Exhibit N
Need

Boardman to Hemingway Transmission Line Project

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Application for Site Certificate

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ACRONYMS AND ABBREVIATIONS

aMW	average megawatt
ATC	available transmission capacity
DOE	United States Department of Energy
EFSC or Council	Energy Facility Siting Council
IPC	Idaho Power Company
IRP	Integrated Resource Plan
IRPAC	Integrated Resource Plan Advisory Council
kV	kilovolt
kWh	kilowatt-hour
LOLE	Loss of Load Expectation
MW	megawatt
NERC	North American Electric Reliability Corporation
OAR	Oregon Administrative Rules
OPUC	Public Utility Commission of Oregon
Project	Boardman to Hemingway Transmission Line Project
SAE	Statistically Adjusted End-use
SCR	selective catalytic reduction
Second Amended Project Order	Second Amended Project Order, Regarding Statutes, Administrative Rules, and Other Requirements Applicable to the Proposed BOARDMAN TO HEMINGWAY TRANSMISSION LINE (July 26, 2018)
TPL	Transmission Planning
WECC	Western Electricity Coordinating Council

Exhibit N
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1.0 INTRODUCTION

The need for the Boardman to Hemingway Transmission Line Project (Project) is established by showing the Public Utility Commission of Oregon has acknowledged the Project in Idaho Power Company's (IPC) Integrated Resource Plan. Additionally, and in the alternative, IPC demonstrates need by showing the Project is needed to meet the company's firm capacity demands or firm annual electricity sales; the Project is consistent with North American Electric Reliability Corporation (NERC) reliability standards; and the Project is an economically reasonable means of meeting the company's needs and NERC standards.

2.0 APPLICABLE RULES AND AMENDED PROJECT ORDER PROVISIONS

2.1 Need Standard for Nongenerating Facilities

2.1.1 Need for a Facility

Oregon Administrative Rule (OAR) 345-023-0005 provides that IPC shall demonstrate the need for the Project as follows:

> *(1) For electric transmission lines under the least-cost plan rule, OAR 345-023-0020(1), or the system reliability rule for transmission lines, OAR 345-023-0030, or by demonstrating that the transmission line is proposed to be located within a "National Interest Electric Transmission Corridor" designated by the U.S. Department of Energy under Section 216 of the Federal Power Act;*

2.1.2 Least-Cost Plan Rule

The least-cost plan rule, OAR 345-023-0020(1), states:

> *(1) The Council shall find that the applicant has demonstrated need for the facility if the capacity of the proposed facility or a facility substantially similar to the proposed facility, as defined by OAR 345-001-0010, is identified for acquisition in the short-term plan of action of an energy resource plan or combination of plans . . . .*
>
> *(2) The Council shall find that a least-cost plan meets the criteria of an energy resource plan described in section (1) if the Public Utility Commission of Oregon has acknowledged the least cost plan.*

2.1.3 System Reliability Rule for Electric Transmission Lines

The system reliability rule, OAR 345-023-0030, provides:

> *The Council shall find that the applicant has demonstrated need for an electric transmission line that is an energy facility under the definition in ORS 469.300 if the Council finds that:*
>
> > *(1) The facility is needed to enable the transmission system of which it is to be a part to meet firm capacity demands for electricity or firm annual electricity sales that are reasonably expected to occur within five years of the facility's proposed*

in-service date based on weather conditions that have at least a 5 percent chance of occurrence in any year in the area to be served by the facility;

(2) The facility is consistent with the applicable mandatory and enforceable North American Reliability Corporation (NERC) Reliability Standards in effect as of September 18, 2015 as they apply either internally or externally to a utility system; and

(3) Construction and operation of the facility is an economically reasonable method of meeting the requirements of sections (1) and (2) compared to the alternatives evaluated in the application for a site certificate.

2.2 Site Certificate Application Requirements

2.2.1 General Requirements

OAR 345-021-0000(8) provides the following:

If the proposed facility is a non-generating facility for which the applicant must demonstrate need under OAR 345-023-0005, in addition to the application for a site certificate described in OAR 345-021-0010, the applicant shall submit to the Department three copies of each energy resource plan or combination of plans on which the applicant relies to demonstrate need under 345-023-0020, unless the applicant chooses to incorporate copies of the plan(s) as part of the application for a site certificate. The applicant shall submit the plan(s) to the Department with the site certificate application. The Department may not find the site certificate application to be complete before receiving copies of the plan(s). The plan or plans described in this section are part of the decision record for the Department's proposed order, described in 345-015-0230.

2.2.2 Contents of Application

OAR 345-021-0010(1)(n) provides Exhibit N must include the following Information about the need for the Project:

(A) Identification of the rule in Division 23 of this chapter under which the applicant chooses to demonstrate need.

(B) If the applicant chooses to demonstrate need for the proposed facility under OAR 345-023-0020(1), the least-cost plan rule:

(i) Identification of the energy resource plan or combination of plans on which the applicant relies to demonstrate need.

(ii) The name, address and telephone number of the person responsible for preparing each energy resource plan identified in subparagraph (i).

(iii) For each plan reviewed by a regulatory agency, the agency's findings and final decision, including:

(I) For a plan reviewed by the Oregon Public Utility Commission, the acknowledgment order; or

(II) For a plan reviewed by any other regulatory agency, a summary of the public process including evidence to support a finding by the Council that the agency's decision process included a full, fair and open public participation and comment process as required by OAR 345-023-

0020(1)(L), and the location of and means by which the Department can obtain a complete copy of the public record.

(iv) Identification of the section(s) of the short-term action plan(s) that call(s) for the acquisition of the proposed facility or, as defined in OAR 345-001-0010, a facility substantially similar to the proposed facility.

(v) The attributes of the proposed facility that qualify it as one called for in the short-term action plan of the energy resource plan or combination of plans identified in subparagraph (i) or a demonstration that, as defined in OAR 345-001-0010, a facility substantially similar to the proposed facility is called for in the plan(s).

. . .[1]

(F) If the applicant chooses to demonstrate need for a proposed electric transmission line under OAR 345-023-0030, the system reliability rule:

(i) Load-resource balance tables for the area to be served by the proposed facility. In the tables, the applicant shall include firm capacity demands and existing and committed firm resources for each of the years from the date of submission of the application to at least five years after the expected in-service date of the facility.

(ii) Within the tables described in subparagraph (i), a forecast of firm capacity demands for electricity and firm annual electricity sales for the area to be served by the proposed facility. The applicant shall separate firm capacity demands and firm annual electricity sales into loads of retail customers, system losses, reserve margins and each wholesale contract for firm sale. In the forecast, the applicant shall include a discussion of how the forecast incorporates reductions in firm capacity demand and firm annual electricity sales resulting from:

(I) Existing federal, state or local building codes, and equipment standards and conservation programs required by law for the area to be served by the proposed facility;

(II) Conservation programs provided by the energy supplier, as defined in OAR 345-001-0010;

(III) Conservation that results from responses to price; and

(IV) Retail customer fuel choice;

(iii) Within the tables described in subparagraph (i), a forecast of existing and committed firm resources used to meet the demands described in subparagraph (ii). The applicant shall include, as existing and committed firm resources, existing generation and transmission facilities, firm contract resources and

[1] Subsections (C) and (E) of OAR 345-021-0010(1)(n) are relevant to energy projects that rely on an energy resource plan not acknowledged by the Public Utility Commission of Oregon to demonstrate need. Here, because IPC is not relying on a resource plan not acknowledged by the Commission, subsections (C) and (D) are not applicable to the Project. Further, subsection (D) is not applicable because it relates to natural gas pipeline or storage facility projects and not transmission line projects.

committed new resources minus expected resource retirements or displacement. In the forecast, the applicant shall list each resource separately.

(iv) A discussion of the reasons each resource is being retired or displaced if the forecast described in subparagraph (iii) includes expected retirements or displacements.

(v) A discussion of the annual capacity factors assumed for any generating facilities listed in the forecast described in subparagraph (iii).

(vi) A discussion of the reliability criteria the applicant uses to demonstrate the proposed facility is needed, considering the load carrying capability of existing transmission system facilities supporting the area to be served by the proposed facility.

(vii) A discussion of reasons why the proposed facility is economically reasonable compared to the alternatives described below. In the discussion, the applicant shall include a table showing the amounts of firm capacity and firm annual electricity available from the proposed facility and each alternative and the estimated direct cost, as defined in OAR 345-001-0010, of the proposed facility and each alternative. The applicant shall include documentation of assumptions and calculations supporting the table. The applicant shall evaluate alternatives to construction and operation of the proposed facility that include, but are not limited to:

(I) Implementation of cost-effective conservation, peak load management and voluntary customer interruption as a substitute for the proposed facility.

(II) Construction and operation of electric generating facilities as a substitute for the proposed facility.

(III) Direct use of natural gas, solar or geothermal resources at retail loads as a substitute for use of electricity transmitted by the proposed facility.

(IV) Adding standard sized smaller or larger transmission line capacity.

(viii) The earliest and latest expected in-service dates of the facility and a discussion of the circumstances of the energy supplier, as defined in OAR 345-001-0010, that determine these dates.

. . . .[2]

2.3 Second Amended Project Order Provisions

The Second Amended Project Order includes the following discussion:

The Council requires applicants to demonstrate public need for an electric transmission line facility under the least-cost plan rule (OAR 345-023-0020), the system reliability rule for transmission lines (OAR 345-023-0030), or by demonstrating that the transmission line is proposed to be within a "National Interest Electric Transmission Corridor" designated by the US Department of Energy under Section 216 of the Federal Power Act. The applicant may provide evidence demonstrating the need for the facility under

[2] Subsection (G) of OAR 345-021-0010(1)(n) is not applicable to the Project, because subsection (G) relates to natural gas pipeline or storage facility projects and not transmission line projects.

> *one or more of the methods described in Division 23. Note that on October 20, 2015, OAR 345-023-0030 was updated to reflect the North American Electric Reliability Corporation (NERC) Reliability Standards.*
>
> *The Least-Cost Plan Rule (OAR 345-023-0020) can be satisified if the Oregon Public Utility Commission (PUC) acknowledges an energy resource plan/least-cost plan which identifies for acquisition in the short-term plan of action the proposed facility or a facility substantially similar to the proposed facility. On April 10, 2018 the Oregon PUC held a regular public meeting regarding Idaho Power's 2017 Integrated Resource Plan. Based on PUC staff recommendations, the PUC acknowledged conducting ongoing permitting, planning studies, and regulatory filings for the B2H transmission line and to conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.*

(Second Amended Project Order, Section III(n)).

3.0 ANALYSIS

3.1 Rules under which IPC Will Demonstrate Need

OAR 345-021-0010(1)(n)(A): Identification of the rule in Division 23 of this chapter under which the applicant chooses to demonstrate need.

IPC chooses to demonstrate the need for the Project under the least-cost plan rule and system reliability rule. The Energy Facility Siting Council (EFSC or Council) may find the Project need is sufficiently demonstrated under one or both of those rules.

3.2 Demonstration of Need Under the Least-Cost Plan Rule

3.2.1 Least-Cost Plan Rule

OAR 345-023-0020(2): The Council shall find that a least-cost plan meets the criteria of an energy resource plan described in section (1) if the Public Utility Commission of Oregon has acknowledged the least cost plan.

Under OAR 345-023-0020(2), the Council shall find IPC has demonstrated the Project need if the capacity of the Project or a facility substantially similar to the Project is identified for acquisition in the short-term plan of action of an Integrated Resource Plan (IRP) acknowledged by the Oregon Public Utility Commission (OPUC). Here, the development of the Project has been acknowledged by the OPUC in the 2009, 2011, 2013, 2015, and 2017 IRPs (Attachments N-1, N-2, N-3, N-4, and N-5; see Section 3.2.2.3 below). Therefore, EFSC must find that the need standard has been satisfied.

3.2.2 Application Content Requirements

3.2.2.1 Relevant Integrated Resource Plans

OAR 345-021-0010(1)(n)(B)(i): Identification of the energy resource plan or combination of plans on which the applicant relies to demonstrate need.

IPC relies on its 2009, 2011, 2013, 2015, and 2017 IRPs (Attachments N-1, N-2, N-3, N-4, and N-5) to demonstrate the Project need. The 2009, 2011, 2013, 2015, and 2017 IRPs were acknowledged by the OPUC and are attached as Attachments N-1, N-2, N-3, N-4, and N-5

respectively. Appendix D of the 2017 IRP provides a comprehensive review of the Project as a resource, including addressing the need for the Project, discussing (qualitatively and quantitatively) the benefits of the Project, and considering the risks and benefits of the Project in contrast to a traditional generation source.

3.2.2.2 Person Responsible for Preparing the Integrated Resource Plans

OAR 345-021-0010(1)(n)(B)(ii): The name, address and telephone number of the person responsible for preparing each energy resource plan identified in subparagraph (i).

The person responsible for preparing IPC's IRPs is:

Rick Haener, Integrated Resource and Operations Plan Manager
1221 West Idaho Street
Boise, Idaho 83702
(208) 388-5862

3.2.2.3 IPC's Acknowledged Integrated Resource Plans

OAR 345-021-0010(1)(n)(B): (iii) For each plan reviewed by a regulatory agency, the agency's findings and final decision, including: (I) For a plan reviewed by the Oregon Public Utility Commission, the acknowledgment order; or (II) . . . .[3] (iv) Identification of the section(s) of the short-term action plan(s) that call(s) for the acquisition of the proposed facility or, as defined in OAR 345-001-0010, a facility substantially similar to the proposed facility. (v) The attributes of the proposed facility that qualify it as one called for in the short-term action plan of the energy resource plan or combination of plans identified in subparagraph (i) or a demonstration that, as defined in OAR 345-001-0010, a facility substantially similar to the proposed facility is called for in the plan(s).

The OPUC's IRP process is "an approach to utility planning which requires consideration of all known resources for meeting the utility's load."[4] These resources include both supply-side resources (such as generation plants) and demand-side resources (such as conservation and load management). The OPUC has adopted guidelines that govern the development and acknowledgement of utility IRPs. As relevant here, the IRP process must include significant public involvement in the preparation of the plan.[5] Substantively, the plan must:

- Evaluate all resources on a consistent and comparable basis;
- Consider uncertainty;
- Include as its primary goal the least cost to the utility and ratepayers, consistent with the long-run public interest; and
- Be consistent with Oregon's energy policy.[6]

[3] Subsection (II) of OAR 345-021-0010(1)(n)(B)(iii) applies to applicants relying on energy resource plans reviewed by agencies other than the OPUC. Because IPC is relying on OPUC energy plans and not plans reviewed by other agencies, Subsection (II) does not apply to the Project.
[4] OPUC Order No. 89-507, p. 8 (Apr. 20, 1981).
[5] OPUC Order No. 07-002, p. 1 (Jan. 8, 2007).
[6] Order No. 07-002, p. 2.

The IRP process requires a utility to identify several portfolios of different combinations of resources that can be used to meet the utility's load over a 20-year planning horizon. The portfolios are analyzed and a preferred portfolio is identified, representing the best combination of costs and risks. Next, an action plan is developed to explain how the utility will obtain the resources identified in the preferred portfolio.

OPUC's acknowledgement of an IRP means that the IRP is "reasonable, based on information available at the time."[7] IRP guidelines recognize that all utility planning encompasses uncertainty and requires only that utilities consider the uncertainties in their planning and that the preferred portfolio represent the best combination of expected costs, associated risks, and uncertainties.[8]

IPC's 2009 IRP

IPC filed its 2009 IRP with the OPUC on December 30, 2009 (Attachment N-1). The filing was docketed as LC 50. IPC provided notice of the filing to all parties that had participated in IPC's previous IRP docket, LC 41.

In developing the 2009 IRP, IPC engaged in an extensive public process, including the creation of an IRP Advisory Council (IRPAC), which included major stakeholders including representatives of political organizations, environmental groups, customer representatives, and others. The IRPAC generally met monthly and all meetings were open to the public. The meetings allowed stakeholders to provide input to IPC on all aspects of the planning process, including the development of the portfolios that were ultimately included in the IRP.

The 2009 IRP divided the 20-year planning period into two 10-year periods. IPC then developed different portfolios for each of those 10-year periods. The portfolios each represented the resources that IPC planned to obtain during each of the 10-year periods. For the first period, 2010 to 2019, IPC developed four different resources portfolios. For the second period, 2019 to 2029, IPC developed five different resource portfolios.

To analyze the portfolios, IPC used an electric market model. The tool enabled IPC to model resource operations and determine operating costs for the entire 20-year planning horizon. The analysis was based on the application of economic principles and dispatch simulation to model the relationships between generation, transmission, and demand to forecast market prices. The operation of existing and future resources was based on forecasts of key fundamental elements, such as demand, fuel prices, hydroelectric conditions, and operating characteristics of new resources. The modeling simulated the regional electrical system to determine how utility generation and transmission resources operate to serve load. The analysis included multiple electricity markets, zones, and hubs. IPC modeled the entire Western Electricity Coordinating Council (WECC) system when evaluating the resource portfolios.

IPC's analysis also included detailed assessment of risk, both quantitative and qualitative. The analysis identified portfolios that performed well in a variety of possible future scenarios. The risk analysis identified six risk variables that were then included in IPC's modeling—carbon risk, natural gas price risk, capital cost risk, risk associated with demand side management variability, risk caused by load variability, and risk associated with renewable energy certificate price changes. The stochastic modeling was used to estimate the distribution of the incremental

[7] Order No. 07-002, p. 10.
[8] Order No. 07-002, p. 5 (defining "uncertainty" as a "measure of the quality of information about an event or outcome").

portfolio costs. Based on the modeling and analysis, IPC selected a preferred portfolio for each 10-year period.

The 2009 IRP's preferred portfolio for the first 10-year period included the Project as a supply-side resource. IPC's analysis demonstrated that the preferred portfolio represented the best combination of cost and risk for IPC and its ratepayers. The IRP also included IPC's action plan, which described the specific actions IPC intended to take to implement its preferred portfolio. That action plan included the construction of the Project.[9] Chapter 10 of the 2009 IRP described the modeling and risk analysis of each of the identified portfolios and identified the selection of the portfolio including the Project as the preferred portfolio.

The OPUC's analysis and public process on the 2009 IRP were both extensive and thorough. The IRP was the subject of discussion at two separate OPUC public meetings. In addition, there was a public hearing held in Ontario, Oregon. The hearing allowed members of the public to submit both oral and written comments for the OPUC's consideration. The OPUC's process also allowed parties that formally intervened in the docket to submit written comments on two separate occasions. Over 25 individuals and organizations submitted written comments that were considered by the OPUC in the IRP process.

In addition to public comment, the staff of the OPUC undertook a comprehensive and independent review of the 2009 IRP. As part of that process, the staff issued to IPC 69 data requests to which IPC responded with additional analysis and explanation. OPUC staff ultimately concluded that IPC's preferred portfolio, which included the Project, represented the "best combination of expected costs and associated risks and uncertainties for IPC and its customers."[10] OPUC staff concluded that IPC's analysis demonstrated the "robustness of the Preferred Portfolio." As OPUC staff noted, for the next best portfolio to break even with the preferred portfolio (meaning only that the two portfolios' cost assumptions become comparable), the Project's capital costs would have to increase by 40 percent and the subscription rates would have to decrease by 15 percent.[11] This demonstrated that not only was the preferred portfolio the most cost effective and lowest risk, the preferred portfolio also tolerated a great deal of uncertainty before the next best alternative became competitive.

On October 11, 2010, the OPUC issued Order No. 10-392, which acknowledged IPC's 2009 IRP. The OPUC concluded that it is "reasonable to proceed with [the Project] based on the information available now and acknowledge it as part of [IPC's] 2009 IRP."[12] Order No. 10-392 is included as Attachment N-6 to this Exhibit.

IPC's 2011 IRP

On June 30, 2011, IPC filed its 2011 IRP (Attachment N-2) with the OPUC. It was docketed as LC 53. IPC provided notice of the filing to all parties that had participated in IPC's previous IRP docket.

Like the 2009 IRP (Attachment N-1), IPC's 2011 IRP also included extensive public participation through the IRPAC process, which allowed for significant input into the portfolios included for analysis in the 2011 IRP. The IRPAC held nine monthly meetings, all of which were open to the public. In addition, IPC hosted a field trip covering wind, hydroelectric, and natural gas

[9] OPUC Order No. 10-392 (Attachment N-6), p. 5 (Oct. 11, 2010).
[10] *See* Final Comments and Recommendations, p. 6, and Appendix A, p. 1 (Comments); Order No. 07-002 at 5 ("The primary goal [of the IRP process] 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.").
[11] LC 50, Staff Proposed Order, p. 6.
[12] Order No. 10-392, p. 9.

resources and held two resource portfolio-design workshops. Several of the portfolios included in the 2011 IRP were developed during these workshops.

The 2011 IRP again utilized two 10-year planning periods to develop its resource portfolios. For the first 10-year period, 2011 to 2020, IPC developed and analyzed nine different portfolios. These portfolios included eight different types of supply-side resources—solar, single-cycle combustion turbine, combined-cycle combustion turbine, geothermal, pumped storage, distributed generation, combined heat and power, and the Project. For the second 10-year period, 2020 to 2030, IPC developed and analyzed 10 different resource portfolios.

IPC's analysis in the 2011 IRP was largely the same as that used in the 2009 IRP, although the 2011 IRP included significantly more resource portfolios. As a result, the analysis in the 2011 IRP was more robust, and compared the Project against a greater range of potential alternatives.

Based on the analysis and modeling in the 2011 IRP, IPC selected for the first 10-year period a preferred portfolio that included the Project. This selection was based on the expected low costs and the limited risk spread provided by this portfolio. Because the Project was included in the preferred portfolio, it was also included in the 2011 IRP's Action Plan, which is described in Chapter 10 of the 2011 IRP.

On September 20, 2011, IPC presented its IRP to the OPUC at a public meeting. Thereafter, the OPUC held a technical workshop for parties in the docket. Staff and intervenors filed initial comments on October 18, 2011, followed by several additional rounds of comments from IPC and other parties. Staff filed its report and proposed order on January 24, 2012, recommending acknowledgement of the Project. Staff noted its general agreement "regarding the benefits [the Project] brings," and the fact that the Project was "proposed and justified as the primary resource in a portfolio representing the best combination of cost and risk for Idaho Power and its ratepayers."[13]

At the OPUC's February 14, 2012 public meeting, the OPUC reviewed and acknowledged IPC's 2011 IRP. On May 21, 2012, the OPUC confirmed its acknowledgement of IPC's 2011 IRP in a written order (Order No. 12-177), including acknowledging the Project in the near-term action plan.[14] Order No. 12-177 is included as Attachment N-7 to this Exhibit.

IPC's 2013 IRP

On June 28, 2013, IPC filed its 2013 IRP with the OPUC (Attachment N-3), which was docketed as LC 58. IPC provided notice of the filing to all parties that had participated in IPC's previous IRP docket.

Like the 2009 and 2011 IRPs (Attachments N-1 and N-2), IPC's 2013 IRP included extensive public participation through the IRPAC. This process allowed for significant input into the portfolios included for analysis in the 2013 IRP. The IRPAC held 11 meetings, including a resource portfolio design workshop, and hosted a field trip covering the distribution and transmission system and natural gas power generation.

Prior to performing the portfolio analysis, IPC performed a resource alternatives analysis, which allowed a direct comparison of the major resource types considered in the 2013 IRP. This analysis informed the selection of resources to include and evaluate in the subsequent portfolio analysis.

[13] LC 53, Staff Proposed Order, pp. 9-10.
[14] Attachment N-7, Order No. 12-177, Appendix A, p. 2 (May 21, 2012).

The 2013 IRP utilized one 20-year planning period to develop its nine resource portfolios. These portfolios included eight different types of supply-side resources—solar, single-cycle combustion turbine, combined-cycle combustion turbine, geothermal, pumped storage, distributed generation, combined heat and power, and the Project.

Based on the analysis and modeling in the 2013 IRP, IPC selected the Project portfolio as the preferred portfolio. This selection recognized the expected low costs and the limited risk spread provided by this portfolio.

The OPUC's analysis and public process for the 2013 IRP was similarly extensive and thorough as that described for the 2009 and 2011 IRPs. On December 2, 2013, IPC presented its IRP to the OPUC at a public meeting. Staff and intervenors filed initial comments on January 15, 2014, followed by several additional rounds of comments from IPC and other parties. Staff filed its recommendations in its Staff Report dated March 7, 2014. In that Report, Staff recommended that the OPUC acknowledge the action item calling for "ongoing permitting, planning studies and regulatory filings" for the Project.[15] Staff stated that it did not recommend acknowledgement of the action item calling for the construction of Project because "it is beyond the two to four year timeframe for an IRP action plan."[16] At its March 17, 2014, public meeting, the OPUC reviewed and acknowledged portions of IPC's 2013 IRP. On July 8, 2014, the OPUC confirmed its acknowledgement in Order No. 14-253, included as Attachment N-8 to this Exhibit. Specifically regarding the Project, as recommended by Staff, the Commission acknowledged the near-term action plan items for ongoing permitting, planning studies, and regulatory filings for the Project.[17] Also as recommended by Staff, the Commission declined to acknowledge the completion of the Project as falling outside the appropriate time period for IRP action plans.[18] Importantly, the Commission's decision not to acknowledge the construction action item was based only on its policy of approving action items to be completed within the 2- to 4-year time period, and does not reflect any concerns regarding the merit of the IPC's plans to construct the resource.

IPC's 2015 IRP

On June 30, 2015, IPC filed its 2015 IRP with the OPUC (Attachment N-4), which docketed the filing as LC 63. IPC provided notice of the filing to all parties that had participated in IPC's previous IRP docket.

Like the 2009, 2011, and 2013 IRPs (Attachments N-1, N-2, and N-3), IPC's 2015 IRP included extensive public participation through the IRPAC. This process allowed for significant input into the portfolios included for analysis in the 2015 IRP. The IRPAC held 12 meetings, including a resource portfolio design workshop, and hosted a field trip covering the distribution and transmission system and hydroelectric power generation.

Prior to performing the portfolio analysis, IPC performed a resource alternatives analysis, which allowed a direct comparison of the major resource types considered in the 2015 IRP and informed the selection of resources to include and evaluate in the subsequent portfolio analysis.

The 2015 IRP utilized one 20-year planning period to develop its nine resource portfolios. These portfolios included eight different types of supply-side resources—solar, single-cycle combustion

[15] LC 58, Staff Report, p. 8.
[16] LC 58, Staff Report, p. 8.
[17] Attachment N-8, OPUC Order No. 14-253, p. 5 (July 8, 2014); *see also id.,* Appendix A.
[18] *Id.*

turbine, combined-cycle combustion turbine, geothermal, pumped storage, distributed generation, combined heat and power, ice-based thermal energy storage, and the Project.

Based on the analysis and modeling in the 2015 IRP, IPC selected its preferred portfolio, which included the Project. The preferred portfolio represented the portfolio of resources with the best combination of expected costs and associated risks and uncertainties.

The OPUC's analysis and public process for the 2015 IRP was as extensive and thorough as that described for the 2009, 2011, and 2013 IRPs. On April 28, 2016, the OPUC acknowledged IPC's 2015 IRP in Order No. 16-160, attached hereto as Attachment N-9.

IPC's 2017 IRP

On June 30, 2017, IPC filed its 2017 IRP with the OPUC (Attachment N-5), which docketed the filing as LC 68.

Like the 2009, 2011, 2013, and 2015 IRPs (Attachments N-1, N-2, N-3, and N-4), IPC's 2017 IRP included extensive public participation through the IRPAC. This process allowed for significant input into the portfolios included for analysis in the 2017 IRP. The IRPAC held eight meetings, including a workshop designed to explore the potential for distributed generation to defer grid investment.

Preparation of IPC's 2017 IRP began with the forecast of future customer demand. Existing generation resources, demand-side resources, and transmission import capacity were combined with forecasted customer demand to create a load and resource balance for energy and capacity over the 20-year planning period. IPC then evaluated expansion of energy efficiency programs to revise energy and capacity deficits. IPC designed the portfolio analysis for the 2017 IRP to inform the IRP's action plan with respect to two key resource actions: (1) selective catalytic reduction (SCR) investments required for Jim Bridger units 1 and 2 by 2022 and 2021, respectively; and (2) the Boardman to Hemingway Transmission Line Project.

Based on the analysis and modeling in the 2017 IRP, IPC selected its preferred portfolio, which represents the portfolio of resources with the best combination of expected costs and associated risks and uncertainties. In the 2017 IRP, the preferred portfolio continues to include the Project, showing the Project as a top-performing resource alternative, capable of providing low-cost energy and capacity, as well as increasingly critical flexibility. The 2017 IRP also shows the Project positions IPC and the region well because the Project facilitiates the delivery of cost-effective resources throughout the region. The Project also provides additional flexibility in support of the the evolution of advanced energy markets in the West.

On May 23, 2018, the OPUC acknowledged IPC's 2017 IRP (Attachment N-10).

3.3 Demonstration of Need under the System Reliability Rule

This section addresses the requirements of the system reliability rule, OAR 345-023-0030, and the relevant application content requirements of OAR 345-021-0010(n).

3.3.1 System Reliability Rule

OAR 345-023-0030: The Council shall find that the applicant has demonstrated need for an electric transmission line that is an energy facility under the definition in ORS 469.300 if the Council finds that: (1) The facility is needed to enable the transmission system of which it is to be a part to meet firm capacity demands for electricity or firm annual electricity sales that are reasonably expected to occur within five years of the facility's proposed in-service date based on weather conditions that have at least a 5 percent chance of occurrence in any year

in the area to be served by the facility; (2) The facility is consistent with the applicable mandatory and enforceable North American Electric Reliability Corporation (NERC) Reliability Standards in effect as of September 18, 2015 as they apply either internally or externally to a utility system; and (3) Construction and operation of the facility is an economically reasonable method of meeting the requirements of sections (1) and (2) compared to the alternatives evaluated in the application for a site certificate.

The system reliability rule requires a showing that the Project is: (1) needed to allow IPC to meet its projected firm capacity demands or firm annual sales; (2) consistent with applicable NERC reliability standards; and (3) an economically reasonable method of meeting these requirements as compared to other alternatives.

First, the Project is required to meet projected loads. Without additional supply-side resources or the inclusion of demand response programs, the 2017 IRP projects a resource deficiency (unmet peak-hour load) of up to 34 megawatts (MW) in 2026, 94 MW in 2027, 159 MW in 2028, 397 MW in 2029, and up to 986 MW by 2036. Moreover, additional transmission capacity is also needed to meet IPC's minimum operating criteria for reliability and to provide transmission service to wholesale customers.

Second, the Project is consistent with the applicable mandatory and enforceable NERC Reliability Standards in effect as of September 18, 2015.

Third, the Project is an economically reasonable approach to meeting IPC's projected firm capacity demands. As discussed in Section 3.2.2.3 above, the Project has been part of IPC's preferred portfolio in each of the last five IRPs, demonstrating that the Project is an economic alternative for meeting IPC's needs to serve its native load, satisfy minimum reliability standards, and provide service to wholesale transmission customers. Accordingly, the Project meets the requirements of the system reliability rule and the Council must find that IPC has demonstrated the need for the Project.

3.3.2 Application Content Requirements

3.3.2.1 Load-Resource Balance Tables

OAR 345-021-0010(1)(n)(F): If the applicant chooses to demonstrate need for a proposed electric transmission line under OAR 345-023-0030, the system reliability rule: (i) Load-resource balance tables for the area to be served by the proposed facility. In the tables, the applicant shall include firm capacity demands and existing and committed firm resources for each of the years from the date of submission of the application to at least five years after the expected in-service date of the facility.

The load-resource balance tables for the area to be served by the Project are included in IPC's 2017 IRP, Appendix C – Technical Report, at pages 19 through 59 (attached hereto as Attachment N-5). The monthly average energy load-resource balance values are reported on pages 19 through 38, and the monthly peak hour load-resource balance values are reported on pages 40 through 59. These tables include annual firm capacity demands and existing and committed firm resources for a 20-year period beginning in 2017.

3.3.2.2 Firm Capacity Demand and Firm Annual Electricity Sales Forecasts

OAR 345-021-0010(1)(n)(F)(ii): Within the tables described in subparagraph (i), a forecast of firm capacity demands for electricity and firm annual electricity sales for the area to be served by the proposed facility. The applicant shall separate firm capacity demands and firm

annual electricity sales into loads of retail customers, system losses, reserve margins and each wholesale contract for firm sale. . . .

The load-resource balance tables in IPC's 2017 IRP (Attachment N-5, Appendix C) are based on a forecast of firm capacity demands for electricity and firm annual electricity sales for the area to be served by the Project. As explained below, (1) the firm capacity demands for electricity or firm annual electricity sales are those reasonably expected to occur within 5 years of the facility's proposed in-service date based on weather conditions that have at least a 5 percent chance of occurrence in any year; and (2) IPC has separated firm capacity demands and firm annual electricity sales into loads of retail customers, system losses, reserve margins, and each wholesale contract for firm sales.

The sales and load forecast values are reported in IPC's 2017 IRP at Attachment N-5, Appendix C – Technical Report, pages 1 through 18. The expected-case (or 50th percentile) load forecast is shown on pages 2 through 10 of the Technical Report. The expected-case load forecast is based on median forecast data. The load forecast values for IPC's planning cases are shown on pages 12 through 18 of the Technical Report. The planning case load forecast is based on 70th percentile average energy and 95th percentile peak forecast data. IPC has separated firm capacity demands and firm annual electricity sales into loads of retail customers and system losses. Reserve or planning margins deserve special discussion. IPC does not explicitly include a planning margin in its IRP; instead, IPC uses 70th percentile planning criteria as discussed on page 124 of IPC's 2017 IRP:

> *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 2017 IRP, Idaho Power calculated the capacity planning margin resulting from the resource development identified in P7, the preferred resource portfolio. When calculating the planning margin, the total resources available to meet demand consist of the additional resources available under the preferred portfolio plus the generation from existing and committed resources, assuming expected-case (50th-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 (50th-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.*

IPC 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 IPC'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 IPC to import energy during an emergency via the Northwest Power Pool. A 330-MW reserve margin is also roughly equivalent to a Loss of Load Expectation (LOLE) of 1 day in 10 years, a standard industry measurement. Capacity planning margin calculations for July of each year through the planning period are shown in Table 9.11 of the 2017 IRP (Attachment N-5). The 95th percentile means that 95 percent of the time, the peak load is expected to be less than the peak load value used for planning, and five percent of the

time the peak load is expected to be greater than the peak load value used in the planning analysis. The 95th percentile peak load distribution is based on observations of the IPC peak load and the historical probability distribution of the peak load. The 95th percentile calculations for peak load mean that the peak load has approximately a 5 percent probability of occurrence.

IPC has calculated the capacity planning margin resulting from the resource planning process. The capacity planning margin calculations are for the month of July, the month of IPC's peak load. The capacity planning margin calculations are shown in Table 9.11 on pages 125 and 126 of IPC's 2017 IRP.

3.3.2.3 Reductions in Firm Capacity Demand and Firm Annual Electricity Sales

> OAR 345-021-0010(1)(n)(F)(ii): . . . In the forecast, the applicant shall include a discussion of how the forecast incorporates reductions in firm capacity demand and firm annual electricity sales resulting from: (I) Existing federal, state or local building codes, and equipment standards and conservation programs required by law for the area to be served by the proposed facility; (II) Conservation programs provided by the energy supplier, as defined in OAR 345-001-0010; (III) Conservation that results from responses to price; and (IV) Retail customer fuel choice;

The forecast incorporates reductions in firm capacity demand and firm annual electricity sales resulting from the factors set forth in OAR 345-021-0010(1)(n)(F)(ii)(I)-(IV).

First, IPC's forecast reflects "Existing federal, state or local building codes, and equipment standards and conservation programs required by law for the area to be served by the proposed facility," as discussed in OAR 345-021-0010(1)(n)(F)(ii)(I). IPC's forecasting process integrates conservation through the Statistically Adjusted End-use (SAE) methodology.[19] This approach incorporates the most recent codes and standards of the U.S. Department of Energy (DOE) National Energy Modeling System. The regionally based data are conformed to the IPC service territory data through incorporating building characteristics and equipment installation shares associated with the territory. The intensity of the conservation is developed through product efficiency and equipment shipment data into the region from manufacturers and suppliers.

In addition, large industrial and irrigation customer code-related conservation is typically tied to large process/operational investments that integrate IPC efficiency engineering as part of the process. The conservation reductions are recognized by virtue of integrating the results from the engineering measurement and validation process for codifying energy savings (both code-impacted and utility-incentivized installations) and are discussed in the following paragraphs responding to OAR 345-021-0010(1)(n)(F)(ii)(II).

Second, IPC's forecast reflects "Conservation programs provided by the energy supplier, as defined in OAR 345-001-0010," as discussed in OAR 345-021-0010(1)(n)(F)(ii)(II). Conservation programs provided by energy suppliers are integrated into the SAE conservation curve. To ensure IPC is capturing internal conservation program acquisition, individual utility energy reports of conservation acquisition to DOE for the region are compared to IPC acquisition to validate assumptions used in the regional model. IPC adjusts model output for deviations of IPC program savings from the DOE model.

[19] The SAE model is designed for developing long-term energy and demand forecasts and entails integrating end-use information into an econometric modeling framework. It is designed to explicitly capture the impact of end-use saturation and efficiency trends as well as economic conditions on long-term residential and commercial energy demand. SAE models can also be used for developing long-term peak demand forecasts.

Large industrial and irrigation customer conservation is modeled by utilizing survey data from individual customers and directly subtracting it from the forecast output. For aggregated sector forecasts, IPC analyzes historical conservation data for marginal impact (rate of change) and compares this to future conservation to establish trend reductions of forecast model output. Implied trends of improvement in industrial and irrigation equipment are integrated into the utility conservation forecasts applied to the total energy forecasts. As part of the internal forecasting methodology monitoring and evaluation process, IPC evaluates analytical methods for explicitly segregating code impacts that are presently captured in aggregated fashion for these sectors.

Third, IPC's forecast reflects "Conservation that results from responses to price" as discussed in OAR 345-021-0010(1)(n)(F)(ii)(III). Price impacts on energy sales are captured in the regression models for each sector as an independent variable. IPC utilizes the most recent IRP preferred-portfolio rate impact in developing the price variable.

Fourth, IPC's forecast reflects "Retail customer fuel choice" as discussed in OAR 345-021-0010(1)(n)(F)(ii)(IV). For SAE-based models, fuel switching is integrated via the consumption and equipment stock manufacturer shipments data from DOE. For example, these data capture usage of electric versus gas space heating appliances and fuel price differentials to capture the impacts of fuel choice dynamics on the forecast.

3.3.3 Firm Resources to be Used to Meet Demands

OAR 345-021-0010(1)(n)(F)(iii): Within the tables described in subparagraph (i), a forecast of existing and committed firm resources used to meet the demands described in subparagraph (ii). The applicant shall include, as existing and committed firm resources, existing generation and transmission facilities, firm contract resources and committed new resources minus expected resource retirements or displacement. In the forecast, the applicant shall list each resource separately.

As discussed in Section 3.3.1, the load-resource balance tables for the area to be served by the Project are included in IPC's 2017 IRP, Appendix C – Technical Report, at pages 19 through 59 (Attachment N-5). The monthly sales and load forecast data are reported on pages 1 through 18. The load-resource balance tables provide a forecast of IPC's existing and committed firm resources used to meet its forecast demands. IPC has included its existing generation and transmission facilities, firm contract resources and committed new resources minus expected resource retirements or displacement. IPC has listed each resource separately.

3.3.4 Retirement or Displacement of Resources

OAR 345-021-0010(1)(n)(F)(iv): A discussion of the reasons each resource is being retired or displaced if the forecast described in subparagraph (iii) includes expected retirements or displacements.

A baseline assumption included in the load-resource tables in IPC's 2017 IRP (Attachment N-5, Appendix C) is the retirement of the Boardman coal plant and the Valmy coal plant. IPC is a 10 percent owner of the Boardman coal plant, which typically provides IPC with 55 average megawatts (aMW)[20] of generation per year. This facility is expected to cease coal-fired operations in 2020 in compliance with an Oregon Environmental Quality Commission plan approved in December 2010. IPC is a 50 percent owner of the North Valmy coal plant, which

[20] An "average megawatt" or "aMW" is defined as one megawatt of capacity produced continuously over a period of one year. 1 aMW = 1 MW x 8760 hours/year = 8,760 MWh = 8,760,000 kilowatt-hour (kWh).

typically provides IPC with 262 aMW of generation per year. North Valmy Units 1 and 2 are expected to be retired in 2019 and 2025, respectively.

The preferred portfolio assumes the retirement of Jim Bridger Unit 2 in 2028 and Unit 1 in 2032.

While the North Valmy and Jim Bridger retirement dates are planning targets and subject to planning considerations with plant co-owners and/or negotiations with regulatory agencies, it could be assumed that over the next 15 years IPC could retire over 700 MW of coal-fired generating capacity.

3.3.5 Assumed Annual Capacity Factors

OAR 345-021-0010(1)(n)(F)(v): A discussion of the annual capacity factors assumed for any generating facilities listed in the forecast described in subparagraph (iii).

The assumed annual capacity factors for IPC generation resources by resource type are set forth in the tables in Attachment N-11. The annual capacity factor calculations are based on the average annual forecasted MW for hydro, coal, and gas facilities in IPC's 2017 IRP (see Attachment N-4, Appendix C – Technical Report, Monthly Average Energy Load and Resource Balance, pages 19 through 38, and Hydro Modeling Results [PDR580], pages 118 through 147). For informational purposes, the capacity factors of IPC's hydroelectric resources are presented under 50th percentile, 70th percentile, and 90th percentile water assumptions. IPC's 2017 IRP assumes a 70th percentile water condition for energy-based resource adequacy assessments, and 90th percentile water condition for peak-hour resource adequacy assessments.

3.3.6 Reliability Criteria Demonstrating Need for the Project

OAR 345-021-0010(1)(n)(F)(vi): A discussion of the reliability criteria the applicant uses to demonstrate the proposed facility is needed, considering the load carrying capability of existing transmission system facilities supporting the area to be served by the proposed facility.

NERC and WECC reliability criteria require IPC to: (a) reliably serve customer demand; (b) operate the system within facility limits; (c) maintain voltage through reactive power control; and (d) maintain contingency reserves—i.e., operate the system such that the most severe single contingency does not result in loss of load or instability. The following discussion shows that the Project is needed to satisfy these criteria.

NERC Transmission Planning (TPL) standards provide the criteria for reliably serving future load and system performance under normal and outage conditions. These standards require that system facilities operate within NERC accepted operating limits for a wide range of system conditions, including loss of generator units and transmission facilities. The Project has been evaluated annually as part of NERC TPL compliance requirements. With the Project modeled in-service, IPC has demonstrated through assessments that IPC can meet NERC TPL criteria for the planning horizon.

As part of the WECC Project Coordination, Path Rating and Progress Report Process, IPC organized a regional project review group composed of western utility representatives to study the addition of the Project to the western grid. Through the WECC Rating Process, the Project was determined to meet regional performance criteria.[21]

[21] See WECC Memorandum re: Hemingway-Boardman 500 kV Transmission Project Achieves Phase 3 Status (Nov. 27, 2012).

NERC Transmission Operations Standards require that transmission schedules across WECC transmission paths do not exceed system operating limits. Currently, IPC's intertie lines are constrained with little or no available transmission capacity (ATC). In the past, IPC has needed to utilize nearly 100 percent of ATC to purchase resources from the Northwest in order to serve load while maintaining necessary contingency reserves and capacity margins. Because IPC maintains contingency reserves on the Idaho–Northwest intertie transmission lines, without ATC, serving load with transmission reserves could put IPC's native load at risk if the most severe single contingency were to occur. The Project will increase IPC's transmission import capability and will allow IPC to maintain a margin between actual flow and facility limits.

Heavily loaded transmission lines consume large amounts of reactive power. In order to prevent voltage collapse and regional blackouts, IPC maintains reactive power margin at critical locations on the IPC system. Certain outages on the IPC system have historically driven reactive margins near the margin limits. The Project's transmission connectivity to the Northwest will reduce previously heavily loaded transmission lines and greatly increase the reactive margin across the IPC system, making it even more unlikely that a system event could lead to voltage collapse.

IPC utilizes reactive power/voltage stability adequacy criteria contained in WECC Standard *TPL-001-WECC-RBP-2 – System Performance Criterion Under Normal Conditions, Following Loss of a Single BES Element, and Following Extreme BES Events*. IPC has demonstrated through its Ten-Year Transmission Reliability Assessments that the future transmission system, with the addition of Project, provides sufficient reactive power resources to ensure system performance as defined in TPL-001-WECC-RB2.

IPC's 2017 IRP analysis demonstrates that the resource adequacy and reliability margins requirements will be met with the Project. LOLE analysis is conducted as part of the IRP (refer to pages 124-132 in Attachment N-5). IPC used a spreadsheet model to calculate the LOLE for the resource portfolios identified in the 2017 IRP. The analysis in IPC's 2017 IRP concludes that the Project provides the requisite LOLE performance and thus sufficient resource adequacy for IPC's projected customer demands.

3.3.7 The Project is an Economically Reasonable Alternative

OAR 345-021-0010(1)(n)(F)(vii): A discussion of reasons why the proposed facility is economically reasonable compared to the alternatives described below. In the discussion, the applicant shall include a table showing the amounts of firm capacity and firm annual electricity available from the proposed facility and each alternative and the estimated direct cost, as defined in OAR 345-001-0010, of the proposed facility and each alternative. The applicant shall include documentation of assumptions and calculations supporting the table. . . .

The preferred portfolio in the 2009, 2011, 2013, 2015, and 2017 IRPs (Attachments N-1, N-2, N-3, N-4, and N-5), which includes the Project, represents the portfolio of resources with the best combination of expected costs and associated risks and uncertainties to meet IPC's growing load and to maintain its system in a safe, reliable, and economic manner. The Project portfolio was selected on the basis of, among other things, extensive cost analysis, considering the discounted sum of all monetary costs as described in OAR 345-001-0010(16) (providing the definition of "direct cost").

Chapter 8 of the 2017 IRP describes the 12 portfolios considered (see Attachment N-5). The total cost for each portfolio is shown in Chapter 9 and Table 9.3 on page 111 of the 2017 IRP. Financial assumptions for the 2017 IRP portfolio cost analysis are provided in table form in IPC's 2017 IRP, Attachment N-5, Appendix C – Technical Report. An overview of the IRP

methodology for evaluating resource portfolios is provided in Chapter 1 of this document. The results of the expected-case portfolio analysis are presented in Table N-1 below.

Table N-1. Expected-Case Total Portfolio Cost (2015-2034)

Portfolio				Variable Costs	Fixed Costs	Summary	
Portfolio Index	Portfolio Description	B2H	Bridger Capacity Retirement	Operating (AURORA)	Total Fixed Costs	Total Fixed + Variable Costs	Lowest Cost Rank
P1	SCR invest, B2H, recips	✓		$5,782,181	$91,266	$6,400,696	4
P2	SCR invest, DR, recips, solar			$5,670,820	$299,436	$6,497,505	6
P3	SCR invest, DR, recips, CCCT			$5,731,938	$271,669	$6,530,856	9
P4	Bridger retire in 24 & 28, B2H, recips	✓	✓	$5,796,035	$207,739	$6,338,683	2
P5	Bridger retire in 24 & 28, DR, recips, solar		✓	$5,577,721	$653,937	$6,566,567	10
P6	Bridger retire in 24 & 28, DR, recips, CCCT		✓	$5,729,526	$443,808	$6,508,242	8
P7	Bridger retire in 28 & 32, B2H, recips, CCCT	✓	✓	$5,755,589	$214,229	$6,335,771	1
P8	Bridger retire in 28 & 32, DR, recips, solar, CCCT		✓	$5,654,210	$483,362	$6,503,524	7
P9	Bridger retire in 28 & 32, DR, recips, CCCT		✓	$5,701,053	$415,995	$6,483,000	5
P10	Bridger retire in 21 & 22, B2H, recips	✓	✓	$5,807,951	$309,227	$6,400,507	3
P11	Bridger retire in 21 & 22, DR, recips, solar		✓	$5,529,258	$767,183	$6,579,769	11
P12	Bridger retire in 21 & 22, DR, recips, CCCT		✓	$5,689,172	$699,009	$6,671,510	12

Source: IPC 2017 IRP (Attachment N-5, Table 9.3)
B2H – Boardman to Hemingway Transmission Line Project; CCCT – combined-cycle combustion turbine; DR – demand response; recips – reciprocating engines; SCR – selective catalytic reduction.

3.3.8 Required Alternatives Evaluated

OAR 345-021-0010(1)(n)(F)(vii): . . . The applicant shall evaluate alternatives to construction and operation of the proposed facility that include, but are not limited to: (I) Implementation of cost-effective conservation, peak load management and voluntary customer interruption as a substitute for the proposed facility. (II) Construction and operation of electric generating facilities as a substitute for the proposed facility. (III) Direct use of natural gas, solar or geothermal resources at retail loads as a substitute for use of electricity transmitted by the proposed facility. (IV) Adding standard sized smaller or larger transmission line capacity.

First, IPC's economic analysis of alternatives included evaluation of "Implementation of cost-effective conservation, peak load management and voluntary customer interruption as a substitute for the proposed facility," as required by OAR 345-021-0010(1)(n)(F)(vii)(I). In the IRP process, IPC has committed to implementing all cost-effective, demand-side management measures prior to considering supply-side alternatives, including the Project. Further description of the analyses and assumptions associated with demand-side measures is included in

Attachment N-4, Chapter 4 of the 2017 IRP and Attachment N-5, Appendix B – Demand-Side Management Annual Report.

Second, IPC evaluated "Construction and operation of electric generating facilities as a substitute for the proposed facility," as required by OAR 345-021-0010(1)(n)(F)(vii)(II). The portfolios considered in the 2017 IRP include a variety of generation resources. Based on the IRP analysis, portfolios containing these resources and no Project were expected to result in higher total costs (as defined by OAR 345-001-0010(16)) than the portfolios that included the Project, including the preferred portfolio (see Attachment N-5, Table 9.3).

Third, IPC evaluated "Direct use of natural gas, solar or geothermal resources at retail loads as a substitute for use of electricity transmitted by the proposed facility," as required by OAR 345-021-0010(1)(n)(F)(vii)(III). Natural gas and solar resources were included in multiple alternative portfolios considered for the 2017 IRP. The IRP cost analysis indicated that the costs associated with alternative portfolios that included natural gas or solar resources and no Project were expected to be greater than the portfolios that included the Project, including the preferred portfolio (see Attachment N-5, Table 9.3).

Fourth, IPC evaluated "Adding standard sized smaller or larger transmission line capacity," as required by OAR 345-021-0010(1)(n)(F)(vii)(IV). A number of factors impact the transfer capability of transmission lines, including distance, technical design, source/sink capabilities, relative location in the bulk electric system, etc. IPC's analysis assumed a 300-mile line between Longhorn Station, near Boardman, Oregon, and the Hemingway station in southwestern Idaho. Table N-2a contains a summary of relative capacities, anticipated ratings, and losses for new transmission lines at different operating voltages. Table N-2b summarizes the potential capacities of a new line built in place of an existing transmission line ("rebuild") for a portion of the total line length and new line built in a new right-of-way for the remaining portion of the total line length. Every rebuild scenario in Table N-2b requires at least 136 miles of new construction in a new right-of-way. Tables N-2a and N-2b indicate that the only scenarios capable of providing 1,050 MW of west-to-east capacity are new lines at an operating voltage of 500-kilovolt (kV) or greater.

Table N-2a. Comparison of Transmission Line Capacity Scenarios – New Lines from Longhorn to Hemingway

Scenario	Line Capacity[1]	Potential Path 14 W-E Increase[2]	Losses on New Circuit(s)[3]
a. Longhorn to Hemingway 230-kV single circuit	956 MW	525 MW	10.8%
b. Longhorn to Hemingway 230-kV double circuit	1,912 MW	915 MW	9.5%
c. Longhorn to Hemingway 345-kV single circuit	1,434 MW	730 MW	6.6%
d. Longhorn to Hemingway 500-kV single circuit	3,214 MW	1,050 MW	4.2%
e. Longhorn to Hemingway 500-kV – two separate lines	6,428 MW	2,215 MW	3.7%
f. Longhorn to Hemingway 500-kV double circuit	6,428 MW	1,235 MW	2.9%

Scenario	Line Capacity[1]	Potential Path 14 W-E Increase[2]	Losses on New Circuit(s)[3]
g. Longhorn to Hemingway 765-kV single circuit	4,770 MW	1,200 MW	2.4%

[1] Line Capacity is the thermal rating of the assumed conductors and does not account for system limitations of voltage, stability, or reliability requirements.

[2] Potential Rating is based upon study results to date to meet reliability design requirements for the WECC ratings processes, not including simultaneous interaction studies.

[3] Estimated Losses are percent losses for the new line at the Potential Rating loading level. Annual energy losses are dependent on total system loss reductions. All of the scenarios would likely yield a total system loss reduction for the flow levels above.

Table N-2b. Comparison of Transmission Line Capacity Scenarios – Rebuild Existing Lines to the Northwest

Scenario	Line Capacity[1]	Potential Path 14 Increase[2]	Losses on New Circuit(s)[3]	Length of Line / New ROW[4]
a. Replace Oxbow - Lolo 230 kV with Hatwai - Hemingway 500 kV	3,214 MW	430 MW W-E 675 MW E-W	3.8%	255 Miles / 136 Miles
b. Replace Oxbow - Lolo 230kV with Hatwai - Hemingway 500 kV - No double circuiting with existing lines	3,214 MW	710 MW W-E 745 MW E-W	4.1%	255 Miles / 167 Miles
c. Replace Walla Walla to Brownlee 230 kV with Sacajawea Tap- Hemingway 500kV	3,214 MW	400 MW W-E 675 MW E-W	3.5%	288 Miles / 150 Miles
d. Replace Walla Walla to Pallette 230 kV with Sacajawea Tap - Hemingway 500 kV - No double circuiting with existing lines	3,214 MW	720 MW W-E 730 MW E-W	3.8%	288 Miles / 181 Miles
e. Build double circuit 500 kV/230 kV line from McNary to Quartz. Build 500 kV from Quartz to Hemingway	3,214 MW	765 MW W-E 870 MW E-W	3.9%	298 Miles / 168 Miles

[1] Line Capacity is the thermal rating of the assumed conductors and does not account for system limitations of voltage, stability, or reliability requirements.

[2] Potential Rating is based upon study results to date to meet reliability design requirements for the WECC ratings processes, not including simultaneous interaction studies.

[3] Estimated Losses are percent losses for the new line at the Potential Rating W-E loading level. Annual energy losses are dependent on total system loss reductions. All of the scenarios would likely yield a total system loss reduction for the flow levels above.

[4] In addition to utilizing the existing 230-kV right-of-way, each of the scenarios above will require a new ROW to be obtained.

3.3.9 Earliest and Latest Expected In-Service Dates

OAR 345-021-0010(1)(n)(F)(viii): The earliest and latest expected in-service dates of the facility and a discussion of the circumstances of the energy supplier, as defined in OAR 345-001-0010, that determine these dates.

As discussed in IPC's 2017 IRP (Attachment N-5), current estimates based on IPC's updated assessment of siting, permitting, regulatory approvals, in-service date requirements of the parties electing to construct the line, the terms of any resulting joint construction agreements, and other conditions and factors conclude the Project is not expected to be in-service any earlier than 2024.

4.0 CONCLUSION

Exhibit N includes the application information provided for in OAR 345-021-0010(1)(n) and provides the evidence necessary to show the need for the Project under both the least-cost plan rule (OAR 345-023-0020) and the system reliability rule for transmission lines (OAR 345-023-0030).

5.0 COMPLIANCE CROSS-REFERENCES

Table N-3 identifies the location within the application for site certificate of the information responsive to the need standard for non-generating facilities, OAR 345-0023-0005, the application submittal requirements in OAR 345-021-0000(8) and OAR 345-021-0010(n), and the relevant Second Amended Project Order provisions.

Table N-3. Compliance Requirements and Relevant Cross-References

Requirement	Location
OAR 345-023-0005	
This division applies to nongenerating facilities as defined in ORS 469.503(2)(e), except nongenerating facilities that are related or supporting facilities. To issue a site certificate for a facility described in sections (1) through (3), the Council must find that the applicant has demonstrated the need for the facility. The Council may adopt need standards for other nongenerating facilities. This division describes the methods the applicant shall use to demonstrate need. In accordance with ORS 469.501(1)(L), the Council has no standard requiring a showing of need or cost-effectiveness for generating facilities. The applicant shall demonstrate need: (1) For electric transmission lines under the least-cost plan rule, OAR 345-023-0020(1), or the system reliability rule for transmission lines, OAR 345-023-0030, or by demonstrating that the transmission line is proposed to be located within a "National Interest Electric Transmission Corridor" designated by the U.S. Department of Energy under Section 216 of the Federal Power Act;	Exhibit N, Section 3.2 and Section 3.3
OAR 345-023-0020(1)	
(1) The Council shall find that the applicant has demonstrated need for the facility if the capacity of the proposed facility or a facility substantially similar to the proposed facility, as defined by OAR 345-001-0010, is identified for acquisition in the short-term plan of action of an energy resource plan or combination of plans . . . . (2) The Council shall find that a least-cost plan meets the criteria of an energy resource plan described in section (1) if the Public Utility Commission of Oregon has acknowledged the least cost plan.	Exhibit N, Section 3.2 Attachment N-1, Attachment N-2, Attachment N-3, Attachment N-4, Attachment N-5

Requirement	Location
OAR 345-023-0030	
The Council shall find that the applicant has demonstrated need for an electric transmission line that is an energy facility under the definition in ORS 469.300 if the Council finds that: (1) The facility is needed to enable the transmission system of which it is to be a part to meet firm capacity demands for electricity or firm annual electricity sales that are reasonably expected to occur within five years of the facility's proposed in-service date based on weather conditions that have at least a 5 percent chance of occurrence in any year in the area to be served by the facility; (2) The facility is consistent with the applicable mandatory and enforceable North American Reliability Corporation (NERC) Reliability Standards in effect as of September 18, 2015 as they apply either internally or externally to a utility system; and (3) Construction and operation of the facility is an economically reasonable method of meeting the requirements of sections (1) and (2) compared to the alternatives evaluated in the application for a site certificate.	Exhibit N, Section 3.3
OAR 345-021-0000(8)	
If the proposed facility is a non-generating facility for which the applicant must demonstrate need under OAR 345-023-0005, in addition to the application for a site certificate described in OAR 345-021-0010, the applicant shall submit to the Department three copies of each energy resource plan or combination of plans on which the applicant relies to demonstrate need under 345-023-0020, unless the applicant chooses to incorporate copies of the plan(s) as part of the application for a site certificate. The applicant shall submit the plan(s) to the Department with the site certificate application. The Department may not find the site certificate application to be complete before receiving copies of the plan(s). The plan or plans described in this section are part of the decision record for the Department's proposed order, described in 345-015-0230.	Exhibit N, Section 3.2, Attachment N-1, Attachment N-2, Attachment N-3, Attachment N-4, Attachment N-5
OAR 345-021-0010(1)(n)	
Exhibit N. If the proposed facility is a non-generating facility for which the applicant must demonstrate need under OAR 345-023-0005, information about the need for the facility, providing evidence to support a finding by the Council as required by OAR 345-023-0005, including:	
(A) Identification of the rule in Division 23 of this chapter under which the applicant chooses to demonstrate need;	Exhibit N, Section 3.1
(B) If the applicant chooses to demonstrate need for the proposed facility under OAR 345-023-0020(1), the least-cost plan rule:	Exhibit N, Section 3.2.1
(i) Identification of the energy resource plan or combination of plans on which the applicant relies to demonstrate need;	Exhibit N, Section 3.2.2.1, Attachment N-1, Attachment N-2, Attachment N-3, Attachment N-4, Attachment N-5

Requirement	Location
(ii) The name, address and telephone number of the person responsible for preparing each energy resource plan identified in subparagraph (i);	Exhibit N, Section 3.2.2.2
(iii) For each plan reviewed by a regulatory agency, the agency's findings and final decision, including:	Exhibit N, Section 3.2.2.3
(I) For a plan reviewed by the Oregon Public Utility Commission, the acknowledgment order; or	Exhibit N, Section 3.2.2.3
(II) For a plan reviewed by any other regulatory agency, a summary of the public process including evidence to support a finding by the Council that the agency's decision process included a full, fair and open public participation and comment process as required by OAR 345-023-0020(1)(L), and the location of and means by which the Department can obtain a complete copy of the public record;	Not Applicable
(iv) Identification of the section(s) of the short-term action plan(s) that call(s) for the acquisition of the proposed facility or, as defined in OAR 345-001-0010, a facility substantially similar to the proposed facility; and	Exhibit N, Section 3.2.2.3
(v) The attributes of the proposed facility that qualify it as one called for in the short-term action plan of the energy resource plan or combination of plans identified in subparagraph (i) or a demonstration that, as defined in OAR 345-001-0010, a facility substantially similar to the proposed facility is called for in the plan(s);	Exhibit N, Section 3.2.2.3
(C) In addition to the information described in paragraph (B), if the applicant chooses to demonstrate need for the proposed facility under OAR 345-023-0020(1), the least-cost plan rule, and relies on an energy resource plan not acknowledged by the Public Utility Commission of Oregon	Not Applicable
(D) In addition to the information described in paragraphs (B) and (C), if the applicant chooses to demonstrate need for a proposed natural gas pipeline or storage facility for liquefied natural gas under OAR 345-023-0020(1), the least-cost plan rule, and relies on an energy resource plan not acknowledged by the Public Utility Commission of Oregon, the applicant shall include the information described in paragraph (G) of this subsection if the energy resource plan or combination of plans does not contain that information. If the energy resource plan or combination of plans contains the information described in paragraph (G), the applicant shall provide a list of citations to the sections of the energy resource plan(s) that contain the information;	Not Applicable

Requirement	Location
(E) In addition to the information described in paragraphs (B) and (C), if the applicant chooses to demonstrate need for a proposed electric transmission line under OAR 345-023-0020(1), the least-cost plan rule and relies on an energy resource plan not acknowledged by the Public Utility Commission of Oregon, the applicant shall include the information described in paragraph (F) of this subsection if the energy resource plan or combination of plans does not contain that information. If the energy resource plan or combination of plans contains the information described in paragraph (F), the applicant shall provide a list of citations to the sections of the energy resource plan(s) that contain the information;	Not Applicable
(F) If the applicant chooses to demonstrate need for a proposed electric transmission line under OAR 345-023-0030, the system reliability rule:	Exhibit N, Section 3.3
(i) Load-resource balance tables for the area to be served by the proposed facility. In the tables, the applicant shall include firm capacity demands and existing and committed firm resources for each of the years from the date of submission of the application to at least five years after the expected in-service date of the facility.	Exhibit N, Section 3.3.2.1 and Attachment N-4
(ii) Within the tables described in subparagraph (i), a forecast of firm capacity demands for electricity and firm annual electricity sales for the area to be served by the proposed facility. The applicant shall separate firm capacity demands and firm annual electricity sales into loads of retail customers, system losses, reserve margins and each wholesale contract for firm sale. In the forecast, the applicant shall include a discussion of how the forecast incorporates reductions in firm capacity demand and firm annual electricity sales resulting from:	Exhibit N, Section 3.3.2.2 and Attachment N-5
(I) Existing federal, state or local building codes, and equipment standards and conservation programs required by law for the area to be served by the proposed facility;	Exhibit N, Section 3.3.2.3
(II) Conservation programs provided by the energy supplier, as defined in OAR 345-001-0010;	Exhibit N, Section 3.3.2.3
(III) Conservation that results from responses to price; and	Exhibit N, Section 3.3.2.3
(IV) Retail customer fuel choice;	Exhibit N, Section 3.3.2.3
(iii) Within the tables described in subparagraph (i), a forecast of existing and committed firm resources used to meet the demands described in subparagraph (ii). The applicant shall include, as existing and committed firm resources, existing generation and transmission facilities, firm contract resources and committed new resources minus expected resource retirements or displacement. In the forecast, the applicant shall list each resource separately;	Exhibit N, Section 3.3.3 and Attachment N-5
(iv) A discussion of the reasons each resource is being retired or displaced if the forecast described in subparagraph (iii) includes expected retirements or displacements;	Exhibit N, Section 3.3.4
(v) A discussion of the annual capacity factors assumed for any generating facilities listed in the forecast described in subparagraph (iii);	Exhibit N, Section 3.3.5 and Attachment N-11

Requirement	Location
(vi) A discussion of the reliability criteria the applicant uses to demonstrate the proposed facility is needed, considering the load carrying capability of existing transmission system facilities supporting the area to be served by the proposed facility; and	Exhibit N, Section 3.3.6, Attachment N-1, and Attachment N-2
(vii) A discussion of reasons why the proposed facility is economically reasonable compared to the alternatives described below. In the discussion, the applicant shall include a table showing the amounts of firm capacity and firm annual electricity available from the proposed facility and each alternative and the estimated direct cost, as defined in OAR 345-001-0010, of the proposed facility and each alternative. The applicant shall include documentation of assumptions and calculations supporting the table. The applicant shall evaluate alternatives to construction and operation of the proposed facility that include, but are not limited to:	Exhibit N, Section 3.3.7 and Table N-1
(I) Implementation of cost-effective conservation, peak load management and voluntary customer interruption as a substitute for the proposed facility;	Exhibit N, Section 3.3.8
(II) Construction and operation of electric generating facilities as a substitute for the proposed facility;	Exhibit N, Section 3.3.8
(III) Direct use of natural gas, solar or geothermal resources at retail loads as a substitute for use of electricity transmitted by the proposed facility; and	Exhibit N, Section 3.3.8
(IV) Adding standard sized smaller or larger transmission line capacity;	Exhibit N, Section 3.3.8, Table N-2
(viii) The earliest and latest expected in-service dates of the facility and a discussion of the circumstances of the energy supplier, as defined in OAR 345-001-0010, that determine these dates; and	Exhibit N, Section 3.3.9
(G) If the applicant chooses to demonstrate need for a proposed natural gas pipeline or a proposed facility for storing liquefied natural gas under OAR 345-023-0040, the economically reasonable rule: . . .	Not Applicable
Second Amended Project Order, Section III(n)	
The Council requires applicants to demonstrate public need for an electric transmission line facility under the least-cost plan rule (OAR 345-023-0020), the system reliability rule for transmission lines (OAR 345-023-0030), or by demonstrating that the transmission line is proposed to be within a "National Interest Electric Transmission Corridor" designated by the US Department of Energy under Section 216 of the Federal Power Act. The applicant may provide evidence demonstrating the need for the facility under one or more of the methods described in Division 23. Note that on October 20, 2015, OAR 345-023-0030 was updated to reflect the North American Electric Reliability Corporation (NERC) Reliability Standards.	Exhibit N, Section 3.2 and Section 3.3

Requirement	Location
The Least-Cost Plan Rule (OAR 345-023-0020) can be satisified if the Oregon Public Utility Commission (PUC) acknowledges an energy resource plan/least-cost plan which identifies for acquisition in the short-term plan of action the proposed facility or a facility substantially similar to the proposed facility. On April 10, 2018 the Oregon PUC held a regular public meeting regarding Idaho Power's 2017 Integrated Resource Plan. Based on PUC staff recommendations, the PUC acknowledged conducting ongoing permitting, planning studies, and regulatory filings for the B2H transmission line and to conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.The Council requires applicants to demonstrate public need for an electric transmission line facility under the least-cost plan rule (OAR 345-023-0020), the system reliability rule for transmission lines (OAR 345-023-0030), or by demonstrating that the transmission line is proposed to be within a “National Interest Electric Transmission Corridor” designated by the US Department of Energy under Section 216 of the Federal Power Act. The applicant may provide evidence demonstrating the need for the facility under one or more of the methods described in Division 23.	Exhibit N, Section 3.2 and Section 3.3

ATTACHMENT N-1
IDAHO POWER COMPANY'S 2009 INTEGRATED RESOURCE PLAN (DOCKET LC 50)



2009 Integrated Resource Plan

December 2009

IDAHO POWER®
An IDACORP Company

2009 Integrated Resource Plan

December 2009



IDAHO POWER®

An IDACORP Company

Acknowledgement

Resource planning is a continuous process that Idaho Power Company constantly works to improve. Idaho Power prepares and publishes a resource plan every two years and expects the experience gained over the next few years will lead to modifications in the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the *2009 Integrated Resource Plan* (IRP). Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council, and the comments provided by other concerned citizens and customers.

In recognition of the amount of time and effort expended by the IRP Advisory Council, members discussed the possibility of including a statement in the IRP indicating the advisory council's support of the IRP. Because the advisory council represents such a diverse set of stakeholders, the members determined it would not be possible for the group to unanimously support all aspects of the IRP. However, the members were supportive of the public process and asked Idaho Power to include the following statement in the 2009 IRP: "The members of the IRP Advisory Council support the public process Idaho Power Company conducted as part of preparing the 2009 IRP."

Idaho Power looks forward to continuing the resource planning process with its customers and other interested parties. You can learn more about Idaho Power's resource planning process at www.idahopower.com.

Safe Harbor Statement

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

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Appendix C–Technical Appendix

GLOSSARY OF ABBREVIATIONS

AC–Alternating Current

A/C–Air Conditioning

ADI–Ace Diversity Interchange

AFUDC–Allowance for Funds Used During Construction

AMPS–Associated Mountain Power System

aMW–Average Megawatt

B2H–Boardman to Hemingway Transmission Project

BLM–Bureau of Land Management

BOR–Bureau of Reclamation

BPA–Bonneville Power Administration

Btu–British Thermal Unit

CAMP–Comprehensive Aquifer Management Plan

CAP–Community Advisory Process

CBM–Capacity Benefit Margin

CCCT–Combined-Cycle Combustion Turbine

CHP–Combined Heat and Power

Clatskanie PUD–Clatskanie People's Utility District

CO_2–Carbon Dioxide

CPCN–Certificate of Public Convenience and Necessity

CREP–Conservation Reserve Enhancement Program

DC–Direct Current

DOE–Department of Energy

DG–Distributed Generation

DRAM–Dynamic Random Access Memory

DSM–Demand-Side Management

EA–Environmental Assessment

EEAG–Energy Efficiency Advisory Group

EIA–Energy Information Administration

EPRI–Electric Power Research Institute

ESA–Endangered Species Act

ESPA–Eastern Snake River Plain Aquifer

F–Fahrenheit

FCA–Fixed-Cost Adjustment

FCP–Formal Consultation Package

FCRPS–Federal Columbia River Power System

FERC–Federal Energy Regulatory Commission

FPA–Federal Power Act

GHG–Greenhouse Gas

GW–Gigawatt

HRSG–Heat Recovery Steam Generator

ICIP–Industrial Customers of Idaho Power

IDWR–Idaho Department of Water Resources

IGCC–Integrated Gasification Combined Cycle

INL–Idaho National Laboratory

IOER–Idaho Office of Energy Resources

IPUC–Idaho Public Utilities Commission

IRP–Integrated Resource Plan

IRPAC–IRP Advisory Council

kV–Kilovolt

kW–Kilowatt

kWh–Kilowatt Hour

lbs–Pounds

LED–Light-Emitting Diode

LOLE–Loss of Load Expectation

LT–Long Term

MIT–Massachusetts Institute of Technology

mm–Millimeter

MMBTU–Million British Thermal Units

MSA– Metropolitan Statistical Area

MW–Megawatt

MWh–Megawatt Hour

NEEA–Northwest Energy Efficiency Alliance

NEO–Northeast Oregon

NEPA–National Environmental Policy Act

NiCd–Nickel Cadmium

NTTG–Northern Tier Transmission Group

NPCC–Northwest Power and Conservation Council

NOx–Nitrogen Oxide

NOI–Notice of Intent

NPV–Net Profit Value

NREL–National Renewable Energy Laboratories

NYMEX–New York Mercantile Exchange

O&M–Operating and Maintenance

OATT–Open Access Transmission Tariff

OPUC–Public Utility Commission of Oregon

PCA–Power Cost Adjustment

PCC–Planning Coordination Council

PM&E–Protection, Mitigation, and Enhancement

PGE–Portland General Electric Company

PPA–Power Purchase Agreement

PTC–Production Tax Credit

PURPA–Public Utility Regulatory Policies Act of 1978

PV–Photovoltaic

QF–Qualifying Facility

REC–Renewable Energy Credit

RES–Renewable Electricity Standard

RFP–Request for Proposal

RISEC–River In-Stream Energy Conversion

RPS–Renewable Portfolio Standard

SAR–Surrogate Avoided Resource

SCCT–Simple Cycle Combustion Turbine

SMES–Superconducting Magnetic Energy Storage

SO_2–Sulfur Dioxide

SRBA–Snake River Basin Adjudication

TEPPC–Transmission Expansion Planning Policy Committee

UAMPS–Utah Associated Municipal Power Systems

U.S. Army COE–United States Army Corps of Engineers

USFWS–United States Fish and Wildlife Service

USFS–United States Forest Service

VRB–Vanadium Redox Battery

WACC–Weighted Average Cost of Capital

WAQC–Weatherization Assistance for Qualified Customers

WECC–Western Electricity Coordinating Council

1. SUMMARY

Introduction

The *2009 Integrated Resource Plan* (IRP) is Idaho Power's ninth resource plan prepared to fulfill the regulatory requirements and guidelines established by the Idaho Public Utilities Commission (IPUC) and the Public Utility Commission of Oregon (OPUC).

The 2009 IRP assumes that during the planning period (2010–2029), Idaho Power will continue to be responsible for acquiring resources sufficient to serve all of its retail customers in its mandated Idaho and Oregon service areas and that the company will continue to operate as a vertically integrated electric utility. In developing this plan, Idaho Power has worked with the IRP Advisory Council (IRPAC), comprised of major stakeholders representing the environmental community, major industrial customers, irrigation customers, state legislators, public utility commission representatives, and others. There are four primary goals of Idaho Power's planning process.

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
4. Involve the public in the planning process in a meaningful way

Idaho Power is responsible for providing safe and reliable electrical service to its service area, which includes most of southern Idaho and a portion of eastern Oregon. In addition to operating under the regulatory oversight of the IPUC and the OPUC, Idaho Power is a public utility under the jurisdiction of the Federal Energy Regulatory Commission (FERC) and is obligated to plan for and expand its transmission system to provide requested firm transmission service to third parties, and to construct and place in service sufficient transmission capacity to reliably deliver resources to network customers[1] and native load customers[2]. The 2009 IRP only evaluates the need for additional transmission capacity necessary to serve native load customers. The total capacity of proposed transmission line projects may be larger than identified in the IRP in order to accommodate third-party requests and network customer obligations for capacity on the same transmission path.

[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.

Highlights

- The 2009 IRP load forecast projects peak-hour load will grow at an average annual rate of 53 MW (1.5 percent) and average system load will grow at 13 aMW (0.7 percent) over the 20-year planning period.
- By 2012, Idaho Power's demand response programs are expected to reduce peak–hour load by 380 MW.
- Existing and new energy efficiency programs are forecasted to reduce average annual system load by 382 aMW by 2029.

The number of customers in Idaho Power's service area is expected to increase from around 486,000 in 2008 to over 680,000 by the end of the planning period in 2029. Even with the current recession, population growth in Idaho Power's service area will require the company to add physical resources to meet the energy demands of its growing customer base.

With hydroelectric generation as the foundation of its energy production, Idaho Power has an obligation to serve customer loads regardless of the water conditions that may occur. In light of public input and regulatory support of the more conservative planning criteria used in the 2002 IRP, Idaho Power will continue to emphasize a resource plan based upon a worse-than-median level of water. The IRP uses more conservative planning criteria than median water planning, but the criteria are less conservative than critical water planning. Further discussion of Idaho Power's planning criteria can be found in Chapter 8.

Idaho Power extended the planning horizon in the 2006 IRP to 20 years. Prior Idaho Power IRPs used a 10-year planning horizon, but with the increased need for baseload resources with long construction lead times along with the need for a 20-year resource plan to support Public Utilities Regulatory Policies Act (PURPA) contract negotiations, Idaho Power and the IRPAC decided to extend the planning horizon of the 2006 and future resource plans to 20 years.

Planning for the future is necessary to meet the needs of Idaho Power's customers today and tomorrow. While the 2009 IRP addresses Idaho Power's long-term resource needs, the company plans for the near-term through the *Energy Risk Management Policy* that was collaboratively developed in 2002 between Idaho Power, the IPUC staff, and interested customers (IPUC Case No. IPC-E-01-16). While the IRP has a planning horizon of 20 years and is updated every two years, the *Energy Risk Management Policy* focuses on an 18-month period and is updated every month.

Public Advisory Process

Idaho Power has involved representatives of the public in the IRP planning process since the early 1990s. In earlier years, the public forum was called the Technical Advisory Panel. Idaho Power revised the public involvement process and formed the IRPAC when preparing the 2004 IRP and has continued working with the council in the preparation of the 2006 and 2009 resource plans.

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. A list of the IRPAC members can be found in *Appendix C—Technical Appendix*. Idaho Power continued the public involvement process for the 2009 IRP and the IRPAC meetings served as an open forum for discussions related to the development of the IRP. The IRPAC members and the public have made significant contributions to the 2009 IRP.

Idaho Power has found that working with members of the IRPAC and the public has been very rewarding and the company believes the 2004, 2006, and the 2009 IRPs are 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 2009 IRP are made by Idaho Power. Idaho Power encourages IRPAC members and members of the public to submit comments expressing their views regarding the 2009 IRP and the planning process in general.

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

IRP Methodology

The preparation of Idaho Power's 2009 IRP begins with updating the forecast of future customer demand. Existing resources, the ability to import electricity, and the performance of existing demand-side management (DSM) programs are then accounted for in the load and resource balance. The next step involves evaluating new DSM programs and the expansion of existing programs. Idaho Power is committed to implementing all cost-effective DSM programs and the impact of the new programs is accounted for in the load and resource balance. Finally, Idaho Power evaluates portfolios of supply-side resources designed to eliminate any remaining deficits.

Idaho Power primarily uses a financial analysis to compare various resource portfolios in order to determine the preferred portfolio. Idaho Power attempts to financially value all of the resource costs and benefits. Traditional resources have both a fuel cost and a market value for the delivered energy and Idaho Power includes both the cost and the value when evaluating resources. Further, the value of renewable energy credits (REC) is also included in the financial analysis.

Each resource portfolio is designed to substantially meet the energy and capacity deficits identified in the load and resource balance. Idaho Power continues to face load and resource deficits during the next few years, but each resource portfolio meets the energy and capacity requirements after the 2013 time period.

Three resources identified in the 2006 IRP are considered committed resources in the 2009 IRP—1) the Langley Gulch combined-cycle combustion turbine (CCCT) that will be used as a dispatchable resource, 2) up to 150 megawatts (MW) of wind generation from the 2012 Wind Request for Proposals (RFP), and 3) two 20 MW increments of geothermal energy coming on-line in 2012 and 2016.

For the 2009 IRP, the 20-year planning period was divided into two 10-year segments. Dividing the planning period into these two segments prevents near-term resource decisions from being influenced by the availability of resources that are dependent on technological advancements in the second 10 years.

In the first 10-year period (2010–2019), four resource portfolios were examined. The preferred resource portfolio from the first 10-year period was coupled with a variety of portfolios containing advanced technologies in the second 10-year period. Using the preferred portfolio from the first 10-year period insures that all of the advanced technologies are considered equally in the second 10-year period. It is not necessary for Idaho Power to commit to a single advanced technology at the present time. Idaho Power anticipates discussing its preferred long-term portfolio options with other Pacific Northwest utilities over the next several years and is contemplating forming a regional partnership to further explore some of the more promising advanced technologies.

Demand-Side Management

New energy efficiency programs included in the 2009 IRP are forecast to reduce average load by 127 aMW by 2029, which represents a 53 percent increase over the measures included in the 2006 IRP. New energy efficiency measures come from a combination of new Idaho Power programs, new measures recommended in the 2009 potential study performed by Nexant, Inc., and a review of measures included in the Northwest Power and Conservation Council's (NPCC) *Draft 6th Power Plan*.

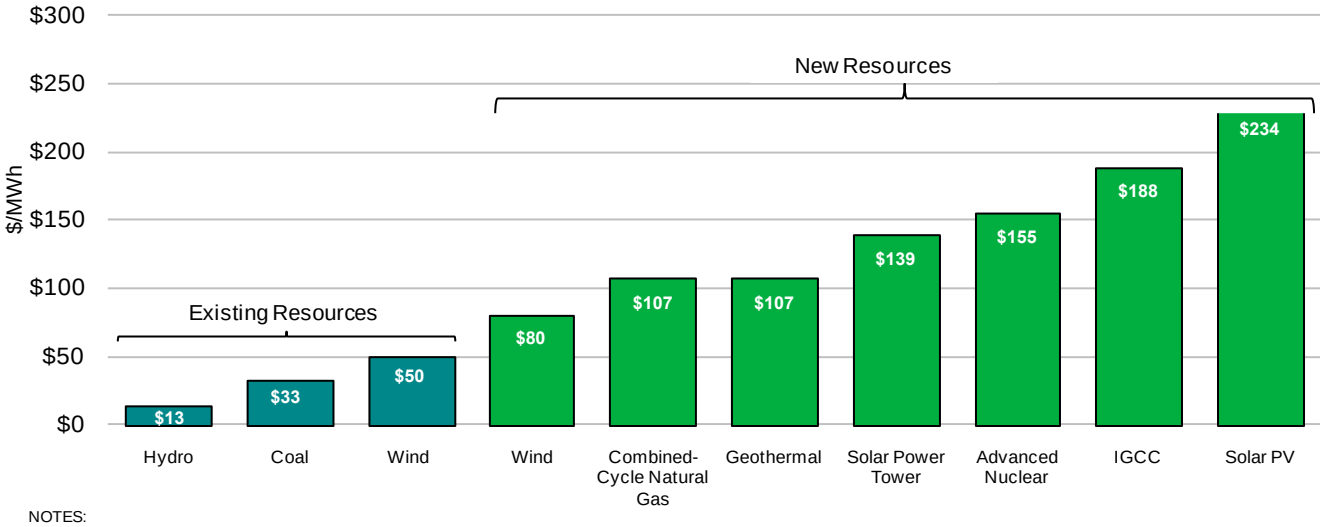
New and expanded demand response programs developed as part of the 2009 IRP are expected to reduce peak summer load by 323 MW by 2012 when the programs mature. This reflects tremendous growth over 2006 IRP forecasts where demand response programs were estimated to provide 78 MW of peak reduction by 2026. The large increase comes from the introduction of the FlexPeak Management program which targets commercial and industrial customers and also the transition of the Irrigation Peak Rewards program into a dispatchable, direct load control program.

Chapter 4 contains details on Idaho Power's existing and proposed DSM programs, and *Appendix A–Sales and Load Forecast* contains the forecast performance of energy efficiency and demand response programs by customer class.

Supply-Side Resource Costs

The 2009 IRP forecasts load growth in Idaho Power's service area and identifies supply-side resources and demand-side measures necessary to meet the future needs of customers. Recent cost increases have significantly impacted the cost of new supply-side resources, especially when compared to the cost of the existing resources in Idaho Power's generation portfolio. Figure 1.1 shows the 2008 costs in dollars per megawatt hour (MWh) for Idaho Power's existing hydroelectric resources, coal generation facilities, and power purchased from the Elkhorn Valley Wind Project. In addition, Figure 1.1 shows the estimated cost of new resources considered in the 2009 IRP. Existing resource costs are based on 2008 actual costs of capital, fuel, and non-fuel operating and maintenance (O&M). New resource costs are 30-year levelized estimates (based on expected annual generation), which include capital, fuel, non-fuel O&M, plus a cost of $43 per ton for carbon-emitting resources.

Figure 1.1 Cost of Existing and New Supply-Side Resources



NOTES:
1) Cost of existing resources based on 2008 costs
2) Cost of new resources based on 30-year levelized cost estimates
3) Cost of existing wind is for the Elkhorn Wind Project only (Elkhorn produced approximately 80 percent of the wind generation purchased by Idaho Power during 2008).

In 2008, 78 percent of Idaho Power's electricity came from existing, low-cost hydroelectric and coal resources. These resources are the primary reason Idaho Power has historically had some of the lowest retail electric rates in the country. As Idaho Power adds new resources in the future, either due to load growth or reduced generation from coal facilities, power supply expenses and customer rates are going to increase. Additional discussion regarding new resources and associated costs is presented in Chapter 6 of the 2009 IRP.

Risk Management

Long-term resource planning requires many assumptions regarding future conditions. Forecasts for load growth, DSM program performance, fuel prices, and many other factors are required as part of the planning process. Due to the amount of uncertainty in preparing these forecasts, risk factors are evaluated in the 2009 IRP as part of determining the preferred portfolio. Risk factors are evaluated by performing sensitivity analyses on each portfolio.

The load forecast used for the 2009 IRP reflects the current economic recession as well as the potential impact of carbon regulation on future energy rates charged to Idaho Power customers. Both of these factors resulted in a load forecast substantially lower than seen in recent years. To evaluate the risk associated with higher-than-expected load growth, the 2009 IRP includes an analysis of a high load growth scenario where projected load growth continues at historical levels.

In the 2009 IRP, considerable energy efficiency measures and demand response programs are expected to reduce future load growth. In the event these programs do not develop and perform as planned, a low conservation scenario was analyzed as part of the 2009 IRP risk analysis.

Natural gas prices are highly correlated to market energy prices in the Pacific Northwest as gas resources typically represent the marginal resource in the region. Natural gas price volatility, as well as higher than forecast prices, have been analyzed in Idaho Power's previous IRPs. The natural gas price analysis is also included in the 2009 IRP.

Idaho Power believes some form of carbon regulation will be enacted in the near future. However, there is still a great deal of uncertainty on how the regulation will be implemented and what the costs will be. In the 2009 IRP, Idaho Power has attempted to quantify the impact of a carbon tax scenario as well as a cap-and-trade scenario based on the provisions contained in the Waxman–Markey bill (H.R. 2454). In addition to the Waxman–Markey bill passed by the U.S. House of Representatives in June 2009, the Boxer–Kerry bill (S. 1733) was introduced in the U.S. Senate in September 2009.

Renewable portfolio standards (RPS) have been passed by many states, including Oregon. In addition, a federal renewable electricity standard (RES) is included in the provisions of the Waxman–Markey bill. RECs, which are needed to comply with RPS (or RES) requirements, are valued according to a forward price curve developed for the 2009 IRP. Although a market for RECs has developed recently, there is uncertainty associated with the future market value of RECs and potential limitations on the quantity of RECs that may be purchased to meet state RPS requirements or a federal RES. As part of the risk analysis, the 2009 IRP analyzes a high REC price scenario and estimates the effect on each portfolio.

Idaho Power believes that maintaining a diverse resource portfolio is the best way to mitigate risk given the amount of uncertainty in the planning process. As part of this strategy and in addition to the quantitative analyses previously discussed, the 2009 IRP contains a qualitative discussion of the potential risk associated with carbon regulation, developing technologies, resourcing siting, and relying on market purchases. This discussion can be found in the Qualitative Risk Analysis section in Chapter 10.

