakeholder Engagement in CAA 111(d) Proceedings

With Action Item 10, Idaho Power seeks to develop other ways in which carbon policy risk can be addressed in its IRP process, and plans to stay engaged as an active stakeholder in CAA 111(d) proceedings.

Staff recommends acknowledgement of this action item. Staff recommends that the company develop a report for the next IRP to assess the risks that climate change presents to the company and its customers.

We acknowledge this action item, and request that Idaho Power include as part of its 2019 IRP a report describing the risks to the company and its customers associated with climate change.

## K. Request for Waiver

As part of its final comments, Idaho Power requests a waiver from IRP guideline 3(f). IRP guideline 3(f) requires an annual update on a utility's most recently acknowledged plan on or before the acknowledgement order anniversary date. Idaho Power requests a waiver of this filing requirement because the update will likely be due concurrent with or a month prior to the filing of the 2019 IRP. Staff recommends against granting this waiver in its report, but at the April 10 Regular Public Meeting agreed with Idaho Power on the waiver request with the expectation that Idaho Power would file a report on key information prior to the filing of the 2019 IRP.

We grant Idaho Power's request for a waiver of IRP guideline 3(f), but require that five months prior to the filing of the 2019 IRP, Idaho Power file a report in this docket providing the following information:

- A comprehensive update of the B2H project.
- Information about the planned gas price forecast for the 2019 IRP, and any appropriate updates on the natural gas price forecast.
- A discussion of portfolio modeling options and preferences for the 2019 IRP.
- An update on Jim Bridger environmental control developments and options.
- Updates as requested by Staff.

Several stakeholders commented on Idaho Power's gas price forecast, arguing that it ultimately led to an estimate of forward gas prices that are unreasonably low. We have ordered that Idaho Power provide updated, detailed information on its gas price forecast as part of the 2019 IRP. Idaho Power sufficiently demonstrated that sensitivities associated with its gas price forecast did not affect its portfolio selection, and we do not in this order make a determination as to whether or not the IRP gas price forecast is reasonable.

## V. ORDER

IT IS ORDERED that:

The Integrated Resource Plan filed by Idaho Power is acknowledged as described with the terms of this order and the attached Appendix A.

Made, entered, and effective MAY 23 2018.

**Lisa D. Hardie**
Chair

**Stephen M. Bloom**
Commissioner

**Megan W. Decker**
Commissioner

## Appendix A

Acknowledged Action Items with Modifications

**Action Items 5 and 6** (Boardman to Hemingway)

- 5 – Conduct ongoing permitting, planning studies, and regulatory filings.
- 6 – Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.

**Action Item 8** (Gateway West)

- 8 – Conduct ongoing permitting, planning studies, and regulatory filings.

Modifications:

  - Idaho Power should provide additional information to the Commission on an ongoing basis on Energy Gateway's progress, Idaho Power's inclusion of it as a least-cost/least risk portfolio, the status of co-participants and Energy Gateway's role in the IRP.

**Action Items 3 and 11** (North Valmy Units 1 and 2, respectively)

- 3 – Plan and coordinate with NV Energy Idaho Power's exit from coal-fired operations by year-end 2019. Assess import dependability from northern Nevada.
- 11 – Plan and coordinate with NV Energy Idaho Power's exit from coal-fired operations by year-end 2025.

**Action Item 7** (Boardman)

- Continue to coordinate with PGE to achieve cessation of coal-fired operations by year-end 2020 and the subsequent decommission and demolition of the unit.

**Action Item 9** (Energy efficiency)

- Continue the pursuit of cost-effective energy efficiency.

Modifications:

  - In its 2019 IRP Idaho Power will report on future expanded energy efficiency opportunities and improvements to its avoided cost methodology.

**Action Item 2** (Loss-of-load and solar contribution to peak)

- Investigate solar PV contribution to peak and loss-of-load probability analysis.

**Action Item 10** (Carbon emission regulations)

- Continue stakeholder involvement in CAA Section 111(d) proceedings, or alternative regulations affecting carbon emissions.

