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June 30, 2015

VIA ELECTRONIC EMAIL AND UPS

PUC Filing Center
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088

Re: Docket LC ____ - Idaho Power Company's 2015 Integrated Resource Plan ("IRP")

Attached for filing in the above-identified docket are an original and twenty copies of Idaho Power Company's Application of the 2015 Integrated Resource Plan. The hard copies of the materials are being delivered via UPS tomorrow.

Please contact this office with any questions.

Very truly yours,

Sharon Cooper

Sharon Cooper
Legal Assistant

Attachments (5)

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC ______

In the Matter of IDAHO POWER COMPANY'S 2015 Integrated Resource Plan.	))))))	**APPLICATION**

I. INTRODUCTION

Idaho Power Company ("Idaho Power" or "Company"), in accordance with the Public Utility Commission of Oregon's ("Commission") Order Nos. 89-507, 07-002, 07-747, and 12-013, hereby requests that the Commission issue an order acknowledging the Company's 2015 Integrated Resource Plan ("IRP" or "Plan").

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

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II. BACKGROUND

Idaho Power's 2015 IRP addresses available supply-side and demand-side resource options, planning period load forecasts, potential resource portfolios, a risk analysis, and an action plan that details the steps the Company plans to take to implement the 2015 IRP.

The complete 2015 IRP consists of four separate documents: (1) the 2015 Integrated Resource Plan; (2) Appendix A – Sales and Load Forecast; (3) Appendix B – Demand-Side Management 2014 Annual Report; and (4) Appendix C – Technical Appendix. A copy of the complete 2015 IRP is provided as Attachment 1 and can also be found on the Company's website at www.idahopower.com. Interested persons may also request a printed copy of the 2015 IRP by contacting irp@idahopower.com.

Idaho Power has worked with stakeholders over the last year to develop the 2015 IRP. To incorporate stakeholder and public input, the Company worked with the Integrated Resource Plan Advisory Council ("IRPAC"), comprised of members of the environmental community, major industrial customers, agricultural interests, representatives from both the Commission and Idaho Public Utilities Commission, representatives from the Idaho Office of Energy Resources and the Northwest Power and Conservation Council, and others. 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.

Following the filing of the 2015 IRP, Idaho Power will present the resource plan at public meetings in various communities around the Company's service area. In addition, Idaho Power staff will present the plan and discuss the planning process with various civic groups and at educational seminars as requested.

III. IRP GOALS AND ASSUMPTIONS

The primary goals of Idaho Power's 2015 IRP are to: (1) identify sufficient resources to reliably serve the growing demand for energy within Idaho Power's service area throughout the 20-year planning period; (2) ensure the selected resource portfolio balances cost, risk, and environmental concerns; (3) give equal and balanced treatment to both supply-side resources and demand-side measures; and (4) involve the public in the planning process in a meaningful way.

The 2015 IRP assumes that during the 20-year planning period in the IRP (2015-2034), Idaho Power will continue to be responsible for acquiring resources sufficient to serve all of its retail customers in its Idaho and Oregon service territories and will continue to operate as a vertically-integrated electric utility. 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 increase to 711,000 by 2034 from 515,000 in 2014. Idaho Power continues to use 70th percentile water conditions and 70th percentile average load for energy planning. For peak-hour capacity planning, Idaho Power uses 90th percentile water conditions and 95th percentile peak-hour load. Additional Company-owned resources will be needed to meet these increased demands in combination with demand-side measures.

IV. 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, transmission upgrades, and anticipated environmental controls and emission costs. The financial benefits include

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economic resource operations, projected market sales, and the market value of renewable energy certificates.

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 now known as the Boardman to Hemingway ("B2H") Transmission Line Project. Idaho Power again evaluated the B2H transmission line as an uncommitted resource in the 2015 resource plan to ensure the transmission addition remains a prudent resource acquisition.

V. PREFERRED RESOURCE PORTFOLIO

A fundamental goal of the IRP process is to identify a selected, or preferred, resource portfolio. The preferred portfolio identifies resource options and timing to allow Idaho Power to continue to reliably serve customer demand, balancing cost, risk, and environmental factors over the 2015 to 2034 planning period. The 2015 IRP presented by this Application provides the Company's estimate of future loads and sets forth how the Company intends to serve the electrical requirements of its native load customers over the next 20 years. While the proposed preferred resource portfolio represents current resource acquisition targets, it is important to note that the actual resource portfolio may differ from the quantities and types of resources outlined in the IRP depending on the changing needs of Idaho Power and its customers.

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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, acceleration in the completion of the B2H transmission 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 thermal energy storage in 2030 and a 300-MW combined cycle combustion turbine generation resource 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:

- Uncertainty related to planned but yet-to-be-built Public Utility Regulatory Policies Act (PURPA) solar qualifying facilities; further project cancellations beyond those already observed will have a greater impact on portfolios requiring capacity additions in the early 2020s.
- Uncertainty related to the Environmental Protection Agency's proposed regulation of CO_2 emissions from existing power plants under Clean Air Act (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.
- Uncertainty related to the completion date of the B2H transmission line due to permitting issues and needs of project partners.

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- 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 transmission 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.

VI. ACTION PLAN (2015-2018)

Consistent with the Commission's direction in Order No. 14-253, the 2015 IRP includes an action plan with resource activities that the Company plans to take in the next two to four years.[1] 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 the provisions of the final regulation become clear, and

[1] Order No. 14-253 at 17.

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Below is a summary of the 2015 IRP's Action Plan:[2]

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
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

VII. COMPLIANCE WITH ORDER NO. 14-253

In Order No. 14-253, the Commission acknowledged in part the Company's 2013 IRP. In so doing, the Commission required Idaho Power to address certain subject matters in its 2015 IRP. As described in Appendix C to the IRP, the Company has addressed each of the issues raised by the Commission in the 2013 IRP.[3]

Regarding pollution control investments at coal-fired resources, the Commission directed Idaho Power to model a broader range of early shutdown scenarios after engaging with Staff and stakeholders to design coal investment analysis for the 2015 IRP.[4] The Commission also directed Idaho Power to work with stakeholders to explore options for compliance with the requirements of CAA Section 111(d). The 2015 IRP considers multiple

[2] 2015 IRP at 142-143.
[3] Appendix C at 192-216.
[4] Order No. 14-253 at 8.

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as implementation planning is developed, Idaho Power will assess the impacts of CAA Section 111(d) on the preferred portfolio.

In addition to continued transmission permitting efforts and evaluation of potential changes in thermal fleet operations, the action plan also includes the following items:

- Continued pursuit of cost-effective energy efficiency, working with stakeholder groups, such as Energy Efficiency Advisory Group ("EEAG") and regional groups such as Northwest Energy Efficiency Alliance ("NEEA").
- Filing to amend the Federal Energy Regulatory Commission ("FERC") license to adjust the 50-MW Shoshone Falls project expansion and efforts related to the study and construction of a smaller upgrade to the project with a scheduled on-line date in the first quarter of 2019.
- Completion of selective catalytic reduction ("SCR") additions for Jim Bridger units 3 and 4.
- Begin economic evaluation of SCR additions for Jim Bridger units 1 and 2 (SCR installation required for Unit 1 in 2022 and for Unit 2 in 2021).

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early retirement scenarios, which were developed with input from the IRPAC and public participants of the IRP process. In addition, CAA Section 111(d) was discussed frequently during IRPAC meetings and the 2015 IRP includes multiple sensitivities for CAA Section 111(d).

During the 2013 IRP proceeding, the Oregon Department of Energy ("ODOE") recommended changes to how capacity credits are determined by solar, wind, and hydro resources. The Company agreed to examine the issues identified by ODOE and the Commission indicated that it expected to see the results of Idaho Power's work in its 2015 IRP.[5] In response, Idaho Power convened public working group meetings to address solar-related issues, including capacity contribution, and the results of the solar capacity contribution analysis are included in the 2015 IRP. In addition, the Commission has opened a generic investigation to specifically examine the capacity contribution provided by solar resources and Idaho Power is actively participating in that docket.

When analyzing the 2013 IRP, Staff expressed a concern regarding the gas price forecast used to develop the IRP. Specifically, Staff was concerned about 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.[6] The Commission indicated that Staff's concerns should be addressed during the planning process for the 2015 IRP. In response, 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 2015 IRP also includes verification that future power

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[5] Order No. 14-253 at 14.
[6] Order No. 14-253 at 14.

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market prices derived by AURORA maintain their historic relationship to natural gas market prices and this verification was presented at an IRPAC meeting in February 2015.

In Order No. 14-253, the Commission found that the Company's 2013 IRP did not comply with the Flexible Resources Guideline established in Order No. 12-013.[7] The Commission directed Idaho Power to use the recommendations provided by Staff and stakeholders to provide a compliant and more robust analysis regarding flexible resources in its 2015 IRP. The Company's 2015 IRP now includes robust quantitative analysis indicating that the Company has 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. Based on its analysis, the Company is currently investigating methods to address potential down-regulation issues.[8]

The Commission also directed the Company to include in its 2015 IRP an assessment of the available cost-effective conservation voltage reduction ("CVR") resource potential in its service area.[9] The Company's 2014 Smart Grid Report included a Conservation Voltage Reduction Enhancements Project intended to validate the energy savings and reduced peak demand of CVR using new technologies and methods of measurement. Idaho Power expects to complete the CVR analysis in 2016.[10]

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[7] Order No. 14-253 at 15.
[8] 2015 IRP at 135-139.
[9] Order No. 14-253 at 16. Order No. 14-253 at 15.
[9] 2015 IRP at 135-139.
[9] Order
[10] 2015 IRP at 48.

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The 2015 IRP action plan also 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 in the Company's 2013 IRP.[11] And Idaho Power has continued its commitment to NEEA as a participant in NEEA's 2015 to 2019 funding cycle.

VIII. REQUEST FOR ACKNOWLEDGMENT

Idaho Power respectfully requests that the Commission issue an order acknowledging the Company's 2015 IRP and finding that the 2015 IRP meets both the procedural and substantive requirements of Order Nos. 89-507, 07-002, 07-747, and 12-013.

DATED this 30th day of June 2015.

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Lisa F. Rackner
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Attorneys for Idaho Power Company

[11] Order No. 14-253 at 16.

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing documents in Docket LC ____ on the following named persons on the date indicated below by e-mail addressed to said persons at his or her last-known email address indicated below.

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DATED: June 30, 2015

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June 2015

IDAHO POWER®
An IDACORP Company

Integrated Resource Plan 2015

SAFE HARBOR STATEMENT

June 2015

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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.

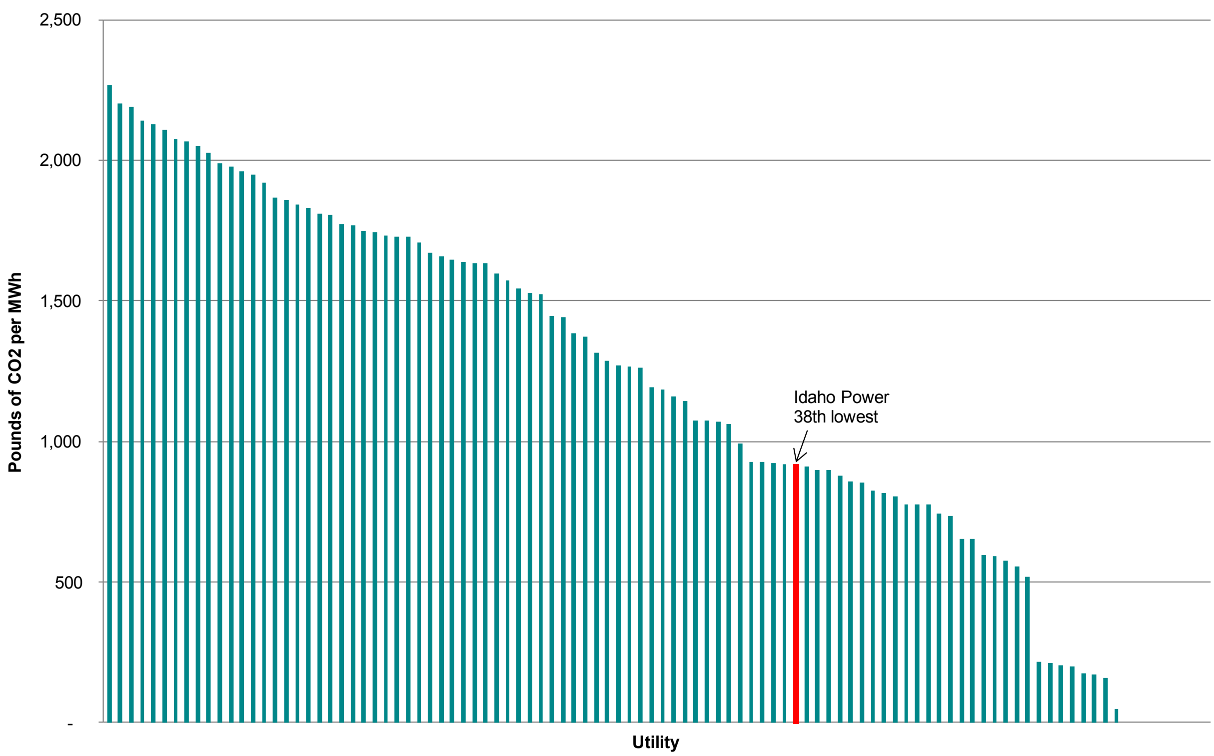

Figure 1.1 CO_2 emissions intensity of the largest 100 utilities

[3] M. J. Bradley & Associates. 2014. Benchmarking air emissions of the 100 largest electric power producers in the United States.

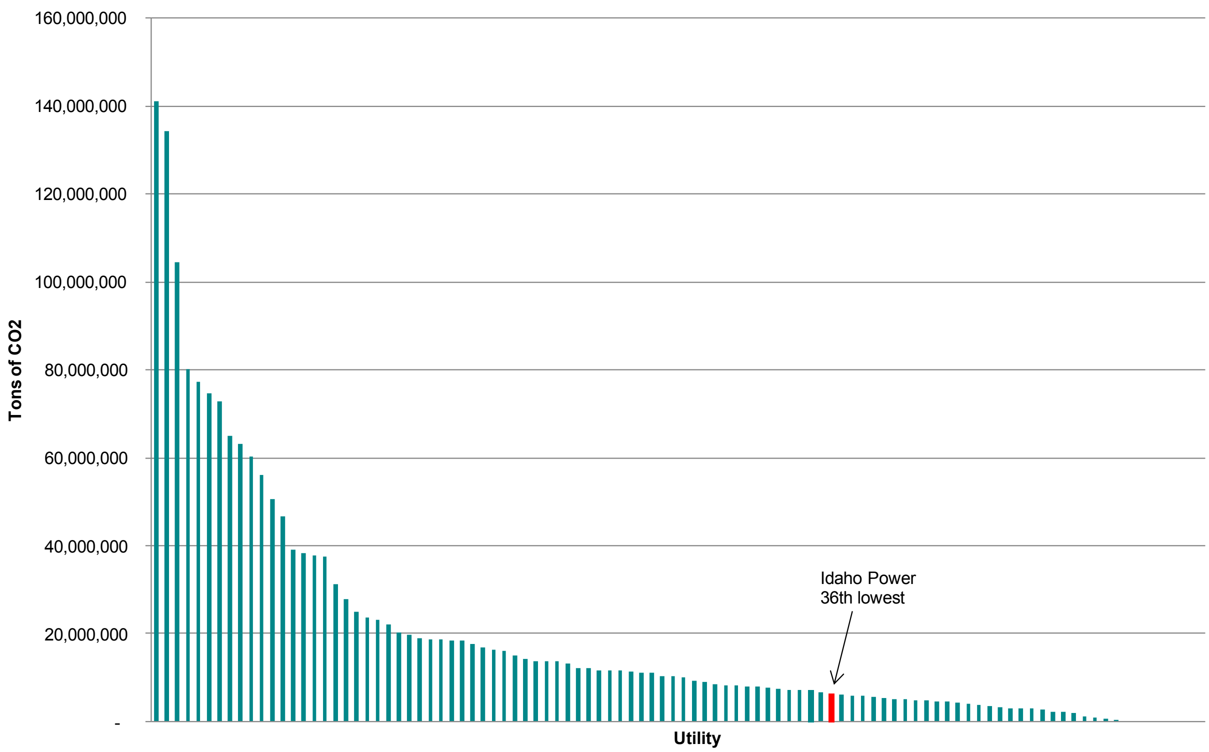

Figure 1.2 **CO_2 emissions of the largest 100 utilities**

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 • Tucson Electric Power—Bright Tucson Program	• University Park Community Solar, LLC • Clean Energy Collective, LLC • Island Community Solar, LLC	• Winthrop Community Solar Project • 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.

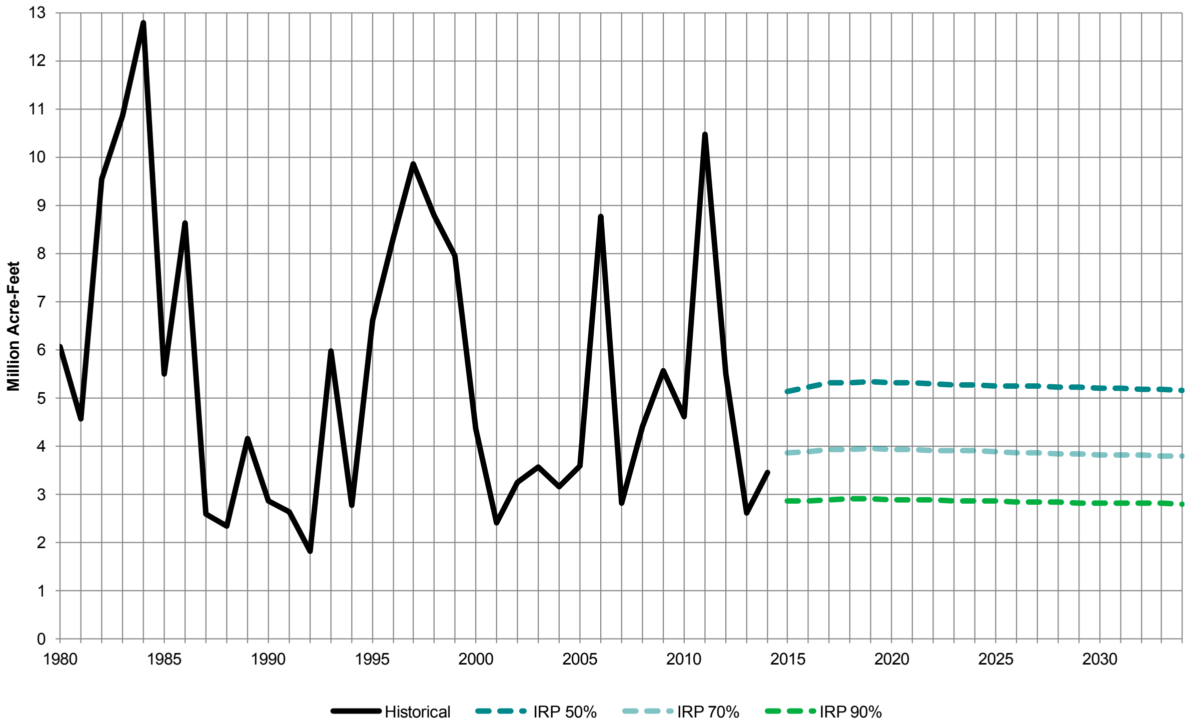


Figure 2.1 Brownlee historical and 2015 to 2034 forecasted April to July inflow

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.

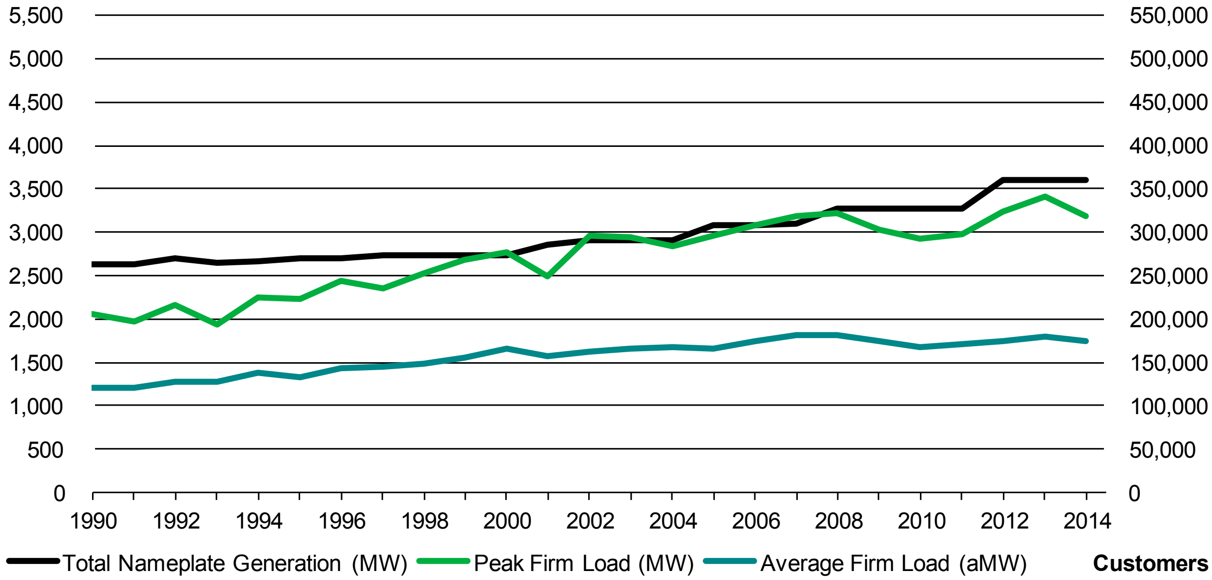


Figure 3.1 Historical capacity, load, and customer data

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.

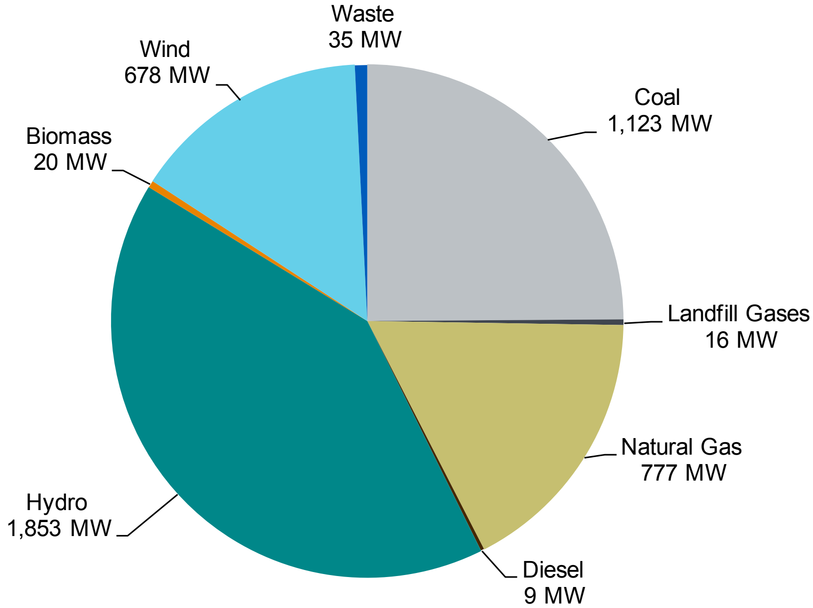


Figure 3.2 2014 Idaho Power system nameplate by fuel type (MW) (owned resources plus purchased power)

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.

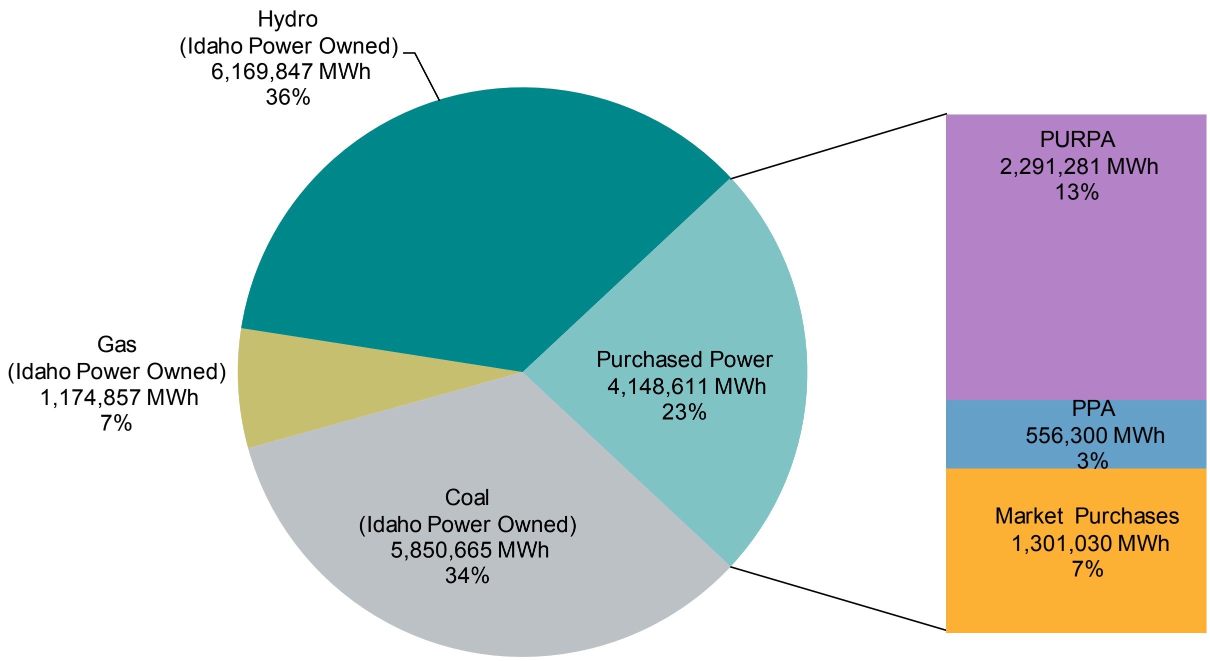


Figure 3.3 2014 energy by source

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.