Greenhouse Gas Emissions

Idaho Power owns and operates 17 hydroelectric projects, two natural gas-fired plants, one diesel-powered generator, and shares ownership in three 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, both in terms of total CO_2 emissions (tons) and CO_2 emissions intensity (pounds [lbs]/MWh), based on the report of 2006 CO_2 emissions presented in *Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States*, released May 2008 by the Ceres investor coalition, the Natural Resources Defense Council, Public Service Enterprise Group, and PG&E Corporation.

In September 2009, Idaho Power's Board of Directors approved guidelines to establish a goal to reduce the CO_2 emission intensity of the company's utility operations. The guidelines are intended to prepare the company for potential legislative and/or regulatory restrictions on greenhouse gas (GHG) emissions, while minimizing the cost of complying with such reductions on Idaho Power's customers.

The guidelines establish a goal to reduce Idaho Power's resource portfolio's average CO_2 emission intensity for the 2010 through 2013 time period to a level of 10 percent—15 percent below the company's 2005 CO_2 emission intensity of 1,194 lbs/MWh. Since Idaho Power's CO_2 emission intensity fluctuates with stream flows and the production levels of existing and anticipated renewable resources, the company has adopted an average intensity reduction goal, to be achieved over several years.

Generation from company-owned resources and any renewable resources under contract, for which Idaho Power has long-term rights to RECs, will be included in the denominator of the intensity calculation. The company's progress toward achieving this intensity reduction goal, as well as additional information on Idaho Power's CO_2 emissions, will be reported on the company's Web site at www.idahopower.com. Information related to Idaho Power's CO_2 emissions is also available through the Carbon Disclosure Project at www.cdproject.net.

The guidelines are intended to reduce Idaho Power's near-term CO_2 emission intensity levels in a manner that minimizes the costs of the reductions on the company's customers. The 2009 IRP attempts to quantify the cost and longer term impacts of carbon regulations proposed in the Waxman–Markey bill (H.R. 2454). Additional details regarding the analysis are presented in Chapter 10 of the 2009 IRP.

Preferred Resource Portfolio

The preferred portfolio for the 2009 IRP presented in Table 1.1 was constructed by combining the preferred portfolio for the first 10 years of the planning horizon (2010–2019) with the preferred portfolio for the second 10-year period (2020-2029). In addition to the committed resources previously discussed, the preferred resource portfolio includes 250 MW of market purchases beginning in 2015 with an additional 175 MW in 2017. These purchases rely on the completion of the Boardman to Hemingway Transmission Project (Boardman to Hemingway) in 2015. The total west-to-east transfer capacity reserved on Boardman to Hemingway by Idaho Power is expected to be 425 MW. The first 10-year period also includes the Shoshone Falls Upgrade Project in 2015.

The preferred portfolio for the second 10-year period (2020–2029) represents a strategy of adding wind resources sufficient to provide energy and RECs along with simple-cycle natural gas plants to provide peaking capacity and operating reserves necessary to integrate wind generation. The preferred portfolio also assumes the completion of the Gateway West Transmission Project (Gateway West) by 2022 in order to add the additional wind resources to the portfolio. Due to existing transmission constraints, all portfolios analyzed for the 2020–2029 timeframe assume capacity is available on the Gateway West transmission project.

Table 1.1 Preferred Portfolio

1–4 Boardman to Hemingway (2010–2019)			2–4 Wind & Peakers (2020–2029)		
Year	**Resource**	**MW**	**Year**	**Resource**	**MW**
2012	Wind*	150	2020	SCCT (Large Aero)	100
2012	CCCT (Langley Gulch)*	300	2022	Wind	100
2012	Geothermal*	20	2024	SCCT (Large Aero)	200
2015	Shoshone Falls	49	2025	Gateway West	100
2015	Boardman to Hemingway	250	2026	SCCT (Large Aero)	200
2016	Geothermal*	20	2027	Wind	400
2017	Boardman to Hemingway	175	2028	SCCT (Large Aero)	400
			2029	SCCT (Large Aero)	500

*Committed resource

Idaho Power anticipates the resources in the second 10-year period will be reconsidered in the 2011 IRP and subsequent plans as more certainty regarding carbon regulation and a federal RES become available. Future uncertainty requires alternate portfolios be considered in the resource planning process. Further details regarding the preferred portfolio and the alternate portfolios can be found in Chapter 10.

Near-Term Action Plan

Idaho Power has completed the competitive procurement process for the Langley Gulch CCCT and has nearly completed the RFP process for the 2012 wind resource. Both resources are expected to be on-line in 2012. Idaho Power anticipates expanding both the irrigation and commercial demand response programs in 2010 and 2011 to address expected growth in peak-hour loads. Idaho Power anticipates beginning construction of the Shoshone Falls Upgrade Project in 2012 with the project being completed by 2015. Idaho Power is also continuing to work with federal and state agencies, FERC, other transmission providers, and the public on the Boardman to Hemingway and Gateway West transmission projects. Major milestones associated with these resources and programs are presented in Table 1.2.

Table 1.2 Near-Term Action Plan Milestones

Year	Action
2010	Present and gain acceptance of 2009 IRP with regulatory commissions
	File wind contract resulting from the 2012 Wind RFP with the IPUC
	File geothermal contract with the IPUC (approximately 20 MW)
	Irrigation Peak Rewards program increases from 160 MW to 220 MW
	FlexPeak Management program increases from 20 MW to 40 MW
	Langley Gulch CCCT construction begins
2011	Wind project construction begins
	Langley Gulch CCCT construction continues
	Irrigation Peak Rewards demand response program increases from 220 MW to 250 MW
	FlexPeak Management program increases to from 40 MW to 45 MW
	File 2011 IRP with regulatory commissions
2012	Wind project on-line (approximately 150 MW)
	Langley Gulch CCCT on-line (300 MW)
	Geothermal project on-line (approximately 20 MW)
2013	Boardman to Hemingway construction begins
	Shoshone Falls Upgrade Project construction begins
	File 2013 IRP with regulatory commissions
2014	Shoshone Falls Upgrade Project construction continues
	Boardman to Hemingway construction continues
2015	Shoshone Falls Upgrade Project on-line (49 MW)
	Boardman to Hemingway completed (250 MW)
	File 2015 IRP with regulatory commissions
2016	Geothermal project on-line (approximately 20 MW)
2017	Boardman to Hemingway additional capacity for market purchases (175 MW)
	File 2017 IRP with regulatory commissions
2018	No action
2019	File 2019 IRP with regulatory commissions

Public Policy Issues

The 2009 IRP was completed using computer modeling and other analytical methods. However, certain public policy questions exist that cannot be directly examined through analytical methods. Idaho Power has presented these issues to the IRPAC for discussion, but the nature of the issues typically precludes a strong majority opinion from the IRPAC members. The public policy issues presented to the IRPAC are discussed below.

New Large Loads

Locally, Idaho Power and its customers face internal conflicts created by traditional rate determination and the cost difference between existing resources and future resources. New customers that connect to Idaho Power's system benefit from energy rates based on the low-cost of existing resources that are embedded in current rates. However, Idaho Power's existing resources and transmission system are fully used and new customers require the addition of generation, transmission, and distribution resources. Each new customer dilutes the existing resource base and increases the cost to all customers. The question of rate determination based on embedded resources is a significant public policy issue and Idaho Power senses a desire by some parties to discuss the existing rate determination principles.

Idaho Power's ability to serve new large loads is limited. Previously existing surplus energy and capacity have been consumed by load growth over the past several years. Idaho Power's ability to serve new large loads has an impact on Idaho's economy. New businesses are attracted to southern Idaho in part due to Idaho Power's low rates which have consistently been some of the lowest in the nation.

Asset Ownership

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

Renewable Energy Credits

In late 2008, Idaho Power filed an application with the IPUC asking to retire RECs received as part of the long-term PPAs for generation from the Elkhorn Valley Wind Project and the Raft River Geothermal Project. Because the state of Idaho does not have an RPS, these RECs could be either voluntarily retired or sold. Idaho Power's application pointed out that these RECs needed to be retired in order for Idaho Power to represent to its customers that they were receiving renewable energy from these projects.

In May 2009, the IPUC issued Order No. 30818 which required Idaho Power to sell the eligible 2007 and 2008 RECs from these projects. The order also instructed Idaho Power to file a business plan addressing the disposition of future RECs by the end of 2009. When this issue was presented to the IRPAC, environmental representatives felt future RECs should be retired while customer representatives generally felt they should be sold so that the value could be returned to customers.

Idaho Power believes a federal RES requiring Idaho Power to retire RECs for compliance will be passed by Congress in the near future. Idaho Power believes it is prudent to continue acquiring RECs associated with renewable resources to minimize the impact when a federal RES is implemented. Because of recent increases in costs and customer rates, along with feedback from the IPUC, Idaho Power feels it would be

prudent to sell the RECs until they are required by a federal RES. Additional information on RECs and the proposed federal legislation can be found in Chapter 2.

Emission Offsets

Depending on market conditions and future regulations, it may be possible to purchase emission or carbon offsets for less than the cost of a carbon allowance. Some members of the IRPAC have suggested it would be prudent for Idaho Power to hedge carbon emission risk by purchasing emission offsets prior to the formal passage of carbon legislation. However, there are differing opinions among IRPAC members. The principal reason cited for not purchasing offsets today is the uncertainty associated with whether or not carbon offsets purchased today will meet future carbon control requirements and regulations. In addition, draft federal legislation limits the amount of offsets that may be used to meet reduction targets.

Idaho Power believes it should investigate purchasing either emission offsets or options to acquire future carbon offsets. Idaho Power could potentially reduce the large financial exposure of possible carbon regulation for the cost of the option premium. Idaho Power believes it should be able to recover the cost of purchasing emission offset options as well as the cost of any emission offsets purchased.

Technology Risk and Joint Development Opportunities

In the 2009 IRP, several resource options dependent on developing technology have been evaluated in various portfolios. Carbon capture and sequestration, integrated gasification combined-cycle (IGCC), advanced nuclear, and numerous storage technologies are not yet commercially available; however, the technology may become available during the 20-year planning horizon evaluated in the IRP. This raises the question of whether Idaho Power should participate in development efforts related to any of these technologies prior to them becoming commercially available.

Idaho Power believes that as a medium-sized utility it would be impractical to lead the development work on any particular technology. However, as certain technologies are identified that show promise as being beneficial to Idaho Power and its customers, the company may chose to participate in development efforts. Idaho Power's participation would most likely be part of a larger group effort to develop a technology jointly with other utilities with similar needs.

Similarly, certain existing and emerging resource technologies are available only in large sizes—larger than what Idaho Power could or would consider developing alone. If opportunities become available to jointly develop large resources, Idaho Power would evaluate them on a case-by-case basis. A similar strategy has been used in the past and resulted in Idaho Power's joint ownership of three coal-fired resources.

Solar Pilot Project

For the 2009 IRP, Idaho Power hired Black & Veatch to prepare a feasibility study to assess the performance and associated costs of various solar technologies in southwest Idaho. While solar technology continues to be more expensive than other alternatives, the cost of solar resources has come down in recent months during a time when the cost of most other resource options has increased substantially. In addition to providing RECs, solar resources provide the benefit of delivering energy during the time of day when Idaho Power's customer demand is peaking.

Several possibilities exist for the structure of a solar pilot project. One option Idaho Power is interested in pursuing would be to develop a photovoltaic (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 customers to buy the output from the project as a means of investing in renewable energy.

A solar resource at a company substation would provide customers a physical asset they could identify with as the source of their electricity, and commercial customers would also be able to advertise their use of renewable energy. The level of customer subscription in this type of project would also provide an indication of customers' willingness to pay a premium for renewable energy. This concept was generally well received and supported when it was presented and discussed at a recent IRPAC meeting.

2. Political, Regulatory, Operational, and Technology Issues

Political and Regulatory Issues

Idaho Power is a regulated utility. On the federal level, Idaho Power is subject to the rules and regulation of FERC. On the state level, Idaho Power has customers in both Idaho and Oregon, with approximately 95 percent of Idaho Power's customers being located in the state of Idaho. The following sections describe some of the federal and state regulatory issues facing Idaho Power.

Idaho Energy Plan

In 2006, the Idaho State Legislature directed an Interim Committee on Energy, Environment, and Technology to develop a state energy plan that provides for the state's power generation needs and protects the health and safety of the citizens of Idaho. In January 2007, the committee completed the Idaho Energy Plan and concluded that all Idaho energy systems have performed very well with retail electric and natural gas prices that remain some of the lowest in the country.



The Idaho Legislature sets state energy policy in Idaho.

The committee also recognized that Idaho's reliance on low-cost coal plants may become a source of risk in the future due to the economic impact of potential federal regulation of carbon and mercury emissions. To address these concerns, the committee recommended increasing investments in energy conservation and in-state renewable resources. In a resource priority policy statement, the committee stated, "When acquiring resources, Idaho and Idaho utilities should give priority to: 1) conservation, energy efficiency and demand response; and 2) renewable resources; recognizing that these alone may not fulfill Idaho's growing energy requirements." The committee further stated, ". . . energy suppliers must continue to have access to conventional energy resources to keep Idaho's energy costs as low as possible."

Highlights

- The Idaho Energy Plan recommends increasing investments in energy conservation and in-state renewable resources.
- Proposed federal energy legislation would establish greenhouse gas (GHG) reduction goals and require a percentage of electricity supplied to customers to come from renewable resources.
- Idaho Power continues to operate the Hells Canyon Complex under annual licenses issued by FERC until a new license is issued.
- The 2009 IRP explores clean coal technologies and carbon capture and sequestration as well as storage technologies that could aid in the integration of renewable resources.

The committee also expressed support for the "25x25" vision, which states "By 2025, America's farms, forests, and ranches will provide 25 percent of the total energy consumed in the United States, while continuing to produce safe, abundant, and affordable food, feed and fiber." Additional information regarding the "25x25" vision can be found at www.25x25.org.

Idaho Strategic Energy Alliance

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

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

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

Idaho Power representatives serve on many of these task forces. The alliance is governed by a board of directors comprised of representatives from Idaho stakeholders and industry experts. The workings of the alliance are overseen by the Governor's Council, a group of the governor's cabinet members.

Idaho State Legislature—Senate Bill 1123

Recent economic conditions have increased the cost of financing new capital projects—generation, transmission, and distribution. The electric utility business is a capital-intensive industry with significant financing requirements. Idaho Power has worked with the Idaho State Legislature to address some of the capital issues by proposing legislation to allow the authorization of capital recovery to occur prior to project construction rather than after the project is completed.

As a result of these efforts, the Idaho State Legislature passed Senate Bill 1123 in April 2009. The bill became law in July 2009 when it was signed by Governor Otter. Idaho Power recognizes that the policy change will require cost-containment commitments from the company, but Idaho Power anticipates that the legislation will lower the cost to finance new capital projects and, ultimately lower the capital costs included in customer rates. In September 2009, the IPUC issued an order granting a certificate of public convenience and necessity (CPCN) for the Langley Gulch combined-cycle combustion turbine (CCCT) project. The CPCN included provisions for ratemaking treatment as provided in the new Idaho law.

Oregon Renewable Portfolio Standard

The state of Oregon's Renewable Portfolio Standard (RPS) requires utilities and electricity service suppliers serving Oregon load to include in their portfolio of power sold to retail customers a percentage of electricity generated from qualifying renewable energy sources. Like most states, Oregon's RPS is phased-in over a number of years, with final targets set for the year 2025. The Oregon RPS also includes

a tiered system based on the amount of load a utility serves in Oregon. Larger utilities have higher RPS requirements and interim targets while smaller utilities have less rigorous requirements and no interim targets.

Under the Oregon RPS, Idaho Power is categorized as a "smaller utility" because the percentage of the company's retail electric sales in Oregon are between 1.5 and 3 percent of the total retail sales in the state (approximately 5 percent of Idaho Power's total load is in Oregon). As a "smaller utility" Idaho Power is not subject to interim targets; however, by 2025 at least 10 percent of Idaho Power's retail sales in Oregon must come from qualifying renewable energy sources.

Proposed Federal Energy Legislation

Congress is developing comprehensive federal energy legislation that addresses two important factors in resource planning—greenhouse gas (GHG) emission reductions and a federal renewable electricity standard (RES). Proposed GHG regulations target the reduction of carbon and other GHG emissions nationwide and a federal RES would require a percentage of electricity supplied to customers to come from renewable resources.

In June 2009, the U.S. House of Representatives narrowly passed H.R. 2454, the American Clean Energy and Security Act sponsored by Representatives Henry A. Waxman and Edward J. Markey. The Waxman-Markey bill proposes a cap-and-trade system that establishes a limit or cap on the total amount of GHG emissions. Under a cap-and-trade system, utilities would be allocated emission allowances that would be decreased over time in order to achieve a total emission reduction goal. A certain amount of allowances would also be auctioned as part of establishing a market where allowances could be bought and sold. In effect, a buyer would be paying a charge for polluting, while a seller would be rewarded for having reduced emissions by more than was required. The theory is those who can reduce emissions most economically will do so, achieving the pollution reduction at the lowest possible cost to society. Details of the Waxman-Markey bill related to GHG reduction include:

- **Reduction Goals**–Three percent below 2005 levels by 2012, 17 percent by 2020, 42 percent by 2030, and 83 percent by 2050. Average annual emissions calculation based upon data from 2006 through 2008, or any three consecutive calendar years between 1999 and 2008.
- **Allocation of Allowances**–From 2011 through 2028, 50 percent of allowances are allocated on the basis of a utility's share of emissions associated with retail sales and 50 percent are allocated based on a utility's annual average electricity deliveries.
- **Carbon Offsets**–Allows the use of some forms of carbon offsets in lieu of allowances for compliance.

The Waxman–Markey bill also includes provisions for a federal RES that would require a percentage of electricity supplied to customers come from renewable resources. Details of the RES in the Waxman–Markey bill include:

- **Required Annual Percentage**–Starts at 6 percent in 2012 and escalates to 20 percent by 2020.
- **Resources Eligible to Meet RES**–Wind, solar, geothermal, renewable biomass, biogas and biofuels derived exclusively from renewable biomass, marine, hydrokinetic, and qualified hydropower (efficiency improvements or capacity additions since January 1, 1992). Utilities can also meet up to 25 percent of their requirements through energy efficiency savings.
- **Treatment of Existing Hydro**–Generation from existing hydroelectric resources would be subtracted from the sales base used to calculate RES requirements. While this does not fully recognize the renewable aspect of hydropower, it does provide a benefit to utilities with existing hydroelectric facilities that do not qualify for renewable energy credits (REC).

In September 2009, Senators Barbara Boxer and John Kerry jointly released the Clean Energy Jobs and American Power Act which addresses climate change. The draft bill includes a GHG emission reduction goal of 20 percent below 2005 levels by 2020. The Boxer-Kerry bill (S. 1733) does not include a federal RES provision; however, a separate proposal by Senator Jeff Bingaman does include a federal RES that includes the following provisions:

- **Required Annual Percentage**–Starts at 3 percent in 2011 and escalates to 15 percent by 2021.
- **Resources Eligible to Meet RES**–Wind, solar, geothermal, ocean, biomass, landfill gas, incremental hydropower (efficiency improvements or capacity additions), hydrokinetic, and new hydropower at existing dams with no generation. Utilities can also meet up to 26.67 percent of their requirements through energy efficiency savings.
- **Treatment of Existing Hydro**–Excluded from the sales base used to calculate the RES.

Idaho Power has incorporated elements of the Waxman–Markey bill in the 2009 IRP to quantify the impact of the proposed GHG reduction goals. Idaho Power also anticipates that some form of a federal RES will be passed in the near future; therefore all portfolios analyzed in the 2009 IRP are designed to meet the requirements proposed in the Waxman–Markey bill.

Renewable Energy Credits (Green Tags)

To promote the construction of renewable resources, a system was created that separates renewable generation into two parts 1) the electrical energy produced by a renewable resource and 2) the renewable attributes of that generation. These renewable attributes are referred to as RECs or green tags. The entity that holds a REC has the right to make claims about the environmental benefits associated with the renewable energy from the project. One REC is issued for each megawatt hour (MWh) of electricity generated by a qualified resource. Electricity that is split from the REC is no longer considered renewable and cannot be marketed as renewable by the entity that purchases the electricity.

A REC must be retired once it has been used for regulatory compliance and once a REC is retired, it cannot be sold or transferred to another party. The same REC may not be claimed by more than one entity, including any environmental claims made pursuant to electricity coming from renewable energy resources, environmental labeling, or disclosure requirements. State RPS requirements also typically specify a "shelf life" for RECs so they cannot be banked indefinitely.

Idaho Power is currently receiving all of the RECs from the 101 megawatt (MW) Elkhorn Valley Wind Project in northeast Oregon. The Elkhorn wind project is expected to provide approximately 300,000 RECs to Idaho Power annually throughout the term of the power purchase agreement (PPA) that expires in 2027.

Idaho Power is also receiving RECs from the 13 MW Raft River Geothermal Project. For the first 10 years of the agreement (2008 –2017), Idaho Power is entitled to 75 percent of the RECs from the project for generation that exceeds a monthly average of 10 MW. For the second 10 years of the agreement (2018–2027), Idaho Power is entitled to 51 percent of the RECs generated by the project.

Idaho Power expects a federal RES will be enacted in the near future, and, in the 2009 IRP, the portfolios being analyzed are designed to substantially comply with the federal RES contained in the Waxman–Markey bill. Idaho Power also anticipates RECs generated from both the Elkhorn Valley Wind Project and the Raft River Geothermal Project will be needed to meet federal RES requirements once implemented.

FERC Relicensing



Idaho Power's Hells Canyon Project is licensed by FERC.

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 is actively pursuing the relicensing of the Hells Canyon Complex and the Swan Falls Hydroelectric Projects.

Idaho Power's most significant ongoing relicensing effort is the Hells Canyon Complex. The Hells Canyon Complex provides approximately two-thirds of Idaho Power's hydroelectric generating capacity and 40 percent of the company's total generating capacity. The current license for the Hells Canyon Complex expired at the end of July 2005. Until the new multi-year license is issued, Idaho Power continues to operate the project under an annual license issued by FERC.

The Hells Canyon Complex 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 (FPA); the *National Environmental Policy Act of 1969*, as amended (NEPA); the Endangered Species Act (ESA); and other applicable federal laws.

The license for the Swan Falls project expires in June 2010. In March 2005, Idaho Power issued a Formal Consultation Package (FCP) to the public relating to environmental studies designed to determine project effects for the relicensing of the project. In September 2007, Idaho Power submitted a draft license application to FERC for public review and comment. The draft application was based on the results of environmental studies along with agency and public consultation. Idaho Power filed a final license application for the Swan Falls hydroelectric project with FERC in June 2008, and anticipates NEPA consultation to initiate in early 2010.

Failure to relicense any of the existing hydropower projects at a reasonable cost will create upward pressure on the current electric rates of Idaho Power customers. The relicensing process also has the potential to decrease available capacity and increase the cost of a project's generation through additional operating constraints and requirements for environmental protection, mitigation, and enhancement (PM&E) measures imposed as a condition for 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 was assumed as part of the 2009 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 is dependent on the state water rights held by the company for these projects. The long-term sustainability of the Snake River Basin stream flows, including tributary spring flows and the regional aquifer system, is crucial for Idaho Power to be able to maintain generation from these projects. The company is dedicated to the vigorous defense of its water rights. None of the pending water management issues are expected to impact Idaho Power's hydroelectric generation in the near term, but the company cannot predict the ultimate outcome of the legal and administrative water rights proceedings. Idaho Power's ongoing participation in water rights issues is intended to guarantee that sufficient water is available for use at the company's hydroelectric projects on the Snake River.

Idaho Power is engaged in the Snake River Basin Adjudication (SRBA), a general streamflow adjudication process commenced 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. The purpose of the agreement was to resolve litigation related to the company's water rights at the Swan Falls project. Idaho Power has filed claims for all of its hydropower water rights in the SRBA, is actively protecting those water rights, and is objecting to claims that may potentially injure or affect those water rights.

Idaho Power has also actively participated in proceedings associated with the Comprehensive Aquifer Management Plan (CAMP) of the Eastern Snake River Plain Aquifer (ESPA). Remedial actions identified in CAMP are intended to address persistently declining aquifer conditions. Given the high degree of interconnection between ESPA and the Snake River, Idaho Power recognizes the importance of aquifer management planning in promoting the long-term sustainability of the Snake River.

The company is hopeful the implementation of the ESPA CAMP will restore aquifer levels and tributary spring flows to the Snake River. For the 2009 IRP, it is assumed that CAMP measures specified under Phase I of the plan are implemented. Phase I recommendations consist of a combination of ground water to surface water conversions, managed aquifer recharge, demand reduction programs, and weather modification programs designed to produce an increase in average annual aquifer discharge between 200,000 and 300,000 acre-feet. Further discussion of the ESPA CAMP is included in *Appendix C—Technical Appendix*. The Phase I measures with associated target water volumes are shown in Table 2.1.

Table 2.1 Phase I Measures

Measure	Target (acre-feet)
Ground Water to Surface Water Conversions	100,000
Managed Aquifer Recharge	100,000
Demand Reduction	
Surface Water Conservation	50,000
Crop Mix Modification	5,000
Rotating Fallowing, Dry-Year Lease, Conservation Reserve Enhancement Program (CREP)	40,000
Weather Modifications	50,000

Fixed Cost Adjustment



The IPUC regulates Idaho Power in Idaho.

In January 2006, Idaho Power filed an application with the IPUC requesting to implement a fixed-cost adjustment (FCA) mechanism similar to the Power Cost Adjustment (PCA), which accounts for changes in power supply expenses. The FCA is designed to separate fixed cost rate recovery from energy sales. The FCA adjusts rates downward or upward to recover fixed costs independent of the volume of the company's energy sales. The filing was a continuation of a 2004 case that was opened by Idaho Power to investigate energy efficiency investments and financial disincentives. Idaho Power recognizes that energy efficiency improvements lower the company's energy sales, which then reduce the company's income. Like most utilities, Idaho Power recovers a portion of fixed costs through variable energy sales—the fixed costs to serve customers are much larger than customers' fixed fees, and a significant portion of the fixed costs are included in customers' kilowatt hour (kWh) energy charges.

Idaho Power and IPUC staff agreed in concept to a three-year pilot program and a stipulation was filed in December 2006 indicating the pilot program would begin in January 2007. The stipulation called for the implementation of the FCA mechanism pilot program as proposed by Idaho Power in the original application, with additional conditions and provisions related to customer count and weather normalization methods, recording of the FCA deferral amount in reports to the IPUC, and detailed reporting of demand-side management (DSM) activities. The IPUC approved the stipulation in March 2007. The pilot program retroactively began in January 2007 and runs through December 2009. The first rate adjustment occurred in June 2008, the second in June 2009, and the final adjustment will occur in June 2010.

Idaho Power believes the FCA removes an inherent disincentive to utility-sponsored DSM programs. In response to implementation of the FCA, Idaho Power has committed to enhancing the efforts promoting DSM and energy efficiency in several key areas, including a broad availability of efficiency and load management programs, building code improvement activity, pursuit of appliance code standards, continued expansion of DSM programs beyond peak-shaving and load-shifting programs, and third-party verification of program effectiveness. Additional details on Idaho Power's DSM programs and results can be found in Chapter 4.

Idaho Power has been successful in achieving its previously established DSM targets and the company continues to pursue additional cost-effective DSM resource options through the IRP planning process. Furthermore, in response to the FCA, Idaho Power has further reduced any financial bias toward supply-side resource alternatives by removing "earnings neutrality" from the criteria for assessing the viability of DSM resource options in the 2009 IRP analysis.

In October 2009, Idaho Power submitted an application to the IPUC (Case No. IPC-E-09-28) requesting authorization for the company to convert the FCA from a pilot program to an ongoing and permanent program.

Operational and Technology Issues

Supply-side resources have different characteristics that impact how they ultimately perform. Renewable resources tend to be variable and intermittent and present operational issues. Many forms of storage technology aimed at addressing these issues are under development. Likewise, significant effort is being made to develop technologies such as carbon capture and sequestration, to allow the continued use of coal as a fuel. These topics are all relevant to resource planning, and the following sections provide details on the operational and technology issues associated with various resources.

Wind Integration

In February 2007, Idaho Power filed a wind integration study with the IPUC. Idaho Power also filed a petition requesting removal of the temporary restriction on the size of Public Utilities Regulatory Policies Act (PURPA) wind projects and an adjustment to the avoided cost rates to compensate for the increase in system costs due to wind variability. In March and June 2007, public workshops were held to present and discuss the results of the wind integration study.

Following negotiations, Idaho Power entered into a settlement stipulation in October 2007. The settlement stipulation prescribed a methodology for calculating a wind integration charge to be applied to new PURPA wind projects, as well as other provisions to account for the characteristics of wind generation. The integration charge is calculated as a percentage of the current 20-year, levelized, avoided-cost rate and is subject to a cap of $6.50 per MWh. In February 2008, the IPUC issued an order approving the settlement stipulation and returned the PURPA cap to 10 average megawatts (aMW). In compliance with the terms of the settlement stipulation, Idaho Power held a follow-up public workshop in August 2008 during which further analysis results were presented along with the operational strategies being used to integrate wind.

Idaho Power currently has 192 MW (nameplate) of wind generation on-line. Signed PURPA contracts exist for 266 MW of wind generation that is expected to be on-line by the end of 2010. The 2012 Wind RFP is also expected to add up to 150 MW by 2012, which will put the total wind generation on Idaho Power's system in excess of 600 MW. Given this projected increase, it is critical that integration methodologies in practice continue to evolve through ongoing operational experience and further study. Idaho Power plans to update its wind integration study in the first half of 2010 during the time between filing the 2009 IRP and starting the 2011 IRP process in July 2010. The updated study will incorporate planned increases in wind generation as well as the capability of the new Langley Gulch CCCT to provide additional operating reserves.

Along with other regional balancing authorities, Idaho Power shares the belief that improvements in wind forecasting are necessary as wind resources continue to be built in the Pacific Northwest. As a consequence, the company is currently developing a wind forecasting tool to forecast production from PURPA wind projects. Data collection and testing of the new system is being performed to determine whether this low-cost, in-house approach offers comparable performance to services offered by third-party forecasting companies. A status report on this effort will be included in the updated wind integration study to be released in 2010.

Idaho Power continues to explore potential changes in operating practices to aid in the integration of wind resources. Included among these efforts are two programs designed to collaborate with surrounding balancing authorities to manage balancing issues due to the variable and intermittent nature of wind generation. ACE Diversity Interchange (ADI) and the concepts of dynamic and intra-hour scheduling are based on the principle that sub-hour imbalances between generation and load will impact system reliability less if balancing authorities are able to efficiently transfer and account for energy moving between balancing authority areas within the hour.

Clean Coal Technologies

Integrated Gasification Combined Cycle

Integrated gasification combined cycle (IGCC), is a process that converts low-value fuels such as coal, petroleum coke, orimulsion, biomass, and municipal wastes into a high-value, low-British thermal unit (Btu), environmentally friendly natural gas type fuel, also called "synthesis gas" or simply "syngas." When used to fuel a CCCT, coal-based syngas fuel produces electricity more efficiently and with lower emissions of sulfur dioxide (SO_2), particulates, and mercury than traditional direct-fire coal boilers.

A significant amount of work continues worldwide on IGCC research and development. IGCC technology is already being demonstrated at several plants around the world, and there are at least five IGCC plants being planned in the United States. More than 40 IGCC projects with a combined capacity of over 20 gigawatts (GW) have been announced globally. Major power generation equipment suppliers, including Siemens and GE Energy, are investing substantial amounts of capital in IGCC research and development. Idaho Power will continue to monitor the activities and results of IGCC research and development and will continue to evaluate this technology in future IRPs.

Sequestration

Carbon capture and sequestration begins with the separation and capture of carbon dioxide (CO_2) from power plant flue gas and other stationary CO_2 sources. At present, the process is costly and energy intensive, accounting for the majority of the cost of sequestration. Post-combustion, pre-combustion, and oxy-combustion capture systems being developed are expected to be capable of capturing more than 90 percent of flue gas CO_2.

After separating the CO_2, the next step is to sequester or store the CO_2 by injecting it into geologic formations or using terrestrial applications. Geologic sequestration involves taking the CO_2 that has been captured from power plants and other stationary sources and storing it deep underground. Geologic formations, such as oil and gas reservoirs, un-mineable coal seams, and underground saline formations are potential options for storing CO_2. Storage in basalt formations and organic-rich shales is also being investigated.

Terrestrial sequestration involves the net removal of CO_2 from the atmosphere by plants and microorganisms that use CO_2 in their natural cycles. Terrestrial sequestration requires the development of technologies to quantify, with a high degree of precision and reliability, the amount of carbon stored in a given ecosystem. Program efforts in this area are focused on increasing carbon uptake on mined lands and evaluation of no-till agriculture, reforestation, rangeland improvement, wetlands recovery, and riparian restoration.

Research and development continues on carbon capture and sequestration with the U.S. Department of Energy (DOE) in a lead role. The DOE is pursuing evolutionary improvements in existing CO_2 capture systems and exploring new capture and sequestration concepts. Additional research is being performed in the private sector with companies such as Alstom and with utility-affiliated organizations, such as the Electric Power Research Institute (EPRI). Idaho Power will continue to monitor the activities and results of carbon capture and sequestration research and development and will modify future portfolios as appropriate.

Carbon Recycling Using Algae

Carbon recycling using algae is an emerging technology and an alternative method for reducing CO_2 emissions. Algae "farms" rely on the capture of CO_2 from coal plant flue gases, which is then used to accelerate algae growth and eventually produce a biofuel that is similar to natural gas.

To create the biofuel, algae (biomass) is harvested and then gasified in a highly efficient, catalytic, hydrothermal gasifier to produce a fuel that can be either injected into a natural gas pipeline or burned in a combustion turbine to produce electricity. Compared with other methods of gasifying biomass, this process is 400 times faster than anaerobic digestion and gives higher yields according to the DOE's Pacific Northwest National Laboratory. Currently, funding is being solicited to construct a commercial demonstration project next to an existing coal-fired facility.

Storage Technologies

In order to keep the electric power system balanced, generation must match system load at all times. Intermittent renewable resources, such as wind and solar, present a problem because they are not dispatchable. The advent of large-scale storage technologies may help utilities address this issue because surplus energy could be stored and used at a later time. Energy storage technologies convert electrical power into potential or kinetic energy, which can then be converted back into electrical energy when needed, in effect making it dispatchable. The following sections present an update on the status of various storage technologies.

Pumped Storage

Pumped storage technology has existed for some time, and Idaho Power has evaluated the technology in numerous IRPs. The economics of pumped storage has always relied on a significant differential between peak and off-peak market prices because the value is realized by storing water during off-peak times and generating electricity with it during peak load periods. Historically, the differential between peak and off-peak market prices in the Pacific Northwest has not been enough to justify the economics of pumped storage.

Pumped storage recovers about 75 percent of the energy consumed, and is currently one of the most cost-effective technologies for power storage. Pumped storage requires two nearby reservoirs at considerably different elevations, linked with a pipeline or penstock. Because of the required facilities and equipment, pumped storage typically requires considerable capital expenditures.

A relatively new concept in pumped storage is using wind power or other intermittent renewable resources to pump water to the upper reservoir instead of relying on off-peak, baseload generation. However, the capital cost of this pumped storage concept is still considerable because of the required equipment and facilities.

Batteries

Battery technology has existed for a long time; however, utility-scale battery storage technologies are still under development. Batteries are generally expensive and have a limited lifespan, but they also have a relatively high efficiency, as high as 90 percent or better. To date, the most common use of batteries has been in small off-grid domestic systems.

A nickel cadmium (NiCd) battery uses nickel oxide hydroxide and metallic cadmium as electrodes. The world's largest NiCd installation is in Fairbanks, Alaska and is used to stabilize voltage at the end of a long transmission line. This battery system has a capacity of 27 MW for a duration of 15 minutes.

A Vanadium Redox Battery (VRB) is a type of rechargeable flow battery that employs vanadium redox couples in both half cells. The King Island Wind Farm in Tasmania is connected to a VRB that allows up to 800 kWh of surplus electricity to be stored. The battery has an output of 200 kW and is used to help stabilize and improve the reliability of the local power system.

As the adoption of plug-in hybrid electric vehicles increases, batteries could be used for energy storage. Vehicle-to-grid technology would turn each vehicle into a 20 to 50 kWh distributed, load-balancing device or emergency power source. For example, during peak daytime hours when people tend to be at

work and their vehicles are parked, utilities could draw power from the batteries. During off-peak nighttime hours when people and their cars are at home, the batteries would be recharged.

Compressed Air

Compressed air technology typically involves compressing and storing air in underground geological features. During times of peak electricity demand, the compressed air is heated with a small amount of natural gas and run through a turbine to generate electricity. A proposed hybrid power plant using compressed air is currently under consideration in Iowa. This project also proposes a 75 to 150 MW wind project to generate the electricity needed for air compression.

Thermal

Thermal storage technology typically uses molten salt to store heat collected by a solar thermal generation plant. Heat from the molten salt is then used to generate electricity for a few hours after the sun sets or during cloudy periods when normal generation is reduced. Molten salt technologies can provide three to seven hours of energy storage. Solar Millennium and Abengoa are constructing two 50 MW solar thermal plants in Spain with seven hours of thermal storage.

Flywheel

Mechanical inertia is the basis of the flywheel storage technology where energy is stored in the kinetic motion of a rotating mass. A heavy, rotating disc is typically accelerated by an electric motor, which also functions as a generator when reversed. Friction loss must be kept to a minimum to extend the relatively short storage time. Because of the limited storage time, flywheel technology is best suited for back-up applications during brief outages.

Flywheel storage technology is currently being used for uninterruptible power supply systems in large data centers. The flywheel provides generation during transfer, which is the relatively brief time between loss of power and the start up of an alternate source, such as a diesel generator. In addition, flywheels can be used to minimize minor power disturbances and improve power quality.

Hydrogen

The concept of hydrogen as a storage technology involves using electricity from intermittent renewable resources to extract hydrogen through the electrolysis of water. The resulting hydrogen is stored and later burned as fuel to generate electricity. A pilot project using wind turbines and hydrogen generators was undertaken in 2007 on Ramea Island in Newfoundland, Canada. Wind energy is also currently being used to extract hydrogen through the electrolysis process at a small facility southeast of Boise, Idaho. The hydrogen generated at the Idaho facility is sold commercially.

Superconducting Magnetic Energy Storage

Superconducting magnetic energy storage (SMES) systems store energy in the magnetic field created by the flow of direct current in a superconducting coil that has been cryogenically cooled to a temperature below its superconducting critical temperature. A typical SMES system includes three parts, 1) a superconducting coil, 2) the power conditioning system, and 3) a cryogenically cooled refrigerator. Once the superconducting coil is charged, the current will not decay and the magnetic energy can be stored indefinitely. The stored energy can then be released back into the electric system by discharging the coil.

SMES systems are highly efficient, greater than 95 percent; however, the high cost of superconductors limits the commercial application of this technology. The SMES technology would most likely be useful to utilities as a diurnal storage device where less expensive, off-peak energy could be used to charge the system which would then be discharged during the peak-load hours the following day. SMES is

currently being used in a utility application in northern Wisconsin where a string of distributed SMES units are deployed to enhance the reliability of a transmission loop.

Fuel Conservation

The concept of fuel conservation combines an intermittent renewable resource with a dispatchable fossil fuel generation resource. Under this concept, generation from the intermittent resource is combined with an appropriate amount of generation from the fossil fuel resource to maintain a constant level of output from the combined resources. While the concept is not specifically a storage technology, fuel conservation does provide a means of firming the generation from a renewable resource. Other benefits of this concept include reduced fossil fuel consumption and better use of available transmission capacity.

3. IDAHO POWER TODAY

Customer and Load Growth

In 1990, Idaho Power had approximately 290,000 general business customers. Today, Idaho Power serves more than 486,000 general business customers in Idaho and Oregon. Firm peak-hour load has increased from 2,052 megawatts (MW) in 1990 to over 3,000 MW in 2006, 2007, 2008, and 2009. In June 2008, the peak-hour load reached 3,214 MW, which was a new system peak-hour record. Average firm load (excluding Astaris/FMC) has increased from nearly 1,200 average megawatts (aMW) in 1990 to over 1,800 aMW in 2008. Additional details of Idaho Power's historical load and customer data are shown in Figure 3.1 and Table 3.1.



Idaho Power commercial customers in downtown Boise.

Simple calculations using the data in Table 3.1 suggest that each new customer adds approximately 5.9 kilowatts (kW) to the peak-hour load and about 3.1 average kilowatts to average load. In actuality, residential, commercial, and irrigation customers generally contribute more to the peak-hour load, whereas industrial customers contribute more to average load. Industrial customers generally have a more consistent load shape, whereas residential, commercial, and irrigation customers have a load shape with greater daily and seasonal variation.

Since 1990, Idaho Power's total nameplate generation has increased from 2,635 MW to 3,276 MW. This includes Idaho Power's newest supply-side resource, a 170 MW simple-cycle combustion turbine (SCCT) at the Danskin Project that was completed in April 2008. The 641 MW increase in capacity represents enough generation to serve approximately 108,000 customers at peak times. Table 3.1 shows Idaho Power's changes in reported nameplate capacity since 1990.

Highlights

- Idaho Power had over 486,000 retail customers at the end of 2008.
- Idaho Power expects to add almost 10,000 retail customers per year through 2029.
- In June 2008, Idaho Power set a new peak-hour system load record of 3,214 MW.
- The 300 MW Langley Gulch natural gas-fired combined-cycle combustion turbine (CCCT) is expected to begin operating in July 2012.
- In May 2009, Idaho Power released an RFP for up to 150 MW of wind generation.

Since 1990, Idaho Power has added more than 195,000 new customers. The simple peak-hour and average-energy calculations mentioned earlier suggest the additional 195,000 customers require over 1,100 MW of additional peakhour capacity and about 600 aMW of energy.

Figure 3.1 Historical Capacity, Load, and Customer Data

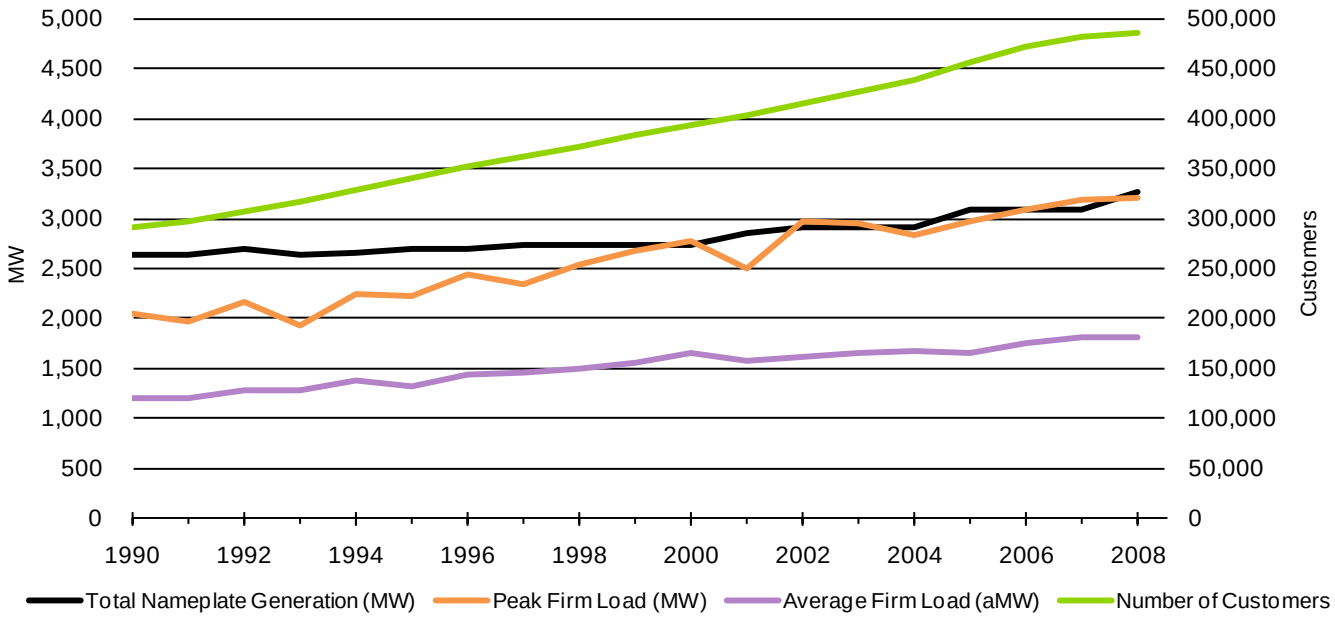


Table 3.1 Historical Capacity, Load, and Customer Data

Year	Total Nameplate Generation (MW)	Peak Firm Load (MW)	Average Firm Load (aMW)	Customers
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

Idaho Power anticipates adding nearly 10,000 customers each year throughout the planning period. The expected-case load forecast predicts that peak-hour load requirements are expected to grow at about 57 MW per year and average energy is forecast to grow at approximately 11 aMW per year. More detailed customer and load forecast information is presented in Chapter 4 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 173 MW Bennett Mountain plant every three years throughout the entire planning period. However, this calculation does not include the expected impact demand response programs will have on peak-hour load. The near-term and long-term action plans to meet the requirements of Idaho Power's load growth are discussed in Chapter 11.

The generation costs per kW included in Chapter 6 help put forecast customer growth in perspective. Load research data indicate the average residential customer requires about 1.5 kW of baseload generation and 5.0 to 5.5 kW of peak-hour generation. Baseload generation capital costs are about $2,000 per kW for wind resources, and peak-hour generation capital costs are about $750 per kW for a natural gas-fired SCCT. These capital costs do not include fuel or any other operation and maintenance expenses.

Based on these capital cost estimates, each new residential customer requires about $3,000 of capital investment for 1.5 kW of baseload generation, plus an additional $4,000 for 5.0 to 5.5 kW of peak-hour capacity for a total generation capital cost of $7,000. Other capital expenditures for transmission, distribution, customer systems, and other administrative costs are not included in the $7,000 capital generation requirement. The forecasted residential customer growth rate of 10,000 new customers per year translates into over $70 million of new generation plant capital per year to serve new residential customers.

Existing and Committed Resources

Idaho Power primarily relies on company-owned hydroelectric and coal-fired generation facilities and long-term power purchase agreements (PPAs) to supply the energy needed to serve customers. Idaho Power's annual hydroelectric generation varies depending on water conditions in the Snake River and market purchases and sales used to balance supply and demand throughout the year. The next sections provide specific details on Idaho Power's sources of energy in 2008 followed by a description of Idaho Power's existing and committed resources.

2008 Energy Sources

In 2008, 79 percent of Idaho Power's supply of electricity came from company-owned generation resources. In above-average water years, Idaho Power's low-cost hydroelectric plants are typically the company's largest source of electricity. Figure 3.2 shows Idaho Power's electricity sources for 2008, including generation from company-owned resources and purchased power. Market purchases are electric power purchases from other utilities in the wholesale electric market.

Long-term power purchases are electric power contracts with independent power producers and firm PPAs 3with other utilities and can typically be identified by resource type. In 2008, Idaho Power purchased 1,194,087 megawatt hours (MWh) of electricity through long-term PPAs that are shown by resource type in Figure 3.3. Long-term power purchases that cannot be identified by resource type are shown as "other" in the chart.

Figure 3.2 2008 Energy Sources

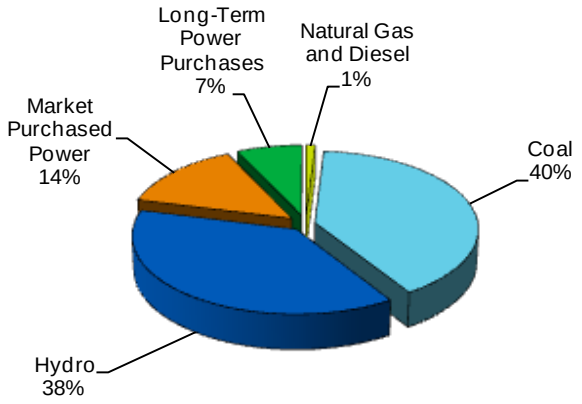
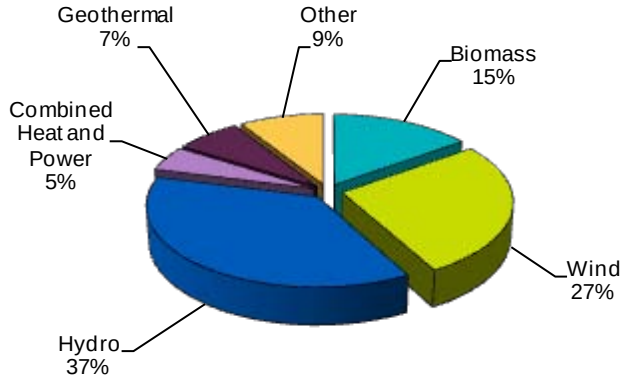


Figure 3.3 2008 Long-Term Power Purchases by Resource Type



Electricity delivered to retail customers includes both electricity generated by Idaho Power-owned facilities and energy purchased from others. Electricity produced by resources typically considered to be renewable, such as wind, biomass, geothermal, etc., is not counted as renewable energy delivered to retail customers in a given year, unless Idaho Power holds and retires an equivalent number of renewable energy credits (REC) in that year. Energy for which Idaho Power holds and retires an equivalent number of RECs will be counted as renewable energy delivered to customers in the year the RECs are retired.

Idaho Power has been directed by the IPUC to sell its eligible 2007 and 2008 RECs. The IPUC also has directed Idaho Power to file by December 31, 2009, a report explaining how the company intends to manage its RECs on an ongoing basis. Table 3.2 represents the electricity Idaho Power delivered to customers in 2008. Because Idaho Power sells electricity to other utilities and to retail customers, not all electricity purchased or generated by Idaho Power is delivered to its retail customers. Table 3.2 assumes that all 2008 RECs will be sold. If any of the 2008 RECs are retained and retired, the actual amount of renewable energy delivered to retail customers could be higher than what is presented in Table 3.2.

Table 3.2 Electricity Delivered to Customers (2008)

Resource by Type	MWh
Hydroelectric	6,908,211
Coal	7,278,844
Natural Gas & Diesel	217,152
Purchased Power	3,716,429
Total	**18,120,636**

Existing Supply-Side Resources

In order to identify the need and timing of future resources, Idaho Power prepares a load and resource balance which accounts for forecast load growth and generation from all of the company's existing resources and planned purchases. The load and resource balance worksheets showing Idaho Power's existing and committed resources for average energy and peak-hour load are presented in *Appendix C–Technical Appendix*. Table 3.3 shows all of Idaho Power's existing resources, nameplate capacities, and general locations.

Table 3.3 Existing Resources

Resource	Type	Generator Nameplate Capacity (MW)	Location
American Falls	Hydro	92.3	Upper Snake
Bliss	Hydro	75.0	Mid-Snake
Brownlee	Hydro	585.4	Hells Canyon
C.J. Strike	Hydro	82.8	Mid-Snake
Cascade	Hydro	12.4	North Fork Payette
Clear Lake	Hydro	2.5	South Central Idaho
Hells Canyon	Hydro	391.5	Hells Canyon
Lower Malad	Hydro	13.5	South Central Idaho
Lower Salmon	Hydro	60.0	Mid-Snake
Milner	Hydro	59.4	Upper Snake
Oxbow	Hydro	190.0	Hells Canyon
Shoshone Falls	Hydro	12.5	Upper Snake
Swan Falls	Hydro	27.2	Mid-Snake
Thousand Springs	Hydro	8.8	South Central Idaho
Twin Falls	Hydro	52.9	Mid-Snake
Upper Malad	Hydro	8.3	South Central Idaho
Upper Salmon A	Hydro	18.0	Mid-Snake
Upper Salmon B	Hydro	17.0	Mid-Snake
Boardman	Coal	64.2	North Central Oregon
Jim Bridger	Coal	770.5	Southwest Wyoming
Valmy	Coal	283.5	North Central Nevada
Bennett Mountain	Natural Gas	172.8	Southwest Idaho
Danskin	Natural Gas	270.9	Southwest Idaho
Salmon Diesel	Diesel	5.0	East Idaho
Total Existing Nameplate Capacity		*3,276.4*	

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

Hydro Facilities

Idaho Power operates 17 hydroelectric projects located on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,709 MW and 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 Hells Canyon Complex in the Hells Canyon reach of the Snake River. The Hells Canyon Complex consists of the Brownlee, Oxbow, and Hells Canyon dams and the associated generation facilities. In a normal water year, the three plants provide approximately 68 percent of Idaho Power's annual hydroelectric generation and approximately 35 percent of the total energy generated. Water storage in Brownlee Reservoir also enables the Hells Canyon Complex projects to provide the major portion of Idaho Power's peaking and load-following capability.



High runoff at Idaho Power's Hell's Canyon Dam.

Idaho Power operates the Hells Canyon Complex to comply with the existing FERC license, as well as voluntary arrangements to accommodate other interests, such as recreational use and environmental resources. Among the arrangements are the fall Chinook plan, voluntarily adopted by Idaho Power in 1991 to protect spawning and incubation of fall Chinook below Hells Canyon Dam. The fall Chinook species is listed as threatened under the Endangered Species Act (ESA).

Brownlee Reservoir is the only one of the three Hells Canyon Complex reservoirs—and Idaho Power's only reservoir—with significant active storage. Brownlee Reservoir has 101 vertical feet of active storage capacity, which equals approximately one million acre-feet of water. Both Oxbow and Hells Canyon reservoirs have significantly smaller active storage capacities—approximately 0.5 percent and 1.0 percent of Brownlee Reservoir's volume, respectively.

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

Brownlee Dam is one of several Pacific Northwest dams that are 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 United States Army Corps of Engineers (U.S. Army COE) as outlined in Article 42 of the existing FERC license.

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

The U.S. Bureau of Reclamation (BOR) periodically releases water from BOR storage reservoirs in the upper Snake River in an effort to augment flows in the lower Snake River to help anadromous fish

migrate past the Federal Columbia River Power System (FCRPS) projects. The periodic releases are part of the flow augmentation implemented by the 2000 FCRPS biological opinion. The flow augmentation water travels through Idaho Power's Mid-Snake projects and eventually through the Hells Canyon Complex before reaching the FCRPS projects.

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

Maintaining constant flows to protect the fall Chinook spawning contributes to the need for additional generation resources during the fall months. The fall Chinook operations result in lower reservoir elevations in Brownlee Reservoir, which reduces the power production capability of the project. The reduced power production may necessitate Idaho Power to acquire power from other sources to meet customer load.

Mid-Snake Projects

Idaho Power's hydroelectric facilities upstream from the Hells Canyon Complex include the American Falls, Milner, Twin Falls, Shoshone Falls, Clear Lake, Thousand Springs, Upper and Lower Malad, Upper and Lower Salmon, Bliss, C.J. Strike, Swan Falls, and Cascade projects. Although the Mid-Snake projects of Upper and Lower Salmon, Bliss, and C.J. Strike, typically follow run-of-river operations, the Lower Salmon, Bliss, and C.J. Strike plants do provide a limited amount of peaking and load-following capability. When possible, the projects are operated within FERC license requirements to coincide with the daily system peak demand. All of the other upstream plants are operated as run-of-river projects.



Idaho Power's C.J. Strike project on the Mid-Snake.

Idaho Power has entered into a settlement agreement with the U.S. Fish and Wildlife Service (USFWS) that provides for a study of the ESA listed snails and their habitat. The objective of the research study is to determine the impact of load-following operations on the Bliss Rapids snail and the Idaho Springsnail. The study required Idaho Power to operate the Bliss and Lower Salmon facilities under varying operational constraints to facilitate the Idaho Springsnail research. Run-of-river operations during 2003 and 2004 serve as the baseline, or control, for the study. These facilities were again operated as run-of-river plants during 2004 and 2005 and then were used to follow load during 2006, 2007, 2008, and 2009. Idaho Power is developing, in consultation with the USFWS, a snail protection plan that will be completed in March 2010. The plan will define how the Bliss and Lower Salmon hydroelectric facilities will be operated in the future.

Water Lease Agreements

Idaho Power views the lease of water for delivery through its hydroelectric system as a potentially cost-effective power supply alternative. This approach is particularly attractive for water lease agreements allowing the company to request delivery as needed. Water lease agreements in 2008

included the release of 41,620 acre-feet of water from the Idaho Water District No.1 rental pool and 45,716 acre-feet from the Shoshone–Bannock Tribal Water Supply Bank. The water released under both of these agreements was delivered through the company's entire system of main stem Snake River hydroelectric projects.

The company also signed agreements with two irrigation districts on the Boise and Payette River systems to lease approximately 16,400 acre-feet of storage water released in December 2008 and January 2009. Because of high carryover storage levels in the Boise River reservoir system, the lease agreement for the Boise system water (approximately 10,500 acre-feet) has been renewed for the winter of 2009-2010.

In August 2009, the company also entered into a five year (2009–2013) water lease agreement with the Shoshone–Bannock Tribal Water Supply Bank for 45,716 acre-feet of American Falls storage water. Under the terms of this agreement, Idaho Power can schedule the releases of the water in order to maximize the value of the generation. The company plans to schedule delivery of the water between July and October of each year during the term of the lease. The Shoshone–Bannock agreement was executed in part to offset the impact of drought and changing water use patterns in southern Idaho and to provide additional generation in summer months when customer demand is high. Acquiring water through leases also helps the company to improve water quality and temperature conditions in the Snake River as part of ongoing relicensing efforts associated with the Hells Canyon Complex. Idaho Power intends to continue to pursue water lease opportunities as part of its regular operations.

Cloud Seeding

In 2003, Idaho Power implemented a winter cloud-seeding program for snowpack augmentation. The program initially focused on increasing snow accumulation in the south fork of the Payette River watershed. In 2008 it was expanded to enhance an existing program operated by a coalition of counties and other entities (coalition) in the Upper Snake River system above Milner Dam. Cloud seeding, as practiced by Idaho Power, extracts additional precipitation from passing storm systems. Storms with an abundance of super-cooled liquid water vapor provide optimal conditions to increase precipitation.

To seed clouds, ground generators located near mountain tops, or special flares attached to modified airplanes, release silver iodide into passing storms. Minute water particles within the clouds freeze on contact with the silver iodide and eventually grow and fall to the ground in the form of snow. Silver iodide has been used as a seeding agent in numerous western states for decades, and there are no known harmful effects. Analysis conducted since the program began in 2003 suggests consistent enhancement of annual snowpack in the Payette River between 5 and 15 percent, which is estimated to provide an additional 120,000 to 180,000 acre-feet of water. Studies conducted by the Desert Research Institute from 2003 to 2005 support the effectiveness of the program.

For the 2009–2010 winter season, the program consists of 10 remote–controlled, ground-based generators and one airplane for the Payette Basin operations. The Upper Snake Basin cloud seeding program consists of nine remote-controlled ground-based generators operated by Idaho Power and 25 manual ground-based generators operated by the coalition. Idaho Power provides the coalition with meteorological data and forecasting to guide their operations.

Thermal Facilities

Jim Bridger

Idaho Power owns a one-third share of the Jim Bridger coal-fired plant located near Rock Springs, Wyoming. The plant consists of four nearly identical generating units. Idaho Power's one-third share of the generator nameplate capacity of the Jim Bridger plant currently is 771 MW. After adjustment for scheduled maintenance periods, estimated forced outages, de-ratings, efficiency upgrades, and transmission losses, the annual energy generating capability of Idaho Power's share of the plant is approximately 625 aMW. PacifiCorp has two-thirds ownership and is the operator of the Jim Bridger facility.



The Jim Bridger Plant is located near Rock Springs, Wyoming.

Valmy

Idaho Power owns a 50 percent share, or 284 MW, of the 568 MW (nameplate) Valmy coal-fired plant located east of Winnemucca, Nevada. The plant is owned jointly with NV Energy, which performs operation and maintenance services. After adjustment for scheduled maintenance periods, estimated forced outages, de-ratings, and transmission losses, the annual energy generating capability of Idaho Power's share of the Valmy plant is approximately 230 aMW.

Boardman

Idaho Power owns a 10 percent share, or 64 MW, of the 642 MW (nameplate) coal-fired plant near Boardman, Oregon, operated by Portland General Electric Company (PGE). After adjustment for scheduled maintenance periods, estimated forced outages, de-ratings, and transmission losses, the annual energy generating capability of Idaho Power's share of the Boardman plant is approximately 50 aMW.

Because of concerns regarding the future of the Boardman plant and pending legal action, PGE analyzed two scenarios in its 2009 IRP regarding the future of the Boardman plant. First, shutting down the plant in 2014 and, second, adding pollution control equipment required to continue operating the plant until the year 2040. Due to uncertainty in the ability to find alternate sources of replacement energy, PGE indicated the best option was to invest in the pollution control equipment and continue to operate the plant.

While Idaho Power has not specifically modeled either of PGE's scenarios in the 2009 IRP, significant reductions in generation from all of Idaho Power's coal resources, including Boardman, have been modeled in the 2009 IRP. If PGE continues to operate the plant beyond 2014, Idaho Power will evaluate the required additional capital cost and the associated risk when more details are known. If the project is shut down in 2014, the existing transmission capacity from the Pacific Northwest currently used to deliver Boardman's generation to Idaho Power's system would be available to import energy from other resources.

Peaking Facilities

Danskin

Idaho Power owns and operates the Danskin plant, a 271 MW natural gas-fired project. The plant consists of one 179 MW Siemens 501F simple-cycle combustion turbine and two 46 MW Siemens W251B12A combustion turbines. The 12-acre facility was initially constructed during 2001 and is located northwest of Mountain Home, Idaho. The two smaller turbines were installed in 2001 and the larger turbine was recently installed in 2008. The Danskin plant operates as needed to support system load.



The 45-MW combustion turbines at Danskin are used to meet peak customer load.

Bennett Mountain

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

Salmon Diesel

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

Solar Facilities

In 1994, a 25 kW photovoltaic (PV) array with 90 individual panels was installed on the rooftop of Idaho Power's corporate headquarters in Boise, Idaho. The company also maintains a remote off-grid 80 kW PV array for the U.S. Air Force near Grasmere, Idaho.



25 kW PV array on top of Idaho Power's corporate headquarters.

Idaho Power uses small PV panels in its daily operations to supply power to equipment used for monitoring water quality, measuring stream flows, and for operating cloud seeding equipment. In addition to these PV installations, Idaho Power participates in the *Solar 4R Schools Program*; has a mobile solar trailer that can be used to supply power for concerts, radio remotes, and other events and has a 200 watt solar water pump that is used for demonstrations and the promotion of PV technology.

Idaho Power's net metering program also allows customers to install small-scale, renewable generation projects on their property and connect to Idaho Power's system. Under the program, net energy generated beyond what the customer uses is sold back to Idaho Power. A majority of the program's

participants are solar projects. Currently there are 77 PV installations under this program with a total capacity of 227 kW.

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 wind project was constructed during 2007 and began commercial operations in December 2007.



The Elkhorn Valley Wind Project in northeast Oregon.

Under the PPA, Idaho Power receives the RECs from the project. However, in May 2009 the IPUC issued Order No. 30818, which required Idaho Power to sell 2007 and 2008 RECs and to submit a business plan by the end of 2009 addressing the disposition of future RECs from this project. This issue is discussed further in the public policy section in Chapter 1 and the renewable energy credits section in Chapter 2.

Raft River Geothermal Project

The 2006 IRP identified a need for Idaho Power to acquire geothermal generation resources and a request for proposals (RFP) for geothermal energy was released in June 2006. In March 2007, Idaho Power identified U.S. Geothermal, Inc. as the successful bidder based on their proposal to supply 45.5 MW of geothermal energy. 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 Public Utilities Regulatory Policies Act (PURPA) contract with Idaho Power that was subsequently 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. For the second 10 years of the agreement (2018–2027), Idaho Power is entitled to 51 percent of the RECs generated by the Raft River Geothermal Project. These RECs are also subject to IPUC Order No. 30818, as discussed above.

Neal Hot Springs Geothermal Project

After extensive discussions with U.S. Geothermal, it was mutually agreed that development of the additional 32.5 MW of geothermal generation units originally proposed in the 2006 RFP process was not feasible within the terms and conditions as specified in the RFP. However, over the past two years Idaho Power continued discussions with U.S. Geothermal regarding the development of the Neal Hot Springs project in eastern Oregon. During much of 2009, Idaho Power negotiated a PPA with U.S. Geothermal. In December 2009, Idaho Power submitted a PPA to the IPUC for approval for approximately 20 MW of geothermal energy from the Neal Hot Springs 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 newly constructed 18 MW power plant at Arrowrock Dam on the Boise River, and in exchange Idaho Power provides Clatskanie PUD energy of equivalent value

delivered seasonally—primarily during months when Idaho Power expects to have surplus energy. An energy bank account will be 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 is expected to begin 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



The Bennett Creek and Hot Springs PURPA wind projects are located in Elmore County.

In 1978, Congress passed PURPA requiring investor–owned electric utilities to purchase the energy from any qualifying facility (QF) that delivers energy to the utility. A QF is defined within the FERC regulations as a small renewable generation project or small cogeneration project. Individual states were given the task of establishing the PPA terms and conditions, including price, that each state's utilities are required to pay as part of the PURPA agreements. Because Idaho Power operates in both Idaho and Oregon, the company must adhere to both the IPUC rules and regulations for all PURPA facilities not located in the state of Oregon, and the OPUC rules and regulations for all PURPA facilities located in the state of Oregon. The rules and regulations are similar, but not identical, for the two states. Because Idaho Power cannot accurately predict the level of future PURPA development, only signed contracts are accounted for in Idaho Power's resource planning process.

Idaho Power currently has 96 contracts with independent developers for over 560 MW of nameplate capacity. The PURPA generation facilities consist of low head hydro projects on various irrigation canals, cogeneration projects at industrial facilities, wind projects, anaerobic digesters, landfill gas, wood-burning facilities and various other small renewable power projects. Of the 96 contracts, 80 are on-line as of November 2009 with a cumulative nameplate rating of approximately 300 MW. Of the remaining contracts, 15 are expected to be on-line in late 2010 and one in late 2012.

Published Avoided Costs

A key component of the 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 costs. Subsequently, the IPUC and OPUC have established specific rules and regulations to calculate the published avoided cost that Idaho Power is required to include in the PURPA contracts.

Idaho PURPA Contracts and Published Avoided Costs

- The term of the agreements cannot exceed 20 years.
- For projects up to 10 aMW, energy prices are based on the published avoided cost.
- For projects greater than 10 aMW, energy prices and other contract terms and conditions are negotiated.
- The published avoided costs are based upon a surrogate avoided resource (SAR) model and both non-firm and firm contracts are available:
  - Firm contracts have a specific term and contain published avoided cost energy pricing.

- Non-firm contracts contain no specific term and energy pricing is based on market prices.

Oregon Published Avoided Costs

OPUC docket UM 1129 established PURPA PPA rules and regulations for projects located in Oregon. In UM 1129, the OPUC adopted the basic published avoided cost concepts used in Idaho for Idaho Power agreements. One exception is that Oregon QF projects also have the option of selecting energy pricing that is based on monthly natural gas prices. Idaho Power's Oregon Schedule 85 is the direct result of OPUC docket UM 1129.

Oregon PURPA Contracts and Published Avoided Costs

- The term of the agreements cannot exceed 20 years.
- For projects up to 10 MW nameplate rating, energy prices are based on the published avoided cost. Idaho Power is required to use standard contracts that have been pre-approved by the OPUC (Oregon Schedule 85).
- For projects greater than 10 MW nameplate rating, energy prices and other contract terms and conditions are negotiated. The starting point for the negotiations are the terms and conditions of the Oregon Schedule 85 standard contract and there are three pricing options available:
  - **Fixed Price Option**–The energy price is fixed for all energy deliveries.
  - **Deadband Option**–The deadband option contains a fixed price component plus a variable price component that is based on monthly natural gas prices. The calculated gas price is then confined between a cap and floor creating the "deadband".
  - **Gas Index Option**–The gas price option contains a fixed price component plus a variable price component that is based on monthly natural gas prices.

Wholesale Contracts

Idaho Power currently has one, fixed-term, off-system sales contract to supply 6 aMW to the Raft River Rural Electric Cooperative. Since the 2006 IRP was published, the term of the contract has been renewed annually and is expected to continue to be renewed each year until the contract expires at the end of September 2011.

The Raft River Cooperative is the electric distribution utility serving Idaho Power's former customers in Nevada. The agreement was established as a full-requirements contract after being approved by FERC and the Public Utilities Commission of Nevada.

The contract requiring Idaho Power to supply 6 aMW to the City of Weiser expired at the end of 2006 and was not renewed. The expiration of the City of Weiser contract was anticipated in the 2006 IRP.

Idaho Power and Montana's NorthWestern Energy negotiated a load-following agreement in which Idaho Power provided NorthWestern Energy 30 MW of load-following service. Idaho Power did not renew the load-following agreement at the end of 2007 because of concerns regarding the integration of new wind generation anticipated to be interconnected on Idaho Power's system.

NorthWestern has provided load-following services for the Salmon, Idaho area which is located in the NorthWestern Balancing Authority Area. Idaho Power and NorthWestern are currently working together to move the Salmon area load into the Idaho Power Balancing Authority Area. Idaho Power continues to use its transmission capacity on the Jefferson line to import power from Montana during the summer months. At present, Idaho Power purchases 83 MW during summertime, heavy-load hours from PPL EnergyPlus, LLC. Although the purchase agreement expires in 2012, Idaho Power plans to continue to use the available transmission capacity during the summer months.

Market Purchases and Sales

Idaho Power relies on regional markets to supply a significant portion of energy and capacity. Idaho Power is especially dependent on the regional markets and the existing transmission system used to import these purchases during peak periods. Reliance on regional markets has benefited Idaho Power customers during times of low prices as the cost of purchases, revenue from surplus sales, and fuel expenses are shared with customers through the power cost adjustment (PCA).

Committed Supply-Side Resources

Langley Gulch

The need for a new baseload power plant was identified in Idaho Power's 2004 and 2006 IRPs. The initial decision was to construct a coal-fired baseload resource, but regulatory, price, and environmental issues led Idaho Power to reconsider the coal resource and instead select a natural gas-fired combined-cycle combustion turbine (CCCT). Idaho Power completed the competitive bidding process in early 2009 and selected a 300 MW CCCT project near New Plymouth, Idaho to meet the resource need.

The Langley Gulch project is expected to begin delivering energy in time to meet summer peaking needs in July 2012. The Langley Gulch project will require the construction of short segments of 138-kV and 230-kV transmission lines to connect to the existing system in order to deliver energy and provide capacity support to Idaho Power customers in Idaho and Oregon. The Langley Gulch resource is included when calculating the energy and capacity deficits discussed later in the IRP.

Wind RFP

Idaho Power's acknowledged 2006 IRP included a 150 MW wind generation resource to be added in 2012. With the passage of the American Recovery and Reinvestment Act of 2009 (the economic stimulus package), Idaho Power believed it would be advantageous to accelerate the timing of this resource acquisition. In May 2009, Idaho Power released an RFP for up to 150 MW of wind generation. Proposals were received in June 2009; however, the evaluation process was delayed due to the analysis of transmission constraints impacting all of the proposed projects. In October 2009, the company initiated contract negotiations which are anticipated to be completed by the end of 2009. Idaho Power expects to have a signed contract to submit for regulatory approval during the first quarter of 2010.

Shoshone Falls Upgrade Project

In August 2006, Idaho Power filed a license amendment application with FERC to upgrade the Shoshone Falls Hydroelectric 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 upgrade project involves replacing the two smaller units with a single 50 MW unit which will result in a net upgrade of 49 MW.

In March 2007, Idaho Power received a draft Environmental Assessment (EA) and Notice of Ready for Environmental Analysis from FERC that provided a 60-day comment period for interested parties. FERC issued a supplemental EA in December 2007 and Idaho Power expects a license amendment will be issued during 2010. For the 2009 IRP, Idaho Power is planning on the additional capacity from the Shoshone Falls upgrade being available in October 2015. When the project is completed, Idaho Power expects the additional generation from the upgrade will qualify for RECs that can be used to satisfy federal renewable electricity standard (RES) requirements.

The Shoshone Falls Upgrade Project has been included in previous Idaho Power IRPs as a committed resource. For the 2009 IRP, the project was treated as an uncommitted resource; however, it was included in all the portfolios analyzed because it is the most cost-effective new supply-side resource

available. In order to quantify the value of the project, the preferred portfolio was subsequently analyzed without the upgrade project included. The results of this analysis indicate the project adds approximately $11.5 million of value (excluding capital cost and REC value) to the portfolio each year (average annual nominal dollars for 2016–2019), and $15 million with RECs using the expected-case REC price curve.

In the 2009 IRP, the expected levelized cost of energy from the upgrade (without RECs) is $73 per MWh under median water assumptions, which makes the project the least expensive of all the supply-side options analyzed in the 2009 IRP. The project becomes even more economically attractive depending on the assumed future value of RECs. While the evaluation of the Shoshone Falls upgrade was done under median water conditions, some uncertainty exists regarding future Snake River streamflows that would not only impact the Shoshone Falls project, but all of Idaho Power's Snake River hydroelectric projects. Additional details regarding water issues can be found in Chapter 2.

Because of the benefits and additional value provided by the Shoshone Falls Upgrade Project, it remains in the 2009 IRP preferred portfolio. Idaho Power will continue to pursue this project in conjunction with the resolution of water issues in the state of Idaho.

Geothermal, Combined Heat and Power, and Small Hydro

The preferred portfolio in Idaho Power's 2006 IRP included 50 MW of geothermal energy in 2009 and 50 MW of energy from Combined Heat and Power (CHP) in 2010. In June 2006, Idaho Power released a geothermal RFP that resulted in a long-term PPA with U.S. Geothermal, Inc. for approximately 13 MW of generation from the Raft River Geothermal Project. In January 2008, Idaho Power released another RFP for up to 100 MW of geothermal energy; however, by the time the evaluation process was completed all the bidders had withdrawn their proposals.

Although the results of the geothermal RFP processes have been disappointing, Idaho Power has continued to work with project developers capable of delivering energy to the company's service area. Idaho Power has included two 20 MW increments of geothermal energy in 2012 and 2016 in the 2009 IRP as a committed resource. While there is still uncertainty regarding the development of geothermal projects, ongoing contract negotiations warrant the inclusion of a small amount of geothermal energy in the IRP. Idaho Power will continue to monitor geothermal project development and is hopeful geothermal energy will become an economic and readily available resource for its customers.

The 2006 IRP also included 50 MW of CHP coming on-line in 2010. In April 2008, Idaho Power solicited large industrial customers to determine the level of interest in CHP development. Because the level of interest in CHP development was far less than anticipated in the 2006 IRP, CHP is not shown as a committed resource in the 2009 IRP. However, Idaho Power continues to work with parties to explore CHP projects and will pursue opportunities as they develop.

Idaho Power's commitment to continue investigating CHP projects is evidenced by an agreement signed in November 2009 with the Idaho Office of Energy Resources (IOER) and Amalgamated Sugar, one of Idaho Power's large industrial customers. The agreement establishes the framework for a CHP feasibility study to be performed at Amalgamated Sugar's Nampa, Idaho facility that could be as large as 100 MW. Under the agreement, IOER will allocate up to $20,000 of DOE grant funds and Idaho Power will contribute up to an additional $20,000 to fund the study.

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 hydro sites have been extensively developed in southern Idaho on irrigation canals and others sites, many of which have PURPA contracts with Idaho Power.

Because small hydro, in particular, run-of-river and projects requiring small or no impoundments, does not have the same level of environmental and permitting issues as large hydro, the IRP Advisory Council (IRPAC) expressed an interest in including small hydro in the 2009 IRP. The potential for new small hydro projects was recently studied by the Idaho Strategic Alliance's Hydropower Task Force. The results of this evaluation are presented in a draft report available on the IOER's Web site at www.energy.idaho.gov. Idaho Power and others also continue to evaluate pumped storage opportunities and the state of Idaho is examining possible large water storage projects for flow augmentation and the potential for hydropower.

Due to potential regulation of carbon emissions and the associated costs, new small hydro may be a feasible resource option for Idaho Power. However, uncertainty exists in the level of available sites and the likelihood the sites would be developed as PURPA projects. Therefore, Idaho Power has not included small hydro as a committed resource in the 2009 IRP. Similar to geothermal and CHP resources, Idaho Power will evaluate small hydro development opportunities as they emerge.

Distributed Generation

In 2006, Idaho Power renewed its investigation of a dispatchable customer generation program. As initially conceptualized by the company, the program would use non-residential customers' standby generators for up to 400 hours a year to help meet system peak power demands. Customer generators would operate parallel with Idaho Power's generation resources during times of peak energy demand and also provide back-up for the customer's facility when needed. The customers' generators would be started remotely by Idaho Power's dispatch center.

Idaho Power performed a feasibility analysis of the concept, examining the various costs involved in the interconnection of backup generators as well as the resulting operations and maintenance costs. Both initial generator installations and existing retrofits were considered. The analysis concluded that Idaho Power would have to make a significant infrastructure investment.

Idaho Power determined that it was necessary to do an in-depth analysis of the interconnection costs, targeting generators of different sizes, ages, and locations. Five Idaho Power customers committed to the detailed analysis and allowed the company to perform an on-site interconnection analysis. The on-site analysis provided a more detailed cost estimate and determination of the program's potential viability. Idaho Power concluded that it may be economical to operate customers' generators during short periods of high energy demand.

Following the detailed analysis, Idaho Power began investigating air quality and permitting issues. If a customer generation program was implemented, Idaho Power would most likely dispatch customers' generators, almost all of which use diesel fuel, at times of peak system demand, which occurs most often on hot, summer afternoons—the times when air quality may already be compromised. In addition, Idaho Power has received concerns from the environmental community regarding air quality issues associated with operating diesel generators.

In April 2008, Idaho Power filed an updated status report on the investigation with the IPUC. In late 2008, Idaho Power held several meetings with the Industrial Customers of Idaho Power (ICIP) and the IPUC staff to discuss the research and findings related to a dispatchable generation program. However, none of the meetings resulted in sufficient support to file a dispatchable generation program at that time. Idaho Power did agree to further analyze a dispatchable generation resource option targeting new generator installations that are fueled by natural gas as part of the company's 2009 IRP.

Both natural gas- and diesel-fueled distributed generation (DG) options were analyzed as part of the 2009 IRP. Because of air quality concerns the potential programs were analyzed at a lower capacity factor of 0.69 percent (60 hours-per-year), which more closely matches the capacity factor of demand response programs. At a capacity factor of 0.69 percent, the results of the analysis indicated a natural gas

option would have a 30-year, levelized cost of $519 per MWh and $808 per MWh for diesel. The cost estimate for a natural gas-fired peaking resource (SCCT) is $234 per MWh at a 6 percent capacity factor and $1,165 per MWh at a capacity factor of 0.69 percent. Because the cost estimates for the DG options fall within the range of costs for a SCCT, Idaho Power has committed to work with the ICIP to determine if a cost-effective program can be established.

Several questions remain to be answered regarding air quality issues and whether the backup generators can qualify as operating reserves. Based on Idaho Power's survey of industrial customers, the initial size of the program is expected to reach approximately 15 MW; however, the ICIP is more optimistic and believes the program could reach 80 MW. Idaho Power will continue to work with the ICIP to resolve outstanding issues and is optimistic a program can be developed that will benefit all of Idaho Power's customers.

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4. DEMAND-SIDE MANAGEMENT

Demand-side management (DSM) customer programs are an essential component of Idaho Power's resource strategy. Idaho Power works with its customers to promote energy efficiency and produce the same output or provide the same level of service with lower energy consumption. Through demand response programs, Idaho Power provides incentives to customers to identify applications where a short-term load reduction can be timed to coincide with peak energy consumption when purchased power is most expensive. Energy efficiency and demand response programs address all four major customer classes: residential, irrigation, commercial, and industrial.

Market transformation, an additional program category, targets energy savings through engaging and influencing large national and regional organizations to promote energy efficiency. Idaho Power collaborates with other regional utilities and organizations in funding the Northwest Energy Efficiency Alliance (NEEA) market transformation promotional activities. *Appendix B—Demand-Side Management 2008 Annual Report* shows a detailed description of Idaho Power's energy efficiency program portfolio.

During each Integrated Resource Plan (IRP) planning period, Idaho Power uses various resources, including current program expansion, new program development, potential studies, Northwest Power and Conservation Council (NPCC) research, NEEA, and Idaho Power's Energy Efficiency Advisory Group (EEAG), to determine how future energy efficiency and demand response programs can fulfill electricity resource needs from demand-side resources. Idaho Power adopts new demand-side resources when determined cost-effective, indicating the benefits of avoided power generation costs exceed the costs of offering an energy efficiency program. Energy efficiency resources are usually one of the least-cost resources available for Idaho Power's resource stack. Figures 6.1 and 6.2 in Chapter 6 compare demand response and energy efficiency program costs with Idaho Power's supply-side resource options.

DSM Potential Study

In August 2007, Idaho Power contracted with Nexant, Inc. to conduct a DSM potential study to identify cost-effective new programs and opportunities to expand existing programs. The study took place during 2008, with a draft report delivered in September 2008. The DSM potential study included a comprehensive report detailing forecast reductions from Idaho Power's existing programs and the forecast reductions from new programs. In early 2009, Idaho Power requested a revision to the study methodology to make the models used for the study more adaptable and useful for the IRP process.

Highlights

- Idaho Power conducted a DSM potential study as part of preparing the 2009 IRP.
- Idaho Power implements all cost-effective DSM measures prior to analyzing the need for new supply-side resources.
- Existing and new energy efficiency programs are forecast to reduce average annual system load by 382 aMW by 2029.
- Demand response programs are forecast to reduce Idaho Power's summer peak load by 380 MW in 2012 and by nearly 500 MW in 2029.

Interactive models were provided by Nexant, which allowed Idaho Power to change the inputs based on new DSM avoided costs, market penetration, and other factors affecting energy savings potential. The overall potential assessment for Idaho Power's DSM programs was determined by characterizing a baseline profile for energy consumption by customer class, defining a list of applicable measures within each customer class, and calculating the achievable potential.

The achievable potential for energy efficiency programs was calculated by determining the technical and economic potential. Technical potential describes the possible savings if all baseline equipment stock in a program is replaced. Economic potential is a calculation of savings when all cost-effective measures are installed. Achievable potential is determined by applying expected market penetration rates to the economic potential. Achievable potential represents the savings Idaho Power expects to achieve from energy efficiency programs.

Forecast program savings were determined using the results of the DSM potential study and analyzing cost effectiveness with calculated avoided costs. The following sections provide additional details of the DSM potential study. Analysis for the IRP focused solely on new cost-effective measures that are currently not part of existing programs for the residential and commercial sectors and potential expansion over existing program performance for industrial efficiency.

Residential Efficiency Potential

Residential efficiency potential focused on increased savings by expanding weatherization measures for homes. Expansion potential included program measures similar to existing low income weatherization programs that would be available to all residential homes in Idaho Power's service area. Other measures included adding high efficiency water heating and freezers to the Home Products program, which promotes and incents the purchase and use of ENERGY STAR® products. As new products receive ENERGY STAR certification, the products will be reviewed for possible inclusion in the program. In addition, potential new savings could come from expanding Idaho Power's ENERGY STAR Homes Northwest program to non-owner occupied multi-family housing units. Savings from these new measures are forecast to start out at approximately 0.3 average megawatts (aMW) in 2010 and grow to 16 aMW by 2029.

Commercial Efficiency Potential

Nexant provided recommendations focused on the existing Easy Upgrades program, which was adopted as part of the 2006 IRP. The program targets commercial energy efficiency retrofit projects and offers a menu of measures. Nexant recommended several measures, including the expansion of high-efficiency motor offerings and various measures that would benefit commercial dairies, a growing industry in Idaho Power's service area. Savings from these new measures are forecast to be 0.8 aMW in 2010 and grow to 31 aMW by 2029.

Industrial Efficiency Potential

The primary driver for industrial efficiency potential is customer adoption rates, which are correlated to the incentive levels being offered. Nexant provided four tracks of achievable potential: low, moderate, aggressive, and maximum, correlating to incentives levels of 25, 50, 75 and 100 percent of customer costs, respectively. Idaho Power chose the aggressive potential level to model potential expansion to the current Custom Efficiency program, which pays industrial and large commercial customers proportionally to the electrical savings achieved on a per-project basis. With the adoption of the aggressive potential level, it is anticipated that 1 aMW of additional industrial energy efficiency can be obtained in 2010, which will increase to 67 aMW by 2029.

Irrigation Efficiency Potential

DSM potential research of Idaho Power's irrigation efficiency program offerings looked at energy savings relative to irrigation load, annual customer participation, turnover, and the list of measures available in the program for customers relative to other similar programs. In 2007, savings from the 819 completed projects under the Irrigation Efficiency Rewards program totaled 12,304 megawatt hours (MWh), representing 0.76 percent of the sector energy sales for the year. The present level of savings is at the high end of the range of results of similar programs offered by other utilities (0.1 to 0.8 percent). Considering the number of systems that might be replaced on an annual basis, Idaho Power's program may be reaching 80 percent of the potential customers. Because of the current success of the existing program, Nexant did not recommend implementation of any new energy efficiency programs for the irrigation sector.

Appliance Standard Assessment

Idaho Power contracted with Quantec, LLC, in 2007 to conduct a study of the potential energy savings and costs associated with enacting appliance energy efficiency standards in Idaho similar to the standards enacted in Oregon during 2007. The intent of the evaluation was to provide information regarding the costs and potential for energy savings that would occur if the appliance standards enacted by Oregon were applicable in Idaho. In addition, the evaluation provided information and an analytical base to promote new or additional appliance standards in Idaho. The study also addressed the concern that higher standards already in place in Washington and Oregon would increase the potential of less-efficient equipment being marketed and sold to Idaho residents.

Unlike a potential study, Idaho Power's Appliance Standards Assessment did not address the creation of corresponding cost-effective utility programs that would capture the savings discussed in the report. Some basic qualitative information about the level and type of effort required to conduct an appliance standards development program were considered as part of the report, while detailed programmatic recommendations were beyond the scope of the report. The energy savings shown in the report are similar in methodology to the technical potential savings defined in a typical energy efficiency potential study, where it is assumed that every available measure or appliance is replaced. Table 4.1 shows the 10 appliances that were considered for the study and their status in neighboring states. Table 4.2 summarizes the total savings forecast if standards were enacted, adopted, and allowed to penetrate the marketplace over 20 years throughout Idaho.

Table 4.1 Analyzed Appliances and Code Implementation Status

		Oregon		Neighboring States	
Appliance	Sector	Enacted	Effective	Washington	California
Metal halide lamps/fixtures	Commercial	2005	2008	Enacted	Enacted
Incandescent reflector lamps	Commercial	2005	2007	Enacted	Enacted
External power supplies	Commercial/Residential	2005	2007	Enacted	Enacted
Bottle-type water dispensers	Commercial	2007	2009		Enacted
Hot food holding cabinets	Commercial	2007	2009		Enacted
Walk-in refrigerators and freezers	Commercial	2007	2009		Enacted
Compact audio products (CD players)	Residential	2007	2009		Enacted
DVD players and recorders	Residential	2007	2009		Enacted
Portable electric spas/hot tubs	Residential	2007	2009		Enacted
Residential furnace fans	Residential	2007	2009		

Table 4.2 Appliance Standard Potential Savings—Idaho Statewide

Sector	Total estimated Energy Savings (MWh)	Total Estimated Demand Savings (MW)
Commercial	56,916	12
Residential	221,893	31
Overall	278,809	43

Based on the findings, Quantec recommended that Idaho Power consider developing and adopting Idaho appliance standards for the first nine appliances shown in Table 4.1. In addition, Quantec recommended specific alternatives be investigated for the possibility of increasing the efficiency of furnace fans. Quantec also recommended Idaho Power examine the options and monitor progress in setting standards for general service incandescent and metal halide fixtures.