Modifications:

  - Idaho Power will provide a report as part of its 2019 IRP filing describing the risks to the company and its customers associated with climate change.

# ATTACHMENT N-11
# ANNUAL CAPACITY FACTORS

Exhibit N 3.3.6 Table
Idaho Power - Power Supply
T Noll May 2012

**Annual Capacity Factors**

| | **2011** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** |
|---|---|---|---|---|---|---|---|
| Hydro Nameplate Capacity (MW)[1] | 1,709 | 1,709 | 1,709 | 1,709 | 1,709 | 1,709 | 1,758 |
| Annual Hydro Forecast (aMW) at 50th Percentile Water | 982.3 | 982.1 | 981.3 | 977.4 | 974.9 | 972.0 | 987.2 |
| Hydro Annual Capacity factor at 90th Percentile Water | **0.57** | **0.57** | **0.57** | **0.57** | **0.57** | **0.57** | **0.56** |
| Annual Hydro Forecast (aMW) at 70th Percentile Water | 807.8 | 806.7 | 805.8 | 800.2 | 795.4 | 792.3 | 793.9 |
| Hydro Annual Capacity factor at 70th Percentile Water | **0.47** | **0.47** | **0.47** | **0.47** | **0.47** | **0.46** | **0.45** |
| Annual Hydro Forecast (aMW) at 90th Percentile Water | 681.9 | 681.2 | 680.4 | 676.9 | 673.3 | 665.0 | 661.9 |
| Hydro Annual Capacity factor at 90th Percentile Water | **0.40** | **0.40** | **0.40** | **0.40** | **0.39** | **0.39** | **0.38** |
| Total Coal Annual Forecast (aMW) | 879.3 | 891.6 | 867.0 | 879.5 | 870.3 | 900.6 | 908.0 |
| Total Coal Nameplate Capacity (MW) [2] [3] | 1,118.2 | 1,118.2 | 1,118.2 | 1,118.2 | 1,118.2 | 1,118.2 | 1,118.2 |
| Coal Annual Capacity Factor | **0.79** | **0.80** | **0.78** | **0.79** | **0.78** | **0.81** | **0.81** |
| Total CCCT Annual Forecast (aMW) | 0.0 | 125.5 | 251.0 | 251.0 | 251.0 | 251.0 | 251.0 |
| Total CCCT Nameplate Capacity (MW) [4],[5] | 0.0 | 150.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 |
| CCCT Annual Capacity Factor | **0.00** | **0.84** | **0.84** | **0.84** | **0.84** | **0.84** | **0.84** |
| Total SCCT Annual Forecast (aMW) | 96.8 | 96.1 | 96.8 | 96.8 | 97.6 | 96.8 | 96.1 |
| Total SCCT Nameplate Capacity (MW) [6] | 443.7 | 443.7 | 443.7 | 443.7 | 443.7 | 443.7 | 443.7 |
| SCCT Annual Capacity Factor | **0.22** | **0.22** | **0.22** | **0.22** | **0.22** | **0.22** | **0.22** |

[1] Shoshone Falls upgrade assumed to be operational in 2017

[2] Boardman coal plant assumed to be decommissioned after 2020

[3] Coal nameplate capacity assumes Idaho Power share

[4] Langley Gulch nameplate capacity assumed to be 300 MW

[5] Additional 300 MW CCCT assumed to be operational in 2025

[6] Two additional 170 MW SCCT units assumed to be operational, one in 2022 and the second in 2029

Construction Notes (not for publication)