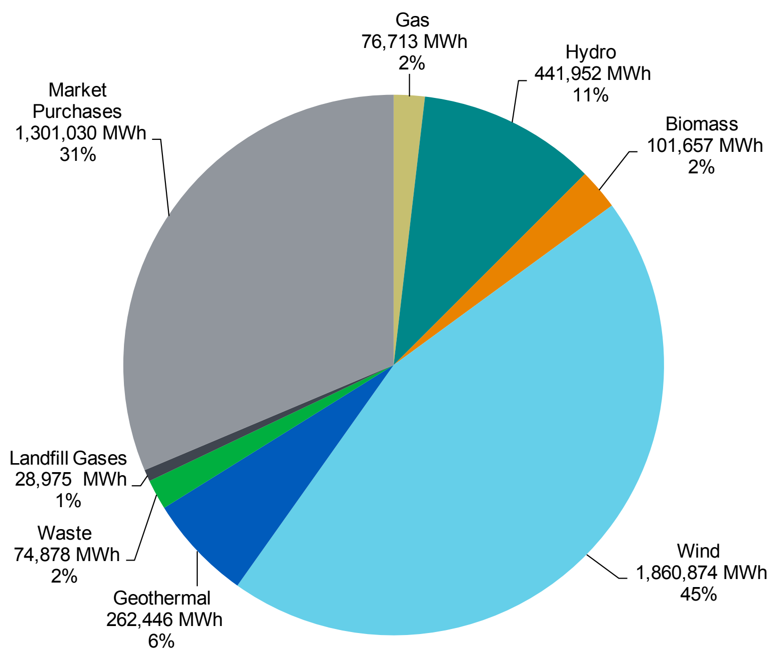


Figure 3.4 2014 power purchases by fuel type

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.

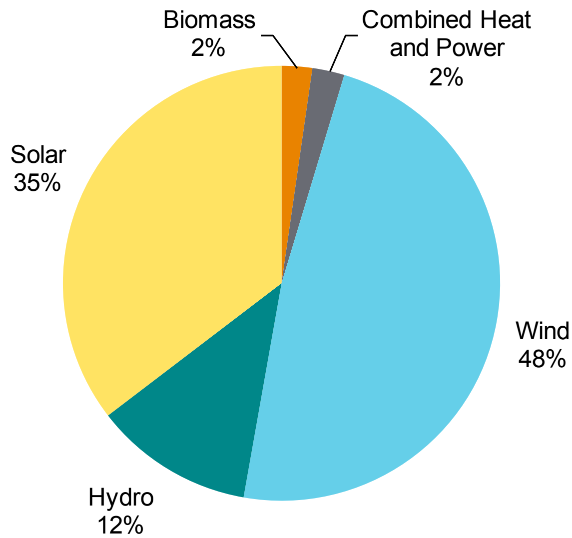


Figure 3.5 PURPA contracts by resource type

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.

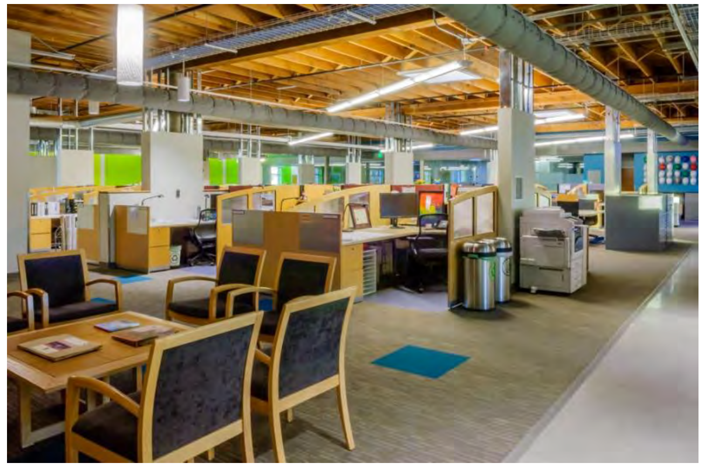
Market Purchases and Sales

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.

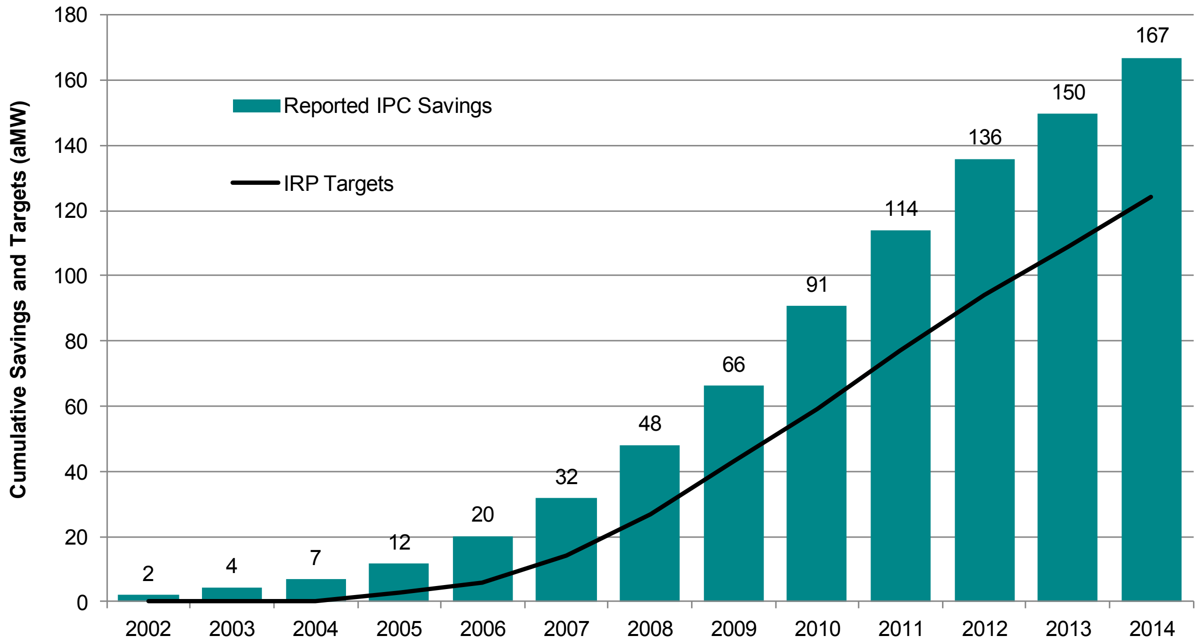


Figure 4.1 Cumulative energy efficiency savings, 2002–2014 (aMW)

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.

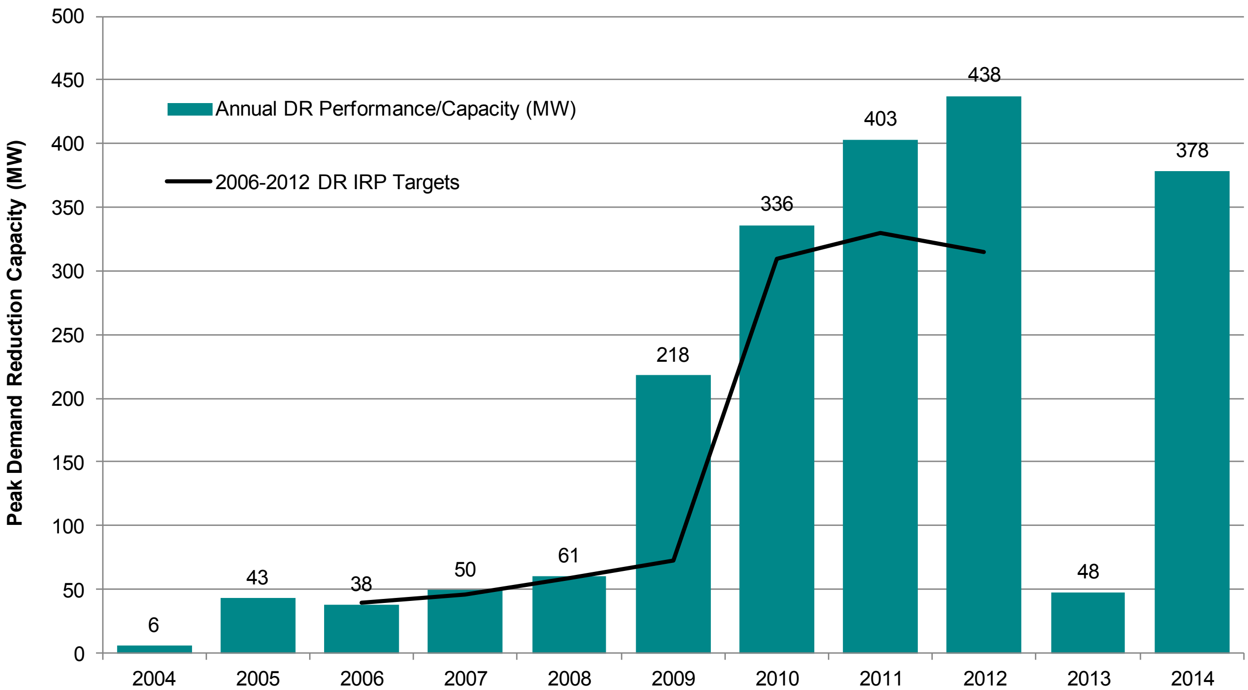


Figure 4.2 Demand response peak reduction capacity and IRP targets, 2004–2014 (MW)

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 90th 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.

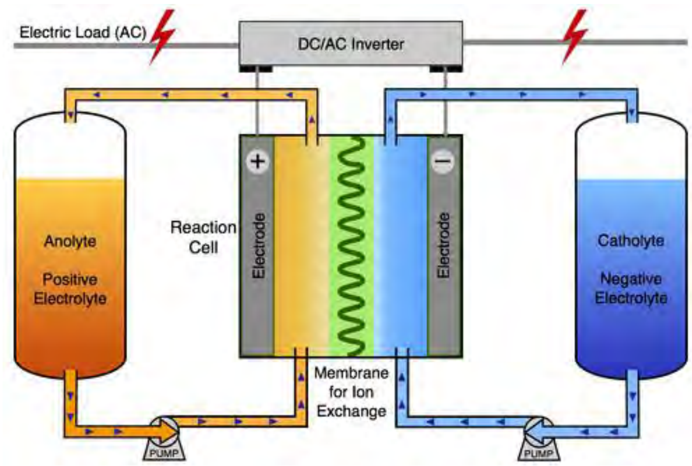
Storage Technologies

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.

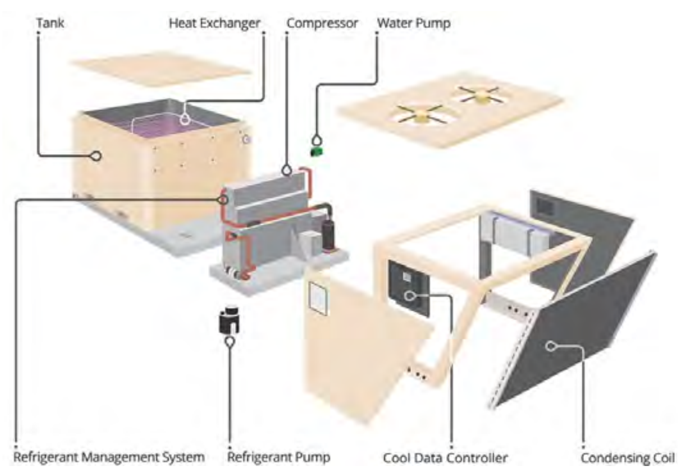


Illustration of an ice-based TES system.[8]

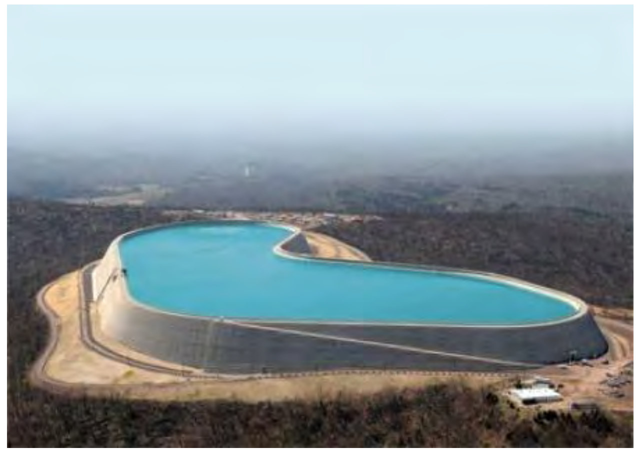
[7] Source: http://strategy.sauder.ubc.ca/antweiler/blog.php?item=2014-09-28.

[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.

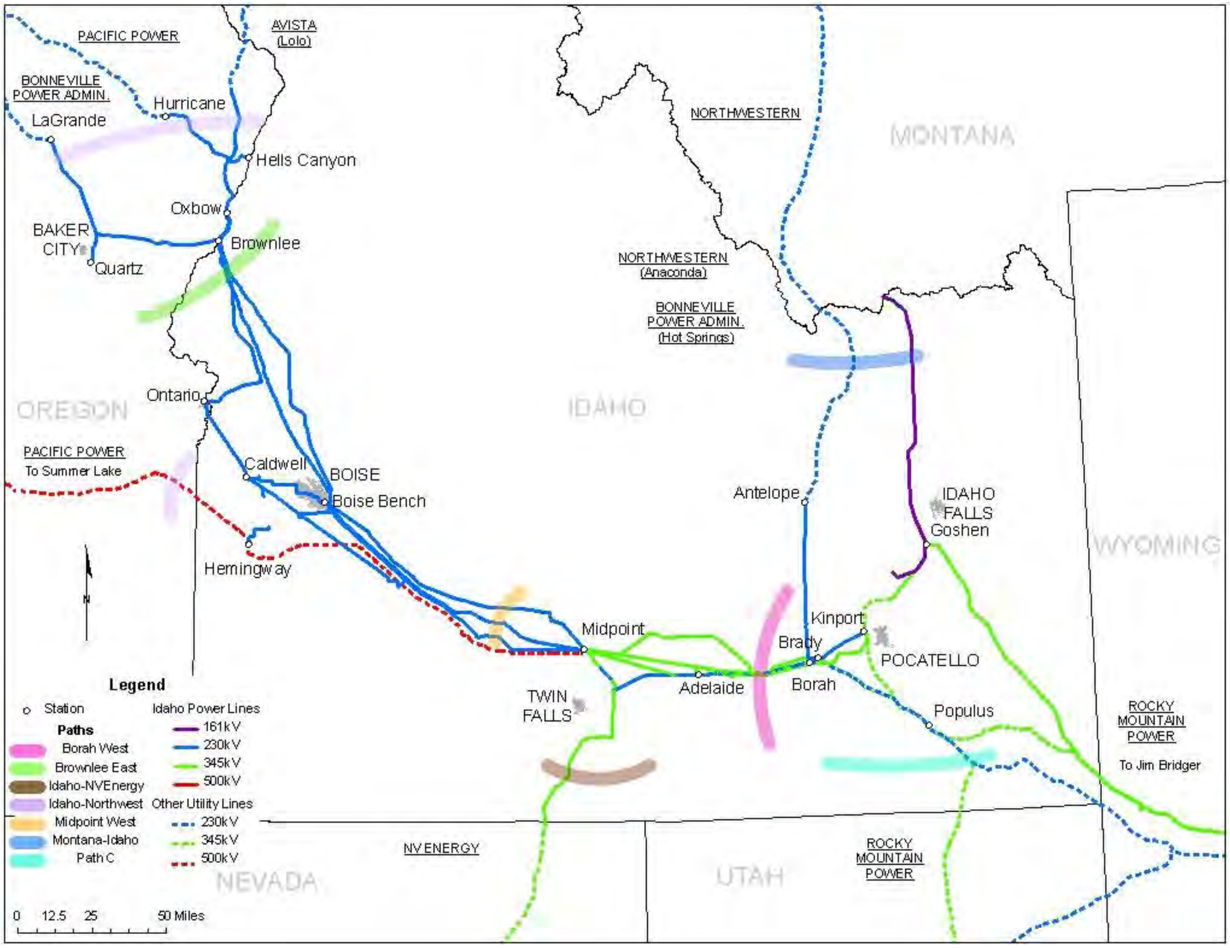


Figure 6.1 Idaho Power transmission system map

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

Additionally, a Memorandum of Understanding (MOU) was executed between Idaho Power, BPA, and PacifiCorp to explore opportunities for BPA to establish eastern Idaho load service from the Hemingway Substation. BPA identified six solutions—including two 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.

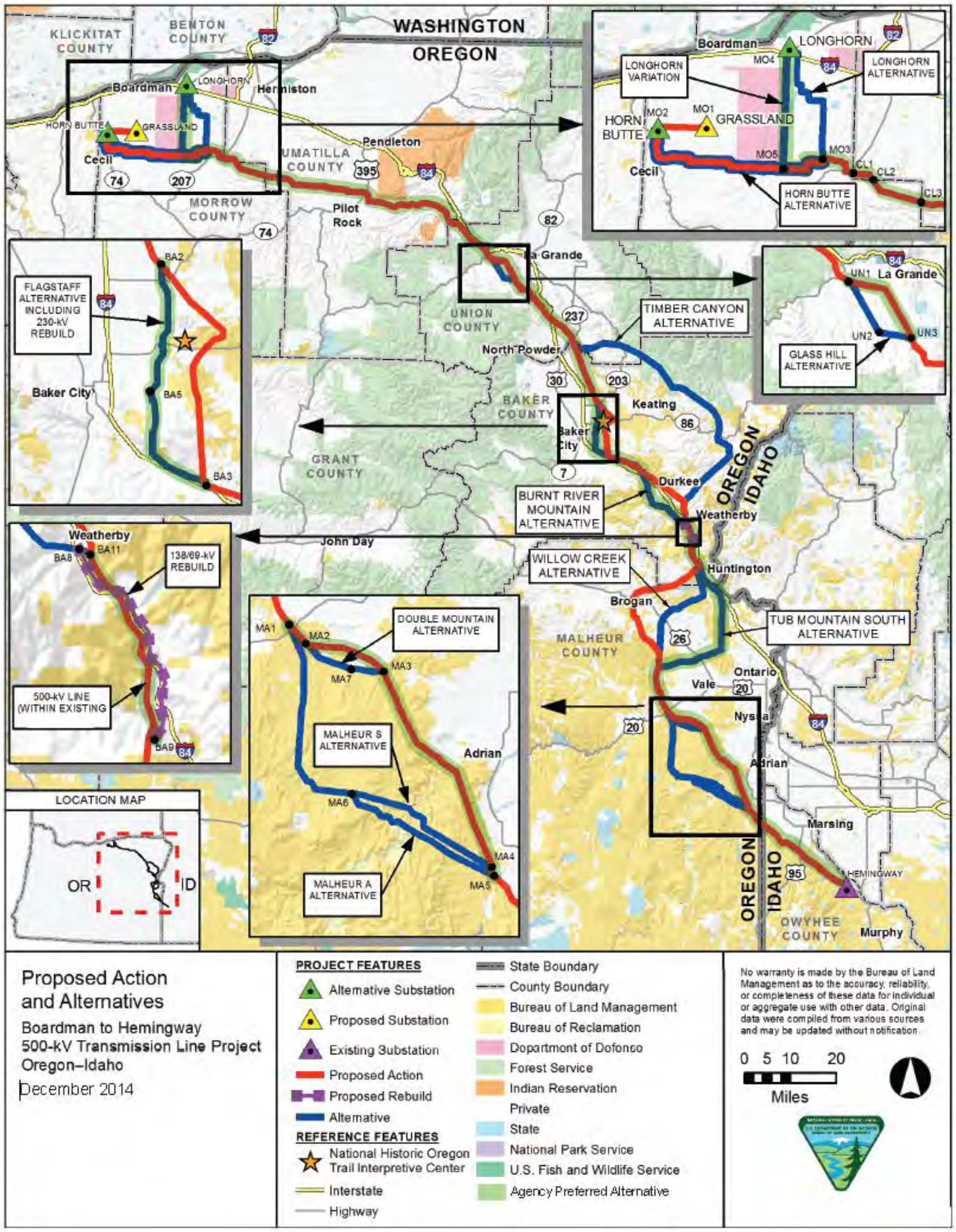


Figure 6.2 B2H routes with the agency-preferred alternative

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:

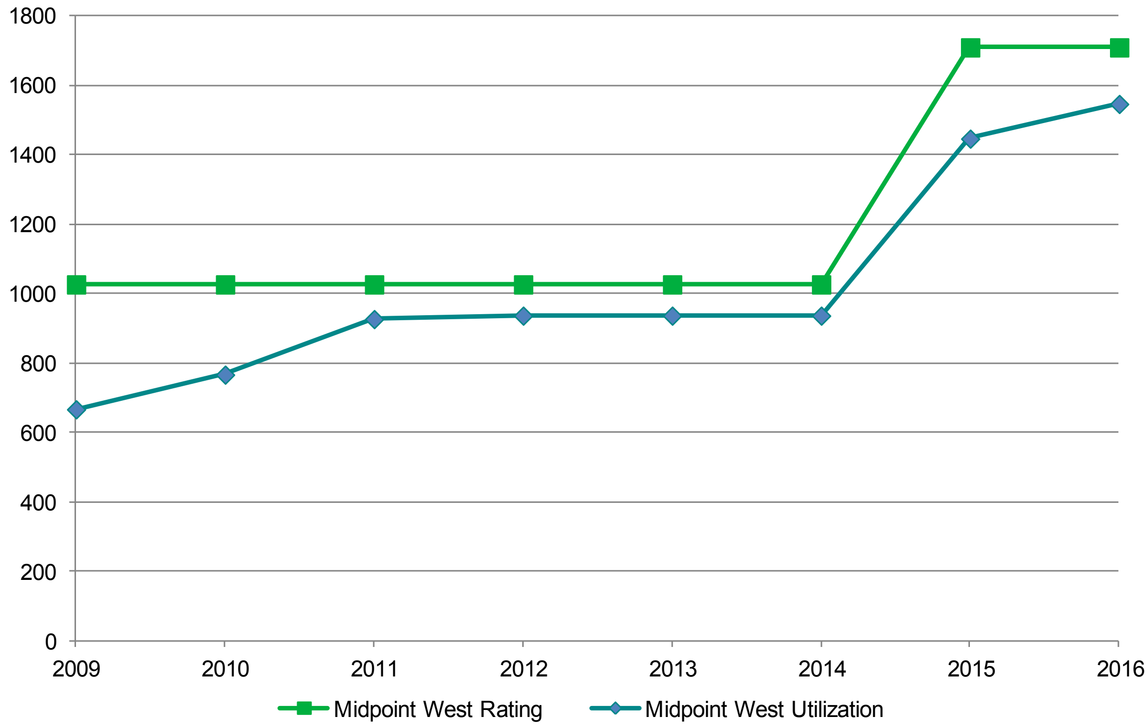
- Boise East
- Midpoint West

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

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

Economic Effects

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 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—3,407 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, 90th percentile, and 95th percentile. 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. The alternative scenarios are based on their respective peak-day average temperature probabilities to determine forecast outcomes.

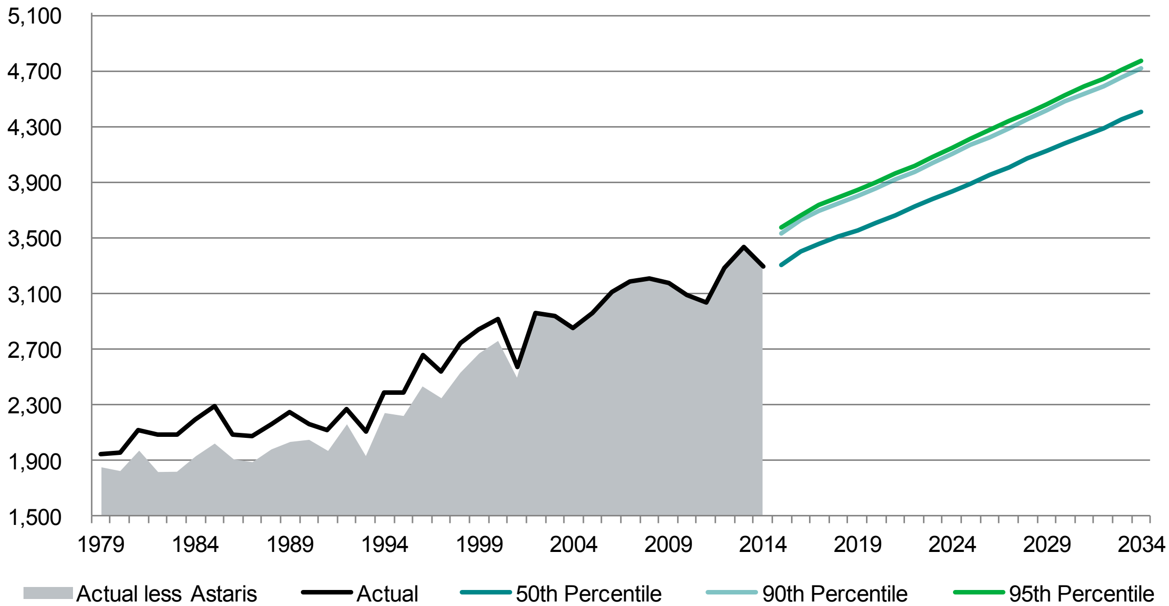


Figure 7.1 Peak-hour load-growth forecast (MW)

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.

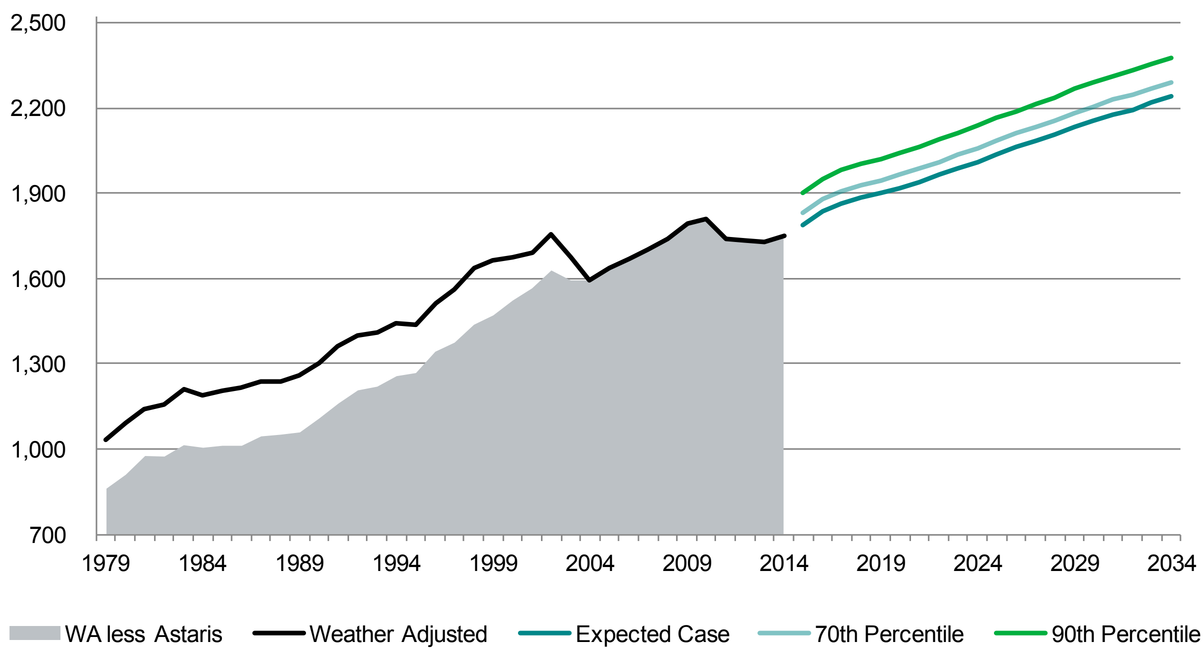


Figure 7.2 Average monthly load-growth forecast (aMW)

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 70th-percentile forecast streamflow conditions for the Snake River Basin as the basis for the projections of monthly average hydroelectric generation. The 70th percentile means basin streamflows are expected to exceed the planning criteria 70 percent of the time and are expected to be worse than the planning criteria 30 percent of the time.