To support the development of efficiency standards, Quantec also recommended that Idaho Power and other entities in Idaho identify priorities for conducting research and develop the data needed for such efforts. Expanding current collaborative efforts would leverage existing resources and minimize the need for additional resources.

At the state level, Quantec recommended the State of Idaho invest in the capability required to research and adopt standards for the appliances analyzed in the study. In addition, the state could investigate the option of developing a regulatory framework similar to California's that would recognize utilities' efforts dedicated to efficiency standards; similar to how utility energy efficiency acquisition programs are treated.

Demand-Side Management Analysis

Prior to the final portfolio selection, the current working portfolio of supply-side resources is used to model the value of avoided supply-side generation and market purchases that are being avoided through the implementation of DSM. The value of avoided generation is then balanced against program costs and costs incurred by customers in programs to create benefit-cost ratios.

Tables 4.3 and 4.4 summarize the analysis for the new energy efficiency and demand response resources forecasted for the 2009 IRP planning period. Each column represents the net present value of the 20-year stream of energy, utility costs, and resource costs. Utility costs are the direct expenses Idaho Power incurs in planning, implementing, and evaluating a DSM program, while the total resource cost is a measure of the total net resource expenditures of a DSM program from the point of view of the utility and its ratepayers as a whole. *Appendix C–Technical Appendix* describes Idaho Power's methodology of calculating cost effectiveness.

Energy Efficiency Cost Effectiveness

Table 4.3 demonstrates the new energy efficiency program measures and expansions adopted for resource planning in the 2009 IRP. The new energy efficiency programs are estimated to be effective with a total resource benefit-to-cost ratio of 3.2. The ratio indicates that the benefits of avoided power generation due to the energy efficiency programs exceed the costs to the utility and its customers by more than three times. The highest total resource benefit-to-cost ratio is the industrial efficiency programs with a benefit-to-cost ratio of 4.9 and levelized cost of 2.6 cents per kilowatt hour (kWh). Cost effectiveness screening for the residential and commercial sectors yielded benefit-to-cost ratios of 2.8 and 2.1, respectively.

The 20-year levelized total resource cost of each saved kWh is 4.0 cents; the programs save energy at a cost of $41 per MWh. For all of the energy efficiency programs, the combined net present value of the 20-year stream of avoided generation costs is over $587 million.

Table 4.3 New Energy Efficiency Cost Effectiveness Summary

	Impact		20-Year NPV Costs			Utility Costs		Total Resource Costs	
	2029 Load (aMW)	20-Year Energy (MWh)	Utility	Resource	Avoided Energy	Benefit/Cost Ratio	Levelized ($/kWh)	Benefit/Cost Ratio	Levelized ($/kWh)
Residential	29	1,097,000	$42,647,000	$51,412,000	$142,492,000	3.3	$0.039	2.8	$0.047
Commercial	31	1,043,000	15,207,000	68,482,000	143,366,000	9.4	0.015	2.1	0.066
Industrial	67	2,391,000	46,583,000	61,693,000	301,075,000	6.5	0.019	4.9	0.026
Total	127	4,531,000	104,437,000	181,587,000	586,933,000	5.6	0.023	3.2	0.040

Demand Response Cost Effectiveness

Table 4.4 summarizes the cost-effectiveness analysis for all demand response programs, existing or new, that were considered for the 2009 IRP. The overall 20-year levelized cost for the demand response portfolio of programs is estimated at $46 per kW, with a peak forecasted demand reduction of 367 megawatts (MW) during the planning period. The benefit-to-cost ratio for the portfolio of programs is 1.5, with an estimated net present value of $258 million in avoided generation capacity costs over 20 years, relative to the estimated $176 million dollars to administer the programs.

Table 4.4 Demand Response Cost-Effectiveness Summary

	Impact		20-Year NPV Costs			Total Resource Costs	
	2029 Load (MW)	20-Year Energy (MWh)	Utility	Resource	Avoided Energy	Benefit/Cost Ratio	Levelized ($/kW)
Residential	51	555	$21,020,000	$21,020,000	$33,418,000	1.6	$38
Commercial/Industrial	56	574	35,339,000	35,339,000	39,982,000	1.1	62
Irrigation	260	2,749	120,389,000	120,389,000	185,239,000	1.5	44
Total	367	3,878	176,748,000	176,748,000	258,639,000	1.5	46

Energy Efficiency Programs

During the preparation of the IRP, Idaho Power analyzes various DSM options, including current program expansion and new program development. Idaho Power also uses potential studies, NPCC research, NEEA, and the EEAG to determine the best methods of designing and implementing DSM programs. Idaho Power is committed to adopting all cost-effective DSM, which is determined by comparing the cost of DSM programs to the cost of supply-side resource options. Table 6.2 compares the cost of DSM options to various supply-side alternatives that were also evaluated in the 2009 IRP. The methodology used to screen the cost effectiveness of DSM programs is discussed later in this chapter and in greater detail in *Appendix C–Technical Appendix.*

In addition to the new program identification resulting from the DSM potential study, internal program development identified an additional four new energy efficiency programs and one demand response program for the 2009 IRP. One existing demand response program, Irrigation Peak Rewards, was redesigned as a dispatchable program with significantly more peak reduction capability. The additional peak reduction potential from the program was modeled as a new resource for the

2009 IRP, along with the other new programs. No new industrial or irrigation efficiency programs were planned as new resources for the 2009 IRP.

By 2029, existing and committed energy efficiency programs are forecast to provide 255 aMW of system load reduction and 289 MW of peak-hour load reduction. The energy and capacity effects from the company's existing and committed energy efficiency programs are accounted for in Idaho Power's sales and load forecast. However, peak-hour load reduction due to demand response programs is not included in the forecast, but is accounted for in the peak-hour load and resource balance. *Appendix A– Sales and Load Forecast* includes the annual forecast impact of existing and committed DSM programs by customer class for each year of the IRP planning horizon.

New energy efficiency measures are forecast to offset 127 aMW of average annual load by 2029 at an estimated total resource cost of 4.0 cents per kWh. Industrial efficiency program expansion identified in the potential study will provide more than 50 percent of the reduction, or almost 67 aMW at a cost of 2.6 cents per kWh. The next lowest cost energy efficiency acquisition is from residential programs which include new weatherization program measures and an expansion of the Home Products Program that provides incentives for customers to purchase ENERGY STAR qualified appliances. The combined contribution is forecast to reduce load by 29 aMW at a total resource cost of 4.7 cents per kWh. For the commercial customer class, the new energy efficiency portfolio from the potential study includes higher cost measures, such as higher efficiency motors and agricultural measures along with one new small commercial Holiday Lighting program. The commercial sector is forecast to provide 31 aMW of load reduction by 2029 at a total resource cost of 6.6 cents per kWh.

Residential Program Planning

Three new efficiency programs were implemented during 2009. The Home Improvement Program offers customer incentives for attic insulation retrofits into existing residential homes. The Weatherization Solutions for Eligible Customers program provides increased home weatherization opportunities for families that do not qualify for the long standing Weatherization Assistance for Qualified Customers (WAQC) program. The See Ya Later Refrigerator program incents customers to recycle secondary refrigerators and freezers. The combined forecasted impact for these three new programs in 2010 is 2,440 MWh in annual energy savings, or 0.28 aMW of system load reduction, growing to an estimated impact of 82,113 MWh in 2029 or 9.4 aMW of reduced average system load.

Commercial Program Planning

The Holiday Lighting program enables commercial customers to recycle old incandescent holiday lights and replace them with light-emitting diode (LED) bulbs. The seasonal program was added to the portfolio of existing commercial programs during 2009 and will result in savings of approximately 0.1 aMW in 2010, growing to 0.5 aMW at the end of the IRP planning period. While relatively small, the Holiday Lighting program provides a unique opportunity for educating all customers about the energy savings potential of LED technologies.

Demand Response Resources



Irrigation customers make significant contributions to Idaho Power's DSM programs.

The goal of demand response programs at Idaho Power is to reduce the summer peak electric load during periods of high demand and minimize or delay the need to build new supply-side alternatives, such as gas-turbine peaking resources.

Two major demand response program changes occurred in 2009 that expanded the dispatch capability of Idaho Power to reduce system demand during critical summer peak load events. The Irrigation Peak Rewards program, originally identified as a resource in 2004, was changed to a direct load control or dispatchable program. In prior years, demand reduction through the program was controlled with programmed timers that provided demand reduction from irrigation pumping systems from 4:00 p.m. to 8:00 p.m. on weekdays in June, July, and August. Options added to the program in 2009 allowed direct load control or dispatch capabilities to match demand response resources with actual system peaks. While fixed timers remain an option, the dispatchable change in the program will increase the program's peaking resource capacity from its previous range of 34 to 37 MW to a forecasted impact of 260 MW at program maturity in 2012. Actual demand reductions from the revised program will depend on the level of irrigation customer participation, drought conditions, and agricultural business cycles. Details on the approved Irrigation Peak Rewards tariff changes are listed as part of Case No. IPC-E-08-23 on the IPUC Web site.

Another demand response program that emerged for the 2009 IRP planning period was the FlexPeak Management program. The program is offered to commercial and industrial customers through a third-party demand response aggregator. FlexPeak Management is expected to provide nearly 40 MW of peak demand reduction in 2010 and over 56 MW by 2012, as part of a five-year contract. For details corresponding to the program addition, view Case No. IPC-E-09-02, Order No. 30805 on the IPUC Web site.

As part of the 2009 IRP process, Idaho Power prepared an updated forecast of the A/C Cool Credit program. Using communication hardware and software, Idaho Power cycles participants' central air conditioners on and off during summer peak load events. The A/C Cool Credit program is forecast to exceed 50 MW in potential reduction with continued growth in the Treasure Valley and planned expansion into Twin Falls, Mountain Home, and Pocatello, Idaho. Through the life of the planning period, combined total impact of the three programs is forecast to be 310 MW in 2010 and 367 MW in 2012. Table 4.4, in the Demand Response Cost Effectiveness section of this chapter shows expected program performance and associated costs.

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5. Planning Period Forecasts

The Integrated Resource Plan (IRP) process requires the preparation of numerous forecasts which can be grouped into three main categories—load forecasts, a generation forecast, and financial assumptions. The load and generation forecasts, including supply-side resources, demand-side management (DSM), and transmission import capability, are used to estimate surplus and deficit positions in the load and resource balance. The identified deficits are then used to develop resource portfolios which are evaluated using financial tools and forecasts. The following sections provide details on the forecasts prepared as part of the 2009 IRP.



Idaho Power has served Idaho and Oregon customers for almost 100 years.

Load Forecast

Historically, Idaho Power has been a summer peaking utility, with peak loads driven by irrigation pumps and air conditioning in the months of June, July, and August. In recent years, the growth rate of peak-hour load has exceeded the growth of average monthly load. However, both measures are important in planning for future resources and are part of the load forecast prepared for the 2009 IRP.

The expected-case (median) load forecasts for peak-hour and average energy represent Idaho Power's most probable outcome for load growth during the planning period. However, the actual path of future electricity sales will not exactly follow the path suggested by the expected-case forecast. Therefore, four additional load forecasts were prepared, two that provide a range of possible load growths due to economic uncertainty, and two that address the load variability associated with abnormal weather.

Highlights

- The 2009 IRP load forecast projects peak-hour load will grow at an average annual rate of 53 MW (1.5 percent) and average system load at 13 aMW (0.07 percent) over the 20-year planning period.
- Idaho Power expects the number of residential customers to increase 1.7 percent annually to more than 550,000 by the end of the planning period in 2029.
- The 2009 IRP sales and load forecast is influenced by the estimated impact of proposed carbon legislation on retail electricity prices.
- Idaho Power's customers set a new, winter system peak record of 2,527 MW on December 10, 2009 during several days of below normal temperatures.

The high-growth and low-growth scenarios provide boundaries on each side of the expected-case forecast and historical load variability potential on future load due to demographic, economic, and other non-weather related influences. The 70th percentile and 90th percentile load forecast scenarios were developed to assist Idaho Power's review of the resource requirements that would result from higher loads due to adverse weather conditions.

Idaho Power prepares a sales and load forecast each year as part of the company's annual financial forecast. The economic forecast is based on a forecast of national and regional economic activity developed by Moody's Analytics, a national econometric consulting firm. Moody's Analytics June 2009 macroeconomic forecast strongly influenced the 2009 IRP load forecast. The national, state, metropolitan statistical area (MSA), and county econometric projections are tailored to Idaho Power's service area using an economic database developed by an outside consultant. Specific demographic projections are also developed for the service area from national and local census data. National economic drivers from Moody's Analytics are also used in developing the 2009 IRP load forecast. The forecast of the number of households and employment projections, along with customer consumption patterns, are used to develop customer forecasts and load projections.

Weather Impacts

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

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

Weather conditions are the primary factor affecting the load forecast on the hourly, daily, weekly, monthly, and seasonal time horizon. Economic and demographic conditions affect the load forecast over the long-term time horizon.

Economic Impacts

The national recession that began in 2007 underscores the effects of the national and local economy on energy use in Idaho Power's service area. The severity of the current recession has resulted in a reduction in new residential customer growth from an average of 2,000 new residential customers per month prior to the recession, to approximately 200 new customers per month at the present time. Commercial and industrial customer energy use has contracted and overall system energy use has declined by 3.6 percent in 2009 from the prior year; the first time that overall energy use has declined since the energy crisis of 2001.

Increased population in Idaho Power's service area due to migration to Idaho from other states is expected to continue throughout the planning period and has been included in the load forecast model. Idaho Power also continues to receive requests from prospective new large load customers that are

attracted to southern Idaho due to the relatively low electric rates. In addition, the economic conditions in surrounding states may encourage some manufacturers to consider moving operations to Idaho.

The number of households in Idaho is projected to grow at an annual average rate of 1.3 percent during the 20-year forecast period. Growth in the number of households within individual counties in Idaho Power's service area differs from statewide household growth patterns. Service area household projections are derived from individual county specific household forecasts. Growth in the number of households within Idaho Power's service area, combined with estimated consumption per household adjusted for DSM measures, results in a 0.7 percent residential load growth rate. The number of residential customers in Idaho Power's service area is expected to increase 1.7 percent annually from approximately 404,000 at the end of 2008 to over 563,000 by the end of the planning period in 2029.

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 0.6 percent (over the period 2010 through 2029) is comprised of residential load growth of 0.7 percent, commercial load growth of 0.7 percent, declining irrigation load growth of -0.3 percent, industrial load growth of 1.0 percent, and additional firm load growth of 2.3 percent.

The 2009 IRP average system load forecast is lower than the 2006 IRP average system load forecast in all years of the forecast period. The slowdown in the national and service-area economy caused load growth to slow significantly. In addition, the significant increase in assumed DSM combined with retail electricity price assumptions that incorporate estimates of assumed carbon legislation both serve to decrease the forecast of average loads. Significant factors and considerations that influenced the outcome of the 2009 IRP load forecast include:

- For the first time, the sales and load forecast is influenced by the estimated impact of proposed carbon legislation on retail electricity prices. Retail electricity prices move significantly higher throughout the forecast period, reducing future electricity sales.
- Existing energy efficiency program performance is estimated and included in the sales and load forecast base, lowering the energy and peak demand forecast. However, the impact of demand response programs is accounted for in the load and resource balance. 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*.
- A collapse in the housing sector has significantly slowed the growth in the number of residential customers being added within Idaho Power's service area. The number of commercial customers being added has also slowed as a result of the economic downturn. Both forecasts of the number of residential and commercial customers were adjusted downward in the near term to reflect the current housing slowdown and credit crisis. By 2012, residential and commercial customer growth is expected to recover and customer additions are expected to be similar to the growth that occurred in the 1993–2003 timeframe, prior to the housing bubble.
- A somewhat higher irrigation sales forecast compared to recent years due to a substantial increase in weather-adjusted irrigation sales over the last two years (6 percent in 2007 and 8 percent in 2008). High commodity prices appear to be the primary reason behind the irrigation sales increase. Farmers appear to have taken advantage of the commodities market by planting all available acreage. In addition, the conversion of hand lines to electrically operated pivots may explain a part of the increased energy consumption. In recent years, the increased labor costs associated with moving hand lines has triggered the substitution of labor with electrically operated pivots.

- The uncertainty associated with the industrial and special contract sales forecasts. The forecast uncertainty is due to the number of parties that contacted Idaho Power and expressed interest in locating production operations within Idaho Power's service area and the unknown magnitude of the energy and peak demand requirements. The current sales and load forecast reflects only those customers that have a high probability of locating in the service area or have made financial commitments and whose facilities are actually being constructed at this time. Therefore, the number of large customers that have contacted Idaho Power and shown interest, but have not made commitments, are not included in the current sales and load forecast.

Peak-Hour Load Forecast

The firm 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 (excluding Astaris), and the Raft River Rural Electric Cooperative wholesale agreement. Idaho Power uses the 95th percentile forecast as the basis for peak-hour planning in the IRP. The 95th percentile forecast is based on 95th percentile average peak day temperatures to forecast monthly peak-hour load.

Idaho Power's system peak-hour load record is 3,214 MW, which was recorded on Monday, June 30, 2008, at 3:00 p.m. The previous year's summer peak demand was 3,193 MW and occurred on Friday, July 13, 2007, at 4:00 p.m. Summertime peak-hour load growth has accelerated over the past 10 years as air conditioning has become standard in nearly all new residential home construction and new commercial buildings. The 2009 IRP load forecast projects peak-hour load to grow by approximately 53 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.

Figure 5.1 and Table 5.1 summarize three forecast outcomes of Idaho Power's estimate of annual system peak load considering median, 90th percentile and 95th percentile weather impacts on the expected (median) peak forecast. The 95th percentile forecast uses the 95th percentile peak-day average temperature to determine monthly peak-hour demand. The planning criteria for determining the need for peak-hour capacity assumes the 95th percentile peak-day temperature conditions.

Figure 5.1 Peak-Hour Load Growth Forecast

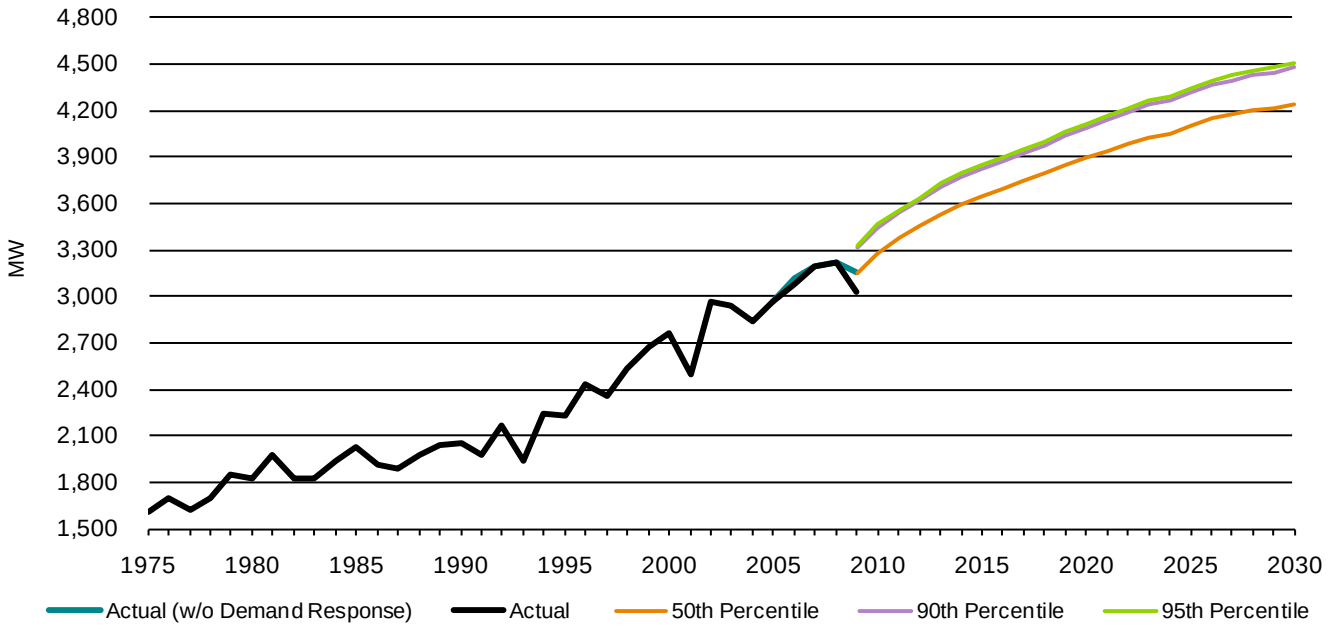


Table 5.1 Load Forecast—Peak-Hour (MW)

Year	Median	90th Percentile	95th Percentile
2009 (Actual)	3,160	3,160	3,160
2010	3,279	3,439	3,460
2011	3,375	3,538	3,560
2012	3,447	3,614	3,636
2013	3,533	3,703	3,726
2014	3,592	3,766	3,789
2015	3,641	3,819	3,843
2016	3,689	3,871	3,895
2017	3,739	3,925	3,949
2018	3,790	3,978	4,003
2019	3,842	4,034	4,060
2020	3,895	4,091	4,118
2021	3,933	4,133	4,160
2022	3,980	4,183	4,210
2023	4,027	4,234	4,261
2024	4,052	4,262	4,290
2025	4,098	4,312	4,341
2026	4,146	4,364	4,393
2027	4,173	4,394	4,424
2028	4,204	4,430	4,460
2029	4,216	4,445	4,475
Growth Rate *(2010–2029)*	1.5%	1.5%	1.5%

The median or expected-case peak-hour load forecast predicts peak-hour load will grow from 3,160 MW in 2009 to 4,216 MW in 2029, 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 3,160 MW in 2009 to 4,475 MW in 2029. Historical peak-hour loads as well as the three forecast scenarios are shown in Figure 5.1.

Idaho Power's winter peak-hour load record was 2,527 MW, recorded on Thursday, 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 the variability of peak day temperatures 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 a series of four load forecasts that reflect a range of load uncertainty resulting from differing economic growth and weather-related assumptions. Figure 5.2 and Table 5.2 show the results of the four forecasts used in the 2009 IRP to estimate the boundaries of annual system load growth over the planning period. There is approximately a 90 percent probability that Idaho Power's load growth will exceed the low-load growth forecast, a 50 percent probability of load growth exceeding the expected-case forecast, a 30 percent probability of load growth exceeding the 70th percentile forecast, and approximately a 10 percent probability that load growth will exceed the high-growth forecast. The projected 20-year average annual compound growth rate in the expected-load forecast is 0.7 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 hydro generation, and 95th percentile average peak day temperature to forecast monthly peak-hour load.

Figure 5.2 Average Monthly Load Growth Forecast

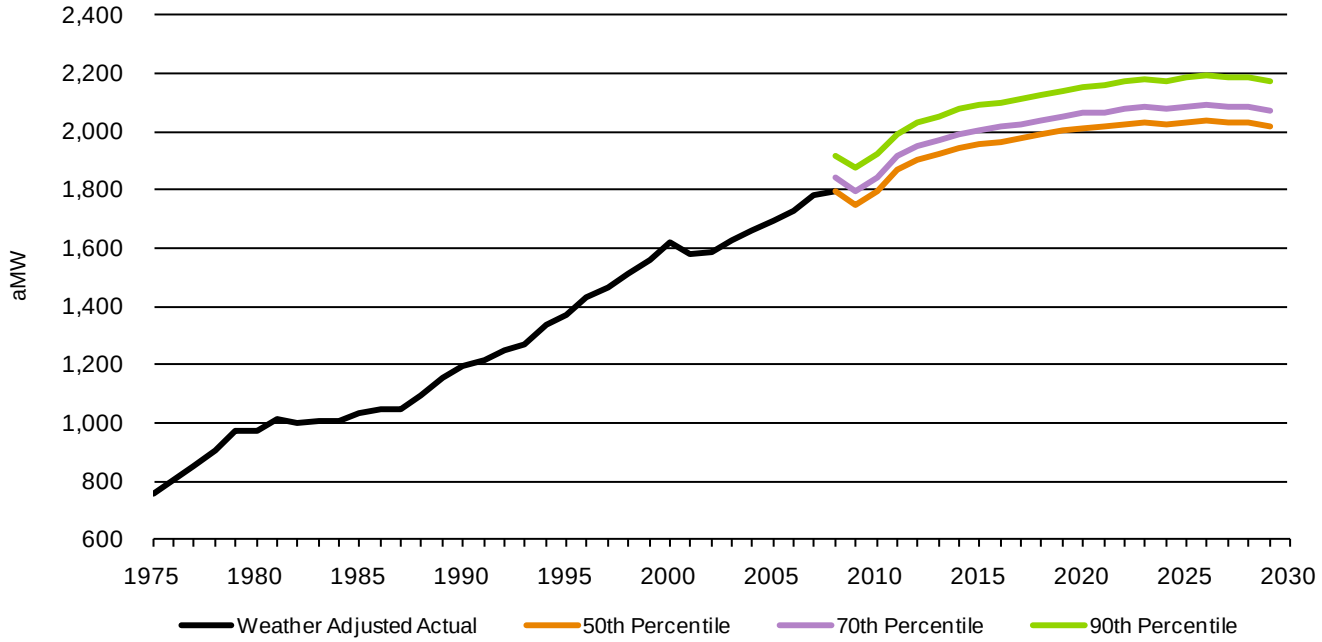


Table 5.2 Load Forecast—Average Monthly Energy (aMW)

Year	Median	70th Percentile	Low	High
2010	1,797	1,842	1,796	1,863
2011	1,869	1,914	1,834	1,933
2012	1,906	1,952	1,851	1,974
2013	1,926	1,972	1,859	2,003
2014	1,947	1,994	1,857	2,020
2015	1,957	2,005	1,858	2,039
2016	1,967	2,015	1,858	2,055
2017	1,979	2,028	1,864	2,078
2018	1,991	2,040	1,857	2,085
2019	2,002	2,051	1,862	2,105
2020	2,013	2,063	1,867	2,125
2021	2,017	2,067	1,872	2,145
2022	2,026	2,077	1,886	2,174
2023	2,032	2,083	1,901	2,205
2024	2,024	2,077	1,917	2,237
2025	2,035	2,088	1,932	2,268
2026	2,041	2,094	1,947	2,297
2027	2,034	2,088	1,961	2,328
2028	2,030	2,084	1,977	2,359
2029	2,015	2,070	1,991	2,389
Growth Rate	0.7%	0.7%	0.6%	1.6%

Additional Firm Load

Special contracts currently exist for five large customers that are recognized as firm load customers. The five customers are Micron Technology, Simplot Fertilizer, Idaho National Laboratory (INL), Hoku Materials, and Raft River. Together, these customers make up the additional firm load category.

Micron Technology

Micron Technology is currently Idaho Power's largest individual customer. In this forecast, electricity sales to Micron Technology are expected to move downward in 2009 as Micron phases out 200 millimeter (mm) dynamic random access memory (DRAM) operations at its Boise facility. Micron Technology will continue to operate its 300 mm research and development fabrication facility in Boise and perform a variety of other activities, including product design and support, quality assurance, systems integration and related manufacturing, corporate, and general services. Once establishing a new floor for energy consumption at the facility, at about a quarter less energy use than in recent years, Micron Technology's electricity use is expected to increase based on Moody's forecast of manufacturing employment in the Electronic and Electrical sector for the Boise MSA.

Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western United States. The future electricity usage at the plant is expected to grow at a slow pace throughout the planning period (2010–2029). The primary driver of long-term electricity sales growth at Simplot Fertilizer is Moody's forecast of gross product in the Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing sector for the Pocatello MSA.

Idaho National Laboratory

The INL is a U.S. Department of Energy (DOE) research facility located in eastern Idaho. The INL is operated for the DOE by Battelle Energy Alliance, LLC which includes the Battelle Memorial Institute teamed with several institutions, including BWXT Services, Inc., Washington Group International, the Electric Power Research Institute, and the Massachusetts Institute of Technology (MIT). The laboratory employs about 8,000 people.

The DOE provided an energy consumption and peak demand forecast through 2029 for the INL. The DOE forecast calls for loads to increase through 2012, remain flat for six years, and then slowly decline throughout the remainder of the forecast period.

Hoku Materials, Inc.

The sales and load forecast reflects the increased expected demand for energy and peak capacity of Idaho Power's newest special contract customer, Hoku Materials, located in Pocatello, Idaho. Hoku Materials plans to begin operation in December 2009 and reach full capacity by October 2010. The current sales and load forecast assumes that Hoku Materials will consume 74 aMW of energy each year and have a peak demand of 82 MW (each measure excluding line losses), once continuous operation is reached in 2012.

Planning Scenarios

The timing and necessity of future generation resources are based on a 20-year forecast of surpluses and deficiencies for monthly average load (energy) and peak-hour load. For both of these areas, one set of criteria has been chosen for planning purposes; however, additional scenarios have been analyzed to provide a comparison. Table 5.3 provides a summary of six planning scenarios analyzed for the 2009 IRP and the criteria used for planning purposes are shown in bold. Median water and median load forecast scenarios were included to enable comparison of the 2009 IRP with plans developed during the 1990s. The median forecast is no longer used for resource planning, although the median forecast is used to set retail rates and avoided cost rates during regulatory proceedings. The planning criteria used to prepare Idaho Power's 2009 IRP are consistent with the criteria used in the 2006 IRP.

Table 5.3 Planning Criteria for Average Load and Peak-Hour Load

Average Load/Energy (aMW)	50th Percentile Water, 50th Percentile Average Load **70th Percentile Water, 70th Percentile Average Load** 90th Percentile Water, 70th Percentile Average Load
Peak-Hour Load (MW)	50th Percentile Water, 90th Percentile Peak-Hour Load 70th Percentile Water, 95th Percentile Peak-Hour Load **90th Percentile Water, 95th Percentile Peak-Hour Load**

The planning criteria used for energy or average load are 70th percentile water and 70th percentile average load. In addition, 50th percentile water and 50th percentile average load conditions are analyzed to represent a median condition, and 90th percentile water and 70th percentile average load are analyzed to examine the effects of low water conditions.

Peak-hour load planning criteria consist of 90th percentile water and 95th percentile peak-hour load conditions, coupled with Idaho Power's ability to import additional energy on its transmission system. A median condition of 50th percentile water and 50th percentile peak hour load are also analyzed, as well as 70th percentile water and 95th percentile peak-hour load. Peak-hour load planning criteria are more stringent than average load planning criteria because Idaho Power's ability to import additional energy is typically limited during peak-hour load periods. Surpluses and deficiencies for the average and peak-hour load scenarios can be found in *Appendix C–Technical Appendix*.

Existing Resources

In order to identify the need and timing of future resources, Idaho Power prepares a load and resource balance which accounts for forecast load growth and generation from all of the company's existing resources and planned purchases. Updated load and resource balance worksheets showing Idaho Power's existing and committed resources for average energy and peak-hour load are shown in *Appendix C–Technical Appendix.* The following sections describe recent events or changes that are accounted for in the load and resource balance regarding Idaho Power's hydro, thermal, and transmission resources.

Hydro



Idaho Power manages stream flows for energy and wildlife.

For the 2009 IRP, Idaho Power continues the practice of using 70th percentile streamflow conditions for the Snake River Basin as the basis for the projections of monthly average hydroelectric generation. The 70th percentile means that 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 that 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.

The 50th, 70th, and 90th percentile streamflow forecasts used in the IRP are derived from a streamflow planning model developed by the Idaho Department of Water Resources (IDWR). The IDWR streamflow planning model is used by Idaho Power to produce a normalized hydrologic record for the Snake River Basin from 1928 through 2005. The normalized model accounts for current hydro conditions and historical hydro development with regard to groundwater discharge to the river, water management facilities, irrigation facilities, and operations.

In the past, Idaho Power has assumed the representative streamflow conditions calculated from the normalized record are static through the IRP planning period. For example, the practice has been to assume that a 70th percentile year in 2010 is identical to a 70th percentile year in 2015. A review of Snake River Basin streamflow trends suggests that persistent decline documented in the Eastern Snake Plain Aquifer (ESPA) is mirrored by downward trends in total surface water outflow from the river basin. The Comprehensive Aquifer Management Plan (CAMP) for the ESPA includes demand reduction and weather modification measures which will add new water to the basin water budget. However, it is the judgment of Idaho Power hydrologists that the positive effect of the new water associated with the new measures is likely to be temporary, and over time the water use practices driving the steady decline over recent years are expected to resume and result in a return to persistently declining basin outflows. For this reason, Idaho Power assumes that aside from a temporary increase in flows associated with the phasing in of demand reduction and weather modification measures, flows in the Snake River Basin are expected to decline year to year throughout the IRP planning period. The expected year to year decline in annual hydroelectric generation is less than 0.5 percent.

River temperature is an important concern that can affect the timing of Snake River streamflows. Various federal agencies involved in salmon migration studies have indicated a desire to shift delivery of flow augmentation water from the Upper Snake River and Boise River basins from the traditional

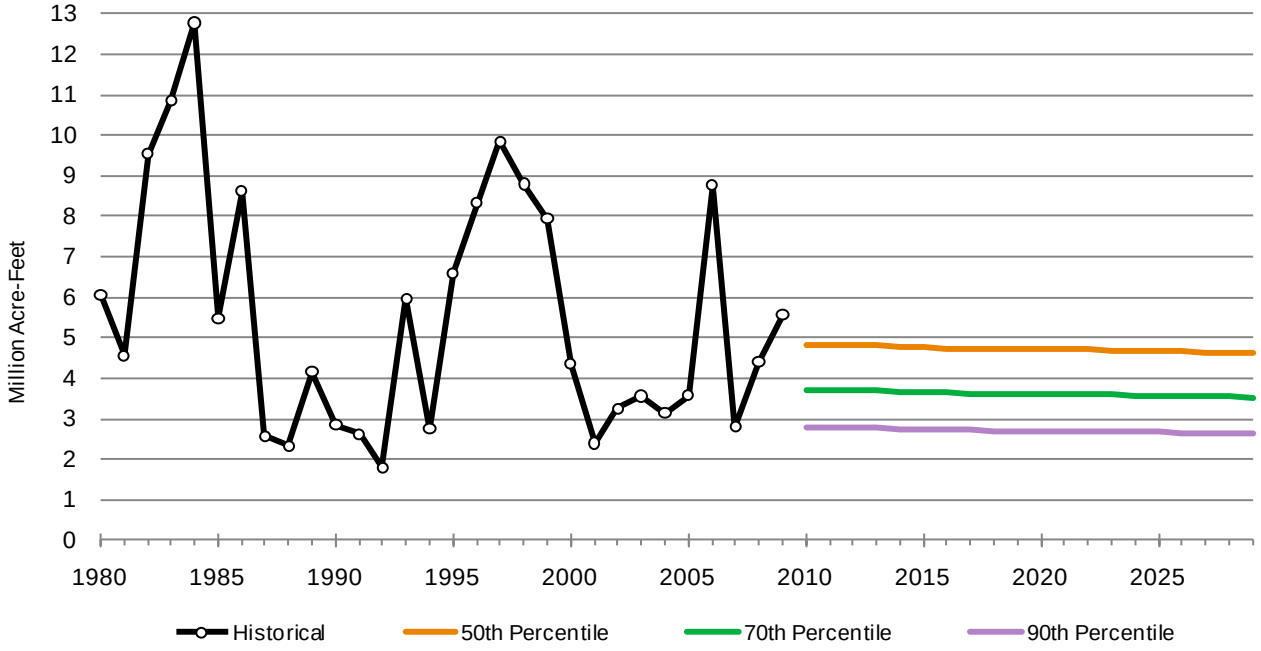
months of July and August to the spring months of April, May, and June. The objective of the streamflow augmentation is to more closely mimic the timing of the naturally occurring flow conditions. A federal study report indicates the shift in water delivery is most likely to take place during worse than median water years.

Because worse-than-median water is assumed in the IRP, and the importance of July as a resource constrained month, Idaho Power has incorporated the shifted delivery of flow augmentation water from the Upper Snake River and Boise River basins for the 2009 IRP. Augmentation water delivered from the Payette River Basin is assumed to remain in July and August. Based on preliminary resource planning analyses, monthly average hydroelectric generation for July under the 70th percentile streamflow condition is projected to decline by approximately 115 aMW as a result of the water being shifted out of the month of July.

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 Hells Canyon Complex as run-of-river plants. The generation model mathematically manages reservoir storage in the Hells Canyon Complex 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, an internally developed spreadsheet utilizing a commercial optimization routine is used to shape the monthly average generation for the Brownlee, Oxbow, and Hells Canyon projects into hourly generation profiles, while approximating compliance with Hells Canyon outflow ramp rate constraints, Brownlee Reservoir level constraints, and operating reserve obligations.

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

Figure 5.3 Brownlee Historical and Forecast Inflows



Idaho Power recognizes the need to remain apprised of scientific advancements concerning climate change on the regional and global scale. Idaho Power believes that 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 2009 IRP.

Thermal

Idaho Power's thermal generation resources are comprised of coal and natural gas-fired facilities. The coal-fired resources generally operate 24 hours-per-day, every day, to provide baseload energy. The natural gas-fired resources are generally used to meet peak-hour load on certain days during the summer months.

Monthly average energy forecasts for the coal-fired projects are based on typical baseload output levels, with seasonal reductions occurring primarily during spring months for regularly scheduled maintenance activities. Idaho Power schedules periodic maintenance to coincide with periods of high hydro generation, seasonally low market prices, and moderate customer load.

Plant modifications that are required to maintain compliance with air-quality standards are projected for the Boardman plant in 2014 and 2018, for the Valmy plant in 2018, and for the Bridger plant in 2009, 2015, and 2016. The total effect of the air quality modifications is a reduction in coal-fired generation of less than one percent. Offsetting the modifications at the Jim Bridger plant are planned efficiency upgrades that will create a net increase in average generation of 17 aMW by 2016.

With respect to peak-hour output, the coal-fired projects are forecast to generate at the full rated maximum dependable capacity, minus six percent to account for forced outages. The gas-fired resources are projected to be fully available to meet extreme load conditions or during periods of transmission congestion. The peaking capability of the natural gas resources is adjusted seasonally to reflect the effect of ambient air temperature.

Planned Upgrades at Thermal Facilities

Efficiency upgrades are planned for each of the four units at the Jim Bridger plant starting in 2010. The upgrades consist of replacing turbine components with higher efficiency designs for each unit's high pressure, intermediate pressure, and low pressure turbines. This project will start with the high pressure/intermediate pressure turbine upgrade on Unit 1 which will result in a generation increase of 2.1 MW. The low pressure turbines on Unit 1 will be replaced in 2018 which will increase output by another 4 MW for a total of 6.1 MW. Units 2, 3, and 4 will have all high pressure, intermediate pressure, and low pressure turbines replaced in 2016, 2017, and 2019. Idaho Power's share of the projected generation increase associated with each upgrade is a total of 6.1 MW per unit, with the increased output related solely to efficiency improvements with no additional fuel required. Idaho Power's share of the costs for the upgrades is expected to be approximately $11 million per unit.

Coal Price Forecast

The expected coal price forecast for the 2009 IRP is an average of Idaho Power's coal forecasts for its Valmy and Jim Bridger thermal plants. The coal price forecasts were created using current coal and rail transportation market information and the Global Insight 2008 U.S. Power Outlook report. The resulting costs are shown in Figure 5.4 and represent the delivered cost of coal, including rail costs, and use taxes. A summary of the coal price forecast can also be found in *Appendix C–Technical Appendix*.

Transmission Resources

Transmission constraints are an important factor in Idaho Power's ability to reliably serve peak-hour load. Idaho Power uses spot market purchases when the company's generating resources and firm purchases are inadequate to meet peak-hour load requirements and transmission constraints limit Idaho Power's ability to import additional energy.

For the IRP, the transmission analysis requires hourly forecasts for the entire 20-year planning period for both customer load and company generation. The hourly transmission analysis is used to quantify the magnitude of off-system market purchases necessary to serve forecast load, and to determine if adequate transmission capacity is available to deliver additional market purchases to load centers.

From the hourly load and generation forecasts, a determination can be made regarding the need for, and the magnitude of, the off-system market purchases needed to serve system load. The projected off-system market purchases are added to all other committed transmission obligations to determine if the additional imported energy will exceed the operational limits of the transmission system. The analysis assumes that all off-system market purchases will come from the Pacific Northwest.

Historically, during Idaho Power's peak-hour load periods, off-system market purchases from the east and south have proven to be unavailable or very expensive. Many of the utilities to the east and south of Idaho Power also experience a summer peak, and the weather conditions that drive Idaho Power's summer peak-hour load are often similar across the Intermountain Region. Therefore, Idaho Power does not typically rely on imports from the Intermountain Region for planning purposes.

For the 2009 IRP, Idaho Power has restricted its transmission analysis to the scenario assuming 90th percentile streamflows, 70th percentile load, and 95th percentile peak-hour load. The 95th percentile peak-hour load planning criterion means that there is a one in twenty chance that Idaho Power will be required to initiate more drastic measures such as curtailing load if attempts to acquire energy and transmission access from the spot market are unsuccessful.

Idaho Power used the results of the transmission analysis to establish a capacity target for planning purposes. The capacity target identifies the amount of additional generation, demand response programs, or transmission resources that must be added to Idaho Power's system to avoid capacity deficits.

On a yearly basis, Idaho Power's transmission capacity is reserved for native load service based on annual load and resource forecasts. Although transmission resources are owned by Idaho Power, the unreserved transmission capacity may be purchased by other parties due to FERC's open access requirements. Idaho Power must reserve the use of its own transmission system under FERC's open access rules. Often, Snake River flow forecasts for the remainder of the year are not known with a high degree of accuracy until May or June and late spring is often too late to acquire firm transmission capacity for the summer months.

Natural Gas Price Forecast

Future natural gas price assumptions significantly influence the financial results of the operational modeling used to evaluate and rank resource portfolios. The 2009 IRP natural gas price forecast uses several outside public and private forecast sources to develop a composite future yearly Henry Hub price curve. The forecast sources include the Northwest Power and Conservation Council (NPCC), the New York Mercantile Exchange (NYMEX), the Natural Gas Exchange, the Energy Information Administration (EIA), and Global Insight.

The individual annual forecasts from the outside sources are evaluated and weighted to calculate the composite forecast. The weighting is based on a combination of Idaho Power's expectation of price, the reasonableness when compared with other forecasts, and the current forward price of actual contracts

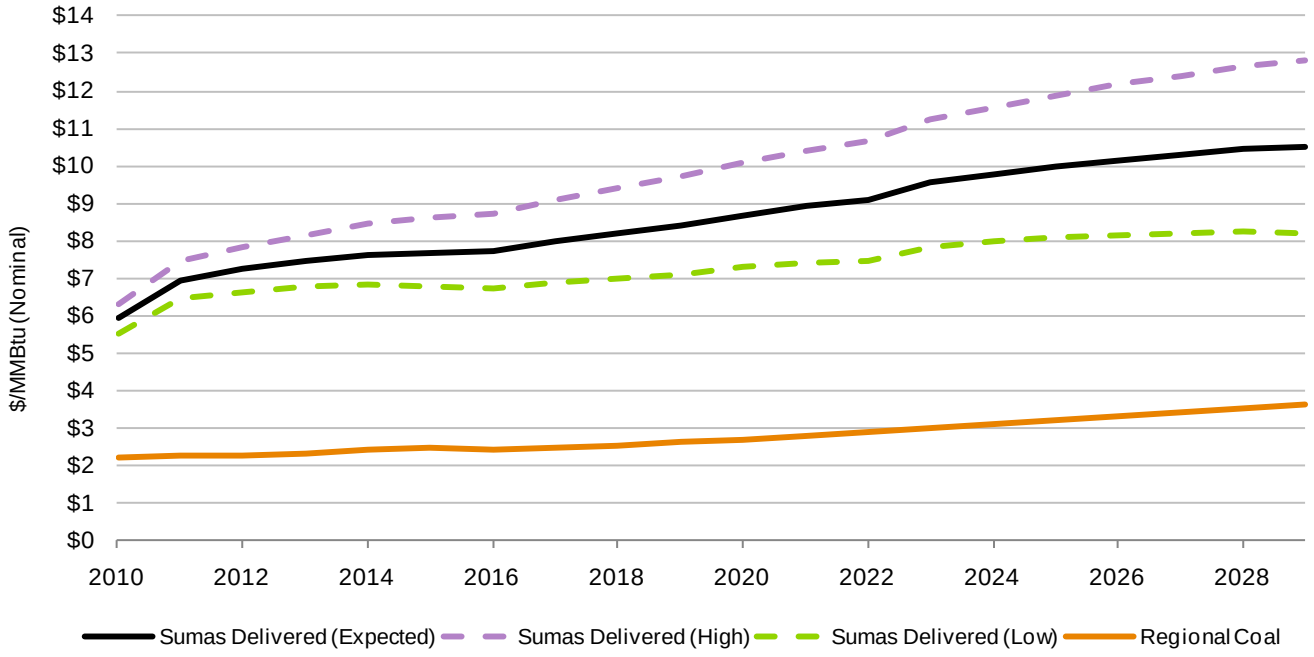
being executed on various exchanges. In the near-term forecast horizon, greater weight is given to actual commitment contracts being executed on the NYMEX compared to the longer term forecast which is weighted more heavily towards projected prices without underlying financial trades (EIA, Global Insight).

Regional price variability from the Henry Hub can be significant. Idaho Power uses a price adjustment based on the cost of delivering natural gas from the Sumas trading hub to model natural gas prices in southwest Idaho. The Sumas price adjustment incorporates the Pacific Northwest regional price variation from Henry Hub and the transportation charges from Northwest Pipeline Corporation to deliver natural gas to Idaho Power's service area. The 2009 IRP assumes pipeline transport capacity will be available for future resources at the current tariff rate that is included in the natural gas price forecast.

The Henry Hub price including the Sumas adjustment is shaped by month to reflect the normal seasonal supply and demand price variation. The gas price forecast in all future years receives the same monthly price shaping. Sumas gas prices can have high spot seasonal price variability, especially in the winter months and the Sumas price volatility is not included in the regional adjustment. Idaho Power's geographic position between Sumas gas and Rockies gas allows Idaho Power to access two independent gas markets that may not have high price correlation. Also, Idaho Power expects the majority of the gas planned for use in the resource portfolios will be scheduled and purchased on longer term contracts which will diminish Idaho Power's exposure to spot price and seasonal price volatility.

In addition to an expected gas price forecast, high and low natural gas price forecasts are developed in order to analyze the risk associated with prices substantially different than the expected-case. Figure 5.4 shows the expected, high and low natural gas price forecasts used in the 2009 IRP.

Figure 5.4 Fuel Price Forecast



Cost of Carbon Emissions

Idaho Power's 2009 IRP analyzes the potential cost of carbon emissions differently than has been done in previous IRPs. Historically, a "carbon adder" or tax has been used to account for the social costs of emitting carbon or other combustion byproducts. The purpose of a carbon adder is to account for all of the costs in the price of energy produced by carbon-emmitting resources. Both the Waxman–Markey bill (H.R. 2454) and the Boxer–Kerry bill (S. 1733) propose a cap-and-trade system for reducing carbon emissions and Idaho Power considers the implementation of a cap-and-trade system to be more likely than a carbon tax.

Although Idaho Power believes a cap-and-trade system is more likely, regulatory requirements dictate the analysis be performed using a carbon adder, which Idaho Power has also done. However, the primary discussion in the 2009 IRP regarding carbon emissions is related to Idaho Power's attempt to model a cap-and-trade scenario under the provisions of the Waxman–Markey bill. To model the cap-and-trade scenario, Idaho Power has reduced the output from its coal facilities based on the number of allowances that are expected to be allocated to the company. The cost of resource portfolios with emissions in excess of the allocated amount of allowances are increased by purchasing additional allowances.

The primary reason for adopting the cap-and-trade analysis in the 2009 IRP is to quantify the effects of the proposed carbon legislation. Idaho Power's analysis indicated that a pure carbon tax increased portfolio costs but did not result in a substantial reduction of emissions. Since the purpose of the legislation is to reduce carbon emissions, Idaho Power selected a modeling approach that actually reduced carbon emissions. In addition, Idaho Power considers the cap-and-trade legislation the most likely to be implemented.

In order to quantify the cost of the proposed legislation, Idaho Power has also modeled a scenario where output from existing coal facilities has not been curtailed. A more thorough discussion of the analysis of carbon emissions is contained in Chapters 8, 9 and 10.

6. Supply-Side Resources

Supply-side facilities are traditional generation resources. Early integrated resource plan (IRP) utility commission orders directed Idaho Power and other utilities to give equal treatment to both supply-side and demand-side resources. The company has done that and today, demand-side programs are an essential component of Idaho Power's resource strategy. The following sections describe all of the supply-side resources that were considered when Idaho Power developed the resource portfolios for the 2009 IRP. Not all of the supply-side resources described in this section were included in the preliminary resource portfolios, but every resource described below was considered.

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 2009 IRP, renewable resources were included in all portfolios analyzed in order to meet proposed federal renewable electricity standard (RES) legislation. Renewable resources are discussed in general terms in the following sections.



The Raft River Geothermal Project is located in southern Idaho.

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. Most of the 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 is somewhat uncertain. In addition, 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. Flash 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

Highlights

- Idaho Power expects to have over 600 MW of wind generation on its system by 2012.
- For the 2009 IRP, Idaho Power hired Black & Veatch to perform a feasibility study for solar technologies in southwest Idaho.
- Simple-cycle combustion turbines (SCCT) continue to be one of the lowest cost supply-side peaking resources because of low fixed costs.
- The dairy industry in southern Idaho has spurred the development of several biomass projects under the Public Utilities Regulatory Policies Act (PURPA).

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 for binary cycle geothermal generation in the IRP are based on data from independent geothermal developers and information from the Geothermal Energy Association. Estimates for flashed steam geothermal generation are based on data from the Northwest Power and Conservation Council's (NPCC) Fifth Power Plan (2005).

Wind

A typical wind project consists of an array of wind turbines ranging in size from 1–3 megawatts (MW) each. The majority of the 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 Region, which is evidenced by the number of existing and planned projects. Wind resources present a problem for utilities due to the variable and intermittent nature of wind generation. Therefore, planning for new wind resources requires estimates of the expected annual energy and peak-hour capacity. For the 2009 IRP, Idaho Power used an annual average capacity factor of 32 percent and a capacity factor of 5 percent for peak-hour planning.

Idaho Power currently has 192 MW (nameplate) of wind generation on-line. Signed PURPA contracts exist for 266 MW of wind generation that is expected to be on-line by the end of 2010. The 2012 Wind Request for Proposals (RFP) is also expected to add up to 150 MW by 2012, which will put the total wind generation on Idaho Power's system in excess of 600 MW. Given this projected increase, it is critical that integration methodologies in practice continue to evolve through ongoing operational experience and further study. Idaho Power plans to update its wind integration study in the first half of 2010 during the time between filing the 2009 IRP and starting the 2011 IRP process in July 2010. The updated study will incorporate planned increases in wind generation as well as the capability of the new Langley Gulch combined-cycle combustion turbine (CCCT) to provide additional operating reserves.

Hydro

Hydropower is the foundation of Idaho Power's generation fleet. The existing generation is low cost and does not emit potentially harmful pollutants like fossil fuel based resources. 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 hydro sites have been extensively developed in southern Idaho on irrigation canals and others sites, many of which have PURPA contracts with Idaho Power.

Because small hydro, in particular, run-of-river and projects requiring small or no impoundments, does not have the same level of environmental and permitting issues as large hydro, the IRP Advisory Council (IRPAC) expressed an interest in including small hydro in the 2009 IRP. The potential for new small hydro projects was recently studied by the Idaho Strategic Alliance's Hydropower Task Force. The results of this evaluation are presented in a draft report available on the Idaho Office of Energy Resources' (IOER) Web site at www.energy.idaho.gov. Idaho Power and others also continue to evaluate pumped storage opportunities and the state of Idaho is examining possible large water storage projects for flow augmentation and the potential for hydropower.

Due to the potential regulation of carbon emissions and associated costs, new small hydro may become a good resource option for Idaho Power. However, uncertainty exists in the level of available sites and the likelihood the sites would be developed as PURPA projects.

Solar

There are two primary types of solar technology; solar thermal and photovoltaic (PV). Solar thermal technologies utilize mirrors to focus the sun's rays onto a central receiver or a "collector" to collect thermal energy that can be used to make steam and power a turbine, creating electricity. PV panels absorb 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 creating an electric current.

On cloudy days, solar thermal generation will not produce power. However, thermal storage using molten salt functions as an energy storage system allowing solar thermal generation plants to generate electricity after the sun sets or during brief cloudy periods, generally for three to seven hours. PV technology uses panels that convert the sun's rays directly to electricity. 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 kilowatt hour (kWh)/m^2/day (daily insolation average over a year). The higher the insolation number, the better the solar power potential for an area. National Renewable Energy Laboratories (NREL) insolation charts show the Desert Southwest has the highest solar potential in the United States.

For the 2009 IRP, Idaho Power hired Black & Veatch to perform an independent, evaluation of the feasibility of using solar generation technology in southwest Idaho. The purpose of the study was to identify solar power generation technology options for southwest Idaho and to develop cost estimates associated for each technology. In the study, Black & Veatch concluded that during the summer, southwest Idaho's insolation is very similar to the desert Southwest. However, during winter months insolation values are approximately 50 percent lower than the Desert Southwest.

Black and Veatch modeled generation output of the various technologies using the Boise weather station because of its robust data set. Depending on the solar technology, capacity factors ranged from 17 to 28 percent, and for a 100 MW facility, land requirements ranged from 570–1,300 acres. The modeled generation for an entire year resulted in the highest production occurring in July and the lowest in January and February.

Idaho Power's peak demand occurs during July typically between 4:00 p.m. and 8:00 pm and is primarily due to air conditioning and irrigation load. Modeled July daily generation output from a parabolic trough or power tower with molten salt storage closely follows the system load curve on summer peak days. Additional details and the entire Black & Veatch study can be found on Idaho Power's Web site at www.idahopower.com. The cost estimates contained in the study were used in the 2009 IRP.

Solar Generation Technologies

Black & Veatch analyzed various solar thermal and photovoltaic technologies in the study. The following sections contain details on each of the technologies.

Parabolic Trough

Parabolic trough technology is a closed looped system that consists of a solar field where single axis parabolic mirrors heat pipes containing a transfer fluid. The hot fluid returns from the solar field where heat energy is transferred to water, creating steam at 700 F. The steam is then used to drive a turbine and

generate electricity. In addition to heating water for steam, the hot fluid can also heat salt until the salt becomes molten. When the sun is not shining, the transfer fluid can be heated by the molten salt. After transferring the heat energy, the fluid returns to the solar field to be reheated.

Power Tower

Power tower technology uses thousands of small, flat, two-axis mirrors, called heliostats, to reflect the sun's rays onto a boiler at the top a central tower. The concentrated sunlight strikes the boiler's pipes, heating the water inside to 1,000°F. The high temperature steam is then piped from the boiler to a turbine where electricity is generated.

Parabolic Dish Engine

A two-axis parabolic dish focuses the sunlight striking the dish onto a collector placed above the dish. The collector is connected to a Stirling engine which uses the thermal energy to heat hydrogen in a closed-loop system. The expansion of the hydrogen gas creates a pressure wave on the pistons of the Stirling engine which turns a generator to create electricity.

Photovoltaic

PV panels absorb 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 creating an electric current. The solar cells have one or more electric fields which 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) which can then be used on-site, stored in a battery, or sent to the grid.

Biomass

Biomass fuels, such as wood residues, organic components of municipal solid waste, animal manure, and wastewater treatment plant gas, can be used to power a turbine or reciprocating engine to produce electricity. Most of the biomass generating resources in the region are small-scale local cogenerating facilities operating under PURPA contracts. The use of biomass fuels has not proven to be economic for large scale commercial power production. Available fuel supply can vary as production from the industry fluctuates. The biomass fuel sources assumed in the resource cost analysis for the 2009 IRP are wood by-products from the forest and wood products industry. Because of the relatively small size of biomass projects and recent PURPA biomass project development, biomass resources were not included in the portfolios analyzed for the 2009 IRP.



Biomass energy is produced from agricultural waste in southern Idaho.

River In-stream Generation

River in-stream generation is the conversion of the kinetic energy of water in free flowing rivers and channels to electricity. River in-stream energy conversion (RISEC) technology is still largely in a conceptual stage of development, with a few small vendors focused on the technology and limited operating experience in natural waters. The use of in-stream generation has not proven to be economic for large scale or commercial power production. The cost estimates and operating parameters for

in-stream generation are based on data from a feasibility study performed by the Electric Power Research Institute (EPRI) on two specific locations in Idaho Power's service area.

Natural Gas-Fired Resources

Natural gas-fired resources burn natural gas in a combustion turbine in order to generate electricity. CCCT 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.

Combined-Cycle Combustion Turbines

Until recently, 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 less harmful emissions when compared to coal.



Natural gas-fired generation is an important component of Idaho Power's resource portfolio.

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 produces steam that drives a steam-turbine generator to produce electricity. In a CCCT plant, heat that would otherwise be wasted is used to produce additional power beyond that typically produced by a SCCT. New CCCT plants can be built or existing SCCT plants can be converted to combined cycle units.

Several CCCT plants, including 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. If natural gas supplies become constrained, efforts will have to be made to identify additional regional sources or off shore sources through the construction of liquefied natural gas terminals.

Simple-Cycle Combustion Turbines

Simple-cycle natural gas turbine technology involves pressurizing air which is then heated by burning gas in fuel combustors. The hot pressurized air is expanded through the blades of the turbine which is connected by a shaft to the electric generator. Designs range from larger industrial machines at 80–200 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 the 2000–2001 time period 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 resources. Peak summertime electricity demand continues to grow significantly within Idaho Power's service area, and SCCT generating resources have been constructed to meet peak load during the 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. Like CCCTs, feasible sites and gas supply currently exist for future SCCT development. The SCCT resources studied in the 2009 IRP are assumed to be located in southwestern Idaho in close proximity to the mainline fuel supply and near Idaho Power's main load center in the Treasure Valley. Furthermore, in the 2009 IRP, natural gas pipeline capacity is assumed to be available. Given the limits of available natural gas pipeline capacity, Idaho Power may need to begin acquiring additional transport capacity.

Conventional Coal Resources

Conventional coal-fired generation is a mature technology and has been the primary source of commercial power production in the United States for many decades. Traditional pulverized coal plants have been a significant part of Idaho Power's generation mix since the early 1970s. Idaho Power currently has over 1,000 MW of pulverized coal generation in service. All of Idaho Power's pulverized coal generation is in neighboring states and is owned with other regional utilities.



The Boardman Plant in Oregon provides baseload energy to Idaho Power customers.

A pulverized coal facility uses coal that is ground into a dust-like consistency and burned to heat water and produce steam to drive a steam turbine and generator. Emission controls at coal plants have become increasingly important in recent years and many units in the region have been upgraded to include the latest scrubber and low Nitrous Oxide (NOx) burner technology to help reduce harmful emissions and particulates. Coal has the highest ratio of carbon-to-hydrogen of all the fossil fuels and significant research is being done in hopes of developing carbon capture and sequestration technology that can be economically added to existing coal facilities.

Even though coal-fired power plants require significant capital commitments to develop, coal resources take advantage of a low-cost fuel and provide reliable and dispatchable energy. Coal supplies are abundant in the Intermountain Region and are sufficient to fuel Idaho Power's existing plants for many years to come.

In 2007, Idaho Power decided to not pursue the development of a coal-fired resource identified in the 2006 IRP. In addition to considering the cost of a coal-based resource, the company considered the uncertainty surrounding the regulation of carbon emissions and the ability to permit a new coal resource. Idaho Power continues to evaluate other coal-fired resource opportunities, including efficiency improvements at its jointly owned facilities as well as monitoring the development of clean coal technologies. However, due to the uncertainty regarding future carbon regulations, conventional coal resources were not included in any of the portfolios analyzed in the 2009 IRP.

Advanced Nuclear

The *Energy Policy Act of 2005* authorized funds to be appropriated for the development of a next-generation nuclear power project at the Idaho National Laboratory (INL). The project would consist of the research and development, design, construction, and operation of a prototype plant, including a nuclear reactor used to generate electricity, produce hydrogen, or both. The target completion date for the prototype nuclear reactor is September 2021. For fiscal years 2006–2015, $1.25 billion has been authorized for appropriation. In addition, the act authorizes additional appropriations deemed necessary between fiscal years 2016–2021 to complete the project. Whether funds will actually be appropriated to develop the project is unknown at the present time.

The act also establishes tax credits for up to 6,000 MW of new advanced nuclear power development. Projects must be in service by January 2021 to qualify. Multiple projects in the southeastern states will likely make up the next 6,000 MW of development, and therefore qualify for the credits. The first of the new nuclear projects are expected to be on-line by 2014. Idaho Power will follow the progress of the projects in the coming years and special attention will be paid to the issues surrounding spent nuclear fuel disposal.

In the 2006 IRP, the preferred portfolio included a power purchase agreement (PPA) for a 250 MW share of the proposed Next Generation Nuclear Plant project beginning as early as 2022. Recent discussions with INL suggest the likelihood of the project being located in Idaho is less than when the 2006 IRP was prepared. Although the preferred portfolio for the 2009 IRP does not contain a nuclear resource, Idaho Power will continue to monitor the progress of the advanced nuclear research and development efforts as well as new modular nuclear designs that are being proposed and investigated by others.

Resource Advantages and Disadvantages

Different resource types have specific characteristics that can be either an advantage or a disadvantage. In order to summarize the differences between the resource types, Idaho Power has prepared Table 6.1 which shows both the advantages and disadvantages of the resources analyzed in the 2009 IRP.

Resource Cost Analysis

The costs of a variety of supply-side and demand-side resources were analyzed for the 2009 IRP. Cost inputs and operating data used to develop the resource cost analysis were derived from various sources including, but not limited to, the NPCC, Department of Energy (DOE), independent consultants, and regional energy project developers. Resource costs are presented as:

- Levelized fixed cost-per-kilowatt (kW) of installed (nameplate) capacity per month, and
- Total levelized cost-per-megawatt hour (MWh) of expected plant output or energy saved, given assumed capacity factors and other operating assumptions.

The levelized costs for the various supply-side alternatives include the cost of capital, operating and maintenance (O&M) costs, fuel costs, and other applicable adders and credits. The cost estimates used to determine the cost of capital for the supply-side resources include engineering development costs, generating and ancillary equipment purchase costs, installation, applicable balance of plant construction, and the costs for a generic transmission interconnection to Idaho Power's network system. More detailed interconnection and transmission system backbone upgrade costs were estimated by Idaho Power's transmission planning group. The cost of capital also includes 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 renewable energy credits (RECs) is not included in the levelized cost estimates.

The levelized costs for each of the demand-side resource options include annual administrative and marketing costs of the program, annual incentive or rebate payments, and annual participant costs. The demand-side resource costs do not reflect the financial impact to Idaho Power as a result of these load reduction programs.

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

Table 6.1 Supply-Side Resources Advantages and Disadvantages

Resource Type	Advantages	Disadvantages
Geothermal	• Renewable resource • No harmful emissions • Minimum fuel risk (once developed) • Low, variable operating costs • Baseload generation (90%+ capacity factor)	• Limited number of sites • High exploration costs due to drilling risks • Uncertainty surrounding future tax incentives
Wind	• Renewable resource • No fuel cost • No harmful emissions • Low, variable operating costs	• Limited number of good sites in southern Idaho • Intermittent and non-dispatchable resource • Inefficient use of limited firm transmission capacity • Avian and aesthetic impacts • Uncertainty surrounding future tax incentives
Hydro	• Renewable resource • No fuel cost • No harmful emissions • Low, variable operating costs	• Limited number of sites • Future development is limited to small sites or at existing dams without power generation • Fish and other environmental issues
Solar (General)	• Renewable resource • No fuel cost • No harmful emissions • Low, variable operating costs • Generation would match well with summer peak loads.	• More expensive than other resource options • Poor generation during winter months • Intermittent and non-dispatchable resource • Inefficient use of limited firm transmission capacity • Limited utility scale projects exist
Parabolic Trough	• Can be built with thermal storage	• Utility scale production is limited
Power Tower	• By using molten salt, thermal storage can be built integrally into the system	• Utility scale production is unproven • Requires land slope of 1 percent of less
Parabolic Dish	• Off-grid electricity production in remote areas	• Not suitable for storage options • Unproven technology
Photovoltaic	• Proven & reliable technology • Suitable for distributed generation	• Cloud cover creates a rapid power drop-off • Utility scale projects are only practical up to 10 MW
Biomass	• Renewable resource • No harmful emissions • Minimum fuel risk • Low, variable operating costs • Baseload generation (90%+ capacity factor)	• Limited number of sites • Uncertainty surrounding future tax incentives • Fuel supply risk

Resource Type	Advantages	Disadvantages
In-stream Generation	• Renewable resource • No harmful emissions • No fuel cost	• Small size, many sites would be required • Environmental impact and permitting • High maintenance cost
Distributed Generation	• Utilize existing backup generators at customer sites • Dispatchable resource • Provides operating reserves	• More expensive than other resource options • Limited number of sites • Fuel price risk and volatility • Existing air quality permits may need to be modified • Small size, many sites would be required
Natural Gas		
Combined-Cycle Combustion Turbines (CCCT)	• Proven and reliable technology • Dispatchable resource • Provides operating reserves necessary for integration of renewable generation • More efficient than a SCCT • Greater than 50% reduction in CO_2 emissions per MWh of output compared to conventional pulverized coal technology	• Fuel price risk and volatility • Potential fuel supply and transportation issues
Simple-Cycle Combustion Turbines (SCCT)	• Dispatchable resource • Proven, reliable resource • Low capital cost • Short construction lead times • Ideal for peaking service	• High variable operating cost • Fuel price risk and volatility • Less efficient than a CCCT
Coal		
Pulverized	• Abundant, low cost fuel • Less price volatility than natural gas • Proven and reliable technology • Dispatchable resource • Well suited for baseload operations	• Potential lack of public acceptance • Significant particulate and gas emissions, particularly CO_2 • Significant capital investment • Long construction lead times • Lengthy environmental permitting and siting processes
Advanced Technology	• Abundant, low cost fuel • Potentially lower greenhouse gas emissions if CO_2 is sequestered • Potential for financial incentives • Dispatchable resource	• New, unproven technologies • Higher capital costs than pulverized coal • Long construction lead times
Nuclear	• Forecasted low fuel costs • Forecasted adequate fuel availability • Lack of greenhouse gas emissions • Potential low cost of production • Proven technology (existing reactor types)	• Lack of public acceptance • Safety concerns • Waste disposal • Construction cost uncertainties and the potential for construction cost overruns • Security concerns

Emission Adders for Fossil Fuel-Based Resources

All resource alternatives have potential environmental and other social costs that extend beyond just the capital and operating costs included in the cost of electricity. Fossil fuel-based generating resources are particularly sensitive to some of the environmental and social costs. It is likely that further emissions regulations will be implemented during the period covered in the 2009 IRP.

In the analysis, Idaho Power incorporated estimates for the future costs of certain emissions into the overall cost of the various fossil fuel-based resources. Within the resource cost analysis ranking, the levelized costs for the various fossil fuel-based resources include emission adders for greenhouse gases (GHG), NOx, and mercury. The additional costs are assumed to begin in 2012. Table 6.2 provides the emission adder rates assumed in the analysis. Based on the assumptions in Table 6 2, Table 6.3 provides the emissions costs for the various fossil fuel-based resources that were analyzed.

Table 6.2 Emissions Adder Assumptions

Adder	Cost in 2009 U.S. dollars	First Year Applied	Annual Escalation
GHG	$43 per ton	2012	2.50%
NO_x	2,600 per ton	2012	2.50%
Mercury	1,443 per ounce	2012	2.50%

Table 6.3 Emission Adders (lbs/MWh)

Adder	GHG	NO_x	Hg
Pulverized Coal	1,886	0.44	0.00
IGCC	1,797	0.21	0.00
IGCC with Carbon Sequestration	309	0.43	0.00
Distributed Generation Diesel	1,540	0.00	0.00
SCCT	1,127	0.11	0.00
CCCT	809	0.08	0.00

Production Tax Credits for Renewable Generating Resources

Various federal tax incentives for renewable resources were extended and/or renewed within the Emergency Economic Stabilization Act of 2008. This legislation requires most projects to be on-line by December 31, 2016, to be eligible for the federal production tax credits (PTCs) identified in Section 45 of the Internal Revenue Code. The credit is earned on power produced by the project during the first 10 years of operation. The credit, which is adjusted annually for inflation is currently valued at $21 per MWh for wind and geothermal resources.

Levelized Capacity (Fixed) Cost

The annual fixed revenue requirement in nominal dollars for each resource were summed and levelized over a 30 year operating life and are presented as dollars-per-kW of plant nameplate capacity per month. Included in these costs were the cost of capital and fixed O&M estimates. Figure 6.1 provides a combined ranking of all the various resource options, in order of lowest to highest levelized fixed cost-per-kW-per-month. The ranking shows that distributed generation and natural gas peaking resources are the lowest capacity cost alternatives. Distributed generation and gas peaking resources do have high operating costs, but the operating costs are not as important when the resource is only used a limited number of hours per year to meet peak-hour demand.

Levelized Cost of Production

Certain resource alternatives carry low-fixed costs and high-variable operating costs while other alternatives require significantly higher capital investment and fixed operating costs, but have low-variable operating costs. The levelized cost of production measurement represents the estimated annual cost-per-MWh in nominal dollars for a resource based on an expected level of energy output (capacity factor) over a 30-year operating life.

The nominal, levelized cost of production assuming the expected capacity factors for each resource type is shown in Figure 6.2. Included in these costs are the cost of capital, non-fuel O&M, fuel, and emission adders; however, no value for RECs was assumed in this analysis. Resources such as DSM measures, the Shoshone Falls upgrade, geothermal, wind, and certain types of thermal generation appear to be the lowest cost for meeting baseload requirements.

Figure 6.1 30-Year Levelized Capacity (Fixed) Costs

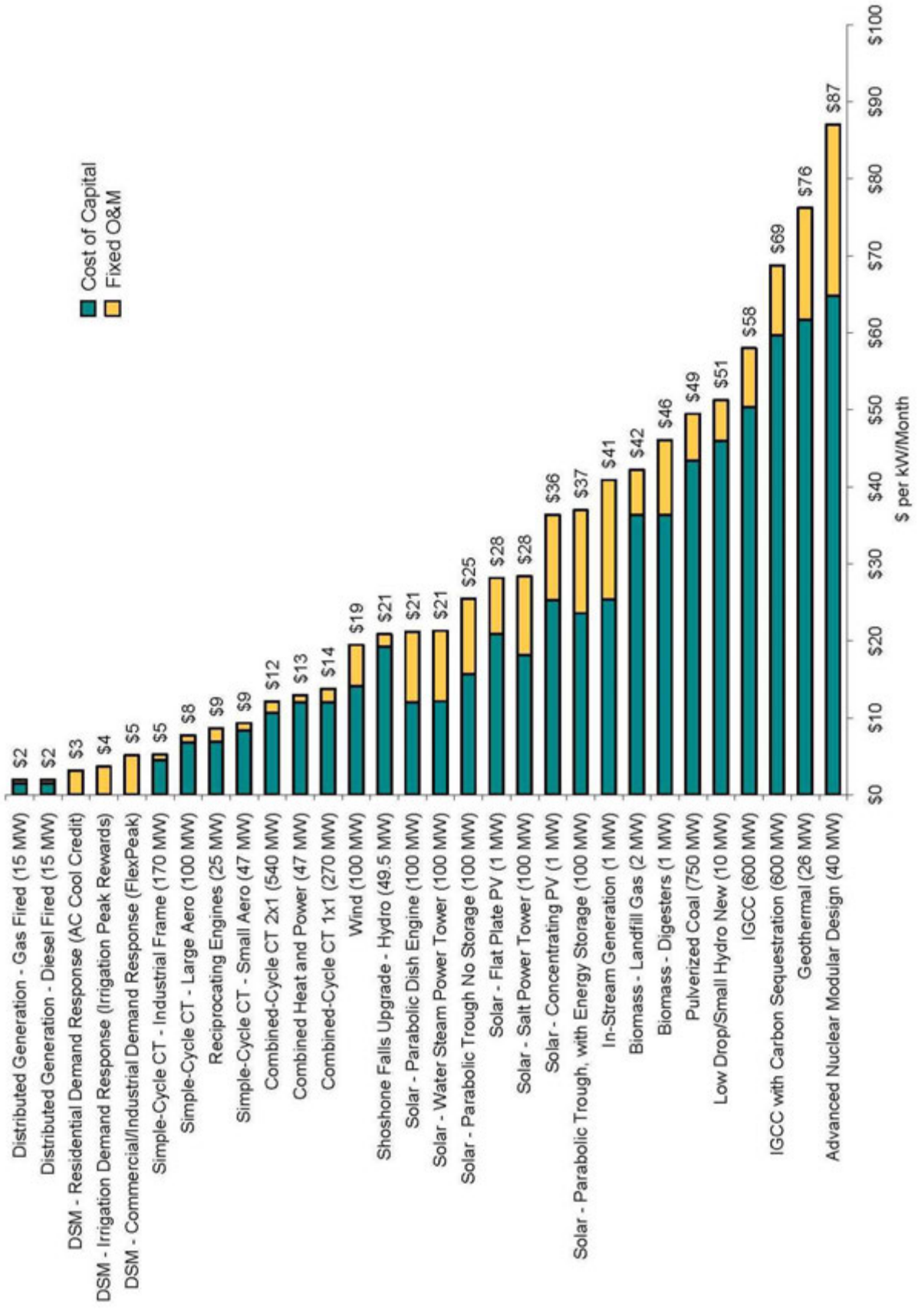
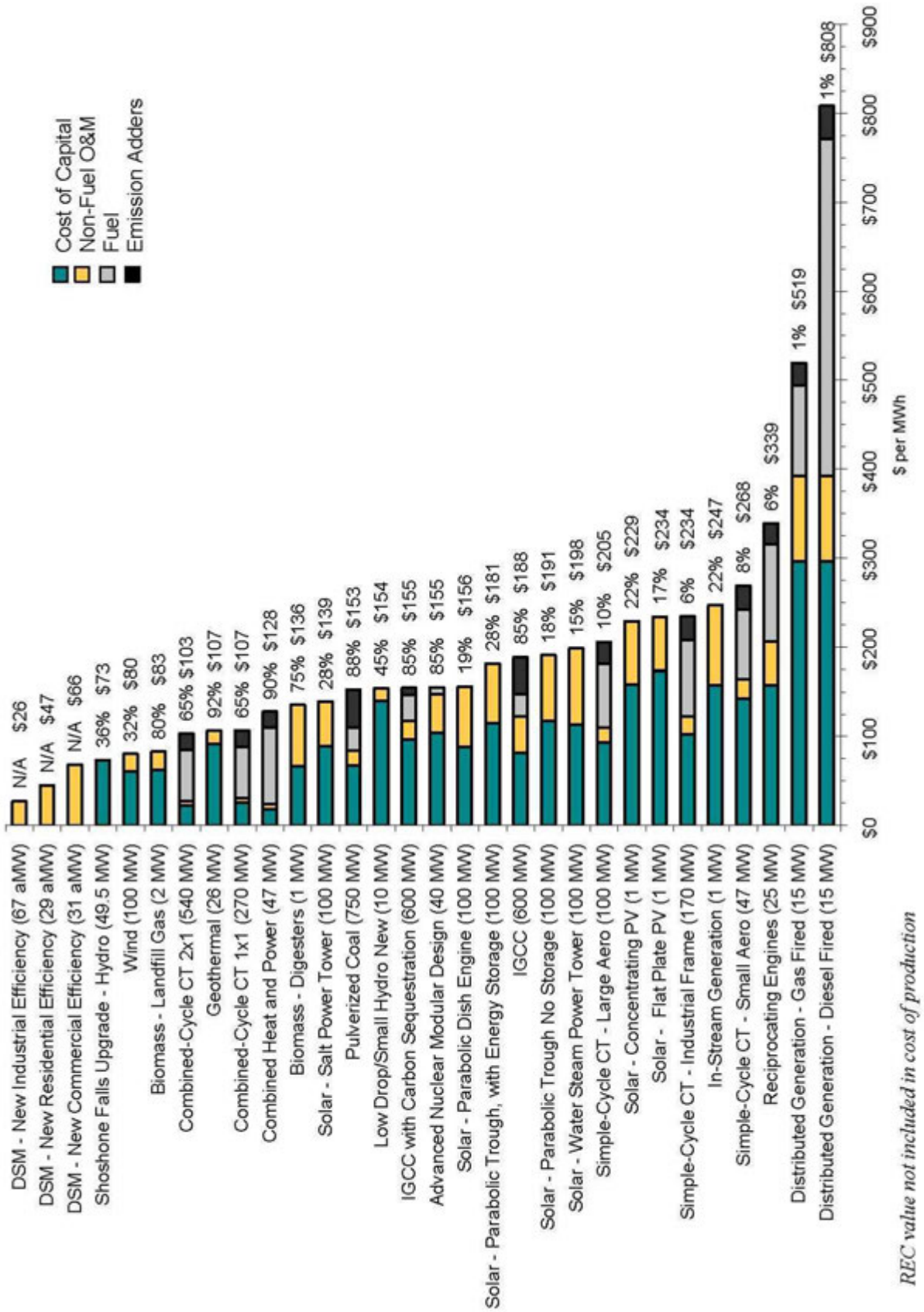


Figure 6.2 30-Year Levelized Cost of Production (at Stated Capacity Factors)



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7. TRANSMISSION RESOURCES



High-voltage transmission lines are necessary to interconnect with other regional utilities.

High-voltage transmission lines are a key element in operating Idaho Power's electrical system and are necessary for reliability, which makes them an essential part of Idaho Power's resource portfolio. In order to keep the electric power system balanced, generation must match system load at all times. Regional transmission interconnections improve reliability by providing the flexibility to move electricity between balancing authorities and also provide economic benefits from 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 this, Idaho Power is able to purchase energy from the Mid-Columbia market to meet peak summer load and sell excess energy to Pacific Northwest utilities during the winter and spring. This practice benefits Idaho Power's customers because the construction of additional peaking resources is avoided and revenue from off-system sales is returned to customers through the power cost adjustment (PCA).

Transmission Interconnections

While Idaho Power has added generation resources in the recent past to meet load growth, the ability to import additional amounts of energy from the Pacific Northwest has been, and continues to be, limited by constraints on the existing transmission system. Idaho Power's transmission system is shown in Figure 7.1 and the associated interconnections and capacities are shown in Table 7.1.

The rated capacity of a transmission path may be less than the sum of the individual circuit thermal capacities. The difference is due to a number of factors, including load distribution, potential outage impacts, and surrounding system limitations. In addition, not all of the transmission capacity identified in Table 7.1 is available for Idaho Power's use. Reliability reserve margins, ownership rights,

Highlights

- Regional transmission interconnections improve reliability by providing the flexibility to move electricity between balancing authorities.
- Idaho Power's ability to import additional amounts of energy from the Pacific Northwest is limited by constraints on the existing transmission system.
- Restrictions on the Brownlee-East and Northwest to Idaho transmission paths limit the import of Hells Canyon Complex generation and off-system purchases from the Pacific Northwest.
- The 500-kV Boardman to Hemingway project, expected to be in service in 2015, would be a major addition to the Brownlee-East and Northwest to Idaho paths and will remove the existing constraints.

contractual restrictions, and prior obligations commit much of the transmission capacity to other parties. In addition to the restrictions on interconnection capacities, other internal transmission constraints may limit Idaho Power's ability to access specific energy markets. The internal transmission paths needed to import resources from other utilities are shown in Figure 7.1 and Table 7.1. The following sections provide additional details on Idaho Power's primary interconnections and the constraints on each path.

Idaho Power regularly evaluates transmission improvements, such as the installation of reactive devices, to prove incremental transmission capacity increases on external interconnections and internal paths. When determined to be cost effective, Idaho Power commits capital resources to the improvements. Incremental transmission capacity increases are typically small and do not materially impact the Integrated Resource Plan (IRP) planning process.

Table 7.1 Transmission Interconnections

Transmission Interconnections	Capacity		Line or Transformers	Connects to Idaho Power
	To Idaho	From Idaho		
Idaho to Northwest	1,090–1,200 MW	2,400 MW	Oxbow Lolo 230-kV	Avista
			Midpoint Summer Lake 500-kV	Pacific Power
			Hells Canyon Enterprise 230-kV	Pacific Power
			Quartz Tap LaGrande 230-kV	BPA
			Hines Harney 138/115-kV	BPA
Sierra	262 MW	500 MW	Midpoint Humboldt 345-kV	Sierra Pacific Power
Eastern Idaho[1]			Kinport Goshen 345-kV	Rocky Mountain Power
			Bridger Goshen 345-kV	Rocky Mountain Power
			Brady Antelope 230-kV	Rocky Mountain Power
			Blackfoot Goshen 161-kV	Rocky Mountain Power
Utah (Path C)[2]	775–950 MW	830–870 MW	Borah Ben Lomond 345-kV	Rocky Mountain Power
			Brady Treasureton 230-kV	Rocky Mountain Power
			American Falls Malad 138-kV	Rocky Mountain Power
Montana[3]	79 MW	58 MW	Antelope Anaconda 230-kV	NorthWestern Energy
	87 MW	70 MW	Jefferson Dillon 161-kV	NorthWestern Energy
Pacific (Wyoming)	600 MW	600 MW	Jim Bridger 345/230-kV	Rocky Mountain Power

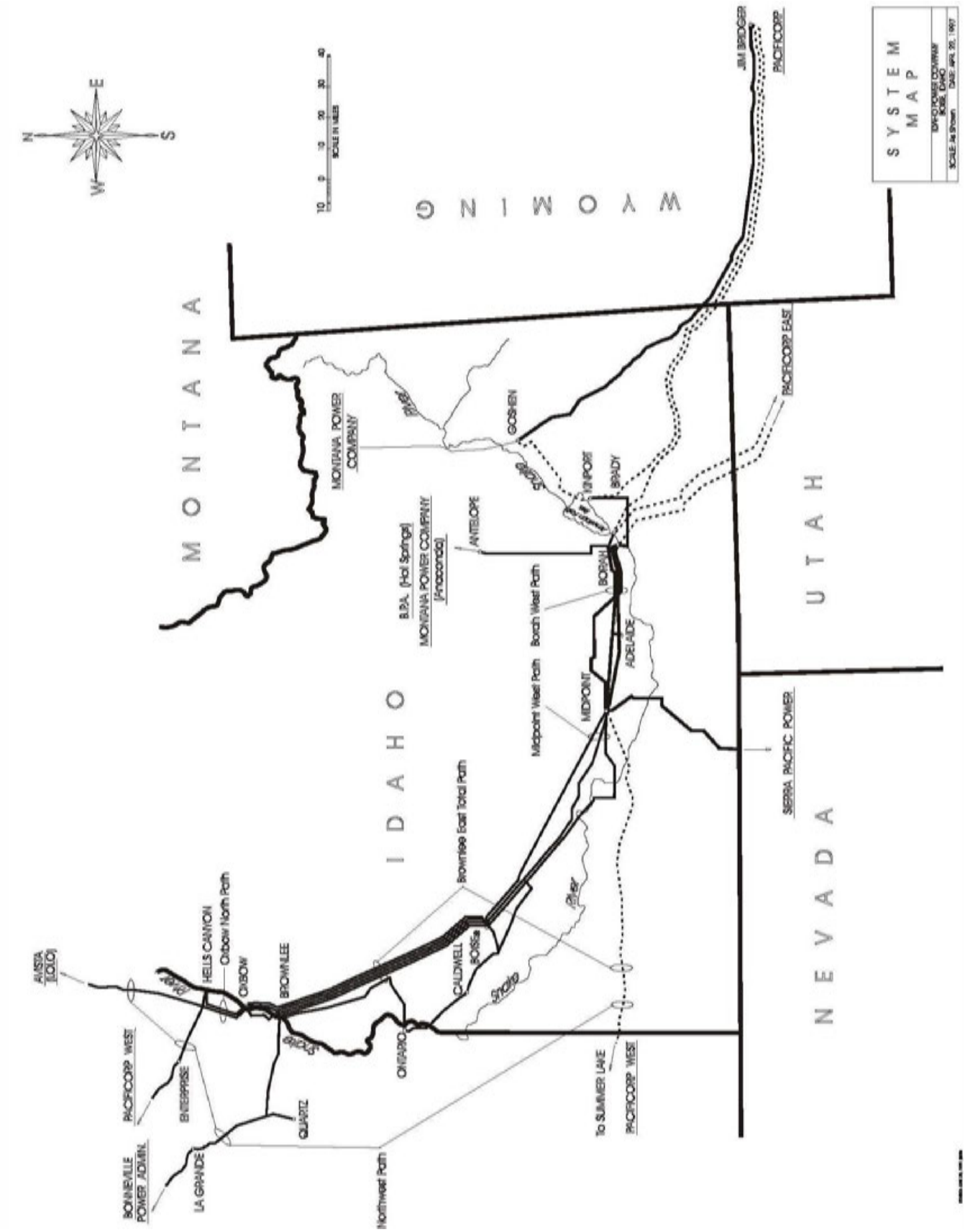
Power Transfer Capacity for Idaho Power's Interconnections

1 The Idaho Power-Rocky Mountain Power interconnection total capacities in eastern Idaho and Utah include Jim Bridger resource integration.

2 The Path C transmission path also includes the internal Rocky Mountain Power Goshen-Grace 161-kV line and the Three Mile Knoll 345/138-kV transformer.

3 The direct Idaho Power-Montana Power schedule is through the Brady-Antelope 230-kV line and through the Blackfoot-Goshen 161-kV line that are listed as an interconnection with Rocky Mountain Power. As a result, Idaho–Montana and Idaho–Utah capacities are not independent.

Figure 7.1 Idaho Power Transmission System Map



Brownlee-East Path

The Brownlee–East transmission path is on the east side of the Northwest Interconnection shown in Table 7.1. Brownlee–East is comprised of the 230-kilovolt (kV) and 138-kV lines east of the Brownlee/Oxbow/Quartz area. When the Midpoint–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 constraint on the Brownlee–East transmission path is within Idaho Power's main transmission grid and located in the area between Brownlee and Boise on the west side of the system.

The Brownlee–East path is most likely to face summer constraints during normal-to-high water years. The constraints result from a combination of Hells Canyon Complex hydro generation flowing east into the Treasure Valley, concurrent with transmission wheeling obligations and purchases from the Pacific Northwest. Transmission wheeling obligations also affect southeastern flow into and through southern Idaho. Significant congestion affecting southeast energy transmission flow from the Pacific Northwest may also occur during December. Restrictions on the Brownlee–East path limit the amount of energy Idaho Power can import from the Hells Canyon Complex, as well as off-system purchases from the Pacific Northwest.