Existing Nameplate Capacity from 2011 IRP page 27

Hydro forecast values from 2011 IRP Technical Appendix, pages 96 through 125

Coal, CCCT, SCCT forrecast values from 2011 IRP Technical Appendix

| 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1,758 | 1,758 | 1,758 | 1,758 | 1,758 | 1,758 | 1,758 | 1,758 | 1,758 | 1,758 | 1,758 | 1,758 | 1,758 |
| 982.6 | 979.0 | 976.6 | 975.1 | 973.9 | 973.5 | 973.5 | 973.5 | 973.5 | 973.5 | 973.5 | 973.5 | 973.5 |
| **0.56** | **0.56** | **0.56** | **0.55** | **0.55** | **0.55** | **0.55** | **0.55** | **0.55** | **0.55** | **0.55** | **0.55** | **0.55** |
| 788.8 | 784.8 | 781.5 | 778.9 | 777.6 | 777.1 | 777.1 | 777.1 | 777.1 | 777.1 | 777.1 | 777.1 | 777.1 |
| **0.45** | **0.45** | **0.44** | **0.44** | **0.44** | **0.44** | **0.44** | **0.44** | **0.44** | **0.44** | **0.44** | **0.44** | **0.44** |
| 657.9 | 655.1 | 653.2 | 651.8 | 650.3 | 650.0 | 650.0 | 650.0 | 650.0 | 650.0 | 650.0 | 650.0 | 650.0 |
| **0.37** | **0.37** | **0.37** | **0.37** | **0.37** | **0.37** | **0.37** | **0.37** | **0.37** | **0.37** | **0.37** | **0.37** | **0.37** |
| 913.7 | 917.0 | 918.6 | 867.1 | 863.0 | 866.4 | 867.8 | 867.1 | 863.0 | 866.4 | 867.8 | 867.1 | 863.0 |
| 1,118.2 | 1,118.2 | 1,118.2 | 1,118.2 | 1,059.6 | 1,059.6 | 1,059.6 | 1,059.6 | 1,059.6 | 1,059.6 | 1,059.6 | 1,059.6 | 1,059.6 |
| **0.82** | **0.82** | **0.82** | **0.78** | **0.81** | **0.82** | **0.82** | **0.82** | **0.81** | **0.82** | **0.82** | **0.82** | **0.81** |
| 251.0 | 251.0 | 251.0 | 251.0 | 251.0 | 251.0 | 251.0 | 397.4 | 502.0 | 502.0 | 502.0 | 502.0 | 502.0 |
| 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 300.0 | 600.0 | 600.0 | 600.0 | 600.0 | 600.0 | 600.0 |
| **0.84** | **0.84** | **0.84** | **0.84** | **0.84** | **0.84** | **0.84** | **0.66** | **0.84** | **0.84** | **0.84** | **0.84** | **0.84** |
| 96.8 | 96.8 | 97.6 | 97.6 | 121.6 | 120.9 | 120.8 | 120.8 | 121.6 | 121.6 | 120.1 | 144.9 | 144.9 |
| 443.7 | 443.7 | 443.7 | 443.7 | 613.7 | 613.7 | 613.7 | 613.7 | 613.7 | 613.7 | 613.7 | 783.7 | 783.7 |
| **0.22** | **0.22** | **0.22** | **0.22** | **0.20** | **0.20** | **0.20** | **0.20** | **0.20** | **0.20** | **0.20** | **0.18** | **0.18** |