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

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

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

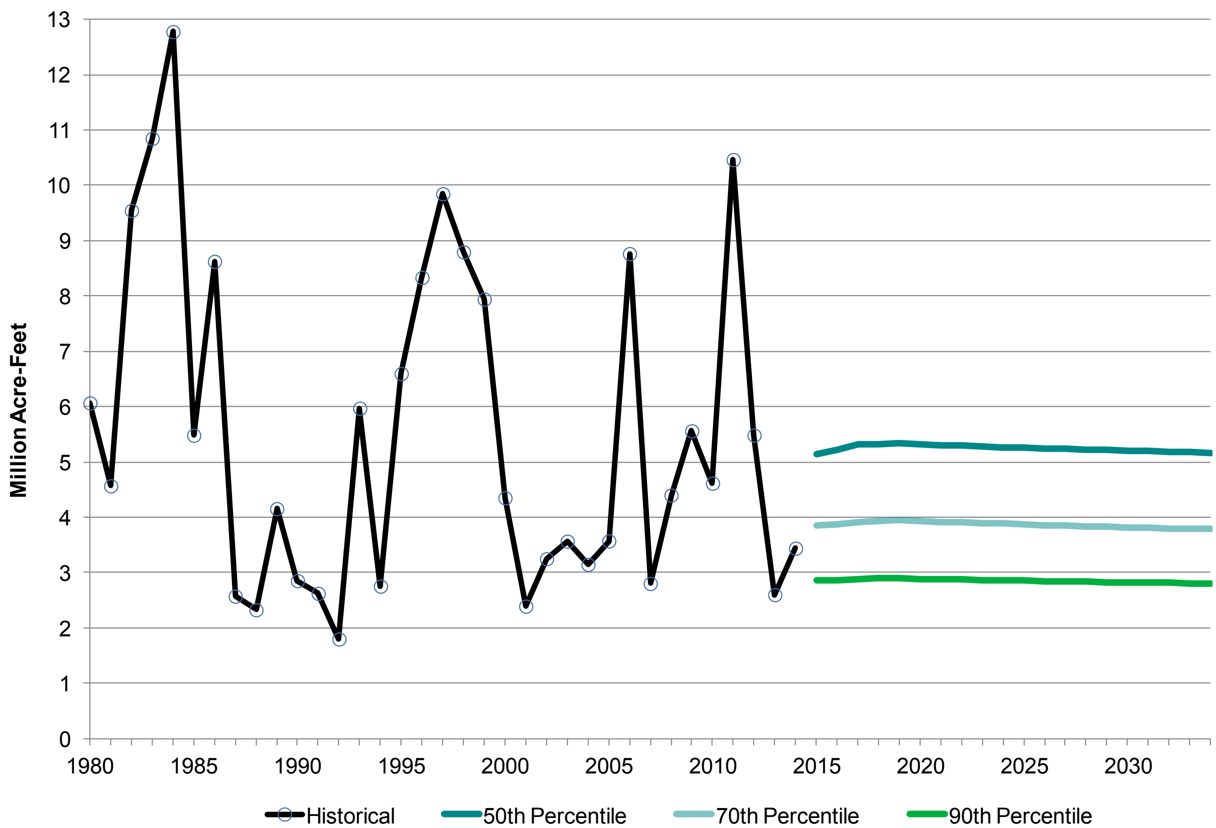


Figure 7.3 Brownlee historical and forecast inflows

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*.

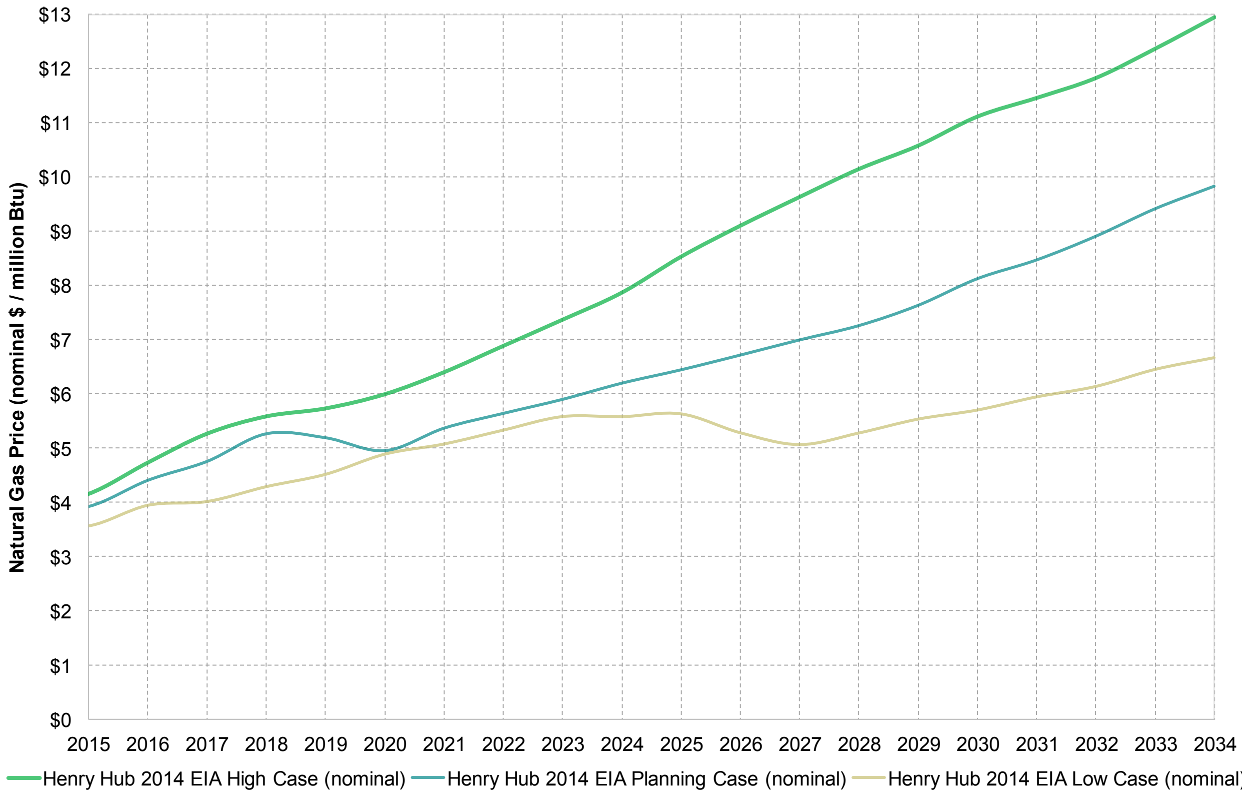


Figure 7.4 Henry Hub price forecast—EIA *Annual Energy Outlook 2014* (nominal dollars)

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

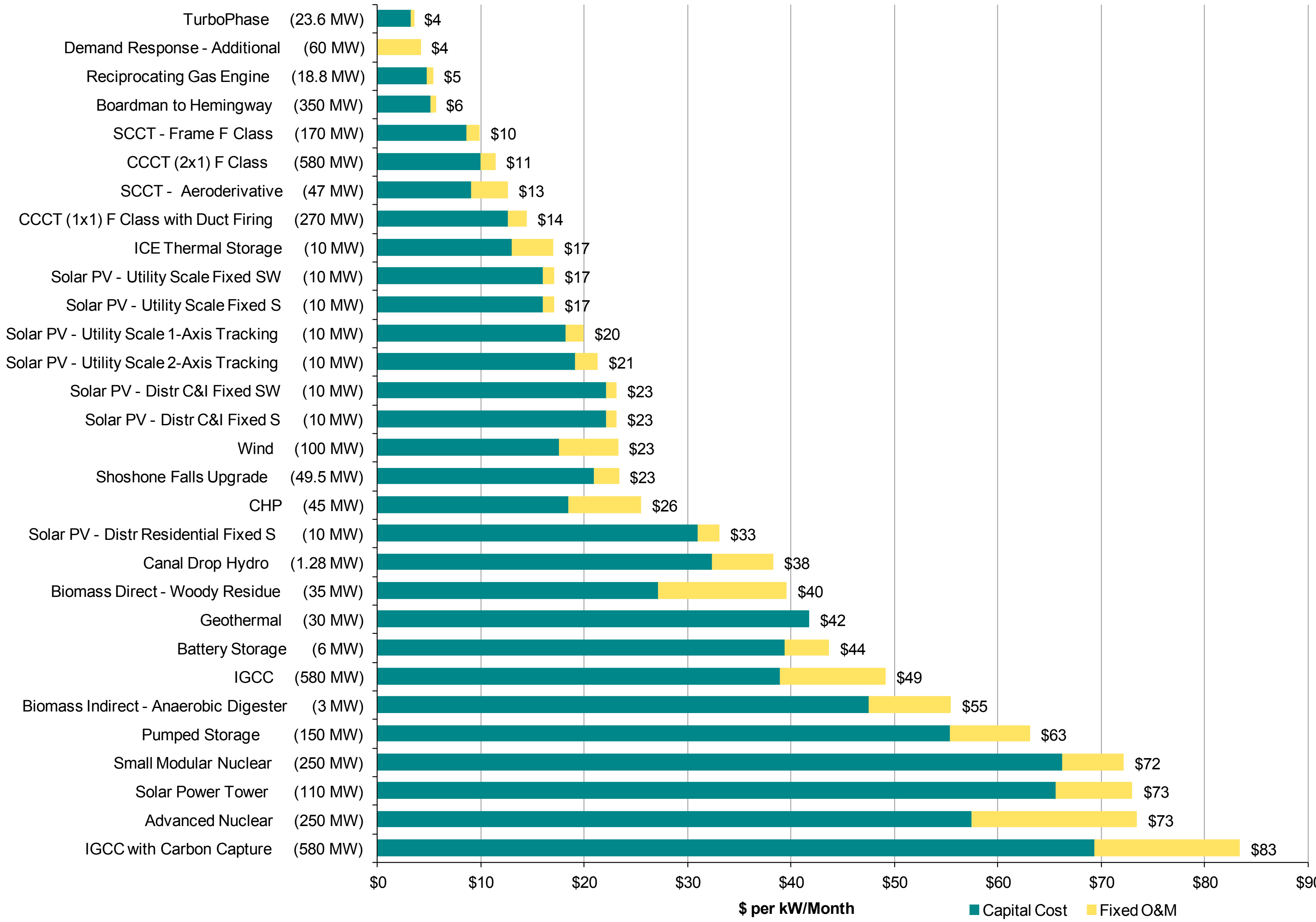
Certain resource alternatives carry low fixed costs and high variable operating costs, while other alternatives require significantly higher capital investment and fixed operating costs but have low variable operating costs. The levelized cost-of-production measurement represents the estimated annual 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

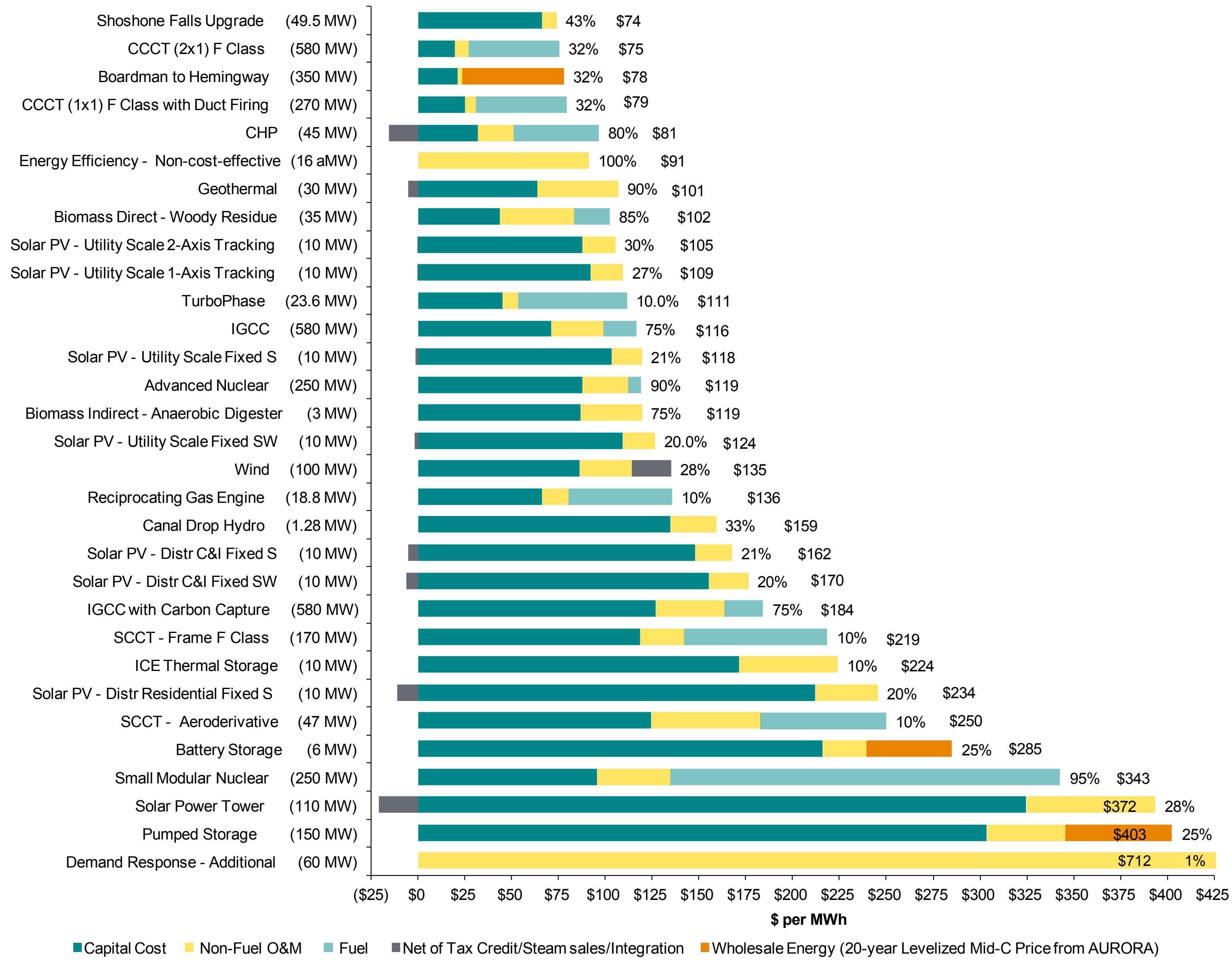


Figure 7.6 30-year levelized cost of production (at stated capacity factors)

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.

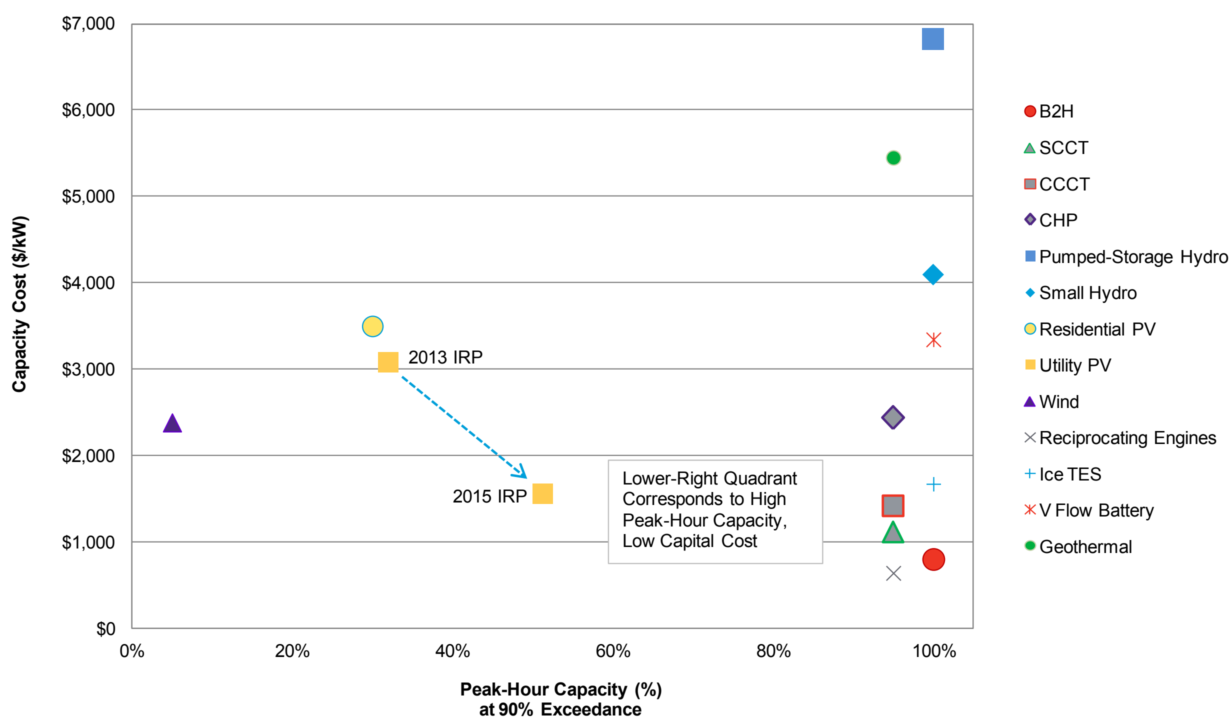


Figure 7.7 Capacity cost of new supply-side resources, online 2020

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.

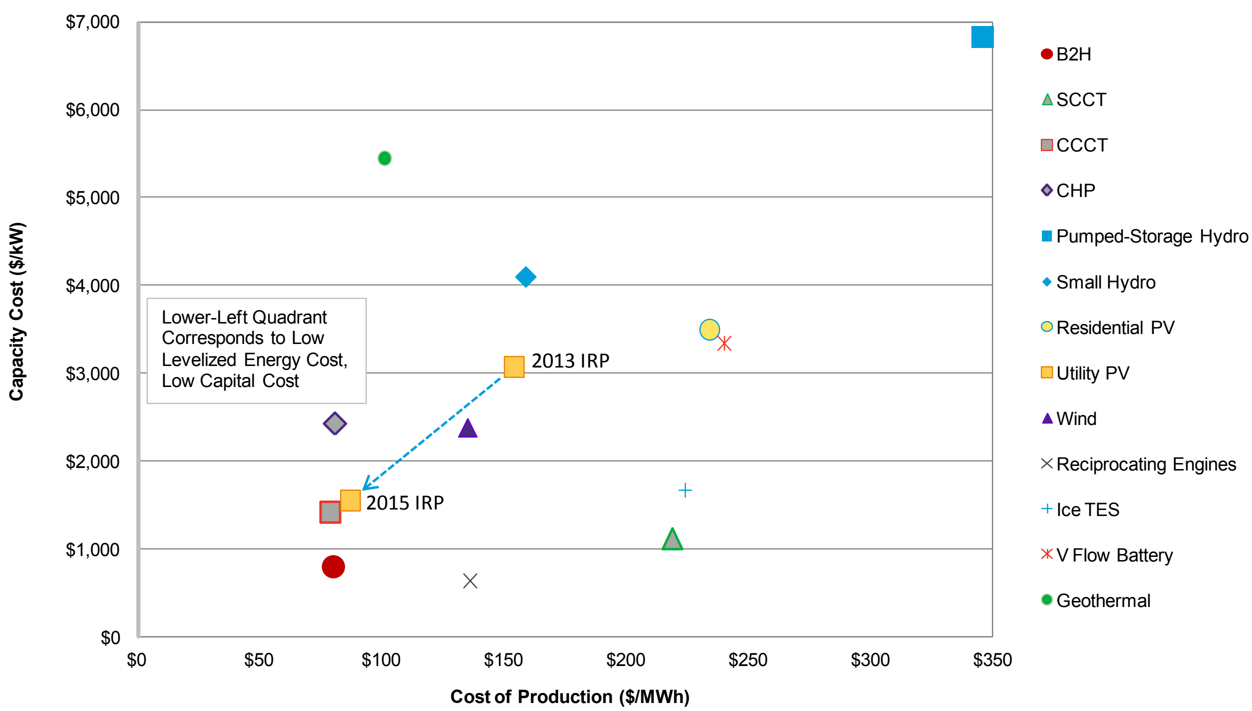


Figure 7.8 Energy cost of new supply-side resources

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 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.

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

All load and resource balances, 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 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 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 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 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 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 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 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 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 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 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 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 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 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 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 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 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 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 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 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 (13.8% below 2012 MWh)	3,675,608 MWh (19.1% below 2012 MWh)
North Valmy	574,382 MWh (29.5% below 2012 MWh)	533,343 MWh (34.5% below 2012 MWh)
Boardman	149,967 MWh (43.2% below 2012 MWh)	137,029 MWh (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				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	System-Wide Mass-Based Compliance	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)

		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
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.

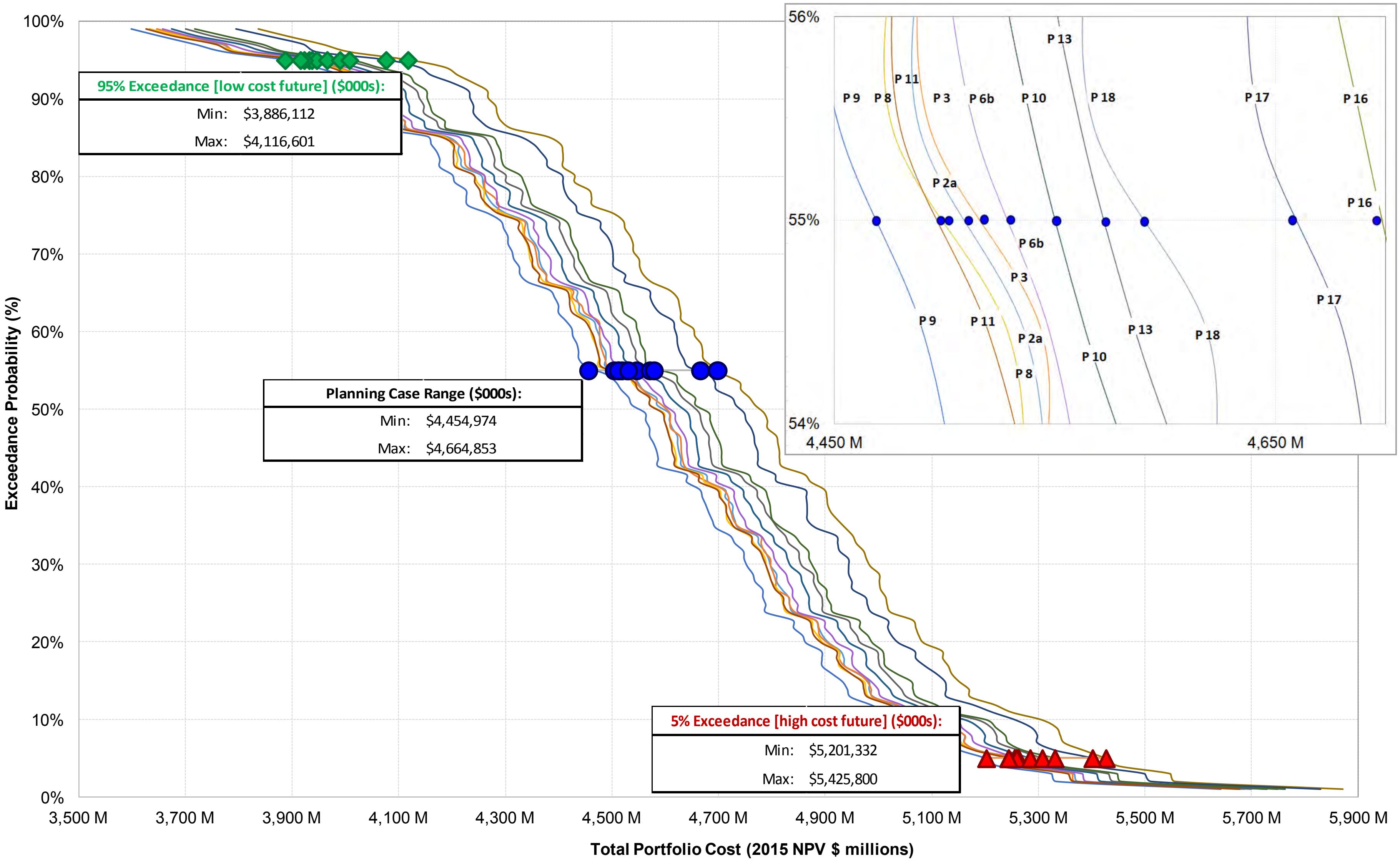

Figure 9.1 Portfolio stochastic analysis

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.

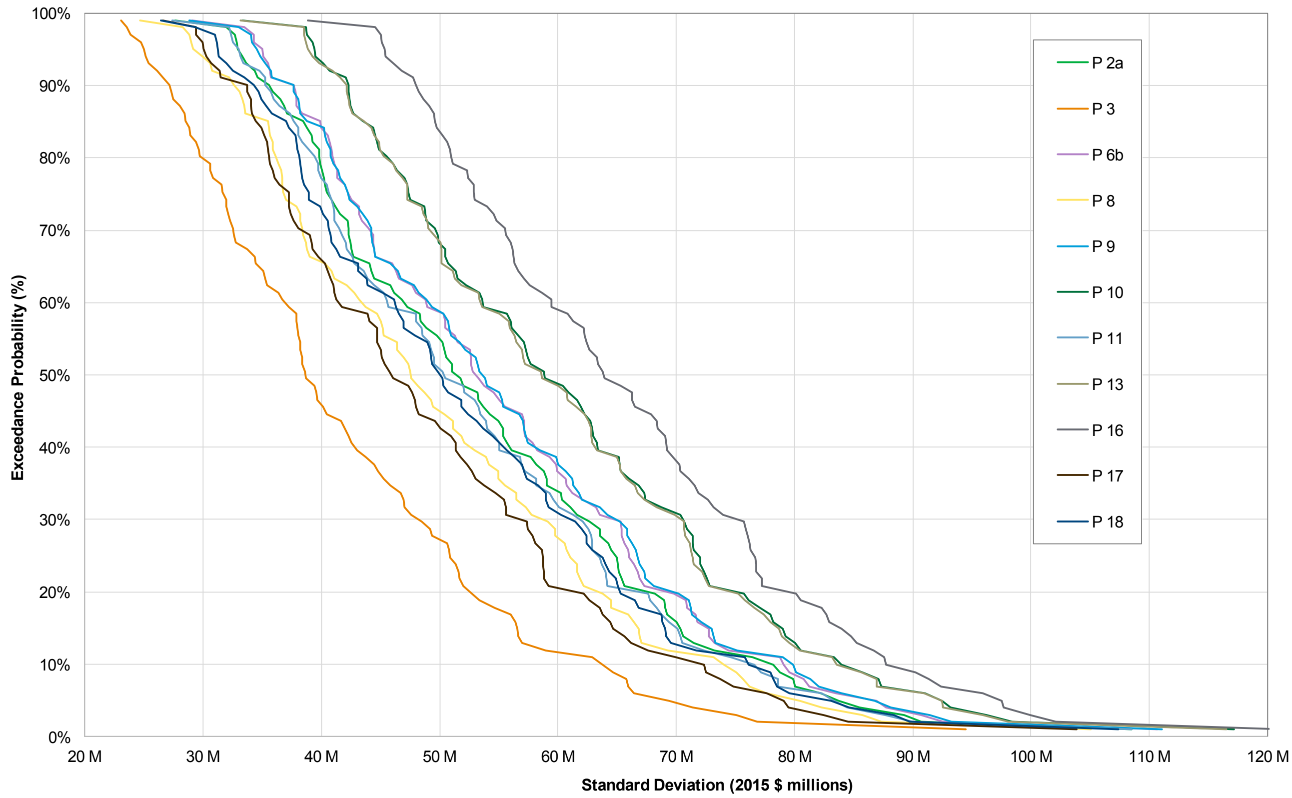

Figure 9.2 Exceedance graph of standard deviations

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).