The Brownlee–East Total constraint is the primary restriction on imports of energy from the Pacific Northwest during normal and high water years. If new resources are sited west of the constraint, additional transmission capacity will be required to remove the existing Brownlee–East transmission constraint to deliver the energy to the Boise/Treasure Valley load area. The Boardman to Hemingway project is a major addition to the Brownlee East Total Path and will remove the existing Brownlee–East constraint.

Oxbow-North Path

The Oxbow–North path is a part of the Northwest Interconnection and consists of the Hells Canyon–Brownlee and Lolo–Oxbow 230-kV double-circuit line. The Oxbow–North path is most likely to face constraints during the summer months when high northwest-to-southeast energy flows and high hydro production levels coincide.

Northwest Path

The Idaho to Northwest path consists of the 500-kV Midpoint–Summer Lake line, the three 230-kV lines between the Northwest and Brownlee, and the 115-kV interconnection at Harney. The Northwest path has different constrains than the Brownlee–East path. During summer months, the Northwest path is more constrained in low-to-normal water years due to transmission wheeling obligations and off-system purchases from the Pacific Northwest. The Boardman to Hemingway project is a major addition to the Idaho to Northwest path and will relieve constraints on the path.

Montana Path

The Montana path consists of the Antelope–Anaconda 230-kV and Jefferson–Dillon 161-kV transmission lines. The Montana path is also constrained during the summer months. The Antelope–Anaconda 230-kV transmission line is one segment of the Associated Mountain Power System (AMPS) project which is owned by Idaho Power, NorthWestern Energy and PacifiCorp, collectively known as the AMPS participants. The AMPS participants have initiated the process to increase the path rating by installing reactive devices. The transmission capacity increase is subject to formalization of the agreement between the partners and the WECC rating process. Idaho Power would be allocated a portion of any capacity increase and plans for the capacity to be used for network and native load service.

Transmission Planning

Idaho Power has discussed possible transmission upgrades linking the company's service area to the regional energy market in the Pacific Northwest since the 2000 IRP. Idaho Power discussed the Pacific Northwest transmission upgrades in general terms in both the 2000 and 2002 IRPs and identified 225 megawatts (MW) of capacity on the Boardman to Hemingway path, originally identified as the McNary to Boise transmission path, in the preferred portfolio of the 2006 Integrated Resource Plan (IRP). This chapter provides details regarding Idaho Power's existing transmission system, planning considerations, and proposed transmission projects. Details of the analysis methods and results are provided later in Chapters 9 and 10.

Transmission Adequacy

Prior to 2000, Idaho Power was able to reasonably plan for the use of short-term power purchases to meet temporary water related generation deficiencies on its own system. Short-term power purchases have been successful because Idaho Power is a summer peaking utility while the majority of other utilities in the Pacific Northwest region experience peak loads during the winter.

The transmission adequacy analysis reflects Idaho Power's contractual obligations to provide wheeling service to the Bonneville Power Administration (BPA) loads in southern Idaho. The BPA loads are typically served with a combination of energy and capacity from the Pacific Northwest and several Bureau of Reclamation (BOR) projects located in southern Idaho. BPA is a network transmission customer and Idaho Power's contractual obligations to BPA are detailed in four Network Service Agreements under the Idaho Power Open Access Transmission Tariff (OATT).

Although Idaho Power has transmission interconnections to the Southwest, the Pacific Northwest market is the preferred source of purchased power. The Pacific Northwest market has a large number of participants, high transaction volume, and is very liquid. The accessible power markets south and east of Idaho Power's system tend to be smaller, less liquid, and have greater transmission distances. In addition, the markets south and east of Idaho Power's system can be very limited during summer peak conditions.

Prior to 2000, Idaho Power's IRPs often emphasized acquisition of energy rather than construction of generating resources to satisfy load obligations as transmission constraints were not a major impediment to Idaho Power's purchasing power to meet its service obligations. Transmission constraints began to place limits on purchased power supply strategies starting with the 2000 IRP. In addition to evaluating transmission alternatives in the IRP process, Idaho Power participates in regional transmission planning efforts as a member of the Northern Tier Transmission Group (NTTG).

Northern Tier Transmission Group

The NTTG was formed in early 2007 with an overall goal of improving the operation and expansion of the high-voltage transmission system that delivers power to consumers in seven western states. In addition to Idaho Power, other members include Deseret Power Electric Cooperative, NorthWestern Energy, Portland General Electric (PGE), Rocky Mountain Power/PacifiCorp and the Utah Associated Municipal Power Systems (UAMPS).

Idaho Power is active in regional transmission planning through the NTTG, along with the Western Electricity Coordinating Council's (WECC) Transmission Expansion Planning Policy Committee (TEPPC) and Planning Coordination Committee (PCC). In addition to integrated resource planning requirements, coordinated regional and sub-regional planning studies are conducted and reviews of various transmission projects are evaluated through technical studies in the WECC rating process.

Through the NTTG planning process conducted in 2007, along with the 2008–2009 biennial planning process, a number of potential transmission projects, including the Boardman to Hemingway and Gateway West projects, have been identified. The public stakeholder process evaluates transmission needs as determined by state mandated integrated resource plans and load forecasts, proposed resource development and generation interconnection queues, and forecast uses of the transmission system by wholesale transmission customers.

By identifying potential resource areas and load center growth, the required transmission capacity expansions to safely and reliably provide service to customers are identified. The process considers not only Idaho Power's obligations to retail customers and network customers, such as BPA, but also provides for open access interstate wholesale obligations required by FERC's planning requirements under FERC Order No. 890's Attachment K planning process.

Proposed Transmission Projects

Idaho Power is responsible for providing safe and reliable electrical service to its service area, which includes most of southern Idaho and a portion of eastern Oregon. In addition to operating under regulatory oversight of the IPUC and the OPUC, Idaho Power is a public utility under the jurisdiction of FERC and is obligated to expand its transmission system to provide requested firm transmission service and to construct and place in service sufficient capacity to reliably deliver electrical resources to customers.

Because of the potential for renewable resource development in the region and the constraints on the existing transmission system, Idaho Power has considered two major transmission projects in the 2009 IRP—Boardman to Hemingway and Gateway West. These two projects were also evaluated in NTTG's regional, biennial planning process along with several other large projects. For the 2009 IRP, two portfolios requiring Boardman to Hemingway capacity were analyzed for the first 10 years of the planning horizon (2010–2019). In the second 10 years (2020–2029), the Gateway West project was included in every portfolio because current constraints require the addition of new transmission capacity for resources to be added in southern Idaho, east of the Treasure Valley load center. However, the amount of Gateway West capacity is different in each portfolio depending on other included resources.

Idaho Power will face increasing demands for transmission capacity in the coming decade. Additional requirements include the forecast growth of existing network customers, including BPA's southern Idaho contracts and another 1,000 MW of energy that is expected to be wheeled through Idaho Power's system to other regional customers. The development of wind and other renewable resources in response to renewable portfolio standards (RPS) is anticipated to further increase the demand for transmission capacity between the Intermountain Region and the Pacific Northwest.

The concept of "right sizing" a transmission project, or building the project to an appropriate potential, has been carefully considered. There are many factors involved in the decision process prior to proposing a solution to the identified requirements, including planning horizon perspectives. The Boardman to Hemingway and Gateway West projects have been designed to appropriately size the transmission line, and allow phased construction to meet Idaho Power's needs as well as satisfy requests from third parties for capacity on the same path. A more detailed description of each project is presented in the following sections.

Boardman to Hemingway



Public involvement is an important part of determining the route of proposed transmission lines.

The Boardman to Hemingway project is a new, 300 mile long, single-circuit, electric transmission line between northeast Oregon and southwest Idaho. The new line is intended to provide access to the Pacific Northwest electric market and is not intended to deliver energy from the Boardman coal facility to Idaho Power's service area.

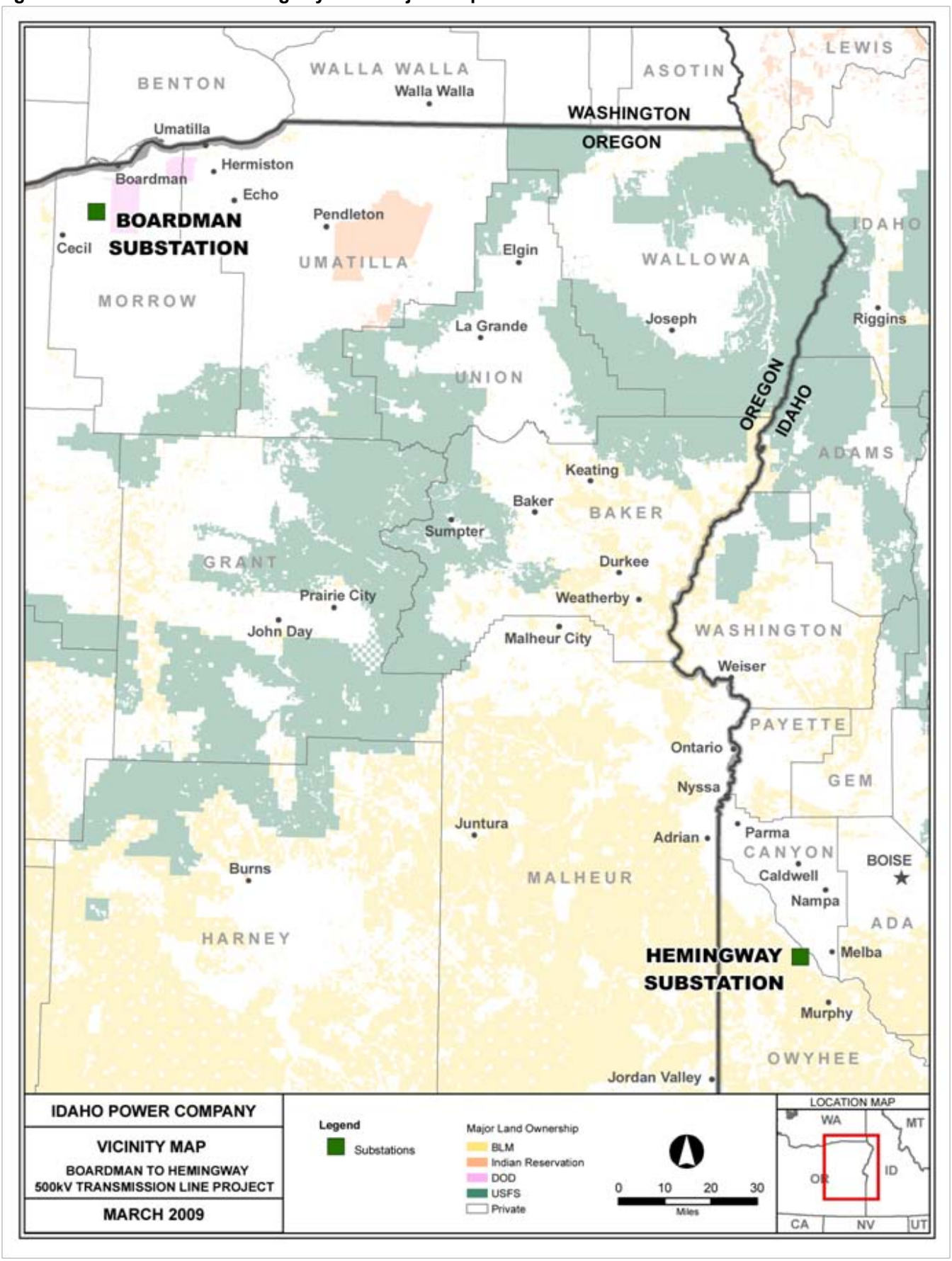
The project is expected to be completed and in service in 2015. The overhead, 500-kV, high-voltage transmission line will connect a switching yard at the Boardman Power Plant, near Boardman, Morrow County, Oregon to the Hemingway Substation, located in Owyhee County, Idaho. The proposed transmission line will connect with other transmission lines on either end of the project to convey electricity on a regional scale. Figure 7.2 shows a map of the region with the Boardman and Hemingway substation termination points.

The northern terminal of the project is expected to interconnect with the existing Boardman substation, which Idaho Power is a part owner. In the 2006 IRP, the new line was anticipated to interconnect at the McNary substation; however, there is insufficient room at the existing McNary substation for major transmission expansion options. A northeast Oregon (NEO) substation is also contemplated by a number of utilities, providing future interconnectivity of regional projects. The in-service date for the NEO substation is unknown at this time. The proposed Boardman to Hemingway project is not dependent upon completion of the NEO substation project, or any of the other transmission proposals to satisfy Idaho Power's need or other existing service requests.

The Boardman to Hemingway project is likely to utilize a bundled conductor design capable of a thermal continuous rating of about 3,000 MW. However, due to reliability standards and the WECC's rating process, the initial implementation of the Boardman to Hemingway project along with the Gateway West project is likely to result in an increased rating of approximately 1,400 MW from east to west (exports into the Pacific Northwest), and about 850 MW from west to east (imports into Idaho Power's balancing authority area). The ratings are subject to technical peer review and will be revisited as other regional projects continue to develop. As additional projects reinforce the transmission network, additional capacity rating increases of the Boardman to Hemingway project may occur.

The Boardman to Hemingway project capacity or sizing considerations and termination locations were developed in the public review process conducted by the NTTG and the project WECC phase 0 rating process (the regional planning phase). During the review process, it was determined a 230-kV project would be unable to meet Idaho Power's overall resource planning requirements and would underutilize a substantial transmission corridor. A project operating voltage of 500-kV was selected to match the existing Pacific Northwest transmission grid. A 765-kV line designed with a thermal capacity of approximately 7,000 MW would not achieve a greater rating that the proposed 500-kV project, but would be nearly twice the cost. Because of the higher cost, no further consideration was given to a 765-kV transmission line.

Figure 7.2 Boardman to Hemingway Line Project Map



Idaho Power has received more than 4,000 MW of requests to commence transmission service between 2005 and 2014 on the Idaho-Northwest transmission path. Of the 4,000 MW of service requests, only 133 MW were granted up through 2007 due to the limited available transmission capacity of the existing system. There are currently active transmission service requests being studied that are expected to commence operations when the proposed Boardman to Hemingway project is completed. In the 2006 IRP, Idaho Power requested 225 MW of energy imports from the Pacific Northwest to Idaho Power's system. However, the 2009 IRP analyzed various levels of imports.

The Boardman to Hemingway project is important for the development of renewable resources as northeast Oregon has the potential for both wind and geothermal resource development. Idaho Power and Horizon Wind Energy recently developed the first phase of the 101 MW Elkhorn Valley Wind Project in Union County, Oregon. Firm transmission capacity existed for the first 66 MW of the wind project. The remaining 34 MW of output from the Elkhorn project may face curtailment during times of transmission congestion. Further renewable resource development in northeast Oregon will require additional transmission resources.

Idaho Power is committed to working with communities to identify proposed and alternate routes for the Boardman to Hemingway project. The initial process of identifying a route began in late 2007 when Idaho Power submitted documents to the Bureau of Land Management (BLM), the U.S. Forest Service (USFS), and the Oregon Department of Energy (DOE).

Following public scoping meetings held in October 2008, the agencies received public input requesting Idaho Power to conduct more extensive outreach as part of identifying a route for the new transmission line. In response, Idaho Power initiated the Community Advisory Process (CAP) to engage communities from Boardman, Oregon to Melba, Idaho in siting the Boardman to Hemingway project. The CAP enlists project advisory team members in three geographic regions within the project area. The members are familiar with the local areas and issues; the topography, recreation, wildlife and view shed issues; and work collaboratively with Idaho Power to identify and recommend potential line routes. Idaho Power has been working with communities in the CAP since spring 2009 and the process is expected to be completed in early 2010.

The results of the 2009 IRP analysis indicate the Boardman to Hemingway transmission line will be a well used resource that benefits customers and generators in both the Pacific Northwest and the Intermountain Region. The capital cost of the Boardman to Hemingway project, as measured on a dollar per kW of capacity basis, is estimated to be well below the capital cost of any supply-side resource alternative. Additional information about the Boardman to Hemingway project can be found at www.boardmantohemingway.gov.

Gateway West

The Gateway West transmission line project is a joint project between Idaho Power and Rocky Mountain Power to build and operate approximately 1,150 miles of new transmission lines from the planned Windstar substation near Glenrock, Wyoming to the Hemingway substation near Melba, Idaho. The project is being designed such that multiple construction phases can provide transmission segments as needs materialize. Some segments of the Gateway West project are planned to be in service as early as 2014.

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

Significant resource development potential exists in Wyoming and southern and eastern Idaho. Idaho Power's transmission system is currently limited in the ability to transmit energy from new resources from the east to the major load centers in Idaho. Gateway West will provide new transmission capacity to integrate and deliver any such selected resources, in addition to meeting third-party transmission service requests under Idaho Power's Open Access Transmission Tariff (OATT).

The Gateway West project is currently undergoing a public involvement process regarding route selection, environmental studies, and permitting. The project as proposed in Idaho includes two separate 500-kV lines between the Populus substation in southeast Idaho, and the Hemingway substation in southwestern Idaho, with connections in central Idaho at the Midpoint and proposed Cedar Hill substations.

Phase 1 is expected to provide between 700 MW and 1,500 MW of additional transfer capacity across Idaho. The fully completed project would provide an additional 3,000 MW of transfer capacity. Similarly, the project extending east from Populus substation into eastern Wyoming is expected to provide Phase 1 capacity improvements of approximately 700 to 1,500 MW, with the full build out capacity increase being greater than 2,000 MW east of Jim Bridger, and 3,000 MW between the Populus substation and Jim Bridger.

The project cost and capacity is expected to be shared between Idaho Power and Rocky Mountain Power based upon load service requirements and third-party transmission service request obligations. Additional information about the Gateway West project can be found at www.gatewaywestproject.com.

8. PLANNING CRITERIA AND PORTFOLIO SELECTION

Many utilities plan to median, or expected, conditions and then include a reserve margin to cover the 50 percent of the time when conditions are less favorable than median. Idaho Power discussed planning criteria with commission staff members and the public criteria as part of the 2002 Integrated Resource Plan (IRP). Out of these discussions came the company's practice of using more stringent planning criteria than median conditions. The planning criteria and planning scenarios are discussed in the following section.

Planning Scenarios and Criteria

The timing and necessity of future generation resources are based on a 20-year forecast of surpluses and deficiencies for monthly average load and peak-hour load. The 20-year forecast is further divided into two 10-year periods that coincide with the near-term action plan and the long-term action plan.

The planning criteria for monthly average load planning are 70th percentile water and 70th percentile average load conditions. For peak-hour load conditions, the planning criteria used are 90th percentile water and 95th percentile peak-hour load. The peak-hour analysis is coupled with Idaho Power's ability to import additional energy on its transmission system. Peak-hour load planning criteria are more stringent than average-load planning criteria because Idaho Power's ability to import additional energy is typically limited during peak load periods. The median forecast is no longer used for resource planning although the median forecast is used to set retail rates and avoided cost rates during regulatory proceedings.

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 capacity margin in excess of load while using median load and water conditions. Both approaches are designed to result in a system having generating capacity in reserve for meeting day-to-day operating reserve requirements.

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

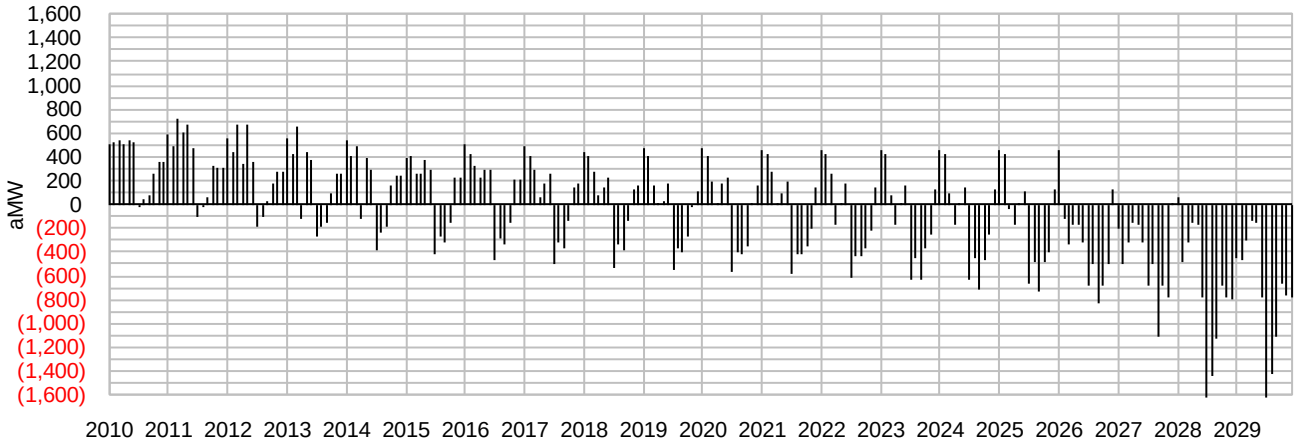
Highlights

- Idaho Power uses 70th percentile average load and 70th percentile water conditions for energy planning.
- For peak–hour capacity planning, Idaho Power uses 90th percentile water conditions and 95th percentile peak–hour loads.
- Peak–hour load deficiencies with 2009 IRP demand response and committed generating resources are close to 200 MW by 2014, and approximately 700 MW by 2025.

Average Monthly Energy Planning

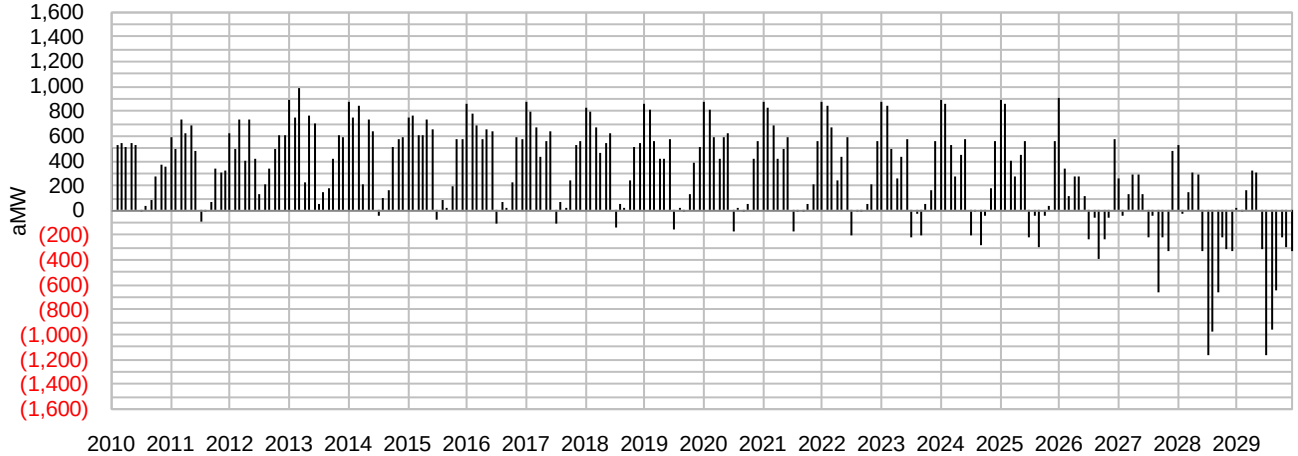
Average energy surpluses and deficiencies are determined using 70th percentile water and 70th percentile average load conditions, coupled with Idaho Power's ability to import energy from firm market purchases using reserved network capacity. Figure 8.1 shows the monthly average energy surpluses and deficits with existing resources. The energy positions shown in Figure 8.1 include the forecast impact of existing demand-side management (DSM) programs, coal curtailment, the current level of Public Utilities Regulatory Act (PURPA) development, existing power purchase agreements (PPAs), firm Pacific Northwest import capability, and gas peaking unit output. Figure 8.1 illustrates that monthly average deficit positions grow steadily in magnitude and number of months affected. By 2014, four months are affected with deficits reaching nearly 400 aMW for the most deficit month and, near the end of the planning period, energy deficits become substantial as generation from Idaho Power's coal facilities is totally curtailed.

Figure 8.1 Monthly Average Energy Surpluses and Deficits with Existing Resources (70th Percentile Water and 70th Percentile Load)



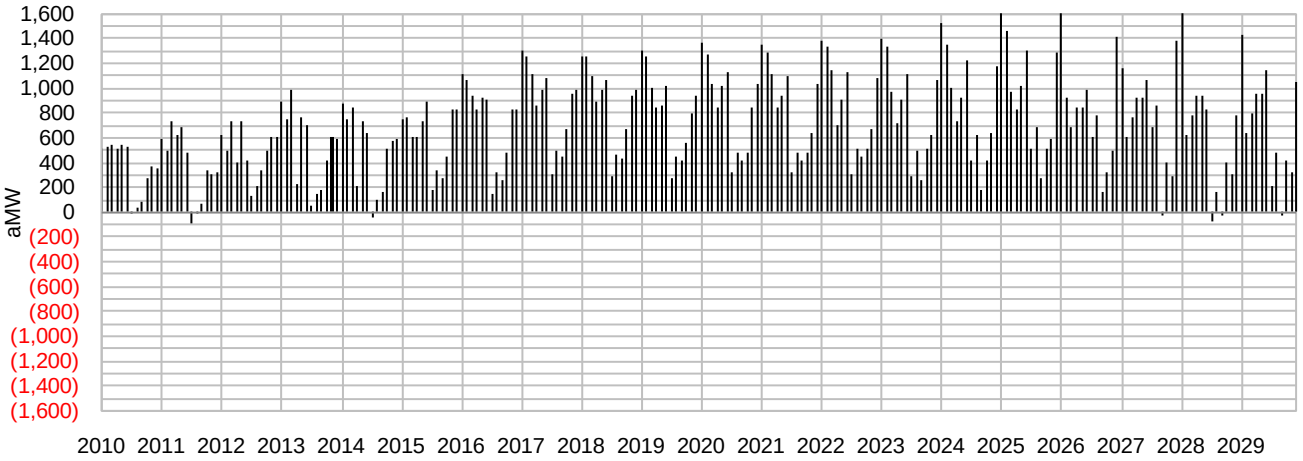
Resource deficits are substantially improved as shown in Figure 8.2 with the addition of committed resources from the 2006 IRP and the new DSM programs proposed in the 2009 IRP. The committed resources supply-side include the Langley Gulch combined-cycle combustion turbine (CCCT), the 2012 Wind Request for Proposal (RFP), and geothermal projects.

Figure 8.2 Monthly Average Energy Surpluses and Deficits with Existing and Committed Resources and New DSM (70th Percentile Water and 70th Percentile Load)



By design, the inclusion of generating and transmission resources in the 2009 IRP preferred portfolio substantially eliminates all energy deficits. Figure 8.3 shows the resulting positions for monthly average energy. The surpluses shown in Figure 8.3 are a result of the assumption that all resources are dispatched and operating.

Figure 8.3 Monthly Average Energy Surpluses and Deficits with 2009 IRP Resources (70th Percentile Water and 70th Percentile Load)

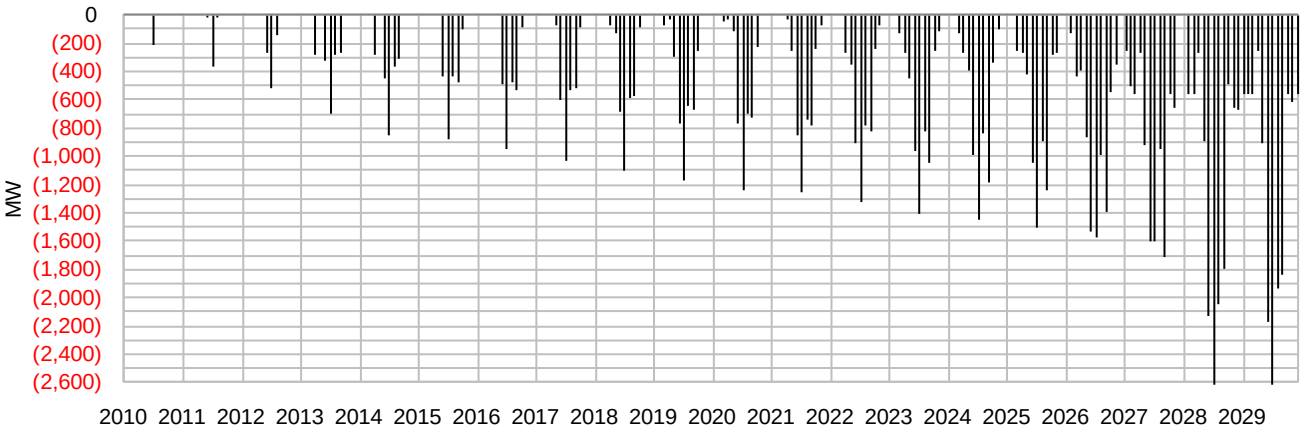


As shown in Figure 8.1, energy deficits of approximately 200 average megawatts (aMW) exist in July 2012 without the addition of the Langley Gulch project and the 2012 Wind RFP. As shown in Figure 8.2, with the addition of these two resources, deficiencies do not appear again until the 2014 to 2015 timeframe. Portfolios for the 2009 IRP were designed to eliminate the remaining deficits which were accomplished as shown in Figure 8.3. Additional details regarding the selection of the preferred portfolio are presented in Chapter 10.

Peak-Hour Planning

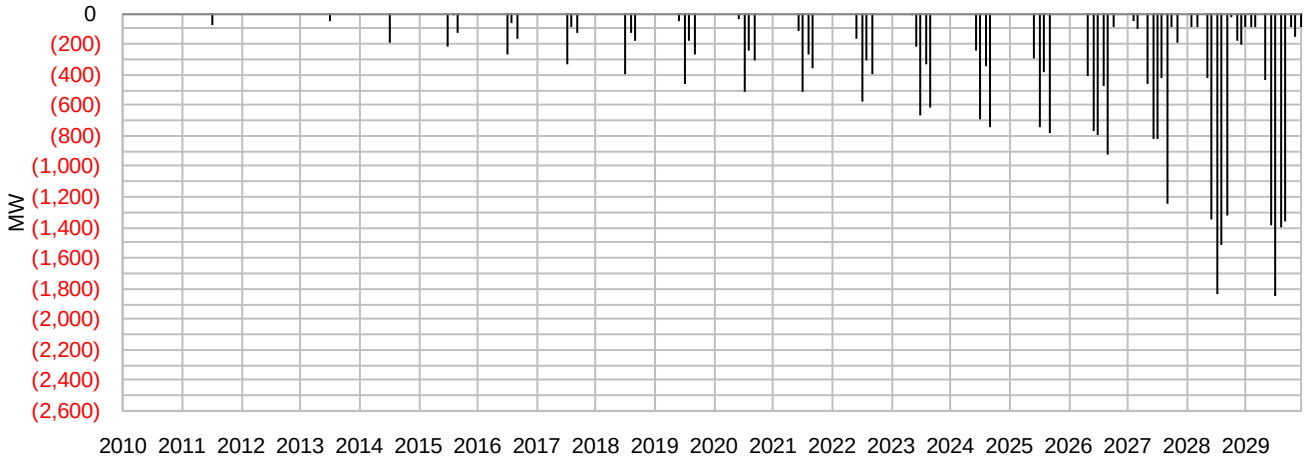
Peak-hour load deficiencies are determined using 90th percentile water and 95th percentile peak-hour load conditions, coupled with Idaho Power's ability to import additional energy on its transmission system to reduce any deficits. Monthly peak-hour deficits with existing resources are illustrated in Figure 8.4. Figure 8.4 illustrates considerable peak-hour deficits reaching in excess of 500 MW by 2012, and continuing to grow through the remainder of the 20-year planning period.

Figure 8.4 Peak-Hour Deficits with Existing Resources (90th Percentile Water and 95th Percentile Load)



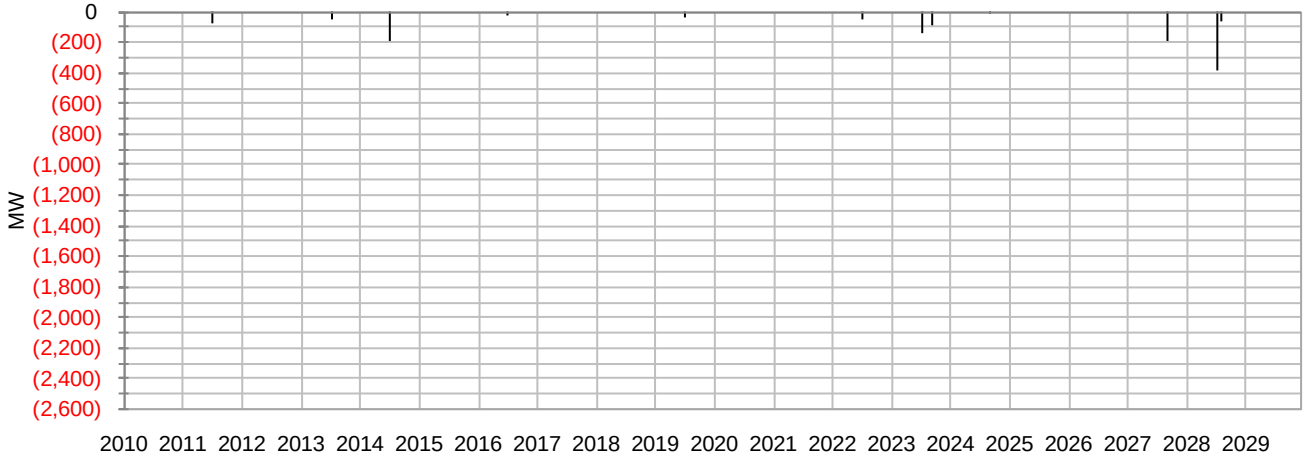
Peak-hour positions are substantially improved as shown in Figure 8.5 with the addition of committed resources from the 2006 IRP and the new demand response programs proposed in the 2009 IRP. The committed supply-side resources include the Langley Gulch CCCT, the 2012 Wind RFP, and geothermal projects.

Figure 8.5 Peak-Hour Deficits with Existing and Committed Resources and New DSM (90th Percentile Water and 95th Percentile Load)



Again by design, the inclusion of generation and transmission resources in the 2009 IRP preferred portfolio substantially eliminates all peak-hour deficits. Figure 8.6 shows the resulting monthly positions for peak-hour planning.

Figure 8.6 Peak-Hour Deficits with 2009 IRP Resources (90th Percentile Water and 95th Percentile Load)



Peak-hour load deficiencies are determined using 90th percentile water and 95th percentile peak-hour load conditions. In addition to these criteria, 70th percentile average load conditions are assumed, but the hydrologic and peak-hour load criteria are the major factors in determining peak-hour load deficiencies. 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.

The deficits shown in Figure 8.5 account for the updated sales and load forecast, forecast performance of DSM programs, adjustments to the hydro generation forecast, the current level of PURPA development, the Langley Gulch CCCT, the 2012 Wind RFP and Idaho Power's natural gas-fired peaking resources. Similar to the deficits shown for average energy, the peak-hour analysis shows deficits beginning in 2014. With the addition of the 2009 IRP preferred portfolio, these deficits are

substantially eliminated as shown in Figure 8.6. Additional details regarding the selection of the preferred portfolio are presented in Chapter 10.

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

At times of peak summer load, Idaho Power is fully using all available transmission capacity from the Pacific Northwest. If Idaho Power were to face a significant outage at one of its main generation facilities, or a transmission interruption on one of the main import paths, the company would fail to meet reserve requirement standards. If Idaho Power is unable to meet reserve requirements, then the company is 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.

Portfolio Design and Selection

The 2009 IRP portfolio development strategy divides the study period into two 10-year periods; 2010 - through 2019, and 2020 through 2029. Resource portfolios in each 10–year period are designed to satisfy the energy and peak-hour deficits shown in the load and resource balance. Idaho Power also believes a federal renewable electricity standard (RES) will be enacted in the near future, and each portfolio is designed to substantially comply with the RES provisions contained in the Waxman–Markey bill.

The Shoshone Falls Upgrade Project has been included in numerous past IRPs as a committed resource. For the 2009 IRP, the project was included in all the portfolios analyzed. However, in order to quantify the value of the project, the preferred portfolio was also analyzed without including the Shoshone Falls upgrade project. The results of this analysis are presented in Chapter 10. A summary of the resource portfolios analyzed for the first 10 years of the planning horizon is shown below in Figure 8.7.

Figure 8.7 Initial Resource Portfolios (2010–2019)

	1-1 Solar		1-2 Gas Peaker		1-3 Gas Peaker & B2H[1]		1-4 B2H	
Year	Resource	MW	Resource	MW	Resource	MW	Resource	MW
2012	Wind*	150	Wind*	150	Wind*	150	Wind*	150
	CCCT (Langley Gulch)*	300	CCCT (Langley Gulch)*	300	CCCT (Langley Gulch)*	300	CCCT (Langley Gulch)*	300
	Geothermal*	20	Geothermal*	20	Geothermal*	20	Geothermal*	20
2015	Shoshone Falls	49	Shoshone Falls	49	Shoshone Falls	49	Shoshone Falls	49
	SCCT (Large Aero)	200	SCCT (Frame Peaker)	170	B2H	250	B2H	250
2016	Geothermal*	20	Geothermal*	20	Geothermal*	20	Geothermal*	20
2017	Solar PT w/St	100	SCCT (Frame Peaker)	170	SCCT (Large Aero)	100	B2H	175
2019	Solar PT w/St	100			SCCT (Large Aero)	100		

[1] B2H-Boardman to Hemingway
*Committed Resource

The first 10–year planning period has significant committed resources which are also shown in Figure 8.7. The committed resources included in all of the portfolios. The committed resources are not

included in the capital cost for comparison between portfolios. The new resources shown are designed to reduce previously discussed deficiencies and to meet proposed RES requirements. Because the identified deficiencies are not large and the list of possible resources is limited, it was not necessary to analyze a large number of portfolios for the first 10-year period. The limited number of resource options results in similar portfolios with regards to fuel and technology. A description of the major differences between each portfolio is presented below.

- **1–1 Solar**–Includes two, 100 MW solar power tower resources
- **1–2 Gas Peaker**–Includes two, 170 MW frame peaking units (simple-cycle combustion turbines [SCCT])
- **1-3 Gas Peaker and Boardman to Hemingway**–Includes a 250 MW market purchase on the Boardman to Hemingway transmission line and two, 100 MW aero derivative peaking units (SCCTs)
- **1-4 Boardman to Hemingway**–Includes two market purchases on the Boardman to Hemingway transmission line (250 MW and 175 MW)

In the second 10-year planning period, Idaho Power analyzed six portfolios and all portfolios were again designed to substantially meet the proposed RES requirements in the Waxman–Markey bill. In addition, advanced nuclear and integrated gasification combined cycle (IGCC) were included in separate portfolios to determine how they would impact portfolio performance. A summary of the resource portfolios analyzed for the second 10 years of the planning horizon is shown below in Figure 8.8.

Figure 8.8 Initial Resource Portfolios (2020–2029)

	2-1 Nuclear/Green		2-2 Gateway West		2-3 IGCC		2-4 Wind & Peakers		2-5 Limited Curtailment	
Year	Resource	MW	Resource	MW	Resource	MW	Resource	MW	Resource	MW
2020	Solar PT w/St	100					SCCT (Large Aero)	100		
2021	Wind	100	Wind	100					Wind	100
2022	Solar PT w/St	100	Gateway West	200	Solar PT w/St	100	Wind	100	SCCT (Large Aero)	100
2023	Nuclear	270								
2024	Geothermal	52			IGCC w/Seq.	600	SCCT (Large Aero)	200		
2025	Solar PT w/St	100	Gateway West	200			Gateway West	100		
2026			Wind	100			SCCT (Large Aero)	200	SCCT (Large Aero)	100
2027	Geothermal	52	Gateway West	400	Solar PT w/St	100	Wind	400	Wind	200
									SCCT (Large Aero)	100
2028	Nuclear	400	Gateway West	600	SCCT (Large Aero)	400	SCCT (Large Aero)	400		
2029	Gateway West	250			Solar PT w/St	100	SCCT (Large Aero)	500		

Portfolio 2-1 contains an advanced nuclear resource along with a mixture of renewable resources to meet RES requirements. Portfolio 2-2 relies heavily on market purchases and wind resources. Portfolio 2-3 includes an IGCC resource combined with solar power tower technology. Portfolio 2-4 relies on wind resources for energy and natural gas peaking units necessary for peak-hour loads and wind integration, and portfolio 2-5 includes limited curtailment of Idaho Power's coal resources with wind and natural gas peaking units. A description of each resource portfolio is presented below.

- **2-1 Nuclear/Green**–Includes a 270 MW nuclear resource in 2023 and another 400 MW nuclear resource in 2028. Renewable resources include wind, solar and geothermal

- **2-2 Market Purchases**–Includes 1,400 MW of purchases on the Gateway West transmission line and wind resources necessary to meet RES requirements
- **2-3 IGCC with Sequestration**–Includes 600 MW from an integrated gasification combined-cycle (IGCC) resource in 2024, 300 MW of solar for RES requirements, and 400 MW of natural gas peaking units
- **2-4 Wind and Peakers**–Includes 500 MW of wind resources and 1,400 MW of natural gas peaking units
- **2-5 Limited Curtailment**–Includes 300 MW of wind resources and 200 MW of natural gas peaking units. Portfolio 2-5 also includes limited curtailment of Idaho Power's existing coal resources

Chapter 9 provides details on how the portfolios were modeled and the assumptions used in the analysis. Chapter 10 presents a detailed discussion of the modeling results and risk analysis.

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9. MODELING APPROACH AND ASSUMPTIONS

Idaho Power uses the AURORAxmp® (AURORA) market model as the primary tool for determining future resource operations and to estimate the portfolio costs for the 20-year integrated resource plan (IRP) planning horizon. AURORA uses a long-term (LT) study option to develop a future Western Electricity Coordinating Council (WECC) resource optimization scenario. In addition, AURORA modeling results provide detailed estimates on wholesale energy pricing, resource values under various market conditions, and electricity pricing and portfolio values.

The AURORA software applies economic principles and dispatch simulation to model the relationships of supply, transmission, and electricity demand in order to forecast market prices. The operation of existing and future resources are based on forecasts of key fundamental elements such as demand, fuel prices, hydro conditions, and operating characteristics of new resources. Various mathematical algorithms are used in unit dispatch, unit commitment, pool pricing logic, and in the long-term capacity expansion capability. The algorithms simulate the regional electrical system to determine how utility generation and transmission resources operate to serve load.

Multiple electricity markets, zones, hubs, and operating pools can be modeled using AURORA. Idaho Power models the entire WECC when evaluating the various resource portfolios. Idaho Power does not maintain detailed data on all WECC resources in the AURORA model and the company relies on a database maintained and updated by EPIS, Inc. Idaho Power evaluates the AURORA database and makes changes based on available information prior to modeling the IRP portfolios.

Future WECC resources are determined in a two step process. The first step uses the AURORA LT module to optimize the WECC future resources per the AURORA LT process. Since the AURORA LT process does not account for state renewable portfolio standards (RPS), Idaho Power estimates RPS requirements for future years on a state-by-state basis and replaces some AURORA LT resources in the database with RPS qualifying resources. Enough RPS resources are added for compliance with the anticipated state requirements.

Highlights

- Idaho Power uses the AURORA Electric Market Model as the primary tool for determining future resource build-out of operations and portfolio cost impacts for the 20-year IRP planning period.
- The 2009 IRP evaluates proposed carbon reduction legislation differently than previous IRPs by specifically defining carbon reduction targets and curtailing coal units.
- The 2009 IRP incorporates anticipated federal renewable electricity standard (RES) legislation and plans for the resources necessary to comply with the legislation.
- Two categories of transmission, backbone and interstate transmission, are accounted for in the IRP.

AURORA Setup Enhancements

Idaho Power incorporated several changes to the AURORA database which are designed to increase AURORA's operational modeling realism. The Idaho Power changes to the database generally add additional hourly operational detail and move away from flat generation output, de-rates, and fixed capacity factors over the term of the study. The 2009 IRP also incorporates 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.

Several other enhancements to the LT model are included to incorporate the effects of legislated renewable energy requirements and specific WECC planned resources. The WECC resources are determined from the *2007 WECC Long Term Resource Adequacy* study.

Carbon Modeling Approach

Idaho Power's 2009 IRP analyzes the potential cost of carbon emissions differently than has been done in previous IRPs. Historically, a carbon adder, or tax, has been used to account for the social costs of emitting carbon or other combustion byproducts. The purpose of a carbon tax is to account for all of the costs in the price of energy produced by carbon-emitting resources. Both the Waxman–Markey bill (H.R. 2454) and the Boxer–Kerry bill (S. 1733) propose a cap-and-trade system for reducing carbon emissions and Idaho Power considers the implementation of a cap-and-trade system to be more likely than a carbon tax.

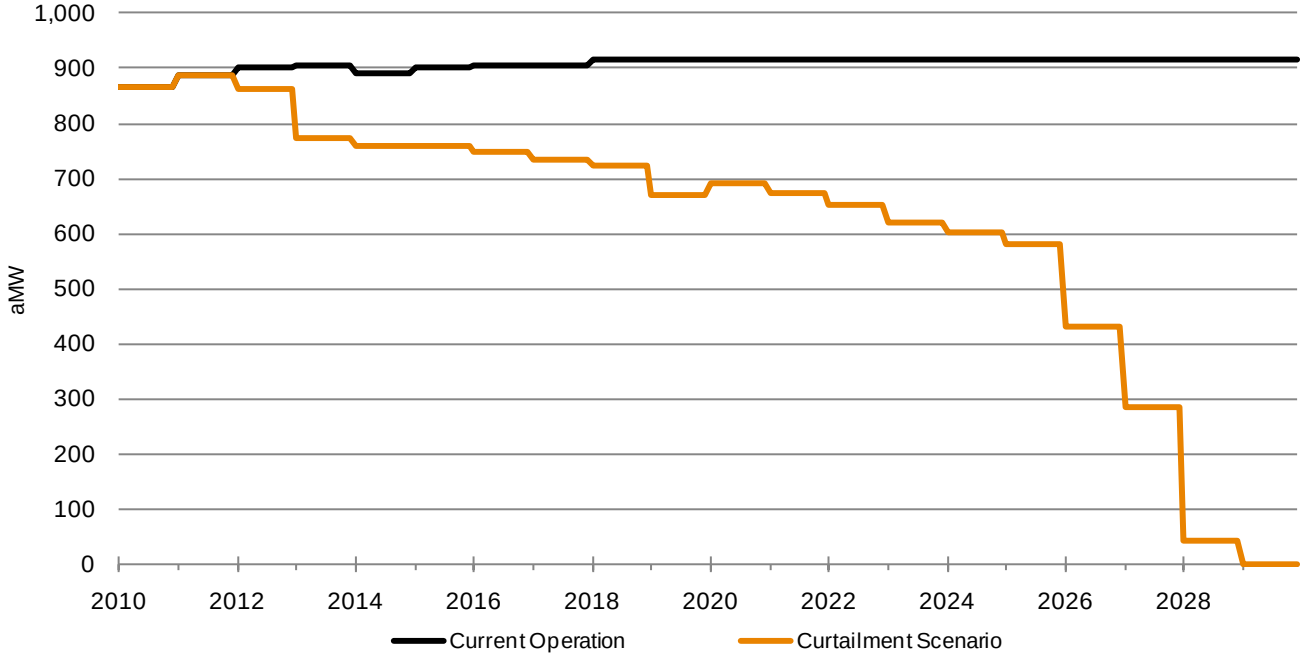
Although Idaho Power believes a cap-and-trade system is more likely, regulatory requirements dictate the analysis be performed using a carbon adder, which Idaho Power has also done. However, the primary discussion in the 2009 IRP regarding carbon emissions is related to Idaho Power's attempt to model a cap-and-trade scenario under the provisions of the Waxman–Markey bill. To model the cap-and-trade scenario, Idaho Power has reduced the output from its coal facilities based on the number of allowances that are expected to be allocated to the company. The cost of resource portfolios with emissions in excess of the allocated amount are increased by purchasing additional allowances.

Idaho Power has also analyzed the effects of carbon legislation by modeling a $43 per ton carbon tax. The carbon tax analysis suggests that the $43 carbon adder significantly increases the portfolio costs, and increases the retail energy rates, but does not create a significant decrease in carbon emissions. The carbon tax appears to be less effective than the proposed cap-and-trade legislation.

In addition, the carbon adder approach does not appear to promote resource dispatch decisions that result in reduced emissions from existing resources. Coal curtailment forces the resource plan to replace the coal generation and quantifies the cost implications of the resource replacement. Figure 9.1 shows annual average megawatt (aMW) coal output under the existing operations and the annual aMW of coal-fired generation under the coal curtailment scenario. In this scenario, coal-fired generation is completely curtailed by the end of the planning period in 2029.

The emissions targets used to define the new total coal-fired generation are based on the limits proposed in the Waxman–Markey bill. The legislation was passed by the House of Representatives in June 2009, but has not yet been debated in the Senate. The assumed coal curtailment is the primary reason behind the resource needs in the second 10-year planning period. For additional details on the AURORA modeling comparisons, refer to the carbon allowance determination section of *Appendix C–Technical Appendix*.

Figure 9.1 Average Annual Generation from Coal Resources



An alternative to full coal curtailment is evaluated in Portfolio 2-5. Portfolio 2-5 reduces coal unit output to comply with 2020 target levels of emissions and then holds the 2020 carbon emission levels constant for years 2021–2029. In Portfolio 2-5, Idaho Power operates coal resources at the 2020 emission levels and acquires the necessary carbon emission allowances from the market. The required carbon emission allowances are valued at the price cap proposed in the Boxer–Kerry legislation. The total price of the coal curtailment portfolio 2-4 and the partial coal curtailment portfolio 2-5 are roughly equivalent assuming that the necessary carbon emission allowances can be acquired at costs equal to the proposed price cap.

The three distinct carbon futures are modeled in AURORA for all of the resource portfolios; 1) coal curtailment (as described above), 2) a $43 carbon adder without coal curtailment, and 3) continuation of present operations with no carbon adder and no coal curtailment. The results of the analysis are shown in *Appendix C–Technical Appendix* in the carbon futures comparison section.

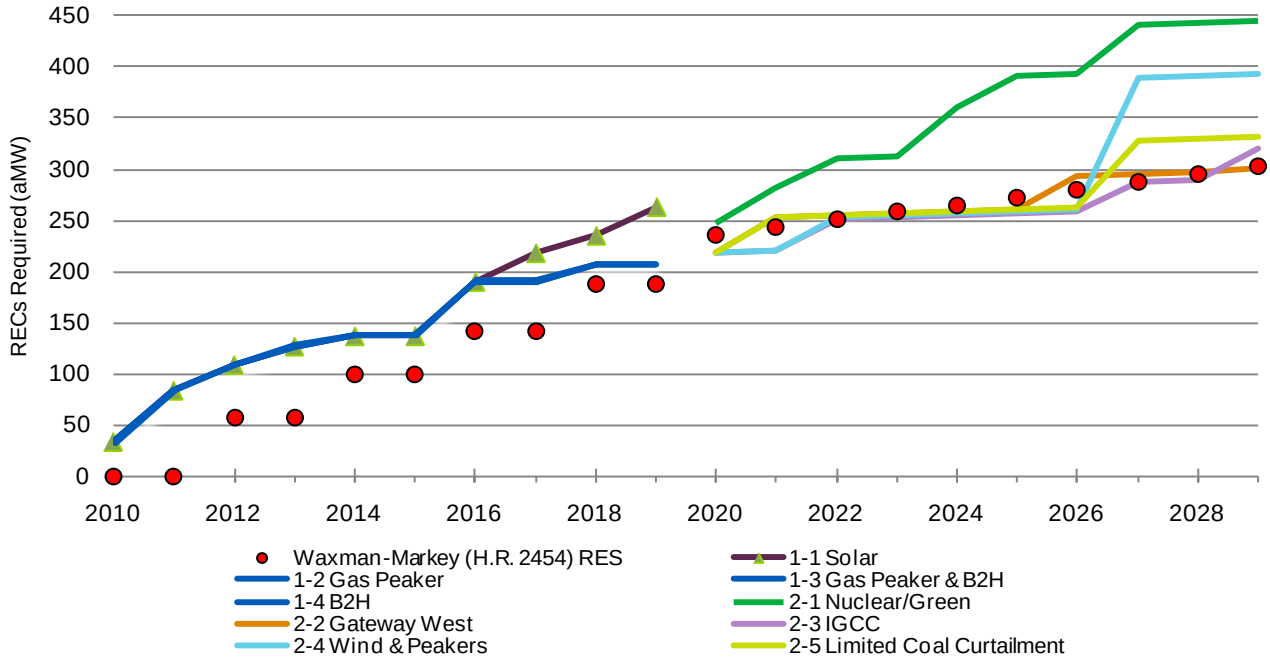
Renewable Energy Credits

The 2009 IRP considers the proposed federal renewable electricity standard (RES) legislation and the resource plan includes the resources necessary to meet the proposed requirements. In addition, some neighboring states such as Washington, Oregon, Colorado, and California have already enacted significant RPS requirements. The state legislation has prompted the construction of renewable energy projects throughout the west even in states like Idaho without specific RPS requirements. Even if the renewable energy is not delivered to the specific state, the renewable energy credits (REC) have value and can be traded in a regional market.

Idaho does not have RPS and Idaho Power can meet the requirements of the Oregon RPS with a portion of the RECs from the Elkhorn Valley Wind Project. Idaho Power has not included defined RES planning criteria in previous resource plans. However, the increasing likelihood of a federal RES led Idaho Power to develop a formal plan to satisfy the expected future federal requirements. The planning goal in the 2009 IRP is to substantially satisfy the proposed federal RES targets with existing or new portfolio resources. Figure 9.2 shows the expected quantity of RECs Idaho Power would need under the Waxman–Markey bill along with the number of RECs each resource portfolio would provide. The

resource portfolios analyzed for the 2009 IRP meet the requirements in the first 10 years and substantially meet the requirements in the second 10-year period.

Figure 9.2 Waxman–Markey RES Requirements and Portfolio RECs



Transmission and Market Purchases

The need for additional power from either new resources or market purchases will require additional transmission. Idaho Power faces severe transmission constraints when evaluating additional supply-side resources. Transmission constraints have been a major factor in evaluating each new supply-side resource; Bennett Mountain, Danskin 1, the Elkhorn Valley Wind Project, Langley Gulch, and the 2012 Wind Request for Proposals (RFP).



High-voltage transmission lines are an important part of delivering energy to customers.

Two categories of transmission are accounted for in the IRP. The first is backbone transmission which integrates resources and allows energy to flow from the gen

eration project to the load centers within a utility's own control area or service territory. Backbone transmission has a designated generating resource and is usually lower voltage and within the service territory. An example of backbone transmission is the transmission lines that deliver generation from the Hells Canyon Complex to the load center in the Treasure Valley.

Interstate transmission is the second transmission type and is generally higher voltage and covers greater distances. Interstate transmission is planned on a regional basis to meet the needs of electric utilities and the needs of third parties requesting transmission service. Very little interstate transmission has been constructed in the last 30 years. Examples of interstate transmission include the proposed Gateway West and Boardman to Hemingway projects.

The portfolios with market purchases in the first 10 years and all of the second 10-year portfolios include proposed interstate transmission projects. The Northern Tier Transmission Group (NTTG) is one entity that coordinates regional transmission plans in the Pacific Northwest. The NTTG annual report is the basis of the interstate transmission alternatives discussed in Idaho Power's 2009 IRP.
The transmission planning scenarios used in the 2009 IRP are taken from NTTG's *2008–2009 Biennial Plan Final Report-DRAFT* dated November 2, 2009.

Transmission costs are evaluated on an annual Network Transmission Revenue Requirement basis. The calculation is similar to the revenue requirement calculations used in Idaho Power's FERC formula rate. In determining the annual revenue requirement, the new transmission investment is calculated in two parts. The first part is based on a percentage of the total cost of an interstate transmission project subscribed to and the second part is the cost of backbone upgrades for planned new resources for each portfolio. The two parts are then added to arrive at the total transmission revenue requirement, which is included in the annual cost of a portfolio. Additional details showing the calculations can be found in *Appendix C–Technical Appendix*.

Regional Transmission Planning (from the NTTG Plan)

NTTG's 2008-2009 biennial plan was produced through public processes in conjunction with related activities of the NTTG Cost Allocation Committee and the NTTG Transmission Use Committee. Technical studies have demonstrated the resulting plan to be capable of reliably meeting the identified regional transmission needs established in the study plan.

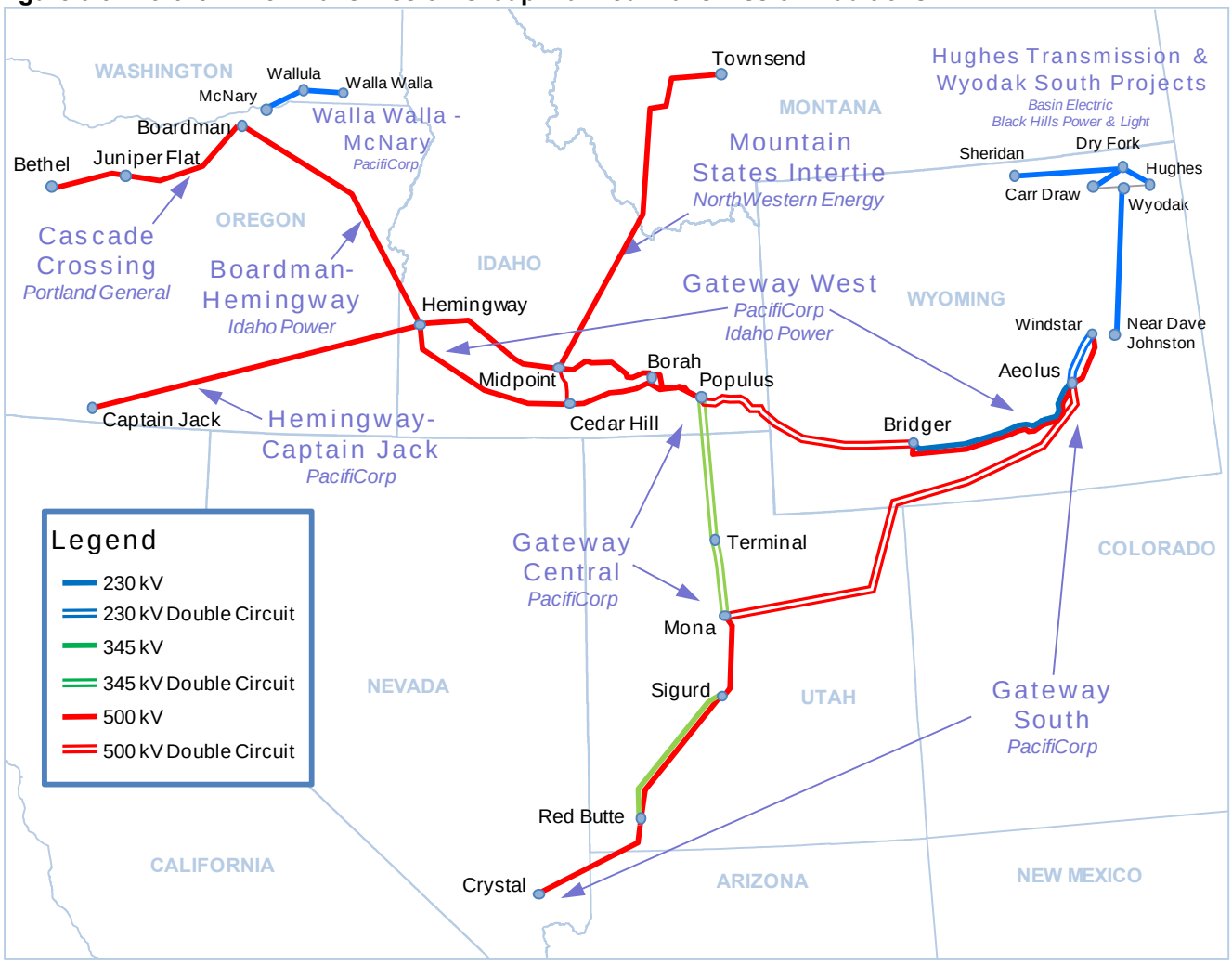
Planning is an iterative process and must work in concert with local transmission plans and IRPs, where they exist. The NTTG transmission plan is a result of a bottom-up load service process to ensure that the transmission planned for the NTTG footprint can reliably serve forecasted load growth and conditions established by data submittals and stakeholder input during the process. There may be broader regional needs outside of the NTTG footprint unmet by this plan. These unmet needs are expected to be addressed as part of regional, interconnection–wide efforts reconciling bottom-up and top-down study efforts.

The NTTG plan establishes the baseline main grid transmission configuration for the NTTG footprint for the planning horizon ending in 2018. The planned transmission should be used as a base plan to inform other planning processes. While Idaho Power cannot assure the NTTG regional plan will be implemented as designed, the plan represents the best information available during the current planning cycle. Changing needs or new information will be accommodated through appropriate data submittals during the next planning cycle.

The NTTG plan identifies a number of specific projects. However, the technical analysis was performed on the premise that the entire transmission plan is in service in 2018. Path and project ratings are determined separately through Western Electricity Coordinating Council (WECC) processes and are the responsibility of the projects' sponsors. Commercial subscription and capacity commitments are administered by each Transmission Provider under their Open Access Transmission Tariff (OATT).

Idaho Power evaluates both the Boardman to Hemingway project for the first 10-year period, and the Gateway West project for the second 10-year period. Figure 9.3 illustrates the identified transmission path upgrades for a variety of interstate transmission projects in the Pacific Northwest and Intermountain Region. The transmission paths shown in Figure 9.3 are for reference only. Actual transmission paths are being determines through public processes involving federal and state agencies and the general public.

Figure 9.3 Northern Tier Transmission Group Planned Transmission Additions



Market Purchase Assumptions

The 2009 integrated resource plan uses different transmission assumptions for each of the 10-year periods. The assumption in the first 10-year period is that transmission capacity is increased only to the extent identified in each resource portfolio. Idaho Power has adopted a conservative approach for the first 10 years and only includes market energy purchases when the market need is specifically identified in a resource portfolio.

The second 10-year period increases the transmission based on the projects identified in the NTTG report discussed earlier. The uncertainty of the entire NTTG transmission expansion plan being completed as proposed is significant. Resource plans that rely heavily on market purchases over transmission that is beyond the reasonable scope of Idaho Power participation or control may not be prudent. The transmission risk is discussed further in Chapter 10.

The transmission upgrades modeled for the 2010-2019 period only increase the transmission capacity to the northwest (Boardman to Hemmingway). Idaho Power subscription on the Boardman to Hemingway project is determined by the capacity and timing of market purchases identified in each resource portfolio.

Transmission is expanded even further in the second 10–year period, 2020-2029 with the Gateway West project. As mentioned earlier, the 2020-2029 transmission expansion is defined by the NTTG plan. The results from the two time periods are evaluated independently.

The degree of Idaho Power's investment participation differs between the portfolios and the costs are included according to the transmission subscription in each resource portfolio. Each transmission subscription represents an Idaho Power equity investment in the project. Each equity investment translates into a revenue requirement and the revenue requirements for the transmission investments are estimated and included in the portfolio total cost comparisons. Idaho Power's investment defines the revenue requirement and the net present value (NPV) of the revenue requirement is included as part of the expected-case cost of each resource portfolio. The NPV of any possible transmission capacity sales to third parties are included in the risk analysis as project benefits.

Economic Evaluation Components and Assumptions

The evaluation of the different resource portfolios incorporates the NPV of the items listed below.

- **AURORA Modeling (Total Portfolio Costing)**–Idaho Power uses the AURORA model to evaluate the variable cost of production for existing and committed resources along with any new resources proposed in the portfolios. Operational constraints are approximated along with energy purchases and sales in the regional market. Idaho Power used a base inflation rate of 3 percent per year discounted to 2010 dollars.
- **Capital Cost**–Idaho Power uses an internal financial analysis model to evaluate the capital cost of new resources and to estimate the associated revenue requirements. Estimated construction costs, including Allowance for Funds Used During Construction (AFUDC), have been escalated at the base inflation rate of 3 percent per year and included in the P-Worth Model. The estimated capital costs are translated into an annual revenue requirement which corresponds to the size and timing of the estimated dollar investment for each resource. The annual revenue requirement for each resource portfolio is then discounted and summed. The annual revenue requirement analysis has the benefit of matching the annual revenue requirements with the corresponding annual energy benefits. The annual revenue requirement analysis eliminates the need to estimate resource values beyond the study period because resource capital costs and resource benefits are matched annually within the study period.
- **Carbon Allowances**–Annual carbon emissions surpluses and deficits from 2012 onward are valued at the Boxer–Kerry allowance cap rate. As previously mentioned, each resource portfolio is designed to substantially comply with the proposed federal legislation. The annual allowance surplus or deficit is valued at the proposed legislative price cap and the total value is discounted and summed for the analysis.
- **Renewable Energy Credits**–Annual REC surpluses and deficits from 2012 forward are valued at the expected REC value. The annual value of the REC surplus or deficit is discounted and summed for the analysis.
- **Transmission Cost**–Idaho Power estimated the total transmission costs for each resource portfolio and the estimated transmission costs are used to determine the annual transmission revenue requirement. The NPV of the transmission revenue requirements are included in the portfolio evaluation. A more detailed presentation of the transmission assumptions for each portfolio can be found in *Appendix C–Technical Appendix.*
- **Financial Assumptions and Interest Rates**–A list of the IRP financial assumptions and interest rates is shown in Table 9.1.

Table 9.1 Financial Assumptions

Plant Operating (Book) Life	30 Years
Discount Rate (aka weighted average cost of capital [WACC])	6.98%
Composite Tax Rate	39.10%
Deferred Rate	35.00%
General O&M Escalation Rate	3.00%
Emission Adder Escalation Rate	2.50%
Annual Property Tax Escalation Rate (% of Investment)	0.29%
Property Tax Escalation Rate	3.00%
Annual Insurance Premium (% of Investment)	0.31%
Insurance Escalation Rate	2.00%
AFUDC Rate (Annual)	7.00%
Production Tax Credit Escalation Rate	3.00%

10. Modeling Results and Risk Analysis

The AURORA modeling results form the basis for evaluating the operational and quantitative risk characteristics of the various resource portfolios. The portfolio resources include Idaho Power's existing and committed resources along with the new resources identified in the specific portfolio. The AURORA portfolio results are aggregated by the two 10-year time periods covered.

Portfolio Modeling Results

Table 10.1 summarizes the market sales, market purchases, portfolio value, and capital costs used in the evaluation of the portfolios for the first 10-year period. The figures in Table 10.1 represent the results of the AURORA analysis, and total transmission and generation capital costs.

Table 10.1 AURORA Results and Capital Costs Used in Portfolio Evaluation (2010–2019)

Year 1–10 Portfolio	1-1 Solar	1-2 Gas Peaker	1-3 Gas Peaker & B2H*	1-4 B2H
AURORA Nominal ($000)				
Market Purchases	$478,000	$511,000	$507,000	$510,000
Market Sales	(1,264,000)	(1,210,000)	(1,229,000)	(1,209,000)
Portfolio Value	3,436,000	3,485,000	3,473,000	3,483,000
Total	2,650,000	2,786,000	2,751,000	2,784,000
AURORA NPV ($000)				
Market Purchases	361,000	382,000	378,000	381,000
Market Sales	(926,000)	(890,000)	(905,000)	(889,000)
Resource Total	2,528,000	2,562,000	2,549,000	2,561,000
Total	1,963,000	2,054,000	2,022,000	2,053,000
Capital Costs (2009 Dollars)				
Transmission Capital Costs	27,000,000	22,000,000	87,000,000	111,000,000
Generation Capital Costs	1,264,000,000	267,000,000	250,000,000	97,000,000

*B2H–Boardman to Hemingway

The second 10-year planning period begins where Portfolio 1-4 ends in 2020. Portfolio 1-4 showed promise early on in the evaluation process as being a low-cost alternative, therefore Portfolio 1-4 was selected as the basis for designing the second-period portfolios. The load forecast for the second period is relatively flat. The primary driver for new resources in the second period is the carbon emission reduction to be compliant with the carbon allowance limits identified in the Waxman-Markey bill

Highlights

- Quantitative risk factors analyzed include third-party transmission subscription, high renewable energy credit (REC) prices, high natural gas prices, high carbon emissions costs, high load growth, and low conservation.
- Qualitative risk factors analyzed include carbon regulation, technology, electric market prices, and resource siting.
- Idaho Power currently maintains a capacity reserve margin of approximately 10 percent.
- Loss of load expectation (LOLE) is based upon the utility industry standard metric of one day in 10 years.

(H.R. 2454). In fact, the base case assumption is that by the end of the integrated resource plan (IRP) planning period, virtually all of Idaho Power's existing coal resources are replaced with lower, or zero, carbon-emitting resources, or market purchases.

Portfolios 2-1 and 2-3 are the most capital intensive; each having over $5 billion dollars in generation resources and approximately $1.35 and $1.23 billion in transmission capital costs respectively (2009 dollars). Less costly, but still significant, is Portfolio 2-4 with almost $2 billion in new generating resources and $800 million in transmission projects. The least costly of the regular portfolios is portfolio 2-2 with $356 million in new resources and $2.25 billion in new transmission. Portfolio 2-5 (Limited Coal Curtailment) has $762 million in generating resources and $337 million in transmission projects. Portfolio 2-5 maintains, and continues to operate, the company's coal plants with limited curtailment.

The operational costs are included in the evaluation in addition to the generation and transmission capital costs. Operational value includes variable costs of operating the resources along with the net contribution of portfolio market purchases and sales. The net operational costs can be either negative or positive depending on the quantity of off-system market sales.

To a significant degree, an inverse correlation exists between the capital cost and the operational costs of the resource portfolios. The relationship is dependent on the exposure to market prices in both energy purchases and energy sales. For example, Portfolio 2-1 has the lowest portfolio operating cost of $2.3 billion (nominal dollars), but Portfolio 2-1 also has the most market sales at $2.2 billion. Because of the large quantity of market sales, portfolio 2-1 has the greatest market price risk.

Portfolio 2-2 has the highest total operating cost at $4.1 billion with over one-third of the total ($1.5 billion) being market purchases. The $1.5 billion gives Portfolio 2-1 a significant market purchases price risk. Table 10.2 summarizes the AURORA results and capital costs used in the portfolio evaluation.

Table 10.2 AURORA Results and Capital Costs Used in Portfolio Evaluation (2020–2029)

Year 11–20 Portfolio	2-1 Nuclear/Green	2-2 Gateway West	2-3 IGCC	2-4 Wind & Peakers	2-5 Limited Coal Curtailment
AURORA Nominal ($000)					
Market Purchases	$540,000	$1,503,000	$631,000	$1,162,000	$840,000
Market Sales	(2,232,000)	(1,174,000)	(2,204,000)	(1,221,000)	(1,818,000)
Portfolio Value	4,050,000	3,758,000	4,309,000	4,003,000	4,574,000
Total	2,358,000	4,087,000	2,736,000	3,944,000	3,596,000
AURORA NPV ($000)					
Market Purchases	214,000	527,000	250,000	423,000	323,000
Market Sales	(823,000)	(473,000)	(818,000)	(484,000)	(669,000)
Portfolio Value	1,559,000	1,465,000	1,644,000	1,540,000	1,717,000
Total	950,000	1,519,000	1,076,000	1,479,000	1,371,000
Capital Costs (2009 Dollars)					
Transmission Capital Costs	1,354,000,000	2,247,000,000	1,227,000,000	799,000,000	338,000,000
Generation Capital Costs	5,834,000,000	356,000,000	5,123,000,000	1,957,000,000	762,000,000

Risk Analysis and Results

Idaho Power evaluated all of the resource portfolios identified in the 2009 IRP for both quantitative and qualitative risks. The objective of risk analysis is to identify resource portfolios that perform well in a variety of possible future scenarios and to reduce total risk.

One of the major risks is load growth uncertainty associated with the present economic conditions. Economic growth has slowed considerably in Idaho Power's service area and there has been extensive speculation regarding the duration of the economic downturn. A quick return to the economic growth rates of the past 20 years will require additional generation resources to meet load. The present load forecast projects a relatively long period of diminished economic growth.

The other factor affecting the load growth is the effectiveness of Idaho Power's demand-side management (DSM) programs. Idaho Power is projecting continued success with DSM programs, but the success is dependent on overall economic conditions as well as program funding and consumer preferences. A lower realization factor for DSM programs will increase load and require additional generation resources.

Electric vehicles are another factor that has the potential to increase load. Idaho Power estimates that the total load from electric vehicles during the early part of the forecast period will not exceed 100 megawatt (MW) and that the load will occur primarily during off-peak-hours. Idaho Power determined the 100 MW estimate by assuming that each vehicle will be charged from a typical 220-volt residential circuit which creates approximately 3 kilowatt (kW) of load. It would take approximately 30,000 electric vehicles charging simultaneously to increase load by 100 MW. Electric vehicles may become a significant load affecting subsequent resource plans.

Many of the other risk factors are regulatory in nature. The electric utility industry, including Idaho Power, faces considerable regulatory risks. Idaho Power proposes to utilize the Boardman to Hemingway transmission line to meet part of its load. However, committed subscription to the Boardman to Hemingway line is not in place which creates uncertainty concerning allocation of the project costs.

In addition, Idaho Power faces regulatory uncertainty associated with carbon regulation and a federal RES. Idaho Power is planning for a resource future that restricts the quantity of carbon that can be released into the earth's atmosphere. The proposed carbon legislation is anticipated to restrict the quantity of carbon emissions and increase the price of renewable energy credits (REC). Limited, or ineffective, carbon legislation could lead Idaho Power and other utilities to continue to generate from traditional fossil-fueled plants.

Natural gas prices are primarily affected by supply and demand; however, economic growth, load growth, carbon legislation, and transmission availability will also influence prices. Presently natural gas prices are relatively low. However, Idaho Power analyzed the portfolio costs under a scenario where natural gas is considerably more expensive.

Quantitative Risk Analysis

For the 2009 IRP, Idaho Power quantitatively analyzed the risk associated with third party transmission subscription, high REC prices, high natural gas prices, high carbon emissions costs, high load growth, and low conservation. The change in expected cost for each portfolio forms the baseline for the risk comparison. Each portfolio is analyzed for the quantitative risk factors mentioned above, and the boundary costs are estimated for each scenario. The results of the quantitative risk analyses are presented in terms of net present value (NPV) resulting in a side-by-side comparison of the expected cost and range of potential risk for each resource portfolio.

Transmission Subscription by Third Parties

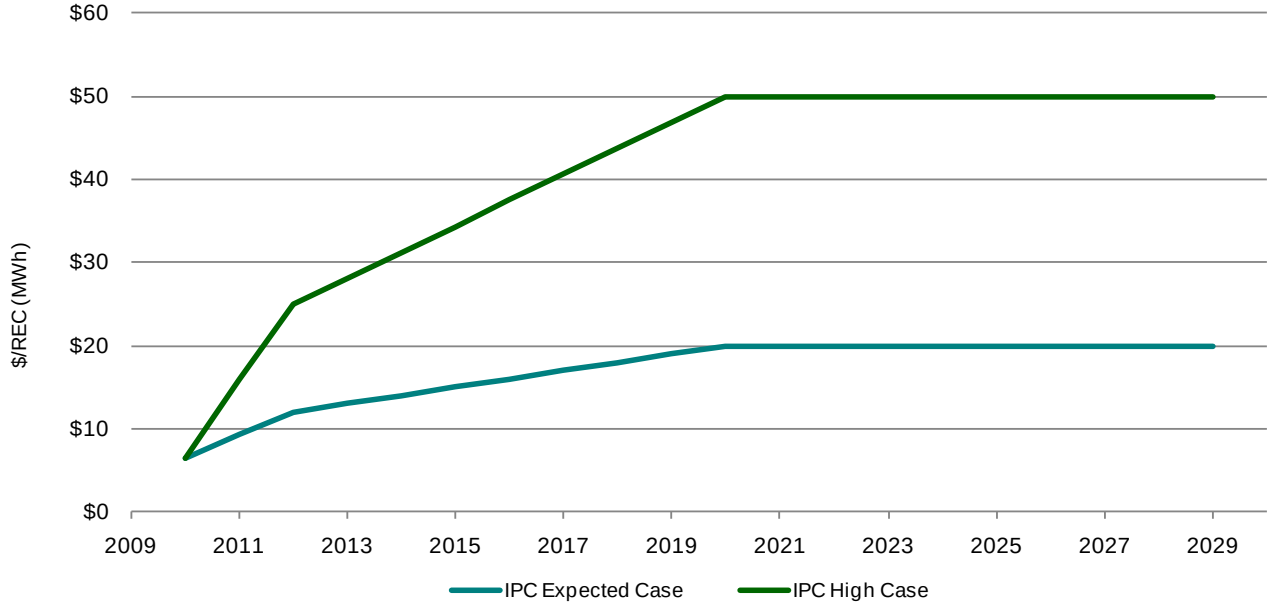
Interstate transmission projects are generally too expensive for a single utility to construct and regional utilities often form partnerships for large-scale transmission projects. Multiple parties commit to fund a portion of the project costs in return for a firm reservation of transfer capacity on the transmission line. Prior to signing the actual agreements, multi-party subscription to new transmission capacity creates significant uncertainty in evaluating actual project costs. At the present time, subscription to both the Boardman to Hemingway and the Gateway West transmission projects has not been determined. Transmission subscription is expected to be better defined in 2010 and will be discussed in the 2011 IRP.

When calculating the expected cost of a portfolio that includes new transmission, the bi-directional transfer capacity of the transmission project is included in the portfolio and is accounted for in the expected cost. For example, Idaho Power intends to use the Boardman to Hemingway transmission line to import energy into Idaho Power's system. Idaho Power's ability to sell transfer capacity from Idaho to the Pacific Northwest represents a possible cost reduction for any portfolio, which includes the Boardman to Hemingway transmission project. The risk analysis estimates that selling all of the unused transmission capacity would reduce the total expected portfolio cost by $46 million (NPV) in Portfolio 1-4 Boardman to Hemingway and by $16.7 million (NVP) in Portfolio 1-3 Gas Peaker and Boardman to Hemingway. Figure 10.5 in the quantitative risk analysis summary (2010-2019) section of this chapter shows the risk associated with third-party transmission subscription in all of the resource portfolios.

Renewable Energy Credit Prices

All the portfolios analyzed in the 2009 IRP are designed to comply with the RES proposed in the Waxman–Markey bill (H.R. 2454). For any given year, the amount of RECs in the resource portfolio is valued based on the projected forward price curve for RECs. For the risk analysis, a high REC price scenario was analyzed using the price cap included in the Boxer–Kerry bill. Portfolios exceeding the Waxman–Markey REC requirement have lower total risk because a high REC price adds additional value to the portfolio. Likewise, portfolios with insufficient RECs are subject to additional REC price risk. Figure 10.1 shows the two REC forward price curves used in the 2009 IRP.

Figure 10.1 REC—Forward Price Curve



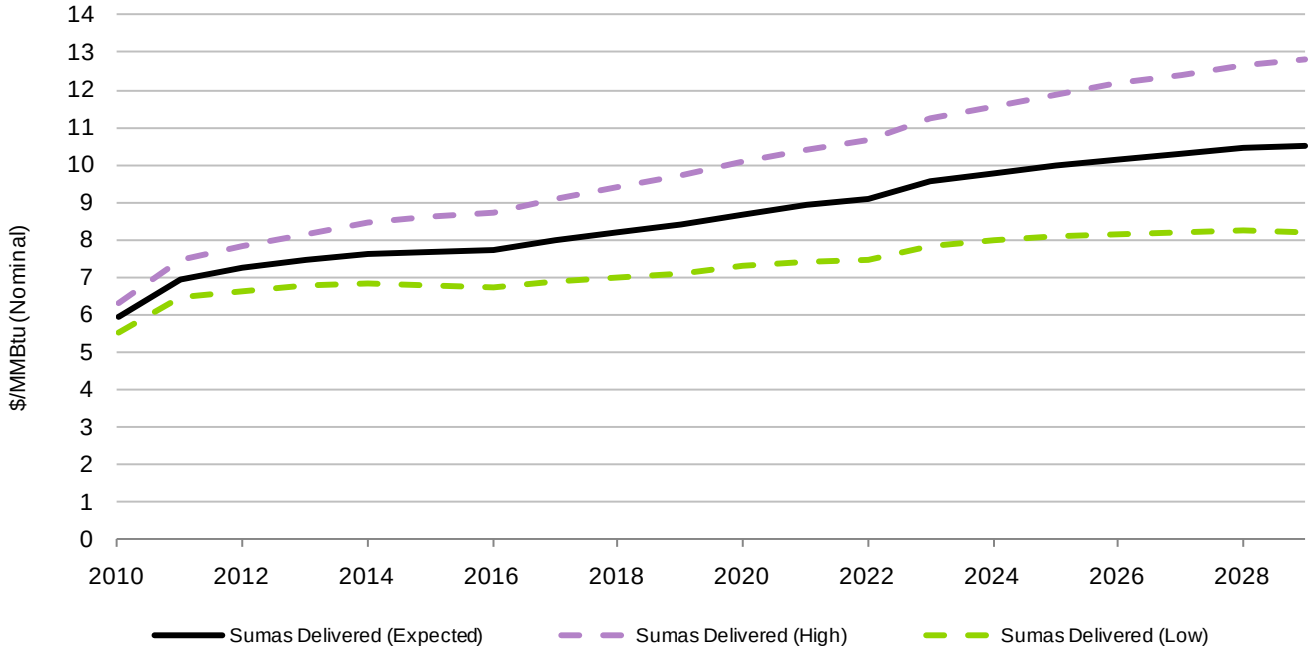
As shown in Figure 9.2 in Chapter 9, all of the resource portfolios considered in the 2009 IRP exceed the Waxman–Markey RES requirements for the first 10-year period. Portfolio 1-1 Solar generates the most RECs. Figure 10.5 shows the REC price risk for each of the portfolios.

During the second 10-year period, all of the proposed resource portfolios substantially meet the Waxman–Markey RES requirements. Portfolio 2-1 Nuclear/Green generates the most RECs during the second 10-year time period. Figures 10.5 and 10.6 show the REC price risk for each of the resource portfolios.

High Natural Gas Prices

The effects of high natural gas prices were analyzed by subtracting the total portfolio cost determined with the expected natural gas prices from the total portfolio cost using high natural gas prices. Figure 10.2 shows the natural gas prices used for the analysis.

Figure 10.2 Natural Gas Price Forecast



High natural gas prices tend to increase the total portfolio value for Idaho Power. During much of the year, natural gas generation is the marginal resource in the Pacific Northwest and natural gas prices indirectly set electricity prices in the regional market. Even though Idaho Power uses natural gas fuel for a portion of its generation, the entire generation output is valued at market cost, and market cost is determined substantially by natural gas generation. High natural gas prices increase the portfolio value for all of the Idaho Power resource portfolios.

During the first 10 years, risk analysis for high gas prices showed that Portfolio 1-3 Gas Peaker and Boardman to Hemingway had the least reduction in expected portfolio costs with portfolios 1-1 Solar, 1-2 Gas Peaker and 1-3 Gas Peaker and Boardman to Hemingway being very similar. Figure 10.5 shows the risk of high gas prices for each of the portfolios.

The risk analysis for the second 10 years showed that high gas prices would increase the expected portfolio cost for Portfolio 2-2 Gateway West and Portfolio 2-4 Wind and Peakers, with the Gateway West portfolio being exposed to market purchases and the Wind and Peakers portfolio containing a significant amount of natural gas resources. Portfolio 2-1 Nuclear/Green, Portfolio 2-3 and Portfolio 2-5 would benefit high gas prices and the resulting high energy prices because these portfolios

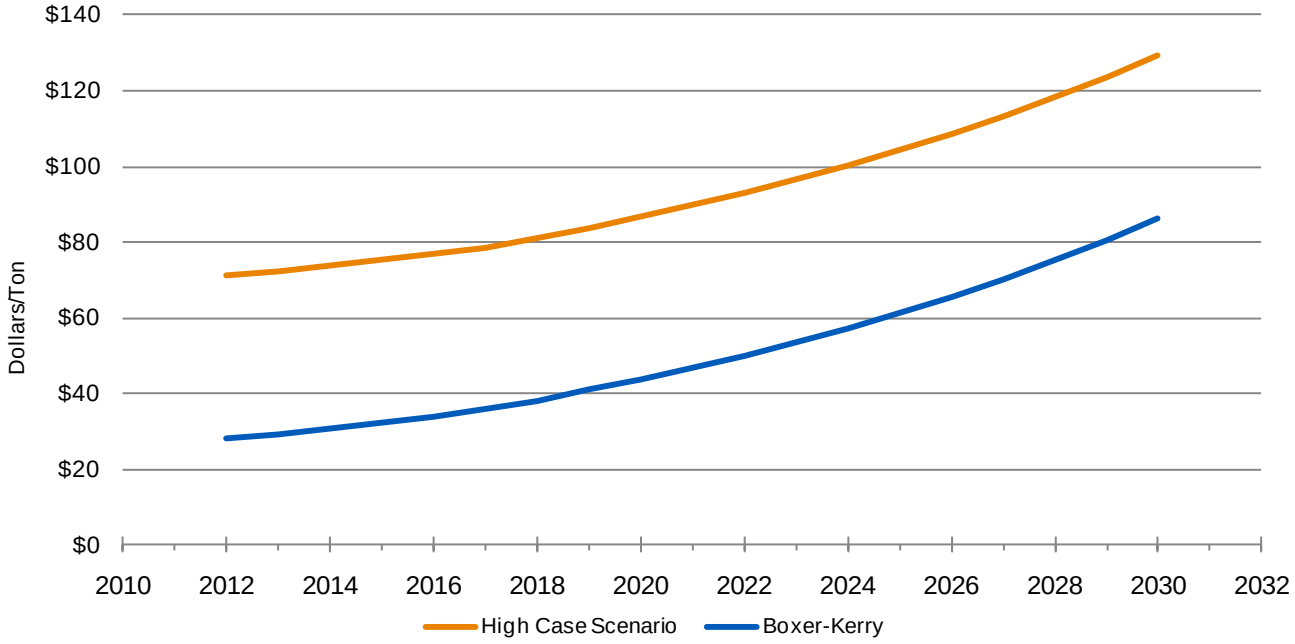
do not rely on a significant amount of natural gas resources. Figure 10.6 shows the risk of high gas prices in all of the portfolios.

CO_2 Allowance Prices

The IRP base case curtails coal production to closely meet the carbon allowances Idaho Power would expect to receive under the Waxman–Markey bill (H.R. 2454). The Boxer–Kerry price cap proposal also sets a price cap on the cost of carbon allowances. Emissions associated with each of the resource portfolios were valued using the Boxer–Kerry price cap curve.

It is important to also understand the portfolio risk with high emission allowance prices. Idaho Power performed a risk analysis to estimate the effect of a $43 per ton carbon tax added to the Boxer–Kerry price cap curve. Figure 10.3 shows the expected case allowance price (Boxer–Kerry cap) and the high price case used for the risk analysis.