Data from 2011 06 01 Load and resource Balance for Appendix C.xlsx

| Year | Month | Date | Coal | Langley | NewCCCT | CCCT | Peakers | NewSCCT1 | NewSCCT2 | SCCT |
|---|---|---|---|---|---|---|---|---|---|---|
| 2011 | 1 | 1/1/2011 | 933.4 | 0.0 | 0.0 | 0.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2011 | 2 | 2/1/2011 | 933.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2011 | 3 | 3/1/2011 | 863.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2011 | 4 | 4/1/2011 | 669.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2011 | 5 | 5/1/2011 | 646.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2011 | 6 | 6/1/2011 | 913.7 | 0.0 | 0.0 | 0.0 | 240.4 | 0.0 | 0.0 | 240.4 |
| 2011 | 7 | 7/1/2011 | 932.4 | 0.0 | 0.0 | 0.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2011 | 8 | 8/1/2011 | 932.4 | 0.0 | 0.0 | 0.0 | 241.5 | 0.0 | 0.0 | 241.5 |
| 2011 | 9 | 9/1/2011 | 932.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2011 | 10 | 10/1/2011 | 931.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2011 | 11 | 11/1/2011 | 932.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2011 | 12 | 12/1/2011 | 932.4 | 0.0 | 0.0 | 0.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2012 | 1 | 1/1/2012 | 932.4 | 0.0 | 0.0 | 0.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2012 | 2 | 2/1/2012 | 932.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2012 | 3 | 3/1/2012 | 885.7 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2012 | 4 | 4/1/2012 | 775.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2012 | 5 | 5/1/2012 | 734.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2012 | 6 | 6/1/2012 | 851.4 | 0.0 | 0.0 | 0.0 | 240.4 | 0.0 | 0.0 | 240.4 |
| 2012 | 7 | 7/1/2012 | 931.4 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2012 | 8 | 8/1/2012 | 931.4 | 251.0 | 0.0 | 251.0 | 241.5 | 0.0 | 0.0 | 241.5 |
| 2012 | 9 | 9/1/2012 | 931.4 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2012 | 10 | 10/1/2012 | 930.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2012 | 11 | 11/1/2012 | 931.4 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2012 | 12 | 12/1/2012 | 931.4 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2013 | 1 | 1/1/2013 | 931.4 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2013 | 2 | 2/1/2013 | 931.4 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2013 | 3 | 3/1/2013 | 852.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2013 | 4 | 4/1/2013 | 558.5 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2013 | 5 | 5/1/2013 | 612.4 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2013 | 6 | 6/1/2013 | 931.4 | 251.0 | 0.0 | 251.0 | 231.1 | 0.0 | 0.0 | 231.1 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 2013 | 7 | 7/1/2013 | 931.4 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2013 | 8 | 8/1/2013 | 931.4 | 251.0 | 0.0 | 251.0 | 241.5 | 0.0 | 0.0 | 241.5 |
| 2013 | 9 | 9/1/2013 | 931.4 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2013 | 10 | 10/1/2013 | 930.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2013 | 11 | 11/1/2013 | 931.4 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2013 | 12 | 12/1/2013 | 931.4 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2014 | 1 | 1/1/2014 | 931.4 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2014 | 2 | 2/1/2014 | 931.4 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2014 | 3 | 3/1/2014 | 879.6 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2014 | 4 | 4/1/2014 | 584.1 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2014 | 5 | 5/1/2014 | 721.9 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2014 | 6 | 6/1/2014 | 920.5 | 251.0 | 0.0 | 251.0 | 231.1 | 0.0 | 0.0 | 231.1 |
| 2014 | 7 | 7/1/2014 | 931.0 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2014 | 8 | 8/1/2014 | 931.0 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2014 | 9 | 9/1/2014 | 931.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2014 | 10 | 10/1/2014 | 929.8 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2014 | 11 | 11/1/2014 | 931.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2014 | 12 | 12/1/2014 | 931.0 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2015 | 1 | 1/1/2015 | 931.0 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2015 | 2 | 2/1/2015 | 931.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2015 | 3 | 3/1/2015 | 834.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2015 | 4 | 4/1/2015 | 634.1 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2015 | 5 | 5/1/2015 | 714.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2015 | 6 | 6/1/2015 | 814.4 | 251.0 | 0.0 | 251.0 | 240.4 | 0.0 | 0.0 | 240.4 |
| 2015 | 7 | 7/1/2015 | 931.0 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2015 | 8 | 8/1/2015 | 931.0 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2015 | 9 | 9/1/2015 | 931.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2015 | 10 | 10/1/2015 | 929.8 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2015 | 11 | 11/1/2015 | 931.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2015 | 12 | 12/1/2015 | 931.0 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2016 | 1 | 1/1/2016 | 931.0 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2016 | 2 | 2/1/2016 | 931.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2016 | 3 | 3/1/2016 | 898.4 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2016 | 4 | 4/1/2016 | 823.4 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |