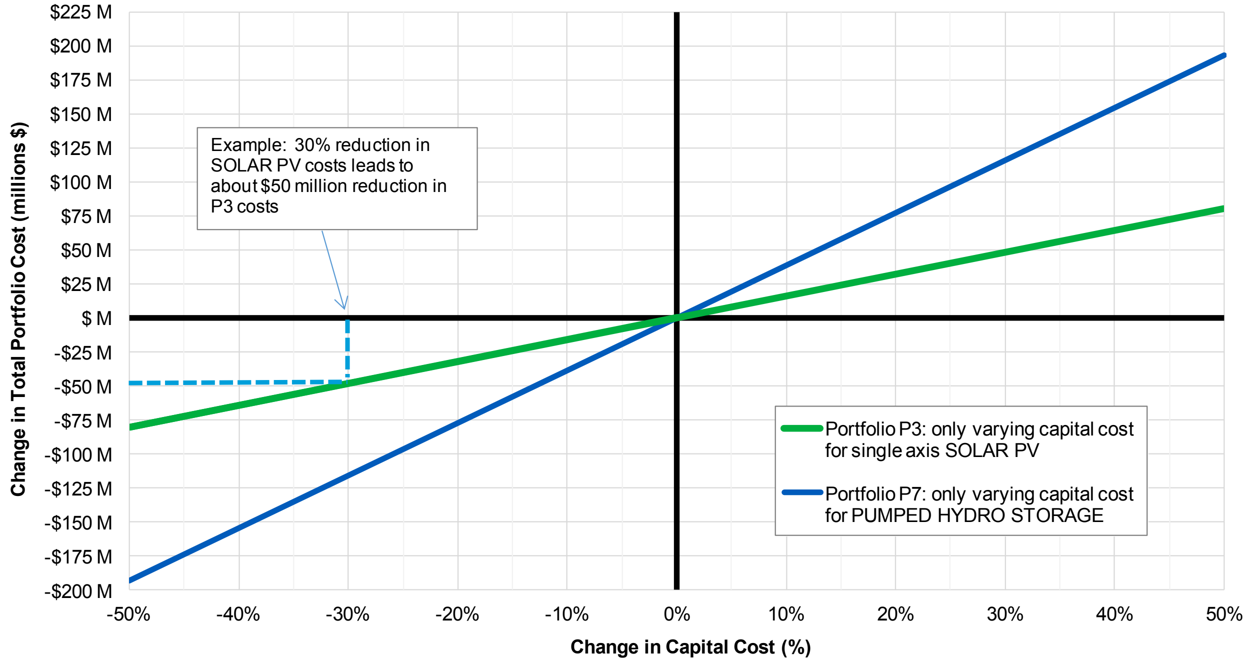

Figure 9.3 Tipping-point analysis results

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.

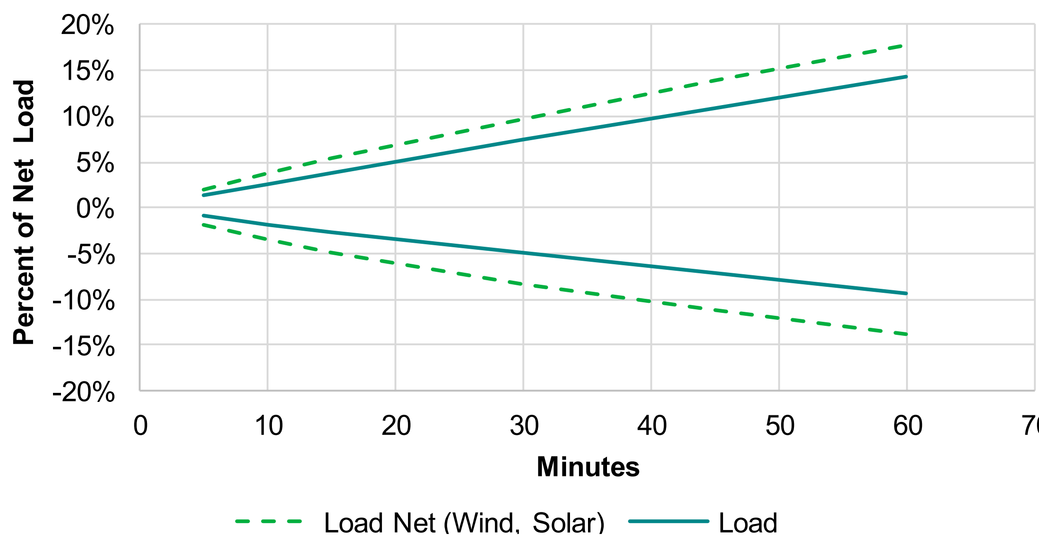

Figure 9.4 Flexibility need (500 MW solar, existing wind, 1% likelihood)

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).

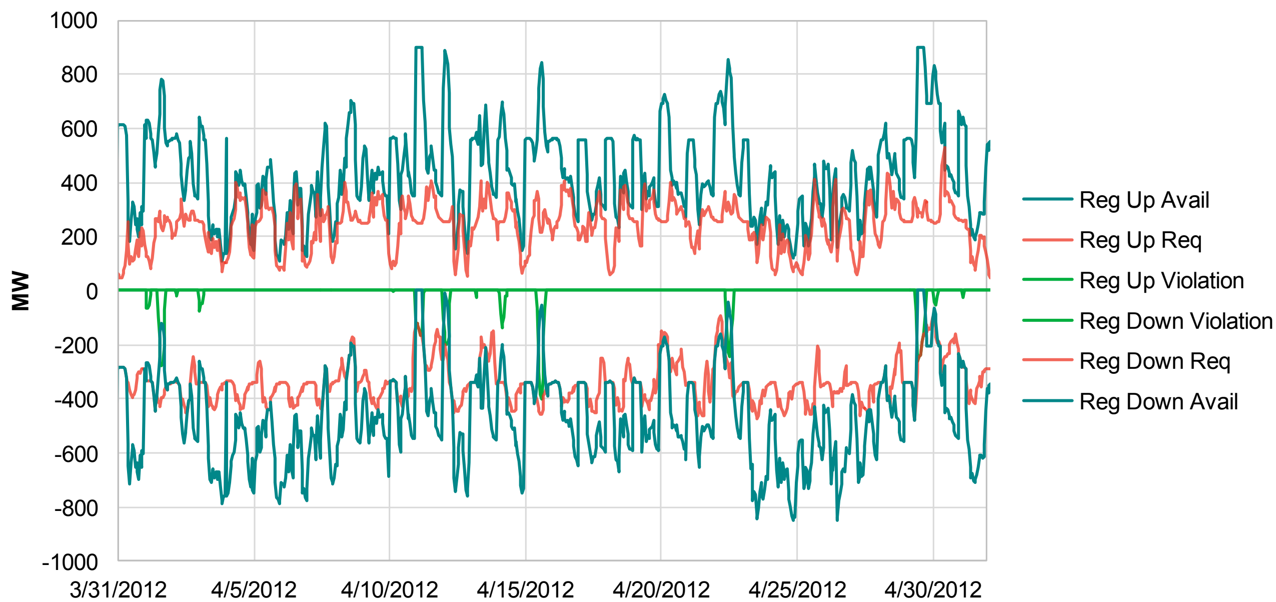

Figure 9.5 System regulation

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.

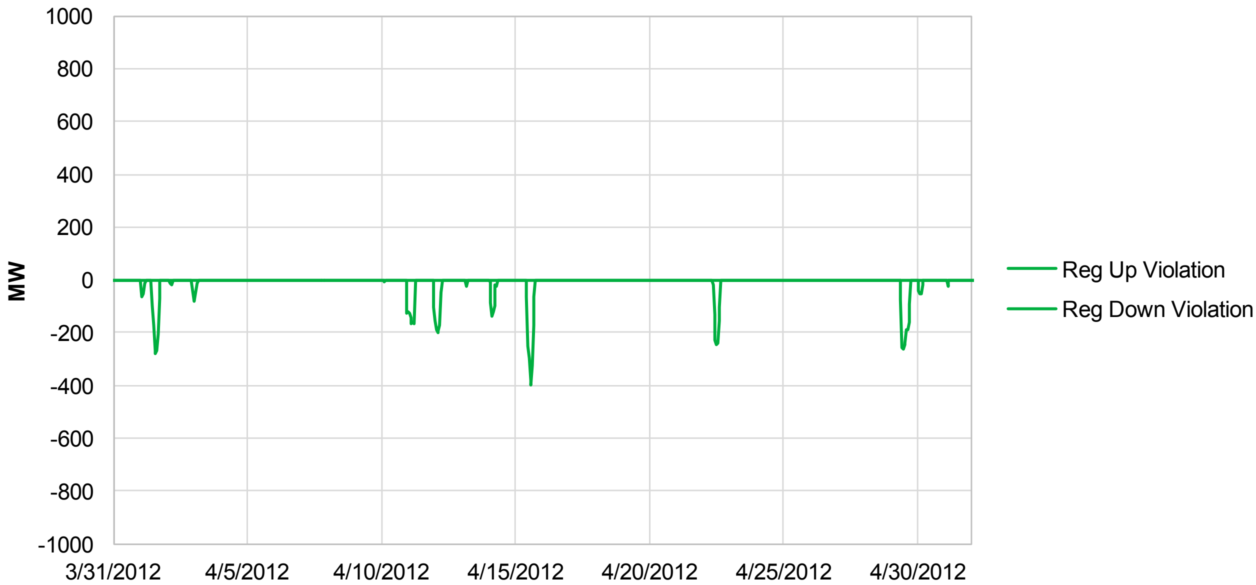

Figure 9.6 Regulation violations, spring 2012

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.

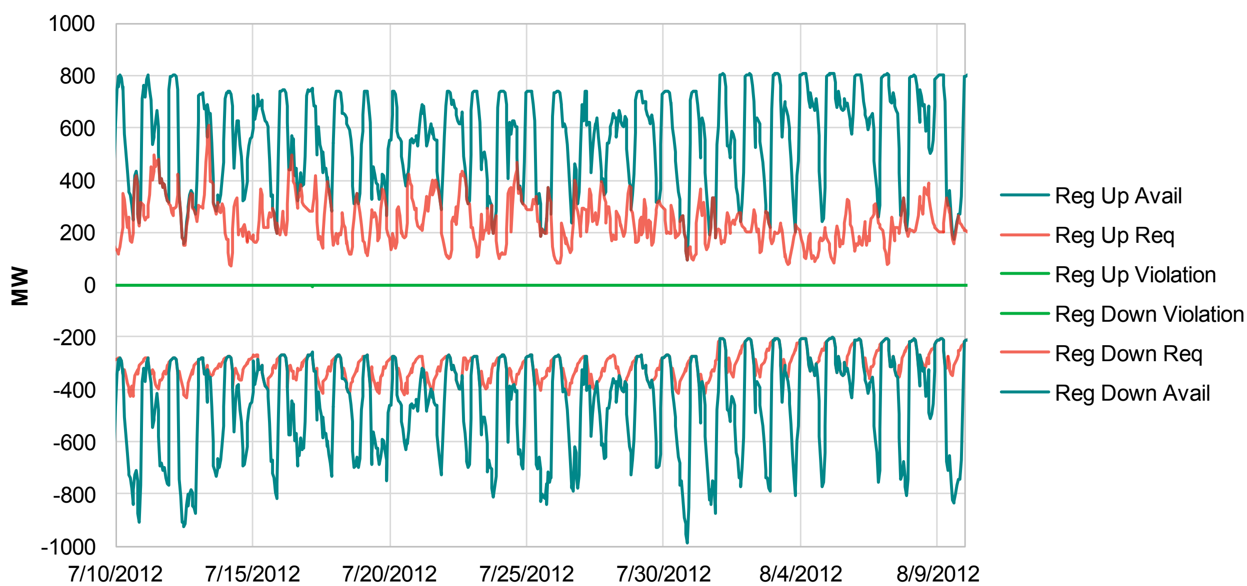

Figure 9.7 Regulation violations, summer 2012

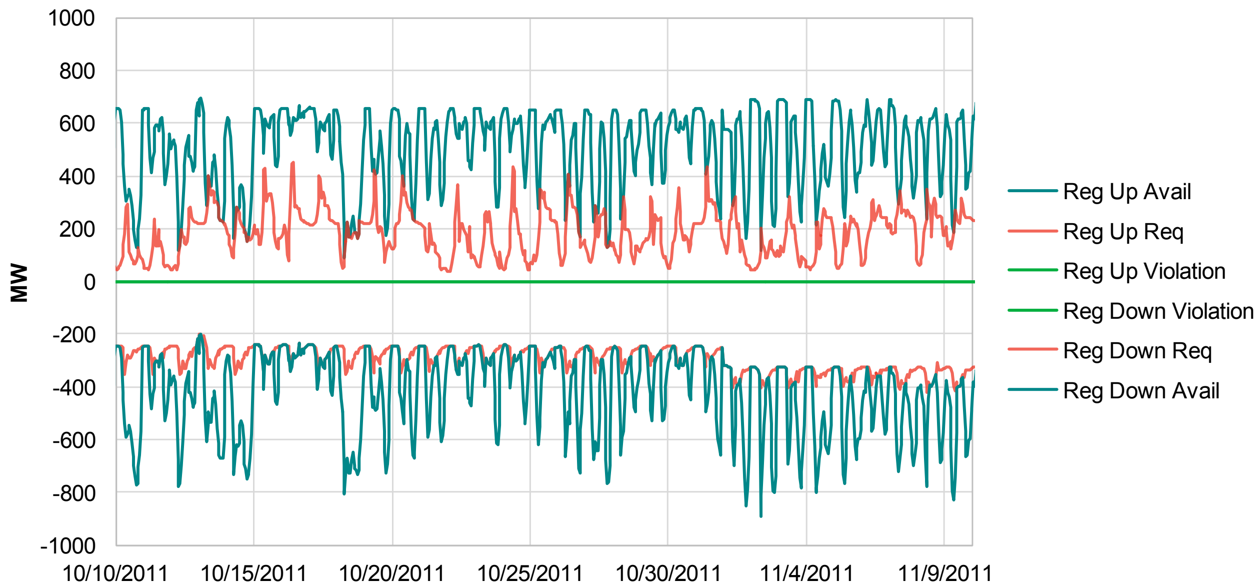

Figure 9.8 Regulation violations, fall 2011

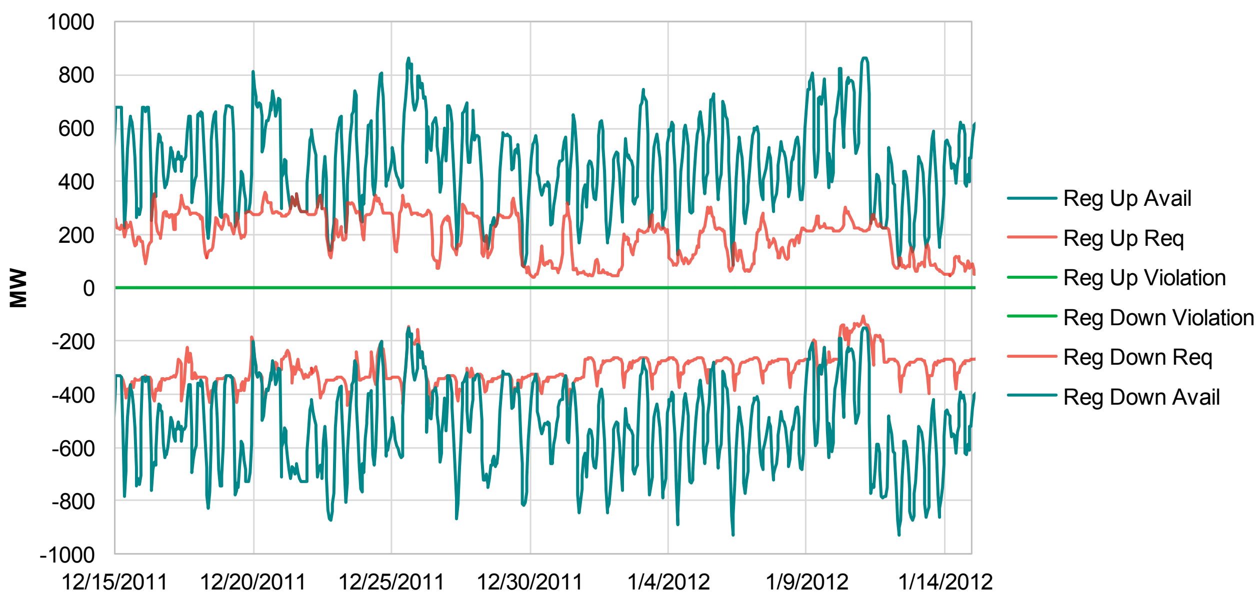

Figure 9.9 Regulation violations, winter 2011/2012

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*.

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

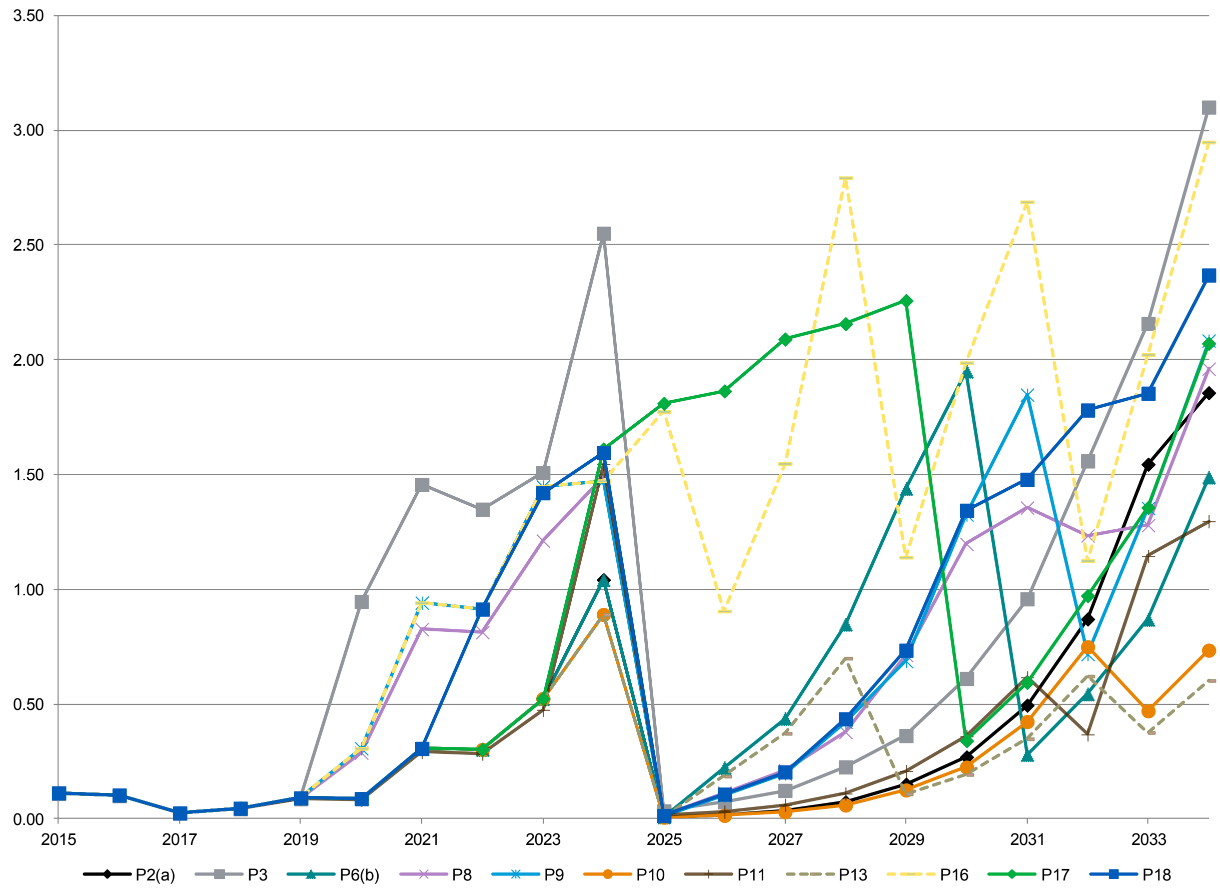

Figure 9.10 LOLE (hours per year)

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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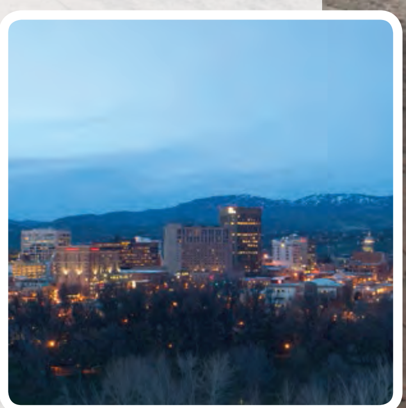
June 2015

APPENDIX A
Sales and Load Forecast

Integrated Resource Plan 2015



SAFE HARBOR STATEMENT

June 2015

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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 70th-percentile and 90th-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 (50th percentile) for temperatures and median rainfall, the weather scenarios are developed with a 70th-percentile and a 90th-percentile weather probability assumption. The 70th-percentile load forecast assumes monthly loads that can be exceeded in 3 out of 10 years (30% of the time). The 90th-percentile load forecast assumes monthly loads that can be exceeded in 1 out of 10 years (10% of the time). Idaho Power uses the 70th-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 70th-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 (95th 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.

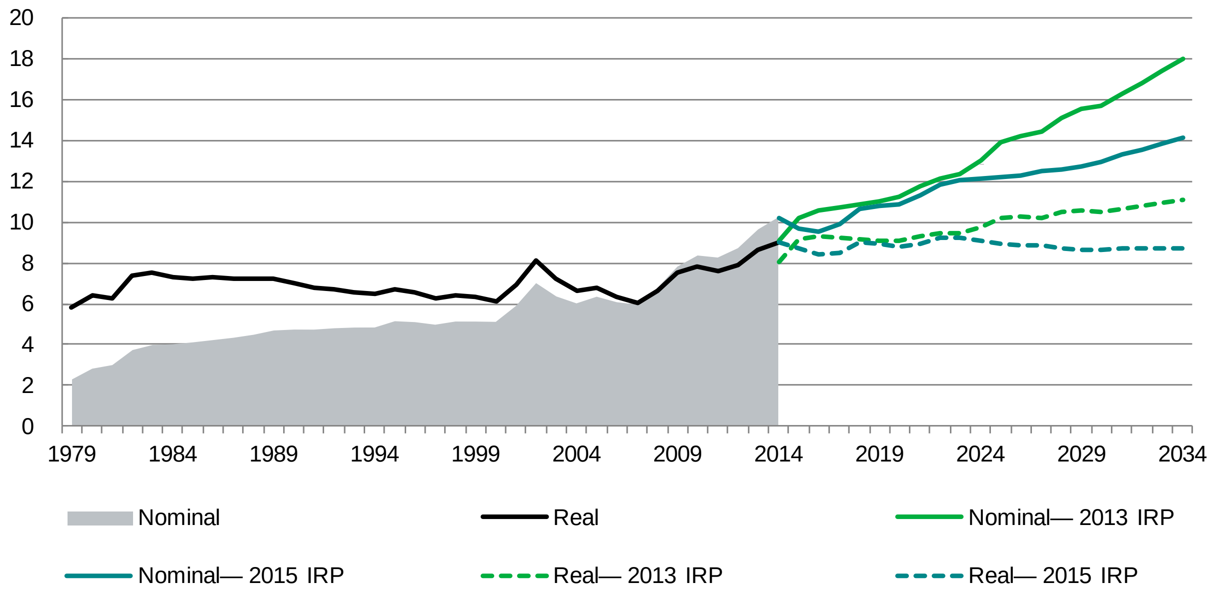

Figure 1. Forecast residential electricity prices (cents per kWh)

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.