Figure 10.3 Boxer–Kerry Carbon Allowance Price Cap and High Case Scenario



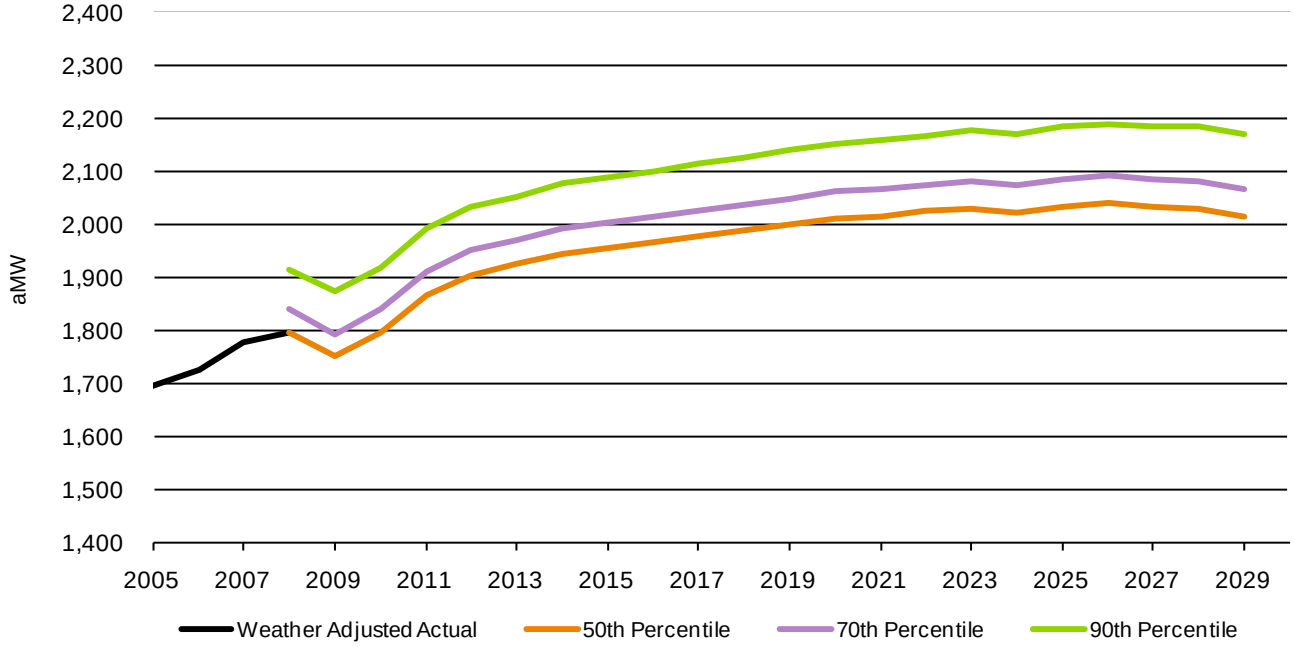
As expected, the high price case risk analysis resulted in a cost increase in all of the resource portfolios. During the first 10 years, Portfolio 1-3 Gas Peaker and Boardman to Hemingway had the greatest increase in costs and Portfolio 1-1 Solar had the lowest increase. Figure 10.5 shows the risk of high carbon allowance prices in all of the portfolios.

In the second 10 years, Portfolio 2-5 Limited Coal Curtailment showed the greatest cost increase and Portfolio 2-1 Nuclear/Green showed the lowest increase. Figure 10.6 shows the risk of high carbon allowance prices in all of the portfolios.

High Load Growth

The current load growth forecast departs significantly from the historical trend line. The general consensus during the company's IRP Advisory Council (IRPAC) meetings was that Idaho Power faces the risk that loads may be higher than forecast. Figure 10.4 shows the various load forecasts used in the 2009 IRP, including the high load growth case used to assess the load forecast risk.

Figure 10.4 Average Monthly Load Growth Forecast



High load growth increased the costs in all resource portfolios as additional energy purchases were required to meet customer load. During the first 10 years, Portfolio 1-3 Gas Peaker and Boardman to Hemingway had the highest increase in costs and Portfolio 1-2 Gas Peaker had the lowest increase. Figure 10.5 shows the risk of high load growth in all of the portfolios.

In the second 10 years, Portfolio 2-4 Wind and Peaker had the highest increase in costs with Portfolio 2-5 Limited Coal Curtailment having the lowest increase. Figure 10.6 shows the risk of high load growth in all of the portfolios.

Low Conservation

Energy efficiency, conservation, and demand response programs are forecast to significantly reduce the need for future generation resources. However, there is some uncertainty and risk associated with the forecast if the expected level of DSM is not achieved. Idaho Power evaluated a low conservation case where only 50 percent of the forecast DSM program performance is achieved to assess the DSM program realization risk.

The low conservation risk analysis showed an increase in costs to all of the portfolios which is similar to the high load growth analysis presented above. During the first 10 years, Portfolio 1-3 Gas Peaker and Boardman to Hemingway had the highest increase in costs and Portfolio 1-2 Gas Peaker had the lowest increase. Figure 10.5 shows the risk of low conservation in all of the portfolios.

In the second 10 years, Portfolio 2-4 Wind and Peakers had the highest increase in costs with Portfolio 2-5 Limited Coal Curtailment having the lowest increase in costs. Figure 10.6 shows the risk of low conservation in all of the portfolios.

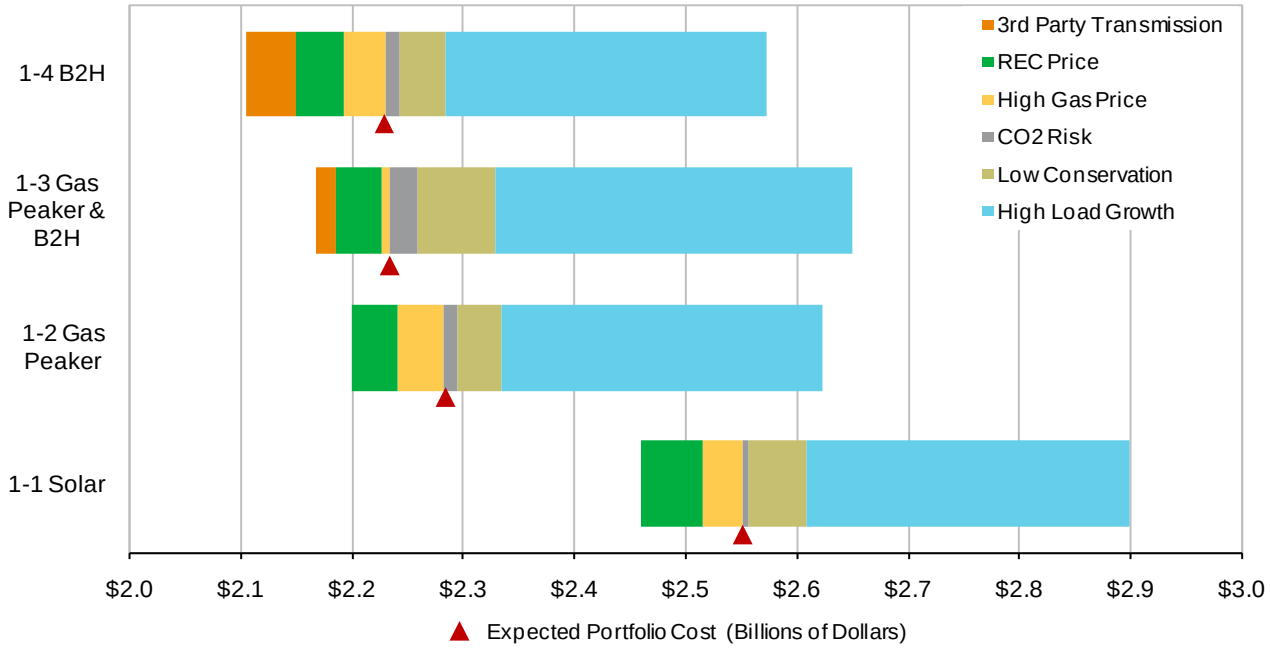
Quantitative Risk Analysis Summary (2010–2019)

The summary conclusions of the quantitative risk analyses are:

- The high load growth and low conservation analyses do not provide significant differentiation between the different resource portfolios, but do quantify the potential for increased costs.
- Additional generation benefits some portfolios due to additional operational flexibility.
- Natural gas prices are correlated with market power prices and high gas prices increase the value of Idaho Power's existing portfolio.
- Portfolios that include the Boardman to Hemingway transmission project have the potential to cost less depending on actual third-party subscription.
- Carbon risk is a significant factor if emission costs exceed the anticipated allowance allocations.

Portfolio 1-4 Boardman to Hemingway has the lowest expected portfolio cost and the potential for the lowest risk. Figure 10.5 shows the expected total portfolio cost and the cumulative risk for each portfolio analyzed for the 2010-2019 time period.

Figure 10.5 Cumulative Portfolio Risk (2010–2019)



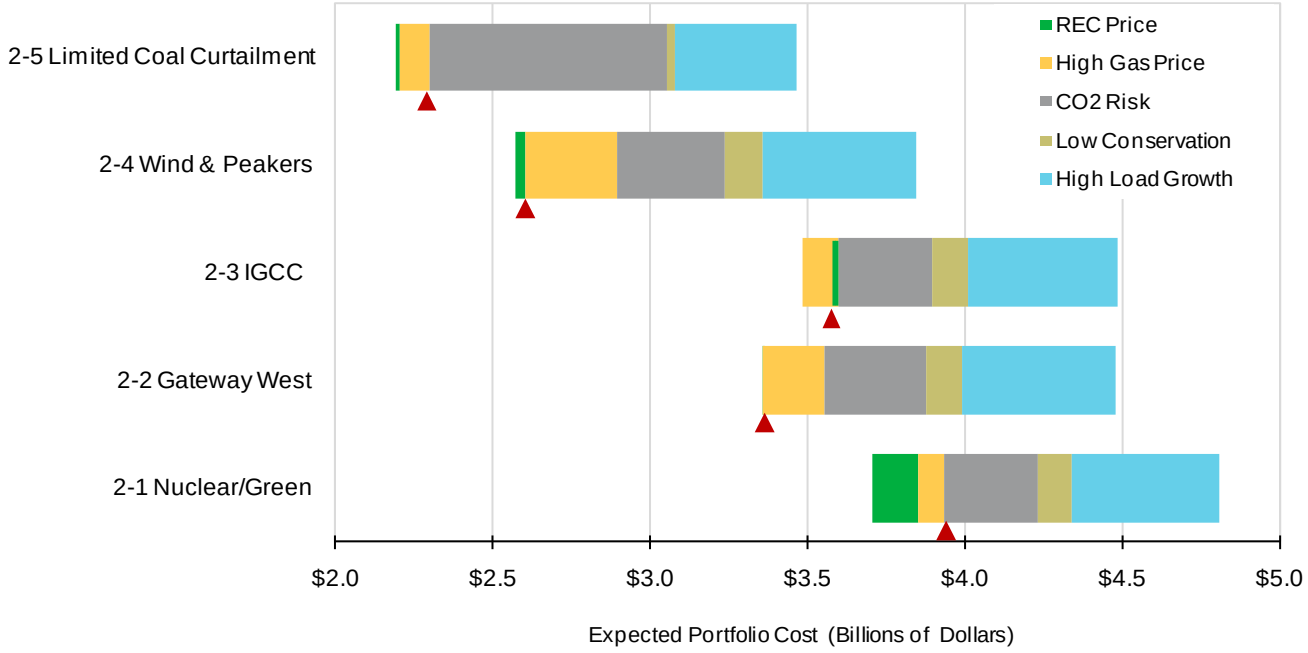
Quantitative Risk Analysis Summary (2020-2029)

The 2009 IRP considered several assumptions when analyzing the quantitative risk analysis for years 2020 through 2029. Portfolio 1-4 was used to define the 2010-2019 resources for the second 10–year modeling period. Another assumption that had a substantial effect on total portfolio costs is the addition of the Gateway West transmission project. Additional quantitative risk factors with significant portfolio differentiation include natural gas price effects ranging from $0–$1,140 million and the expected carbon allowance price with a $43 increase ranging between $296 to $749 million.

Portfolio 2-5 Limited Coal Curtailment has the lowest expected portfolio cost, but has the highest carbon risk of all the portfolios. The carbon risk in Portfolio 2-5 could be even greater than the estimate should the carbon allowance price caps be adjusted upward. Portfolio 2-1 Nuclear/Green has the highest expected portfolio cost, but has the least risk because of the limited exposure to the carbon price risk.

Figure 10.6 shows the expected total portfolio cost and the cumulative risk for each portfolio analyzed for the 2020–2029 time period.

Figure 10.6 Cumulative Portfolio Risk (2020–2029)



Qualitative Risk Analysis

The qualitative risks associated with the four 2010-2019 resource portfolios and the five 2020-2029 resource portfolios are more difficult to assess. Qualitative analysis preferences are chosen through judgment and do not lend themselves to the deterministic quantitative metrics. Many of the qualitative factors are considered in public forums like the IRPAC meetings as well as in regulatory workshops and proceedings. For the 2009 IRP, Idaho Power qualitatively analyzed the risk associated with carbon regulation, technology, and resource siting.

Carbon Regulation

Congress is embarking on the most comprehensive energy legislation in many years. While the Waxman–Markey bill (H.R. 2454) has emerged from the House with an extensive section on carbon regulation, at the time of this IRP, the form of carbon regulation from a Senate bill is still uncertain. Carbon regulation has become a contentious point in the Senate. Idaho Power has analyzed the Waxman–Markey bill and developed portfolios to comply with proposed carbon regulations. If the Senate were to pass an energy bill, the bill would then go to conference with the House of Representatives. Major components could be changed, particularly carbon regulation. In addition, political analysts and Washington D.C. insiders have speculated that due to the record federal deficit and continued high unemployment in the economy, President Obama could ask Congress to drop the carbon emission cap-and-trade provisions from the energy bill. If cap-and-trade was removed, carbon regulation could become an independent piece of legislation separate from any energy bill. Given the energy legislation uncertainty, Idaho Power believes that it is important to select a resource portfolio that has the flexibility to adapt to carbon regulation changes.

Technology

Technology risk primarily occurs during the second 10-year period of the forecast. The principal area in which technology risk is considered in this resource plan is the uncertainty associated with developing

new advanced nuclear and coal technologies, such as integrated gasification combined cycle (IGCC). IGCC resources provide increased efficiency, reduced emissions, and the ability to capture and potentially sequester CO_2 emissions at reduced costs. However, IGCC plants have higher capital costs and there is uncertainty regarding the performance of the proposed technology.

While there are certain risks associated with each type of generation resource, Idaho Power is specifically concerned about the technology risk associated with IGCC projects. IGCC projects have received a considerable amount of attention in the press recently. Idaho Power is supportive of IGCC technology and believes that the technology may play a significant role in meeting the nation's future energy needs. However, Idaho Power also believes that there is considerable technology risk associated with developing an IGCC project for use with western coals. With only two operating IGCC projects in the entire United States, much of the electric industry, including Idaho Power, does not consider IGCC to be a proven technology.

Considering Idaho Power's modest size and the significant cost of an IGCC project, Idaho Power believes it would be imprudent for the company to assume the IGCC development risk alone. Idaho Power is more comfortable taking a lesser share in a jointly-owned regional IGCC project and the company believes that an ownership share is the appropriate way for Idaho Power to allocate the IGCC technology risk if a future joint development opportunity becomes available.

Market Risk

All market participants, including Idaho Power, face price risks when buying or selling in the market. The magnitude of the risk depends on the characteristics of the portfolio of power supply resources. Portfolios with a large quantity of either market sales or market purchases have greater exposure to changes in market prices. Additional factors to consider in the market price risk faced by each portfolio are the quantity and timing, e.g., spring, summer, daytime or nighttime of renewable resource generation, the quantity of natural gas-fired resources, and the seasonal cost of natural gas.

Idaho Power's current resource base consists primarily of low, marginal-cost coal and hydroelectric resources. Idaho Power's customers have historically benefited because the company can sell excess capacity to the market on a short-term basis during periods of high prices. To a lesser degree, Idaho Power can buy from the market during low-price periods and curtail existing resources, thereby shifting fuel (water and coal) use to more valuable hours. However, both opportunities are limited by existing transmission constraints.

In the 2009 IRP, Idaho Power's excess capacity is eventually consumed by load growth and the base case assumption of coal resource curtailment. These assumptions reduce seasonal excess capacity and limit the opportunities to capitalize on market price volatility. Tables 10.3 and 10.4 show the amount of market purchases and sales for each portfolio. "Resource Total" represents the total generation from existing resources and the new resources in each portfolio. "Native Load" represents the amount of generation required to serve customers.

As shown in Table 10.3, Portfolio 1-1 has the least exposure to market purchases and the greatest exposure to market sales, thus leaving it more exposed to a future of low prices when selling power in the wholesale electric market. On the other hand, Portfolio 1-2 has the least amount of market sales and the greatest amount of market purchases, leaving it more exposed to the risk of high market prices. Although there are differences between each of the portfolios in the amount of market purchases and sales, the differences are minor. The relatively small difference between the portfolios highlights the fact that Idaho Power is able to use market purchases and sales to increase the total value of any portfolio.

Compared to the first ten-year period, the second ten-year period shows a more significant variation between portfolios. The portfolios with large base-load units that are not impaired by carbon legislation (Portfolios 2-1, 2-2 and 2-5) show greater exposure to low market prices. The remaining portfolios (2-2

and 2-4) are significantly more exposed to high market prices due to a reliance on market purchases. Figure 10.4 shows the results of the analysis for the second ten-year period.

Table 10.3 Market Purchases and Sales Summary (2010–2019)

MWh (000)	1-1 Solar	1-2 Gas Peaker	1-3 Gas Peaker & B2H*	1-4 B2H
Market Purchases	8,312	8,861	8,771	8,828
Market Sales	(26,395)	(25,175)	(25,722)	(25,178)
Resource Total	187,614	185,845	186,482	185,881
Native Load	169,531	169,531	169,531	169,531
Diff Market Purchases to Lowest		549	459	516
Diff Market Sales to Lowest	(1,220)		(547)	(3)

*B2H–Boardman to Hemingway

Table 10.4 Market Purchases and Sales Summary (2020–2029)

MWh (000)	2-1 Nuclear/Green	2-2 Gateway West	2-3 IGCC	2-4 Wind & Peakers	2-5 Limited Coal Curtailment
Market Purchases	7,186	19,629	8,475	15,566	11,135
Market Sales	(34,372)	(18,645)	(34,170)	(19,246)	(28,063)
Resource Total	204,869	176,698	203,378	181,363	194,610
Native Load	177,683	177,683	177,683	177,683	177,683
Diff Market Purchases to Lowest		12,440	1,289	8,380	3,949
Diff Market Sales to Lowest	(15,727)		(15,525)	(601)	(9,418)

Resource Siting

Time delays and cost increases associated with resource siting and public acceptance are risks that Idaho Power considers when developing generation and transmission resources. Resource siting becomes even more critical when attempting to locate a generation resource close to an existing load center. In addition to the permitting requirements associated with developing generation resources, Idaho Power must also ensure that the public supports the project and that the project will remain productive throughout its useful life.

The problems that Alternate Energy Holdings, Inc has encountered during the past several years with a proposed nuclear generation plant near Bruneau, Idaho, and the difficulties MidAmerican Nuclear Energy Company, LLC faced with a proposed nuclear generation plant in Payette County are indicative of the risks associated with resource siting and public acceptance. Presently, Idaho Power recognizes there are siting concerns with portions of the Boardman to Hemingway transmission line and the company is working with the local communities and regulatory agencies to develop the project in appropriate areas. Resource siting is a potential issue with any of the generation and transmission resources identified in the IRP.

Qualitative Risk Analysis Summary

Generation resources represent significant capital expenditures and resource development entails considerable risk. The public recognizes the risk and electric utilities are regulated to insure that the risks are prudent. One part of the risk assessment is the public involvement when developing long-term resource plans. A second part of the risk assessment is regular periodic review of the company's long-term resource strategy. Idaho Power develops its IRP on a biennial schedule to address the

changing economic, regulatory, and technology risks. Idaho Power recognizes the capital risk in developing generation resources and understands that a diverse resource portfolio of a variety of supply-side, demand-side, and regional transmission resources will allow the company to maintain operational flexibility, minimize risk, and adapt to future economic, demographic, and regulatory conditions.

Preferred Portfolio Selection

2010–2019 (Portfolio 1-4 Boardman to Hemingway)

The selection Portfolio 1-4 Boardman to Hemingway is based primarily on the portfolio having the lowest expected portfolio cost. The low cost is a result of the portfolio having a relatively low new resource capital cost and low AURORA portfolio cost. Portfolio 1-4 has the highest transmission cost with a 37 percent stake in the Boardman to Hemingway project.

An important consideration in selecting a preferred portfolio is the ability to maintain flexibility in the face of uncertainty and not to foreclose various resource options. The flexibility to adjust to changes during the present period of unusually high regulatory uncertainty is very important. To maintain operational flexibility in some cases means Idaho Power must commit to long lead time resources, such as the Boardman to Hemingway project.

2020–2029 (Portfolio 2-4 Wind and Peakers)

The theme of maintaining resource flexibility continues in the second 10-year period. Portfolio 2-4 focuses on relatively short lead time resources, such as wind projects and natural gas-fired resources. The coal curtailment assumption in Portfolio 2-4 will require significant replacement resources during the last years of the study horizon. In order to accommodate the needed quantity of replacement resources, a significant share (600 MW) of Gateway West is included in the preferred portfolio. The Gateway West transmission project enables access to the high-capacity wind regions of Wyoming (500 MW) as well as access to some energy-rich coal and natural gas deposits in southern Wyoming. The feasibility and risks of natural gas transport for 1,400 MW of new natural gas generation located near the load center in the Treasure Valley has not been included in this analysis.

Figures 10.7 and 10.8 show projections for Idaho Power's energy sources by resource type, for 2019 and 2029 respectively, assuming the preferred portfolio for each 10-year period and the carbon regulations proposed in the Waxman–Markey bill are implemented. The percentages presented in Figures 10.7 and 10.8 are estimates of Idaho Power's future energy sources and are not a representation of the energy expected to be delivered to customers. An accounting of the energy delivered to customers, by resource type, is posted on Idaho Power's Web site at www.idahopower.com.

It is important to note the Waxman–Markey bill presents only one scenario out of many possible futures for the regulation of carbon emissions. In addition, alternative compliance options implemented as part of any future carbon regulation may allow the continued operation of Idaho Power's coal resources.

The level of hydroelectric generation presented in Figures 10.7 and 10.8 is based on 50th percentile or median water conditions. As shown in the figures, the addition of the Langley Gulch combined-cycle combustion turbine (CCCT) in 2012 increases the amount of natural gas generation in 2019 to 12 percent which increases to 29 percent in 2029 with the addition of the natural gas peaking units identified in the second 10 years of the planning period. The addition of gas peaking resources is necessary to integrate the wind resources (500 MW) in the preferred portfolio.

The annual percentage of energy supplied through power purchases is projected to increase from 7 percent in 2019 to 12 percent in 2029. The market purchases component of the power supply portfolio

includes purchases from non-wind Public Utility Regulatory Policy Act (PURPA) resources and market-purchased power. Existing PURPA wind generation is accounted for in the wind generation category.

Figure 10.7 2019 Supply-Side Resources

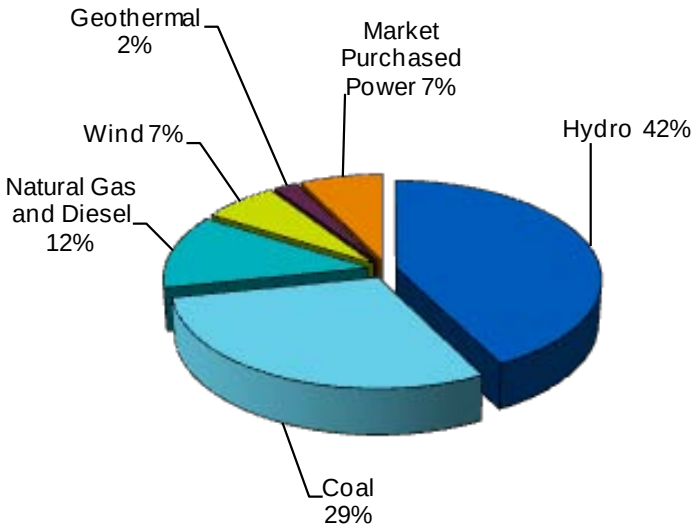
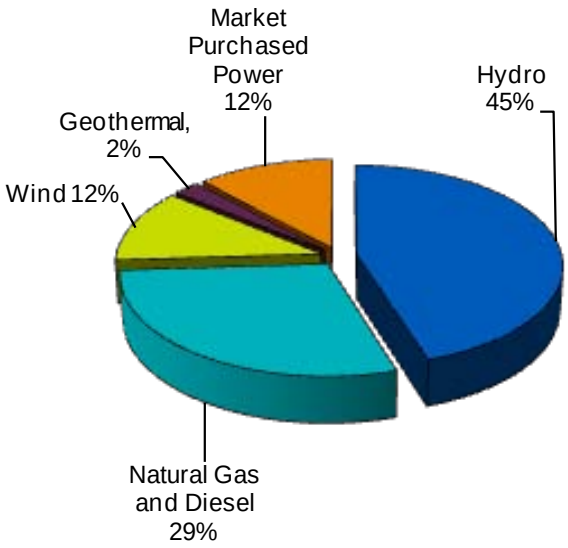


Figure 10.8 2029 Supply-Side Resources



Figures 10.7 and 10.8 represent Idaho Power's energy resource mix in 2019 and 2029 respectively, under the assumptions that Idaho Power's coal resources are curtailed as proposed in the Waxman–Markey bill, and portfolios 1-4 Boardman to Hemingway and 2-4 Wind and Peakers are implemented. If the cost of emitting carbon is less than $30 per ton, it may be more economical for Idaho Power to continue to operate existing coal resources.

Developing Alternate Portfolios

Idaho Power developed two alternate resource portfolios that identify the resource choices should the assumptions used to determine the preferred portfolio not materialize. The most likely scenario leading to selecting an alternative portfolio in the near term is limited third-party interest in the Boardman to Hemingway transmission line. Idaho Power anticipates identifying other partners for the Boardman to Hemingway transmission line by the end of 2012. Should there be insufficient interest in the project, Idaho Power will assess the construction start date in 2013 and possibly delay construction until there is sufficient committed interest in the project. Idaho Power would likely replace the Boardman to Hemingway project with a natural gas-fired generation resource and begin the acquisition process for the natural gas resource with a competitive RFP in 2013. Idaho Power will review the status of the Boardman to Hemingway project in the 2011 IRP. The preferred and alternate portfolios for the first 10-year period are shown in Table 10.5.

The alternate portfolio for the second 10-year period assumes Idaho Power curtails existing coal resources based on the Waxman–Markey bill through 2020 with no additional curtailment through the second 10 years of the planning period. Idaho Power believes this is a likely scenario and the alternate portfolio contains additional resources to offset the level of coal curtailment. The preferred and alternate portfolios for the second 10-year period are shown in Table 10.6.

Table 10.5 Preferred and Alternate Portfolios (2010–2019)

Preferred Portfolio 1–4 Boardman to Hemingway			Alternate Portfolio 1–2 Gas Peakers		
Year	**Resource**	**MW**	**Year**	**Resource**	**MW**
2010			2010		
2012	Wind*	150	2012	Wind*	150
	CCCT (Langley Gulch)*	300		CCCT (Langley Gulch)*	300
	Geothermal*	20		Geothermal*	20
2015	Shoshone Falls	49	2015	Shoshone Falls	49
	Boardman to Hemingway	250		SCCT (Frame Peaker)	170
2016	Geothermal*	20	2016	Geothermal*	20
2017	Boardman to Hemingway	175	2017	SCCT (Frame Peaker)	170
2019			2019		

* Committed Resource

Table 10.6 Preferred and Alternate Portfolios (2020–2029)

Preferred Portfolio 2–4 Wind & Peakers			Alternate Portfolio 2–5 Limited Curtailment		
Year	**Resource**	**MW**	**Year**	**Resource**	**MW**
2020	SCCT (Large Aero)	100	2020		
2021			2021	Wind	100
2022	Wind	100	2022	SCCT (Large Aero)	100
2023			2023		
2024	SCCT (Large Aero)	200	2024		
2025	Gateway West	100	2025		
2026	Large Aero	200	2026	SCCT (Large Aero)	100
2027	Wind	400	2027	Wind	200
				SCCT (Large Aero)	100
2028	SCCT (Large Aero)	400	2028		
2029	SCCT (Large Aero)	500	2029		

Estimated Cost of Proposed Carbon Legislation

Meeting the proposed carbon legislation is not without cost. As mentioned in Chapter 9, Idaho Power prepared Portfolio 2-5 where carbon emissions are reduced up to 2020 and then held flat at the 2020 level throughout the remainder of the planning period. Idaho Power also prepared an additional resource portfolio, with no carbon emission reductions. The additional portfolio was used to isolate the estimated costs to comply with the proposed carbon legislation. Tables 10.7 and 10.8 compare the estimated costs of the no curtailment portfolio with the cost estimates for the preferred resource portfolios 1-4 and 2-4 for both time periods.

There are only minor costs of the proposed carbon legislation in the first 10 years of the planning period because the carbon legislation does not change Idaho Power's resource choices during the first 10 years. However, the proposed carbon legislation does affect how Idaho Power operates its resources in the first 10 years, but the effects are minor and result from reduced off-system sales.

The second 10-year period is considerably different. By the 2020–2029 time period, Idaho Power must replace the generation capacity lost due to coal curtailment with alternate generation resources. The analysis estimates the total cost of the carbon legislation to be almost one billion dollars. The total is composed of almost $700 million of generation capital and over $300 million in lost market sales.

Idaho Power will continue to evaluate the federal carbon emission legislation and the topic will be discussed in the 2011 IRP.

Table 10.7 Carbon Legislation Costs (2010–2019)

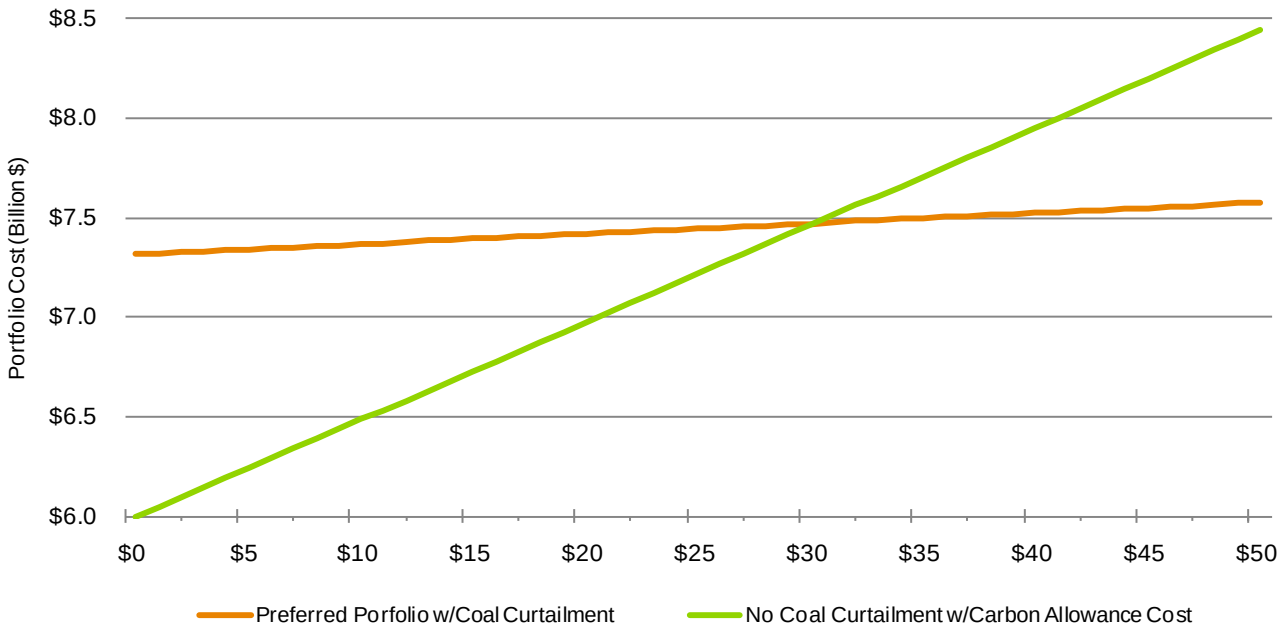
	1-4 Boardman to Hemingway	No Coal Curtailment	Difference
Aurora Nominal ($000)			
Market Purchases	$510,000	$495,000	$15,000
Market Sales	(1,209,000)	(1,458,000)	249,000
Resources Total	3,483,000	3,600,000	(117,000)
Total	2,784,000	2,637,000	147,000
Aurora NPV ($000)			
Market Purchases	381,000	372,000	9,000
Market Sales	(889,000)	(1,055,000)	166,000
Resources Total	2,561,000	2,631,000	(71,000)
Total	2,053,000	1,948,000	104,000
2009 Dollars			
Transmission New	110,870,000	110,870,000	0
Generation Capital Costs	96,951,000	96,951,000	0

Table 10.8 Carbon Legislation Costs (2020–2029)

Aurora Nominal ($000)	2-4 Wind & Peakers	No Coal Curtailment	Difference
Aurora Nominal ($000)			
Market Purchases	$1,162,000	$509,000	$653,000
Market Sales	(1,221,000)	(2,600,000)	1,379,000
Resources Total	4,003,000	5,088,000	(1,085,000)
Total	3,944,000	2,997,000	947,000
Aurora NPV ($000)			
Market Purchases	423,000	199,000	224,000
Market Sales	(484,000)	(953,000)	469,000
Resources Total	1,540,000	1,916,000	(376,000)
Total	1,479,000	1,162,000	317,000
2009 Dollars			
Transmission New	799,000,000	799,000,000	0
Generation Capital Costs	1,957,200,000	1,270,500,000	686,700,000

An analysis was performed to determine the sensitivity of total portfolio cost to the price of carbon allowances. The purpose of the analysis was to determine a "tipping point" where the cost of buying allowances and emitting carbon becomes high enough that coal curtailment becomes a lower cost option. The sensitivity of the total 20-year portfolio costs (AURORA nominal and Capital NPV) of both the preferred portfolios (1-4 and 2-4) and the no-coal curtailment scenario are shown in Figure 10.9. The results of the analysis indicate at an allowance price of less than $30, the no-coal curtailment scenario is a lower cost option. If the cost of carbon allowances exceeds $30, the coal curtailment scenario becomes the lowest cost option.

Figure 10.9 Carbon Allowance Cost and Portfolio Costs



Capacity Planning Margin

Idaho Power discussed planning criteria assumptions 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 instead driven 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 2009 IRP, Idaho Power has calculated the capacity planning margin resulting from the resource development identified in the preferred resource portfolio. When calculating the planning margin, the total resources available to meet demand consist of the additional resources available under the preferred portfolio plus the generation from existing and committed resources assuming expected case (50th percentile) water conditions. The generation from existing resources also includes expected firm purchases from regional markets. The resource total is then compared with expected-case (50th percentile) peak-hour load, with the excess resource capacity designated as 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 forecasted peak load to cover the worst single planning contingency. The worst single planning contingency is defined as an unexpected loss equal to Idaho Power's share of two units at the Jim Bridger coal facility. The reserve level of 330 MW translates into a reserve margin of approximately 10 percent and the reserved transmission capacity allows Idaho Power to import energy during an emergency via the Pacific Northwest Power Pool. A 330 MW reserve margin is also roughly equivalent to a Loss of Load Expectation (LOLE) of one day in 10 years, a standard industry measurement. Capacity planning margin calculations for July of each year through the planning period are shown in Tables 10.9 and 10.10 at the end of this chapter.

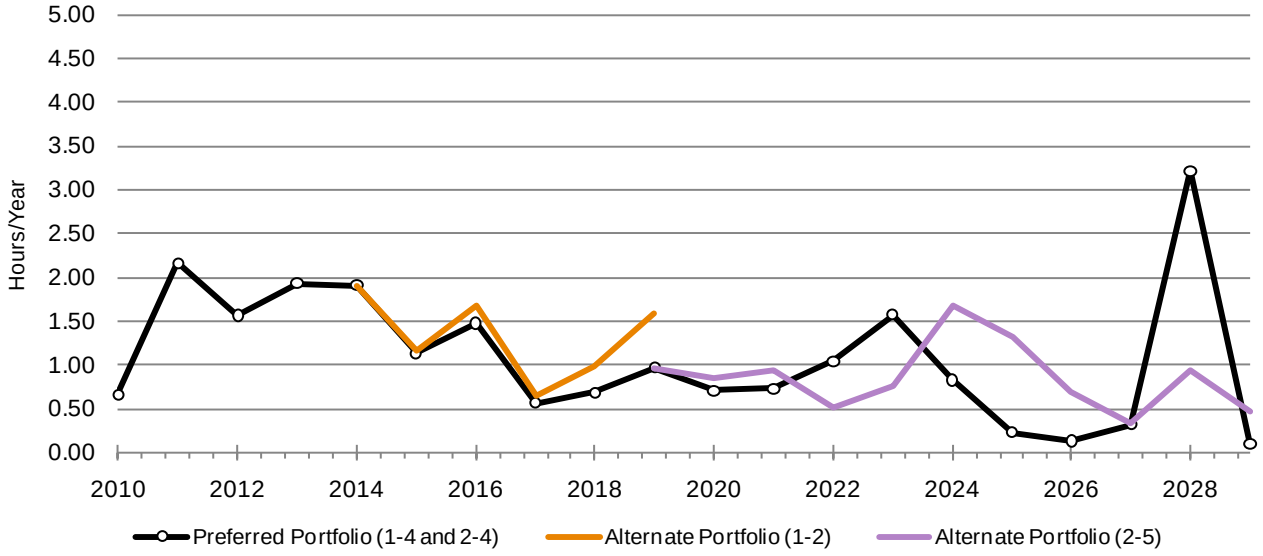
Loss of Load Expectation

Idaho Power used a spreadsheet model[3] to calculate the LOLE for the preferred and alternate portfolios identified in the 2009 IRP. The assessment assumes critical water conditions at the existing hydro facilities and the planned additions for the preferred and alternate scenarios. As mentioned in the previous section, Idaho Power uses a Capacity Benefit Margin (CBM) of 330 MW in transmission planning to provide for the necessary reserves for unit contingencies. The CBM capacity is reserved in the transmission system and sold on a non-firm basis until forced unit outages require use of the transmission capacity. The 2009 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/purchase outage rates (EFORd) and generation and transmission capacities, to compute a LOLE for each hour of the 20-year planning horizon. Demand response programs were modeled as a reduction in the hourly load during the mid-week peak hours rather than as a dispatchable resource due to the limited energy of the demand response programs. The LOLE analysis is performed on a monthly basis to permit capacity de-rates for maintenance or lack of fuel (water).

The typical metric used in the utility industry to assess probability-based resource reliability is a LOLE of 1 day in 10 years. Idaho Power has chosen to calculate 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 2.4 hours/year. The results of the loss of load probability analysis are shown in Figure 10.10 and additional data can be found in *Appendix C–Technical Appendix*.

Figure 10.10 Loss of Load Expectation



In performing the analyses, there were several instances where extending purchases of east-side energy similar to the purchases contemplated in 2010–2012 were necessary to achieve the results shown in Figure 10.10. The high value in 2028 indicates that a minor adjustment in the preferred portfolio would

[3] Based on Roy Billinton "Power System Reliability Evaluation" Charter 2&3, Copyright 1970.

be desirable from a reliability perspective. Moving two of the five 100-MW units scheduled in 2029 to an on-line date in 2028 would reduce the spike without changing the results for 2029.

The LOLE analysis indicates there are periods where a consistent capacity-based load and resource balance was not achieved, in part due to the uneven nature of capacity additions. In future IRPs, Idaho Power may use the LOLE model during the development of the initial resource portfolios to smooth out capacity additions.

Table 10.9 Capacity Planning Margin (2010–2019)

Load and Resource Balance	July-10	July-11	July-12	July-13	July-14	July-15	July-16	July-17	July-18	July-19
Load Forecast (95th%)—Aug 2009 w/No DSM	(3,296)	(3,408)	(3,495)	(3,596)	(3,670)	(3,734)	(3,796)	(3,860)	(3,924)	(3,990)
Existing DSM (Energy Efficiency)	17	33	48	64	79	93	107	121	135	149
Load Forecast (95th%)—w/EE DSM	(3,279)	(3,375)	(3,447)	(3,533)	(3,592)	(3,641)	(3,689)	(3,739)	(3,790)	(3,842)
Existing DSM (Irrigation Timer)	8	6	6	6	6	6	6	6	6	6
Existing DSM (AC Cool Credit)	51	51	51	51	51	51	51	51	51	51
Total Existing Demand Response	59	57	57	57	57	57	57	57	57	57
Peak-Hour Load Forecast w/Existing DSM	(3,220)	(3,318)	(3,390)	(3,476)	(3,535)	(3,585)	(3,633)	(3,683)	(3,733)	(3,785)
Existing Resources										
Coal (w/Curtailment)	967	972	978	983	983	982	980	980	977	977
Hydro (50th%) —HCC	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134
Hydro (50th%)—Other	254	254	253	252	249	246	245	244	243	243
Sho-Ban Water Lease	42	47	48	48	0	0	0	0	0	0
Total Hydro	1,431	1,435	1,435	1,434	1,383	1,380	1,379	1,378	1,377	1,377
CSPP (PURPA)	133	141	141	141	141	141	141	141	141	141
Power Purchase Agreements										
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10
Clatskanie Energy Exchange	12	12	12	12	12	12	12	12	12	12
EnergyPlus—Jefferson (83 MW)	83	83	83	83	83	83	83	83	83	83
East Side Purchase (50 MW)	50	50	50	50	50	50	50	50	50	50
Mead Purchase	75	75	75	75	75	75	75	75	75	75
Total Power Purchase Agreements	235	235	235	235	235	235	235	235	235	235
Firm Pacific NW Import Capability	122	105	97	87	79	71	65	58	54	48
Salmon Diesel	5	5	5	5	5	5	5	5	5	5
Gas Peakers	416	416	416	416	416	416	416	416	416	416
Subtotal	3,309	3,309	3,307	3,302	3,243	3,231	3,221	3,214	3,206	3,199
Net Position - Monthly Surplus/Deficit	88	(9)	(83)	(174)	(292)	(354)	(412)	(469)	(528)	(586)
Planning Margin	2.7%	-0.3%	-2.4%	-5.0%	-8.3%	-9.9%	-11.3%	-12.7%	-14.1%	-15.5%
2006 IRP Resources										
Wind RFP	0	0	8	8	8	8	8	8	8	8
Langley Gulch	0	0	300	300	300	300	300	300	300	300
Geothermal	0	0	0	20	20	20	20	20	20	20
Geothermal	0	0	0	0	0	0	0	20	20	20
Net Position—Remaining Monthly Surplus/Deficit	88	(9)	225	153	35	(26)	(84)	(122)	(180)	(238)
Planning Margin	2.7%	-0.3%	6.6%	4.4%	1.0%	-0.7%	-2.3%	-3.3%	-4.8%	-6.3%
2009 IRP DSM	Jul-10	Jul-11	Jul-12	Jul-13	Jul-14	Jul-15	Jul-16	Jul-17	Jul-18	Jul-19
Commercial (FlexPeak)	40	45	57	57	57	57	57	57	57	57
Irrigation Peak Rewards	212	244	254	254	254	254	254	254	254	254
Energy Efficiency Peak Reduction	3	7	12	18	24	31	37	44	51	58
Total New DSM Peak Reduction	254	296	323	329	335	341	348	355	362	369
Net Position - Remaining Monthly Surplus/Deficit	343	287	547	482	370	315	264	233	182	130
Planning Margin	10.6%	8.7%	16.1%	13.9%	10.5%	8.8%	7.3%	6.3%	4.9%	3.4%
2009 IRP Resources	Jul-10	Jul-11	Jul-12	Jul-13	Jul-14	Jul-15	Jul-16	Jul-17	Jul-18	Jul-19
Boardman-Hemingway Transmission						250	250	250	250	250
Shoshone Falls Upgrade							0	0	0	0
Boardman-Hemingway Transmission								175	175	175
Large Aero										
Wind										
Large Aero										
Gateway West Transmission										
Large Aero										
Wind										
Large Aero										
Large Aero										
Net Position - Monthly Surplus/Deficit	343	287	547	482	370	565	514	658	607	555
Planning Margin	10.6%	8.7%	16.1%	13.9%	10.5%	15.8%	14.1%	17.9%	16.2%	14.7%

Table 10.10 Capacity Planning Margin (2020–2029)

Load and Resource Balance	July-20	July-21	July-22	July-23	July-24	July-25	July-26	July-27	July-28	July-29
Load Forecast (95th%)—Aug 2009 w/No DSM	(4,058)	(4,110)	(4,171)	(4,231)	(4,271)	(4,331)	(4,393)	(4,434)	(4,480)	(4,505)
Existing DSM (Energy Efficiency)	163	177	191	205	219	233	247	261	275	289
Load Forecast (95th%)—w/EE DSM	(3,895)	(3,933)	(3,980)	(4,027)	(4,052)	(4,098)	(4,146)	(4,173)	(4,204)	(4,216)
Existing DSM (Irrigation Timer)	6	6	6	6	6	6	6	6	6	6
Existing DSM (AC Cool Credit)	51	51	51	51	51	51	51	51	51	51
Total Existing Demand Response	57	57	57	57	57	57	57	57	57	57
Peak-Hour Load Forecast w/Existing DSM	(3,839)	(3,877)	(3,923)	(3,970)	(3,995)	(4,041)	(4,089)	(4,116)	(4,148)	(4,159)
Existing Resources										
Coal (w/Curtailment)	977	977	977	977	977	977	977	977	0	0
Hydro (50th%) —HCC	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134	1,134
Hydro (50th%)—Other	242	241	240	240	239	238	237	236	235	234
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0
Total Hydro	1,376	1,375	1,374	1,374	1,373	1,372	1,371	1,370	1,369	1,368
CSPP (PURPA)	141	141	141	141	141	141	141	141	141	141
Power Purchase Agreements										
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10
Clatskanie Energy Exchange	12	12	12	12	12	12	0	0	0	0
EnergyPlus—Jefferson (83 MW)	83	83	83	83	83	83	83	83	83	83
East Side Purchase (50 MW)	50	50	50	50	50	50	50	50	50	50
Mead Purchase	75	75	75	75	75	75	75	75	75	75
Total Power Purchase Agreements	235	235	235	235	235	235	223	223	223	223
Firm Pacific NW Import Capability	41	34	28	23	19	13	6	2	0	0
Salmon Diesel	5	5	5	5	5	5	5	5	5	5
Gas Peakers	416	416	416	416	416	416	416	416	416	416
Subtotal	3,191	3,184	3,177	3,171	3,167	3,160	3,140	3,135	2,155	2,154
Net Position - Monthly Surplus/Deficit	(647)	(693)	(747)	(799)	(828)	(882)	(949)	(981)	(1,993)	(2,005)
Planning Margin	-16.9%	-17.9%	-19.0%	-20.1%	-20.7%	-21.8%	-23.2%	-23.8%	-48.1%	-48.2%
2006 IRP Resources										
Wind RFP	8	8	8	8	8	8	8	8	8	8
Langley Gulch	300	300	300	300	300	300	300	300	300	300
Geothermal	20	20	20	20	20	20	20	20	20	20
Geothermal	20	20	20	20	20	20	20	20	20	20
Net Position—Remaining Monthly Surplus/Deficit	(300)	(346)	(399)	(452)	(481)	(534)	(602)	(634)	(1,646)	(1,658)
Planning Margin	-7.8%	-8.9%	-10.2%	-11.4%	-12.0%	-13.2%	-14.7%	-15.4%	-39.7%	-39.9%
2009 IRP DSM										
Commercial (FlexPeak)	57	57	57	57	57	57	57	57	57	57
Irrigation Peak Rewards	254	254	254	254	254	254	254	254	254	254
Energy Efficiency Peak Reduction	66	73	80	87	95	103	111	119	127	127
Total New DSM Peak Reduction	376	383	390	398	406	413	421	429	438	438
Net Position - Remaining Monthly Surplus/Deficit	76	37	(9)	(54)	(75)	(121)	(181)	(204)	(1,208)	(1,220)
Planning Margin	2.0%	1.0%	-0.2%	-1.4%	-1.9%	-3.0%	-4.4%	-5.0%	-29.1%	-29.3%
2009 IRP Resources										
Boardman-Hemingway Transmission	250	250	250	250	250	250	250	250	250	250
Shoshone Falls Upgrade	0	0	0	0	0	0	0	0	0	0
Boardman-Hemingway Transmission	175	175	175	175	175	175	175	175	175	175
Large Aero	100	100	100	100	100	100	100	100	100	100
Wind			5	5	5	5	5	5	5	5
Large Aero					200	200	200	200	200	200
Gateway West Transmission						100	100	100	100	100
Large Aero							200	200	200	200
Wind								20	20	20
Large Aero									400	400
Large Aero										500
Net Position - Monthly Surplus/Deficit	601	562	521	476	655	709	849	846	242	730
Planning Margin	15.7%	14.5%	13.3%	12.0%	16.4%	17.6%	20.8%	20.5%	5.8%	17.5%

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11. Action Plan

Near-Term Action Plan

The near-term action plan describes the actions Idaho Power plans to take over the next 10 years (2010–2019) as part of implementing the preferred portfolio. Because the near-term time period is so short, no long lead time generation resources, such as advanced nuclear or integrated gasification combined cycle (IGCC) are considered in the near-term plan. However, Idaho Power intends to continue its efforts to explore regional alliances and participate in regional utility planning forums as these technologies develop. Table 11.1 presents a list of the actions Idaho Power expects to take in the next 10 years as part of implementing the preferred portfolio.

Table 11.1 Near-Term Action Plan

Year	Action
2010	Present and gain acceptance of 2009 IRP with regulatory commissions File wind contract resulting from the 2012 Wind RFP with the IPUC File geothermal contract with the IPUC Irrigation Peak Rewards program increases from 160 MW to 220 MW FlexPeak Management program increases from 20 MW to 40 MW Langley Gulch CCCT construction begins
2011	Wind project construction begins Langley Gulch CCCT construction continues Irrigation Peak Rewards program increases from 220 MW to 250 MW FlexPeak Management program increases from 40 MW to 45 MW File 2011 IRP with regulatory commissions
2012	Wind project on-line (approximately 150 MW) Langley Gulch CCCT on-line (300 MW) Geothermal project on-line (approximately 20 MW)
2013	Boardman to Hemingway construction begins Shoshone Falls Upgrade Project construction begins File 2013 IRP with regulatory commissions
2014	Shoshone Falls Upgrade Project construction continues Boardman to Hemingway construction continues
2015	Shoshone Falls Upgrade Project on-line (49 MW) Boardman to Hemingway completed (250 MW) File 2015 IRP with regulatory commissions
2016	Geothermal project on-line (approximately 20 MW)
2017	Boardman to Hemingway additional capacity for market purchases (175 MW) File 2017 IRP with regulatory commissions
2018	No action
2019	File 2019 IRP with regulatory commissions

Long-Term Action Plan

The long-term action plan describes Idaho Power resource acquisitions during the 2020–2029 time period. The long-term action plan assumes that the near-term action plan is completed with only minor variations. The long-term action plan includes a combination of renewable resources and natural gas-fired resources to firm the output from wind resources. The main event in the long-term action plan is that Idaho Power continues to curtail the output from the coal-fired generation resources in order to meet the proposed federal carbon legislation. In this potential future, Idaho Power's coal-fired resource operations will be limited to seasonal needs in early years until they are fully curtailed by the end of the

planning period. Table 11.2 presents a list of the actions Idaho Power expects to take from 2020 through 2029 as part of implementing the preferred portfolio.

Table 11.2 Long-Term Action Plan

Year	Action
2020	Natural gas generation project on-line (approximately 100 MW)
2021	No action
2022	Wind project on-line (approximately 100 MW)
2023	No action
2024	Natural gas generation project on-line (approximately 200 MW)
2025	No action
2026	Natural gas generation project on-line (approximately 200 MW)
2027	Wind project on-line (approximately 400 MW)
2028	Natural gas generation project on-line (approximately 400 MW)
2029	Natural gas generation project on-line (approximately 500 MW)

Delayed interest in the Boardman to Hemingway project may result in Idaho Power constructing both a replacement generation resource as well as constructing the transmission line at a later date. The alternate resource portfolio may lead to constructing the Boardman to Heming project in the second 10-year period. Idaho Power will review the status of the Boardman to Hemingway project in the 2011 IRP. Table 11.3 shows the changes to the near-term action plan if sufficient interest by third parties in the Boardman to Hemingway project does not materialize.

Table 11.3 Alternate Portfolio Near-Term Action Plan

Year	Action
2010	File 2009 IRP with regulatory commissions
	File wind contract (2012 Wind RFP) with the IPUC
	File geothermal contract with IPUC
	Irrigation Peak Rewards Program increases to 220 MW
	FlexPeak Management program increases to 40 MW
	Langley Gulch CCCT construction begins
2011	Wind project construction begins
	Langley Gulch CCCT construction
	Irrigation Peak Rewards Program increases to 250 MW
	FlexPeak Management program increases to 45 MW
	File 2011 IRP with regulatory commissions
2012	Wind project on line (approximately 150 MW)
	Langley Gulch CCCT on-line (300 MW)
	Geothermal generation on-line (approximately 20 MW)
	Natural gas generation resource one RFP
2013	File 2013 IRP with regulatory commissions
2014	Shoshone Falls upgrade construction
	Natural gas generation resource two RFP
2015	Shoshone Falls upgrade on-line (50 MW)
	Natural gas generation resource one on-line
	File 2015 IRP with regulatory commissions
2016	Geothermal Generation on-line (approximately 20 MW)
2017	***Natural Gas generation resource two on-line***
	File 2017 IRP with commissions
2018	No action
2019	File 2019 IRP with commissions

Conclusion

Each Idaho Power Integrated Resource Plan (IRP) builds on the foundation of earlier resource plans and each plan includes incremental changes due to forecasts of future events. The 2009 plan is no exception. However, the 2009 IRP is different in two key aspects.

First, Idaho Power, and other utilities in the west, face major regional transmission decisions. No significant interstate transmission has been built in the region for many years. Idaho Power's 2009 IRP is the first company resource plan where the company and others in the region, must make a significant commitment to new interstate transmission projects.

Secondly, Idaho Power, and the nation, face the likelihood of significant carbon legislation. There has been considerable discussion on aspects of the legislation; however, all recognize the objective of the proposed legislation is to reduce the quantity of carbon released into the earth's atmosphere. Reducing carbon emissions will require curtailment of certain resources as either demand declines or additional energy is produced from alternate resources. Idaho Power has chosen to directly face the issue of curtailment and the 2009 IRP attempts to quantify the impact of proposed carbon legislation.

Idaho Power would like to thank the IRP Advisory Council (IRPAC) members and the public for their contributions to the 2009 IRP. The IRPAC debated these two major issues along with a significant number of other social topics. Idaho Power's 2009 IRP is better because of the contributions from the IRPAC members and the public.

In recognition of the amount of time and effort expended by the IRPAC, at the final meeting members discussed the possibility of including a statement in the IRP indicating the advisory council's support of the IRP. Because the IRPAC represents such a diverse set of stakeholders, the members determined it would not be possible for the group to unanimously support all aspects of the IRP. However, the IRPAC was supportive of the public process and asked Idaho Power to include the following statement in the 2009 IRP: "The members of the IRP Advisory Council support the public process Idaho Power Company conducted as part of preparing the 2009 IRP."

Idaho Power prepares an integrated resource plan biennially. At the time of the next plan in 2011, Idaho Power will have additional information regarding supply-side resources, demand-side management (DSM) programs, fuel prices, economic conditions, and load growth. In addition, Idaho Power hopes to have better information regarding potential carbon regulations, the development of a federal renewable electricity standard (RES), and the feasibility of advanced nuclear, IGCC, and other technology issues.

One of the key strengths of Idaho Power's planning process is that the IRP is updated every two years. Frequent planning allows Idaho Power, the IRPAC, the IPUC and the OPUC, and concerned customers to revisit the resource plan and make periodic adjustments and corrections to reflect changes in technology, economic conditions, and regulatory requirements. During the two years between resource plan filings, the public and regulatory oversight of the activities identified in the near term action plan allows for discussion and adjustment of the IRP as warranted.

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Appendix A — Sales and Load Forecast

For the 2009 Integrated Resource Plan – December 2009



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INTRODUCTION

Idaho Power has prepared *Appendix A–Sales and Load Forecast* as an appendix to its *2009 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 2010 through 2029. For planning purposes, the future demand for electricity by customers in Idaho Power's service area is represented by three load forecasts: 1) a 50th percentile or expected-case load forecast, 2) a 70th percentile load forecast, and 3) a 90th percentile load forecast. These forecasts define three possible load conditions based on variable weather evaluated in the 2009 IRP. The expected-case total load growth rate is 0.7 percent per year over the 20-year planning period. This is 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.

Two additional load forecasts for Idaho Power's service area were prepared. These forecasts provide a range of possible load growths for the 2010–2029 planning period due to variable economic and demographic conditions. The high economic growth and low economic growth scenarios were prepared based on statistical analyses to empirically reflect uncertainty inherent in the load forecast.

The expected-case load forecast assumes median temperatures and median rainfall. Since actual loads can vary significantly, dependent on weather conditions, two alternative scenarios were considered to address the load variability due to weather. A 70th percentile average load forecast and 90th percentile average load forecast were prepared to illustrate the weather-related uncertainty inherent in forecasting electrical loads. The 70th percentile load forecast assumes monthly loads that can be exceeded in three-out-of-ten years (30 percent of the time). The 90th percentile load forecast assumes monthly loads that can be exceeded in one-out-of-ten years (10 percent of the time).

In the expected-case scenario, Idaho Power's total load is forecast to increase to 2,015 average megawatts (aMW) in the year 2029 from the 2010 forecast load of 1,797 aMW. The expected-case forecast total load growth rate averages 0.7 percent per year over the 20 years of the planning period (2010–2029). The number of Idaho Power retail customers increased from the December 2008 level of 485,655 customers to over 682,000 customers at year-end 2029. Idaho Power system peak load is forecast to grow to 4,445 megawatts (MW) in the year 2029 from the 2008 actual system peak of 3,214 MW. The highest system peak on record was 3,214 MW and occurred on Monday, June 30, 2008, at 3:00 p.m. In the expected-case scenario, Idaho Power system peak increases at an average growth rate of 1.5 percent per year over the 20 years of the planning period (2010–2029).

This year's economic forecast was based on a forecast of national and regional economic activity developed by Moody's Analytics, a national econometric consulting firm. Moody's Analytics June 2009 macroeconomic forecast strongly influenced *Appendix A–Sales and Load Forecast*. The national, state, metropolitan statistical area (MSA), and county econometric projections are tailored to Idaho Power's service area using an economic database developed by an outside consultant. 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 development of *Appendix A–Sales and Load Forecast*.

Economic growth assumptions influence several of the individual class of service growth rates. The number of households in Idaho is projected to grow at an annual average rate of 1.3 percent during the forecast period. Growth in the number of households within individual counties in Idaho Power's service area differs from statewide household growth patterns. Service area households are derived from county-specific household forecasts. The number of households, incomes, employment projections,

economic output, real retail electricity prices, and customer consumption patterns are used to form load projections.

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

The future load impacts of implemented and committed Idaho Power energy efficiency demand-side management (DSM) programs are considered within *Appendix A–Sales and Load Forecast*. These programs and their expected impacts are addressed in more detail in Idaho Power's *Demand-Side Management 2008 Annual Report*. This report is Appendix B to the 2009 IRP.

The expected-case load forecast represents Idaho Power's most probable outcome for load growth during the planning period. However, the actual path of future electricity sales will not follow exactly the path suggested by the expected-case load forecast. Therefore, four additional load forecasts were prepared, two that provide a range of possible load growths due to economic uncertainty, and two that address the load variability associated with abnormal weather. The high- and low-growth scenarios provide boundaries on each side of the expected-case scenario and historical load variability potential on future load due to demographic, economic, and other non-weather-related influences. 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.

During the 20-year forecast horizon, there could be major changes in the electric utility industry, such as carbon legislation and fossil fuel market disequilibrium. The high degree of uncertainty associated with such changes is assumed to be reflected in the economic high and low load growth scenarios described above. However, due to the increasing probability of impending carbon legislation becoming law, the impact of carbon legislation on the load forecast was reflected in the forecast of retail electricity prices, which is a driver in the major sector sales forecasting models. The alternative sales and load scenarios of *Appendix A–Sales and Load Forecast* were prepared under the assumption that Idaho Power will continue to serve all customers in its franchised service area during the planning period.

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

2009 IRP SALES AND LOAD FORECAST

Average Load

The 2009 IRP average system load forecast is lower than the 2006 IRP average system load forecast in all years of the forecast period. The slowdown in the national and service-area economy caused load growth to slow dramatically. In addition, the significant increase in energy efficiency and demand response measures, combined with retail electricity prices that incorporate estimates of proposed carbon legislation, result in a decrease of forecast average loads. Significant factors and considerations that influenced the outcome of the 2009 IRP load forecast include the following.

- For the first time, the sales and load forecasts are influenced by the estimated impact of proposed carbon legislation on retail electricity prices. The carbon-impacted retail electricity prices move significantly higher throughout the forecast period, reducing future electricity sales.
- Existing energy efficiency program performance is estimated and included in the sales and load forecast base, lowering the energy and peak demand forecast. However, the impact of demand response programs is accounted for in the load and resource balance. 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 sales and load forecast reflects the increased expected demand for energy and peak capacity of Idaho Power's newest special contract customer, Hoku Materials, located in Pocatello, Idaho. Hoku Materials plans to begin operation in December 2009 and will reach full capacity by October 2010. The current sales and load forecast assumes that Hoku Materials will consume 74 aMW of energy each year and have a peak demand of 82 MW (each measure excluding line losses) once continuous operation is reached in 2012.
- A collapse in the housing sector dramatically slowed the growth in the number of new households and residential customers being added to Idaho Power's service area. The number of commercial customers being added has also slowed dramatically as a result of the economic downturn. Both the residential and commercial customer forecasts were adjusted downward in the near-term to reflect the current housing slowdown and credit crisis. However, by 2012, residential and commercial customer growth is expected to recover, and customer additions are expected to be similar to the growth that occurred prior to the housing bubble in the 1993–2003 timeframe.
- The irrigation sales forecast is somewhat higher due to a substantial increase in weather-adjusted irrigation sales over the last two years (6 percent in 2007 and 8 percent in 2008). Higher farm commodity prices seem to be the primary reason behind the irrigation sales increase. Irrigators appear to have taken advantage of the commodities market by planting all available acreage. In addition, the conversion of hand line to electrically operated pivot irrigation systems may explain a part of the increased energy consumption. In recent years, the increased labor costs associated with moving hand lines and increased concerns for water conservation has triggered the substitution of labor with electrically operated pivots.
- There is uncertainty associated with the growth of new industrial and special contract customers. The forecast uncertainty is associated with the increasing number of entities that have contacted Idaho Power and expressed interest in locating their operations within Idaho Power's service area in conjunction with the uncertain magnitude of associated energy and peak-demand requirements. The current sales and load forecast reflects only those customers that have a very high probability of relocating to the service area or have made financial commitments and whose facilities are actually being constructed at this time. Therefore, the number of large customers that have contacted

Idaho Power and shown interest, but have not made commitments, are not included in the current sales and load forecast.

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 2009 IRP peak forecast reflects the increased expected peak demand of Idaho Power's newest special contract customer, Hoku Materials, located in Pocatello, Idaho.
- The 2009 IRP peak-demand forecast was adjusted downward to reflect the estimated impact of energy efficiency DSM programs that were selected for implementation since 2006. Energy efficiency programs are incorporated into the peak-demand forecast as the programs are committed and implemented.
- The 2009 IRP peak-demand forecast model no longer considers or adjusts for the impact of demand response programs. The demand response programs are included in the load and resource balance as a reduction in peak demand.
- The peak model allows peaks to be calculated at 0, 10th, 20th, 30th, 40th, 50th, 60th, 70th, 80th, 90th, 95th, and 100th percentiles of peak day temperatures for each month of the year.
- Recent historical peak data is added to the peak model regressions. The July 2002, July 2003, June 2005, and July 2005 peak day temperatures were near the 100th percentile, and their addition to the regression models impacted forecast results. In addition, new system peaks were reached in July 2007 and again in June 2008 and were incorporated into the peak forecast model.
- Idaho Power continues to use a median peak day temperature driver in lieu of an average peak day temperature driver. The median peak day temperature has a 50 percent probability of being exceeded. Peak day temperatures are not normally distributed and can be skewed by one or more extreme observations; therefore the median temperature better reflects expected temperatures. The weighted average peak day temperature drivers are calculated over the 1978–2007 time period (the most recent 30 years).

OVERVIEW OF THE FORECAST

The sales and load forecast is constructed by developing a separate forecast for each individual sales category. Independent sales forecasts are prepared for each of the major customer classes: residential, commercial, irrigation, and industrial. Individual energy and peak-demand forecasts are developed for Micron Technology, Inc, (Micron Technology), Simplot Fertilizer Company (Simplot Fertilizer), Idaho National Laboratory (INL), Hoku Materials, and Raft River Rural Electric Cooperative, Inc. (Raft River)—the electric distribution utility serving Idaho Power's former customers in Nevada. These five special-contract customers are combined into a single forecast category labeled Additional Firm Load. Lastly, the contract off-system category represents long-term contracts to supply firm energy and demand to off-system customers. 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 they are billed, it is necessary to adjust these billed sales to the proper timeframe to reflect the required generation needed in each calendar month. To determine calendar-month sales from billed sales, the billed sales must first be allocated to the calendar months in which they are generated. The calendar-month sales are then converted to calendar-month load by adding losses and dividing by the number of hours in each month.

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

The peak-load forecast was prepared in conjunction with the 2009 sales forecast. Idaho Power has two distinct peak periods: a winter peak, resulting from space heating demand that normally occurs in December, January, or February, and a larger summer peak that normally occurs in June or July. The summer peak generally occurs when extensive air conditioning usage coincides with significant irrigation demand.

Peak loads are forecast using 12 regression equations and are a function of temperature, space heating saturation (winter only), air conditioning saturation (summer only), historical 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, Simplot Fertilizer, Hoku Materials, and Raft River are forecast based on historical analysis and contractual considerations.

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

Fuel Prices

Fuel prices, in combination with service area economic drivers, impact long-term trends in electricity sales. Changes in relative fuel prices can also have significant impacts on the future demand for electricity. For the first time, the sales and load forecast is influenced by the estimated impact of proposed carbon legislation on retail electricity prices. The carbon-impacted retail electricity prices move significantly higher throughout the forecast period, reducing future electricity sales. Class level and economic-sector level regression models were used to identify the relationships between real

historical electricity prices and historical electricity sales. The estimated coefficients from these models were used as drivers in the individual sales forecast models.

Short-term and long-term nominal electricity price increases are generated internally from Idaho Power financial models. Moody's Analytics 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.

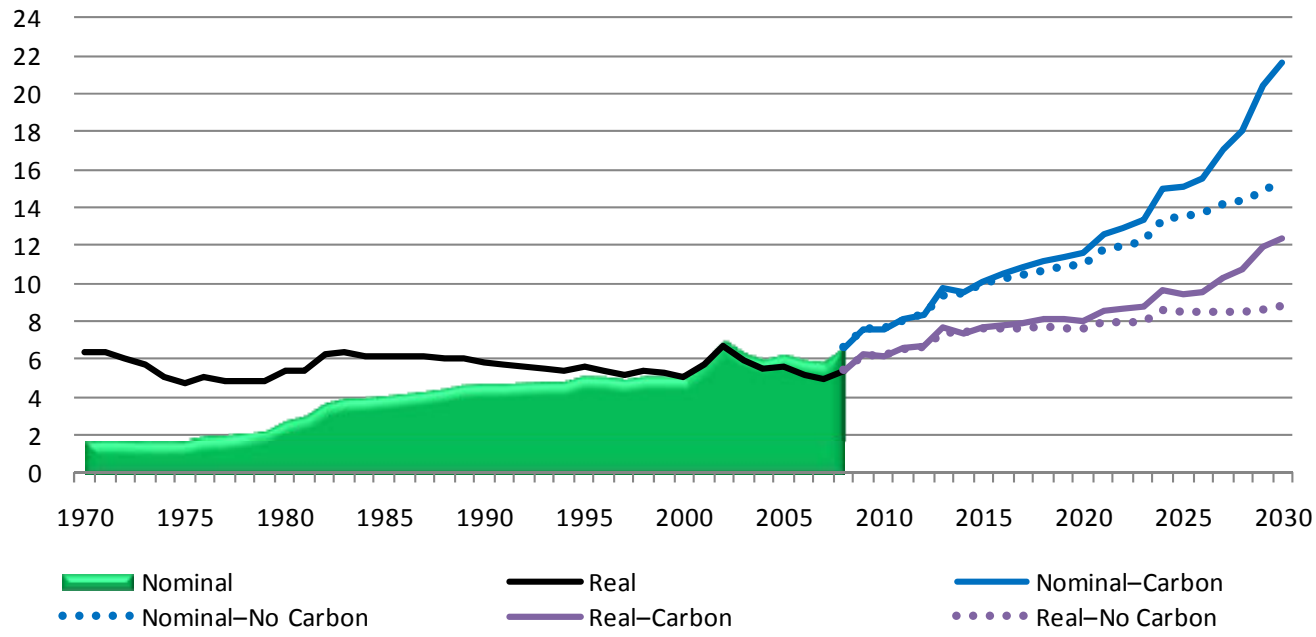
Table 1. Residential Fuel-Price Escalation (2009–2029)
(average annual percent change)

	Nominal	Real*
Electricity–Carbon	5.1%	3.3%
Electricity–No Carbon	3.4%	1.6%
Natural Gas	2.3%	0.5%

*adjusted for inflation

Figure 1 illustrates the average electricity price paid by Idaho Power's residential customers over the historical period 1970–2008 and over the forecast period 2009–2029. Both nominal and real prices are shown. In the carbon scenario, nominal electricity prices are expected to slowly climb to 20 cents per kWh by the end of the forecast period in 2029. Real electricity prices (inflation-adjusted) in the carbon scenario are expected to increase over the forecast period at an average rate of 3.3 percent each year.

Figure 1. Forecasted Electricity Prices
(cents per kWh)

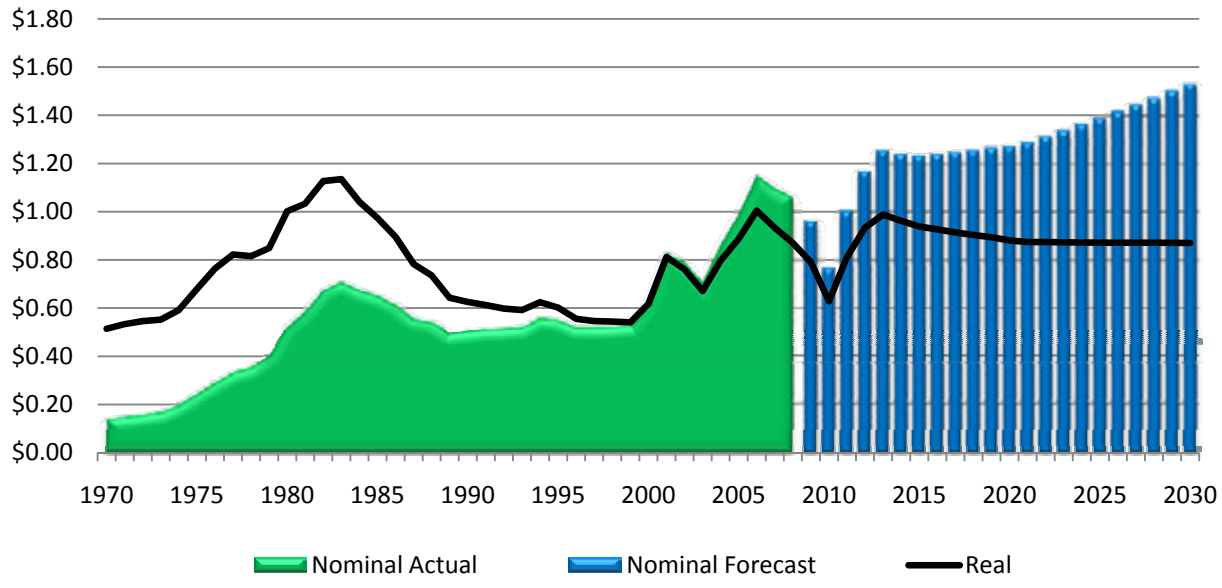


Electricity prices for Idaho Power customers moved significantly higher beginning in 2001 because of the Power Cost Adjustment (PCA) impact on rates. Prior to 2001, Idaho Power's electricity prices were

historically quite stable. Over the 1990–2000 period, electricity prices rose only 8 percent overall, an annual average compound growth rate of 0.8 percent each year.

Figure 2 illustrates the average natural gas price paid by Intermountain Gas Company's residential customers over the historical period 1970–2008. Natural gas prices remained stable and flat throughout the 1990s before moving sharply higher in 2001. Since 2001, natural gas prices moved downward for a couple of years before again moving sharply upward in 2004, 2005, and 2006. Natural gas prices are expected to move downward in 2009 and 2010, reflecting the collapse in natural gas prices in 2009. After bottoming in 2010, nominal natural gas prices are expected to rise rapidly through 2013 and then slowly rise through the remainder of the forecast period. Natural gas prices at the end of the forecast period are expected to be about 40 percent higher than 2008, growing at an average rate of 2.3 percent per year over the forecast period (2009–2029). Real natural gas prices (adjusted for inflation) are expected to increase over the same period at an average rate of 0.5 percent each year.

Figure 2. Forecasted Residential Natural Gas Prices
(dollars per therm)



If future electricity price increases continue to outpace natural gas price increases, as expected in this forecast, the operating costs of space heating and water heating with natural gas will become even more advantageous when compared to that of electricity. This could result in lowering the winter demand for electricity.

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 that 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 over the 1978–2007 time period (the most recent 30 years) was 1,035. The 70th percentile HDD is 1,074 and would be exceeded in three-out-of-ten years. The 90th percentile HDD is 1,291 and would be exceeded in one-out-of-ten 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 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 that 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. It is the monthly forecast numbers that are being 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 2009 IRP. Three average load scenarios were prepared based on a statistical analysis of the historical monthly weather variables listed. The probability associated with each individual 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 temperatures. The probability associated with each individual 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 average load and peak demand to be considered. In other Idaho Power planning, such as the preparation of the financial forecast or the operating plan, the expected-case (50th percentile) average-load forecast and the 90th percentile peak-demand forecast are typically used.

Load Forecasts Based on Economic Uncertainty

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

Two additional load forecasts for the Idaho Power service area were prepared. The forecasts provide a range of possible load growths for the 2010–2029 planning period due to variable economic and demographic conditions. The high economic growth and low economic growth scenarios were prepared based on statistical analysis to empirically reflect 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 (1984–2008).

The estimated probabilities for the three different load scenarios are reported in Table 2. The probability estimates are calculated using the annual growth rates in weather-adjusted firm sales observed between 1984 and 2008. The standard deviation observed during the historical time period is used to estimate the dispersion around the expected-case scenario. The probability estimates assume that the expected forecast is the median growth path, i.e., there is a 50 percent probability that the actual growth rate will be less than the expected-case growth rate, and a 50 percent chance that the actual growth rate will be greater than the expected-case growth rate. In addition, the probability estimates assume that the variation in growth rates will be equivalent to the variation in growth rates observed over the past 25 years (1984–2008). The high- and low-case load forecasts also reflect the full integration of existing energy efficiency DSM program effects as a reduction to the average load forecasts. However, impacts from carbon legislation do not influence the high- and low-case load forecasts at this time.

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

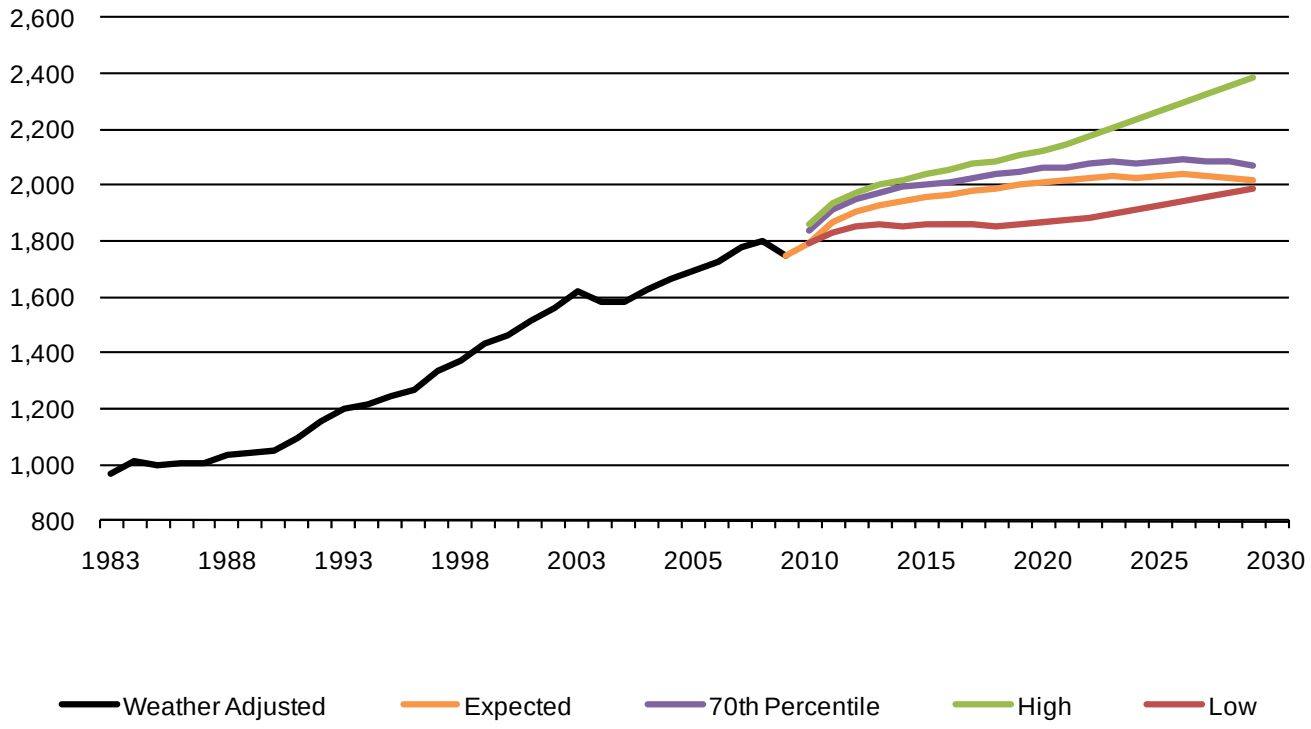
Probability of Occurrence				
Scenario	**1-year**	**5-year**	**10-year**	**20-year**
Low Growth	26%	26%	26%	26%
Expected Case	48%	48%	48%	48%
High Growth	26%	26%	26%	26%

Firm load includes the sum of residential, commercial, industrial, irrigation, as well as special contracts (excluding Astaris), and Raft River. Idaho Power firm load projections are reported in Table 4 and pictured in Figure 3. The expected-case firm load forecast growth rate averages 0.7 percent per year over the 20 years of the planning period. The low scenario projects that firm load will increase at an average rate of 0.6 percent per year throughout the forecast period. The high scenario projects load growth of 1.6 percent per year. Idaho Power has experienced both the high and low growth rates in the past. These scenario forecasts provide a range of projected growth rates that cover approximately 80 percent of the probable outcomes as measured by Idaho Power's historical experience.

Table 4. System/Firm Load Growth
(aMW)

Growth	2009	2014	2019	2029	Growth Rate (per year) 2009–2029
High	1,752	2,020	2,105	2,389	1.6%
Expected	1,752	1,857	2,002	2,015	0.7%
Low	1,752	1,876	1,862	1,991	0.6%

Figure 3. Forecasted Firm Load
(aMW)



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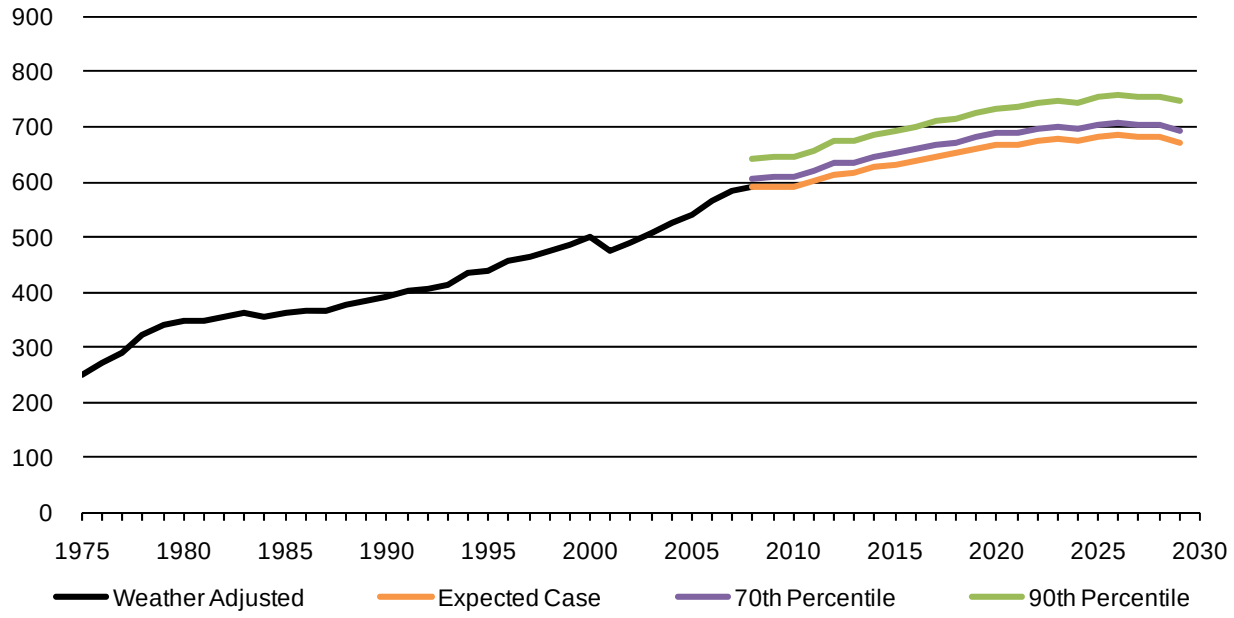
RESIDENTIAL

The expected-case residential load is forecast to increase from 590 aMW in 2009 to 670 aMW in 2029, an average annual compound growth rate of 0.6 percent. In the 70th percentile scenario residential load is forecast to increase from 608 aMW in 2009 to 694 aMW in 2029, nearly matching the expected-case residential growth rate. The residential load forecasts are reported in Table 5 and shown graphically in Figure 4.

Table 5. Residential Load Growth
(aMW)

Growth	2009	2014	2019	2029	Growth Rate (per year) 2009–2029
90th Percentile	645	687	725	747	0.7%
70th Percentile	608	647	681	694	0.7%
Expected Case	590	627	659	670	0.6%

Figure 4. Forecasted Residential Load
(aMW)

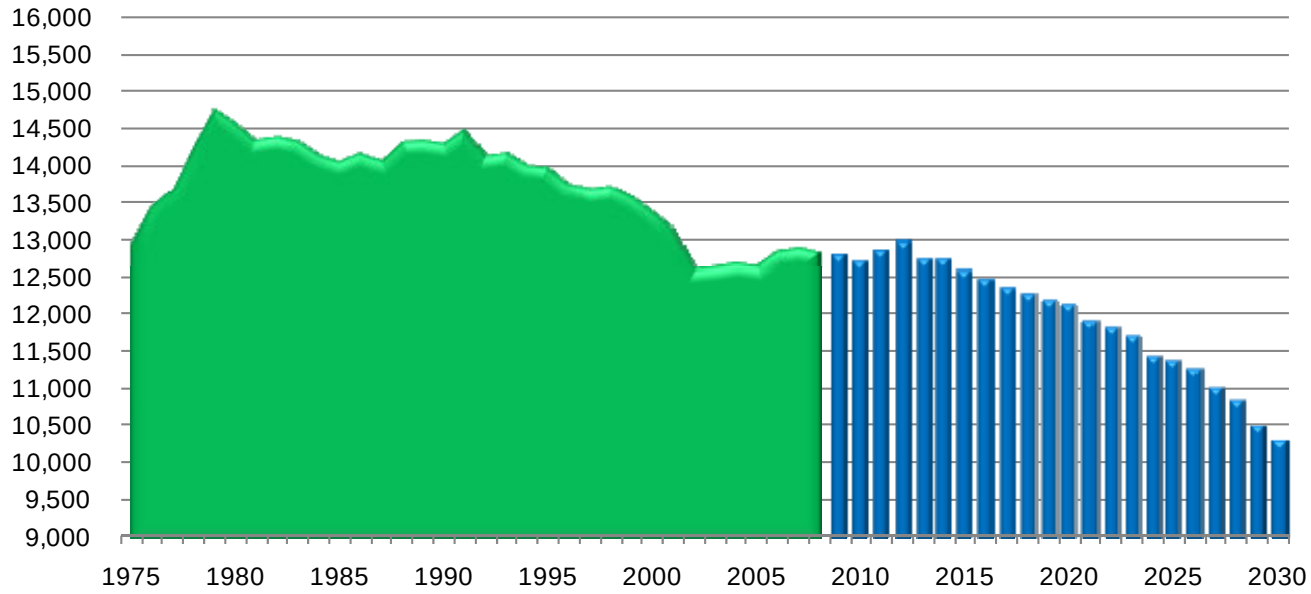


Sales to residential customers made up 24 percent of Idaho Power's system sales in 1970 and 36 percent of system sales in 2008. The residential customer proportion of system sales is forecast to be approximately 36 percent in 2029. There were 404,373 residential customers as of December 2008. The number of residential customers is projected to increase to approximately 563,000 by December 2029. The relative customer proportions of the total Idaho Power electricity sales are shown in Figure 18.

The average sales per residential customer were about 10,000 kWh in 1970. Average sales increased to nearly 14,800 kWh per residential customer in 1979 before declining to 13,150 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 slowed the growth in residential-use-per-customer. The average sales per residential customer are expected to decline to approximately 10,500 kWh per year in 2029. Average annual sales per residential customer are shown in Figure 5.

Figure 5. Forecasted 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 May 2009 forecast of county housing stock and demographic data. The customer forecast for 2010–2029 shows an average annual growth rate of 1.7 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 includes the impact of forecasted DSM, by the residential-customer forecast.