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|---|---|---|---|---|---|---|---|---|---|---|
| 2016 | 5 | 5/1/2016 | 715.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2016 | 6 | 6/1/2016 | 887.8 | 251.0 | 0.0 | 251.0 | 240.4 | 0.0 | 0.0 | 240.4 |
| 2016 | 7 | 7/1/2016 | 937.0 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2016 | 8 | 8/1/2016 | 937.0 | 251.0 | 0.0 | 251.0 | 241.5 | 0.0 | 0.0 | 241.5 |
| 2016 | 9 | 9/1/2016 | 937.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2016 | 10 | 10/1/2016 | 935.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2016 | 11 | 11/1/2016 | 937.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2016 | 12 | 12/1/2016 | 937.0 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2017 | 1 | 1/1/2017 | 937.0 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2017 | 2 | 2/1/2017 | 937.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2017 | 3 | 3/1/2017 | 904.4 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2017 | 4 | 4/1/2017 | 840.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2017 | 5 | 5/1/2017 | 704.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2017 | 6 | 6/1/2017 | 915.6 | 251.0 | 0.0 | 251.0 | 240.4 | 0.0 | 0.0 | 240.4 |
| 2017 | 7 | 7/1/2017 | 943.0 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2017 | 8 | 8/1/2017 | 943.0 | 251.0 | 0.0 | 251.0 | 241.5 | 0.0 | 0.0 | 241.5 |
| 2017 | 9 | 9/1/2017 | 943.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2017 | 10 | 10/1/2017 | 941.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2017 | 11 | 11/1/2017 | 943.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2017 | 12 | 12/1/2017 | 943.0 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2018 | 1 | 1/1/2018 | 943.0 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2018 | 2 | 2/1/2018 | 947.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2018 | 3 | 3/1/2018 | 943.0 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2018 | 4 | 4/1/2018 | 841.4 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2018 | 5 | 5/1/2018 | 726.3 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2018 | 6 | 6/1/2018 | 899.6 | 251.0 | 0.0 | 251.0 | 240.4 | 0.0 | 0.0 | 240.4 |
| 2018 | 7 | 7/1/2018 | 944.2 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2018 | 8 | 8/1/2018 | 944.2 | 251.0 | 0.0 | 251.0 | 241.5 | 0.0 | 0.0 | 241.5 |
| 2018 | 9 | 9/1/2018 | 944.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2018 | 10 | 10/1/2018 | 942.9 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2018 | 11 | 11/1/2018 | 944.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2018 | 12 | 12/1/2018 | 944.2 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2019 | 1 | 1/1/2019 | 944.2 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2019 | 2 | 2/1/2019 | 944.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |

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|---|---|---|---|---|---|---|---|---|---|---|
| 2019 | 3 | 3/1/2019 | 944.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2019 | 4 | 4/1/2019 | 842.6 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2019 | 5 | 5/1/2019 | 727.5 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2019 | 6 | 6/1/2019 | 900.8 | 251.0 | 0.0 | 251.0 | 231.1 | 0.0 | 0.0 | 231.1 |
| 2019 | 7 | 7/1/2019 | 950.2 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2019 | 8 | 8/1/2019 | 950.2 | 251.0 | 0.0 | 251.0 | 241.5 | 0.0 | 0.0 | 241.5 |
| 2019 | 9 | 9/1/2019 | 950.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2019 | 10 | 10/1/2019 | 948.9 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2019 | 11 | 11/1/2019 | 950.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2019 | 12 | 12/1/2019 | 950.2 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2020 | 1 | 1/1/2020 | 944.2 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2020 | 2 | 2/1/2020 | 946.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2020 | 3 | 3/1/2020 | 944.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2020 | 4 | 4/1/2020 | 838.1 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2020 | 5 | 5/1/2020 | 729.5 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2020 | 6 | 6/1/2020 | 896.2 | 251.0 | 0.0 | 251.0 | 240.4 | 0.0 | 0.0 | 240.4 |
| 2020 | 7 | 7/1/2020 | 954.2 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2020 | 8 | 8/1/2020 | 955.2 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2020 | 9 | 9/1/2020 | 948.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2020 | 10 | 10/1/2020 | 956.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2020 | 11 | 11/1/2020 | 950.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2020 | 12 | 12/1/2020 | 959.2 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2021 | 1 | 1/1/2021 | 888.7 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2021 | 2 | 2/1/2021 | 880.6 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2021 | 3 | 3/1/2021 | 888.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2021 | 4 | 4/1/2021 | 788.1 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2021 | 5 | 5/1/2021 | 727.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2021 | 6 | 6/1/2021 | 840.7 | 251.0 | 0.0 | 251.0 | 240.4 | 0.0 | 0.0 | 240.4 |
| 2021 | 7 | 7/1/2021 | 898.7 | 251.0 | 0.0 | 251.0 | 241.5 | 0.0 | 0.0 | 241.5 |
| 2021 | 8 | 8/1/2021 | 899.7 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2021 | 9 | 9/1/2021 | 893.1 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2021 | 10 | 10/1/2021 | 900.8 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2021 | 11 | 11/1/2021 | 895.1 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2021 | 12 | 12/1/2021 | 903.7 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |