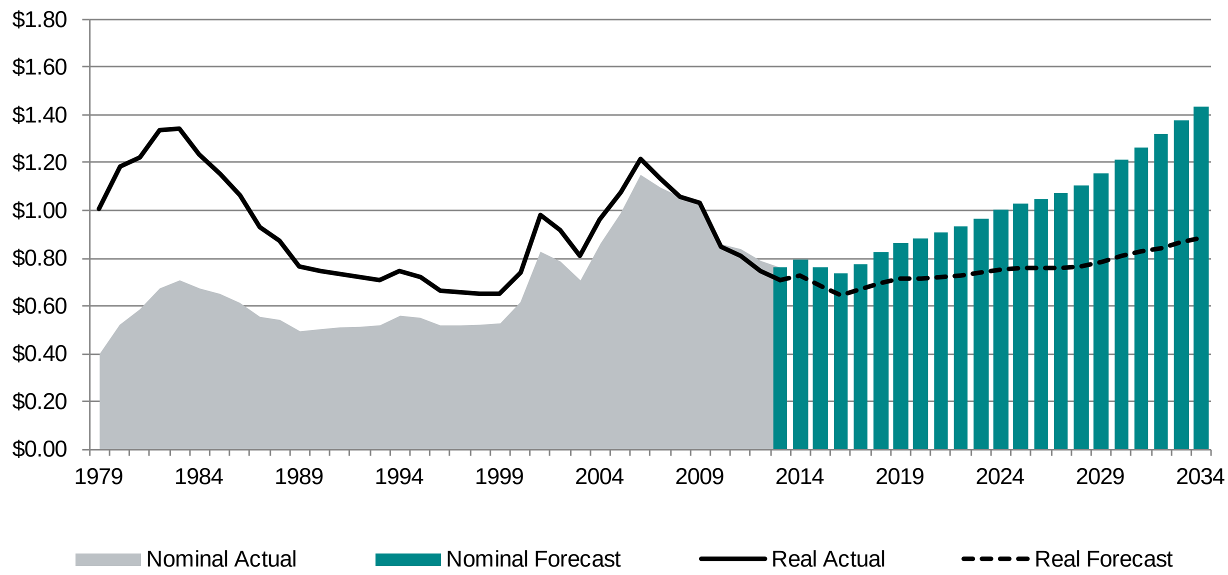

Figure 2. Forecast residential natural gas prices (dollars per therm)

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 70th-percentile HDD is 1,074 and would be exceeded in 3 out of 10 years. The 90th-percentile HDD is 1,268 and would be exceeded in 1 out of 10 years. The 100th-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 70th-percentile residential and commercial load forecasts, temperatures in each month were assumed to be at the 70th percentile of HDD in wintertime and at the 70th percentile of CDD in summertime. In the 70th-percentile irrigation load forecast, GDD were assumed to be at the 70th percentile and precipitation at the 30th percentile, reflecting drier-than-median weather. The 90th-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%

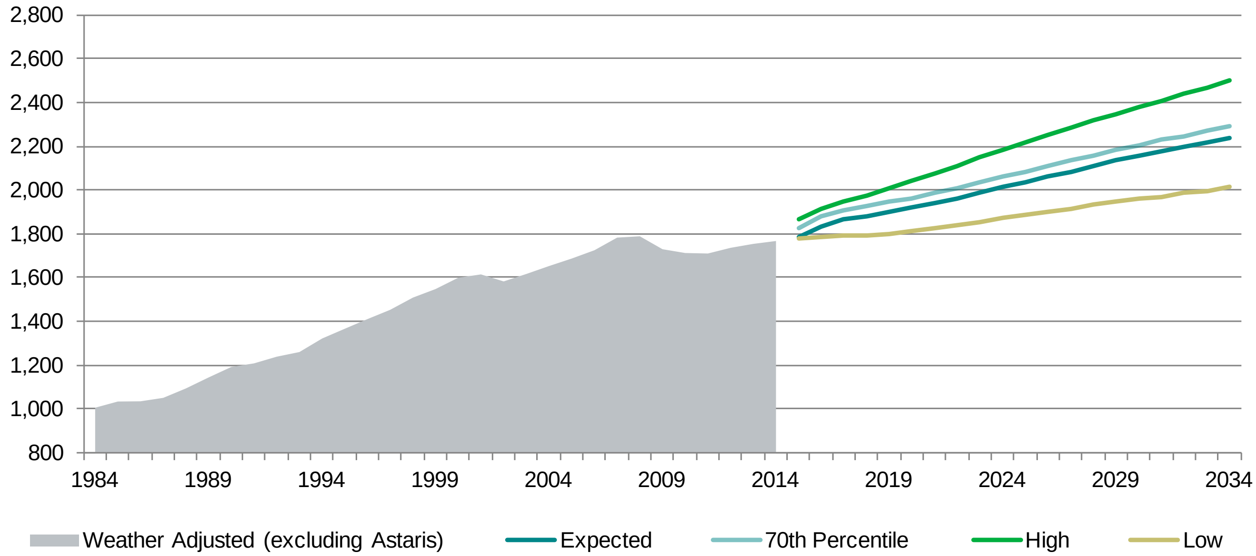

Figure 3. Forecast system load (aMW)

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%

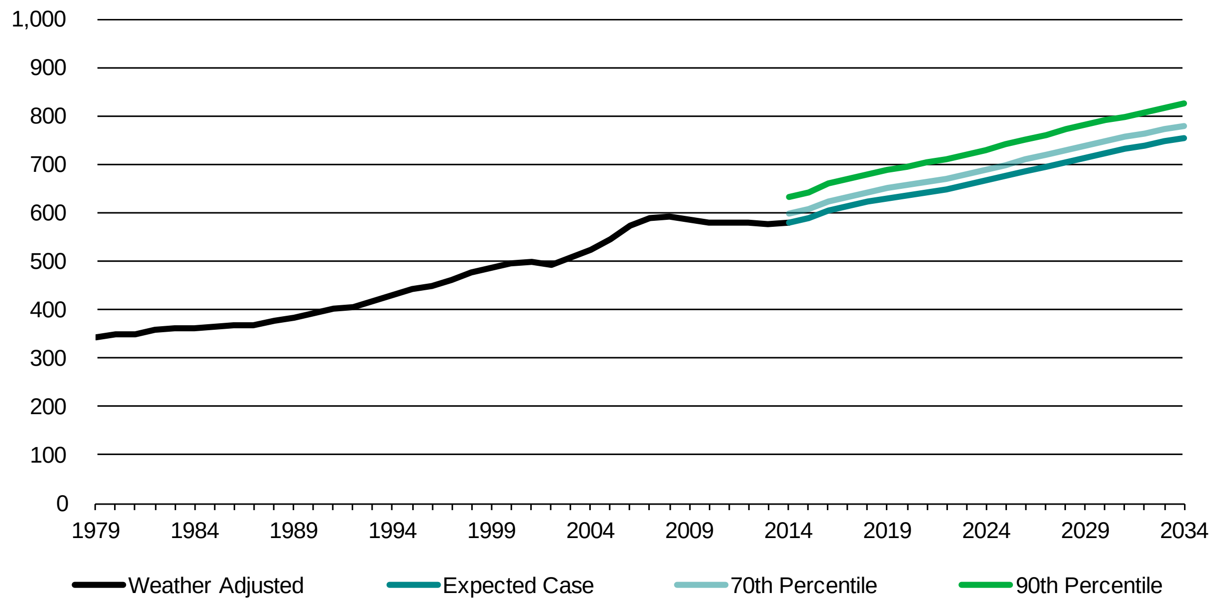

Figure 4. Forecast residential load (aMW)

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.

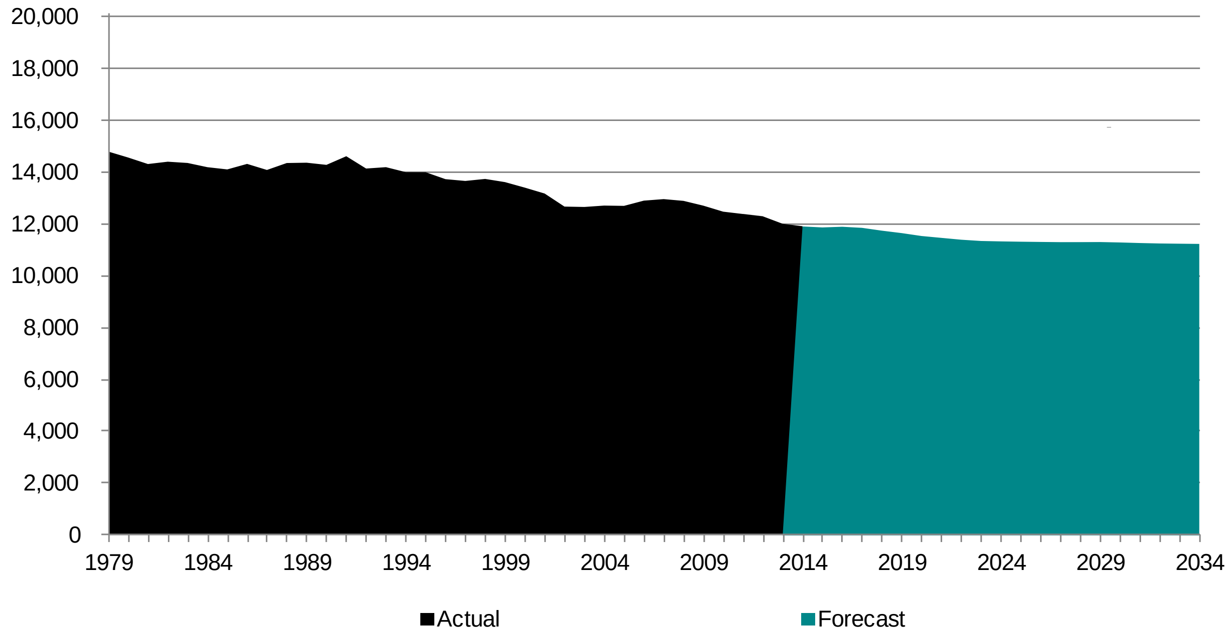

Figure 5. Forecast residential use per customer (weather-adjusted kWh)

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%

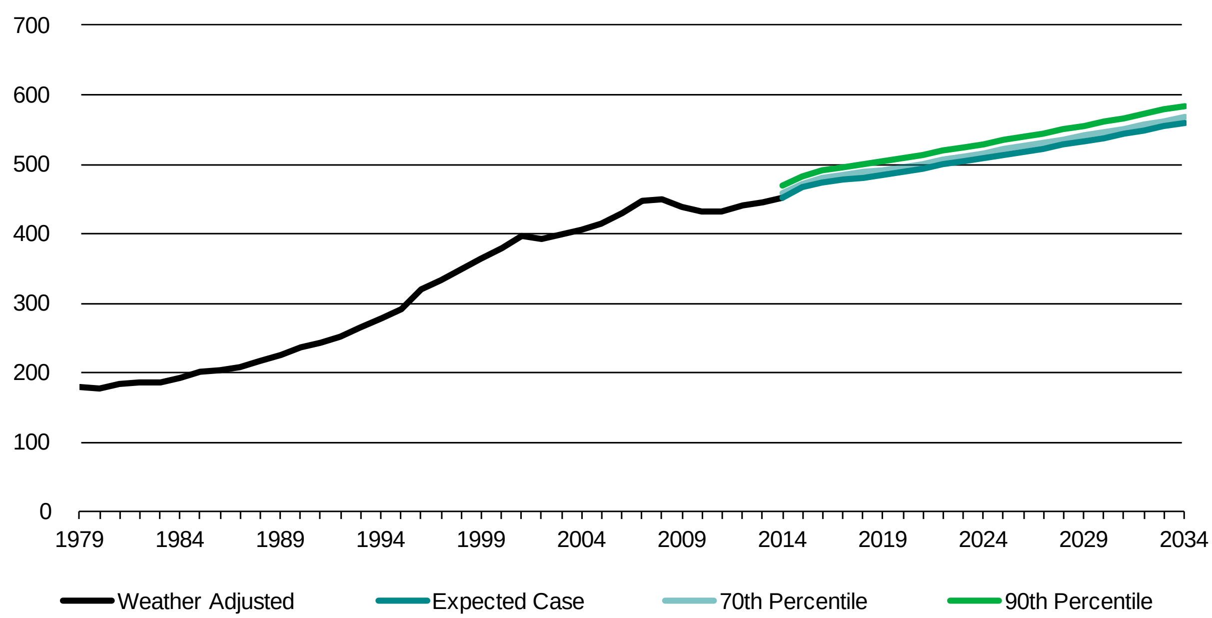

Figure 6. Forecast commercial load (aMW)

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.

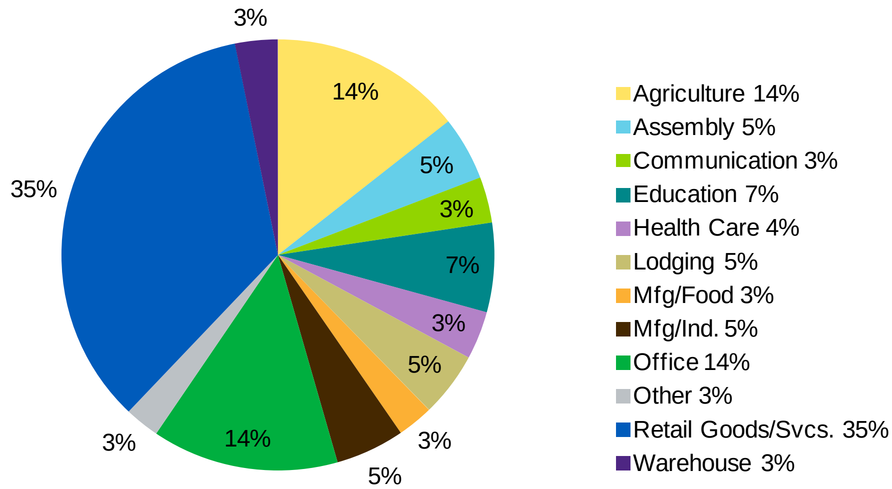

Figure 7. Commercial building share

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).

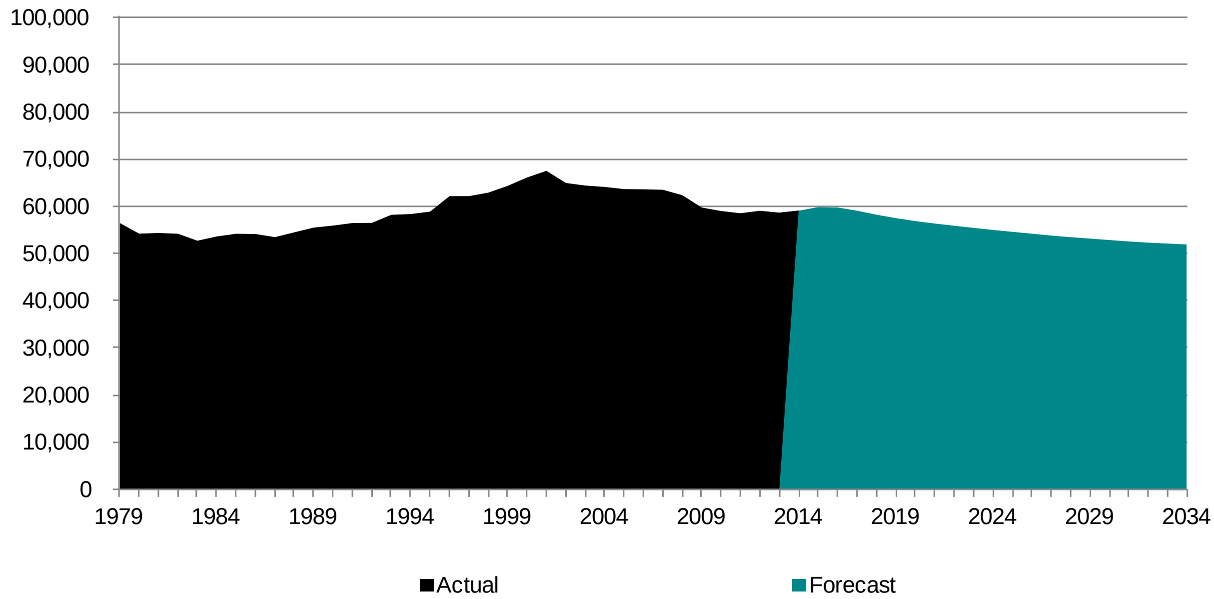

Figure 8. Forecast commercial use per customer (weather-adjusted kWh)

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.

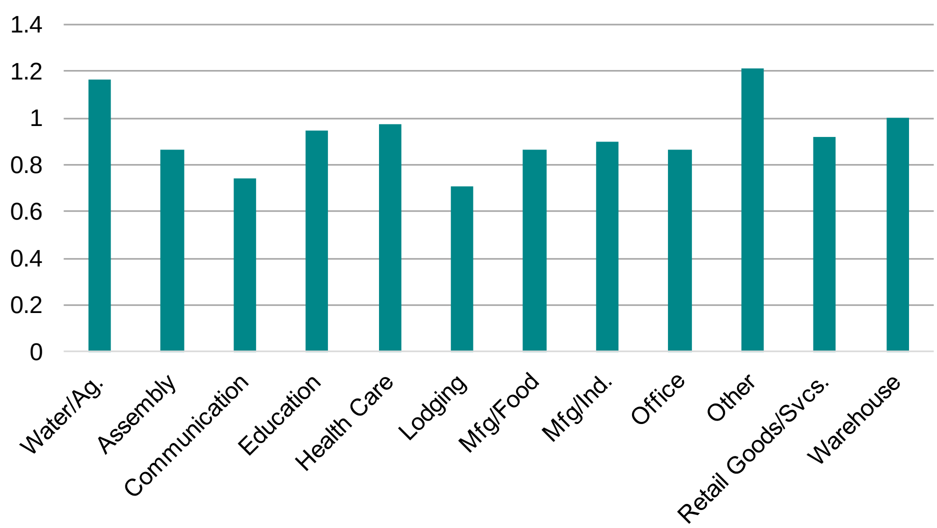

Figure 9. Commercial categories UPC, 2014 relative to 2010

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, 70th-percentile, and 90th-percentile scenarios forecast slow growth in irrigation load from 2015 to 2034. In the 70th-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
90th Percentile	244	250	254	266	0.5%
70th Percentile	226	232	235	248	0.5%
Expected Case	213	218	222	235	0.5%

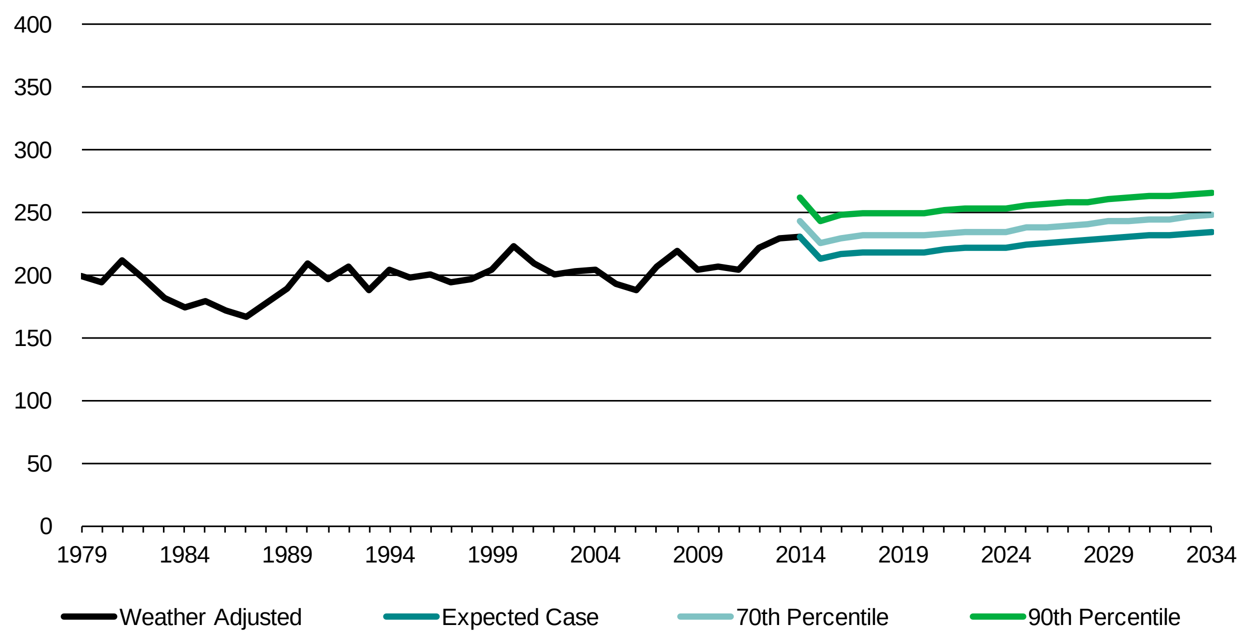

Figure 10. Forecast irrigation load (aMW)

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 70th- and 90th-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%

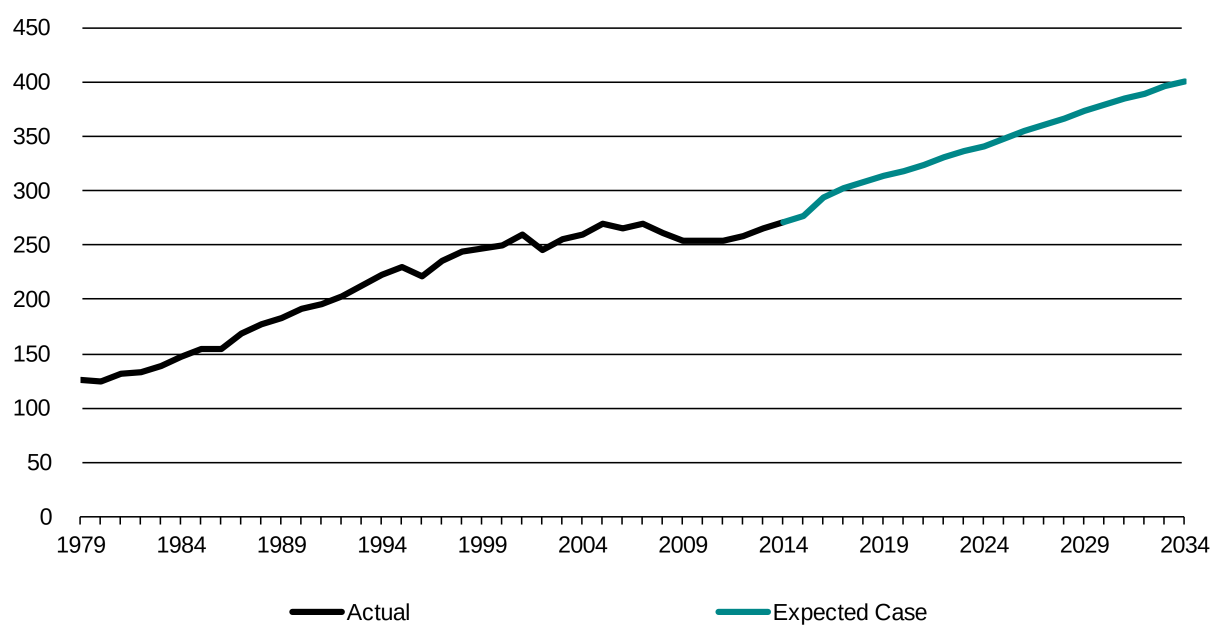

Figure 11. Forecast industrial load (aMW)

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.

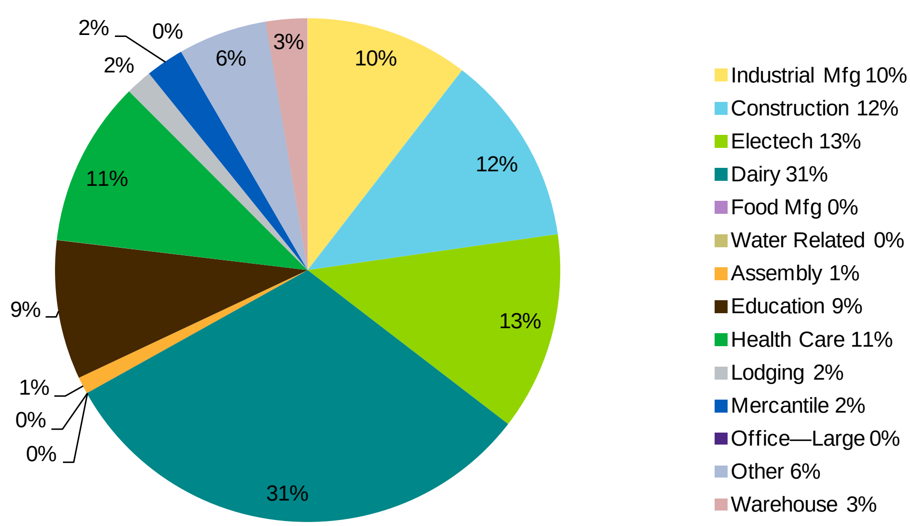

Figure 12. Industrial electricity consumption by industry group (based on 2014 sales)

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 70th and 90th-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%

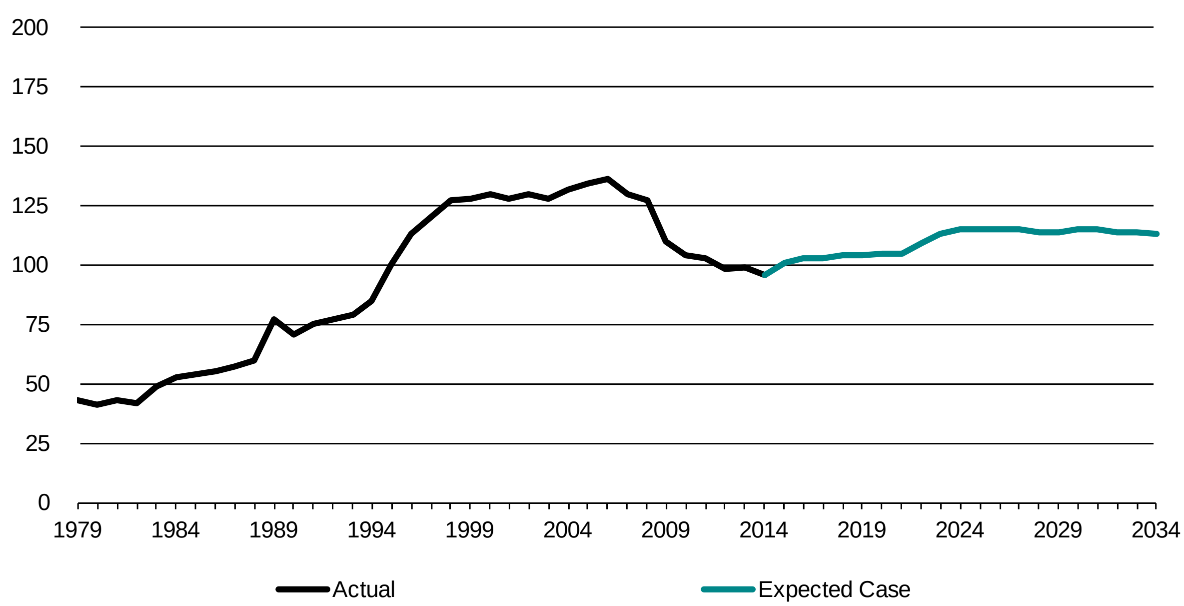

Figure 13. Forecast additional firm load (aMW)

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%

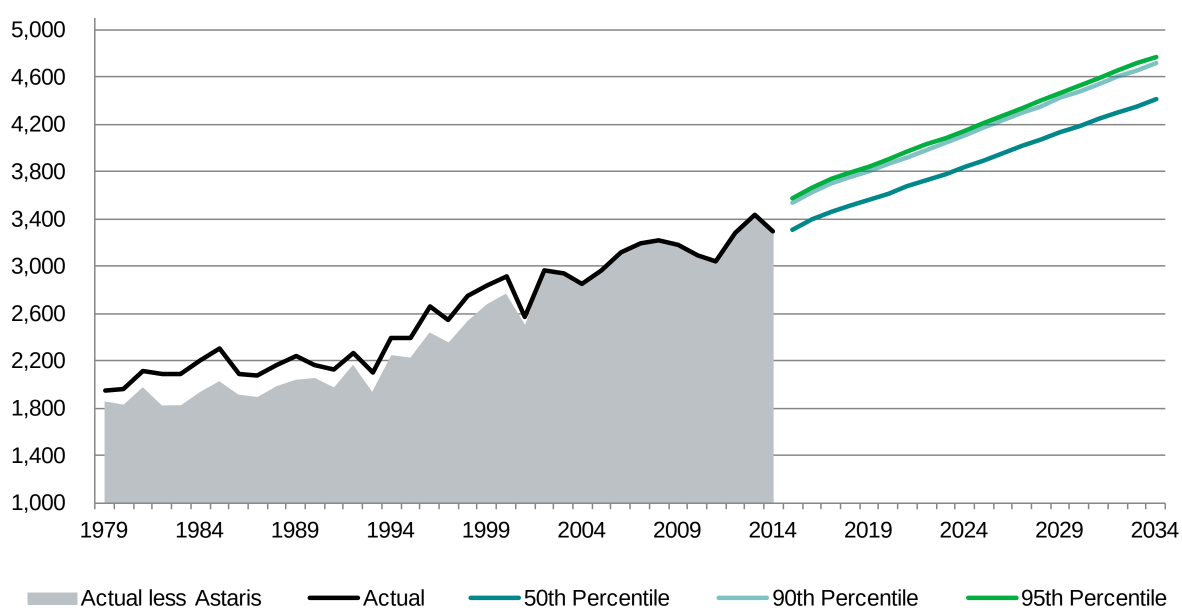

Figure 14. Forecast system summer peak (MW)