COMMERCIAL

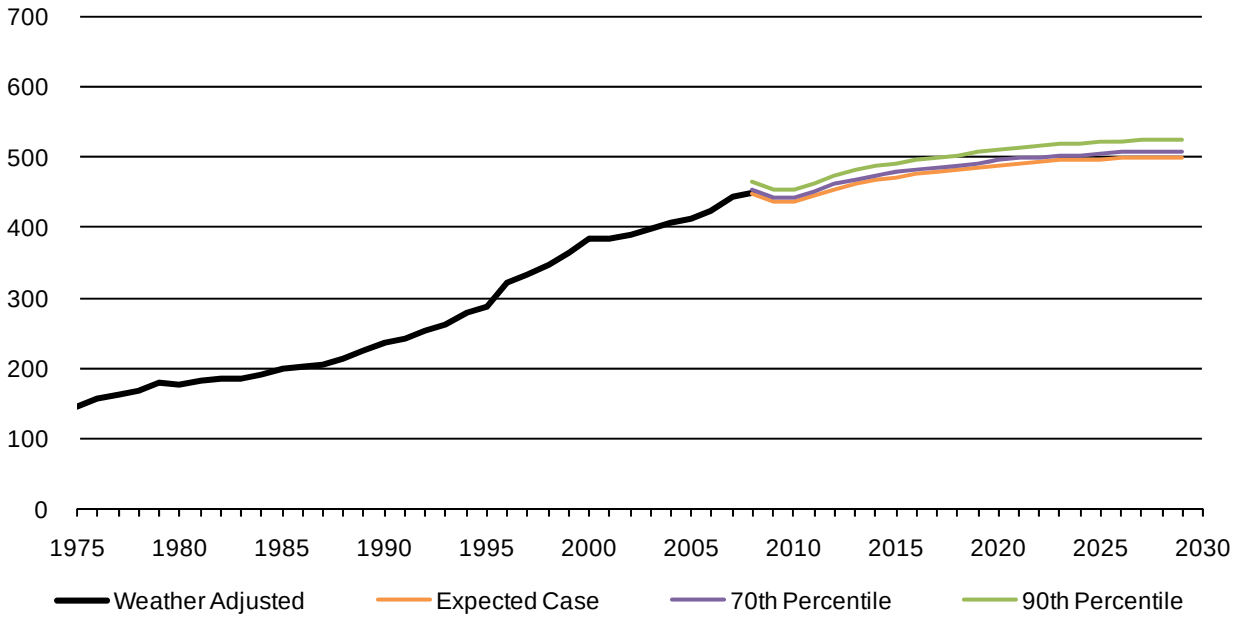
The commercial category is primarily made up of Idaho Power's Small General Service and Large General Service customers. Other schedules that are considered part of the commercial category are Unmetered General Service, Street Lighting Service, Traffic Control Signal Lighting Service, and Dusk-to-Dawn Customer Lighting.

In the expected-case scenario, commercial load is projected to increase from 437 aMW in 2009 to 500 aMW in 2029. The average annual compound growth rate of commercial load is 0.7 percent during the forecast period. As summarized in Table 6, the commercial load in the 70th percentile scenario is projected to increase from 442 aMW in 2009 to 509 aMW in 2029. The commercial load forecasts are illustrated in Figure 6.

Table 6. Commercial Load Growth
(aMW)

Growth	2009	2014	2019	2029	Growth Rate (per year) 2009–2029
90th Percentile	453	488	507	526	0.7%
70th Percentile	442	475	492	509	0.7%
Expected Case	437	469	486	500	0.7%

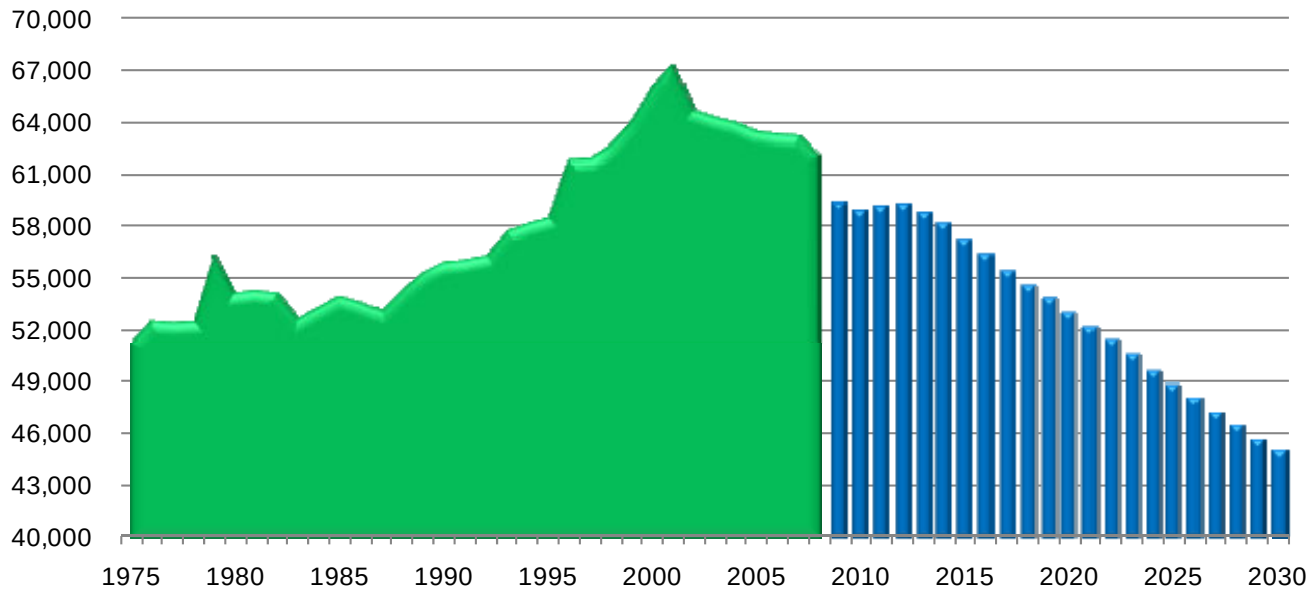
Figure 6. Forecasted Commercial Load
(aMW)



As of December 2008, Idaho Power had 64,125 commercial customers. The number of commercial customers is expected to increase at an average annual growth rate of 2.1 percent, reaching 96,500 customers by 2029. Commercial customers consumed nearly 17 percent of Idaho Power system sales in 1970 and 27 percent of system sales in 2008. The commercial customer proportion of system sales is projected to increase to 27 percent of system sales by 2029. The relative customer proportions of Idaho Power's total electricity sales are shown in Figure 18.

The average consumption per commercial customer increased to a record 67,400 kWh in 2001. However, two years of significantly higher electricity prices combined with a weak national and service area economy caused a setback in the growth of commercial-use-per-customer beginning in 2002. The reduction in electricity prices in June 2003 and a recovery in the service area economy slowed the rate of decline in commercial-use-per-customer through 2007. However, a severe recession in 2008 and 2009 caused commercial-use-per-customer to drop considerably. After flattening over the time period from 2009–2012, commercial-use-per-customer is projected to continue its downward trend. The primary reasons for the decline are higher retail electricity prices due to generating plant additions, carbon regulation, and significant DSM impacts on energy sales. The average consumption per commercial customer is expected to decrease to approximately 46,000 kWh per customer in 2029. Average annual use per commercial customer is shown in Figure 7.

Figure 7. Forecasted Commercial-Use-Per-Customer
(weather-adjusted kWh)



The commercial-use-per-customer forecast is based on a forecast of the number of commercial customers and an econometric analysis of commercial sector sales. The number of commercial customers being added each year is a direct function of the number of new residential customers being added. Additionally, the number of residential customers being added is a direct function of the number of new service area households as derived from Moody's Analytics May 2009 economic forecast of county housing stock and demographic information. The commercial-customer forecast for 2010–2029 shows an average annual growth rate of 2.1 percent.

The commercial-sales forecast equation considers several factors affecting electricity sales to the commercial sector. Commercial sales are a function of HDD (wintertime), CDD (summertime), the number of service area households and service area employment as derived from Moody's Analytics forecasts, and the real price of electricity. The commercial-use-per-customer forecast is arrived at by dividing the commercial sales forecast, including the impacts of DSM, by the commercial customer forecast.

IRRIGATION

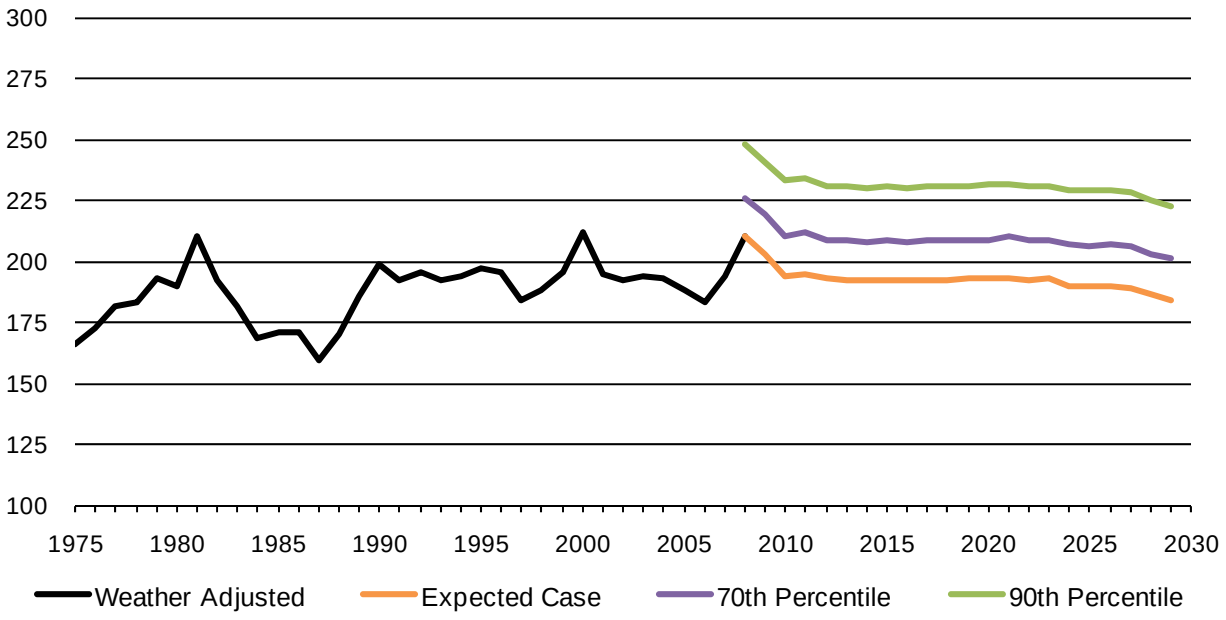
The irrigation category is made up of agricultural irrigation service customers. Service under this schedule is applicable to power and energy supplied to agricultural-use customers at one point-of-delivery for operating water pumping or water delivery systems to irrigate agricultural crops or pasturage.

Throughout the forecasted period, the expected-case irrigation load is forecast to slowly decline from 203 aMW in 2009 to 184 aMW in 2029, an average annual compound growth rate of –0.5 percent. The expected-case, 70th percentile, and 90th percentile scenarios forecast declining growth in irrigation load over the 2009–2029 time period. In the 70th percentile scenario, irrigation load is projected to be 219 aMW in 2009 and 201 aMW in 2029. The individual irrigation load forecasts are reported in Table 7 and shown in Figure 8. The figure illustrates the poorer economic conditions and the drop-off in land being put into production that was experienced by the agricultural economy in the mid-1980s.

Table 7. Irrigation Load Growth
(aMW)

Growth	2009	2014	2019	2029	Growth Rate (per year) 2009–2029
90th Percentile	241	230	231	223	–0.4%
70th Percentile	219	208	209	201	–0.4%
Expected Case	203	192	193	184	–0.5%

Figure 8. Forecasted Irrigation Load
(aMW)



It is important to understand that annual average-load figures being reported in Table 7 and graphed in Figure 8 are calculated using the 8,760 hours of a typical year. In the highly seasonal irrigation sector, over 97 percent of the annual energy is billed during the six months from May through October, and nearly half of the annual energy is billed in just two months, July and August. During the summer, hourly irrigation loads can exceed 900 MW. In a normal July, irrigation pumping accounts for roughly

25 percent of the energy generated during the hour of the annual system peak and 30 percent of the energy generated during the July calendar-month for general business sales. Note that it is the monthly forecast load figures that are being evaluated for resource planning purposes, not the annual average loads.

In early 2001, wholesale electricity prices reached unprecedented levels, and Idaho Power, in an attempt to minimize reliance on the market, developed a voluntary load-reduction program that paid irrigators to not use electricity in 2001. The voluntary load-reduction program was effective and resulted in a 30 percent, or approximately 500,000 megawatt-hours (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. In the future, Idaho Power does not anticipate that it will be necessary to implement similar load-reduction programs to irrigators. Any future reductions to irrigation load are assumed to occur through DSM programs or other natural economic pressures.

The 2009 irrigation sales forecast model considers several factors affecting electricity sales to the irrigation class, including temperature, precipitation, spring rainfall, *Moody's Gross Produce: Farms, for Idaho*, and the real price of electricity. Considerations were made for the unusually low electricity consumption in the 2001 crop year due to the voluntary load-reduction program.

Actual irrigation electricity sales have grown from the 1970 level of 816,000 MWh to a peak amount of 1,990,000 MWh in 2000. During the period 1970–1996, Idaho Power experienced an increase in electricity-using irrigated acres of 1,179,000 acres. This growth in total electricity-using irrigated acres represented approximately a 2.8 percent average annual compound rate of growth. Idaho Power projects no growth in irrigated acres in the service area and limited growth in sprinkler irrigation or conversion to sprinkler irrigation.

Irrigation sales represented over 15 percent of weather-normalized Idaho Power system sales in 1970. Irrigation sales reached a maximum proportion of nearly 20 percent of Idaho Power system sales in 1975–1977. In 2008, the irrigation proportion of system sales was 13 percent due to the very rapid growth in other customer classes. By 2029, irrigation customers are projected to consume 10 percent of Idaho Power system sales. The customer load proportions are shown in Figure 18.

In 1970, Idaho Power had about 7,300 active irrigation accounts. By 2008, the number of active irrigation accounts had increased to 17,428 and is projected to be over 23,000 irrigation accounts at the end of the planning period in 2029.

Since 1988, Idaho Power has experienced some growth in the number of irrigation customers, but very little, if any, growth in total electricity sales 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 for these customers is substantially less than the average existing Idaho Power irrigation customer. This is due to the fact that water for furrow irrigation is gravity-drawn from canals and not pumped from deep groundwater wells. In 2007 and 2008, electricity sales (weather-adjusted) increased by 6 percent and over 8 percent, respectively, over each prior year. However, this is not completely unexpected because both 2007 and 2008 irrigation sales were below the annual sales numbers for years 1992 and 2000. Part of the increase can be explained by the gradual increase in the planting of more water-intensive crops, such as alfalfa and corn, to meet the higher demand for feed associated with the growing dairy industry in Idaho. Also, 2008 saw unprecedented crop prices for almost all crops, causing customers to irrigate all of the acreage that was available in 2008.

Bell Rapids, a large high-lift cooperative irrigation company that irrigated about 25,000 acres from 1970 to 2004, was Idaho Power's largest irrigation customer. The Bell Rapids combined accounts included more than 40 individual irrigation service points that accounted for approximately 3 to 4 percent of

Idaho Power's annual irrigation sales. In early 2005, the State of Idaho purchased the water rights from Bell Rapids, which resulted in the loss of Bell Rapids as an irrigation customer. Prior to 2005, Bell Rapids has consumed, on average, 55,000 MWh each year.

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

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INDUSTRIAL

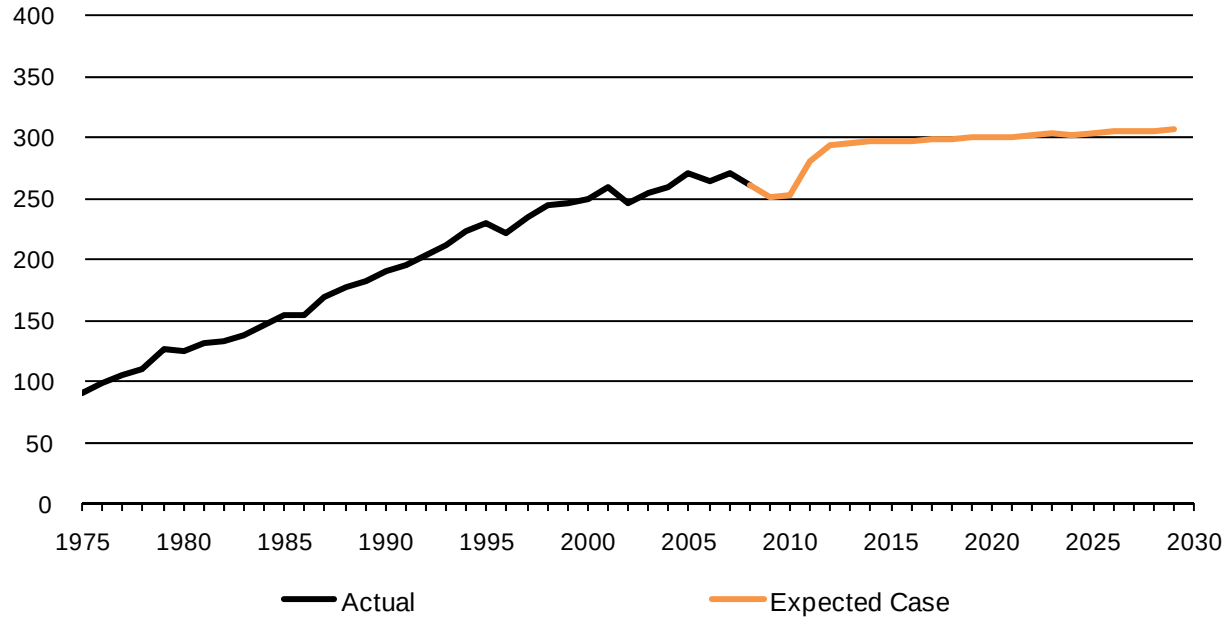
The industrial category is made up of Idaho Power's Large Power Service (Schedule 19) customers with metered demands exceeding 1,000 kilowatts (kw). In 1970, Idaho Power had about 50 industrial customers which represented 8 percent of Idaho Power system sales. By December 2008, the number of industrial customers had risen to 122, representing approximately 16 percent of system sales. Special contracts are addressed in the Additional Firm Load section of this document.

In the expected-case forecast, industrial load grows from 251 aMW in 2009 to 306 aMW in 2029, an average annual growth rate of 1.0 percent (Table 8). As a general rule, industrial loads are not weather sensitive, and the forecasts in the 70th and 90th percentile scenarios are identical to the expected-case industrial load scenario. The industrial load forecast is pictured in Figure 9.

Table 8. Industrial Load Growth
(aMW)

Growth	2009	2014	2019	2029	Growth Rate (per year) 2009–2028
Expected Case	251	297	300	306	1.0%

Figure 9. Forecasted Industrial Load
(aMW)



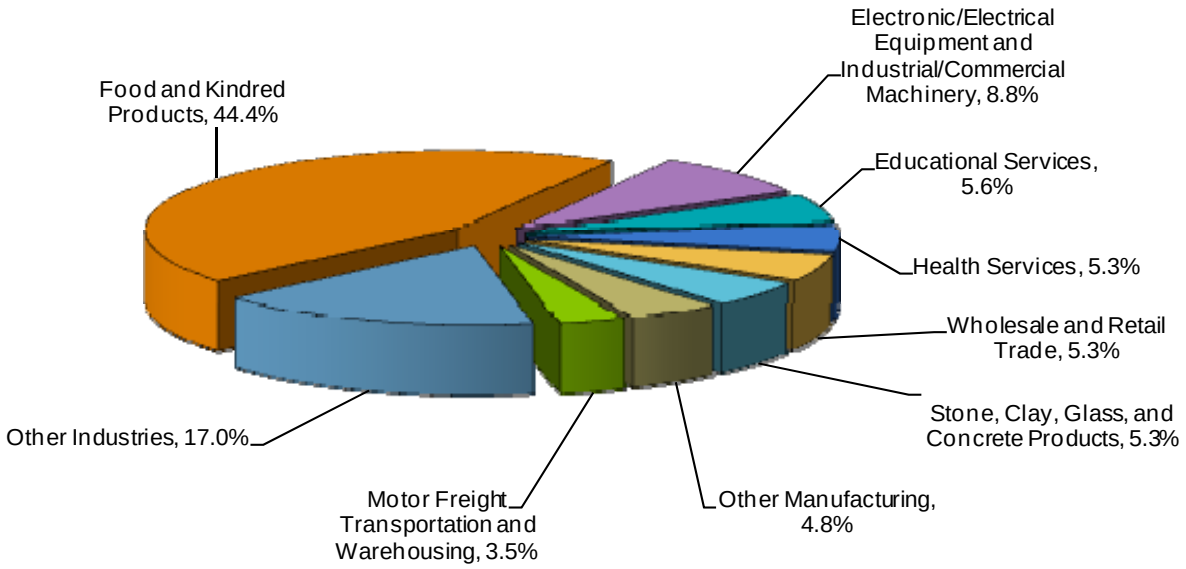
The industrial energy forecast is based on the most recent (June 2009) national, state, MSA, and county economic forecasts from Moody's Analytics and the resulting derived economic forecast for Idaho Power's service area.

Since rate tariff definitions do not correspond with economic activity types, Idaho Power's Schedule 19 customers were categorized, and their historical electricity sales were summarized by economic activity. This is also true for the large commercial loads, so Schedule 9 Primary and Transmission customers' energy sales were also included for forecasting purposes and later recombined with the commercial sector sales forecast. The appropriate employment series (or population time series) were matched to

each economic sector or industry group. Regression models were developed for 17 industry groups to determine the relationship between historical electricity sales and historical employment or population and other relevant explanatory variables. The estimated coefficients from the industry group regression models were then applied to the appropriate employment or population drivers, which resulted in the escalation of electricity sales to the various industry groups over time.

Figure 10 illustrates the 2008 industrial electricity consumption by industry group. By far the largest share of electricity was consumed by the Food and Kindred Products sector (44 percent), followed by Electronic/Electrical Equipment and Industrial/Commercial Machinery (9 percent); Educational Services (6 percent); and Health Services, Wholesale and Retail Trade, and Stone, Clay, Glass, and Concrete Products (each representing 5 percent). As Figure 10 shows, several other industry groups make up the remaining share of the 2008 industrial electricity consumption.

Figure 10. Industrial Electricity Consumption by Industry Group
(based on 2008 figures)



ADDITIONAL FIRM LOAD

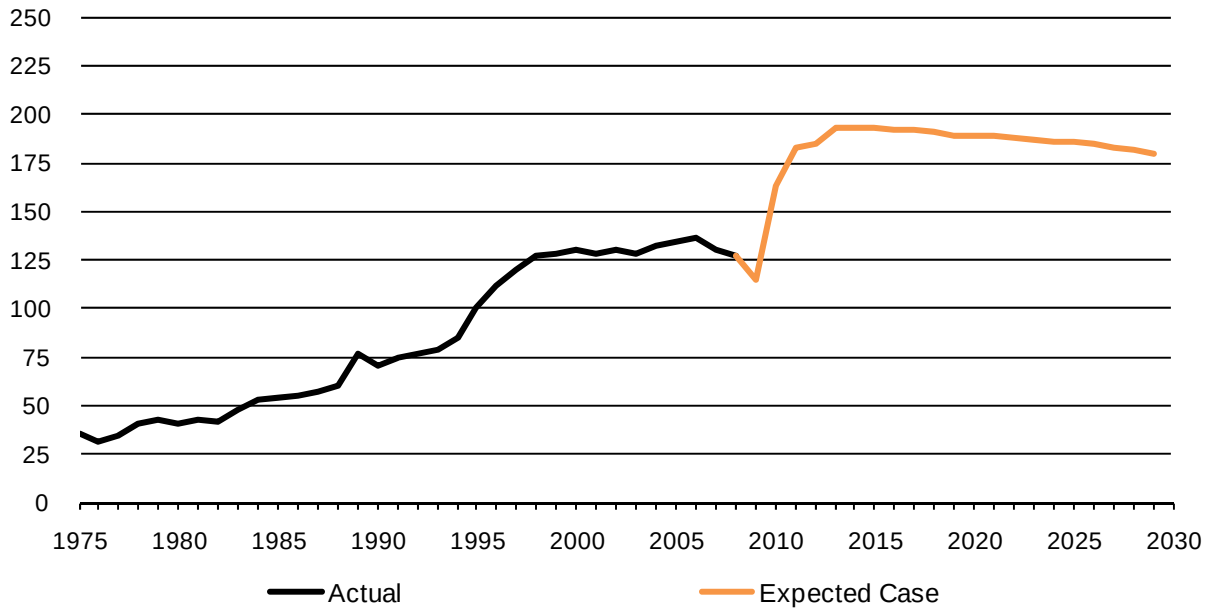
Special contracts currently exist for five large customers that are recognized as firm load customers. These customers are Micron Technology, Simplot Fertilizer, INL, Hoku Materials, and Raft River. Together, these customers make up the additional firm load category. Historically, a long-term firm sales contract existed with the City of Weiser. However, the contract with the City of Weiser expired as of December 31, 2006 and was not renewed.

In the expected-case forecast, additional firm load is expected to increase from 115 aMW in 2009 to 180 aMW in 2029, an average growth rate of 2.3 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 11.

Table 9. Additional Firm Load Growth
(aMW)

Growth	2009	2014	2019	2029	Growth Rate (per year) 2009–2029
Expected Case	115	193	189	180	2.3%

Figure 11. Forecasted Additional Firm Load
(aMW)



Micron Technology

Micron Technology is currently Idaho Power's largest individual customer and employs approximately 9,000 workers in the Boise area. In this forecast, electricity sales to Micron Technology are expected to move downward in 2009 as Micron phases out 200-millimeter (mm) dynamic random access memory (DRAM) operations at its Boise facility. The company will continue to operate its 300-mm research and development fabrication facility in Boise and perform a variety of other activities, including product

design and support, quality assurance, systems integration and related manufacturing, corporate, and general services. Once establishing a new floor for energy consumption at the facility at about a quarter less energy use than in recent years, Micron Technology's electricity use is expected to increase based on new product development and market demand reflected in Moody's Analytics forecast of manufacturing employment in the Electronic and Electrical sector for the Boise MSA.

Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western United States. The future electricity usage at the plant is expected to grow at a slow pace throughout the planning period (2010–2029). The primary driver of long-term electricity sales growth at Simplot Fertilizer is Moody's Analytics forecast of gross product in the Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing for the Pocatello MSA.

Idaho National Laboratory

The United States Department of Energy (DOE) provided an energy-consumption and peak-demand forecast through 2029 for the INL. The forecast calls for loads to increase through 2012, remain flat for six years, and then slowly decline throughout the remainder of the forecast period. Looking back well over a decade ago, the annual loads at the INL were quite volatile due to operational constraints affecting the availability of an on-site nuclear reactor to generate electricity. However, as of October 1994, the INL nuclear reactor no longer generates electricity and, consequently, the amount of electricity provided by Idaho Power increased considerably.

Hoku Materials

The sales and load forecast reflects the increased expected demand for energy and peak capacity of Idaho Power's newest special-contract customer, Hoku Materials, located in Pocatello, Idaho. Hoku Materials plans to begin operation in December 2009 and reach full capacity by October 2010. The current sales and load forecast assumes that Hoku Materials will consume 74 aMW of energy each year and have a peak demand of 82 MW (each measure excluding line losses), once continuous operation is reached in 2012.

Raft River Rural Electric Cooperative

A term sales contract with Raft River was established as a full-requirements contract after being approved by the Federal Energy Regulatory Commission (FERC) and the Public Utility Commission of Nevada. Raft River is the electric distribution utility serving Idaho Power's former customers in Nevada. Idaho Power sold the transmission facilities and rights-of-way that serve about 1,250 customers in northern Nevada and 90 customers in southern Owyhee County to Raft River. The closing date on the transaction was April 2, 2001. Raft River is also located entirely within Idaho Power's load control area.

The contract with Raft River expired on September 30, 2009. However, Raft River may renew the agreement on a year-to-year basis for two additional one-year terms, which would extend service until September 30, 2011. The load forecasts in the 2009 IRP assume that Idaho Power will continue to provide service to the Raft River area by extending contracts each year through September 30, 2011.

COMPANY FIRM LOAD

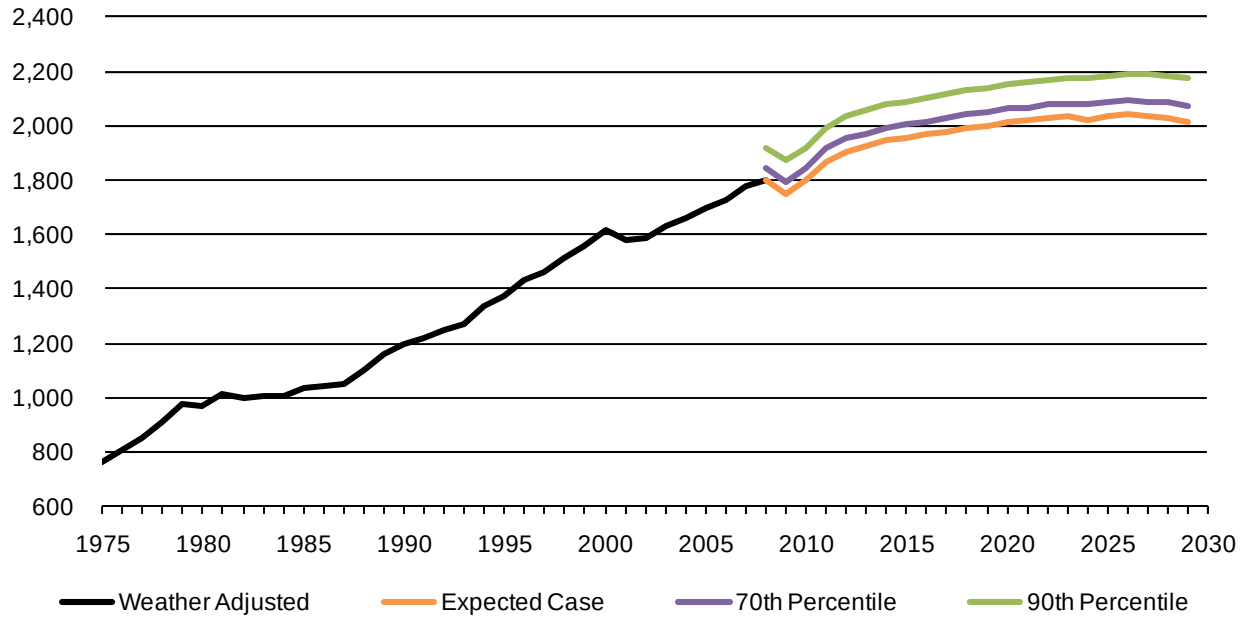
Firm load is the sum of the individual loads of the residential, commercial, industrial, and irrigation customers, as well as special contracts (excluding Astaris), past sales to the City of Weiser, and Raft River. Firm load excludes not only Astaris, but also all contracts to provide firm energy to off-system customers. Without the dampening effects of Astaris and expiring off-system contracts on load growth, firm load more accurately portrays the underlying growth trend within the service area than total load, which includes both Astaris and off-system commitments.

In the expected-case forecast, total firm load is expected to increase from 1,752 aMW in 2009 to 2,015 aMW by 2029, an average growth rate of 0.7 percent per year over the planning period (Table 10). In the 70th percentile forecast, total firm load is expected to increase from 1,796 aMW in 2009 to 2,070 aMW by 2029, an average growth rate of 0.7 percent per year over the planning period (Table 10). The three scenarios of projected firm load are illustrated in Figure 12.

Table 10. Firm Load Growth
(aMW)

Growth	2009	2014	2019	2029	Growth Rate (per year) 2009–2029
90th Percentile	1,875	2,078	2,141	2,172	0.7%
70th Percentile	1,796	1,994	2,051	2,070	0.7%
Expected Case	1,752	1,947	2,002	2,015	0.7%

Figure 12. Forecasted Firm Load
(aMW)



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COMPANY FIRM PEAK

As defined here, firm peak load includes the sum of the individual coincident peak demands of residential, commercial, industrial, and irrigation customers, as well as special contracts (excluding Astaris), and Raft River.

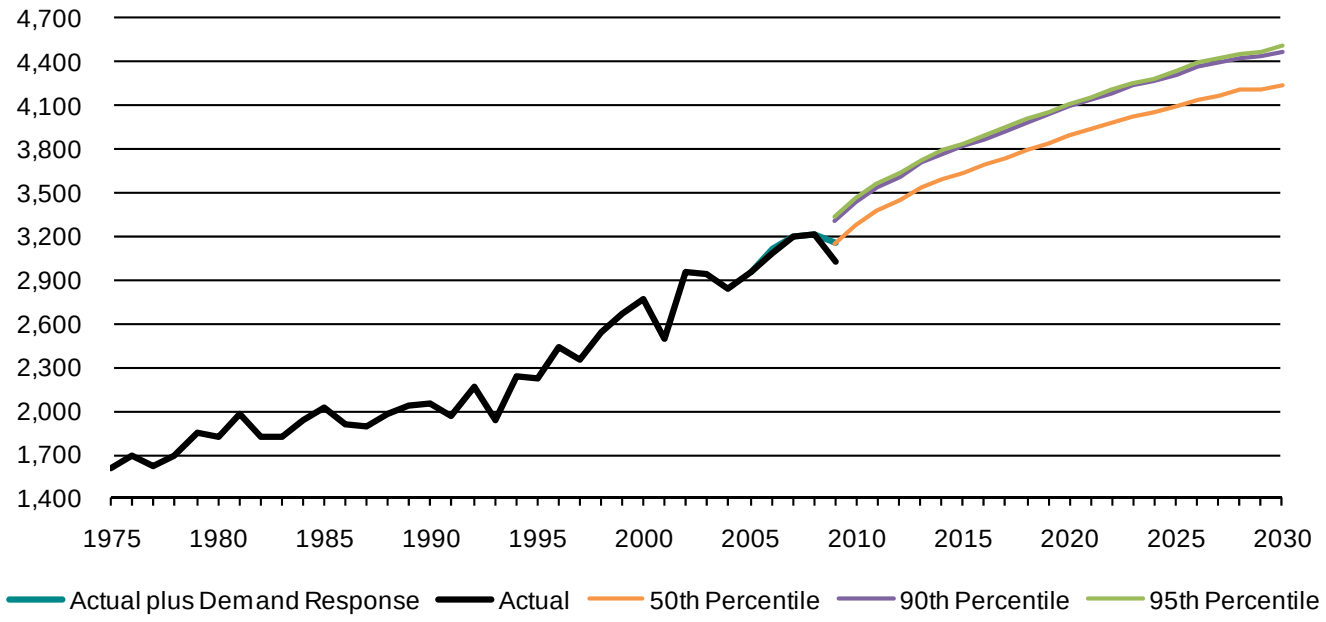
The all-time firm summer peak demand was 3,214 MW, recorded on Monday, June 30, 2008, at 3:00 p.m. The previous year's summer peak demand was 3,193 MW and occurred on Friday, July 13, 2007, at 4:00 p.m. The summer firm peak load growth has accelerated over the past ten years as air conditioning has become standard in nearly all new residential home construction and new commercial buildings. The 2001 summer peak was dampened by the nearly 30 percent curtailment in irrigation load due to the 2001 voluntary load-reduction program.

In the 90th percentile forecast, total firm summer peak load is expected to increase from 3,310 MW in 2009 to 4,445 MW in the year 2029, an average growth rate of 1.5 percent per year over the planning period (Table 11). In the 95th percentile forecast, total firm summer peak load is expected to increase from 3,330 MW in 2009 to 4,475 MW in the year 2029. The three scenarios of projected firm summer peak load are illustrated in Figure 13.

Table 11. Firm Summer Peak-Load Growth
(MW)

Growth	2009	2014	2019	2029	Growth Rate (per year) 2009–2029
95th Percentile	3,330	3,789	4,060	4,475	1.5%
90th Percentile	3,310	3,766	4,034	4,445	1.5%
50th Percentile	3,154	3,592	3,842	4,216	1.5%

Figure 13. Forecasted Firm Summer Peak
(MW)



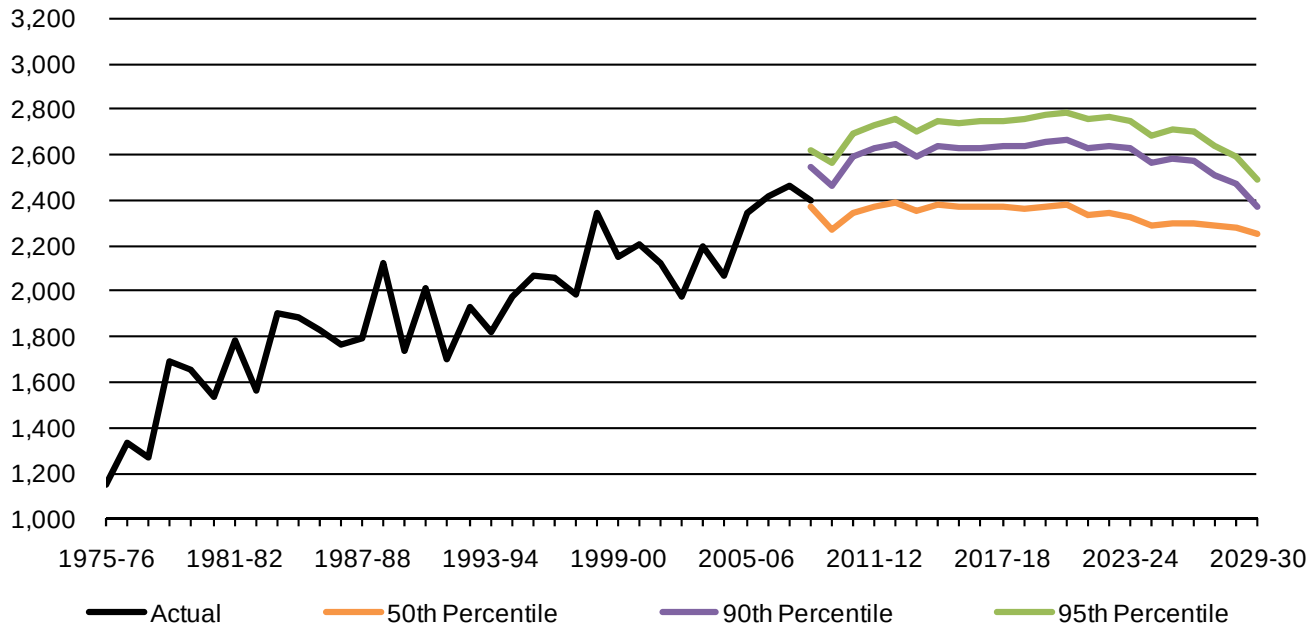
The maximum firm winter peak demand was 2,527 MW, reached on Thursday, December 10, 2009, at 8:00 a.m. As shown in Figure 14, historical firm winter peak load is much more variable than summer firm peak load. This is because the variability of peak day temperatures in winter months is far greater than the variability of peak day temperatures in summer months. The wider spread of the winter peak forecast lines in Figure 14 illustrates the higher variability associated with winter peak day temperatures.

In the 90th percentile forecast, total firm winter peak load is expected to decrease from 2,466 MW in 2009 to 2,376 MW in 2029, an average growth rate of –0.2 percent per year over the planning period (Table 12). In the 95th percentile forecast, total firm winter peak load is expected to decrease from 2,565 MW in 2009 to 2,493 MW in 2029, an average growth rate of –0.1 percent per year over the planning period (Table 12). The three scenarios of projected firm winter peak load are illustrated in Figure 14.

Table 12. Firm Winter Peak Load Growth
(MW)

Growth	2009	2014	2019	2029	Growth Rate (per year) 2009–2029
95th Percentile	2,565	2,748	2,773	2,493	-0.1%
90th Percentile	2,466	2,637	2,654	2,376	-0.2%
50th Percentile	2,270	2,385	2,370	2,250	0.0%

Figure 14. Forecasted Firm Winter Peak
(MW)



COMPANY SYSTEM LOAD

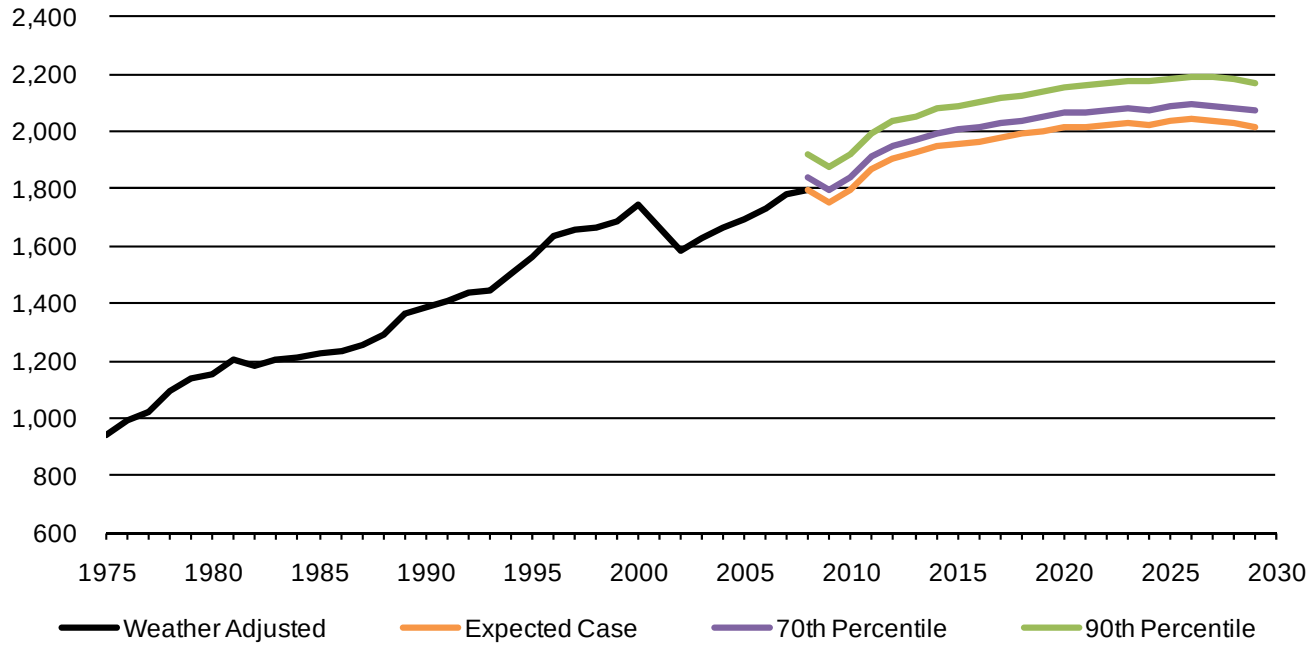
System load historically is made up of firm load plus Astaris load, but excludes long-term, off-system contracts. The Astaris elemental phosphorous plant (previously FMC) was located at the western edge of Pocatello, Idaho. Although no longer a customer of Idaho Power, Astaris was Idaho Power's largest individual customer and, in some past years, averaged nearly 200 aMW each month. In April 2002, the special contract between Astaris and Idaho Power was terminated. Since Astaris ceased production in April 2002, system load and firm load are identical.

The expected-case system load forecast is based on the most recent Moody's Analytics economic forecast for the nation and the service area and represents Idaho Power's most probable load growth during the planning period. The expected-case forecast system load growth rate averages 0.7 percent per year over the 2009–2029 time period. Company system load projections are reported in Table 13 and shown in Figure 15.

Table 13. System Load Growth
(aMW)

Growth	2009	2014	2019	2029	Growth Rate (per year) 2009–2029
90th Percentile	1,875	2,078	2,141	2,172	0.7%
70th Percentile	1,796	1,994	2,051	2,070	0.7%
Expected Case	1,752	1,947	2,002	2,015	0.7%

Figure 15. Forecasted System Load
(aMW)



In the expected-case forecast, company system load is expected to increase from 1,752 aMW in 2009 to 2,015 aMW in 2029. In the 70th percentile forecast, company system load is expected to increase from 1,796 aMW in 2009 to 2,070 aMW by 2029, an average growth rate of 0.7 percent per year over the planning period (Table 13).

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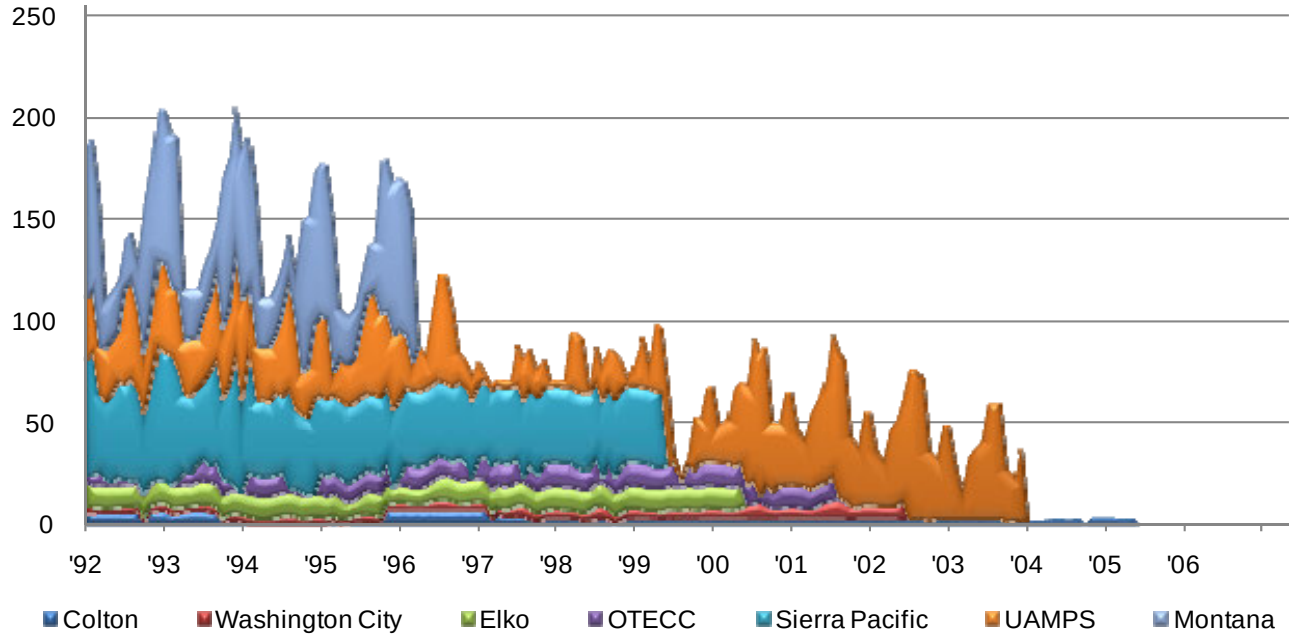
CONTRACT OFF-SYSTEM LOAD

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

As illustrated in Figure 16, 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.

Figure 16. Forecasted Contract Off-System Load by Customer
(aMW)



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TOTAL COMPANY LOAD

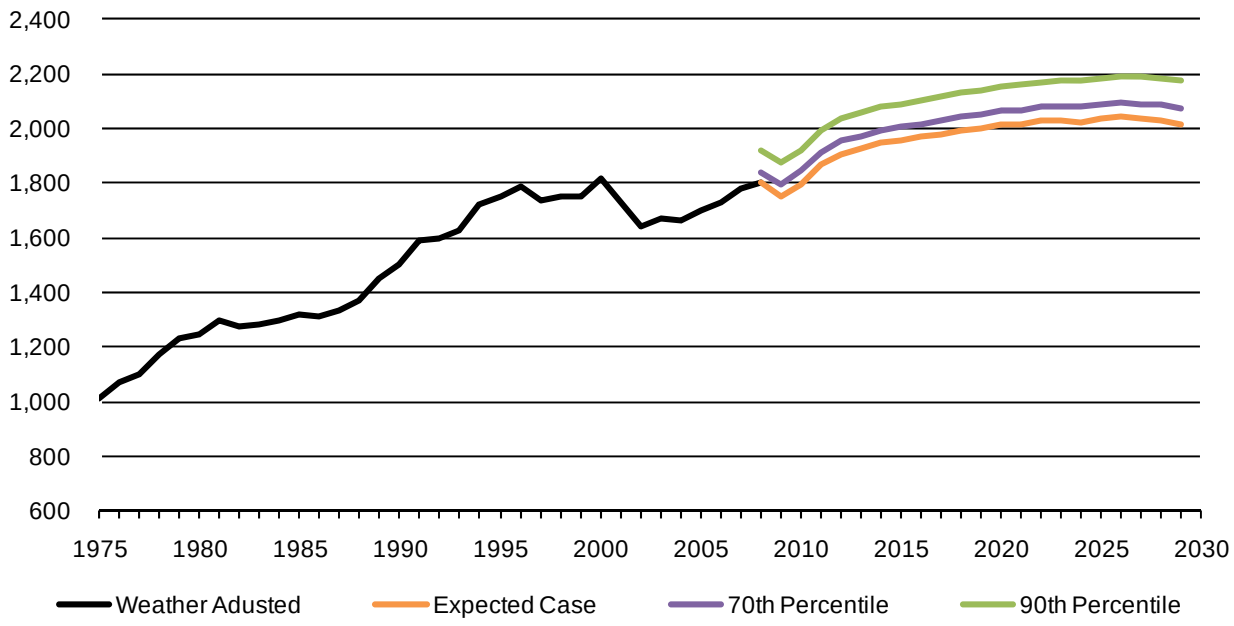
Accompanied by an outlook of moderate economic growth for Idaho Power's service area throughout the forecast period, *Appendix A–Sales and Load Forecast* projects continued growth in Idaho Power's total load. Total load is made up of system load plus long-term firm off-system contracts. At this time,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

Total company load projections are listed in Table 14 and illustrated in Figure 17. The expected-case scenario average growth rate of 0.7 percent per year represents the most probable outlook expected by Idaho Power. In the 70th percentile forecast, company total load is expected to increase from 1,796 aMW in 2009 to 2,070 aMW by 2029.

Table 14. Total Company Load Growth
(aMW)

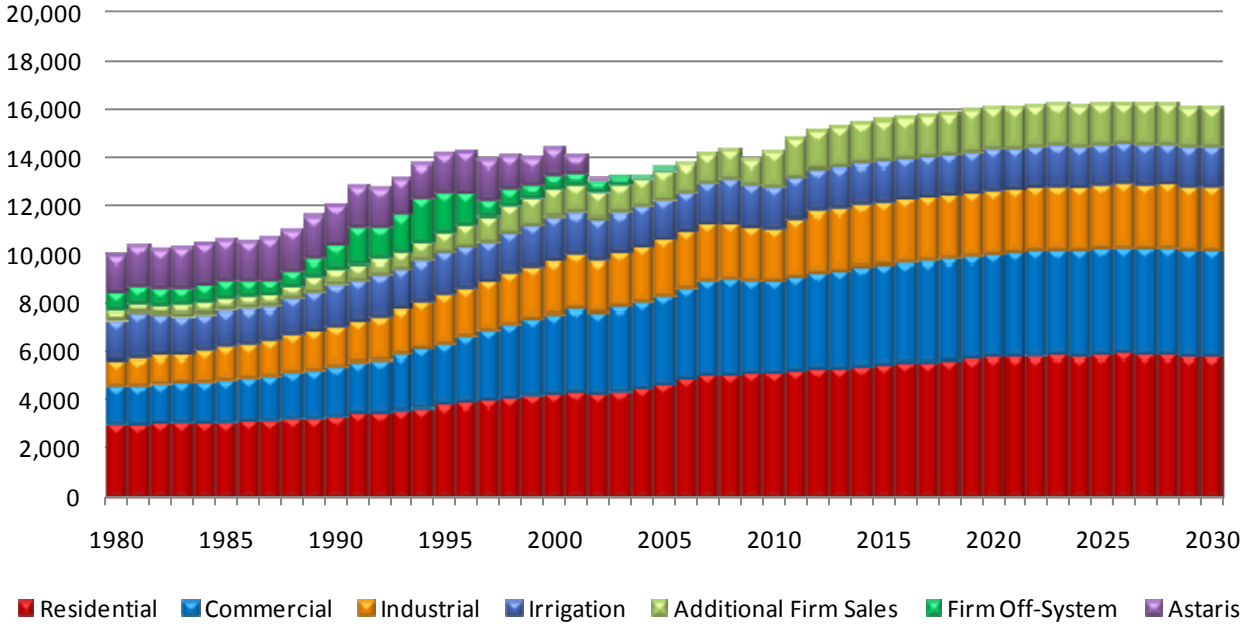
Growth	2009	2014	2019	2029	Growth Rate (per year) 2009–2029
90th Percentile	1,875	2,078	2,141	2,172	0.7%
70th Percentile	1,796	1,994	2,051	2,070	0.7%
Expected Case	1,752	1,947	2,002	2,015	0.7%

Figure 17. Forecasted Total Load
(aMW)



The composition of total company electricity sales by year is shown in Figure 18. Residential sales are forecast to be over 13 percent higher in 2029, gaining nearly 0.7 million MWh over 2009. Commercial sales are expected to be nearly 15 percent higher or nearly 0.6 million MWh above 2009 followed by industrial (22 percent higher or nearly 0.5 million additional MWh) and irrigation (nearly 10 percent lower than 2029). Electricity sales to Astaris ended in April 2002.

Figure 18. Composition of Electricity Sales
(thousands of MWh)



The additional firm sales category (which represents sales to Micron Technology, Simplot Fertilizer, INL, Hoku Materials, and Raft River) is forecast to grow by nearly 57 percent over the 2009–2029 time period, largely due to the addition of Hoku Materials as a special contract customer.

DEMAND-SIDE MANAGEMENT

DSM consists of energy efficiency programs which reduce customer energy use year-round and demand response programs that are targeted at reducing load during specific periods of high demand. The impact of energy efficiency programs are integrated into *Appendix A –Sales and Load Forecast;* however, demand response programs are accounted for in the 2009 IRP load and resource balance. The sales and load forecast, adjusted for existing and committed energy efficiency programs, serves as the basis for establishing the baseline forecast for surpluses and deficits which are used to develop portfolios for the IRP. Table 15 shows the existing and committed energy efficiency programs included in the current sales and load forecast.

Table 15. DSM Programs

DSM Program	Customer Sector
Building Efficiency	Commercial/Industrial
Custom Efficiency	Commercial/Industrial
Easy Upgrades	Commercial/Industrial
Energy House Calls	Residential
Home Products Program	Residential
ENERGY STAR® Homes Northwest	Residential
Energy Efficient Lighting	Residential
Heating & Cooling Efficiency Program	Residential
Irrigation Efficiency Rewards	Irrigation
Oregon Residential Weatherization	Residential
Rebate Advantage	Residential
Weatherization Assistance for Qualified Customers (WAQC)	Residential

Energy Efficiency Programs

In developing data for the forecasting regression models, historical energy sales are adjusted for program performance in past years (which is added to the sales history) in order to isolate sales relationships to the causative independent drivers (economic, demographic, weather, price, et al.) from the impact of energy efficiency programs. The forecast resulting from the adjusted history is designed to reflect sales without the impact of energy efficiency programs. The results from the regression models are subsequently adjusted downward to account for future energy efficiency program performance.

The reduced energy use for each customer class associated with each of the existing energy efficiency programs is shown in Appendix A2. Energy savings from energy efficiency programs are typically measured and reported at the point of delivery (customers' meter). Therefore, energy efficiency savings are increased by the amount of energy lost in transmitting the electricity from the generation source to the customers' meter.

Because the sales and load forecast is prepared before new energy efficiency programs are determined, new energy efficiency programs are not included in the sales and load forecast. The impact of the new programs is accounted for in the IRP load and resource balance prior to determining the need for additional supply-side resources. The forecast performance of both existing and new energy efficiency and demand response programs are shown in the load and resource balance in *Appendix C–Technical Appendix*. In the next planning cycle, the impact of new committed programs will be accounted for in the updated sales and load forecast.

Demand Response Programs

Prior to the 2009 IRP, demand response program performance was accounted for in the sales and load forecast. Beginning with the 2009 IRP, demand response programs are accounted for in the load and resource balance. Demand response programs are described in greater detail in Chapter 4 of the 2009 IRP and in *Appendix C-Technical Appendix*.

Demand response programs are treated as supply-side resources in the IRP and are not incorporated into the sales and load forecast. In the load and resource balance, the forecast performance of existing demand response programs is subtracted from the peak-hour load forecast prior to accounting for existing supply-side resources. Likewise, the performance of new demand response programs is accounted for prior to determining the need for additional supply-side resources. Because energy efficiency programs tend to result in reduced load year-round, there is a component of peak-hour load reduction due to energy efficiency programs that is integrated into the sales and load forecast. This provides a consistent treatment of both types of programs as all energy efficiency programs are integrated into 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 2008 Annual Report*.

Appendix A1. Historical and Projected Sales and Load

Residential Load

Historical Residential Sales and Load, 1970–2008
(weather-adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	132,135		9,983	1,319		152
1971	138,071	4.5%	10,539	1,455	10.3%	167
1972	145,208	5.2%	10,955	1,591	9.3%	184
1973	152,957	5.3%	11,525	1,763	10.8%	202
1974	160,151	4.7%	12,057	1,931	9.5%	223
1975	167,622	4.7%	12,939	2,169	12.3%	250
1976	175,720	4.8%	13,445	2,363	8.9%	271
1977	184,561	5.0%	13,673	2,524	6.8%	290
1978	194,650	5.5%	14,256	2,775	10.0%	321
1979	202,982	4.3%	14,766	2,997	8.0%	342
1980	209,629	3.3%	14,580	3,056	2.0%	348
1981	213,579	1.9%	14,346	3,064	0.2%	349
1982	216,696	1.5%	14,393	3,119	1.8%	356
1983	219,849	1.5%	14,334	3,151	1.0%	362
1984	222,695	1.3%	14,145	3,150	0.0%	357
1985	225,185	1.1%	14,055	3,165	0.5%	362
1986	227,081	0.8%	14,168	3,217	1.7%	367
1987	228,868	0.8%	14,068	3,220	0.1%	366
1988	230,771	0.8%	14,326	3,306	2.7%	377
1989	233,370	1.1%	14,342	3,347	1.2%	384
1990	238,117	2.0%	14,300	3,405	1.7%	393
1991	243,207	2.1%	14,488	3,524	3.5%	401
1992	249,767	2.7%	14,135	3,531	0.2%	407
1993	258,271	3.4%	14,173	3,660	3.7%	413
1994	267,854	3.7%	14,001	3,750	2.4%	434
1995	277,131	3.5%	13,973	3,872	3.3%	437
1996	286,227	3.3%	13,743	3,934	1.6%	456
1997	294,674	3.0%	13,681	4,031	2.5%	463
1998	303,300	2.9%	13,713	4,159	3.2%	475
1999	312,901	3.2%	13,583	4,250	2.2%	487
2000	322,402	3.0%	13,383	4,315	1.5%	499
2001	331,009	2.7%	13,163	4,357	1.0%	476
2002	339,764	2.6%	12,620	4,288	–1.6%	488
2003	349,219	2.8%	12,645	4,416	3.0%	507
2004	360,462	3.2%	12,689	4,574	3.6%	525
2005	373,602	3.6%	12,650	4,726	3.3%	541
2006	387,707	3.8%	12,842	4,979	5.3%	566
2007	397,286	2.5%	12,885	5,119	2.8%	583
2008	402,520	1.3%	12,823	5,161	0.8%	590

Residential Load

Projected Residential Sales and Load, 2009–2029

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2009	404,916	0.6%	12,779	5,174	0.3%	590
2010	406,743	0.5%	12,707	5,168	–0.1%	591
2011	409,192	0.6%	12,846	5,256	1.7%	601
2012	414,346	1.3%	12,984	5,380	2.3%	614
2013	422,101	1.9%	12,737	5,376	–0.1%	615
2014	430,667	2.0%	12,746	5,489	2.1%	627
2015	439,230	2.0%	12,592	5,531	0.8%	632
2016	447,681	1.9%	12,480	5,587	1.0%	638
2017	456,082	1.9%	12,379	5,646	1.0%	645
2018	464,527	1.9%	12,274	5,701	1.0%	651
2019	473,045	1.8%	12,197	5,770	1.2%	659
2020	481,587	1.8%	12,129	5,841	1.2%	667
2021	490,126	1.8%	11,918	5,841	0.0%	667
2022	498,618	1.7%	11,824	5,895	0.9%	673
2023	507,071	1.7%	11,714	5,940	0.8%	678
2024	515,508	1.7%	11,427	5,891	–0.8%	673
2025	523,994	1.6%	11,365	5,955	1.1%	680
2026	532,612	1.6%	11,260	5,997	0.7%	684
2027	541,310	1.6%	11,006	5,957	–0.7%	680
2028	550,147	1.6%	10,830	5,958	0.0%	680
2029	559,091	1.6%	10,494	5,867	–1.5%	670

Commercial Load

Historical Commercial Sales and Load, 1970–2008

(weather-adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	21,375		42,768	914		105
1971	22,077	3.3%	45,386	1,002	9.6%	115
1972	22,585	2.3%	46,141	1,042	4.0%	120
1973	23,286	3.1%	48,142	1,121	7.6%	128
1974	24,096	3.5%	49,025	1,181	5.4%	136
1975	25,045	3.9%	51,217	1,283	8.6%	147
1976	26,034	3.9%	52,509	1,367	6.6%	157
1977	27,112	4.1%	52,415	1,421	4.0%	162
1978	27,831	2.7%	52,467	1,460	2.8%	169
1979	28,087	0.9%	56,394	1,584	8.5%	180
1980	28,797	2.5%	54,135	1,559	-1.6%	178
1981	29,567	2.7%	54,278	1,605	2.9%	184
1982	30,167	2.0%	54,126	1,633	1.7%	186
1983	30,776	2.0%	52,649	1,620	-0.8%	186
1984	31,554	2.5%	53,312	1,682	3.8%	191
1985	32,417	2.7%	53,944	1,749	4.0%	200
1986	33,208	2.4%	53,590	1,780	1.8%	203
1987	33,975	2.3%	53,126	1,805	1.4%	205
1988	34,723	2.2%	54,319	1,886	4.5%	215
1989	35,638	2.6%	55,327	1,972	4.5%	226
1990	36,785	3.2%	55,922	2,057	4.3%	236
1991	37,922	3.1%	56,027	2,125	3.3%	243
1992	39,022	2.9%	56,292	2,197	3.4%	253
1993	40,047	2.6%	57,764	2,313	5.3%	262
1994	41,629	4.0%	58,187	2,422	4.7%	280
1995	43,165	3.7%	58,523	2,526	4.3%	287
1996	44,995	4.2%	61,940	2,787	10.3%	322
1997	46,819	4.1%	62,007	2,903	4.2%	333
1998	48,404	3.4%	62,771	3,038	4.7%	348
1999	49,430	2.1%	64,085	3,168	4.3%	363
2000	50,117	1.4%	66,079	3,312	4.5%	383
2001	51,501	2.8%	67,424	3,472	4.9%	383
2002	52,915	2.7%	64,650	3,421	-1.5%	389
2003	54,194	2.4%	64,268	3,483	1.8%	399
2004	55,577	2.6%	63,972	3,555	2.1%	407
2005	57,145	2.8%	63,472	3,627	2.0%	414
2006	59,050	3.3%	63,320	3,739	3.1%	425
2007	61,640	4.4%	63,233	3,898	4.2%	444
2008	63,492	3.0%	62,122	3,944	1.2%	449

Commercial Load

Projected Commercial Sales and Load, 2009–2029

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2009	64,261	1.2%	59,445	3,820	–3.2%	437
2010	64,925	1.0%	58,988	3,830	0.3%	438
2011	65,712	1.2%	59,205	3,890	1.6%	445
2012	67,085	2.1%	59,330	3,980	2.3%	455
2013	68,768	2.5%	58,863	4,048	1.7%	463
2014	70,486	2.5%	58,172	4,100	1.3%	469
2015	72,191	2.4%	57,262	4,134	0.8%	472
2016	73,883	2.3%	56,354	4,164	0.7%	476
2017	75,568	2.3%	55,480	4,193	0.7%	479
2018	77,249	2.2%	54,646	4,221	0.7%	482
2019	78,930	2.2%	53,842	4,250	0.7%	486
2020	80,608	2.1%	53,054	4,277	0.6%	489
2021	82,282	2.1%	52,180	4,293	0.4%	490
2022	83,952	2.0%	51,378	4,313	0.5%	493
2023	85,621	2.0%	50,569	4,330	0.4%	495
2024	87,288	1.9%	49,653	4,334	0.1%	495
2025	88,956	1.9%	48,907	4,351	0.4%	497
2026	90,628	1.9%	48,165	4,365	0.3%	499
2027	92,301	1.8%	47,350	4,370	0.1%	499
2028	93,980	1.8%	46,599	4,379	0.2%	500
2029	95,661	1.8%	45,780	4,379	0.0%	500

Irrigation Load

Historical Irrigation Sales and Load,1970–2008

(weather-adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	7,319		117,492	860		98
1971	7,518	2.7%	132,445	996	15.8%	114
1972	7,815	4.0%	126,555	989	-0.7%	113
1973	8,341	6.7%	134,540	1,122	13.5%	128
1974	8,971	7.6%	143,892	1,291	15.0%	147
1975	9,480	5.7%	153,349	1,454	12.6%	166
1976	9,936	4.8%	153,080	1,521	4.6%	173
1977	10,238	3.0%	156,073	1,598	5.1%	182
1978	10,476	2.3%	152,167	1,594	-0.2%	183
1979	10,711	2.2%	158,121	1,694	6.2%	193
1980	10,854	1.3%	154,113	1,673	-1.2%	190
1981	11,248	3.6%	163,787	1,842	10.1%	210
1982	11,312	0.6%	148,385	1,679	-8.9%	192
1983	11,133	-1.6%	143,103	1,593	-5.1%	182
1984	11,375	2.2%	130,822	1,488	-6.6%	169
1985	11,576	1.8%	129,069	1,494	0.4%	171
1986	11,308	-2.3%	132,200	1,495	0.1%	171
1987	11,254	-0.5%	124,128	1,397	-6.6%	160
1988	11,378	1.1%	131,448	1,496	7.1%	170
1989	11,957	5.1%	136,351	1,630	9.0%	186
1990	12,340	3.2%	141,532	1,747	7.1%	199
1991	12,484	1.2%	134,476	1,679	-3.9%	192
1992	12,809	2.6%	134,469	1,722	2.6%	196
1993	13,078	2.1%	128,681	1,683	-2.3%	192
1994	13,559	3.7%	125,547	1,702	1.2%	194
1995	13,679	0.9%	126,417	1,729	1.6%	197
1996	14,074	2.9%	122,219	1,720	-0.5%	196
1997	14,383	2.2%	111,783	1,608	-6.5%	184
1998	14,695	2.2%	112,347	1,651	2.7%	188
1999	14,912	1.5%	115,126	1,717	4.0%	196
2000	15,253	2.3%	121,883	1,859	8.3%	212
2001	15,522	1.8%	110,306	1,712	-7.9%	195
2002	15,840	2.0%	105,996	1,679	-1.9%	192
2003	16,020	1.1%	106,160	1,701	1.3%	194
2004	16,297	1.7%	103,886	1,693	-0.4%	193
2005	16,936	3.9%	97,135	1,645	-2.8%	188
2006	17,062	0.7%	94,015	1,604	-2.5%	183
2007	17,001	-0.4%	100,043	1,701	6.0%	194
2008	17,428	2.5%	105,738	1,843	8.3%	210

Irrigation Load

Projected Irrigation Sales and Load, 2009–2029

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2009	17,705	1.6%	100,269	1,775	–3.7%	203
2010	17,982	1.6%	94,477	1,699	–4.3%	194
2011	18,261	1.6%	93,557	1,708	0.6%	195
2012	18,537	1.5%	91,454	1,695	–0.8%	193
2013	18,812	1.5%	89,510	1,684	–0.7%	192
2014	19,090	1.5%	87,891	1,678	–0.4%	192
2015	19,367	1.5%	86,947	1,684	0.4%	192
2016	19,644	1.4%	85,637	1,682	–0.1%	192
2017	19,921	1.4%	84,516	1,684	0.1%	192
2018	20,199	1.4%	83,465	1,686	0.1%	192
2019	20,474	1.4%	82,524	1,690	0.2%	193
2020	20,755	1.4%	81,683	1,695	0.3%	193
2021	21,031	1.3%	80,425	1,691	–0.2%	193
2022	21,308	1.3%	79,093	1,685	–0.4%	192
2023	21,583	1.3%	78,135	1,686	0.1%	193
2024	21,861	1.3%	76,541	1,673	–0.8%	190
2025	22,140	1.3%	75,146	1,664	–0.6%	190
2026	22,415	1.2%	74,420	1,668	0.3%	190
2027	22,691	1.2%	73,007	1,657	–0.7%	189
2028	22,967	1.2%	71,354	1,639	–1.1%	187
2029	23,244	1.2%	69,359	1,612	–1.6%	184

Industrial Load

Historical Industrial Sales and Load, 1970–2008

(weather-adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	49		9,173,784	445		52
1971	50	3.3%	10,474,941	525	17.9%	60
1972	56	12.1%	10,944,714	615	17.2%	71
1973	63	12.3%	10,889,056	687	11.7%	79
1974	65	2.2%	11,464,249	739	7.6%	84
1975	71	10.5%	11,014,121	785	6.1%	91
1976	73	3.0%	11,681,540	858	9.3%	99
1977	85	15.1%	10,988,826	929	8.3%	106
1978	99	17.6%	9,786,753	972	4.7%	111
1979	109	9.6%	9,989,158	1,087	11.8%	126
1980	112	2.7%	9,894,706	1,106	1.7%	125
1981	118	5.7%	9,718,723	1,148	3.9%	132
1982	122	3.5%	9,504,283	1,162	1.2%	133
1983	122	-0.3%	9,797,522	1,194	2.7%	138
1984	124	1.5%	10,369,789	1,282	7.4%	147
1985	125	1.2%	10,844,888	1,357	5.9%	155
1986	129	2.7%	10,550,145	1,357	-0.1%	155
1987	134	4.1%	11,006,455	1,474	8.7%	169
1988	133	-1.0%	11,660,183	1,546	4.9%	177
1989	132	-0.6%	12,091,482	1,594	3.1%	183
1990	132	0.2%	12,584,200	1,662	4.3%	191
1991	135	2.5%	12,699,665	1,719	3.4%	196
1992	140	3.4%	12,650,945	1,770	3.0%	203
1993	141	0.5%	13,179,585	1,854	4.7%	212
1994	143	1.7%	13,616,608	1,948	5.1%	223
1995	120	-15.9%	16,793,437	2,021	3.7%	230
1996	103	-14.4%	18,774,093	1,934	-4.3%	221
1997	106	2.7%	19,309,504	2,042	5.6%	235
1998	111	4.6%	19,378,734	2,145	5.0%	244
1999	108	-2.3%	19,985,029	2,160	0.7%	247
2000	107	-0.8%	20,433,299	2,191	1.5%	250
2001	111	3.5%	20,618,361	2,289	4.4%	260
2002	111	-0.1%	19,441,876	2,156	-5.8%	246
2003	112	1.0%	19,950,866	2,234	3.6%	255
2004	117	4.3%	19,417,310	2,269	1.5%	259
2005	126	7.9%	18,645,220	2,351	3.6%	270
2006	127	1.0%	18,255,385	2,325	-1.1%	265
2007	123	-3.6%	19,275,551	2,366	1.8%	270
2008	119	-3.1%	19,415,391	2,308	-2.4%	261

Industrial Load

Projected Industrial Sales and Load, 2009–2029

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2009	123	3.2%	17,962,012	2,203	–4.6%	251
2010	123	0.3%	17,854,906	2,196	–0.3%	252
2011	125	1.6%	19,535,073	2,442	11.2%	281
2012	128	2.4%	20,058,798	2,568	5.1%	293
2013	128	0.0%	20,226,984	2,589	0.8%	296
2014	130	1.6%	19,997,345	2,600	0.4%	297
2015	131	0.8%	19,881,653	2,604	0.2%	297
2016	134	2.3%	19,485,326	2,611	0.3%	297
2017	134	0.0%	19,527,376	2,617	0.2%	299
2018	136	1.5%	19,281,769	2,622	0.2%	299
2019	136	0.0%	19,327,437	2,629	0.2%	300
2020	138	1.5%	19,089,792	2,634	0.2%	300
2021	140	1.4%	18,842,449	2,638	0.1%	301
2022	141	0.7%	18,758,363	2,645	0.3%	302
2023	141	0.0%	18,812,300	2,653	0.3%	303
2024	145	2.8%	18,316,503	2,656	0.1%	302
2025	146	0.7%	18,230,053	2,662	0.2%	304
2026	147	0.7%	18,153,540	2,669	0.3%	305
2027	148	0.7%	18,053,489	2,672	0.1%	305
2028	150	1.4%	17,857,001	2,679	0.2%	305
2029	151	0.7%	17,741,963	2,679	0.0%	306

Additional Firm Sales and Load*

Historical Additional Firm Sales and Load, 1970–2008

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	319		36
1971	295	-7.5%	34
1972	284	-3.7%	32
1973	290	2.2%	33
1974	282	-2.7%	32
1975	314	11.1%	36
1976	277	-11.9%	31
1977	311	12.4%	35
1978	357	14.8%	41
1979	373	4.6%	43
1980	360	-3.6%	41
1981	376	4.5%	43
1982	368	-2.2%	42
1983	425	15.5%	48
1984	466	9.8%	53
1985	473	1.3%	54
1986	482	2.0%	55
1987	503	4.3%	57
1988	531	5.6%	60
1989	671	26.5%	77
1990	626	-6.8%	71
1991	661	5.7%	75
1992	681	3.0%	77
1993	689	1.3%	79
1994	741	7.5%	85
1995	877	18.4%	100
1996	988	12.6%	112
1997	1,048	6.0%	120
1998	1,112	6.2%	127
1999	1,121	0.8%	128
2000	1,143	1.9%	130
2001	1,118	-2.1%	128
2002	1,139	1.9%	130
2003	1,120	-1.7%	128
2004	1,157	3.3%	132
2005	1,175	1.6%	134
2006	1,189	1.2%	136
2007	1,142	-4.0%	130
2008	1,114	-2.4%	127

*Includes Micron Technology, Simplot Fertilizer, INL, and Raft River Rural Electric Cooperative, Inc.

Additional Firm Sales and Load*

Projected Additional Firm Sales and Load, 2009–2029

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2009	1,004	–9.9%	115
2010	1,429	42.3%	163
2011	1,605	12.3%	183
2012	1,621	1.0%	185
2013	1,687	4.1%	193
2014	1,690	0.2%	193
2015	1,689	0.0%	193
2016	1,684	–0.3%	192
2017	1,678	–0.3%	192
2018	1,676	–0.1%	191
2019	1,657	–1.1%	189
2020	1,657	0.0%	189
2021	1,652	–0.3%	189
2022	1,650	–0.1%	188
2023	1,637	–0.8%	187
2024	1,638	0.1%	186
2025	1,633	–0.3%	186
2026	1,619	–0.8%	185
2027	1,606	–0.9%	183
2028	1,595	–0.6%	182
2029	1,579	–1.0%	180

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

Company Firm Load

Historical Company Firm Load, 1970–2008

(weather-adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	3,857		487
1971	4,272	10.8%	539
1972	4,521	5.8%	571
1973	4,983	10.2%	628
1974	5,425	8.9%	685
1975	6,004	10.7%	759
1976	6,385	6.3%	805
1977	6,782	6.2%	854
1978	7,158	5.5%	907
1979	7,735	8.1%	972
1980	7,753	0.2%	971
1981	8,035	3.6%	1,011
1982	7,960	-0.9%	1,000
1983	7,983	0.3%	1,008
1984	8,069	1.1%	1,008
1985	8,238	2.1%	1,036
1986	8,330	1.1%	1,045
1987	8,398	0.8%	1,051
1988	8,764	4.4%	1,098
1989	9,215	5.1%	1,159
1990	9,496	3.1%	1,198
1991	9,707	2.2%	1,215
1992	9,900	2.0%	1,247
1993	10,200	3.0%	1,271
1994	10,564	3.6%	1,335
1995	11,026	4.4%	1,373
1996	11,363	3.1%	1,434
1997	11,632	2.4%	1,464
1998	12,106	4.1%	1,516
1999	12,416	2.6%	1,558
2000	12,820	3.3%	1,618
2001	12,948	1.0%	1,582
2002	12,683	-2.0%	1,586
2003	12,954	2.1%	1,627
2004	13,247	2.3%	1,663
2005	13,525	2.1%	1,697
2006	13,835	2.3%	1,729
2007	14,225	2.8%	1,780
2008	14,370	1.0%	1,798

Company Firm Load

Projected Company Firm Load, 2009–2029

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2009	13,977	–2.7%	1,752
2010	14,322	2.5%	1,797
2011	14,902	4.0%	1,869
2012	15,244	2.3%	1,906
2013	15,384	0.9%	1,926
2014	15,557	1.1%	1,947
2015	15,642	0.5%	1,957
2016	15,728	0.5%	1,967
2017	15,817	0.6%	1,979
2018	15,907	0.6%	1,991
2019	15,995	0.6%	2,002
2020	16,105	0.7%	2,013
2021	16,116	0.1%	2,017
2022	16,189	0.5%	2,026
2023	16,245	0.3%	2,032
2024	16,192	–0.3%	2,024
2025	16,264	0.4%	2,035
2026	16,318	0.3%	2,041
2027	16,262	–0.3%	2,034
2028	16,250	–0.1%	2,030
2029	16,116	–0.8%	2,015

Astaris Load

Historical Astaris Sales and Load, 1970–2008

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	1,657		189
1971	1,508	-9.0%	172
1972	1,819	20.6%	207
1973	1,645	-9.6%	188
1974	1,643	-0.1%	188
1975	1,557	-5.3%	178
1976	1,575	1.2%	179
1977	1,418	-10.0%	162
1978	1,542	8.8%	176
1979	1,395	-9.6%	159
1980	1,513	8.5%	172
1981	1,634	8.0%	186
1982	1,554	-4.9%	177
1983	1,610	3.6%	184
1984	1,701	5.7%	194
1985	1,614	-5.1%	184
1986	1,554	-3.7%	177
1987	1,692	8.9%	193
1988	1,635	-3.4%	186
1989	1,703	4.2%	194
1990	1,604	-5.8%	183
1991	1,609	0.3%	184
1992	1,570	-2.4%	179
1993	1,437	-8.4%	164
1994	1,420	-1.2%	162
1995	1,567	10.4%	179
1996	1,689	7.8%	192
1997	1,628	-3.6%	186
1998	1,273	-21.8%	145
1999	1,051	-17.4%	120
2000	1,054	0.3%	120
2001	658	-37.5%	75
2002	11	-98.3%	1
2003	0	-100.0%	0
2004	0	0.0%	0
2005	0	0.0%	0
2006	0	0.0%	0
2007	0	0.0%	0
2008	0	0.0%	0

Astaris Load

Projected Astaris Sales and Load, 2009–2029

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2009–2029	0	0.0%	0

Company System Load

Historical Company System Sales and Load, 1970–2008

(weather-adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	5,515		686
1971	5,781	4.8%	719
1972	6,340	9.7%	789
1973	6,628	4.5%	825
1974	7,068	6.6%	882
1975	7,561	7.0%	945
1976	7,960	5.3%	994
1977	8,200	3.0%	1,024
1978	8,701	6.1%	1,092
1979	9,130	4.9%	1,139
1980	9,266	1.5%	1,152
1981	9,669	4.3%	1,207
1982	9,514	-1.6%	1,186
1983	9,593	0.8%	1,201
1984	9,770	1.9%	1,212
1985	9,851	0.8%	1,229
1986	9,884	0.3%	1,231
1987	10,090	2.1%	1,254
1988	10,400	3.1%	1,293
1989	10,918	5.0%	1,363
1990	11,101	1.7%	1,390
1991	11,316	1.9%	1,408
1992	11,470	1.4%	1,435
1993	11,637	1.5%	1,444
1994	11,984	3.0%	1,505
1995	12,593	5.1%	1,561
1996	13,051	3.6%	1,636
1997	13,260	1.6%	1,659
1998	13,378	0.9%	1,668
1999	13,467	0.7%	1,684
2000	13,874	3.0%	1,744
2001	13,607	-1.9%	1,661
2002	12,695	-6.7%	1,587
2003	12,954	2.0%	1,627
2004	13,247	2.3%	1,663
2005	13,525	2.1%	1,697
2006	13,835	2.3%	1,729
2007	14,225	2.8%	1,780
2008	14,370	1.0%	1,798

Company System Load

Projected Company System Sales and Load, 2009–2029

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2009	13,977	–2.7%	1,752
2010	14,322	2.5%	1,797
2011	14,902	4.0%	1,869
2012	15,244	2.3%	1,906
2013	15,384	0.9%	1,926
2014	15,557	1.1%	1,947
2015	15,642	0.5%	1,957
2016	15,728	0.5%	1,967
2017	15,817	0.6%	1,979
2018	15,907	0.6%	1,991
2019	15,995	0.6%	2,002
2020	16,105	0.7%	2,013
2021	16,116	0.1%	2,017
2022	16,189	0.5%	2,026
2023	16,245	0.3%	2,032
2024	16,192	–0.3%	2,024
2025	16,264	0.4%	2,035
2026	16,318	0.3%	2,041
2027	16,262	–0.3%	2,034
2028	16,250	–0.1%	2,030
2029	16,116	–0.8%	2,015

Contract Off-System Load

Historical Contract Off-System Sales and Load, 1970–2008

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	386		44
1971	439	13.6%	50
1972	448	2.0%	51
1973	489	9.3%	56
1974	501	2.3%	57
1975	568	13.5%	65
1976	613	7.9%	70
1977	659	7.5%	75
1978	684	3.7%	78
1979	759	11.1%	87
1980	762	0.3%	87
1981	752	-1.2%	86
1982	736	-2.2%	84
1983	710	-3.5%	81
1984	747	5.2%	85
1985	779	4.3%	89
1986	670	-13.9%	77
1987	644	-4.0%	73
1988	675	4.9%	77
1989	740	9.7%	84
1990	968	30.8%	111
1991	1,537	58.8%	175
1992	1,348	-12.3%	154
1993	1,557	15.5%	178
1994	1,811	16.3%	207
1995	1,583	-12.6%	181
1996	1,285	-18.8%	146
1997	674	-47.5%	77
1998	716	6.2%	82
1999	568	-20.6%	65
2000	587	3.3%	67
2001	538	-8.4%	61
2002	454	-15.7%	52
2003	346	-23.6%	40
2004	19	-94.4%	2
2005	10	-47.0%	1
2006	0	-100.0%	0
2007	0	0.0%	0
2008	0	0.0%	0

Contract Off-System Load

Projected Contract Off-System Sales and Load, 2009–2029

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2009–2029	0	0.0%	0

Total Company Load

Historical Total Company Sales and Load, 1970–2008

(weather-adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	5,901		732
1971	6,220	5.4%	771
1972	6,788	9.1%	841
1973	7,118	4.9%	883
1974	7,569	6.3%	941
1975	8,129	7.4%	1,012
1976	8,573	5.5%	1,066
1977	8,859	3.3%	1,101
1978	9,384	5.9%	1,173
1979	9,889	5.4%	1,229
1980	10,028	1.4%	1,242
1981	10,422	3.9%	1,296
1982	10,250	-1.6%	1,273
1983	10,303	0.5%	1,285
1984	10,517	2.1%	1,300
1985	10,630	1.1%	1,321
1986	10,554	-0.7%	1,310
1987	10,734	1.7%	1,330
1988	11,075	3.2%	1,373
1989	11,658	5.3%	1,451
1990	12,069	3.5%	1,504
1991	12,853	6.5%	1,590
1992	12,818	-0.3%	1,594
1993	13,194	2.9%	1,628
1994	13,795	4.6%	1,719
1995	14,176	2.8%	1,748
1996	14,336	1.1%	1,787
1997	13,934	-2.8%	1,738
1998	14,094	1.1%	1,753
1999	14,035	-0.4%	1,752
2000	14,461	3.0%	1,813
2001	14,145	-2.2%	1,725
2002	13,148	-7.0%	1,641
2003	13,300	1.2%	1,668
2004	13,267	-0.3%	1,665
2005	13,535	2.0%	1,698
2006	13,835	2.2%	1,729
2007	14,225	2.8%	1,780
2008	14,370	1.0%	1,798

Total Company Load

Projected Total Company Sales and Load, 2009–2029

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2009	13,977	–2.7%	1,752
2010	14,322	2.5%	1,797
2011	14,902	4.0%	1,869
2012	15,244	2.3%	1,906
2013	15,384	0.9%	1,926
2014	15,557	1.1%	1,947
2015	15,642	0.5%	1,957
2016	15,728	0.5%	1,967
2017	15,817	0.6%	1,979
2018	15,907	0.6%	1,991
2019	15,995	0.6%	2,002
2020	16,105	0.7%	2,013
2021	16,116	0.1%	2,017
2022	16,189	0.5%	2,026
2023	16,245	0.3%	2,032
2024	16,192	–0.3%	2,024
2025	16,264	0.4%	2,035
2026	16,318	0.3%	2,041
2027	16,262	–0.3%	2,034
2028	16,250	–0.1%	2,030
2029	16,116	–0.8%	2,015

Appendix A2. Demand-Side Management Program Impacts

Energy Efficiency Programs

Residential Programs

(MWh including losses)

Energy Reductions													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2010	2,058	1,871	2,075	2,007	2,049	1,852	1,913	1,913	1,999	2,067	1,999	2,067	23,871
2011	3,410	3,100	3,437	3,325	3,397	3,104	3,199	3,208	3,311	3,424	3,311	3,437	39,663
2012	4,544	4,114	4,563	4,394	4,525	4,146	4,281	4,289	4,375	4,563	4,394	4,525	52,712
2013	5,662	5,125	5,662	5,498	5,662	5,188	5,370	5,370	5,453	5,684	5,475	5,639	65,786
2014	6,781	6,138	6,781	6,584	6,781	6,244	6,454	6,446	6,558	6,807	6,532	6,781	78,886
2015	7,711	6,980	7,711	7,487	7,682	7,131	7,370	7,360	7,487	7,740	7,428	7,711	89,798
2016	8,613	7,828	8,682	8,397	8,578	8,023	8,268	8,293	8,363	8,647	8,363	8,682	100,736
2017	9,587	8,680	9,627	9,271	9,547	8,914	9,186	9,214	9,271	9,587	9,271	9,547	111,703
2018	10,525	9,530	10,570	10,179	10,481	9,797	10,116	10,137	10,135	10,570	10,179	10,481	122,699
2019	11,461	10,375	11,461	11,129	11,461	10,681	11,056	11,056	11,038	11,506	11,084	11,415	133,723
2020	12,396	11,220	12,396	12,035	12,349	11,592	11,980	11,963	12,035	12,443	11,942	12,396	144,748
2021	13,292	12,085	13,404	12,964	13,236	12,486	12,896	12,896	12,908	13,348	12,908	13,348	155,772
2022	14,225	12,929	14,339	13,869	14,168	13,388	13,795	13,838	13,812	14,282	13,812	14,339	166,796
2023	15,230	13,789	15,293	14,728	15,166	14,283	14,717	14,763	14,728	15,230	14,728	15,166	177,819
2024	16,163	14,632	16,163	15,695	16,163	15,147	15,680	15,680	15,566	16,227	15,631	16,098	188,843
2025	17,095	15,474	17,095	16,598	17,095	16,062	16,604	16,582	16,534	17,160	16,469	17,095	199,865
2026	18,035	16,325	18,035	17,511	17,967	16,959	17,528	17,502	17,511	18,104	17,374	18,035	210,887
2027	18,913	17,195	19,072	18,446	18,833	17,854	18,439	18,439	18,367	18,992	18,367	18,992	221,910
2028	19,856	18,059	20,031	19,286	19,856	18,758	19,328	19,389	19,286	19,943	19,286	19,856	232,931
2029	20,873	18,899	20,961	20,186	20,786	19,632	20,271	20,314	20,098	20,961	20,186	20,786	243,952