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|---|---|---|---|---|---|---|---|---|---|---|
| 2022 | 1 | 1/1/2022 | 887.2 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2022 | 2 | 2/1/2022 | 891.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2022 | 3 | 3/1/2022 | 887.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2022 | 4 | 4/1/2022 | 791.1 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2022 | 5 | 5/1/2022 | 724.2 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2022 | 6 | 6/1/2022 | 843.7 | 251.0 | 0.0 | 251.0 | 240.4 | 98.1 | 0.0 | 338.4 |
| 2022 | 7 | 7/1/2022 | 888.7 | 251.0 | 0.0 | 251.0 | 223.7 | 91.5 | 0.0 | 315.2 |
| 2022 | 8 | 8/1/2022 | 888.7 | 251.0 | 0.0 | 251.0 | 241.5 | 98.9 | 0.0 | 340.4 |
| 2022 | 9 | 9/1/2022 | 888.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2022 | 10 | 10/1/2022 | 887.5 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2022 | 11 | 11/1/2022 | 888.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2022 | 12 | 12/1/2022 | 888.7 | 251.0 | 0.0 | 251.0 | 241.5 | 0.0 | 0.0 | 241.5 |
| 2023 | 1 | 1/1/2023 | 888.7 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2023 | 2 | 2/1/2023 | 888.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2023 | 3 | 3/1/2023 | 888.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2023 | 4 | 4/1/2023 | 792.6 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2023 | 5 | 5/1/2023 | 725.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2023 | 6 | 6/1/2023 | 845.2 | 251.0 | 0.0 | 251.0 | 240.4 | 98.1 | 0.0 | 338.4 |
| 2023 | 7 | 7/1/2023 | 894.7 | 251.0 | 0.0 | 251.0 | 223.7 | 91.5 | 0.0 | 315.2 |
| 2023 | 8 | 8/1/2023 | 894.7 | 251.0 | 0.0 | 251.0 | 241.5 | 98.9 | 0.0 | 340.4 |
| 2023 | 9 | 9/1/2023 | 894.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2023 | 10 | 10/1/2023 | 893.5 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2023 | 11 | 11/1/2023 | 894.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2023 | 12 | 12/1/2023 | 894.7 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2024 | 1 | 1/1/2024 | 888.7 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2024 | 2 | 2/1/2024 | 888.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2024 | 3 | 3/1/2024 | 888.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2024 | 4 | 4/1/2024 | 788.1 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2024 | 5 | 5/1/2024 | 727.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2024 | 6 | 6/1/2024 | 840.7 | 251.0 | 0.0 | 251.0 | 231.1 | 98.1 | 0.0 | 329.2 |
| 2024 | 7 | 7/1/2024 | 898.7 | 251.0 | 0.0 | 251.0 | 232.6 | 91.5 | 0.0 | 324.1 |
| 2024 | 8 | 8/1/2024 | 899.7 | 251.0 | 0.0 | 251.0 | 241.5 | 98.9 | 0.0 | 340.4 |
| 2024 | 9 | 9/1/2024 | 893.1 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2024 | 10 | 10/1/2024 | 900.8 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |