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%

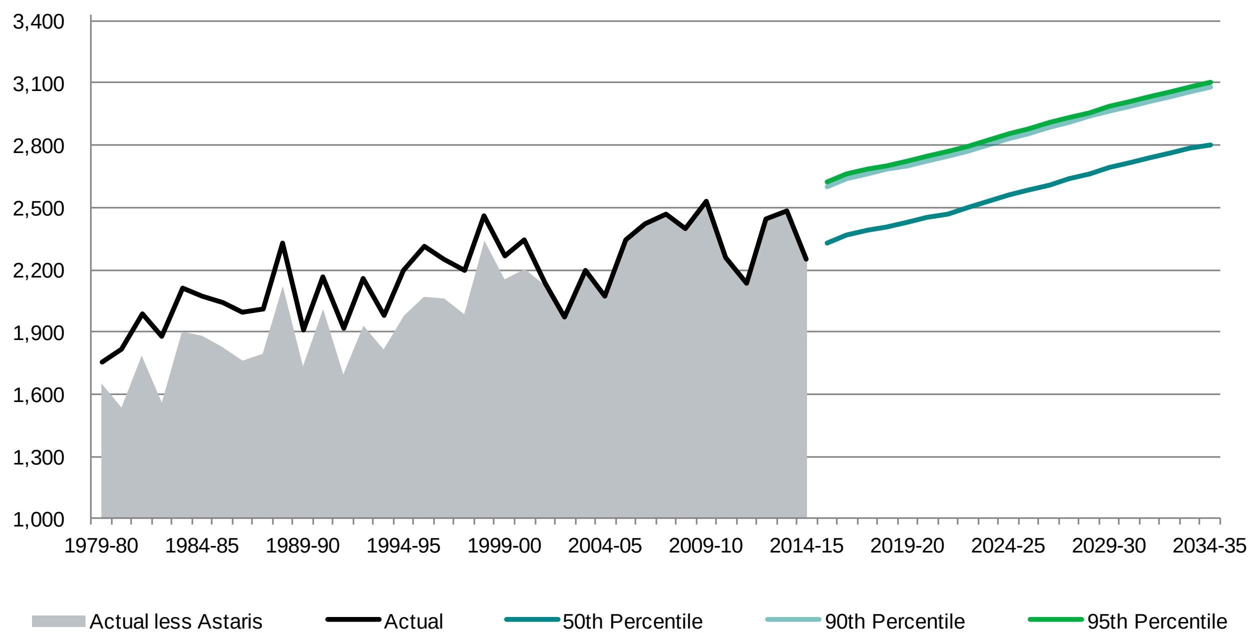

Figure 15. Forecast system winter peak (MW)

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 70th-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
90th Percentile	1,900	2,021	2,139	2,378	1.2%
70th Percentile	1,829	1,946	2,059	2,292	1.2%
Expected Case	1,786	1,900	2,012	2,240	1.2%

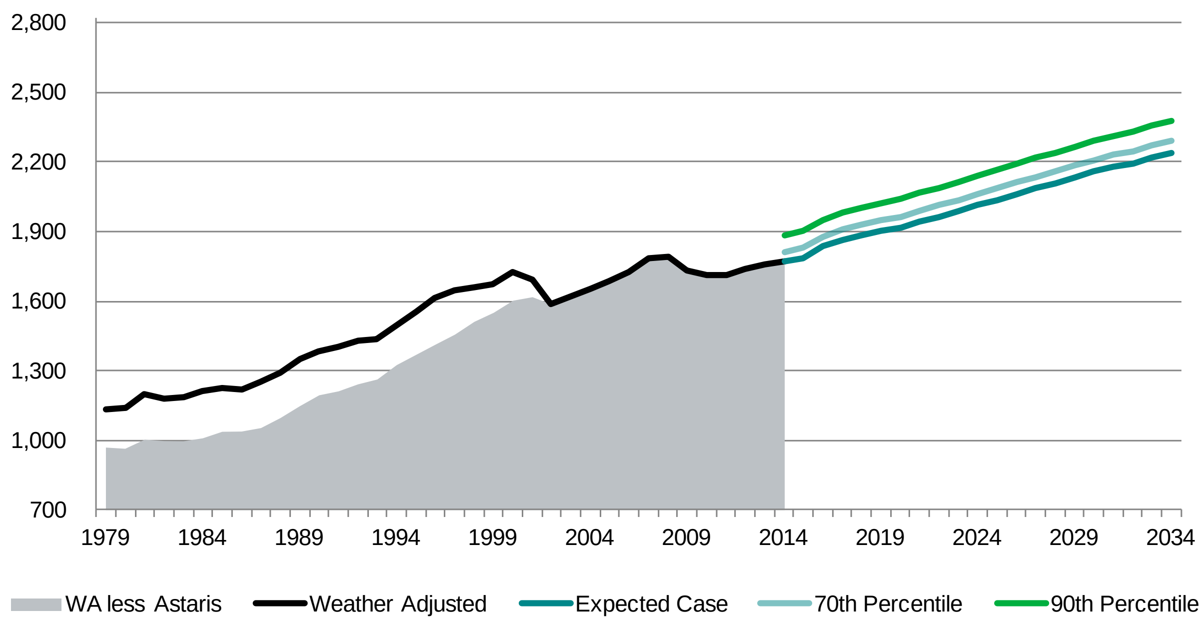

Figure 16. Forecast system load (aMW)

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.

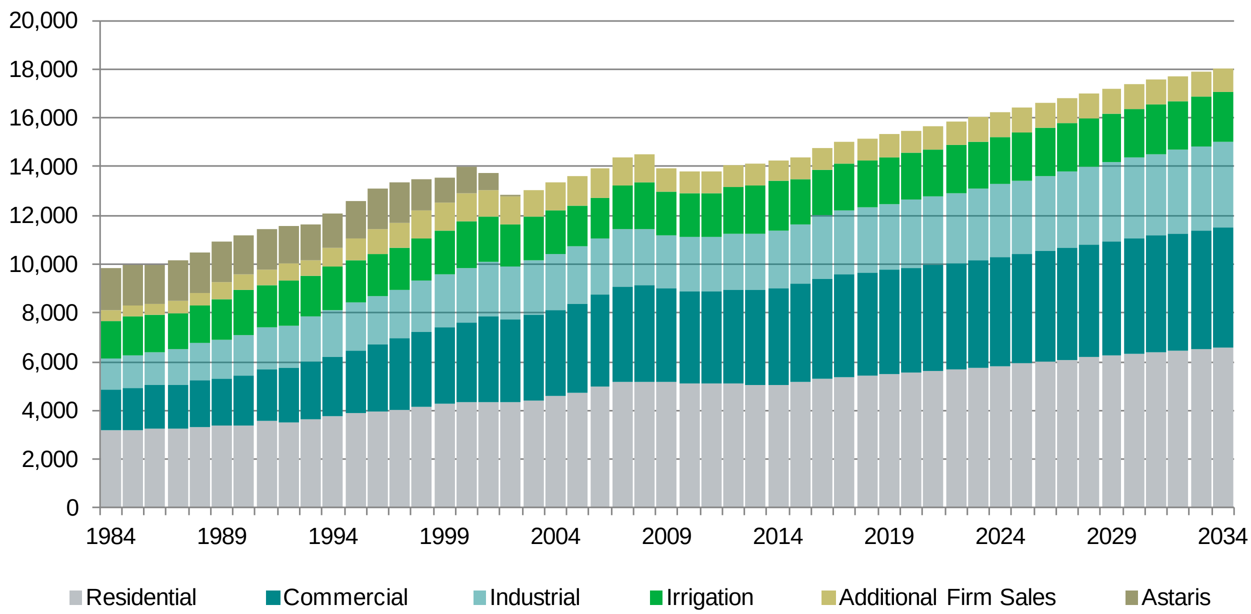

Figure 17. Composition of system company electricity sales (thousands of MWh)

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

An IDACORP Company

March 15, 2015

APPENDIX B

DSM Annual Report

Integrated Resource Plan 2015

SAFE HARBOR STATEMENT

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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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.

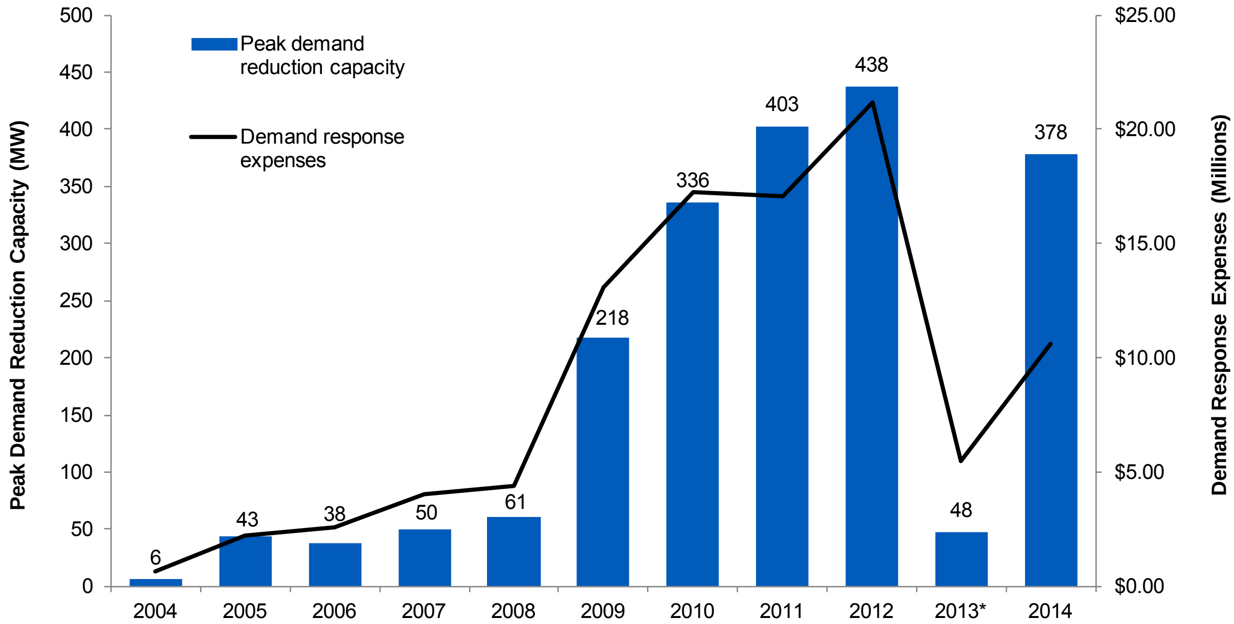

Figure 1. Peak demand-reduction capacity and demand response expenses, 2004–2014 (MW and millions [$])

*In 2013, two of the three demand response programs were temporarily suspended.

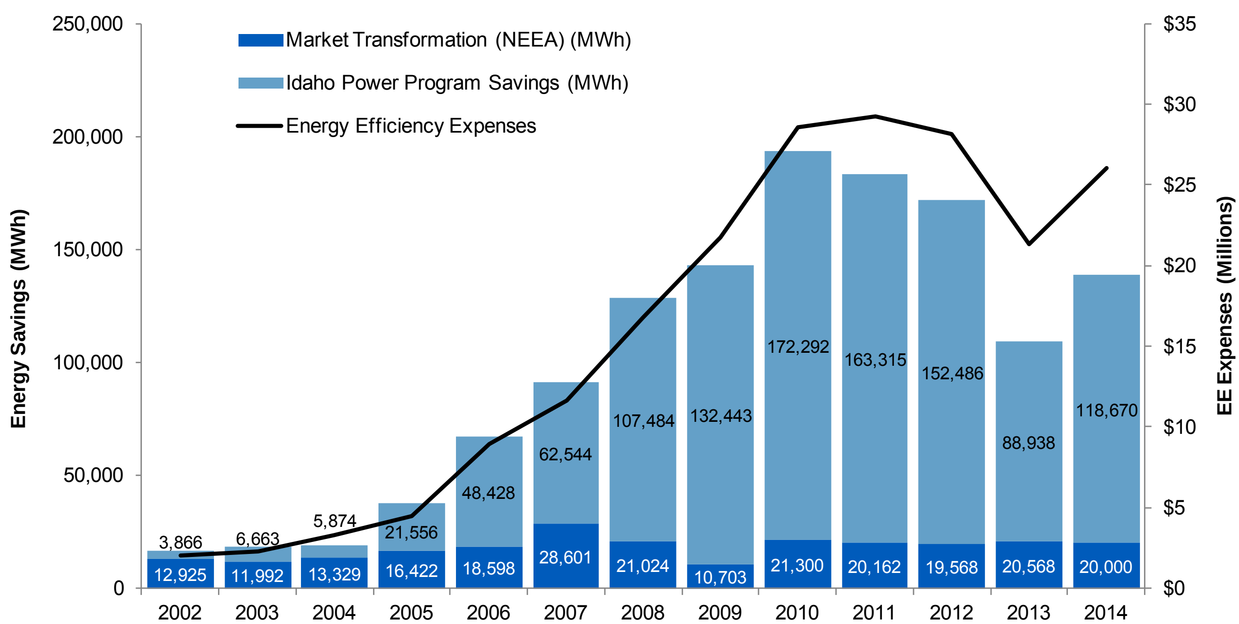

Figure 2. Annual energy savings and energy efficiency program expenses, 2002–2014 (MWh and millions [$])

*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.

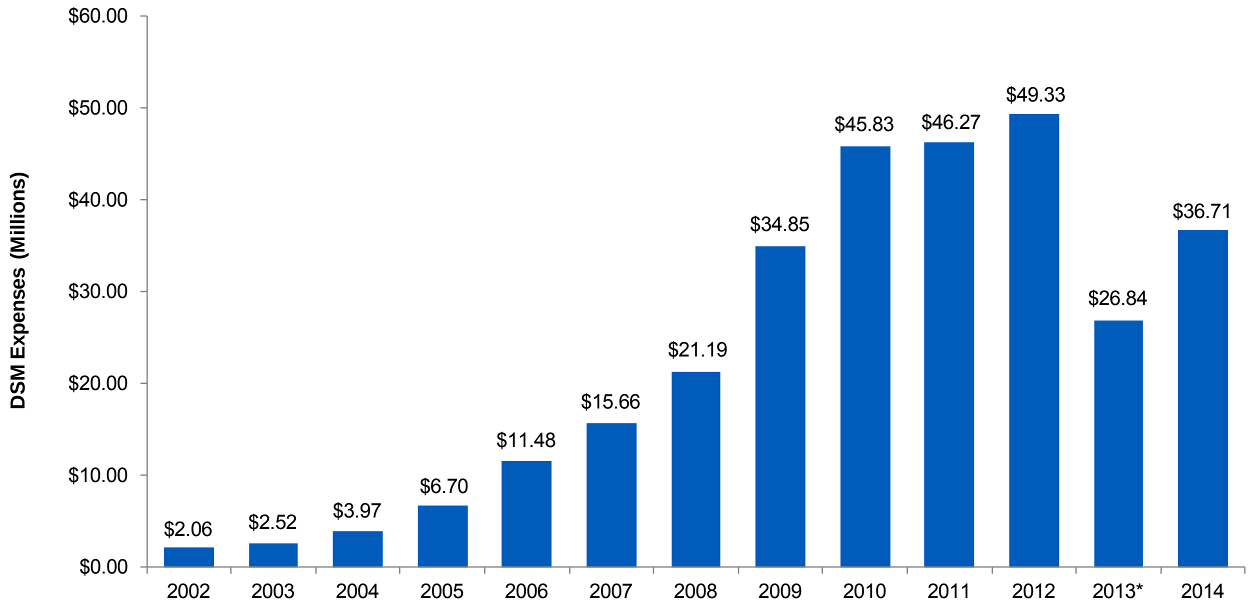

Figure 3. DSM expense history, 2002–2014 (millions of dollars)

*In 2013, two of the three demand response programs were temporarily suspended.

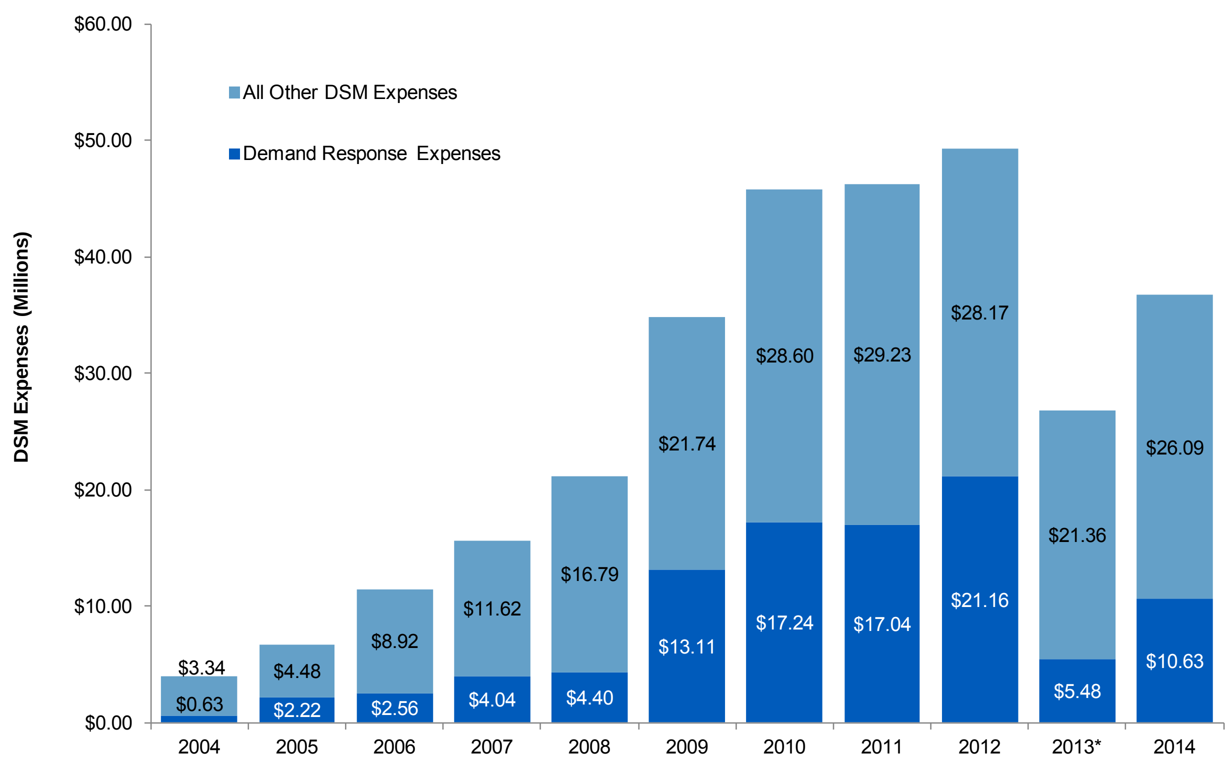

Figure 4. DSM expense history by program type, 2004–2014 (millions of dollars)

*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).

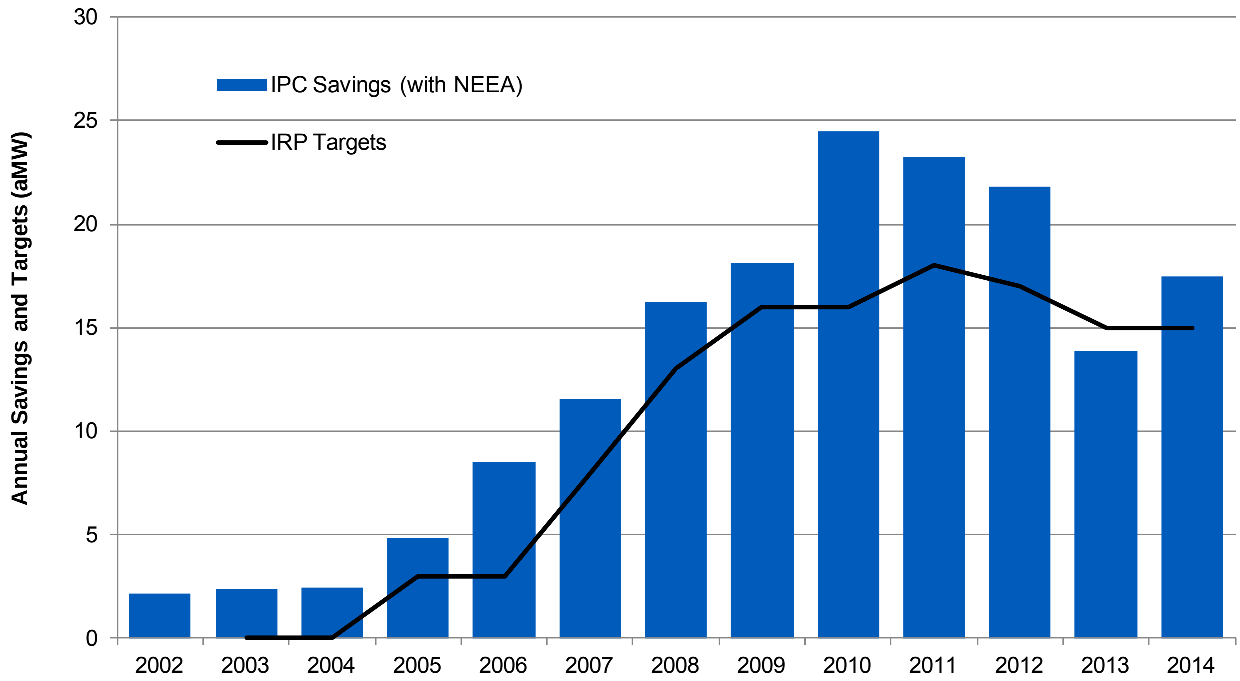

Figure 5. Annual incremental energy efficiency savings (aMW) compared with IRP targets (2002–2014)

Figure 6 shows Idaho Power's total cumulative energy efficiency savings overlaid with the company's cumulative IRP energy-savings targets (aMW).

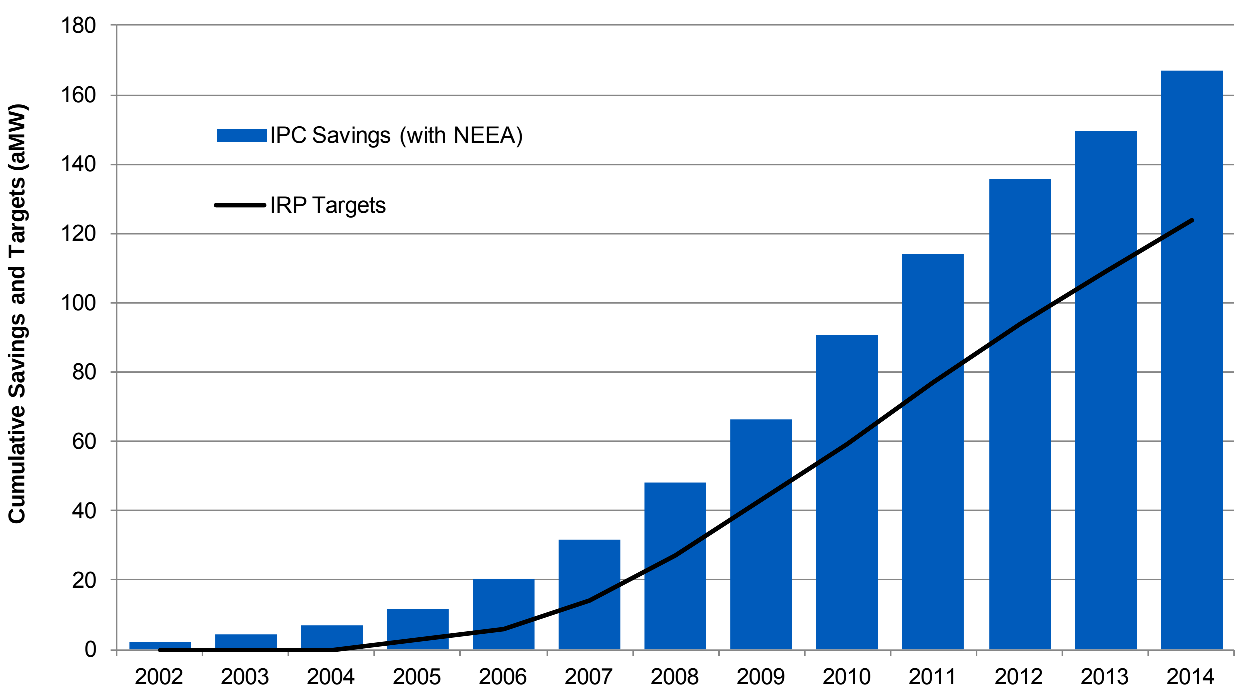

Figure 6. Annual cumulative energy efficiency savings (aMW) compared with IRP targets (2002–2014)

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.