Commercial Building Efficiency

(MWh including losses)

Energy Reductions													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2010	3,898	3,481	3,843	3,722	3,926	3,884	4,014	4,014	3,750	3,870	3,750	3,870	46,024
2011	8,157	7,283	8,037	7,786	8,217	8,121	8,388	8,392	7,846	8,097	7,846	8,037	96,206
2012	12,679	11,405	12,588	12,285	12,770	12,725	13,147	13,152	12,376	12,588	12,285	12,770	150,769
2013	17,282	15,543	17,282	16,617	17,282	17,323	17,911	17,911	16,872	17,154	16,745	17,409	205,331
2014	21,893	19,688	21,893	21,047	21,893	21,937	22,671	22,661	21,213	21,726	21,380	21,893	259,894
2015	26,489	23,821	26,489	25,465	26,691	26,540	27,424	27,428	25,465	26,287	25,869	26,489	314,457
2016	31,288	27,934	30,829	29,864	31,518	31,151	32,173	32,191	30,093	31,058	30,093	30,829	369,020
2017	35,621	32,042	35,366	34,514	35,877	35,757	36,930	36,950	34,514	35,621	34,514	35,877	423,583
2018	40,210	36,170	39,921	38,959	40,499	40,355	41,695	41,710	39,248	39,921	38,959	40,499	478,145
2019	44,835	40,325	44,835	43,111	44,835	44,944	46,469	46,469	43,774	44,503	43,442	45,167	532,708
2020	49,470	44,488	49,470	47,558	49,846	49,565	51,216	51,224	47,558	49,093	48,311	49,470	587,271
2021	54,363	48,552	53,588	51,909	54,750	54,170	55,979	55,979	52,297	53,975	52,297	53,975	641,834
2022	59,045	52,716	58,178	56,357	59,479	58,786	60,715	60,749	56,791	58,612	56,791	58,178	696,397
2023	63,152	56,807	62,699	61,188	63,606	63,392	65,472	65,508	61,188	63,152	61,188	63,606	750,959
2024	67,796	60,976	67,796	65,189	67,796	67,961	70,267	70,267	66,191	67,295	65,690	68,297	805,522
2025	72,451	65,155	72,451	69,651	72,451	72,597	75,027	74,994	70,203	71,900	70,754	72,451	860,085
2026	77,047	69,288	77,047	74,070	77,634	77,195	79,767	79,779	74,070	76,461	75,243	77,047	914,648
2027	82,091	73,316	80,921	78,386	82,677	81,800	84,532	84,532	78,971	81,506	78,971	81,506	969,211
2028	86,628	77,394	85,430	83,350	86,628	86,422	89,258	89,307	83,350	86,029	83,350	86,628	1,023,773
2029	90,683	81,571	90,032	87,863	91,334	91,010	94,032	94,066	88,514	90,032	87,863	91,334	1,078,336

Industrial Program
(MWh including losses)

Energy Reductions													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2010	3,663	3,272	3,611	3,498	3,689	3,650	3,772	3,772	3,524	3,637	3,524	3,637	43,251
2011	7,240	6,464	7,134	6,911	7,293	7,208	7,445	7,449	6,964	7,187	6,964	7,134	85,393
2012	10,445	9,396	10,370	10,120	10,520	10,483	10,831	10,835	10,195	10,370	10,120	10,520	124,208
2013	13,721	12,341	13,721	13,193	13,721	13,754	14,221	14,221	13,396	13,619	13,294	13,822	163,023
2014	17,002	15,290	17,002	16,345	17,002	17,037	17,607	17,599	16,475	16,873	16,604	17,002	201,838
2015	20,272	18,230	20,272	19,489	20,426	20,311	20,987	20,991	19,489	20,118	19,797	20,272	240,653
2016	23,695	21,155	23,347	22,617	23,869	23,591	24,365	24,379	22,790	23,521	22,790	23,347	279,468
2017	26,766	24,077	26,574	25,934	26,958	26,868	27,750	27,765	25,934	26,766	25,934	26,958	318,283
2018	30,030	27,013	29,815	29,096	30,246	30,139	31,139	31,151	29,312	29,815	29,096	30,246	357,098
2019	33,322	29,970	33,322	32,040	33,322	33,403	34,536	34,536	32,533	33,075	32,287	33,568	395,913
2020	36,620	32,932	36,620	35,205	36,899	36,691	37,913	37,918	35,205	36,341	35,763	36,620	434,728
2021	40,109	35,821	39,537	38,298	40,395	39,967	41,301	41,301	38,584	39,823	38,584	39,823	473,543
2022	43,441	38,784	42,803	41,464	43,760	43,251	44,670	44,694	41,783	43,122	41,783	42,803	512,358
2023	46,351	41,694	46,018	44,910	46,684	46,527	48,054	48,080	44,910	46,351	44,910	46,684	551,173
2024	49,656	44,661	49,656	47,746	49,656	49,776	51,466	51,466	48,481	49,289	48,113	50,023	589,988
2025	52,968	47,634	52,968	50,922	52,968	53,075	54,852	54,828	51,325	52,565	51,728	52,968	628,803
2026	56,238	50,575	56,238	54,065	56,666	56,346	58,223	58,232	54,065	55,810	54,921	56,238	667,618
2027	59,834	53,439	58,981	57,134	60,261	59,622	61,613	61,613	57,560	59,408	57,560	59,408	706,433
2028	63,060	56,338	62,188	60,674	63,060	62,910	64,974	65,010	60,674	62,624	60,674	63,060	745,248
2029	65,936	59,311	65,463	63,886	66,410	66,174	68,371	68,396	64,359	65,463	63,886	66,410	784,063

Irrigation Efficiency Program
(MWh including losses)

Energy Reductions													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2010	0	0	0	499	1,831	2,486	2,659	2,244	1,146	225	0	0	11,090
2011	0	0	0	998	3,662	4,973	5,319	4,487	2,291	450	0	0	22,180
2012	0	0	0	1,447	5,310	7,210	7,712	6,506	3,322	653	0	0	32,161
2013	0	0	0	1,846	6,775	9,200	9,840	8,301	4,239	833	0	0	41,033
2014	0	0	0	2,196	8,056	10,940	11,701	9,871	5,041	991	0	0	48,796
2015	0	0	0	2,455	9,008	12,233	13,084	11,038	5,636	1,108	0	0	54,563
2016	0	0	0	2,715	9,960	13,526	14,467	12,205	6,232	1,225	0	0	60,330
2017	0	0	0	2,974	10,913	14,819	15,850	13,371	6,828	1,342	0	0	66,096
2018	0	0	0	3,234	11,865	16,112	17,233	14,538	7,423	1,459	0	0	71,863
2019	0	0	0	3,493	12,817	17,405	18,616	15,705	8,019	1,576	0	0	77,630
2020	0	0	0	3,753	13,769	18,698	19,999	16,871	8,615	1,693	0	0	83,397
2021	0	0	0	4,012	14,721	19,990	21,381	18,038	9,211	1,810	0	0	89,164
2022	0	0	0	4,272	15,673	21,283	22,764	19,204	9,806	1,927	0	0	94,930
2023	0	0	0	4,531	16,625	22,576	24,147	20,371	10,402	2,044	0	0	100,697
2024	0	0	0	4,791	17,577	23,869	25,530	21,538	10,998	2,161	0	0	106,464
2025	0	0	0	5,050	18,529	25,162	26,913	22,704	11,593	2,278	0	0	112,231
2026	0	0	0	5,310	19,481	26,455	28,296	23,871	12,189	2,395	0	0	117,998
2027	0	0	0	5,569	20,434	27,748	29,679	25,038	12,785	2,512	0	0	123,764
2028	0	0	0	5,829	21,386	29,041	31,062	26,204	13,381	2,629	0	0	129,531
2029	0	0	0	6,088	22,338	30,334	32,444	27,371	13,976	2,747	0	0	135,298

Energy Efficiency Programs—Total
(MWh including losses)

Energy Reductions													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2010	9,620	8,624	9,529	9,727	11,496	11,873	12,359	11,943	10,418	9,799	9,273	9,574	124,236
2011	18,807	16,846	18,609	19,019	22,569	23,406	24,351	23,536	20,412	19,158	18,121	18,609	243,442
2012	27,668	24,915	27,521	28,246	33,125	34,564	35,972	34,782	30,268	28,174	26,799	27,815	359,849
2013	36,664	33,009	36,664	37,154	43,438	45,465	47,342	45,803	39,960	37,290	35,514	36,870	475,173
2014	45,676	41,116	45,676	46,171	53,732	56,157	58,434	56,578	49,287	46,396	44,516	45,676	589,415
2015	54,472	49,032	54,472	54,896	63,807	66,215	68,866	66,817	58,077	55,253	53,094	54,472	699,471
2016	63,596	56,917	62,857	63,592	73,925	76,291	79,274	77,067	67,479	64,451	61,247	62,857	809,553
2017	71,975	64,799	71,567	72,693	83,295	86,357	89,715	87,300	76,546	73,316	69,719	72,382	919,665
2018	80,766	72,712	80,305	81,468	93,090	96,402	100,183	97,535	86,118	81,764	78,234	81,226	1,029,805
2019	89,617	80,670	89,617	89,773	102,434	106,432	110,677	107,766	95,364	90,661	86,812	90,150	1,139,974
2020	98,486	88,641	98,486	98,552	112,863	116,545	121,108	117,976	103,414	99,571	96,016	98,486	1,250,144
2021	107,764	96,458	106,529	107,184	123,102	126,614	131,557	128,213	113,000	108,956	103,789	107,146	1,360,313
2022	116,711	104,429	115,320	115,962	133,080	136,708	141,945	138,485	122,192	117,943	112,385	115,320	1,470,481
2023	124,733	112,289	124,011	125,357	142,081	146,778	152,391	148,723	131,228	126,777	120,826	125,455	1,580,649
2024	133,615	120,269	133,615	133,421	151,192	156,753	162,943	158,950	141,236	134,972	129,434	134,419	1,690,817
2025	142,515	128,264	142,515	142,222	161,044	166,897	173,396	169,108	149,655	143,903	138,951	142,515	1,800,984
2026	151,321	136,188	151,321	150,956	171,748	176,956	183,814	179,383	157,835	152,770	147,538	151,321	1,911,151
2027	160,839	143,950	158,974	159,536	182,204	187,025	194,262	189,621	167,683	162,419	154,898	159,906	2,021,318
2028	169,544	151,791	167,648	169,139	190,929	197,130	204,622	199,909	176,691	171,226	163,310	169,544	2,131,484
2029	177,493	159,781	176,456	178,023	200,868	207,150	215,119	210,147	186,948	179,202	171,935	178,530	2,241,649

Residential Programs
(MW including losses)

Peak Demand Reductions													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Max**
2010	3	3	3	3	3	3	3	3	3	3	3	3	3
2011	5	5	5	5	5	4	4	4	5	5	5	5	5
2012	6	6	6	6	6	6	6	6	6	6	6	6	6
2013	8	8	8	8	8	7	7	7	8	8	8	8	8
2014	9	9	9	9	9	9	9	9	9	9	9	9	9
2015	10	10	10	10	10	10	10	10	10	10	10	10	10
2016	12	11	12	12	12	11	11	11	12	12	12	12	12
2017	13	13	13	13	13	12	12	12	13	13	13	13	13
2018	14	14	14	14	14	14	14	14	14	14	14	14	14
2019	15	15	15	15	15	15	15	15	15	15	15	15	15
2020	17	16	17	17	17	16	16	16	17	17	17	17	17
2021	18	18	18	18	18	17	17	17	18	18	18	18	18
2022	19	19	19	19	19	19	19	19	19	19	19	19	19
2023	20	21	21	20	20	20	20	20	20	20	20	20	21
2024	22	21	22	22	22	21	21	21	22	22	22	22	22
2025	23	23	23	23	23	22	22	22	23	23	23	23	23
2026	24	24	24	24	24	24	24	24	24	24	24	24	24
2027	25	26	26	26	25	25	25	25	26	26	25	26	26
2028	27	26	27	27	27	26	26	26	27	27	27	27	27
2029	28	28	28	28	28	27	27	27	28	28	28	28	28

Commercial Programs
(MW including losses)

Peak Demand Reductions													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Max**
2010	5	5	5	5	5	5	5	5	5	5	5	5	5
2011	11	11	11	11	11	11	11	11	11	11	11	11	11
2012	17	16	17	17	17	18	18	18	17	17	17	17	18
2013	23	23	23	23	23	24	24	24	23	23	23	23	24
2014	29	29	29	29	29	30	30	30	29	29	30	29	30
2015	36	35	36	35	36	37	37	37	35	35	36	36	37
2016	42	40	41	41	42	43	43	43	42	42	42	41	43
2017	48	48	48	48	48	50	50	50	48	48	48	48	50
2018	54	54	54	54	54	56	56	56	55	54	54	54	56
2019	60	60	60	60	60	62	62	62	61	60	60	61	62
2020	66	64	67	66	67	69	69	69	66	66	67	66	69
2021	73	72	72	72	74	75	75	75	73	73	73	73	75
2022	79	78	78	78	80	82	82	82	79	79	79	78	82
2023	85	85	84	85	85	88	88	88	85	85	85	85	88
2024	91	88	91	91	91	94	94	94	92	90	91	92	94
2025	97	97	98	97	97	101	101	101	98	97	98	97	101
2026	104	103	104	103	104	107	107	107	103	103	104	104	107
2027	110	109	109	109	111	114	114	114	110	110	110	110	114
2028	116	111	115	116	116	120	120	120	116	116	116	116	120
2029	122	121	121	122	123	126	126	126	123	121	122	123	126

Industrial Program
(MW including losses)

Peak Demand Reductions													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Max**
2010	5	5	5	5	5	5	5	5	5	5	5	5	5
2011	10	10	10	10	10	10	10	10	10	10	10	10	10
2012	14	14	14	14	14	15	15	15	14	14	14	14	15
2013	18	18	18	18	18	19	19	19	19	18	18	19	19
2014	23	23	23	23	23	24	24	24	23	23	23	23	24
2015	27	27	27	27	27	28	28	28	27	27	27	27	28
2016	32	30	31	31	32	33	33	33	32	32	32	31	33
2017	36	36	36	36	36	37	37	37	36	36	36	36	37
2018	40	40	40	40	41	42	42	42	41	40	40	41	42
2019	45	45	45	45	45	46	46	46	45	44	45	45	46
2020	49	47	49	49	50	51	51	51	49	49	50	49	51
2021	54	53	53	53	54	56	56	56	54	54	54	54	56
2022	58	58	58	58	59	60	60	60	58	58	58	58	60
2023	62	62	62	62	63	65	65	65	62	62	62	63	65
2024	67	64	67	66	67	69	69	69	67	66	67	67	69
2025	71	71	71	71	71	74	74	74	71	71	72	71	74
2026	76	75	76	75	76	78	78	78	75	75	76	76	78
2027	80	80	79	79	81	83	83	83	80	80	80	80	83
2028	85	81	84	84	85	87	87	87	84	84	84	85	87
2029	89	88	88	89	89	92	92	92	89	88	89	89	92

Irrigation Efficiency Program
(MW including losses)

Peak Demand Reductions													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Max
2010	0	0	0	1	2	3	4	3	2	0	0	0	4
2011	0	0	0	1	5	7	7	6	3	1	0	0	7
2012	0	0	0	2	7	10	10	9	5	1	0	0	10
2013	0	0	0	3	9	13	13	11	6	1	0	0	13
2014	0	0	0	3	11	15	16	13	7	1	0	0	16
2015	0	0	0	3	12	17	18	15	8	1	0	0	18
2016	0	0	0	4	13	19	19	16	9	2	0	0	19
2017	0	0	0	4	15	21	21	18	9	2	0	0	21
2018	0	0	0	4	16	22	23	20	10	2	0	0	23
2019	0	0	0	5	17	24	25	21	11	2	0	0	25
2020	0	0	0	5	19	26	27	23	12	2	0	0	27
2021	0	0	0	6	20	28	29	24	13	2	0	0	29
2022	0	0	0	6	21	30	31	26	14	3	0	0	31
2023	0	0	0	6	22	31	32	27	14	3	0	0	32
2024	0	0	0	7	24	33	34	29	15	3	0	0	34
2025	0	0	0	7	25	35	36	31	16	3	0	0	36
2026	0	0	0	7	26	37	38	32	17	3	0	0	38
2027	0	0	0	8	27	39	40	34	18	3	0	0	40
2028	0	0	0	8	29	40	42	35	19	4	0	0	42
2029	0	0	0	8	30	42	44	37	19	4	0	0	44

Energy Efficiency Programs—Total
(MW including losses)

Peak Demand Reductions													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Max
2010	13	13	13	14	15	16	17	16	14	13	13	13	17
2011	25	25	25	26	30	33	33	32	28	26	25	25	33
2012	37	36	37	39	45	48	48	47	42	38	37	37	48
2013	49	49	49	52	58	63	64	62	56	50	49	50	64
2014	61	61	61	64	72	78	79	76	68	62	62	61	79
2015	73	73	73	76	86	92	93	90	81	74	74	73	93
2016	85	82	85	88	99	106	107	104	94	87	85	84	107
2017	97	96	96	101	112	120	121	117	106	99	97	97	121
2018	109	108	108	113	125	134	135	131	120	110	109	109	135
2019	120	120	121	125	138	148	149	145	132	122	120	121	149
2020	132	127	133	137	152	162	163	159	144	134	133	132	163
2021	145	144	143	149	165	176	177	172	157	146	144	144	177
2022	157	155	155	161	179	190	191	186	170	159	156	155	191
2023	168	167	167	174	191	204	205	200	182	170	168	169	205
2024	180	173	180	185	203	218	219	214	196	181	180	181	219
2025	192	191	192	198	216	232	233	227	208	193	193	192	233
2026	203	203	204	210	231	246	247	241	219	205	205	203	247
2027	216	214	214	222	245	260	261	255	233	218	215	215	261
2028	228	218	226	235	257	274	275	269	245	230	227	228	275
2029	239	238	237	247	270	288	289	282	260	241	238	240	289

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Demand-Side Management 2008 Annual Report

March 13, 2009

IDAHO POWER®
An IDACORP Company

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GLOSSARY OF ACRONYMS

aMW—Average Megawatt

akW—Average Kilowatt

A/C—Air Conditioning

ACEEE—American Council for an Energy-Efficient Economy

ASHRAE—American Society of Heating, Refrigerating, and Air-Conditioning Engineers

AMI—Advanced Metering Infrastructure

B/C—Benefit Cost

BCA—Building Contractors Association

BEEP—Building Owners and Managers Association's Energy Efficiency Program

BETC—Business Energy Tax Credit

BLC—Basic Load Capacity

BOC—Boise Operations Center

BOMA—Building Owners and Managers Association

BPA—Bonneville Power Administration

BSU—Boise State University

CAC—Central Air Conditioning/Conditioners

CAP—Community Action Partnership

CAPAI—Community Action Partnership Association of Idaho, Inc.

CCOA—Canyon County Organization on Aging and Community Services

CCNO—Community Connection of Northeast Oregon, Inc.

CEE—Consortium for Energy Efficiency Inc.

CFL—Compact Fluorescent Lighting

CHQ—Corporate Headquarters (Idaho Power)

CR—Customer Representative

CSR—Customer Service Representatives

DEI—Distribution Efficiency Initiative

DOE—U.S. Department of Energy

DSM—Demand Side Management

EEAG—Energy Efficiency Advisory Group

El-Ada—El-Ada Community Action Partnership

EEBA—Energy and Environmental Building Association

EICAP—Eastern Idaho Community Action Partnership

ETO—Energy Trust of Oregon

FCA—Fixed-Cost Adjustment

GWh—Gigawatt-hour

H&CE—Heating and Cooling Efficiency Program

HCSCS—Harney County Senior and Community Services Center

HMCAA—Harney–Malheur Community Action Agency

HVAC—Heating, Ventilation, and Air Conditioning

HVR—Home Voltage Regulator

IDL—Integrated Design Lab

IEA—Industrial Efficiency Alliance

IECC—International Energy Conservation Code

IESBP—Idaho ENERGY STAR® Builders Partnership

IPUC—Idaho Public Utilities Commission

IRP—Integrated Resource Plan

kvar—Kilovolt ampere reactive

kW—Kilowatt

kWh—Kilowatt-hour

LDL—Lighting Design Lab

LED—Light-Emitting Diode

LEED—Leadership in Energy and Environmental Design

LEEF—Local Energy Efficiency Funds

LIHEAP—Low Income Home Energy Assistance Programs

MCOA—Malheur Council on Aging

MHAFB—Mountain Home Air Force Base

MW—Megawatt

MWh—Megawatt-hour

NEEM—Northwest Energy Efficient Manufactured Housing Program

NEEA—Northwest Energy Efficiency Alliance

NWPCC—Northwest Power and Conservation Council

OER—Office of Energy Resources (formerly the Idaho Energy Division)

ODOE—Oregon Department of Energy

OPUC—Public Utility Commission of Oregon

PECI—Portland Energy Conservation, Inc.

PLC—Power Line Carrier

PTCS—Performance Tested Comfort System

RFP—Request for Proposal

RTF—Regional Technical Forum

Rider—Idaho Energy Efficiency Rider and Oregon Energy Efficiency Rider

SCCAP—South Central Community Action Partnership

SEER—Seasonal Energy Efficiency Ratio

SEICAA—Southeastern Idaho Community Action Agency

SIR—Savings Investment Ratio

TAG—Technical Assessment Guide

TRC—Total Resource Cost

UC—Utility Cost

USB—Utility Sounding Board

WAQC—Weatherization Assistance for Qualified Customers

EXECUTIVE SUMMARY

Idaho Power's *Demand-Side Management (DSM) 2008 Annual Report* provides a review of its DSM activities and finances throughout 2008, expresses its future plans for DSM activities, and satisfies the reporting requirements set out in the Idaho Public Utilities Commission's (IPUC) Order No. 29419 and the Public Utility Commission of Oregon's (OPUC) Order No. 89–507.

Idaho Power considers energy efficiency and demand response to be an important and necessary part of a balanced approach to meeting the electricity needs of its customers. Energy efficiency is recognized by Idaho Power and its customers as providing economic, operational, and environmental benefits. Therefore, the pursuit of all cost-effective demand-side resources is a primary objective for Idaho Power. Idaho Power accomplishes this objective with input and consultation with its Energy Efficiency Advisory Group (EEAG).

Idaho Power achieves energy and demand savings through four types of programs, 1) Energy Efficiency, 2) Demand Response, 3) Market Transformation, and 4) Other Programs and Activities. Idaho Power's annual energy savings from 2002 through 2008 increased more than eight-fold. This increase was the result of customers' participation in Idaho Power's energy efficiency and demand response programs. In 2008, these efficiency efforts saved 140,156 megawatt-hours (MWh) of electricity, or 16 average megawatts (aMW), enough energy to serve about 11,000 average homes for one year. The 2008 energy savings was a 54% increase over the 91,145 MWh energy savings in 2007.

The demand reduction for Idaho Power's demand response programs increased by 20% from 48 MW in 2007 to 58 MW in 2008. By year-end 2008, participation in the A/C Cool Credit program increased by 72%. Total DSM expenses were slightly over $21 million in 2008, which is a 35% increase over 2007 expenditures of $15.7 million.

In 2008, Idaho Power's energy efficiency and demand response programs continue to increase in number and customer participation. Idaho Power offered 16 energy efficiency programs, two demand response programs, and added three new programs, the Home Products program, the Home Weatherization pilot, and the Attic Insulation pilot. Additional significant energy savings continue to be realized through market transformation partnership activities with the Northwest Energy Efficiency Alliance (NEEA).

Idaho Power was successful in providing customers with accurate and timely information to assist them in making wise energy choices and participating in energy efficiency programs. In 2008, the results of Idaho Power's quarterly customer satisfaction survey showed steady improvement over recent years, as the percent of customers who have a positive perception of Idaho Power's energy efficiency efforts has continued to rise.

The American Council for an Energy-Efficient Economy (ACEEE) annually publishes a scorecard that ranks individual states in terms of commitment to energy efficiency. In 2008, the ACEEE identified Idaho as the "most improved" state in the nation, having moved up 12 spots, compared to the 2007 scorecard. The following annual report provides detailed information on activities and programs resulting from Idaho Power's support of DSM initiatives.

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INTRODUCTION

Idaho Power's *Demand-Side Management (DSM) 2008 Annual Report* provides a review of the financial and operational performance of Idaho Power's DSM activities and initiatives for the 2008 calendar year. These programs provide a wide range of opportunities for all customer classes to balance their energy needs and reduce their energy consumption.

Idaho Power considers energy efficiency to be an important and necessary part of a balanced approach to meeting the growing demand for electricity. Consistent with this view, energy efficiency is one of the cornerstones supporting Idaho Power's resource acquisition strategy. Energy efficiency is recognized by Idaho Power and its customers as providing economic, operational, and environmental benefits. Therefore, the pursuit of all cost-effective demand-side resources is a primary objective for Idaho Power.

This *DSM Annual Report* is produced to convey Idaho Power's DSM activities and finances throughout 2008, to express Idaho Power's future plans for DSM activities, and to conform to the IPUC Order No. 29419 and the OPUC Order No. 89–507.

During 2008, Idaho Power continued to expand the programs that began with the *2004 Integrated Resource Plan* (IRP). Idaho Power's 2006 IRP included the addition of three new DSM programs and the expansion of one program. In addition to the DSM programs identified in the IRP, Idaho Power continued to offer other energy efficiency programs that began prior to the 2004 IRP. Also in 2008, Idaho Power continued to use its field staff in building customer awareness of, and participation in, energy efficiency, demand response, and educational programs.

In 2008, the energy savings from Idaho Power's DSM activities increased by 54%, and the expenditures for DSM-related activities increased by 35%, compared to 2007. This increase in spending included increased participation in programs and the development of new programs that will result in future savings. DSM activities throughout 2008 were focused predominantly on increasing program participation, customer education, and the planning and implementation of new programs.

Idaho Power's two main objectives for DSM programs are to acquire all cost-effective demand-side resources in order to meet the electrical system's energy and demand needs and to provide all Idaho Power customers with programs and information to help them manage their energy usage. Idaho Power achieves these objectives through the development and implementation of programs with specific energy, economic, and customer satisfaction objectives. When possible, Idaho Power implements identical programs in its Idaho and Oregon service areas.

Figures 1 and 2 show the historical growth in expenditures and resource acquisition from 2002 to the present.

Figure 1. DSM Incremental Expense History 2002–2008 (Millions of dollars)

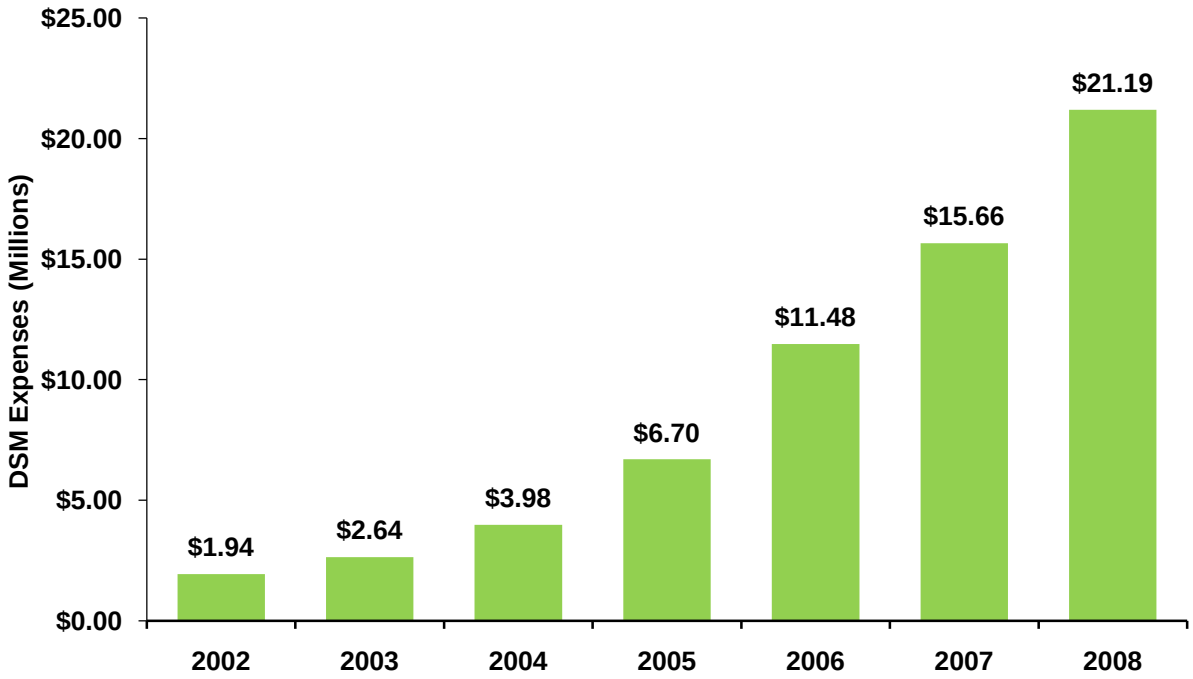
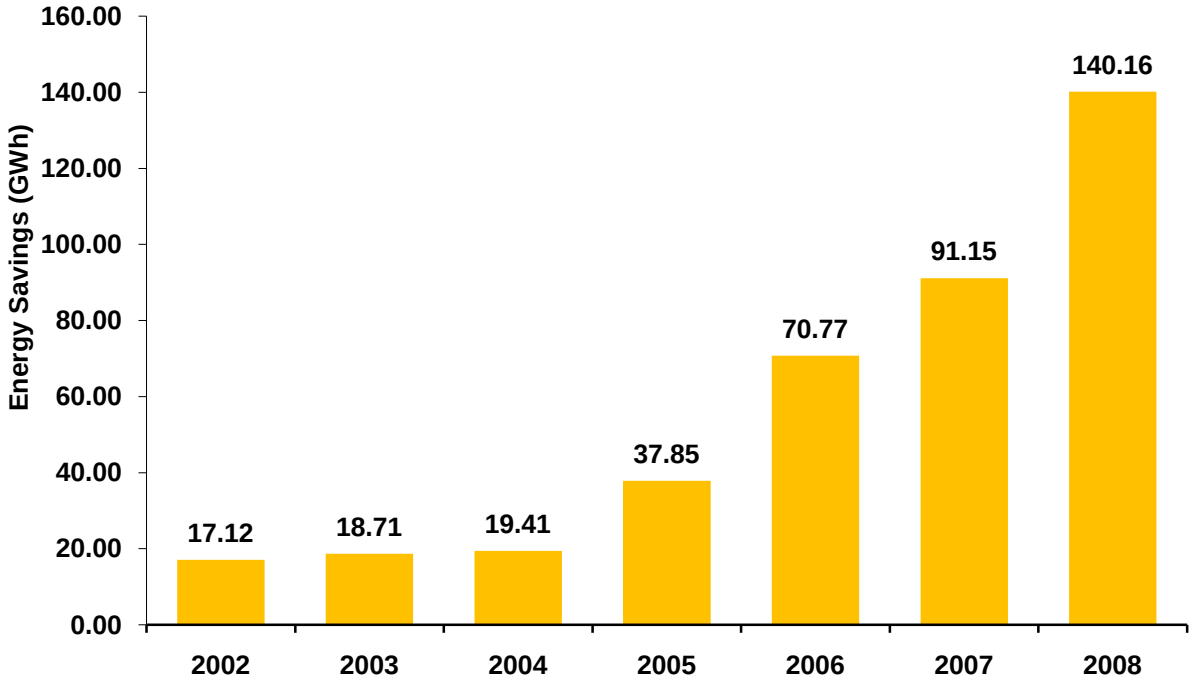


Figure 2. DSM Incremental Energy Savings 2002–2008 (Gigawatt-hour [GWh])



Idaho Power relies on input from the Energy Efficiency Advisory Group (EEAG) to provide customer and public interest review of DSM programs and expenses. In addition to the EEAG, Idaho Power solicits further customer input through stakeholder groups in the residential, commercial, industrial, and irrigation customer sectors. Idaho Power also has enhanced relationships with trade allies,

trade organizations, and regional groups committed to increasing the use of energy efficiency programs and measures to reduce electricity load.

During 2008, Idaho Power continued its contractual participation in, and funding of, the Northwest Energy Efficiency Alliance (NEEA). NEEA's efforts in the northwest impact Idaho Power's customers by providing regional market transformation.

DSM Program Portfolio Structure

The programs within the DSM portfolio are offered to four major customer sectors: residential, commercial, industrial, and irrigation. Beginning in 2007, the commercial and industrial energy efficiency programs were made available to customers in either sector, expanding the availability of these programs. Because of this change, the sector is now often referred to as the commercial/industrial sector. Idaho Power achieved energy and demand savings through four types of programs. These programs include Demand Response, Energy Efficiency, Market Transformation, and Other Programs and Activities. A brief description of each of these operational categories follows.

Demand Response Programs

Demand response programs are designed to reduce participant electricity loads at specific times of the day and year when electricity is normally in short supply. The need for these programs continues to increase. Idaho Power set a new system peak of 3,214 megawatts (MW) on Monday, June 30, 2008, at 3:00 p.m. The goal of demand response programs within Idaho Power's DSM portfolio is to reduce the system summer peak demand, thus minimizing the need for acquiring higher-cost, supply-side alternatives, such as gas turbine generation. Demand reduction through demand response programs is usually achieved through the use of load control devices installed on customer equipment. The measure of program performance is the number of megawatts (MW) of reduced demand for electricity during peak periods. In 2008, Idaho Power offered two demand response programs, one for residential customers and one for irrigation customers.

Energy Efficiency Programs

Energy efficiency programs focus on reducing energy usage through identifying buildings, equipment, or components where energy-efficient design, replacement, or repair can yield significant energy savings. These programs are applicable to all customer sectors. Typical project measures range from entire building construction to simple light bulb replacement. Savings from these programs are measured in terms of reduced kilowatt-hour (kWh) usage, or megawatt-hour (MWh) usage for larger projects. These programs usually supply energy benefits throughout the year. Idaho Power's energy efficiency offerings include programs in residential and commercial new construction, residential and commercial retrofit applications, and irrigation and industrial systems improvement or replacement.

Market Transformation

Market transformation is a method of achieving energy savings through engaging and influencing large national and regional organizations. These organizations are in a position to impact the design of energy usage in products, services, and methods that affect electrical power consumption. Idaho Power primarily achieves market transformation savings through its participation in NEEA. Idaho Power also

supports market transformation accomplished by appliance or building code modifications or enforcement.

Other Programs and Activities

Other Programs and Activities represent a range of small projects that are typically research, development, and education oriented. This category includes the Local Energy Efficiency Funds (LEEF), the Residential Energy Efficiency Education initiative, and the Commercial Educational Initiative. These programs enable Idaho Power to offer support for projects and educational opportunities not normally covered under existing programs.

Table 1 provides a summary of the DSM programs and their respective sectors, as well as operational category and the state in which each was available in 2008.

Table 1. 2008 DSM Programs, Sectors, and Operational Type

Program	Sector	Operational Type	State
A/C Cool Credit	Residential	Demand Response	ID
Attic Insulation Pilot	Residential	Energy Efficiency	ID
Building Efficiency	Commercial/Industrial	Energy Efficiency	ID/OR
Commercial Education Initiative	Commercial/Industrial	Other Programs and Activities	ID/OR
Custom Efficiency	Commercial/Industrial	Energy Efficiency	ID/OR
Easy Upgrades	Commercial/Industrial	Energy Efficiency	ID/OR
Energy Efficient Lighting	Residential	Energy Efficiency	ID/OR
Energy House Calls	Residential	Energy Efficiency	ID/OR
ENERGY STAR® Homes Northwest	Residential	Energy Efficiency	ID/OR
Heating & Cooling Efficiency Program	Residential	Energy Efficiency	ID/OR
Holiday Lighting Program	Commercial/Industrial	Energy Efficiency	ID/OR
Home Products Program	Residential	Energy Efficiency	ID/OR
Home Weatherization Pilot	Residential	Energy Efficiency	ID
Irrigation Efficiency Rewards	Irrigation	Energy Efficiency	ID/OR
Irrigation Peak Rewards	Irrigation	Demand Response	ID/OR
Local Energy Efficiency Funds	All	Other Programs and Activities	ID/OR
Northwest Energy Efficiency Alliance	All	Market Transformation	ID/OR
Oregon Commercial Audits	Commercial/Industrial	Energy Efficiency	OR
Oregon Residential Weatherization	Residential	Energy Efficiency	OR
Rebate Advantage	Residential	Energy Efficiency	ID/OR
Residential Education Initiative	Residential	Other Programs and Activities	ID/OR
Weatherization Assistance for Qualified Customers	Residential	Energy Efficiency	ID/OR

Program Performance

Participation in DSM programs at Idaho Power continues to increase, as does the energy impact in the form of energy savings and demand reduction. The energy savings for Idaho Power's energy efficiency programs in 2008 was 107,484 MWh, a 72% increase over the 62,544 MWh energy savings in 2007. Demand reduction for the demand response programs also increased in 2008. Combined,

the Irrigation Peak Rewards and A/C Cool Credit programs resulted in estimated summer peak reduction of 58 MW, which represented a 20% increase over 48 MW in 2007.

In 2008, energy savings increased, as compared to 2007, for the residential, commercial, and industrial sectors by 75%, 310%, and 38% respectively. The residential sector savings increased to 21,778 MWh, the commercial sector savings increased to 32,786 MWh, and the industrial sector increased to 41,059 MWh. The 2008 irrigation sector energy savings decreased slightly to 11,746 MWh, from 12,304 MWh in 2007. Additional energy savings continue to be realized through market transformation partnership activities with NEEA.

Customer participation increased in nearly every existing program from 2007 to 2008. The number of projects completed under the Easy Upgrades program increased from 104 projects in 2007 to 685 projects in 2008. Projects completed under the Building Efficiency program increased from 22 to 60. While the energy savings decreased slightly from the Irrigation Efficiency Rewards program, participation increased from 816 to 961 projects. As a result of the downturn in the housing market in 2008, the number of homes incented under the ENERGY STAR® Homes Northwest and the Rebate Advantage programs both decreased. Participation in the A/C Cool Credit program increased by 72% to approximately 24,000 customers by year's end.

A few individual programs were big contributors to the overall energy savings. The Custom Efficiency program, the only energy efficiency program in the industrial sector, accounted for 38% of Idaho Power's energy savings from programs, resulting in 41,059 MWh of savings. The Easy Upgrades program in the commercial sector provided 24%, or 25,928 MWh, energy savings. In the residential sector, the Energy Efficient Lighting program saved 14,309 MWh, accounting for 13% of the overall energy savings.

ACEEE publishes an annual scorecard ranking individual states in terms of commitment to energy efficiency. In 2008, Idaho was identified as the "most improved" state in the nation, having moved up 12 spots, as compared to the 2007 scorecard. As the largest utility company in the state, Idaho Power is proud to contribute to this recognition.

Table 2 shows the 2008 annual energy savings, summer peak demand reduction, and average megawatt (aMW) savings associated with each of the DSM program categories. The table also provides a comparison of the 2008 contribution of each sector in terms of weather-adjusted energy usage and its respective size in 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. 2008 Program Sector Summary and Energy Usage

	Energy Efficiency Program Impacts[a]				Idaho Power System Sales		
	Direct Expenses	MWh Energy Savings	aMW Load Reduction	Peak Load Reduction[b]	MWh Sector Total	% of Energy Usage	Number of Customers
Energy Efficiency							
Residential	$7,192,562	21,778	2	23	5,282,337	36%	404,373
Commercial	$4,076,109	32,786	4	5	3,979,113	27%	64,125
Industrial	$4,045,671	41,059	5	5	3,365,761	23%	122
Irrigation	$3,535,542	11,746	1	39	1,921,608	13%	18,542
Market Transformation	$942,014	32,671	4	n/a	n/a	n/a	n/a
Other Programs and Activities	$421,317	116	0	n/a	n/a	n/a	n/a
Total	**$20,213,215**	**140,156**	**16**	**72**	**14,548,819**	**100%**	**487,162**

[a] Energy, demand, and expense data have been rounded to the nearest whole unit, which may result in minor rounding differences.

[b] Includes peak load reduction from both demand response and energy efficiency programs.

Regulatory Initiatives

Idaho Power has aligned itself with the IPUC and the members of the environmental community to work toward creating a financial and regulatory environment supportive of utility DSM resource acquisition. Resulting from this collaborative effort are two financial mechanisms designed to 1) remove the financial disincentives to utility DSM resource acquisition and 2) provide a financial incentive to shareowners when DSM programs perform above baseline goals. Idaho Power is optimistic that this effort will lead to a sustained environment supportive of its plans to pursue all cost-effective DSM opportunities while balancing its shareowner's financial objectives.

In response to these regulatory mechanisms, Idaho Power has committed to enhancing its efforts toward promoting DSM and energy efficiency in several key areas, including a broad availability of efficiency and load-management programs, building code improvement activity, pursuit of appliance code standards, expansion of DSM programs beyond peak shaving/load shifting programs, and third-party verification.

DSM Expenditures and Funding

Funding for DSM programs in 2008 came from several sources. The Idaho Energy Efficiency Rider and Oregon Energy Efficiency Rider funds are collected directly from customers on their monthly bills. In June 2008, the Idaho Rider was increased from a rate of 1.5% of base rate revenues to 2.5%. The monthly caps on residential and irrigation customer contributions formerly in place were removed. The Oregon Rider remains at 1.5% of base rate revenues. DSM-related expenses not funded through the Rider funds, including costs for administration and overhead, are included as part of Idaho Power's ongoing operation and maintenance costs. Total DSM expenses funded from these sources were slightly over $21 million in 2008.

Table 3 provides a summary of the 2008 expenses and energy savings by each funding category.

Table 3. 2008 Funding Source and Energy Impact

Funding Source	Expenses	MWh Savings
Idaho Rider.....	$18,880,276	131,662
Oregon Rider.....	$625,000	4,277
BPA	$6,950	0
Idaho Power	$1,681,294	4,217
Total	**$21,193,520**	**140,156**

Future Plans

Many of Idaho Power's DSM programs are selected for implementation through its biennial IRP. The IRP is a public document that details Idaho Power's strategy for economically maintaining the adequacy of its power system into the future. The IRP process balances risk, environmental, economic, and other considerations in developing a preferred portfolio of future resources that meet the specific energy needs of Idaho Power and its customers. The IRP is normally updated every two years to reflect changes in supply costs, demand for electricity, and other factors. However, with its acceptance of the 2006 IRP, the IPUC requested that Idaho Power align the submittal of its next IRP with those submitted by other utilities. To comply with this request, Idaho Power provided an update on the status of the 2006 IRP to both the IPUC and OPUC in June 2008, and will file a new IRP in June 2009. Idaho Power DSM staff has participated on the collaborative team compiling both the 2006 IRP Update and the 2009 IRP.

In 2009, Idaho Power plans to continue to increase participation and energy savings from existing programs and continue to implement new energy efficiency and demand response programs. In 2009, Idaho Power plans to expand its efforts in energy efficiency by continuing the Attic Insulation Pilot under the new name Home Improvement Program, continuing the Home Weatherization Pilot under the new name Weatherization Solutions for Eligible Customers program, and implementing a refrigerator recycling program. Idaho Power will expand the Irrigation Peak Rewards program to add an option of a dispatchable demand response program, which will greatly increase the demand reduction potential from this program. Also in 2009, Idaho Power plans to offer a demand response program to its commercial and industrial customers through a third-party demand response aggregator.

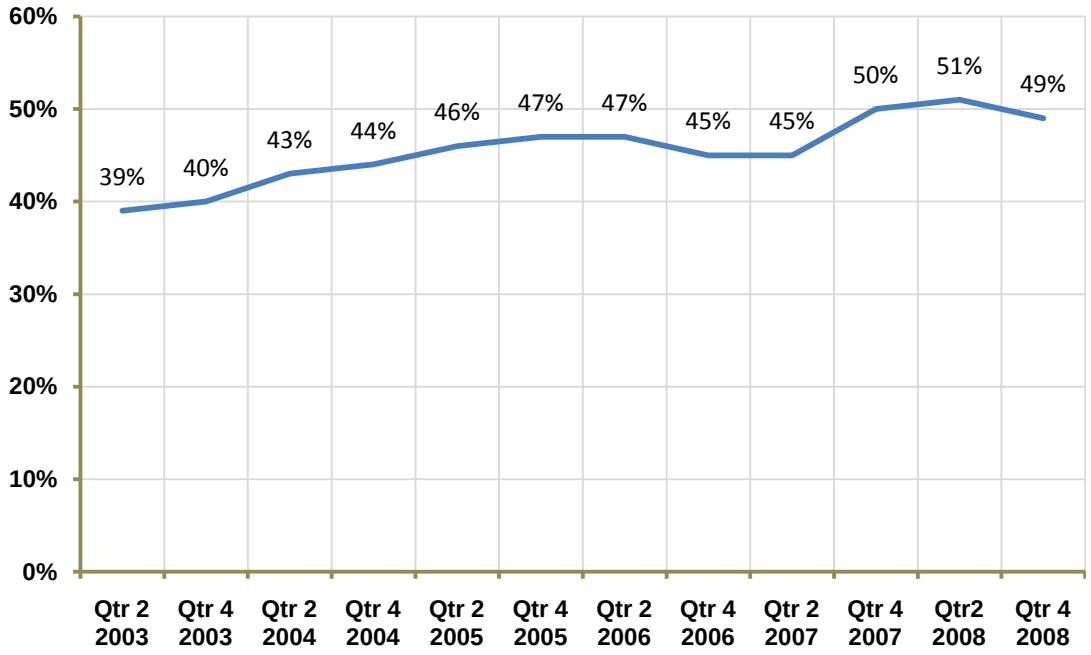
Idaho Power will participate in the development of the Northwest Power and Conservation Council's (NWPCC) Sixth Power Plan, continue and enhance consumer education on energy efficiency, and complete various research and development projects.

Customer Satisfaction

Customer satisfaction is a key consideration in Idaho Power's program design, operations, and management. Idaho Power uses surveys, focus groups, stakeholder input, and input from the EEAG and Idaho Power field personnel to assess and monitor customer satisfaction. This information and input aids in the design and modification of programs and assists in program marketing and management throughout the life of each program.

In 2008, the results of Idaho Power's quarterly customer satisfaction survey showed steady improvement over recent years as the percentage of customers who have a positive perception of Idaho Power's energy efficiency efforts has continued to increase. Customers' positive perception of Idaho Power's energy efficiency efforts increased from 39% in early 2003 to 49% in late 2008. This represents a 26% increase in positive customer perception. Idaho Power continues to expand its customer satisfaction measurement activities, which enable Idaho Power to identify actionable areas for improvement. Figure 3 depicts biannual growth in the number of customers who indicated Idaho Power met or exceeded their needs concerning energy conservation efforts encouraged by Idaho Power.

Figure 3. Percent of Customers Whose Needs are Met or Exceeded by Idaho Power's Conservation Efforts



Several surveys measured customer satisfaction with programs in 2008. The surveys also provide guidance for program modification, marketing, and evaluation. Survey results are presented in the following program sections of this report: A/C Cool Credit, Energy House Calls, Rebate Advantage, Residential Energy Efficiency Education, Heating & Cooling Efficiency Program, Weatherization Assistance for Qualified Customers (WAQC), and Easy Upgrades.

An important measure of customer satisfaction is the retention rate of participants in ongoing programs. A review of utility service agreement end dates indicates less than 1% of A/C Cool Credit participants cancel enrollment due to dissatisfaction with the program. Both irrigation sector programs, the Irrigation Peak Rewards and the Irrigation Efficiency Rewards programs, have continued with a high level of participation. Idaho Power programs have on-going customer satisfaction measurements as a follow-up to the application process. For example, Easy Upgrades provides an ongoing Web-based customer survey for its participants. Results of these surveys indicate general satisfaction and help guide program improvement and marketing efforts. Idaho Power energy efficiency program staff is preparing surveys for future use in determining customer satisfaction. Building Efficiency developed a customer satisfaction survey in 2008 and plans to implement it in 2009. Custom Efficiency plans to develop a customer satisfaction survey in 2009. The WAQC program collected customer satisfaction surveys from participating customers. The results of these surveys showed that customers thought the program helped

them learn about saving electricity in their homes and helped them try some of the ways to save energy in their homes.

Cost-Effectiveness

Idaho Power considers cost-effectiveness the primary screening tool prior to DSM program implementation. Most of Idaho Power's energy efficiency programs are preliminarily identified through the IRP planning process. In this process, specific programs or potential energy savings are screened by sector to determine if the levelized cost of these programs is less than supply-side resource alternatives. If they are shown to be less costly than supply-side resources from a levelized cost perspective, the hourly shaped energy savings is subsequently included in the IRP.

Prior to the actual implementation of energy efficiency or demand response programs, Idaho Power analytical staff creates cost-effectiveness models to assess whether a specific potential program design will be cost effective from the perspective of Idaho Power and its customers. Incorporated into these models are inputs from various sources in order to use the most current and reliable information available. When possible, Idaho Power staff leverages the experiences of other companies in the region, or throughout the country, to help identify specific program parameters. This is typically accomplished through discussions with other utilities' program managers and research staff. Idaho Power also uses electric industry research organizations, such as E Source, Edison Electrical Institute (EEI), Consortium for Energy Efficiency (CEE), American Council for an Energy Efficient Economy (ACEEE), Advanced Load Control Alliance (ALCA), Association of Energy Service Professionals (AESP), Energy Insights, and others, to identify similar programs and their results.

For other assumptions, including estimated costs, savings, and net-to-gross ratio estimates, Idaho Power relies on sources such as the Northwest Power and Conservation Council, the Regional Technical Forum (RTF), NEEA, E Source, the Database for Energy Efficiency Resources (DEER), the Energy Trust of Oregon (ETO), Bonneville Power Administration (BPA), third-party consultants, and other regional utilities. Idaho Power uses a cost-effectiveness model to perform sensitivity analyses in order to determine optimal program designs. The remaining inputs used in the cost-effectiveness models are obtained from the IRP process. The Technical Appendix of Idaho Power's most recent IRP is the source for the financial assumptions, including the discount rate and inflation rate. The IRP is also the source of the DSM alternative costs, which is the value of energy savings and demand reduction resulting from the DSM programs. These DSM alternative costs vary by season and time-of-day. The DSM alternative energy costs are based on either projected fuel costs of a peaking unit or forward market prices as determined by Idaho Power's power supply model, AURORAxmp® Electric Market Model. The avoided capital cost is based on a gas-fired simple-cycle turbine.

For its cost-effectiveness methodology, Idaho Power relies on the Electric Power Research Institute End Use Technical Assessment Guide (TAG) and the California Standard Practice Manual. Idaho Power primarily 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. As defined in the TAG and California Standard Practice Manual, the TRC and UC tests are most similar to supply-side tests and provide a useful basis to compare demand-side and supply-side resources. Idaho Power determines cost-effectiveness on a measure-by-measure basis and a program basis. To be consistent with the IRP, program life B/C ratios for A/C Cool Credit and Irrigation Peak Rewards are calculated over a 20-year period. In order for a measure or a program to be considered cost-effective, it must have B/C ratios greater than one for both the TRC and UC tests.

Idaho Power may choose to launch a pilot or a program to evaluate estimates or assumptions in the cost-effectiveness model. Following implementation of a program, cost-effectiveness models are reviewed as new inputs from actual program activity become available, such as actual program expenses, savings, or participation. If measures or programs are determined to not be cost-effective after implementation, the program or measures are reexamined.

A new addition to the 2008 DSM report is the presentation in Appendix 4 of the UC and TRC B/C ratios using actual cost information over the life of the program through 2008. 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 is realized.

Program Evaluation

Program evaluation is an important facet of Idaho Power's DSM operational activities. Idaho Power relies on evaluation by third-party contractors, internal analyses, and regional studies to ensure the ongoing cost-effectiveness of programs through validation of energy savings and demand reduction. The results of Idaho Power's evaluation efforts are used to enhance or initiate program changes when warranted. In 2008, Idaho Power developed a comprehensive evaluation plan for its energy efficiency programs and commenced evaluations for several programs and measures, including Building Efficiency, ENERGY STAR® Homes Northwest, Rebate Advantage, Energy House Calls, and the Attic Insulation pilot.

As part of its evaluation efforts, Idaho Power is actively participating in several regional studies to identify and promote emerging technologies that may further enhance opportunities for new program deployment. Some examples include 1) the Distribution Efficiency Initiative, which is a study managed by NEEA to determine efficient ways to design and operate distribution feeders through voltage regulators, 2) a regional study to evaluate the energy-savings potential of ductless heat pumps, and 3) efforts to measure the impacts of light-emitting diode (LED) lighting. Other regional analyses in which Idaho Power actively participated include the Commercial Building Stock Assessment and market progress evaluations.

DSM Annual Report Structure

The structure of the remaining portion of this report is based on customer sectors (categorized by residential, commercial/industrial, and irrigation). The description of each sector is followed by information about each program in that sector. Each program section includes a general program description, annual activities, and future plans. A chart at the beginning of each program section contains 2008 and 2007 program metrics in tabular format. 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. The appendices follow the written sections and contain tabular information on the 2008 expenses and savings, as well as historic information for all energy efficiency and demand response activities at Idaho Power.

RESIDENTIAL SECTOR OVERVIEW

Description

With over 404,000 service points serving a population of approximately one million people, residential customers represent Idaho Power's largest customer segment. Growth within this segment slowed considerably in 2008, largely in response to regional and national economic conditions. During 2008, Idaho Power added about 4,000 customers, equaling a growth rate of 1%. Idaho Power experienced the smallest residential customer growth rate since 1989. The residential segment represents 36% of Idaho Power's total electricity usage.

Programs

Table 4. 2008 Residential Program Summary

			Total Costs		Savings	
	Participants		Utility	Resource	Annual Energy	Summer Peak Demand
Program	*(Number)*	*(Units)*	*(Dollars)*	*(Dollars)*	*(kWh)*	*(MW)*
Demand Response						
A/C Cool Credit	20,195	homes	$2,969,377	$2,616,072	n/a	23
Total			**$2,969,377**	**$2,616,072**	**n/a**	23
Energy Efficiency						
Attic Insulation Pilot	282	homes	$123,454	$157,866	317,814	
Energy Efficient Lighting	436,264	CFL bulbs	$1,018,292	$793,265	14,309,444	
Energy House Calls	1,099	homes	$484,379	$484,379	883,038	
ENERGY STAR® Homes Northwest	254	homes	$302,061	$375,007	468,958	1
Heating & Cooling Efficiency Program	359	homes	$473,551	$599,771	561,441	
Home Products Program	3,034	appliances/fixtures	$250,860	$468,056	541,615	
Home Weatherization Pilot	16	homes	$52,807	$48,162	71,680	
Oregon Residential Weatherization	3	homes	$7,417	$28,752	22,196	
Rebate Advantage	107	homes	$90,888	$179,868	463,401	
Weatherization Assistance for Qualified Customers—Idaho	439	homes/non-profits	$1,375,632	$1,755,749	4,064,301	
Weatherization Assistance for Qualified Customers—Oregon	13	homes/non-profits	$43,843	$74,048	73,841	
Total			**$4,223,185**	**$4,964,924**	**21,777,729**	**24**

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

Programs available to residential customers include one demand response program, nine energy efficiency programs, and the energy educational program. The demand response program offering is the A/C Cool Credit program, with approximately 24,000 customers enrolled. During 2008, this program expanded into Idaho Power's Payette and Twin Falls service areas. The residential efficiency programs include Energy House Calls, Rebate Advantage, ENERGY STAR® Homes

Northwest, Oregon Residential Weatherization, Energy Efficient Lighting, WAQC, and Heating & Cooling Efficiency Program. The new ENERGY STAR Home Products Program was operational in 2008, with strong residential customer participation.

Additionally, two new pilots were implemented in 2008. One was the Attic Insulation Pilot and the other was the Home Weatherization Pilot. Analysis was conducted about the viability of the attic retrofit pilot program. Plans are underway for implementation in June 2009 under the name Home Improvement Program. The Home Weatherization Pilot will launch as a program in the Twin Falls area in 2009 under the name Weatherization Solutions for Eligible Customers.

Idaho Power continued significantly increasing its outreach activities by participating in numerous retail and community events during 2008. These partnerships and outreach activities created specific opportunities for the company to share the importance of energy efficiency and give customers information and options about participating.

Many of these events were partnerships with community retailers, including Home Depot, Lowe's, Albertson's, Wal-Mart, and small, locally owned retailers. Idaho Power also participated in home and garden shows, Parade of Homes, library education series, and other community events across Idaho Power's service area. A sample of the new community events Idaho Power participated in during the course of 2008 include the Susan G. Komen Race for a Cure, the St. Luke's Women's Challenge, and the Idaho Green Expo, where Idaho Power released the new booklet *30 Simple Things You Can Do To Save Energy*. These events drew large crowds, providing Idaho Power an opportunity to share energy efficiency information.

Presentations to community groups and businesses were another emphasis during the year. Idaho Power customer representatives made approximately 100 presentations to civic and community groups, including chambers of commerce, school boards, service organizations, and businesses. Idaho Power also developed a new energy efficiency presentation, targeting fourth-grade through sixth-grade students.

A/C Cool Credit

	2008	2007
Participation and Savings		
Participants (homes)[a]	20,195	13,692
Energy Savings (kWh)	n/a	n/a
Demand Reduction (MW)[a]	23	11
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$2,922,985	$2,421,461
Oregon Energy Efficiency Rider	$45,404	$0
Idaho Power Funds	$988	$4,692
Total Program Costs—All Sources	$2,969,377	$2,426,154
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	n/a	n/a
Total Resource Levelized Cost ($/kWh)	n/a	n/a
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	1.38	
Total Resource Benefit/Cost Ratio	1.38	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2003	

[a] Program participation and demand reduction reflect enrollment as of July 15th. Year end enrollment in the program was 23,505 homes.

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 on and off via a direct load-control device installed on the air conditioning unit. Participants receive a monthly, monetary incentive for participating in the program during the summer season. This program enables Idaho Power to reduce system peaking requirements during times when summer peak load is high.

Individual radio-controlled or power line carrier (PLC) switches are installed on customers' air conditioning units. These switches allow Idaho Power to cycle customers' air conditioners during a cycling event. Under this program, Idaho Power may cycle participants' air conditioners for up to 40 hours each month in the months of June, July, and August.

2008 Activities

In 2008, the program expanded beyond Ada County, Canyon County, and the Emmett valley to the Payette and Twin Falls area. Mountain Home Air Force Base (MHAFB) housing residents also joined the program in 2008. Cycling event hours changed from four-hour cycles to three-hour cycles, pinpointing the peak time with less potential impact on participants. There were 15 cycling events in 2008, one in June, seven in July, and seven in August. The 2008 target was 16,000 new participants. There were approximately 13,222 new participants in 2008.

Marketing approaches during 2008 covered a range of methods. A/C Cool Credit pooled resources with the City of Boise Recycling department and with United Water on a joint bill-stuffer campaign. Idaho Power specialists visited large businesses, providing program information to the businesses' employees. Idaho Power in-house A/C Cool Credit promotions attracted further program signups.

A cause-related marketing approach involved partnering with both The Idaho Foodbank and Southeast Oregon Regional Food Bank. During a "limited time offer," a $20 donation went to the food bank in the participant's location for enrolling in the A/C Cool Credit program. As of December 2008, this approach yielded 489 new signups and a total of $9,780 to the two food banks.

During 2008, a call center customer service representative (CSR) pilot was conducted. The CSRs received training in signing up new A/C Cool Credit participants at the point of contact when an Idaho Power customer initiates or transfers his/her account by phone. The project was successful. During the first five months after the training was completed, five trained CSRs signed up 140 new participants.

An outreach project included an Idaho Power specialist and a heating, ventilating, and air conditioning (HVAC) journeyman providing A/C Cool Credit switch training for field technicians of HVAC companies. Technicians learned about the direct load-control device installed on participating Idaho Power customers' air conditioning units. Increasing the HVAC technician's knowledge of switch boxes contributes to positive customer relations between the customer and the technician servicing the A/C Cool Credit program participant's air conditioning unit.

Customer Satisfaction

The A/C Cool Credit program conducted a customer satisfaction survey between September and October 2008. Of the 3,958 surveys sent out, 1,671 completed responses were returned, resulting in a 42% response rate. A portion of the participants received the survey by e-mail, while the others received the survey through postal mail. Results showed a high level of satisfaction with the program, with high ratings in program application process, comfort, frequency of cycling, overall satisfaction with the program, and amount of information received. Most respondents indicated they chose to participate in the program "to help reduce electrical usage on hot summer days," to "receive the bill credit," or both. An overwhelming majority of respondents indicated they would recommend the program to friends or family.

2009 Strategies

The A/C Cool Credit program is expanding into the Pocatello area this spring, with marketing starting in February. The program will expand to areas where the paging signal does not reach, as meters are installed in those areas as part of the Advanced Metering Infrastructure (AMI) project. The 2009 A/C Cool Credit target is to add 12,000 new participants. An evaluation of the results of this demand response program will be implemented in Pocatello, Twin Falls, and MHAFB. Data loggers will be installed on a random sample of participating customer's air conditioning units to collect data on run time. Once the information is collected, analysis will commence in autumn 2009 to estimate demand reduction.

Idaho Power plans to distribute A/C Cool Credit program information by using the technicians installing the new AMI meters in the upcoming year. The technicians will leave a door hanger with A/C Cool Credit program information on the customers' doorknob after completing their installation work.

Attic Insulation Pilot

	2008	2007
Participation and Savings		
Participants (homes)	282	n/a
Energy Savings (kWh)	317,814	n/a
Demand Reduction (MW)	.03	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$123,454	n/a
Oregon Energy Efficiency Rider	$0	n/a
Idaho Power Funds	$0	n/a
Total Program Costs—All Sources	$123,454	n/a
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.029	n/a
Total Resource Levelized Cost ($/kWh)	$0.037	n/a
Program Life Benefit/Cost Ratios		
Utility Cost Benefit/Cost Ratio	2.48	
Total Resource Benefit/Cost Ratio	1.94	
Program Characteristics		
Program Jurisdiction	Idaho	
Program Inception	2008	

Description

The Attic Insulation Pilot, conducted in Idaho during 2008, consisted of paying an incentive to residential customers in the Idaho Power service area for installing additional attic insulation. This program specifically targets the reduction of summer peak demand.

2008 Activities

The pilot was conducted in Boise, Twin Falls, and Pocatello. Installations began May 2008 and were completed by the first week of July. The attic insulation program paid a $0.15 per square foot incentive for professionally installed attic insulation. Analysis of the information obtained from the attic insulation pilot indicates that this is an opportunity for Idaho Power to provide a cost-effective program beginning in 2009.

2009 Strategies

The Attic Insulation Pilot will become a program in Idaho and Oregon in June 2009 under the name Home Improvement Program. Plans include creating program information brochures to market the program and incentive application forms for customers. In July, a bill stuffer explaining the new program will be included in all residential customers' bills. Marketing will include a direct mail campaign after the program launch, followed by a print campaign later in 2009.

Energy Efficient Lighting

	2008	2007
Participation and Savings		
Participants (CFL bulbs)	436,234	219,739
Energy Savings (kWh)	14,309,444	7,207,439
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$1,011,850	$519,818
Oregon Energy Efficiency Rider	$6,242	$11,787
Idaho Power Funds	$200	$10,445
Total Program Costs—All Sources	$1,018,292	$557,646
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.011	$0.012
Total Resource Levelized Cost ($/kWh)	$0.009	$0.015
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	4.56	
Total Resource Benefit/Cost Ratio	4.31	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2002	

Description

The Energy Efficient Lighting program, called the ENERGY STAR® Lighting program in 2007, strives for residential energy savings through the replacement of less efficient lighting with more efficient technology. The average existing home has 38 light bulbs. New homes have an average of 77 light bulbs. Changing these bulbs to more efficient bulbs represents a low-cost, easy way for all customers to achieve energy savings.

ENERGY STAR qualified compact fluorescent lights (CFLs) are an efficient alternative to standard incandescent light bulbs and save money and energy. Bulbs come in a variety of wattages, colors, and applications, including bulbs for three-way and dimmable fixtures. ENERGY STAR qualified bulbs use 75% less energy and last up to 10 times longer than incandescent bulbs.

2008 Activities

In 2008, the majority of energy savings were achieved through Idaho Power's participation in two regional Change a Light promotions sponsored by the BPA and one sponsored by Idaho Power. The 2007 BPA Change a Light promotion (spiral bulbs) carried over until February 2008. The BPA promotion focusing on specialty bulbs extended through December 2008. Additionally, Idaho Power initiated its own spiral-bulb promotion during autumn 2008. This spiral promotion ran independent of the BPA promotion, focusing on smaller retailers and covering a greater Idaho Power service area than the BPA program.

Table 5 describes the energy savings and the number of CFL bulbs contributed by each segment of the program.

Table 5. Energy Efficient Lighting Energy Savings

Promotion	Description	Contractor	Timeframe	Bulbs Sold	Estimated kWh Savings
2007 Change a Light Spiral.....	99¢ spiral single pack spiral bulbs	BPA/Fluid	2007 carryover	60,987	2,000,357
2007 Change a Light Specialty ..	Specialty bulbs in "big-box" stores	BPA/PECI	2007 carryover	31,880	1,045,664
2008 Change a Light Spiral.....	99¢ single pack spiral bulbs	BPA/Fluid	Spring 2008	41,660	1,366,448
2008 Change a Light Specialty ..	Specialty bulbs in "big-box" stores	BPA/PECI	2008	228,169	7,483,943
Change a Light Spiral.....	99¢ single pack spiral bulbs	Fluid	Fall 2008	71,935	2,359,470
Direct Install	Bulbs given directly to customers	n/a	2008	1,633	53,562
			Total	**436,234**	**14,309,444**

Marketing during 2008 focused on education and outreach by educating customers about the benefits of CFLs and selecting the appropriate bulb for a specific application. Idaho Power also marketed the program through point-of-purchase materials and signs, in-store events and energy efficiency events, the Idaho Power *Customer Connection* monthly newsletter, and the Idaho Power Web site.

In 2008, Idaho Power conducted 13 special events at national retail stores in Ontario, Nampa, Boise, Twin Falls, Pocatello, and Chubbuck. Special events served as opportunities for Idaho Power staff to talk directly with customers at the point-of-purchase, answer questions, and promote all Idaho Power energy efficiency programs as well as energy efficient lighting. Idaho Power held staff training events on energy efficient lighting and proper disposal of mercury-containing light bulbs.

2009 Strategies

Idaho Power will continue advocating the Energy Efficient Lighting program in 2009 through participation in regional lighting promotions. To ensure geographic coverage and bulb types that are not included in BPA promotions, Idaho Power will also continue its independent promotion. Additionally, Idaho Power will research purchasing habits and market segments of program participants using coupon-based marketing promotions. The information will be used to enhance program marketing and increase program participation.

Energy House Calls

	2008	2007
Participation and Savings		
Participants (homes)	1,099	700
Energy Savings (kWh)	883,038	699,899
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$448,992	$251,743
Oregon Energy Efficiency Rider	$35,388	$3,349
Idaho Power Funds	$0	$450
Total Program Costs—All Sources	$484,379	$336,372
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.045	$0.039
Total Resource Levelized Cost ($/kWh)	$0.045	$0.039
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	2.20	
Total Resource Benefit/Cost Ratio	2.20	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2002	

Description

The Energy House Calls program helps manufactured and mobile home owners with electric heat save on their energy bills by improving the home's efficiency. This energy efficiency 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.

Leaking duct systems can lose as much as 70% of the air intended for heating or cooling in a home. Ducts operate under pressure, making a one-square-inch hole in a system similar to a 20-square-inch hole in a wall. Previous studies show typical losses from ducts are about 30%.

Services and products offered through the Energy House Calls program include duct testing and sealing according to Performance Tested Comfort System (PTCS) specifications, installation of five CFL bulbs, provision of two furnace filters along with replacement instructions, water heater temperature test for proper setting, and distribution of energy efficiency educational materials for manufactured home occupants. The value of the service to the customer is dependent on the complexity of the repair. The typical range of the average Idaho Power cost of a service call is from $300 to $350. Idaho Power provides the customer with the contractor contact information. Customers access the service by directly calling one of the recognized, certified contractors specially trained to provide these services in their region.

Program management is under contract with Ecos Consulting, a company with experience managing and supplying duct-sealing service programs. Ecos Consulting coordinates the contractors performing local

weatherization and energy efficiency services. To monitor quality assurance, third-party audits are conducted in 5% of the homes served.

2008 Activities

Idaho Power renegotiated the contract with Ecos Consulting for continuation of administrative management of the Energy House Calls program. Idaho Power continued its direct mail campaign. Recipients were targeted using a database of electrically heated manufactured homes in the Idaho Power service area in Idaho and Oregon.

After reviewing the locations of program activity and market saturation, it was determined that marketing efforts should focus primarily in the Treasure Valley area. In 2008, an updated cost-effectiveness analysis was conducted representing the focused regional marketing efforts, and was determined to be cost-effective through 2009.

During 2008, Energy House Calls serviced 1,099 manufactured homes, resulting in approximately 883,038 kWh savings. The program conducted quality assurance on 5% of the homes serviced in the Energy House Calls program. Idaho Power's third-party contractors inspected 57 homes, with 43 homes passing and 13 homes failing the inspection. Contractors are required to revisit failed homes and correct identified problems. The majority of failed homes occurred during a specific period and was the result of one contractor's activity. Once Ecos Consulting, who manages the three contractors, was aware of the issue, the contractor sent a quality-assurance person out with the technician for a few weeks of observation and released one employee from their duties. The inspection failures were from jobs completed in early 2008, while subsequent quality inspections were positive. All contractors sufficiently addressed and corrected issues that were identified.

Customer Satisfaction

Idaho Power conducted a customer satisfaction survey evaluating past experience with the service. A total of 243 Energy House Calls program participants completed the survey. The majority of these customers indicated both an improved comfort level in their home as a result of participating in the program and a high level of satisfaction with the program. Over 90% of the respondents indicated they would recommend the program to friends or family. Additionally, all 57 Energy House Calls customers who participated in the quality assurance check on 5% of the homes serviced reported having a positive experience with the Energy House Calls program.

2009 Strategies

Plans for the upcoming year include continuing the direct mail campaign to all areas to improve limited participation in some areas. Because of turnover in manufactured homes, some of the customers are not being reached. Idaho Power plans to update its database to enable targeting new customers who were not contacted previously. To determine other possible avenues of recruitment and adjustments to direct mail campaign, Idaho Power is conducting a survey of non-participants, defined as those who have received direct mail letters but have elected to not participate.

ENERGY STAR® Homes Northwest

	2008	2007
Participation and Savings		
Participants (homes)	254	303
Energy Savings (kWh)	468,958	629,634
Demand Reduction (MW)	1	1
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$294,579	$451,775
Oregon Energy Efficiency Rider	$6,388	$12,249
Idaho Power Funds	$1,094	$11,020
Total Program Costs—All Sources	$302,061	$475,044
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.048	$0.056
Total Resource Levelized Cost ($/kWh)	$0.059	$0.067
Program Life Benefit/Cost Ratios		
Utility Benefit/cost Ratio	1.76	
Total Resource Benefit/Cost Ratio	1.43	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2003	

Description

ENERGY STAR Homes Northwest is a regionally coordinated initiative supported by a partnership of Idaho Power, NEEA, and the State of Idaho Office of Energy Resources (OER) to improve energy efficient construction practices for new, single-family homes. Although this program results in summer peak reduction, the program specifically targets the reduction in energy usage accomplished by increasing the efficiency of residential building envelope and air delivery system.

The ENERGY STAR Homes Northwest residential construction program builds homes that are at least 20% more energy efficient than those built to standard Idaho code. The program specifications for ENERGY STAR Homes are verified by independent third-party home performance specialists and are certified by the Idaho OER and the United States Environmental Protection Agency. The homes are more efficient, comfortable, and durable than standard homes constructed according to local building codes.

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

Builders involved in ENERGY STAR Homes Northwest receive up to a $400 incentive per home built to the Northwest Builder Option Package standards in Idaho Power’s service area. Builders who enter their homes in a Parade of Homes receive a $1,000 incentive.

The Idaho Power program collaborates with many local entities for program management, such as ENERGY STAR Homes Northwest and builders. A large part of the program's role in 2008 was conducting education and training activities for residential, new construction industry partners.

The 2006 International Energy Conservation Code (IECC), which the State of Idaho adopted as its standard building code, took effect January 1, 2008. This new code meets ENERGY STAR Homes Northwest program standards in several key areas, which decreases the energy savings of each ENERGY STAR Home. As a direct result of the change in Idaho code and the resulting reduction of energy savings, Idaho Power reduced the participating builder incentive to $400 per qualifying home in 2008, down from the $750 incentive previously offered. Incentives for Parade of Homes entries remain unchanged.

2008 Activities

Although new housing starts were down throughout the Idaho Power service area, the ENERGY STAR Homes Northwest program achieved a market share of 6.2% of new housing starts through 2008. This is up from 2007 market share of 5%.

Idaho Power conducted numerous ENERGY STAR promotional activities during 2008. Idaho Power sponsored the energy efficiency awards for the Building Contractor's Association of Southwest Idaho (BCASWI) and the Snake River Valley Building Contractor's Association (SRVBCA) Parade of Homes. Idaho Power presented energy efficiency awards at both the BCASWI Parade of Homes awards banquet and the SRVBCA Parade of Home awards banquet. Idaho Power maintained a presence in the building industry by participating in and supporting the SRVBCA Builder's Expo, the Magic Valley Builder's Association Builders Expo, the Idaho Building Efficiency Conference, the Home Depot Contractor's show, and the Idaho Building Contractors Association Convention.

Media campaigns heightened awareness of the ENERGY STAR Homes program. Using radio and billboard advertising, Idaho Power conducted a cooperative media campaign in conjunction with ENERGY STAR Homes Northwest and the Environmental Protection Agency. Idaho Power also co-sponsored, and participated in, activities such as the Cedar Crossing 100% ENERGY STAR community kick-off event in Caldwell. Cedar Crossing is Caldwell's first 100% ENERGY STAR community.

Training is a major function of Idaho Power's ENERGY STAR Homes program. To that end, numerous realtor trainings were conducted in Caldwell, Nampa, and Boise. A builder training was held in Pocatello.

Other marketing projects involved adding a message about this program to residential customers' electric bill. These bill messages encouraged Idaho Power customers to visit ENERGY STAR qualified homes in their local Parade of Homes events. An ENERGY STAR Homes program bill stuffer sent information to all residential customers in the Idaho Power service area. Additionally, Idaho Power continued to support the activities of the Idaho ENERGY STAR Builder's Partnership (IESBP) 100% Builders group. Idaho Power was instrumental in the formation of this group in 2007. Currently Idaho Power assists the group with marketing activities by funding and offering marketing services.

2009 Strategies

A key promotional strategy is participation in industry conferences and home shows. During 2009, Idaho Power will continue providing realtor trainings; supporting Parade of Homes events, the Building Contractors Association (BCA), and realtor associations; improving marketing material distributions; and supporting the IESBP group and its activities.

Marketing plans include using print advertising to assist existing builders with moving unsold ENERGY STAR qualified homes inventory. The Idaho Power program staff will explore new and innovative ways to educate consumers, realtors, and appraisers about the benefits and features of ENERGY STAR Homes.

Heating & Cooling Efficiency Program

	2008	2007
Participation and Savings		
Participants (homes)	359	4
Energy Savings (kWh)	561,440	1,595
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$466,094	$482,051
Oregon Energy Efficiency Rider	$6,959	$3,289
Idaho Power Funds	$498	$2,871
Total Program Costs—All Sources	$473,551	$488,211
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.073	n/a
Total Resource Levelized Cost ($/kWh)	$0.092	n/a
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	0.53	
Total Resource Benefit/Cost Ratio	0.28	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2007	

Description

The residential Heating & Cooling Efficiency (H&CE) Program provides incentives for the purchase and proper installation of qualified high-efficiency heating and cooling equipment and services to Idaho Power residential customers. This program has been available to Idaho customers since September 2007 and to Oregon customers since August 2008.

Objectives of the H&CE program are acquiring kWh savings through the implementation of energy-saving HVAC measures in the existing and new residential sector. Cash incentives are provided to residential customers and HVAC contractors who install eligible central air conditioners (CAC), heat pumps, and evaporative coolers. Incentives are also awarded for qualifying heat pump tune-ups and CAC tune-ups meeting Idaho Power's program specifications. A participating HVAC company must perform all services, except for installation on evaporative coolers. Evaporative coolers are self-installed pieces of equipment. There is no need for a contractor to be involved and no specific installation requirements as there are for CACs and heat pumps.

In keeping with quality installation principles, the H&CE Program requires contractors to become "participating" companies. To do this, contractors in the program must sign an agreement with Idaho Power. The participating companies must ensure their service technicians and installers attend required training on the proper installation of air conditioners and heat pumps. These companies must purchase and use TrueFlow® Meters to measure air flow and adhere to program specifications.

2008 Activities

New in 2008 was the addition of the open-loop water source heat pump measure. Idaho Power expanded the program into Oregon upon approval, in August 2008, of Schedule 72 by the OPUC. In 2008, the H&CE Program processed 359 incentive applications and paid $72,900 in incentives, resulting in a total energy savings of 561,440 kWh. During 2008, Idaho Power conducted 22 contractor training sessions on the proper sizing and installation of heat pumps and air conditioners, simplified duct design, and program refresher classes, reaching 201 attendees.

Marketing tactics began in March, using bill inserts, radio ads, newspaper articles, home and garden shows, and exhibitor booths at various community events.

Customer Satisfaction

Idaho Power conducted a customer satisfaction survey during 2008. The majority of respondents heard about the H&CE Program from their heating and cooling contractor. Almost 75% of respondents indicated their heating and cooling contractor was “very knowledgeable” about the program. Eight out of ten respondents said they “definitely would recommend” the contractor they used to a friend or relative. Almost 80% of the respondents said participation in the program was “very easy.” The majority of respondents pursued additional program information from the H&CE Program equipment page on Idaho Power’s Web site. Of those who did go to the Web site, most said it was “easy to use” and the information they gained from the Web site was “useful.” Most of the respondents said they were “very satisfied” with the program and would recommend it to a friend or family member. When asked what it was they liked best about the program, most responded that it was the incentive or the energy savings that they liked best.

During 2008, an H&CE Program contractor survey was conducted. Eighteen contractors responded to the survey. Responses reflected contractors from all regions of Idaho Power’s operations. The majority of the respondents said they heard about the program through a “notification letter from Idaho Power” At the time of the survey, in September, most contractors had submitted somewhere between one and five incentive applications, but there were three contractors who had submitted more than 20 applications. Two contractors indicated they had not submitted any incentive applications, and one of those said it was because he/she was too busy. Most of the contractors indicated they have a good understanding of the technical requirements of the programs and had opportunities for training in the program. The majority of the respondents indicated they had promoted the H&CE Program by encouraging customers to participate. Satisfaction with the program was varied with one-third of the contractor respondents being satisfied, one-third being neutral, and one-third being dissatisfied. Results for willingness to recommend the program were similar to satisfaction ratings. Most of the contractors’ dissatisfaction with the program was centered around the paperwork and program design. In response, Idaho Power modified the paperwork to reduce the duplication of information, and also consolidated forms. Several of the contractors requested removing airflow and sizing requirements. Idaho Power considers the quality installation requirements of this program essential to maintaining the program’s integrity. In 2009, Idaho Power will continue to require quality installation of qualifying heats pumps and increase the contractor incentives.

2009 Strategies

The first-year cost-effectiveness review identified measures that were not cost-effective. Plans for the upcoming year include removing air conditioner and tune-up incentives, effective second quarter 2009. The program enhanced its criteria for contractors to remain on the participating Idaho Power list.

Contractor training and marketing the program through bill stuffers and community events will continue throughout 2009. Idaho Power is investigating cross-promoting the evaporative coolers with the Home Products Program and determining the feasibility of adding duct sealing as a measure.

Idaho Power joined the Northwest Ductless Heat Pump Project and will implement the Idaho Power pilot in its service area beginning March 2009. The goals of this pilot are to promote the ductless heat pump technology as an energy-saving alternative for customers with electrically heated homes, to determine how much electricity this technology saves in order to validate a deemed-savings number, and to obtain customer satisfaction and behavior patterns regarding the technology. Idaho Power will offer customers incentives for participating in the pilot. Pilot results will be available in 2011.

Home Products Program

	2008	2007
Participation and Savings		
Participants (appliances)	3,034	n/a
Energy Savings (kWh)	541,615	n/a
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$245,219	$8,746
Oregon Energy Efficiency Rider	$5,541	$460
Idaho Power Funds	$100	$69
Total Program Costs—All Sources	$250,860	$9,275
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.044	n/a
Total Resource Levelized Cost ($/kWh)	$0.082	n/a
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	1.42	
Total Resource Benefit/Cost Ratio	0.77	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2008	

Description

The Home Products Program, formerly the ENERGY STAR® Appliance Program, provides an incentive payment to Idaho Power residential customers for purchasing ENERGY STAR qualified appliances, lighting, or other products. ENERGY STAR is a government-backed program designating products as energy efficient. Appliances and products with ENERGY STAR must meet higher, stricter efficiency criteria than federal standards. Washers must have a Modified Energy Factor of 1.72 or greater and a Water Factor of 8.0 or lower, the minimum qualifications for an ENERGY STAR qualified clothes washer. To qualify, the washer must have been purchased after April 1, 2008 for customers in Idaho and after May 21, 2008 for customers in Oregon.

The ENERGY STAR Appliance Program rolled out on April 1, 2008 for Idaho Power Idaho customers and on May 21, 2008 for Idaho Power Oregon customers. With the addition of ENERGY STAR qualified refrigerators, ceiling fans with light kits, light kits, and light fixtures, the ENERGY STAR Appliance Program was renamed and launched on August 1, 2008.

Initially, the clothes washer incentive was the only product offered under the original program. Current offerings and related incentives include clothes washers ($50), refrigerators ($30), light fixtures (up to $15 per fixture), ceiling fans with light kits, or ceiling fan light kit attachments (up to $20 per fixture). Only products purchased after August 1, 2008 are eligible. Program participation is a simple process for customers. The customer completes the brief incentive application, submits it with a copy of the sales receipt, and then receives an incentive check in the mail if the purchase qualifies.

2008 Activities

Marketing of the Home Product Program to customers occurs primarily through retail outlets. Idaho Power provides information to store managers and employees through training sessions at store staff meetings and through periodic visits by Idaho Power representatives. Collateral materials, such as program brochures with application tear-off forms, were developed and distributed to nearly 100 retail stores. In addition, program modifications are delivered via letters sent directly to store managers.

Retail salespeople also assisted in promoting the program to their customers. Information gathered from a series of marketing questions on the incentive application form indicated salespeople are a proven, effective avenue for marketing the program. One question pertains to how the customer learned about the program. The most common answer was the salesperson.

Idaho Power promotes the program directly to residential customers via bill stuffers, community promotions, Idaho Power field staff, and other outreach activities. During summer 2008, bill stuffers detailing the program were mailed to all Idaho Power residential customers.

The Home Products Program exceeded the goals for 2008. Idaho Power paid the first Home Products Program incentive in May 2008, and paid 3,034 incentives during 2008, resulting in 541,615 kWh of savings. Incentives were issued for 2,451 clothes washers, 480 refrigerators, 98 light fixtures, three ceiling fans, and two light kits.

2009 Strategies

Based on the current success, the marketing strategy for 2009 will remain similar with only minimal adjustments and updates as needed. The current strategy enhances Idaho Power's ability to meet the 2009 program goals. The Home Products Program will cross-promote with other Idaho Power programs, evaluate success, and develop promotional materials. Idaho Power will continue to evaluate potential products for addition to the program during 2009 and beyond.

Home Weatherization Pilot

	2008	2007
Participation and Savings		
Participants (homes)	16	n/a
Energy Savings (kWh)	71,680	n/a
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$51,670	n/a
Oregon Energy Efficiency Rider	$0	n/a
Idaho Power Funds	$1,138	n/a
Total Program Costs—All Sources	$52,807	n/a
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.055	n/a
Total Resource Levelized Cost ($/kWh)	$0.050	n/a
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	1.31	
Total Resource Benefit/Cost Ratio	1.43	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2008	

Description

Idaho Power introduced a new weatherization pilot in the Twin Falls area. This program is modeled after the Weatherization Assistance for Qualified Customers (WAQC) program. The pilot targeted customers who applied, but were deemed financially ineligible, for participation in Low Income Home Energy Assistance Programs (LIHEAP), and who are not likely to participate in other programs. The difference between the existing WAQC program and the pilot are the pilot's higher income eligibility criteria of 151% to 250% of the state poverty level, and federal government dollars are not used in the pilot. In all other aspects, the pilot resembled WAQC.

Idaho Power contracted with Home Energy Management, LLC, with a goal of weatherizing 20 homes in 2008 at no cost for the customer. After the weatherization measures were installed, Idaho Power completed the verification and analysis process, comparing the current Savings Investment Ratio (SIR) with Idaho Power cost-effectiveness model.

2008 Activities

The pilot was launched during the last quarter of 2008 in the Twin Falls area. Home Energy Management, LLC, weatherized 16 electrically heated homes of eligible Idaho Power customers. Energy savings achieved was 71,680 kWh/year with an average home saving 4,480 kWh/year. Total costs were $52,807 with an average job cost of $3,300.

2009 Strategies

Based on the pilot results, Idaho Power plans to expand the pilot into a program offered in the Twin Falls area in 2009. Home Energy Management, LLC, will weatherize 45 homes in Idaho Power's southern region service area under the newly named program, Weatherization Solutions for Eligible Customers Program. Eligible customers will include Idaho Power customers that heat their homes electrically and earn an income between 161% and 250% of the federal poverty level. Customers who are either purchasing or renting their homes may be eligible.

Identification of potential participants is done through the Community Action Partnership Association of Idaho (CAPAI), who serves as administrator for LIHEAP for the Idaho Department of Health and Welfare. Customers deemed financially ineligible for federal LIHEAP assistance are sent denial letters by CAPAI. For the 2009 program, eligible candidates with electrically heated homes are selected from the list of denial letter recipients within the Twin Falls service area.

Idaho Power plans to save an average of 6,000 kWh per weatherized home per year, for a total energy savings of 270,000 kWh annually. The Idaho Power program and field staff plans to complete an evaluation of measures installed in weatherized homes in 2009 and the participants' knowledge gained regarding energy efficiency.