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|---|---|---|---|---|---|---|---|---|---|---|
| 2024 | 11 | 11/1/2024 | 895.1 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2024 | 12 | 12/1/2024 | 903.7 | 251.0 | 0.0 | 251.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2025 | 1 | 1/1/2025 | 888.7 | 251.0 | 0.0 | 251.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2025 | 2 | 2/1/2025 | 880.6 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2025 | 3 | 3/1/2025 | 888.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2025 | 4 | 4/1/2025 | 788.1 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2025 | 5 | 5/1/2025 | 727.7 | 251.0 | 0.0 | 251.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2025 | 6 | 6/1/2025 | 840.7 | 251.0 | 251.0 | 502.0 | 231.1 | 98.1 | 0.0 | 329.2 |
| 2025 | 7 | 7/1/2025 | 898.7 | 251.0 | 251.0 | 502.0 | 232.6 | 91.5 | 0.0 | 324.1 |
| 2025 | 8 | 8/1/2025 | 899.7 | 251.0 | 251.0 | 502.0 | 232.6 | 98.9 | 0.0 | 331.5 |
| 2025 | 9 | 9/1/2025 | 893.1 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2025 | 10 | 10/1/2025 | 900.8 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2025 | 11 | 11/1/2025 | 895.1 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2025 | 12 | 12/1/2025 | 903.7 | 251.0 | 251.0 | 502.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2026 | 1 | 1/1/2026 | 887.2 | 251.0 | 251.0 | 502.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2026 | 2 | 2/1/2026 | 891.2 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2026 | 3 | 3/1/2026 | 887.2 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2026 | 4 | 4/1/2026 | 791.1 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2026 | 5 | 5/1/2026 | 724.2 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2026 | 6 | 6/1/2026 | 843.7 | 251.0 | 251.0 | 502.0 | 240.4 | 98.1 | 0.0 | 338.4 |
| 2026 | 7 | 7/1/2026 | 888.7 | 251.0 | 251.0 | 502.0 | 232.6 | 91.5 | 0.0 | 324.1 |
| 2026 | 8 | 8/1/2026 | 888.7 | 251.0 | 251.0 | 502.0 | 232.6 | 98.9 | 0.0 | 331.5 |
| 2026 | 9 | 9/1/2026 | 888.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2026 | 10 | 10/1/2026 | 887.5 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2026 | 11 | 11/1/2026 | 888.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2026 | 12 | 12/1/2026 | 888.7 | 251.0 | 251.0 | 502.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2027 | 1 | 1/1/2027 | 888.7 | 251.0 | 251.0 | 502.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2027 | 2 | 2/1/2027 | 888.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2027 | 3 | 3/1/2027 | 888.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2027 | 4 | 4/1/2027 | 792.6 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2027 | 5 | 5/1/2027 | 725.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2027 | 6 | 6/1/2027 | 845.2 | 251.0 | 251.0 | 502.0 | 240.4 | 98.1 | 0.0 | 338.4 |
| 2027 | 7 | 7/1/2027 | 894.7 | 251.0 | 251.0 | 502.0 | 241.5 | 91.5 | 0.0 | 333.1 |
| 2027 | 8 | 8/1/2027 | 894.7 | 251.0 | 251.0 | 502.0 | 232.6 | 98.9 | 0.0 | 331.5 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 2027 | 9 | 9/1/2027 | 894.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2027 | 10 | 10/1/2027 | 893.5 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2027 | 11 | 11/1/2027 | 894.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2027 | 12 | 12/1/2027 | 894.7 | 251.0 | 251.0 | 502.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2028 | 1 | 1/1/2028 | 888.7 | 251.0 | 251.0 | 502.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2028 | 2 | 2/1/2028 | 888.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2028 | 3 | 3/1/2028 | 888.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2028 | 4 | 4/1/2028 | 788.1 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2028 | 5 | 5/1/2028 | 727.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2028 | 6 | 6/1/2028 | 840.7 | 251.0 | 251.0 | 502.0 | 240.4 | 98.1 | 0.0 | 338.4 |
| 2028 | 7 | 7/1/2028 | 898.7 | 251.0 | 251.0 | 502.0 | 223.7 | 91.5 | 0.0 | 315.2 |
| 2028 | 8 | 8/1/2028 | 899.7 | 251.0 | 251.0 | 502.0 | 241.5 | 98.9 | 0.0 | 340.4 |
| 2028 | 9 | 9/1/2028 | 893.1 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2028 | 10 | 10/1/2028 | 900.8 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2028 | 11 | 11/1/2028 | 895.1 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2028 | 12 | 12/1/2028 | 903.7 | 251.0 | 251.0 | 502.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2029 | 1 | 1/1/2029 | 888.7 | 251.0 | 251.0 | 502.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2029 | 2 | 2/1/2029 | 880.6 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2029 | 3 | 3/1/2029 | 888.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2029 | 4 | 4/1/2029 | 788.1 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2029 | 5 | 5/1/2029 | 727.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2029 | 6 | 6/1/2029 | 840.7 | 251.0 | 251.0 | 502.0 | 240.4 | 98.1 | 98.1 | 436.5 |
| 2029 | 7 | 7/1/2029 | 898.7 | 251.0 | 251.0 | 502.0 | 223.7 | 91.5 | 91.5 | 406.7 |
| 2029 | 8 | 8/1/2029 | 899.7 | 251.0 | 251.0 | 502.0 | 241.5 | 98.9 | 98.9 | 439.3 |
| 2029 | 9 | 9/1/2029 | 893.1 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2029 | 10 | 10/1/2029 | 900.8 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2029 | 11 | 11/1/2029 | 895.1 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2029 | 12 | 12/1/2029 | 903.7 | 251.0 | 251.0 | 502.0 | 223.7 | 0.0 | 0.0 | 223.7 |
| 2030 | 1 | 1/1/2030 | 887.2 | 251.0 | 251.0 | 502.0 | 232.6 | 0.0 | 0.0 | 232.6 |
| 2030 | 2 | 2/1/2030 | 891.2 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2030 | 3 | 3/1/2030 | 887.2 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2030 | 4 | 4/1/2030 | 791.1 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2030 | 5 | 5/1/2030 | 724.2 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2030 | 6 | 6/1/2030 | 843.7 | 251.0 | 251.0 | 502.0 | 240.4 | 98.1 | 98.1 | 436.5 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 2030 | 7 | 7/1/2030 | 888.7 | 251.0 | 251.0 | 502.0 | 223.7 | 91.5 | 91.5 | 406.7 |
| 2030 | 8 | 8/1/2030 | 888.7 | 251.0 | 251.0 | 502.0 | 241.5 | 98.9 | 98.9 | 439.3 |
| 2030 | 9 | 9/1/2030 | 888.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2030 | 10 | 10/1/2030 | 887.5 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2030 | 11 | 11/1/2030 | 888.7 | 251.0 | 251.0 | 502.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| 2030 | 12 | 12/1/2030 | 888.7 | 251.0 | 251.0 | 502.0 | 223.7 | 0.0 | 0.0 | 223.7 |