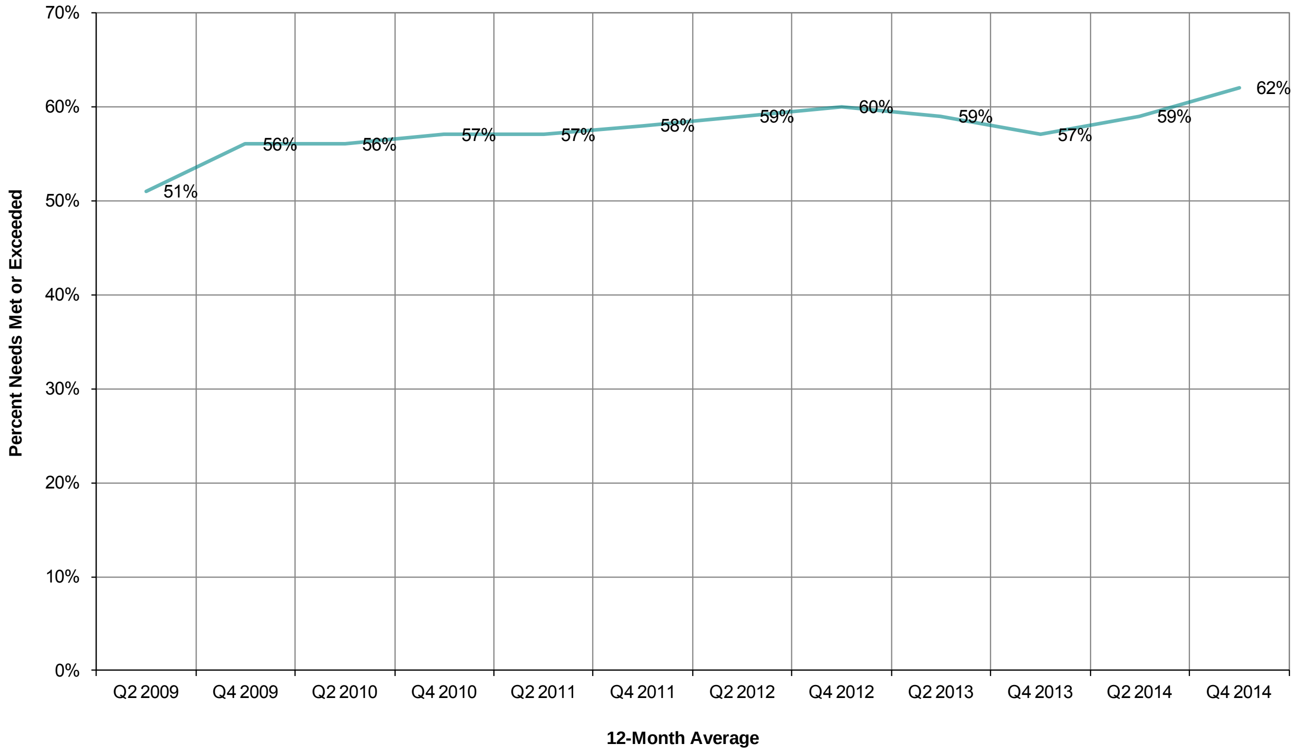

Figure 7. Percent of customers whose needs are met or exceeded by Idaho Power's energy efficiency efforts

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%**

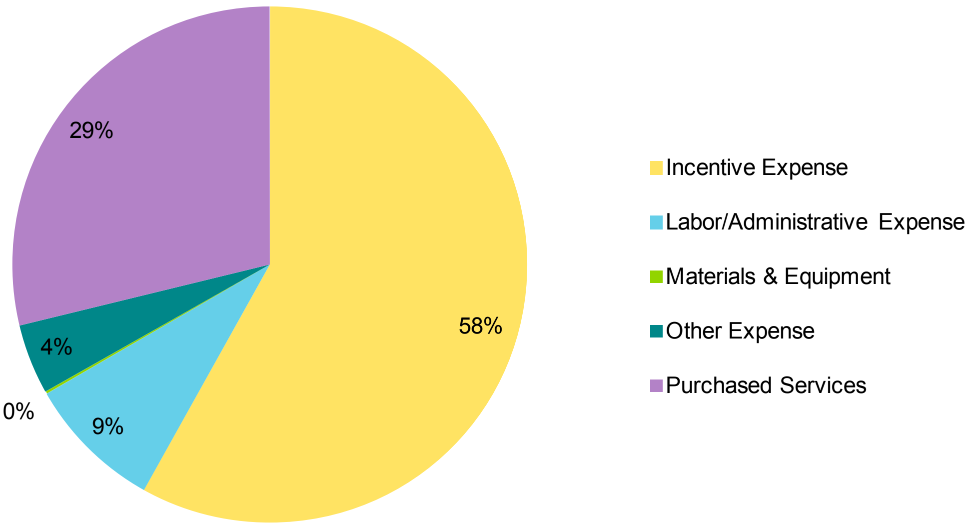

Figure 8. 2014 DSM program expenditures by category

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

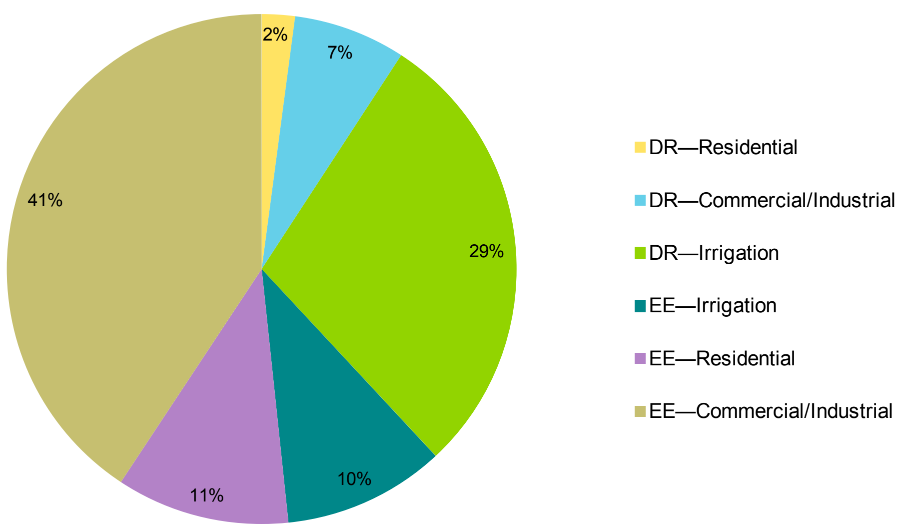

Figure 9. 2014 DSM program incentives by segment and sector

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.

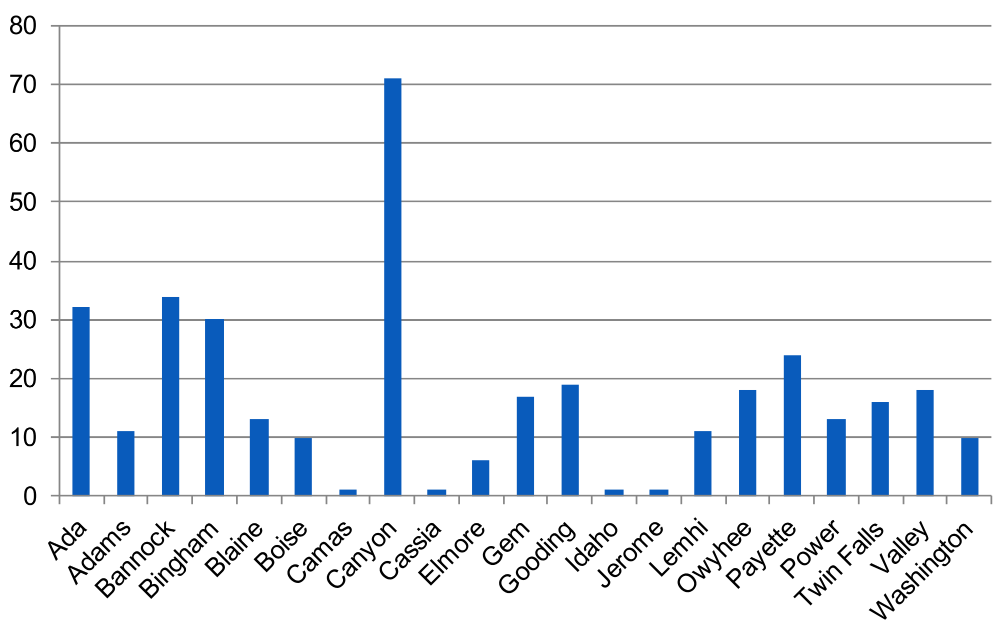

Figure 10. Summary of participating homes by county

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.

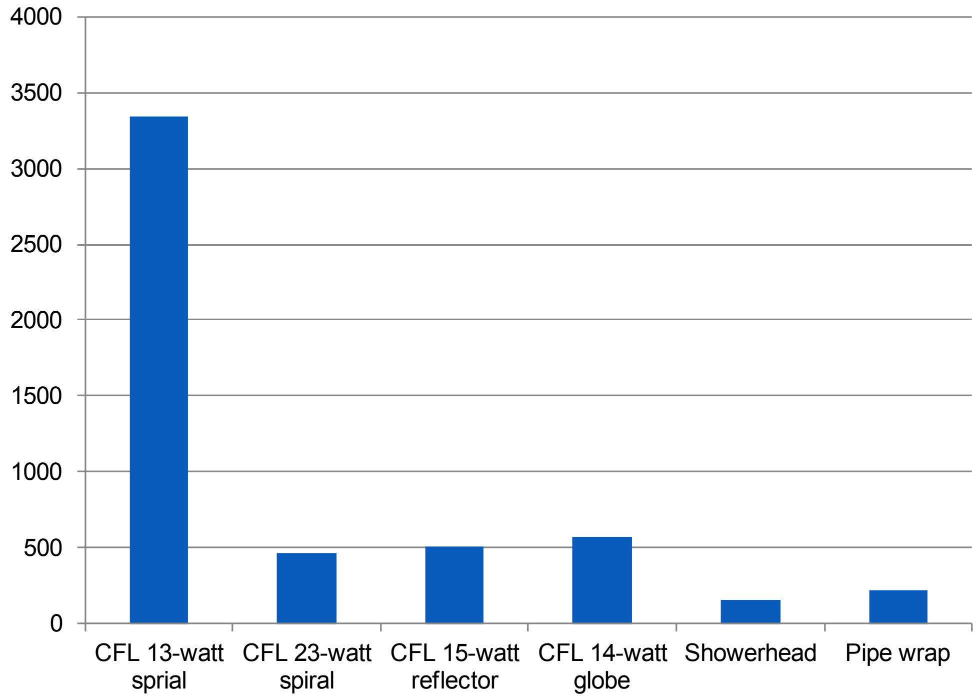

Figure 11. Measures installed in participating homes

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.

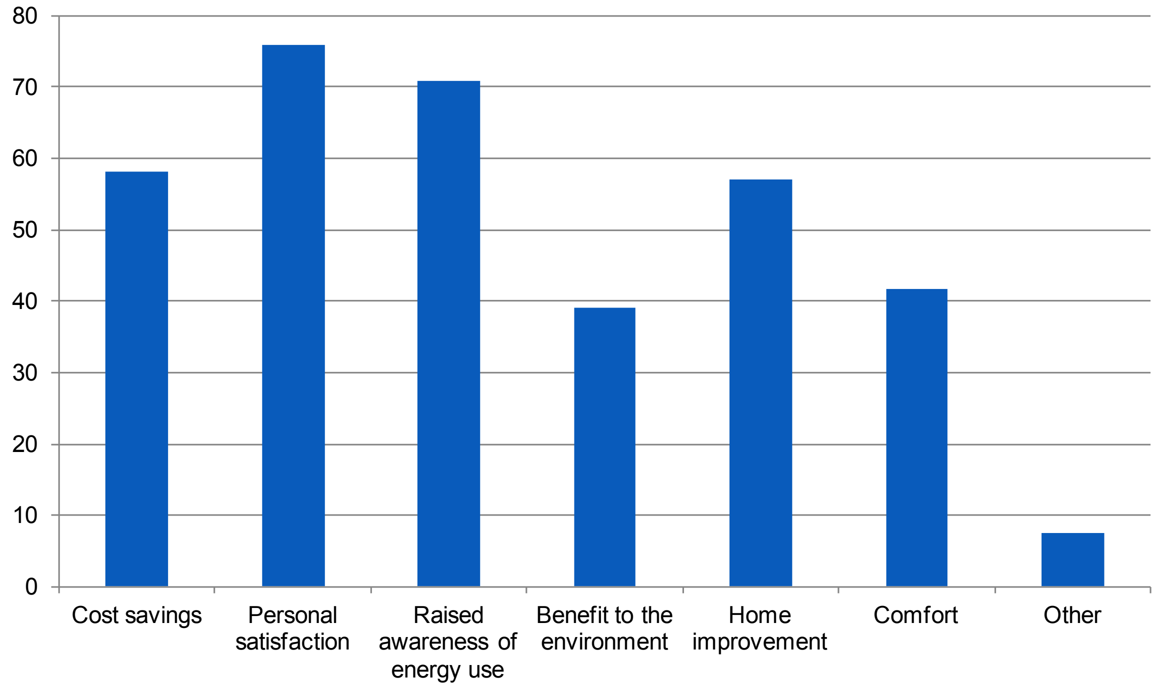

Figure 12. Program participants' benefits experienced

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.

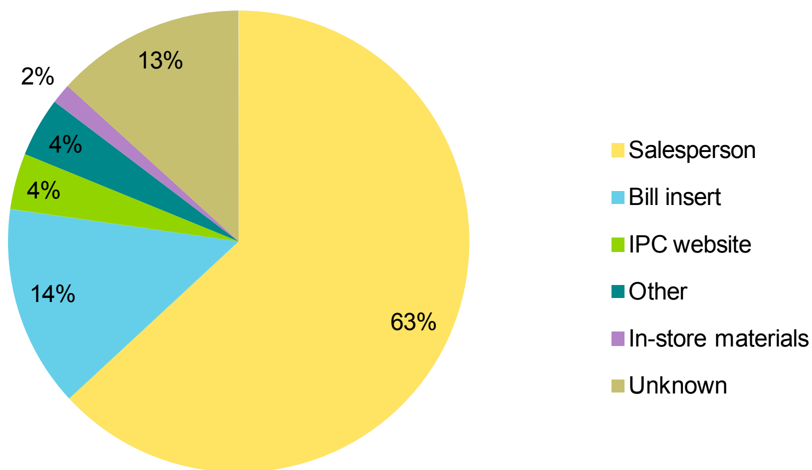

Figure 13. How customers heard about program, 2014

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.

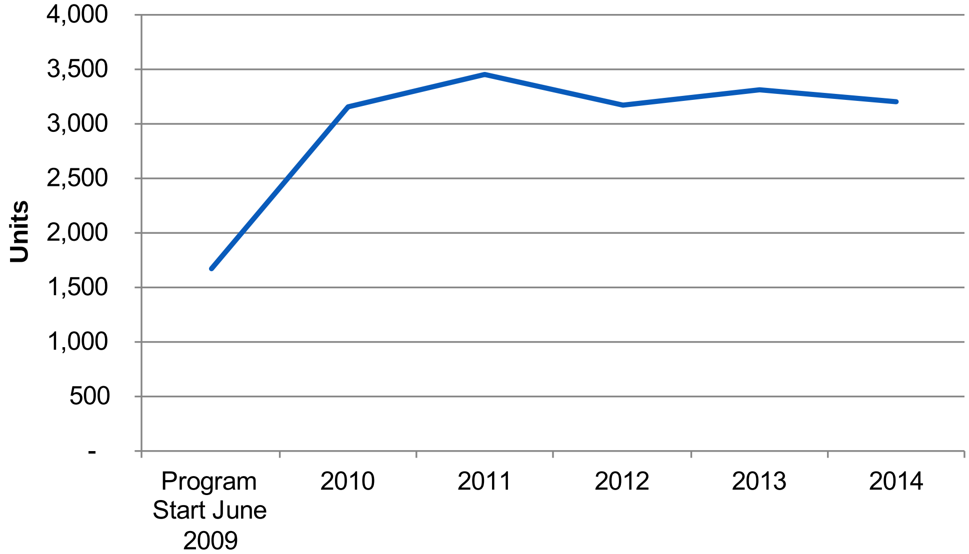

Figure 14. See ya later, refrigerator® participation by year June 2009

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.

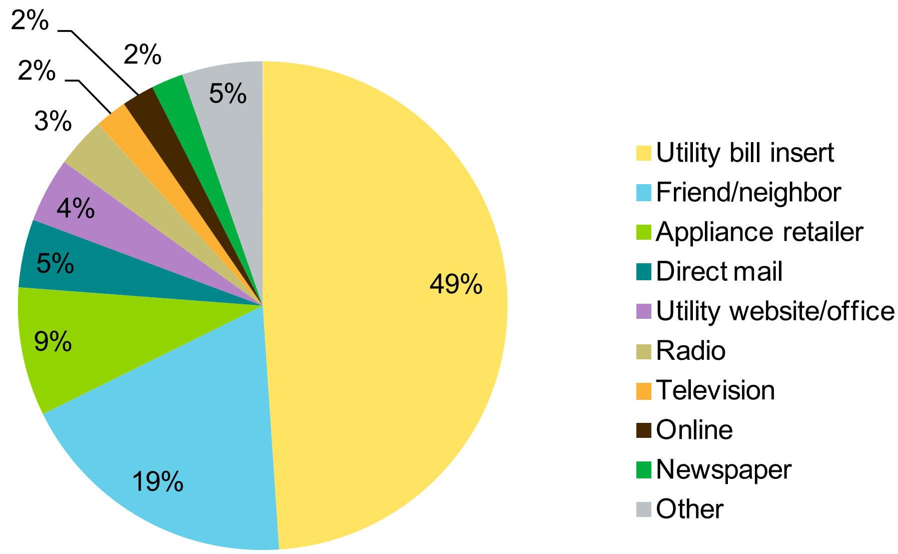

Figure 15. How customers heard about See ya later, refrigerator®

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

		Total Cost		Savings	
Program	**Participants**	**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*.

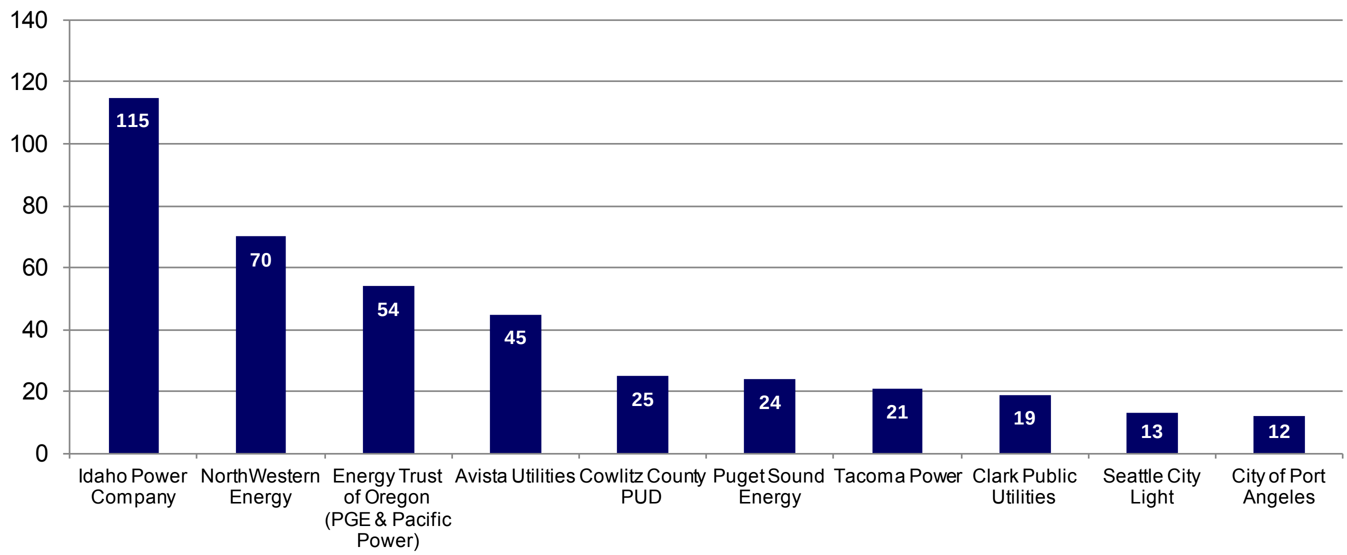

Figure 16. NEEA chart of attendees (in-class seats filled) by attendee sponsor[1]

[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*.

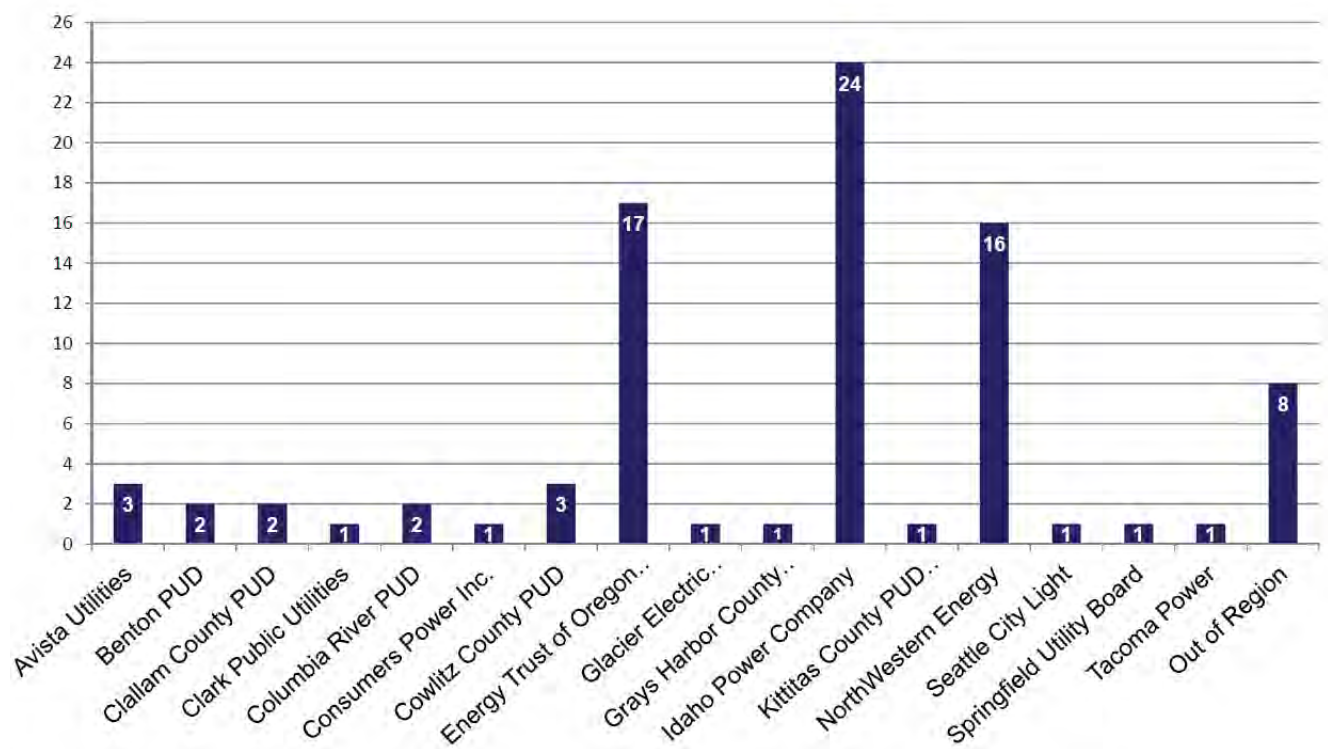

Figure 17. NEEA chart of attendees (webinar-based seats filled) by attendee sponsor[2]

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

		Total Cost		Savings	
Program	Participants	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: Utility[b]	Total Costs: Resource[c]	Savings: Annual Energy (kWh)	Savings: Peak Demand[d] (MW)	Measure Life (Years)	Nominal Levelized Costs[a]: Utility ($/kWh)	Nominal Levelized Costs[a]: Total Resource ($/kWh)
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)

		Total Costs		Savings			Nominal Levelized Costs[a]	
Program	Participants	Utility[b]	Resource[c]	Annual Energy (kWh)	Peak Demand[d] (MW)	Measure Life (Years)	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

		Total Costs		Savings and Demand Reduction			Measure Life (Years)	Levelized Costs[a]		Program Life Benefit/Cost Ratios[b]	
Program/Year	Participants	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)

		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/Cost Ratios[b]	
Program/Year	Participants	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
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)

		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/Cost Ratios[b]	
Program/Year	Participants	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
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)

		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/Cost Ratios[b]	
Program/Year	**Participants**	**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**
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)

		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/Cost Ratios[b]	
Program/Year	**Participants**	**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**
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)

		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/Cost Ratios[b]	
Program/Year	Participants	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
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: 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											
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)

		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/Cost Ratios[b]	
Program/Year	Participants	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
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)

		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/Cost Ratios[b]	
Program/Year	**Participants**	**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**
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)

		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/Cost Ratios[b]	
Program/Year	Participants	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								
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)

		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/Cost Ratios[b]	
Program/Year	Participants	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											
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)

		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/Cost Ratios[b]	
Program/Year	Participants	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											
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: 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
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)

		Total Costs		Savings and Demand Reduction			Measure Life (Years)	Levelized Costs[a]		Program Life Benefit/Cost Ratios[b]	
Program/Year	Participants	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)

	Idaho			Oregon		
Program	**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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June 2015

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Integrated Resource Plan 2015

APPENDIX C
Technical Report

SAFE HARBOR STATEMENT

June 2015

Integrated Resource Plan 2015

APPENDIX C

Technical Report

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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TABLE OF CONTENTS

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 Welcome and opening remarks IRP process explanation System load and operation Demand response update Natural gas forecast Solar workgroup recap
2014	Thursday, September 4	Review of August IRPAC meeting Solar workgroup recap Coal study workgroup recap Natural gas forecast Overview of Idaho Power generation and transmission 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 2015 IRP load forecast Resource stack capital costs IRP risk factors
2014	Thursday, November 6	Review of October IRPAC meeting Coal study Demand-side management Water supply forecast Cloud seeding Hydro generation forecast
2014	Thursday, December 4	Review of November IRPAC meeting Recap of DSM working group meeting Clean Air Act Section 111(d) 500-kV transmission projects Power markets
2015	Thursday, January 8	Review of December IRPAC meeting Recap of DSM working group meetings Energy efficiency potential study final results PURPA/PPA forecast Resource stack
2015	Wednesday, January 28	Portfolio design workshop
2015	Thursday, February 5	Review of January IRPAC meeting AURORA overview Load and resource balance Portfolio design
2015	Thursday, March 12	Review of February IRPAC meeting Conservation voltage reduction update 2015 IRP resource portfolios Portfolio analysis overview

Meeting Dates		Agenda Items
2015	Thursday, April 2	Review of March IRPAC meeting Portfolio analysis results Sustainability at Idaho Power Hells Canyon Complex relicensing
2015	Thursday, May 7	Review of April IRPAC meeting Clean Air Act Section 111(d) sensitivity analysis Stochastic risk analysis Asset replacement deferment End of feeder solar project Flexibility analysis Operational impacts of oversupply
2015	Thursday, June 4	Review of May IRPAC meeting Preferred portfolio discussion Tipping point analysis Natural gas outlook from Potential Gas Committee Shoshone Falls expansion Loss of load expectation analysis 2015 IRP action plan 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 (70^{th}% 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 (70^{th}%)	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)

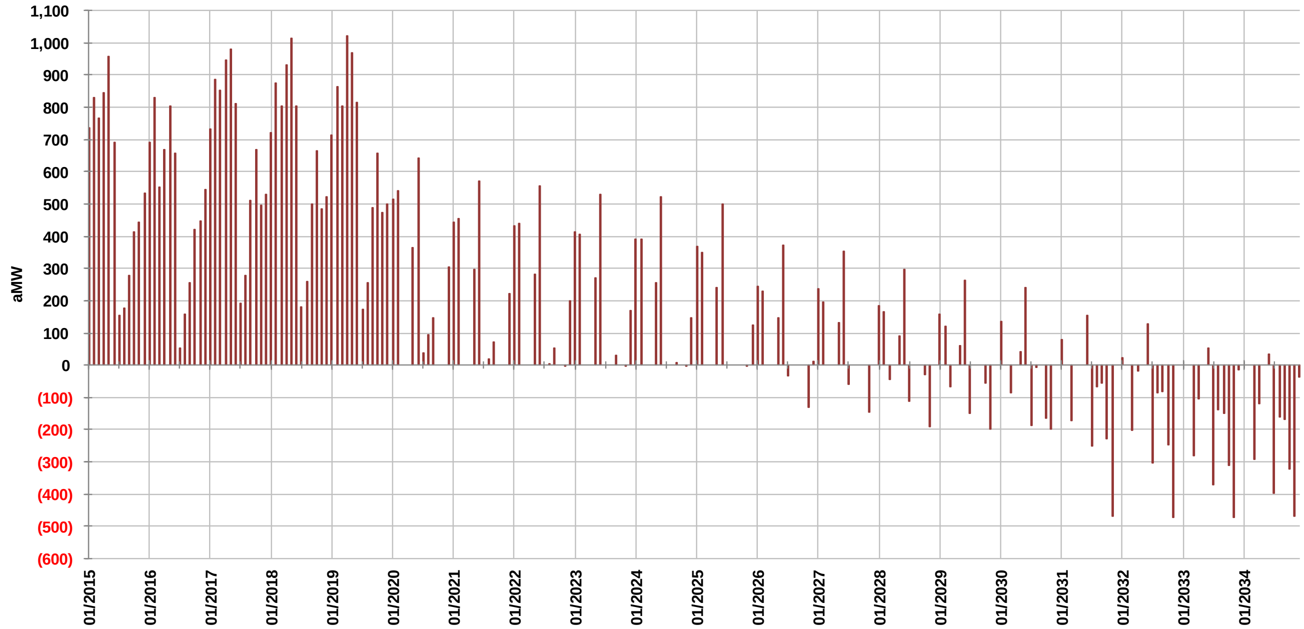
	1/2033	2/2033	3/2033	4/2033	5/2033	6/2033	7/2033	8/2033	9/2033	10/2033	11/2033	12/2033
Forecast EE	119	116	110	109	118	132	145	136	113	102	107	116
Load Forecast (70th% w/EE)	(2,259)	(2,124)	(1,957)	(1,918)	(2,139)	(2,556)	(3,093)	(2,682)	(2,227)	(1,916)	(1,957)	(2,392)
Total non-forecasted trended EE	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)

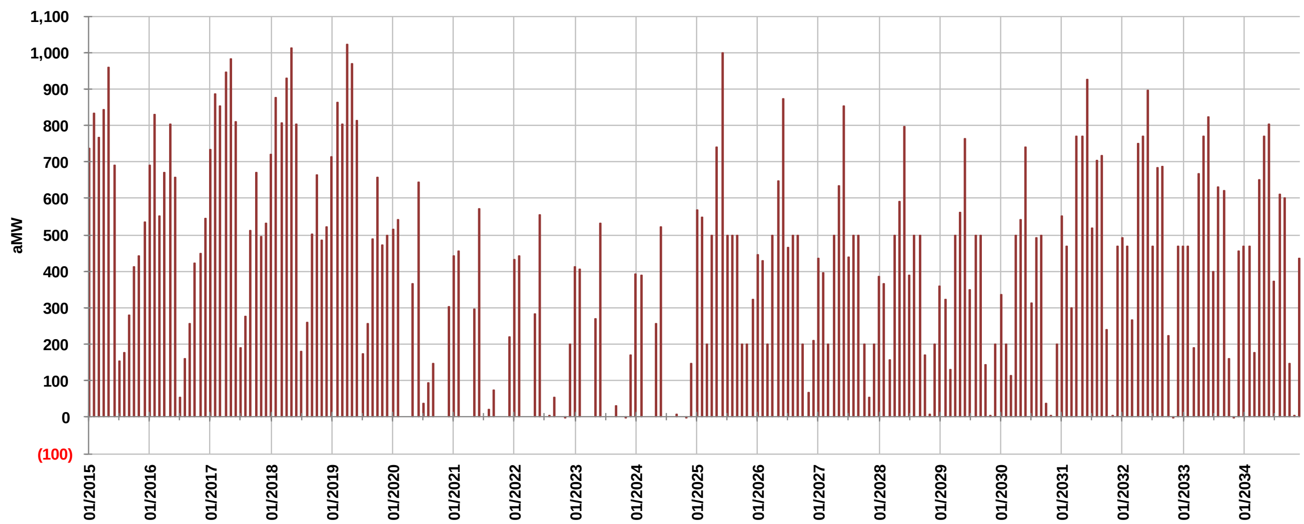
	1/2034	2/2034	3/2034	4/2034	5/2034	6/2034	7/2034	8/2034	9/2034	10/2034	11/2034	12/2034
Forecast EE	124	120	114	113	122	136	149	140	117	105	111	120
Load Forecast (70th% w/EE)	(2,280)	(2,142)	(1,974)	(1,935)	(2,159)	(2,579)	(3,123)	(2,708)	(2,249)	(1,934)	(1,974)	(2,416)
Total non-forecasted trended EE	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)

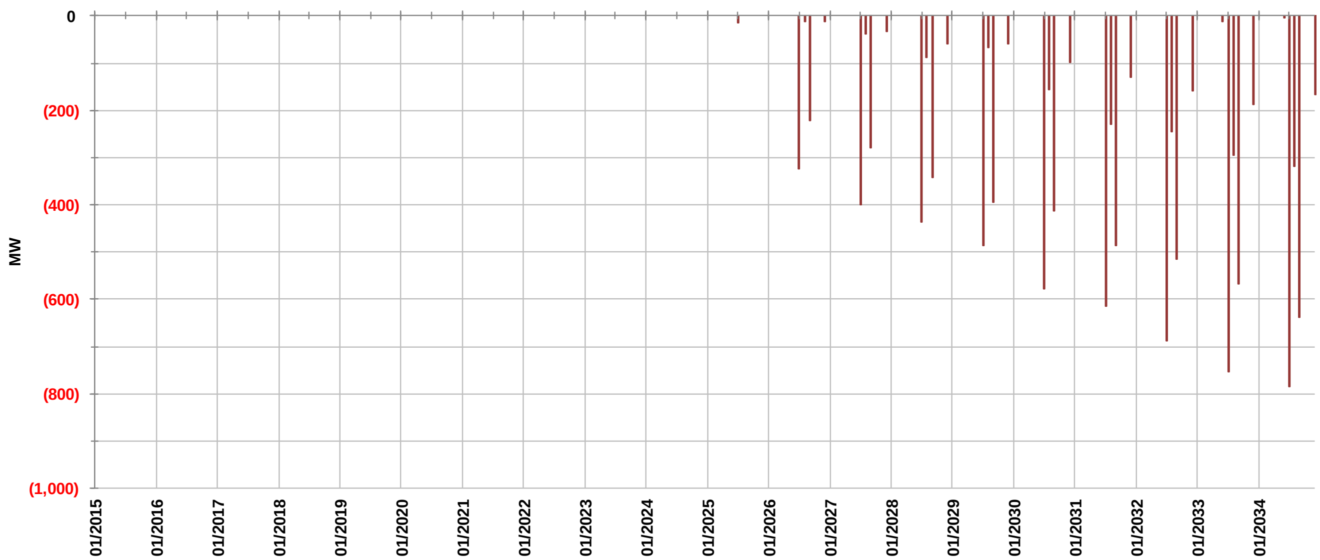
	1/2033	2/2033	3/2033	4/2033	5/2033	6/2033	7/2033	8/2033	9/2033	10/2033	11/2033	12/2033
Load Forecast (95th% w/no DSM)	(2,920)	(2,903)	(2,622)	(2,502)	(3,478)	(4,163)	(4,886)	(3,962)	(3,845)	(2,650)	(2,739)	(3,200)
Existing DSM (EE)	126	141	118	109	129	146	173	145	157	101	119	123
Load Forecast (95th% 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)

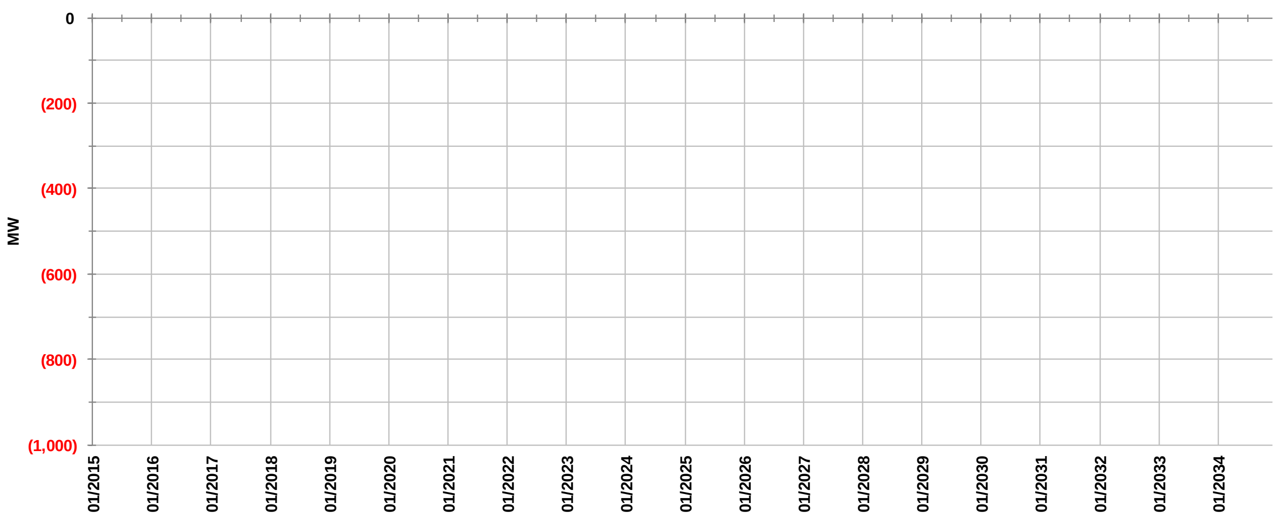
	1/2034	2/2034	3/2034	4/2034	5/2034	6/2034	7/2034	8/2034	9/2034	10/2034	11/2034	12/2034
Load Forecast (95th% w/no DSM)	(2,955)	(2,917)	(2,652)	(2,539)	(3,531)	(4,241)	(4,966)	(4,017)	(3,870)	(2,698)	(2,768)	(3,256)
Existing DSM (EE)	141	139	132	130	149	181	193	160	142	129	131	156
Load Forecast (95th% 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 Danksin–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 350—Average 500—Summer 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 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

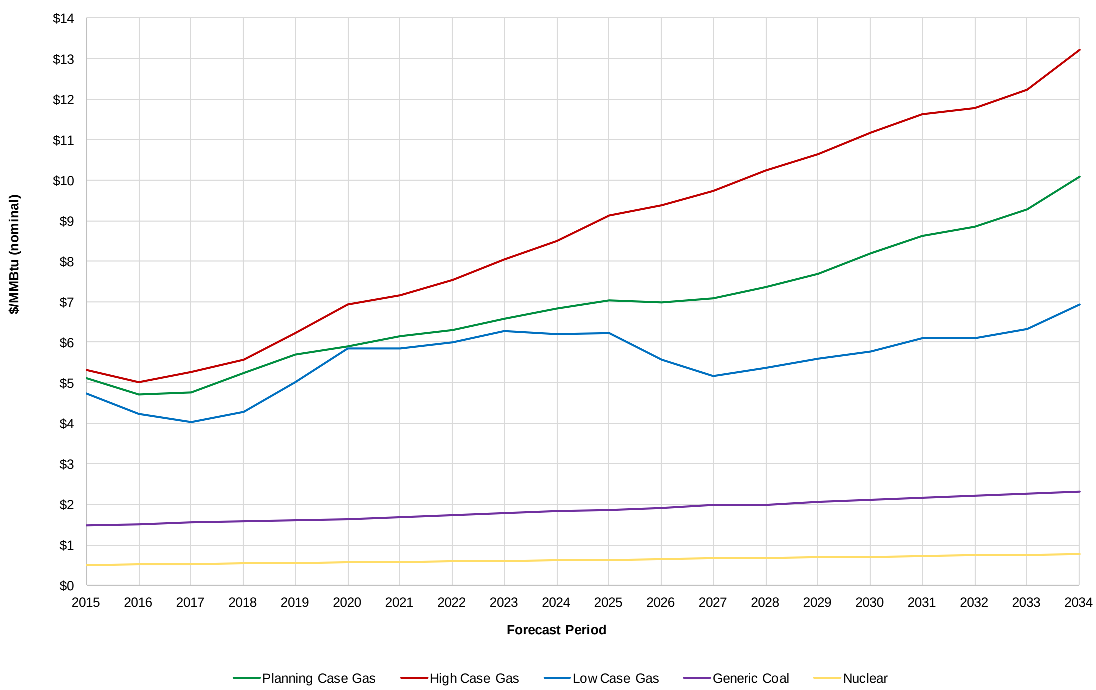
**Residual value (Book value) included in the final year: (163,567,666)

Fuel Price Forecast

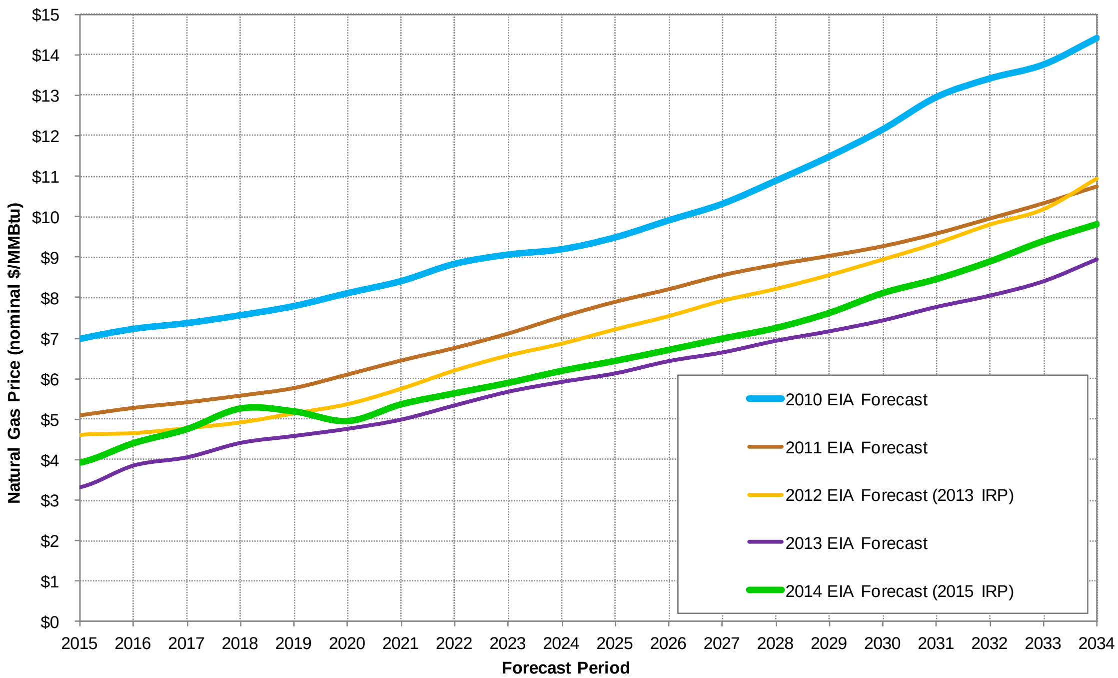
Natural Gas and Coal Price Forecast (nominal $/MMBtu)

	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

2015 IRP Fuel Price Forecast



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 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	75,000	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 Plans	Generator Nameplate Rating Gross kVA	Generator Nameplate Rating Gross kW	Net Dependable Capability (NDC)[6,7] kW	NDC Summer kW	NDC 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**

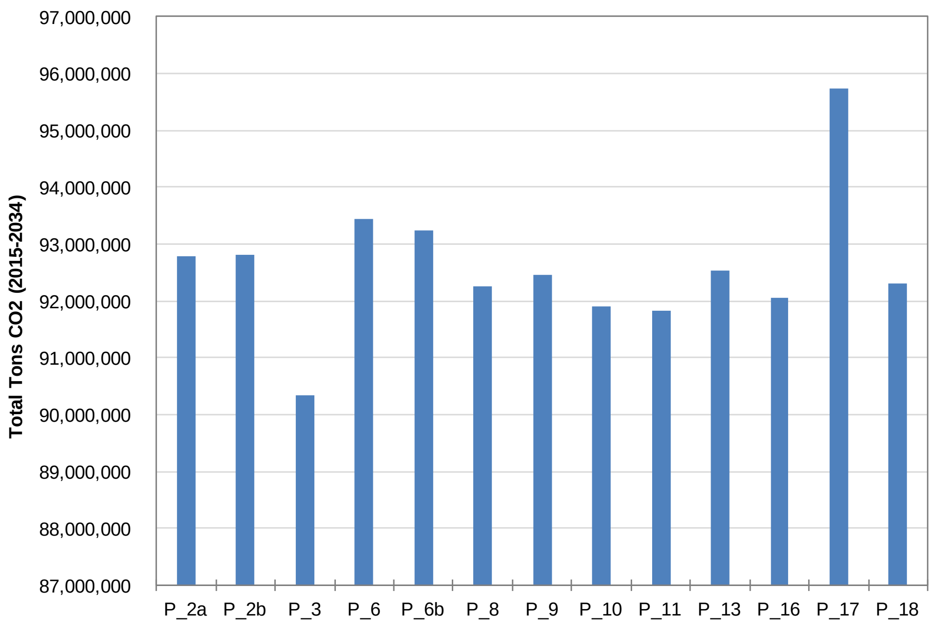
*HCC=Hells Canyon Complex,**ROR= Run of River

PORTFOLIO ANALYSIS, RESULTS, AND SUPPORTING DOCUMENTATION

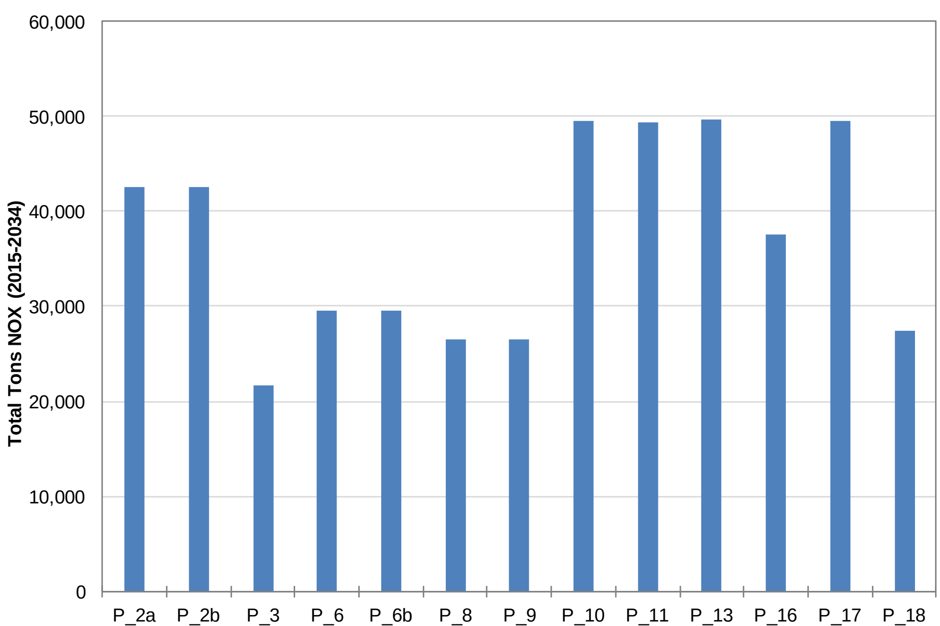
Portfolio Emissions

IPC Systems

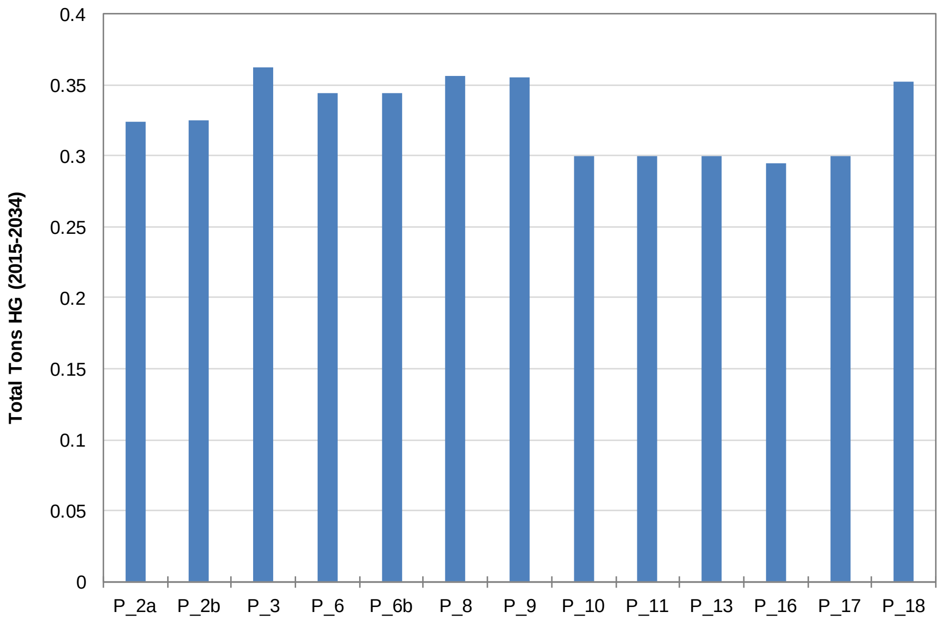
CO_2 Emission



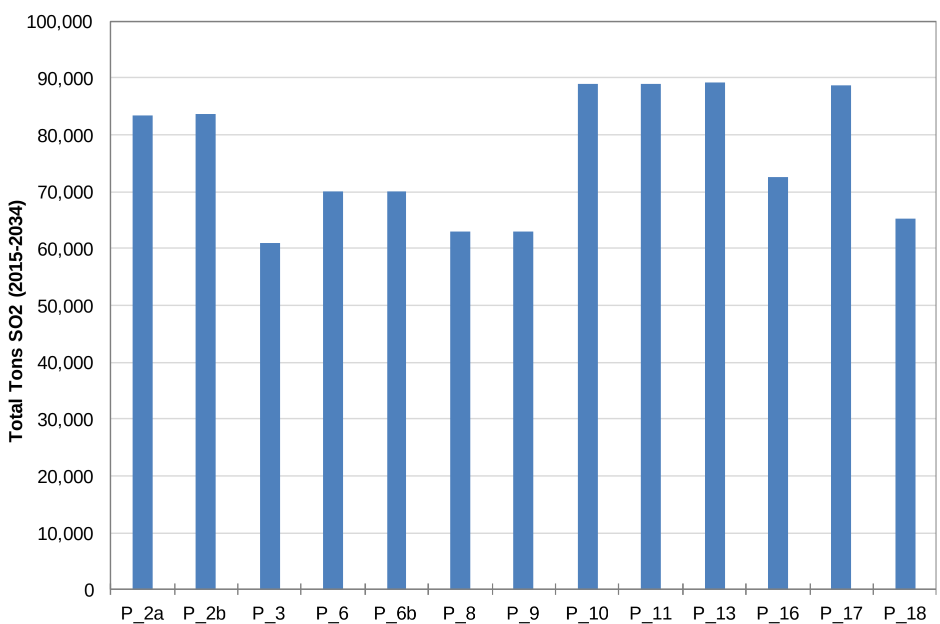
NOx Emission



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	)	
	)	
PUBLIC UTILITY COMMISSION OF OREGON	)	ERRATA ORDER
	)	
Investigation Into Integrated Resource Planning.	)	

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.

ORDER NO. 07-047

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

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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.*

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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;*

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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
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 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. 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 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. • 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.	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. 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. 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. 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. 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. 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. 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. 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. c-1) The IRP methodology and the planning horizon of 20 years are discussed in Chapter 1 (Summary), section *IRP Methodology,* page 3. 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.

Oregon Order 07-047 Action Items	2015 IRP
	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. 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. 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. 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. 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.	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. 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. 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
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.	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. b. Idaho Power will schedule a public meeting at the OPUC after the 2015 IRP has been filed. c. No action needed. d. No action needed unless the OPUC provides Idaho Power an opportunity to revise the plan. 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. 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. g. No action needed.

Oregon Order 07-047 Action Items	2015 IRP
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;	a. Idaho Power anticipates delivering this table in an informal letter to the OPUC staff.
b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;	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.
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;	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.
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;	d. Not applicable.
e. Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;	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).
f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;	f. Resource reliability is covered in Chapter 9 (Modeling Analysis and Results), section *Loss of Load Expectation (LOLE),* beginning on page 139.
g. Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;	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*.
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;	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.
i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;	i. The resource portfolios are evaluated against various risks in Chapter 9, Modeling Analysis and Results, section *Stochastic Risk Analysis,* pages 121–124.
j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;	j. Portfolio cost and risk results, with interpretations, are provided in Chapter 9 (Modeling Analysis and Results).
k. Analysis of the uncertainties associated with each portfolio evaluated;	k. The uncertainties associated with each portfolio are evaluated in Chapter 9 (Modeling Analysis and Results), sections *Stochastic Risk Analysis* and *Qualitative Risk Analysis*.
l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;	l. The selection reasoning for the preferred resource portfolio is identified in Chapter 9 (Modeling Analysis and Results), section *Preferred Portfolio*, page 130.
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	m. No inconsistencies were identified.
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.	n. An action plan is provided in Chapter 1 (Summary), section *Action Plan*, page 10.

Oregon Order 07-047 Action Items	2015 IRP
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.	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. 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.	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. 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*. 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. 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. 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. 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. 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. 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.

Oregon Order 07-047 Action Items	2015 IRP
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 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. 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.	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 10 (Action Plan), section *Action Plan (2015–2018)*, page 143. 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

In the Matter of

PUBLIC UTILITY COMMISSION OF OREGON

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.

ORDER NO. 12 013

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.*

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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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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

PUBLIC UTILITY COMMISSION OF OREGON

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.

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Compliance with EV Guidelines

Oregon Order 12-013 Guideline	2015 IRP
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; **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; **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.	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

In the Matter of IDAHO POWER COMPANY, 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:

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

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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

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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.

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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.

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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

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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,

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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:

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.*

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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.

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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.

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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.

[11] Order No. 12-177 at 5.
[12] Order No. 13-481 at 1-2.

ORDER NO. 12 235

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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ORDER NO. 14 235

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

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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.