Data from 2011IRPAvgGen.accdb
AnnualGenDataQ

| Year | Coal MWa | CCCT MWa | SCCT MWa |
|---|---|---|---|
| 2011 | 879.3 | 0 | 96.8 |
| 2012 | 891.6 | 125.5 | 96.1 |
| 2013 | 867 | 251 | 96.8 |
| 2014 | 879.5 | 251 | 96.8 |
| 2015 | 870.3 | 251 | 97.6 |
| 2016 | 900.6 | 251 | 96.8 |
| 2017 | 908 | 251 | 96.1 |
| 2018 | 913.7 | 251 | 96.8 |
| 2019 | 917 | 251 | 96.8 |
| 2020 | 918.6 | 251 | 97.6 |
| 2021 | 867.1 | 251 | 97.6 |
| 2022 | 863 | 251 | 121.6 |
| 2023 | 866.4 | 251 | 120.9 |
| 2024 | 867.8 | 251 | 120.8 |
| 2025 | 867.1 | 397.4 | 120.8 |
| 2026 | 863 | 502 | 121.6 |
| 2027 | 866.4 | 502 | 121.6 |
| 2028 | 867.8 | 502 | 120.1 |
| 2029 | 867.1 | 502 | 144.9 |
| 2030 | 863 | 502 | 144.9 |