Oregon Residential Weatherization

	2008	2007
Participation and Savings		
Participants (homes)	3	1
Energy Savings (kWh)	22,196	9,971
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$0	$0
Oregon Energy Efficiency Rider	$1,908	$0
Idaho Power Funds	$5,509	$3,781
Total Program Costs—All Sources	$7,417	$3,781
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.025	$0.028
Total Resource Levelized Cost ($/kWh)	$0.096	$0.042
Program Life Benefit/Costs Ratios		
Utility Benefit/Cost Ratio	n/a	
Total Resource Benefit/Cost Ratio	n/a	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	1980	

Description

Idaho Power offers free energy audits for electrically heated homes of customers within the Oregon service area. This is a statutory program offered under Oregon Rate Schedule No. 78. Upon a customer's request, an Idaho Power representative visits the home to analyze it for energy efficiency. An estimate of costs and savings for specific measures is given to the customer. Idaho Power offers financial assistance for a portion of the costs for weatherization measures, either as a cash incentive or with a 6.5% interest loan.

2008 Activities

During the month of July, Idaho Power sent every Oregon residential customer an informational brochure about energy audits and home weatherization financing. A total of 37 Oregon customers responded. Each of the 37 customers returned a card from the brochure indicating they were interested in a home energy audit, weatherization loan, or incentive payment. Twenty-three audits and responses to customer inquiries to the program were completed.

Idaho Power issued three rebates totaling $1,908.22 for 22,196 kWh savings. The rebates and related savings were for ceiling insulation, window replacement, and a wall insulation project. There were no loans made through this program during 2008. Five customer responses were directed to Cascade Natural Gas.

2009 Strategies

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

Rebate Advantage

	2008	2007
Participation and Savings		
Participants (homes)	107	123
Energy Savings (kWh)	463,401	554,018
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$79,547	$58,854
Oregon Energy Efficiency Rider	$11,341	$4,609
Idaho Power Funds	$0	$733
Total Program Costs—All Sources	$90,888	$89,269
Program Levelized Costs Ratios		
Utility Levelized Cost ($/kWh)	$0.012	$0.010
Total Resource Levelized Cost ($/kWh)	$0.025	$0.021
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	7.19	
Total Resource Benefit/Cost Ratio	2.80	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2003	

Description

Idaho Power customers who purchase a new all-electric, ENERGY STAR® qualified manufactured home and site it in Idaho Power's service area are eligible for a $500 rebate through the Rebate Advantage program. Salespersons receive a $100 incentive for each qualified home that they sell.

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. Quality control and energy efficiency specifications for qualified homes are established by the Northwest Energy Efficient Manufactured Housing (NEEM) program. NEEM is a consortium of manufacturers and state energy offices in the Northwest. In addition to specifications and quality, NEEM tracks the production and on-site performance of ENERGY STAR qualified manufactured homes.

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

2008 Activities

During 2008, Idaho Power paid 107 incentives on new manufactured homes. The customer target for 2008 on the number of homes purchased was 150 homes. The slow economy had a dramatic effect on all types of housing and contributed to the lower number of incentives. New Rebate Advantage marketing materials were developed during the year, including a program brochure and new display posters for placement at dealership sales offices and in ENERGY STAR qualified model homes. Idaho Power customer representatives (CR) visited each of the approximately 19 dealerships at least three times during 2008, answering questions and distributing materials.

Customer Satisfaction

Idaho Power conducted two different surveys in 2008 for the Rebate Advantage program. The first survey covered manufactured home dealers who participated in the Rebate Advantage program. Seventeen dealer program participants completed the survey. Results indicated strong awareness and understanding of the Rebate Advantage program. One hundred percent of the respondents indicated they "always use" or "occasionally use" the program materials provided by Idaho Power. Almost 94% of the respondents "strongly agreed" and "somewhat agreed" the materials were useful in promoting ENERGY STAR qualified manufactured homes.

The second Rebate Advantage program survey conducted was with customers who purchased an ENERGY STAR qualified manufactured home and received an incentive from Idaho Power. Ninety-four program participants responded to this survey, with almost 87% using their new home as a primary residence. Close to 68% of the respondents reported they were "very knowledgeable" or "somewhat knowledgeable" about ENERGY STAR qualified homes before entering the dealership, and almost 95% of the respondents were "very knowledgeable" or "somewhat knowledgeable" about ENERGY STAR qualified homes after leaving the dealership.

2009 Strategies

Idaho Power plans to continue the Rebate Advantage program in 2009, explore new marketing methods, and promote the program. CRs will enhance relationships with dealerships by visiting each dealership quarterly, offering program support, answering questions, and distributing materials. The involvement of local Idaho Power personnel interacting with the local dealers reemphasizes the importance of promoting the benefits of ENERGY STAR qualified homes and products.

Weatherization Assistance for Qualified Customers

	2008	2007
Participation and Savings		
Participants (homes/non-profits)	452	408
Energy Savings (KWh)	4,138,142	3,338,126
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	$1,419,475	$1,323,624
Total Program Costs—All Sources	$1,419,475	$1,323,624
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.026	$0.030
Total Resource Levelized Cost ($/kWh)	$0.033	$0.040
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	2.17	
Total Resource Benefit/Cost Ratio	1.50	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	1989	

Description

The WAQC program provides funding for the installation of cost-effective weatherization measures in qualified owner-occupied and rental homes that are electrically heated. Enhancements enable 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 home.

WAQC is modeled after the United States Department of Energy (DOE) Weatherization Program. The DOE program is managed through Health and Human Services offices in Idaho and by the Oregon Housing and Community Services in Oregon. Idaho Power, in conjunction with Community Action Partnership (CAP) agencies in the Idaho Power service area, serves as the administrator of WAQC. Federal funds are allocated to the Idaho Department of Health and Welfare and Oregon Housing and Community Services, then to CAP agencies based upon United States Census data of qualifying household income within each CAP agency's geographic area. The CAP agencies oversee local weatherization crews and contractors providing implementations that improve energy efficiency of the homes. WAQC allows these state agencies to leverage their federal weatherization dollars and serve more residents by attaining nonfederal supplemental funding and other resources to supplement federal LIHEAP and weatherization funds.

2008 Activities

During 2008, Idaho CAP agencies weatherized 434 electrically heated homes in Idaho and 13 in Oregon, totaling 452 weatherized homes. Annual energy savings were 4,064 MWh for Idaho and

74 MWh for Oregon. WAQC funded the weatherization of five buildings housing nonprofit organizations that serve special needs populations in their Idaho communities. The annual energy savings from the nonprofit weatherization was 130 MWh.

Customer Satisfaction

Surveys are sent to program participants after completion of the weatherization process in order to measure satisfaction, education efforts, and behavior changes. Idaho Power mailed a WAQC participant survey during June and December 2008 to customers who received WAQC services in the previous six months. Twenty-nine percent, or 104 of 360, of all customers surveyed responded to the survey about WAQC. Of those customers who responded, nearly 87% said they learned "some" or "a lot" about saving electricity in their home. Additionally, 101 of those same customers, or over 97%, said that they had tried "some" or "a lot" of ways to save energy in their homes.

Additionally, Idaho Power program specialists participated in the Idaho state peer review process, which involved peer agency weatherization crews within the state reviewing homes weatherized by each of the agencies. Results show all CAP agency weatherization departments are weatherizing in accordance to federal guidelines.

2009 Strategies

Idaho Power is involved with the Policy Advisory Council, which serves as an oversight committee for weatherization activities in Idaho. Through this forum, Idaho Power participates in the weatherization policy for the State of Idaho.

The customer satisfaction weatherization survey used during 2008 will be used again in 2009. Additionally, in response to a request from regional CAP agencies, Idaho Power employees plan to participate in National Weatherization Day on October 30.

COMMERCIAL/INDUSTRIAL SECTOR OVERVIEW

Description

The commercial and industrial sector consists of over 64,000 customers. During 2008, new commercial customers increased by 1,360, for an increase of about 2% over 2007. Individual customer energy usage within this segment varies from a few kWh each month to several hundred thousand kWh each month. The commercial segment of this sector represents approximately 27% of total electricity usage, while the industrial segment of this sector represents about 30% of Idaho Power's total electricity usage. Industrial customers and special contract customers in this sector are Idaho Power's largest individual energy consumers. This group consists of approximately 122 customers.

Programs

Table 6. 2008 Commercial/Industrial Program Summary

			Total Costs		Savings	
	Participants		Utility	Resource	Annual Energy	Summer Peak Demand
Program	*(Number)*	*(Units)*	*(Dollars)*	*(Dollars)*	*(kWh)*	*MW*
Energy Efficiency						
Building Efficiency	60	projects	$1,055,009	$1,671,375	6,598,123	1
Easy Upgrades	685	projects	$2,992,261	$10,096,627	25,928,391	4
Holiday Lighting Program	14	businesses	$28,782	$73,108	259,092	
Oregon Commercial Audit	0	audits	$58	$58		
Custom Efficiency	100	projects	$4,045,671	$16,312,379	41,058,639	5
Total			**$8,121,779**	**$28,153,548**	**73,844,245**	**10**

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

Three major programs targeting different energy efficiency market segments are offered to commercial/industrial customers in Idaho Power's Idaho and Oregon service areas. Easy Upgrades offers a menu of typical commercial retrofit measures with prescriptive incentive amounts for lighting, HVAC, motors, building shell, plug loads, and grocery refrigeration. The Building Efficiency program for new construction projects achieves energy savings that are cost-effective at the time of construction, enabling Idaho Power customers to apply energy efficient design features and technologies that would otherwise be lost opportunities for savings to their projects. This program encourages incorporation of qualified energy-saving improvements for lighting, cooling, building shell, and energy control options. Participants in the Building Efficiency and Easy Upgrades programs can receive incentives for any projects completed up to $100,000 per site per year. The Custom Efficiency program offers financial incentives for large commercial and industrial energy users undertaking custom projects to improve the efficiency of their electrical systems or processes. Idaho Power continues to offer the Oregon Commercial Audits program to medium and small commercial customers.

In 2009, Idaho Power plans to launch a commercial demand response program. Idaho Power has contracted with a third-party aggregator to reduce peak demand at critical times. The aggregator contracts directly with Idaho Power commercial and industrial customers to achieve the demand reduction.

In 2008, Idaho Power contracted with the Integrated Design Lab (IDL) in Boise to accomplish specific tasks to be completed in 2009. IDL will create an Energy Use Index database from Idaho Power customers and analyze the quality of commissioning services in the Treasure Valley. IDL will provide educational sessions for the local design community and organize a building simulation users group to help promote and enhance the local simulation skills. Other IDL tasks are to conduct a post-occupancy survey to study customer satisfaction with technology incentives through the commercial energy efficiency programs and to evaluate and report on the current market conditions for system sizing of package rooftop HVAC units. Lastly, IDL will identify and summarize key energy efficiency resources, events, news items, and technologies useful to Idaho Power for evaluating current incentives and future incentive opportunities for the commercial and industrial sector customers.

Building Efficiency

	2008	2007
Participation and Savings		
Participants (projects)	60	22
Energy Savings (kWh)	6,598,123	2,817,248
Demand Reduction (MW)	1	<1
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$1,006,025	$661,485
Oregon Energy Efficiency Rider	$47,550	$5,766
Idaho Power Funds	$1,434	$1,781
Total Program Costs—All Sources	$1,055,009	$669,032
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.017	$0.026
Total Resource Levelized Cost ($/kWh)	$0.028	$0.032
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	2.14	
Total Resource Benefit/Cost Ratio	1.55	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2004	

Description

The Building Efficiency program enables customers in Idaho Power's service area in Idaho and Oregon to apply energy efficient design features and technologies that would otherwise be lost opportunities for savings to their projects. The Building Efficiency program offers a menu of measures and incentives for lighting, cooling, building shell, and control-efficiency options. Program incentives also include funding for custom projects, as well as additional incentives for commissioning that ensures the systems perform as designed.

The Building Efficiency program is offered to commercial and industrial customers involved in the construction of new buildings or construction projects with significant additions, remodels, or expansions. The program offers incentives up to $100,000. Commercial and industrial customers taking service under, or who will take service under, Schedule 7 (Small General Service), Schedule 9 (Large General Service), Schedule 19 (Large Power Service), or special contract customers are eligible to participate.

Program marketing is targeted at architects, engineers, and other local design professionals. Monthly e-mail program updates are sent to building developers, design professionals, contractors, building owners, Idaho Power field personnel, and other interested parties.

Through the Building Efficiency program, Idaho Power is a primary sponsor of the Boise Integrated Design Lab (IDL), which provides technical assistance and training seminars to local architects and

designers. Much of this activity is coordinated and supported through NEEA's BetterBricks® program. The Building Efficiency program sponsors the annual BetterBricks awards held in October in Boise.

2008 Activities

In 2008, Idaho Power made minor modifications to accommodate Idaho's adoption of the 2006 IECC, effective January 1, 2008. Eligibility requirements for three of the 14 measures changed in 2008. The Building Efficiency program completed 60 new construction, major renovations, and major additions projects in 2008, resulting in 6,598,123 kWh in energy savings. Idaho Power paid $846,931 in incentives for completed projects in 2008.

The IDL began a measurement and verification study on four of the 14 measures offered under the Building Efficiency program. Through the contract with IDL, additional measurement and verification activities for the program are expected to continue through 2009. The results of the first four measures evaluated will be available in 2009.

2009 Strategies

Two incentive measures used through 2008 have been altered for 2009. Idaho Power made minor modifications to the menu of 14 measures, effective January 1, 2009. One under-used measure, premium windows, was replaced with a more popular option, exterior window shading. On another measure, demand-control ventilation, the incentive level was adjusted down. The incentive payment is now based on the outside airflow, not the unit-rated airflow, resulting in a lesser incentive amount.

Measurement and verification of selected measures offered through the Building Efficiency program will continue through the IDL. IDL will install monitoring equipment on selected Building Efficiency participant facilities and report the results in 2009. Idaho Power has designed a survey to measure participant satisfaction in the Building Efficiency program. The program plans to implement this survey in 2009.

Custom Efficiency

	2008	2007
Participation and Savings		
Participants (projects)	101	49
Energy Savings (kWh)	41,058,639	29,789,304
Demand Reduction (MW)	5	4
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$3,948,617	$3,032,047
Oregon Energy Efficiency Rider	$86,858	$110,634
Idaho Power Funds	$10,196	$19,185
Total Program Costs—All Sources	$4,045,671	$3,161,866
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.011	$0.012
Total Resource Levelized Cost ($/kWh)	$0.043	$0.026
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	4.83	
Total Resource Benefit/Cost Ratio	1.55	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2003	

Description

The Custom Efficiency program targets energy savings through the implementation of customized energy efficiency projects at customers' sites. The program is an opportunity for large- and mid-sized commercial and industrial customers in Idaho and Oregon to lower their electrical bills and receive a financial incentive by completing energy efficient projects. Incentives enable companies to do projects that might not be completed otherwise. Program offerings include training and education on energy efficiency, energy auditing services for project identification and evaluation, and financial incentives for project implementation.

Interested customers submit applications to Idaho Power for potential projects that have been identified by a third-party consultant, Idaho Power staff, or by the customer as applicable to their facility. The applications must provide sufficient information to support the energy-savings calculations.

Project implementation begins after Idaho Power reviews and approves an application, followed by the finalization of the terms and conditions of the applicant's and Idaho Power's obligations. When possible, Idaho Power conducts on-site power monitoring and data collection, before and after project implementation. The measurement and verification process ensures achievement of projected energy savings. Verifying applicants' information confirms that demand reduction and energy savings are obtained and 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. Large, complex projects may take as long as two years to complete.

2008 Activities

In 2008, the minimum project size requirement increased from an annual 20,000 kWh to 100,000 kWh. This change is expected to result in customers with smaller projects participating in other Idaho Power energy efficiency programs, allowing greater Idaho Power resources to be focused on larger projects. For smaller projects, or those with less complex retrofits, the Easy Upgrades or Building Efficiency programs may be applicable. If a smaller project cannot be accommodated through other Idaho Power energy efficiency programs, the project may be completed under the Custom Efficiency program, subject to cost-effectiveness analysis. Incentive levels for the Custom Efficiency program remain at 70% of the project cost, or $0.12/kWh, whichever is less.

Key components in facilitating customer implementation of energy efficiency projects are energy auditing, customer training, and education services. The link between energy audits and the completion of projects is historically significant; thus, Idaho Power continued expanding the number of contractors available for customer scoping audits from four companies in 2007 to five companies in 2008. Selection of engineering firms was based on the firm's expertise in all major equipment areas and their ability to provide resources for customers throughout Idaho Power's service area.

The Custom Efficiency program achieved a high service area penetration rate. Through 2008, approximately 50% of the large power service customers had submitted an application for a project. Idaho Power reviewed and approved 135 applications for incentive projects in 2008. A total of 101 projects were completed in 2008 for 59 companies, including four Oregon projects.

Program energy savings increased in 2008 by 37% over the prior year, from 29,789 MWh to 41,059 MWh. Additionally, completed projects increased by 106% and approved incentive applications increased by 55%.

Table 7. Custom Efficiency Annual Energy Savings by Measure

Project Breakdowns	# of projects	kWh saved
Lighting	57	15,300,158
Fan	12	11,399,810
Compressed Air	11	6,612,292
Pump	4	717,068
Refrigeration	6	3,554,444
Other	11	3,474,867
Total	**101**	**41,058,639**

2009 Strategies

Eleven more Oregon projects are scheduled for completion in 2009. In 2009, Idaho Power is expanding the Custom Efficiency program through a number of activities. These activities will include direct marketing of the Custom Efficiency program by Idaho Power field staff to inform the customers of

the Idaho Power energy efficiency programs available and ways the customer can reduce energy costs. Also, Idaho Power will continue to provide site visits and energy audits for project identification, technical training for customers, detailed energy audits for larger, complex projects, and delivery of Industrial Efficiency Alliance (IEA)-sponsored continuous energy improvement practices to customers.

Easy Upgrades

	2008	2007
Participation and Savings		
Participants (projects)	685	104
Energy Savings (kWh)	25,928,391	5,183,640
Demand Reduction (MW)	5	1
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$2,922,340	$680,376
Oregon Energy Efficiency Rider	$52,566	$28,014
Idaho Power Funds	$17,364	$3,105
Total Program Costs—All Sources	$2,992,261	$711,494
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.013	$0.015
Total Resource Levelized Cost ($/kWh)	$0.043	$0.040
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	3.88	
Total Resource Benefit/Cost Ratio	1.21	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2006	

Description

Available in the Idaho and Oregon Idaho Power service areas, the objective of the Easy Upgrades program is to encourage commercial and industrial customers to implement energy efficiency retrofits by offering incentives up to $100,000 per site. Eligible measures cover a variety of energy-saving opportunities in lighting, HVAC, motors, building shell, plug loads, and grocery refrigeration.

Idaho Power commercial or industrial customers on Schedule 7 (Small General Service), Schedule 9 (Large General Service), Schedule 19 (Large Power Service), and special contracts are eligible. Potential participants first assess their energy-saving opportunities by talking with their equipment supplier, contractor, or Idaho Power service representative. For projects with expected incentive payments of more than $1,000, applicants must submit a pre-app prior to initiating the project. In that case, the customer completes the preliminary application (pre-app) form and submits it with relevant worksheet(s), describing the location and planned scope of their project. Upon Idaho Power's review and acceptance, the pre-app allows a customer to collect an incentive for up to 90 days for project completion. For smaller projects with expected incentive payments of less than $1,000, customers may elect to skip the pre-app and just submit their final application for payment. These projects must have been completed no more than six months prior to submitting their application for payment.

2008 Activities

In July, a special lighting incentive promotion was offered under Easy Upgrades. This promotion, limited to Idaho customers, offered higher incentives for many lighting measures. A review of prior

lighting projects' actual operating hours justified the higher promotional incentive levels for the lighting measures. An increased number of lighting project applications occurred after the promotion. In Oregon, an expanded state tax credit pass-through was offered in July for lighting projects. No apparent additional activity was generated from the offer.

The special offer for VendingMiser™ installations, initiated in November 2007, concluded in October 2008, with more than 3,600 units installed. An assessment of the VendingMiser installations was conducted to determine if the units remained in place. After revisiting a sampling of the installations, and correcting problems in some cases, the results showed that over 90% of the VendingMisers were still in place and functioning within the year after installation.

Additionally, the Lighting Savings/Incentive Calculator became available on the Idaho Power Web site in April 2008. The calculator helps customers determine the costs and benefits of their potential lighting projects. Due to the lighting promotion and the online savings/incentive calculator, there was an increase in applications received and projects completed.

Marketing activities included publishing "Success Stories" on the Idaho Power Web site, providing workshops, and sponsoring events. Trade ally workshops continued through the spring and autumn. Idaho Power sponsored events, including the Commercial Real Estate Symposium, an American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) technical conference, the second annual Building Owners and Managers Association (BOMA) Energy Efficiency Workshop, and the annual Idaho Energy and Green Building Conference. Additionally, Idaho Power presented payments at incentive check ceremonies when requested by customers.

Idaho Power continued to sponsor the Lighting Design Lab (LDL) in Seattle through the Easy Upgrades program. The LDL provides technical assistance and periodic local training seminars encouraging energy saving lighting. Additionally, Idaho Power is a sponsor of NEEA's BetterBricks® program, disseminating general energy efficiency information to commercial customers.

Customer Satisfaction

Easy Upgrades conducts a regular follow-up regarding customer satisfaction. As of December 2008, 81% of the program participants surveyed "strongly agree" they received excellent value through Easy Upgrades, while 11% of the respondents "somewhat agree." Additionally, 86% of the survey respondents "strongly agree" that they received excellent service while 87% "strongly agree" their experience when dealing with Idaho Power employees was positive.

2009 Strategies

The fall series workshops focused on stakeholder input regarding program change implementation for 2009. Based on input from stakeholders, plans for the upcoming year include significant program changes. New measures eligible for incentives are being added, while others are being dropped. Idaho Power customers will have 143 eligible measures in 2009, in contrast to the 129 offered in 2008.

Certain incentive levels and a few application requirements are scheduled to change in 2009. Additionally, an electronic application form will go online during the upcoming year. To encourage customers to use the electronic application, an additional incentive is being considered for each

electronic application submitted within a limited period. Details on program changes for 2009 and additional “Success Stories” will be available on the Idaho Power Web site in the spring of 2009.

Generally, major program changes occur approximately every two years. A program evaluation is planned for 2009. Results will be available in early 2010, allowing incorporation of the results of this evaluation into the program planning for 2011.

Holiday Lighting Program

	2008	2007
Participation and Savings		
Participants (projects)	14	n/a
Energy Savings (kWh)	259,092	n/a
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$28,782	n/a
Oregon Energy Efficiency Rider	$0	n/a
Idaho Power Funds	$0	n/a
Total Program Costs—All Sources	$28,782	n/a
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.014	n/a
Total Resource Levelized Cost ($/kWh)	$0.035	n/a
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	2.85	
Total Resource Benefit/Cost Ratio	1.12	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2008	

Description

The overall goal of the Holiday Lighting Program is to encourage customers to purchase more efficient light emitting diode (LED) holiday lights. Although the incentive is available only to commercial customers, the program is useful as a means of introducing all Idaho Power customers to the advantages of LED lighting. In doing this, Idaho Power is rapidly helping make LED lighting the preferred choice when it comes to replacing existing holiday lights. In time, the exposure to commercial LED lighting should filter into the residential market. Along with spreading the message of LED lighting's energy efficiency, Idaho Power also informs customers about the safety benefits of using LED lights.

2008 Activities

For the second year, Idaho Power offered an incentive for commercial customers to replace holiday lighting with higher-efficiency LED lighting. There was over a 700% increase in participation compared to 2007, resulting in greatly increased savings. With its revitalization of the downtown and train depot areas, the largest participant in 2008's program was the City of Caldwell. The city's holiday lighting served as an excellent exposure to LED holiday lighting for a large number of viewers. In Boise, the Idaho Botanical Gardens enlarged their Winter Garden Aglow holiday display, replacing nearly 53,000 incandescent lights with LED lights. Posted at the entrance to the Botanical Garden were signs promoting energy and safety benefits of LED lights. It is estimated that over 29,000 visitors attended the event.

2009 Strategies

Many of the same marketing approaches will be used in 2009 to increase customer participation. These promotional methods include providing materials in advance to chambers of commerce, business and professional organizations, and participating trade allies. Idaho Power plans to coordinate with municipalities and the Idaho Botanical Garden to support their LED-display efforts. A Holiday Lighting bill stuffer will be sent in autumn 2009 to promote the program.

Oregon Commercial Audits

	2008	2007
Participation and Savings		
Participants (audits)	0	8
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	$0	$1,800
Idaho Power Funds	$58	$181
Total Program Costs—All Sources	$58	$1,981
Program Levelized Costs Ratios		
Utility Levelized Cost ($/kWh)	n/a	n/a
Total Resource Levelized Cost ($/kWh)	n/a	n/a
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	n/a	
Total Resource Benefit/Cost Ratio	n/a	
Program Characteristics		
Program Jurisdiction	Oregon	
Program Inception	1983	

Description

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

2008 Activities

The third-party energy auditing contract was renewed in 2008, with EnerTech Services providing services through 2011. Idaho Power sent out its annual mailing to all Oregon commercial customers in December 2008. Customers were notified of the availability of no-cost energy audits and the Idaho Power publication *Saving Energy Dollars*. Three customers requested this publication in 2008. There were no energy audits conducted in 2008. However, ten customers requested an energy audit, which will be completed in 2009.

2009 Strategies

In 2009, as a method for introducing participants to additional energy efficiency resources and practices, the audit process will be maximized by providing Idaho Power incentive information targeting specific areas for improvement found in the audits. Idaho Power will help customers turn their maintenance requirements into energy saving opportunities by providing energy efficiency information to the customers.

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IRRIGATION SECTOR OVERVIEW

Description

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

The maximum number of active customers in 2008 was 17,428. In 2008, irrigation customers accounted for 1,921,608 MWh of energy usage and 772 MW of peak demand. This sector represented about 13% of Idaho Power's total electricity usage and about 23% of peak demand.

Programs

Table 8. 2008 Irrigation Program Summary

			Total Costs		Savings	
	Participants		Utility	Resource	Annual Energy	Summer Peak Demand
Program	*(Number)*	*(Units)*	*(Dollars)*	*(Dollars)*	*(kWh)*	*MW*
Demand Response						
Irrigation Peak Rewards	897	service points	$1,431,840	$189,492	n/a	35
Total			**$1,431,840**	**$189,492**	**n/a**	**35**
Energy Efficiency						
Irrigation Efficiency Rewards	961	projects	$2,103,702	$5,850,778	11,746,395	3
Total			**$2,103,702**	**$5,850,778**	**11,746,395**	**38**

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

Idaho Power currently offers two programs to the irrigation sector, 1) Irrigation Peak Rewards, a demand response program designed to decrease peak demand, and 2) the Irrigation Efficiency Rewards, an energy efficiency program designed to encourage replacement or improvement of inefficient systems and components. Energy usage for this sector has not grown significantly in many years; however, there is substantial yearly variation in demand due primarily to the impact of weather on irrigation needs. There are about 200 new service locations added each year. The new locations are typically smaller systems that are only pressurizing water. New for the Irrigation Peak Rewards program in 2009 is a dispatchable demand response option approved by the IPUC on January 14, 2009.

Irrigation Peak Rewards

	2008	2007
Participation and Savings		
Participants (service points)	897	947
Energy Savings (kWh)	n/a	n/a
Demand Reduction (MW)	35	37
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$1,373,855	$1,520,106
Oregon Energy Efficiency Rider	$17,570	$54,747
Idaho Power Funds	$40,415	$41,028
Total Program Costs—All Sources	$1,431,840	$1,615,881
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	n/a	n/a
Total Resource Levelized Cost ($/kWh)	n/a	n/a
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	1.15	
Total Resource Benefit/Cost Ratio	1.15	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2003	

Description

Available to Idaho Power's Idaho and Oregon customers, the 2008 Irrigation Peak Rewards program was a voluntary program targeted toward agricultural irrigation customers with pumps of 75 horsepower (Hp) or greater. The program objective is reduction of peak electrical load during summer, weekday afternoons. In exchange for a financial incentive, preprogrammed electronic time activated switches turn off the pumps of participating irrigation customers during intervals predetermined by Idaho Power.

Participants select one of three different options for the months of June, July, and August. A monthly demand credit is associated with each of the one-, two-, or three-day options and is paid based on the participating customer's monthly billing demand. Electronic timers are programmed to turn irrigation pumps off during preprogrammed times associated with the selected option. The following three options and associated demand credit incentives were available to customers from 4:00 to 8:00 p.m. on weekdays: 1) one day per week, $2.01 per kW demand, 2) two days per week, $3.36 per kW demand, or 3) three days per week, $4.36 per kW demand. Incentive amounts are credited to the monthly billing demand at each customer's metered service point. Customers with pumps of 75–99 Hp pay a one-time $250 installation fee to help offset the cost of the switches and maintain the program's cost effectiveness.

2008 Activities

Idaho Power provided five workshops promoting the Irrigation Peak Rewards program across the service area. Additionally, a list of each customer's pumps, information for estimating potential incentives on each pump, and a program application was mailed to every eligible irrigation customer.

Other marketing efforts included providing an Idaho Power exhibitor booth at regional agricultural trade shows, such as the Eastern and Western Idaho Agriculture Expos, the United Dairymen of Idaho Expo, the Agri-Action Ag show, the Idaho Farm Bureau convention, and the Idaho Irrigation Equipment Association show and convention. In 2008, several meetings occurred with the Idaho Irrigation Pumpers Association, IPUC staff, and customers regarding proposed changes to the program for 2009, which include a dispatchable demand response option. In December 2008, the Irrigation Peak Rewards Program Report was submitted to the IPUC. The report describes program results, costs, and savings for 2008.

2009 Strategies

A dispatchable demand response option was approved by the IPUC on January 14, 2009, and the OPUC on February 25, 2009. The proposal included modifications to the Irrigation Peak Rewards program for 2009. A shorter program operating time throughout the summer, from June 15 to August 15, was proposed. Idaho Power plans to make the program available to all agricultural customers receiving service under Irrigation Rate Schedule 24 in 2009, potentially leading to greater energy demand and increased customer participation.

The program marketing strategy includes sponsoring 7 to 10 program update workshops across Idaho Power's service area, covering new program offerings and demonstrating the new technology operating the dispatchable demand response option. Simultaneously, customer mailings to all eligible customers will provide a detailed explanation of the program offerings and increase awareness of the significant changes to the program. Additionally, one-on-one training with Idaho Power agriculture representatives will familiarize customers with the new technology and program details. Results of the program will be reported in the 2009 Irrigation Peak Rewards Report.

Irrigation Efficiency Rewards

	2008	2007
Participation and Savings		
Participants (projects)	961	819
Energy Savings (kWh)	11,746,395	12,304,073
Demand Reduction (MW)	3	3
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$1,878,960	$1,881,116
Oregon Energy Efficiency Rider	$193,276	$93,924
Idaho Power Funds	$31,466	$26,922
Total Program Costs—All Sources	$2,103,702	$2,001,961
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.026	$0.024
Total Resource Levelized Cost ($/kWh)	$0.073	$0.103
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	5.49	
Total Resource Benefit/Cost Ratio	1.64	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2003	

Description

The Irrigation Efficiency Rewards program encourages energy efficient equipment and design in irrigation systems. Irrigators in Idaho Power's Idaho and Oregon service area can receive financial incentives and reduce their electric bills. Idaho Power helps qualified irrigators pay for energy efficiency features in their irrigation system and helps them use electricity efficiently. Incentives for the Irrigation Efficiency Rewards program helps the customer recover the costs of installation of a new, more efficient irrigation system and energy efficient improvements to an existing irrigation system.

Two separate reward options help meet the needs for major or minor changes on new or existing systems. The Custom Incentive Option addresses extensive retrofits of existing systems or new irrigation systems, providing component upgrades and large-scale improvements. For new systems, the incentive is $0.25 per kWh saved above standard installation methods, not to exceed 10% of total project cost. For existing system upgrades, the incentive is $0.25 per kWh saved or $450 per kW, whichever is greater, not to exceed 75% of the total project cost. Idaho Power reviews, analyzes, and makes recommendations on each application. On each completed project, before final payment, all project information is re-evaluated. Prior usage history, actual invoices, and, in many situations, post-usage demand data, are used to calculate savings and incentives.

The Menu Incentive Option covers a significant portion of the costs of repairing and replacing specific components that help the irrigation system use less energy. This option is designed for systems in which small maintenance upgrades provide energy savings. Incentives vary based on specific component replacement.

Payments are calculated on predetermined average kWh savings per component. Idaho Power reviews and analyzes each proposal for a system or component modification, determining and verifying the energy savings.

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

2008 Activities

Idaho Power provided five workshops promoting the Irrigation Efficiency Reward program across the service area. The program had an Idaho Power exhibitor booth at regional agricultural trade shows, including the Eastern and Western Idaho Agriculture Expos, the United Dairymen of Idaho Expo, Agri-Action Ag show, the Idaho Farm Bureau convention, and the Idaho Irrigation Equipment Association show and convention.

2009 Strategies

Marketing plans for 2009 include conducting seven to 10 irrigation workshops. These workshops enable discussions between Idaho Power representatives and customers, while continually educating customers about the program and ways to participate.

All agricultural customers in Idaho Power's service area are eligible for the Irrigation Efficiency Reward program. The Irrigation Efficiency Reward program has little room for expansion within the customer class, though additional energy-saving measures may expand as technology becomes available. The market is becoming saturated to some extent, though there is still potential in this large market.

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MARKET TRANSFORMATION

Northwest Energy Efficiency Alliance (NEEA)

NEEA encourages and supports cost-effective market transformation efforts in Idaho, Oregon, Washington, and Montana. Through partnerships with local utilities, NEEA motivates 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.

NEEA Activities

Industrial Efficiency Alliance (IEA) Activities in Idaho

The IEA is a multi-year strategic effort designed to improve energy efficiency in two regional industries considered heavy energy users, 1) the food processing and 2) the pulp and paper industries. Although Idaho Power does not have any pulp and paper customers, because of the large number of food processing customers, Idaho Power considers participation in IEA valuable. The IEA also works with companies that produce equipment and provide services for these industries and with the utilities that serve them.

Participants achieve cost savings through the adoption of energy-efficient business practices. The IEA provides expert support, resources, and services, providing companies with the training and tools for making energy efficiency a core business value. Participants are asked for a commitment to a Continuous Energy Improvement Program, which potentially increases production capacity, improves equipment reliability, and reduces operating costs and energy use by 5% to 20%. This effort is supported by providing technical knowledge for individuals, organizations, and manufacturing companies collaborating on energy efficiency implementation. IEA members include the BPA, regional utilities, the Energy Trust of Oregon (ETO), the Oregon Department of Energy (ODOE), and the Idaho Office of Energy Resources (OER).

Training activity in 2008 increased over 2007 and included eight industrial workshops co-sponsored by the IEA, Idaho Power, and others. Topics focused on pumps, compressed air, motors, and industrial refrigeration. A market progress evaluation of the IEA was completed in May 2008.

Commercial Alliance Activities in Idaho

NEEA continued to provide support for commercial energy efficient activities in Idaho in 2008. NEEA continued funding the Boise Integrated Design Lab (IDL) and local BetterBricks® trainings and workshops. NEEA sponsored Idaho's Fourth Annual BetterBricks Awards, issued in October in conjunction with the Idaho Energy & Green Building Conference. Idaho Power's commercial programs, Building Efficiency and Easy Upgrades, are designed to leverage NEEA, BetterBricks, and Boise IDL activities.

Distribution Efficiency Initiative

In 2008, Idaho Power continued to participate with other northwest utilities in NEEA's Distribution Efficiency Initiative (DEI) project study.

Phase I Projects Completed

NEEA conducted a DEI project study, which included a Load Research project and Pilot Demonstration projects. The Load Research project was designed to establish the relationship between applied voltage and energy, in addition to how applied voltage affects demand for different end-use load types, such as electric heating, electric water heating, and air conditioning. The Pilot Demonstration projects controlled the voltage at the substation in order to determine the performance of different efficiency methods.

Phase I Concluded in 2007

The NEEA study's final report shows that operating a utility distribution system in the lower half of the acceptable voltage range of 120 through 114 volts saves energy (kWh), reduces demand (kW), and reduces reactive power (i.e., kilovolt ampere reactive [kvar]) requirements without negatively impacting the customer. The energy-savings results are within the expected values of 1% to 3% total energy reduction, 2% to 4% reduction in kW demand, and a 4% to 10% reduction in kvar demand. As part of the completion of this project, the 66 Home Voltage Regulators (HVRs) operating in southern Idaho since March 2006 were removed during the summer of 2007. The purpose of the HVR was to adjust service entrance voltage at the residence.

Project for 2007

A new pilot was implemented during the second quarter of 2007 to demonstrate remote end-of-feeder control of the station transformer load-tap changer. The project used wireless communication between the end-of-feeder and the substation to adjust the substation voltage based on the measured end-of-feeder voltage. Application of technology allows better control of the end-of-feeder voltage.

In December 2007, R. W. Beck, Inc., a contractor for NEEA, published the Northwest Energy Efficiency Alliance Distribution Efficiency Initiative Project Final Report. This report and additional information about DEI is available at http://rwbeck.com/neea. The estimated, annual project savings were reported to be 8,563 MWh.

Project for 2008

In 2008, the remote end-of-feeder control of the station transformer load-tap changer project was changed from a pilot project to a permanent installation. In addition, studies began to identify additional locations to implement the techniques identified in the pilot study. The initial phase will include locations that can be converted with minimal or no capital expenditures. Future phases will be those locations that require more extensive resources to implement.

In 2008, DEI Calculators, which are Excel-based tools, were completed and presented to the RTF. These calculators include a manager's tool that provides high-level results and an engineer's tool that allows users to develop multiple scenarios and compare results. These tools were developed to be used primarily by smaller utilities that may or may not have the resources to do the analysis necessary to implement a DEI-based project.

Residential NEEA Activities in Idaho

NEEA continues to provide support for the ENERGY STAR® Homes Northwest program offered by Idaho Power. NEEA offers technical assistance, funding for certifications, and builder and marketing support.

Other NEEA Activities in Idaho

In 2008, Idaho Power participated in two major studies in Idaho Power's service area. The ENERGY STAR Homes Northwest impact evaluation continued throughout 2008 with final results available in 2009. Idaho Power assisted NEEA in developing the sample plan for this study and provided data necessary to assess the program. The impact evaluation required that ENERGY STAR certified homes were audited and had measurement and verification equipment installed.

Idaho Power participated with NEEA to conduct a Commercial Building Stock Assessment (CBSA). The purpose of this study was to update the original CBSA completed in 2003. Idaho Power contracted with the Cadmus Group to over-sample buildings in Idaho Power's service area to gather more detailed information to enhance program planning in the commercial sector. Idaho Power provided data and assisted the contractor in reviewing the commercial-building characteristics in Idaho Power's service area.

Each year, NEEA underwrites the Idaho Energy Conference through a contract with the Association of Idaho Cities. NEEA continues to provide general information support to the region by funding the EnergyIdeas Clearinghouse® and ConWeb®.

NEEA funded a variety of research projects that were reported on in 2008. These reports are valuable to Idaho Power in that they provide information for creating and evaluating Idaho Power's programs. These research projects included Baseline Characteristics of the 2002–2004 Nonresidential Sector of Idaho, Montana, Oregon, and Washington. They also included Market Research Reports for ENERGY STAR Homes Northwest Focus Groups, Residential Ductless Heat Pump Market Research and Analysis, Residential New Construction Billing Analysis, Analysis of Window Energy Savings in Commercial Buildings in the Northwest, ENERGY STAR Consumer Products Lighting Project, 80 PLUS Personal Computer Power Supplies, and seven reports on the BetterBricks initiative in the commercial sector.

NEEA Funding

In 2005, Idaho Power began the first year of the 2005–2009 contract and funding agreement with NEEA. Per this agreement, Idaho Power committed to fund $1.3 million annually in support of NEEA's implementation of market transformation programs in Idaho Power's service area. Of this amount in 2008, 72% was funded through the Idaho and Oregon Riders, and 28% was funded by a credit accumulated during the previous contract period.

In 2008, Idaho Power paid $942,014 to NEEA. The Idaho jurisdictional share of the payments was $894,913.31, while $47,100.69 was paid for the Oregon jurisdiction. Other expenses associated with NEEA activities, such as administration and travel, were paid by Idaho Power.

Preliminary estimates reported by NEEA indicate that Idaho Power's share of regional market transformation MWh savings for 2008 is 32,672 MWh, or 3.7 aMW. Idaho Power relies on NEEA to report the energy savings and other benefits of NEEA's regional portfolio of initiatives. For further information about NEEA, visit their Web site at www.nwalliance.org.

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ENERGY EFFICIENCY ADVISORY GROUP (EEAG)

Formed in May 2002, the EEAG provides input on formulating and implementing energy efficiency and demand-reduction programs funded by the Rider. Currently, the EEAG consists of 12 members from across Idaho Power's service area and the Pacific Northwest. Members represent a cross-section of customers, including individuals from the residential, industrial, commercial, and irrigation sectors, as well as representatives for the elderly, low-income, environmental organizations, state agencies, public utility commissions, and Idaho Power.

In 2008, the EEAG met three times: February 7, May 13, and October 2. During the meetings, Idaho Power requested recommendations on new program proposals, provided a status of the Rider funding and expenses, updated ongoing programs and projects, and supplied information on DSM issues.

EEAG Program Recommendations

The following section provides an overview of topics addressed during the meetings and a review of the input provided to Idaho Power by the EEAG regarding major program implementation and operational issues in 2008. Various operational DSM programs were reviewed by EEAG during the 2008 meetings. Only substantial changes or modifications associated with EEAG input and new programs and pilots are presented in the following.

Residential Programs

Residential programs reviewed in 2008 included the Home Products Program, Heating & Cooling Efficiency Program, ENERGY STAR® Homes Northwest, and A/C Cool Credit. Progress updates were provided on the Holiday Lighting Program, Idaho Green Expo, and Energy Efficient Lighting program. Pilots started in 2008, and new programs for 2009, including the Attic Insulation Pilot and the Home Weatherization Pilot, and the 2009 Refrigerator Recycling Program, were also discussed.

Home Products Program

The Home Products Program targets changing consumer purchases from regular appliances to ENERGY STAR qualified appliances. Initially Idaho Power considered three types of appliances to include in this program. Ultimately, clothes washers were the only appliance that met the cost-effectiveness tests. The Consortium for Energy Efficiency, Inc. (CEE) rates the energy efficiency of home appliances, including residential clothes washers. CEE rates clothes washers as tier 1, tier 2, or tier 3, with tier 3 being the most efficient. However, the CEE tier ratings are not readily apparent to customers. Due to this difficulty of letting the public know about the difference in the tier levels of washers, Idaho Power was considering one incentive amount regardless of the ENERGY STAR qualified washer purchased.

Recommendations

Members discussed reasonable incentive amounts and recommended an incentive of $50 for either Tier I or Tier II clothes washers be offered. Idaho Power was advised to consider joining with water suppliers or wastewater companies to add an educational piece to the incentive.

Action

Effective April 2008, the $50 clothes washer incentive was offered for either tier clothes washers. Washer purchases made after April 2008 qualified for Idaho customers, and washer purchases made after May 21, 2008 qualified for Oregon customers. The ENERGY STAR Appliance program was renamed the Home Products Program in August 2008 and expanded to include ENERGY STAR qualified refrigerators, ceiling fans with light kits, or ceiling fan light kit attachments.

Idaho Power staff met with the Idaho Department of Environmental Quality (DEQ) to discuss how to educate water-system operators regarding Idaho Power energy efficiency programs. Many of the water systems use pump configurations similar to irrigation. There might be opportunities for the users to participate in Idaho Power Commercial energy efficiency programs and receive incentives for upgrading pumps or, for larger systems, performing facility upgrades. Discussions included the possibility of putting information in the state drinking and wastewater newsletters.

Refrigerator Recycling Program

Idaho Power proposed to the EEAG two program management options for conducting the Refrigerator Recycling program. The first option was through an internal program managed and operated completely by Idaho Power, while the second option was through a contract with a third-party for management and operation of the program. Pros and cons of the two options were discussed. Under the Idaho Power-operated program, participating customers would be responsible for removal and disposal of the old refrigerator. Some members felt that might be challenging and prohibitive for customers, especially the elderly. The EEAG group favored the third-party management option, where the third-party contractor handles the removal and disposal of the old unit. The third-party contractor could also conduct the verification of the condition of the old unit. Though an internally managed program was the more cost-effective option, EEAG thought that the third-party management option might attract higher participation levels.

Recommendations

The EEAG recommended that Idaho Power pursue a third-party contractor for program implementation and offer the program in Oregon.

Action

Idaho Power plans to issue a request for proposal (RFP) for a third-party contractor to operate the program. After the RFP is received and reviewed, a potential successful contractor will be selected and a contract negotiated. Program implementation is planned for May 2009. Idaho Power plans to offer a $30 refrigerator incentive to customers recycling working refrigerators.

Attic Insulation Pilot

Idaho Power presented to the EEAG a potential program structure for the Attic Insulation Pilot. Potential energy savings, incentives, data collection, and timelines were discussed.

Recommendations

Data collection suggestions included taking spot measures from the air handler and measuring attic temperatures and compressor run-time for air conditioners. Other suggestions included checking the ductwork prior to insulation.

Action

The Attic Insulation Pilot program was launched. It offered customers a $0.15 per square foot incentive for the professional installation of additional attic insulation. The pilot was conducted in Boise, Twin Falls, and Pocatello. Installations began in May 2008 and were completed by mid-July. Idaho Power collected indoor and outdoor temperatures and compressor runtimes. Also collected was information on the physical characteristics of the participants' homes, including the pre- and post-installed insulation R-values.

Information from the pilot was used to evaluate the cost-effectiveness of the potential program. It was determined that this was a cost-effective program opportunity. As a result of the Attic Insulation Pilot, Idaho Power will proceed in 2009 with the pilot, renamed the Home Improvement Program.

Home Weatherization Pilot

Introduced in 2008 was a new Home Weatherization Pilot concept, which targeted customers who applied for, but were deemed ineligible for participation in, WAQC and who are probably not likely to participate in other programs. Idaho Power collaborated with Home Energy Management, LLC, to complete 20 homes in 2008 in the Twin Falls area. Like the WAQC program, there is no cost to the customer. After the weatherization projects are completed, Idaho Power will complete the verification and analysis process, comparing the current SIR with Idaho Power cost-effectiveness models. The differences between the existing WAQC program and the pilot are the pilot's higher income eligibility criteria and that federal dollars cannot be leveraged in the pilot. The guidelines for the pilot resemble WAQC guidelines in all other aspects. Using the pilot structure allows Idaho Power to proceed and evaluate the results to determine utility costs.

Recommendations

Members expressed support of the pilot.

Action

The pilot was launched during the last quarter of 2008. Energy Management, LLC, weatherized 16 homes for the pilot. Energy savings achieved were 71,680 kWh/year. The average home saved 4,480 kWh/year. Total costs were $52,807. Average individual project cost was $3,300. Based on the pilot, Idaho Power plans to expand in 2009 and weatherize 60 homes in Idaho Power's southern region service area under the newly named Weatherization Solutions for Eligible Customers program.

Commercial and Industrial Programs

At the October EEAG meeting, Idaho Power presented the Commercial Demand Response program and the Small Commercial A/C Cycling Pilot program. Updates were also provided on the Easy Upgrades program changes.

Commercial Demand Response Program

Idaho Power proposed the Commercial Demand Response program where Idaho Power would contract with a third-party demand response aggregator for provision of peak load reduction. The third-party would recruit customers and guarantee Idaho Power a determined amount of peak load reduction at a contracted price.

Recommendations

The third-party contractor selected for the program should tailor their program to Idaho Power's service area commercial customers.

Action

Idaho Power issued an RFP in August for a demand response aggregator. Four proposals were received and reviewed. Idaho Power selected EnerNOC as the contractor. EnerNOC provides demand response services for numerous other utility companies throughout the United States, has established relationships with the many businesses in Idaho Power's service area, and understands the unique characteristics of Idaho Power's customers. Idaho Power and EnerNOC have negotiated a contract to reduce peak demand at critical times. The aggregator will negotiate contracts directly with Idaho Power commercial and industrial customers to achieve the contracted demand reduction. Analysis has shown that this program will be cost-effective. Pending IPUC approval, Idaho Power expects to launch the commercial demand response program in 2009.

Small Commercial A/C Cycling Pilot

Idaho Power introduced a proposed demand response program for small commercial users. Demand reduction would be achieved by controlling customers' use of air conditioners using programmable thermostats. It is similar to the residential A/C Cool Credit program, except it is designed for small commercial customers using less than 2,000 kWh per month. Under this proposed program, there would not be a customer bill credit, as there is in the residential program, and the customer's benefit would be the provided programmable thermostat and installation.

Recommendations

Given the high cost of serving the summer peak hours, it was requested that Idaho Power consider aggressively launching the program and, if possible, incorporate a lighting retrofit along with the programmable thermostat.

Action

The cost-effectiveness analysis of a small commercial A/C Cycling program is under review.
The proposed implementation and administrative costs are higher than initially expected. The potential for cost-effective peak load reduction in the market is uncertain. Idaho Power believes a pilot program to study the energy impacts is needed. Idaho Power is renegotiating with vendors, exploring additional program offerings, and considering including the small commercial program in the current residential A/C Cool Credit program. Through these efforts, Idaho Power is attempting to design a cost-effective program.

Irrigation Programs

The redesigned Irrigation Peak Rewards program was introduced at the October 2, 2008, EEAG meeting. Idaho Power proposed the Irrigation Peak Rewards program include a dispatchable demand response option.

This program would be offered to Idaho Power customers in Idaho and Oregon. Three options would be available for customers to choose between: 1) the currently offered timer option, 2) a dispatchable option that allows Idaho Power to remotely turn participants' pumps on or off, or 2) a large service location option that allows participating customers, after being notified by Idaho Power, to turn large horsepower pumps off during summer peak hours. High savings and benefits are expected from this new program.

Recommendations

Based on the success of the current Irrigation Peak Rewards program and the potential for substantially increased cost-effective peak-demand reduction, the EEAG recommended that Idaho Power expand the program. A dispatchable irrigation demand response option could be implemented for irrigation customers in 2009.

Actions

Expanding on the current Irrigation Peak Rewards program, Idaho Power developed a new program that offers three options for eligible service locations in Idaho and Oregon. The first option will continue with a timer option. The second, new dispatchable option allows Idaho Power to remotely turn on and off participating customers' pumps. Under the third option, for large service locations of 1,000 or greater, participants would manually turn their pumps on and off. The combination of these three options enables Idaho Power to substantially decrease demand during peak load hours.

On January 14, 2009, the IPUC approved the program proposal. In February 2009, Idaho Power began sending mailings to irrigation customers and holding workshops to educate irrigation customers and market the new program offering.

Additional Topics Covered

In the EEAG meetings, Idaho Power presented additional topics, including an overview of the *Demand-Side Management 2007 Annual Report*, the report's structure, and 2007 programs documented in the report. EEAG was updated throughout the year regarding the Rider balance and energy efficiency program performance.

In 2008, as the result of an RFP process, Idaho Power hired a consultant company, Nexant, for a DSM potential study regarding creating or expanding programs. Preliminary findings from this report indicated that, within the residential sector, there was a limited amount of additional energy savings potential beyond what Idaho Power is currently offering.

Recommendations

A peer review of the results of the Nexant report 2008 market potential study was recommended.

Action

A peer review was initiated and results are due in the spring of 2009.

OTHER PROGRAMS AND ACTIVITIES

Residential Energy Efficiency Education Initiative

Idaho Power recognizes the value of general energy efficiency awareness and education in creating behavior change and customer demand for, and satisfaction with, its programs. The Residential Energy Efficiency Education initiative's goal is promoting energy efficiency to the residential community sector. This goal is achieved by creating and delivering educational programs that result in energy-efficient and conservation-oriented behaviors and choices.

Activities

The Residential Energy Efficiency Education initiative distributed energy efficiency messages through a variety of communication methods during 2008. Increased customer awareness of energy-saving ideas was accomplished via distribution of over 8,000 copies of the 96-page book *30 Simple Things You Can Do To Save Energy*, a joint publishing project between Idaho Power and The Earthworks Group. In June, an Energy Efficiency Guide outlining the residential programs and monthly tips was published in area newspapers. Energy Awareness month, held in October, included a jointly sponsored energy efficiency exhibit at the Discovery Center, a newspaper campaign, and the Fall Energy Efficiency & Green Livings Series. Held at the Boise Public Library, this five-class series promoting energy efficiency was initiated in 2007. This year's topics included an open dialogue with energy leaders; simple no- and low-cost ways to save energy; easy ways to re-think, reduce, reuse, and recycle; how to landscape for energy savings; and how to remodel existing homes and build new homes consistent with the Leadership in Energy and Environmental Design (LEED) and Northwest ENERGY STAR® Homes Northwest standards. The five sessions combined attracted 147 participants.

The Residential Energy Efficiency Education initiative collected participant evaluations at the end of each of the five classes focusing on energy efficiency held at the Boise Public Library during 2008. Combined, the five sessions had 147 participants and a survey return rate of 51%. The majority of respondents indicated they "strongly agreed" that the information was useful and met their expectations. The majority of respondents indicated they "definitely would" recommend the class to family and friends.

During the fourth quarter of 2008, Idaho Power provided weekly energy efficiency messages on The HomeFix Show with Joe Prin on 580 KIDO AM. Another media campaign around energy-efficient gift purchases rounded out the year.

In addition to these activities, Idaho Power sponsored the Energy Conservation and Recycling track at the first annual Idaho Green Expo. Specialists from Idaho Power presented three workshops and addressed attendees' questions at the Idaho Power's exhibitor booth. During 2008, Idaho Power developed a new educational program for fourth- to sixth-grade students. "Simple Ways to Save Energy" is a 45–60 minute presentation focusing on energy-efficient actions within each child's ability. Idaho Power further increased its energy efficiency presence in the community by providing program information at events such as Teachers' Night Out, Idaho Smart Growth, and the St. Luke's Women's Show.

Plans for 2009 include expanding the Energy Efficiency & Green Livings Series to other customers outside the Treasure Valley. Adult energy efficiency presentations for corporate and community settings are being developed for use by Idaho Power staff. Energy efficiency displays such as three-dimensional demonstration devices, brochures, and other educational materials will be developed in 2009. Placing stand-alone energy efficiency displays in high-traffic public venues, such as libraries and corporate lobbies, is another method Idaho Power intends to use to reach large numbers of customers with energy efficiency messages.

Commercial Education Initiative

Idaho Power launched its Commercial Education initiative in the spring of 2008. The main objectives of this initiative are to educate commercial customers about energy efficiency, increase participation in existing commercial energy efficiency and demand-reduction programs, enhance customer satisfaction, and reduce energy use. In 2008, Idaho Power identified methods for educating customers about energy efficiency and addressed ways of changing customer practices and behaviors.

The initiative made progress in helping commercial customers, trade allies, field staff, professional organizations, and community organizations indentify common problems or energy efficiency opportunities. Potential solutions and ideas were addressed through networking with energy information sources, such as E Source, Idaho Power staff, trade allies, and customers. For example, many customers have been very successful in reducing their energy usage by utilizing Idaho Power incentive programs. Subsequently, customers have invited Idaho Power field staff and other customers with similar facilities to visit their projects and see, firsthand, successful energy efficiency projects.

In 2009, the initiative will continue its efforts in commercial customer education. Plans are to increase the focus on providing commercial customers with information pertinent to their facilities and operational constraints and to identify resources for achievement of their energy efficiency objectives.

Local Energy Efficiency Funds (LEEF)

The purpose of LEEF, formerly called the Small Projects and Education Fund, is to provide modest funding for short-term projects and activities that do not fit within other categories of energy efficiency programs, but that still provide a defined benefit to furthering DSM targets.

Two projects were paid for from this fund in 2008. In spring 2007, MHAFB applied for funds to remove incandescent lighting from an outdoor running track and replace them with solar lighting. A cost-effective analysis was completed for the project in 2007 and permission was provided by Idaho Power for the AFB to move forward. The actual lighting was installed in the summer of 2008, and LEEF funds paid $13,764 for 114,700 kWh savings per year.

Another completed project in 2008 was in a Marsing home. The owner created a “Living Wall” consisting of hundreds of plants blanketing a wall and floor. The plants serve as an air conditioner, decreasing the air temperature around the “Living Wall” and reducing energy use by up to 20% per month. LEEF funds paid $450 for 1,231 kWh savings per year.

REGULATORY INITIATIVES

Idaho Power is testing the effects of a Fixed Cost Adjustment (FCA) and a Performance-Based DSM Incentive as part of a three-year, two-pilot initiative. The two pilots are being operated on a limited basis to allow for a thorough evaluation to be conducted prior to a broader application of the financial mechanisms. 2007 was the first year of the pilots. Actual performance and usage data from 2007 was evaluated during the spring of 2008, and Idaho Power made the following filings in response to the first-year results.

Fixed-Cost Adjustment Pilot

Under the FCA, rates are annually adjusted up or down to recover or refund the difference between the fixed costs authorized by the IPUC in the most recent rate case and the fixed costs that Idaho Power actually received the previous year through energy sales. This decoupling mechanism removes the financial disincentive that exists when Idaho Power invests in DSM resources. The FCA pilot is limited to the residential and small commercial classes in recognition of the fact that, for these customers, a high percentage of fixed costs are recovered through energy charges. Confining the pilot to the residential and small commercial classes also allows the true-up mechanism to be tested on a limited basis to minimize any unintended consequences. On March 12, 2007, the IPUC authorized a three-year pilot of the FCA under Order No. 30267.

On March 14, 2008, Idaho Power filed an application to implement FCA rates reflecting 2007 actual data. According to the application, during 2007, the average energy use per residential customer increased. Idaho Power collected approximately $3.5 million more for its fixed costs than was established in the agreed-upon residential FCA formula. The application also indicated that the small commercial class saw a decrease in per-customer energy use during 2007. This means Idaho Power under-collected approximately $1.1 million of its fixed costs for this customer class. On May 30, 2008, the IPUC issued Order No. 30556 directing Idaho Power to collect the net fixed cost adjustment of $2.4 million and to distribute the rate adjustment across both residential and small commercial customers. This action resulted in a rate reduction of 0.045676 cents/kWh, effective June 1, 2008, through May 31, 2009, for all residential and small commercial customers. On March 13, 2009, Idaho Power will file an application to implement FCA rates reflecting 2008 actual data.

Performance-Based DSM Incentive Pilot

To complement the FCA pilot, Idaho Power is testing the effects of a Performance-Based DSM Incentive mechanism. On March 12, 2007, the IPUC issued Order No. 30268 authorizing the implementation of a Performance-Based DSM Incentive pilot that allows Idaho Power to retain a portion of the financial benefits resulting from DSM activities when energy savings targets are exceeded. Should it fail to meet energy savings levels previously achieved, Idaho Power is subject to a penalty under the incentive pilot. During the pilot period, the incentive mechanism is being applied only to the ENERGY STAR Homes Northwest Program. By applying this mechanism on a limited basis, Idaho Power is able to gain a better understanding of the effects of a performance incentive while minimizing the potential impact to customers. Idaho Power ultimately intends to use the information gained during the pilot period to develop a performance-based incentive mechanism that can be applied to the entire portfolio of DSM programs.

On March 14, 2008, Idaho Power filed the actual 2007 data in the *Performance-Based Demand-Side Management Incentive Pilot Performance Update*. According to the final ENERGY STAR Homes Northwest program results for 2007, Idaho Power has estimated the program achieved a market share of 5%. This value is within the market share dead-band established for 2007 at 5.0% to 7.0%, and, therefore, Idaho Power is not eligible for a performance incentive nor is Idaho Power subject to a penalty.

ENHANCED COMMITMENT

As part of the FCA implementation process, Idaho Power is committed to enhancing its efforts toward promoting energy efficiency. Idaho Power's overall DSM performance last year is an indication of this commitment. In 2008, the energy savings from Idaho Power's DSM in-house programs increased 54% over 2007 levels while expenditures increased only 35%. In several other key areas, Idaho Power actively pursued numerous, additional opportunities to promote energy efficiency, including, but not limited to:

- Broad availability of efficiency and load management programs
- Building code improvement activity
- Pursuit of appliance code standards
- Continued expansion of DSM programs beyond peak-shaving/load-shifting programs
- Third-party verification
- Promotion of energy efficiency through electricity rate design
- Idaho Power's internal energy efficiency commitment

Through its DSM portfolio, Idaho Power now offers programs in virtually every major market segment in its service area. For residential customers, there are programs for new homes, existing homes, and lower-income buildings. In the commercial and industrial sectors, there are programs in both the new and existing building market segments. In the irrigation sector, Idaho Power offers incentives for existing systems and new irrigation systems. Furthermore, Idaho Power has implemented demand response programs in the residential and irrigation sectors and plans to implement a new demand response program in the commercial and industrial sector in 2009. The specific programs added, modified, or expanded in 2008 include:

- A new Home Weatherization Pilot launched in the Twin Falls area in the fourth quarter of 2008. Based on the pilot results, Idaho Power plans to expand the pilot into a full-scale program, titled Weatherization Solutions for Eligible Customers, offered in the Twin Falls area in 2009.
- A new Attic Insulation Pilot was launched in 2008. This successful pilot will expand to a full-scale program in 2009 under the name Home Improvement.
- A new ENERGY STAR® Appliance Program began in 2008 and will continue into 2009 under the name Home Products Program.
- The A/C Cool Credit program expanded into the new service areas of Payette and Twin Falls. Additionally in 2008, Idaho Power applied this program to the housing at Mountain Home Air Force Base.

- The Easy Upgrades program sponsored a special summer lighting product promotion.

- Easy Upgrades concluded a special offer of VendingMiser™ units that ran from November 2007 through October 2008, with more than 3,600 units installed.

- In 2008, Idaho Power filed with the IPUC to expand the Irrigation Peak Rewards program to provide a dispatchable demand response option.

- The Custom Efficiency program was modified to increase the minimum project size from 20,000 kWh to 100,000 kWh in order to allow resources to be focused on larger projects.

- For Oregon customers, Idaho Power filed three new programs and modified three more. The new programs are A/C Cool Credit, Home Products Program, and Heating & Cooling Efficiency Program. The programs modified are Change a Light Program, Easy Upgrades, and Manufactured Housing Energy Efficiency Program.

Building Code Improvement Activity

Through Idaho Power's funding of the NEEA and codes-related efforts, Idaho Power has assisted in increasing energy efficiency requirements in Idaho's building codes, including the adoption of a new commercial and residential code (2006 IECC) effective January 1, 2008. Idaho Power has two key roles once the codes are adopted: 1) informing the design community of code changes and 2) modifying Idaho Power energy efficiency programs to reflect the new codes. In 2008, Idaho Power modified the Building Efficiency program to reflect the adoption of the new 2006 IECC. Furthermore, the new residential code in 2008 resulted in code coming closer to the requirements in the ENERGY STAR Homes Northwest Builder Option Package, which directly led to a decrease in the Idaho Power ENERGY STAR Homes Northwest program incentive amount.

Pursuit of Appliance Code Standards

Idaho Power contracted with Quantec, LLC, to conduct a study of potential savings and costs associated with enacting appliance efficiency standards in Idaho similar to those recently enacted in Oregon. The final report, *Idaho Power Appliance Standards Assessment*, was completed January 9, 2008. The 2009 IRP will include an evaluation of the findings from this study.

Continued Expansion of DSM Programs Beyond Peak-Shaving/Load-Shifting Programs

Idaho Power has focused additional resources toward energy efficiency education, marketing, and promotion. Increased customer awareness of energy-saving ideas was accomplished via distribution of over 8,000 copies of the 96-page book *30 Simple Things You Can Do To Save Energy*. The five-class Fall Energy Efficiency & Green Living Series were held for a second year at the Boise Public Library, with 147 participants attending in 2008. Incremental educational programs for 2008 included weekly energy efficiency messages on The HomeFix Show with Joe Prin on 580 KIDO AM radio, provision of energy efficient gift purchase tips during the holidays, sponsorship of the Energy Conservation and Recycling track at the first annual Idaho Green Expo, and development of a new presentation for fourth- and sixth-grade students titled "Simple Ways to Save Energy."

For industrial and commercial customers, Idaho Power continues to promote the offerings of the IEA through NEEA to food processing customers. In 2008, there were six facilities in the Idaho Power service area committed to implementing Continuous Energy Improvement practices at their facilities. In 2008, there were nine offered classes covering motors, pump systems, compressed air, and ammonia refrigeration. This technical training is a key element of customer education, which helps drive energy efficiency projects at customer facilities. Idaho Power strengthened the working relationship with the Boise chapter of the Building Owners and Managers Association (BOMA). Also, Idaho Power worked closely with Bonneville Power and other utilities on research into the effectiveness of replacing damaged door gaskets in refrigerated walk-ins and reach-in display cases. In 2008, Idaho Power became a member of the Utility IT Energy Efficiency Coalition, which is charged with supporting development of energy efficient instructional technology and data center operations. Idaho Power also became an associate member of the Climate Savers Computing Initiative.

In 2008, Idaho Power continued to increase energy efficiency awareness among its customers through a variety of media outlets. Idaho Power distributed energy efficiency information via 28 *Update* articles, 22 *News Scans* articles, 5 *E-News* videos, 15 articles in *Consumer Connection*, 10 bill inserts, 13 radio interviews, 1 television article, and 2 press releases. In March, Idaho Power celebrated its first company-wide Energy Efficiency Month for employees, encouraging their participation in programs.

Third-Party Verification

Idaho Power uses third-party consultants to verify that program specifications are met, to verify the amount of energy savings achieved, and to obtain data on energy efficiency, demand response measures, and programs.

Idaho Power provides funding and participation in the RTF. The RTF is an advisory committee that was established in 1999 to develop standards for verifying and evaluating savings from energy efficiency programs and measures. Idaho Power uses the RTF as a source for information on programs and measures, and uses the RTF databases to provide deemed savings for some energy efficiency measures.

In 2008, Idaho Power contracted with Nexant, Inc., to assess the market potential for DSM activities in Idaho Power's service area. For this study, Nexant developed spreadsheet models estimating DSM potential as economic conditions and end-use measure assumptions change. Nexant will provide a final document in 2009. The information provided by the potential study will be included in the 2009 IRP.

In spring 2008, Idaho Power contracted with Ecotope, Inc., to provide energy savings estimates for the Attic Insulation Pilot. At the conclusion of the pilot, Idaho Power sought Ecotope's expertise to update the estimated energy savings impacts of the program based on revised assumptions from the pilot. With these updated energy-savings estimates, the cost-effective program will continue under the name Home Improvement Program.

Idaho Power contracted with the Boise Integrated Design Laboratory (IDL) to provide evaluation functions, including measurement and verification. Under this contract, an evaluation has been initiated on certain measures in the Building Efficiency program. Idaho Power expects to work closely with IDL to study other commercial sector programs in the future.

In the commercial sector, Idaho Power participated in the NEEA Commercial Building Stock Assessment (CBSA), updating the original study from 2003, which is used for identifying and verifying commercial building stock characteristics in the Pacific Northwest. Idaho Power contracted with the Cadmus Group for this study, requesting an over-sample of Idaho Power's service area to obtain a statistically valid building sample for program planning purposes.

Since 2005, the A/C Cool Credit program contracted with a third-party installation contractor, Honeywell, Inc., for installation of radio-pager controlled switches on participants' A/C units. To ensure customer satisfaction, this contractor performs quality-assurance inspections on installations and makes follow-up phone calls to recent switch recipients. Honeywell submits weekly reports to Idaho Power program staff on inspections, follow-ups, and results.

Idaho Power participated with NEEA throughout 2008 to evaluate the impacts of the ENERGY STAR Homes Northwest program. Results of this study will be finalized in 2009. The ENERGY STAR Homes program regularly uses certified Home Performance Specialists for third-party verification, ensuring that each ENERGY STAR qualified home is built to ENERGY STAR standards. The Idaho Office of Energy Resources then certifies each of these homes as an ENERGY STAR home.

The Energy House Calls program contracts with third-party experts to perform quality assurance on 5% of homes serviced by the program. These contractors visit the site within approximately one month of the energy house call and verify that the energy efficiency measures were performed to program specifications.

The Heating & Cooling Efficiency Program has a third-party quality assurance contractor. Honeywell, Inc., performs on-site verifications on approximately 5–7% of completed jobs.

Promotion of Energy Efficiency through Electricity Rate Design

In June, Idaho Power filed the 2008 General Rate Case with proposals for significant changes in rate design for most customer classes. These rate-change proposals were driven by the explicit Idaho Power objective of providing customers with cost-based price signals, which encourage the wise and efficient use of energy. Rate design proposals for the residential and small commercial customers included inclining block rates for both summer and non-summer seasons. These block rates encourage customers to use fewer kWh each month and thereby save a larger increment on their electricity bills than if they did not have block rates. Rate design proposals for the larger commercial and industrial customers included time-of-use rates, which encourage customers to reduce or shift electricity usage from peak times of the day. The rate design proposal for the irrigation customer centered around encouraging energy efficiency through load-factor pricing.

Idaho Power's Internal Energy Efficiency Commitment

Idaho Power's continued commitment toward promoting energy efficiency extends beyond encouraging, incenting, and educating its customers. In 2008, Idaho Power constructed a new operations facility in Lake Fork, Idaho. Almost 99% complete as of December 2008, it is the first facility built by Idaho Power to use an integrated approach to maximize expertise and coordination throughout the process. Many companies, including Idaho Power, are concentrating their efforts towards LEED certification.

The Long Valley Operations Center is certain to qualify for Silver LEED certification, and will most likely have enough points for the Gold level.

In 2008, Idaho Power successfully retrofitted the entire fifth floor of the Corporate Headquarters (CHQ). Included in this retrofit was the use of low volatile organic compounds (VOC) paint, recycled carpet tile, and low VOC glue to adhere them. The new window shading and the use of T5 lighting and ballasts are projected to save approximately 40% of the energy expended by the old lighting packages. Additionally, shorter, 53" wall panels are used for cubical partitions, allowing more daylight and reducing lighting costs. The plan is to use the fifth floor as the standard for office space in the CHQ and other office areas as budget dollars are approved. Lighting and HVAC upgrades were also made at the Mini-Cassia Operations Center.

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APPENDICES

This report includes four appendices. Appendix 1 contains financial information for 2008, showing the beginning balance, ending balance, and the expenditures for the Idaho Energy Efficiency Rider, the Oregon Energy Efficiency Rider, BPA funding, and NEEA payments and credits. Appendix 2 also contains financial information. This second appendix shows expenses by funding source for each of Idaho Power's energy efficiency programs or activities. Appendix 3 shows participation, utility cost, total resource cost, energy and demand savings, measure life, and levelized costs for Idaho Power's current energy efficiency programs and activities for 2008. Appendix 4 shows similar data as Appendix 3, but also includes data for past years' program performance, benefit-cost ratios from the utility perspective, and from the total resource cost perspectives for active programs.

Appendix 1. Idaho Rider, Oregon Rider, BPA, and NEEA Funding Balances

Idaho Energy Efficiency Rider		
2008 Beginning Balance	$	1,483,074.58
2008 Funding plus Accrued Interest		13,454,883.09
Total 2008 Funds		14,937,957.67
2008 Expenses		(18,880,275.73)
2008 Year-End Balance	**$**	**(3,942,318.06)**
Oregon Energy Efficiency Rider		
2008 Beginning Balance	$	410,225.46
2008 Funding plus Accrued Interest		411,602.13
Total 2008 Funds		821,827.59
2008 Expenses		(625,000.31)
2008 Year-End Balance	**$**	**196,827.28**
BPA Funding		
Total Funding and Accrued Interest October 2001–December 2007	$	3,156,889.59
2008 Accrued Interest		2,152.12
Total Funds May 2002–December 2008		3,159,041.71
Total Expenses—Inception through December 2007		(3,109,843.04)
2008 Expenses		(6,950.35)
Total BPA Funded Expenses		(3,116,793.39)
2008 Year-End Balance [(a)]	**$**	**42,248.32**
NEEA Payments and Escrow Credit Funds Balance		
2008 IPC Contractual Obligation	$	1,300,000.00
Credit Applied to 2008 Contractual Obligation		(325,588.00)
Interest Credit Applied to 2008 Contract Obligation (b)		(27,337.00)
Interest Credit Applied to 2009 Contract Obligation (c)		(5,061.00)
Total 2008 Cash Payments by IPC		942,014.00
Credit Balance		
Beginning Balance Funds Held by NEEA		(2,115,153.00)
2005-2007 Credit Applied to Contract Obligation		1,463,970.00
2008 Credit Applied to Contract Obligation		325,588.00
2008 Year-End Credit Balance	**$**	**(325,595.00)**

[(a)] The 2008 balance of BPA funds was committed to two Solar 4R Schools projects prior to the suspension of BPA funding in 2007. These projects were scheduled for completion in 2008 but have been delayed to 2009.

[(b)] The first quarter invoice for the Idaho Power 2008 contractual obligation to NEEA was processed in December 2007 with the amount scheduled to be amortized over the first quarter. Interest credit of $14,781 was immediately recognized in 2007.

[(c)] The first quarter invoice for the Idaho Power 2009 contractual obligation to NEEA was processed in December 2008 with the amount scheduled to be amortized over the first quarter. Interest credit of $5,061 was immediately recognized in 2008.

Appendix 2. 2008 DSM Expenses by Funding Source (Dollars)

Sector/Program	Rider Idaho	Rider Oregon	BPA	IPC	Total Program
Energy Efficiency/Demand Response					
Residential					
A/C Cool Credit	$ 2,922,985	$ 45,404	$ 0	$ 988	**$ 2,969,377**
Attic Insulation Pilot	123,454	0	0	0	**$ 123,454**
Energy Efficient Lighting	1,011,850	6,242	0	200	**$ 1,018,292**
Energy House Calls	448,992	35,388	0	0	**$ 484,379**
ENERGY STAR® Homes Northwest	294,579	6,388	0	1,094	**$ 302,061**
Heating & Cooling Efficiency Program	466,094	6,959	0	498	**$ 473,551**
Home Products Program	245,219	5,541	0	100	**$ 250,860**
Home Weatherization Pilot	51,670	0	0	1,138	**$ 52,807**
Oregon Residential Weatherization	0	1,908	0	5,509	**$ 7,417**
Rebate Advantage	79,547	11,341	0	0	**$ 90,888**
Weatherization Assistance for Qualified Customers	0	0	0	1,419,475	**$ 1,419,475**
Commercial/Industrial					
Building Efficiency	1,006,025	47,550	0	1,434	**$ 1,055,009**
Easy Upgrades	2,922,340	52,556	0	17,364	**$ 2,992,261**
Holiday Lighting Program	28,782	0	0	0	**$ 28,782**
Oregon Commercial Audit	0	0	0	58	**$ 58**
Custom Efficiency	3,948,617	86,858	0	10,196	**$ 4,045,671**
Irrigation					
Irrigation Efficiency Rewards	1,878,960	193,276	0	31,466	**$ 2,103,702**
Irrigation Peak Rewards	1,373,855	17,570	0	40,415	**$ 1,431,840**
Energy Efficiency Total	**16,802,969**	**516,981**	**0**	**1,529,934**	**$ 18,849,884**
Market Transformation					
Northwest Energy Efficiency Alliance	894,913	47,101	0	0	**$ 942,014**
Market Transformation Total	**894,913**	**47,101**	**0**	**0**	**$ 942,014**
Other Programs and Activities					
Residential					
Residential Education Initiative	142,969	7,818	0	130	**$ 150,917**
Commercial					
Commercial Education Initiative	69,059	3,632	0	46	**$ 72,738**
Other					
CRC Renewables	0	0	6,950	0	**$ 6,950**
Distribution Efficiency Initiative[(a)]	0	0	0	-1,913	**$ -1,913**
DSM Direct Program Overhead	135,788	6,945	0	27,178	**$ 169,911**
Local Energy Efficiency Funds	22,714	0	0	0	**$ 22,714**
Other Programs and Activities Total	**370,530**	**18,396**	**6,950**	**25,441**	**$ 421,317**
Indirect Program Expenses					
DSM Accounting and Analysis	792,478	41,483	0	123,942	**$ 957,904**
Energy Efficiency Advisory Group	2,148	63	0	0	**$ 2,211**
Special Accounting Entries	17,236	977	0	1,977	**$ 20,191**
Indirect Program Expenses Total	**811,863**	**42,523**	**0**	**125,919**	**$ 980,305**
Totals	**$18,880,276**	**$ 625,000**	**$ 6,950**	**$ 1,681,294**	**$ 21,193,520**

[(a)] 2007 Expenses reversed in 2008.

Appendix 3. 2008 DSM Program Activity

			Total Costs		Savings			Nominal Levelized Costs[a]	
	Participants		Utility[b]	Resource[c]	Annual Energy	Summer Peak Demand[d]	Measure Life	Utility	Total Resource
Program	*(Number)*	*(Units)*	*(Dollars)*	*(Dollars)*	*(kWh)*	*(MW)*	*(Years)*	*($/kWh)*	*($/kWh)*
Demand Response									
A/C Cool Credit	20,195	homes	$2,969,377	$2,616,072	n/a	22.60	n/a	n/a	n/a
Irrigation Peak Rewards	897	service points	$1,431,840	$189,492	n/a	35.10	n/a	n/a	n/a
Total			**$4,401,217**	**$2,805,563**	**n/a**	**57.70**			
Energy Efficiency									
Residential									
Attic Insulation Pilot	282	homes	$123,454	$157,866	317,814	0.03	25	$0.029	$0.037
Energy Efficient Lighting	436,234	CFL bulbs	$1,018,292	$793,265	14,309,444		7	$0.011	$0.009
Energy House Calls	1,099	homes	$484,379	$484,379	883,038		20	$0.045	$0.045
ENERGY STAR® Homes Northwest	254	homes	$302,061	$375,007	468,958	0.61	25	$0.048	$0.059
Heating & Cooling Efficiency Program	359	homes	$473,551	$599,771	561,441		18	$0.073	$0.092
Home Products Program	3,034	appliances/fixtures	$250,860	$468,056	541,615		15	$0.044	$0.082
Home Weatherization Pilot	16	homes	$52,807	$48,162	71,680		25	$0.055	$0.050
Oregon Residential Weatherization	3	homes	$7,417	$28,752	22,196		25	$0.025	$0.096
Rebate Advantage	107	homes	$90,888	$179,868	463,401		45	$0.012	$0.025
Weatherization Assistance for Qualified Customers—Idaho	439	homes/non-profits	$1,375,632	$1,755,749	4,064,301		25	$0.025	$0.032
Weatherization Assistance for Qualified Customers—Oregon	13	homes/non-profits	$43,843	$74,048	73,841		25	$0.040	$0.068
Sector Total			**$4,223,185**	**$4,964,924**	**21,777,729**	**0.64**			

a. Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.
b. The Total Utility Cost is all costs 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 documented.

Appendix 3. 2008 DSM Program Activity (continued)

Program	Participants (Number)	Participants (Units)	Total Costs: Utility[b] (Dollars)	Total Costs: Resource[c] (Dollars)	Savings: Annual Energy (kWh)	Savings: Summer Peak Demand[d] (MW)	Measure Life (Years)	Nominal Levelized Costs[a]: Utility ($/kWh)	Nominal Levelized Costs[a]: Total Resource ($/kWh)
Commercial									
Building Efficiency	60	projects	$1,055,009	$1,673,268	6,598,123	0.96	12	$0.017	$0.028
Easy Upgrades	685	projects	$2,992,261	$10,096,627	25,928,391	4.49	12	$0.013	$0.043
Holiday Lighting Program	14	projects	$28,782	$73,108	259,092		10	$0.014	$0.035
Oregon Commercial Audit	0	audits	$58	$58			n/a	n/a	n/a
Sector Total			**$4,076,109**	**$11,843,061**	**32,785,606**	**5.45**			
Industrial									
Custom Efficiency	101	projects	$4,045,671	$16,312,379	41,058,639	4.77	12	$0.011	$0.044
Sector Total			**$4,045,671**	**$16,312,379**	**41,058,639**	**4.77**			
Irrigation									
Irrigation Efficiency Rewards	961	projects	$2,103,702	$5,850,778	11,746,395	3.47	8	$0.026	$0.073
Sector Total			**$2,103,702**	**$5,850,778**	**11,746,395**	**3.47**			
Market Transformation									
Northwest Energy Efficiency Alliance[1]			$942,014	$942,014	32,671,465				
Other Programs and Activities									
Residential									
Residential Education Initative			$150,917	$150,917					
Commercial									
Commercial Education Initiative			$72,738	$72,738					

a. Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.
b. The Total Utility Cost is all costs 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 documented.
1. Savings are preliminary estimates provided by the NEEA.

Appendix 3. 2008 DSM Program Activity (continued)

			Total Costs		Savings			Nominal Levelized Costs[a]	
	Participants		Utility[b]	Resource[c]	Annual Energy	Summer Peak Demand[d]	Measure Life	Utility	Total Resource
Program	*(Number)*	*(Units)*	*(Dollars)*	*(Dollars)*	*(kWh)*	*(MW)*	*(Years)*	*($/kWh)*	*($/kWh)*
Other									
CRC Renewables			$6,950	$6,950					
Distribution Efficiency Initiative [2]			-$1,913	-$1,913					
DSM Direct Program Overhead			$169,911	$169,911					
Local Energy Efficiency Funds	2	projects	$22,714	$60,100	115,931		15	$0.019	$0.049
Total Program Direct Expense			**$20,213,215**	**$43,177,423**	**140,155,765**	**72.03**			
Indirect Program Expense			**$980,305**						
Total DSM Expense			**$21,193,520**						

a. Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.
b. The Total Utility Cost is all costs 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 documented.
2. 2007 expenses reversed in 2008.

Appendix 4. DSM Expense and Performance 2002–2008

Program/Year		Participants (Number)	Total Costs: Utility Cost[c] (dollars)	Total Costs: Resource Cost[d] (dollars)	Savings and Demand Reduction: Annual Energy (kWh)	Savings and Demand Reduction: Average Demand[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 Benefit/Cost Ratio	Program Life Benefit/Cost Ratios[b]: Total Resource Benefit/Cost Ratio	
Demand Response													
A/C Cool Credit													
	2003	204	$275,645	$269,680			0.00						
	2004	420	$287,253	$274,686			0.40						
	2005	2,369	$754,062	$717,902			2.70						
	2006	5,369	$1,235,476	$1,131,439			5.60						
	2007	13,692	$2,426,154	$2,199,486			10.80						
	2008	20,195	$2,969,377	$2,616,072			22.60						
	Total		**$7,947,966**	**$7,209,266**							**1.38**	**1.38**	
Irrigation Peak Rewards													
	2004	58	$344,714	$185,006			5.60						(1)
	2005	894	$1,468,282	$479,484			40.30						(2)
	2006	906	$1,324,418	$239,977			31.80						(3)
	2007	947	$1,615,881	$239,855			37.40						(3)
	2008	897	$1,431,840	$189,492			35.10						(3)
	Total		**$6,185,135**	**$1,333,814**							**1.15**	**1.15**	
Residential Efficiency													
Attic Insulation Pilot													
	2008	282	$123,454	$157,866	317,814	0.04	0.03	25	$0.029	$0.037			
	Total	**282**	**$123,454**	**$157,866**	**317,814**			**25**	**$0.029**	**$0.037**	**2.48**	**1.94**	
Energy Efficiency Packets													
	2002	2,925	$755	$755	155,757	0.02		7	$0.001	$0.001			(4)
	Total	**2,925**	**$755**	**$755**	**155,757**			**7**	**$0.001**	**$0.001**			

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs 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) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.

(1) Utility cost restated from $320,309 in prior historical reporting to reflect all funding sources.

(2) Peak MW achieved based on mid-week load reduction schedule.

(3) Peak MW achieved based on equally distributed weekly load reduction schedule.

(4) Utility Cost restated from previously reported $4,910.

Appendix 4. DSM Expense and Performance 2002–2008 (continued)

Program/Year		Participants (Number)	Total Costs: Utility Cost[c] (dollars)	Total Costs: Resource Cost[d] (dollars)	Savings and Demand Reduction: Annual Energy (kWh)	Savings and Demand Reduction: Average Demand[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 Benefit/Cost Ratio	Program Life Benefit/Cost Ratios[b]: Total Resource Benefit/Cost Ratio	
Energy Efficient Lighting													
	2002	11,619	$243,033	$310,643	3,299,654	0.38		7	$0.012	$0.015			
	2003	12,663	$314,641	$464,059	3,596,150	0.41		7	$0.014	$0.021			
	2004	0											
	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	$0.010			
	2008	436,234	$1,018,292	$793,265	14,309,444	1.63		7	$0.011	$0.009			
	Total	**902,528**	**$2,505,518**	**$2,649,280**	**36,450,127**			**7**	**$0.011**	**$0.012**	**4.56**	**4.31**	
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			(5)
	2004	1,708	$725,981	$725,981	2,349,783	0.27		20	$0.025	$0.025			(6)
	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	$67,616	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			
	Total	**5,654**	**$2,452,172**	**$2,183,416**	**7,088,457**			**20**	**$0.028**	**$0.025**	**2.20**	**2.20**	

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs 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) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.

(5) Utility costs restated from $183,653 for historical reporting prior to the 2006 DSM Annual Report.

(6) Utility costs restated from $725,732 for historical reporting prior to the 2006 DSM Annual Report.

Appendix 4. DSM Expense and Performance 2002–2008 (continued)

Program/Year		Participants (Number)	Total Costs: Utility Cost[c] (dollars)	Total Costs: Resource Cost[d] (dollars)	Savings and Demand Reduction: Annual Energy (kWh)	Savings and Demand Reduction: Average Demand[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 Benefit/Cost Ratio	Program Life Benefit/Cost Ratios[b]: Total Resource Benefit/Cost Ratio	
ENERGY STAR® Homes Northwest													
	2003	0	$13,597	$13,597									
	2004	44	$140,165	$335,437	101,200	0.01	0.09	25	$0.103	$0.246			(7)
	2005	200	$253,105	$315,311	415,600	0.05	0.40	25	$0.045	$0.056			
	2006	439	$469,609	$602,651	912,242	0.10	0.88	25	$0.038	$0.049			
	2007	303	$475,044	$400,637	629,634	0.07	0.61	25	$0.056	$0.047			
	2008	254	$302,061	$375,007	468,958	0.05	0.61	25	$0.048	$0.059			
	Total	**1,240**	**$1,653,581**	**$2,042,641**	**2,527,634**			**25**	**$0.049**	**$0.060**	**1.76**	**1.43**	
Heating & Cooling Efficiency Program													
	2006	0	$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	561,441	0.06		18	$0.073	$0.092			
	Total	**363**	**$979,207**	**$1,112,204**	**563,036**			**18**	**$0.150**	**$0.170**	**0.53**	**0.28**	
Home Products Program													
	2007	0	$9,275	$9,275									
	2008	3,034	$250,860	$468,056	541,615	0.06		15	$0.044	$0.082			
	Total	**3,034**	**$260,135**	**$477,331**	**541,615**			**15**	**$0.044**	**$0.082**	**1.42**	**0.77**	
Home Weatherization Pilot													
	2008	16	$52,807	$48,162	71,680	0.01		25	$0.055	$0.050			
	Total	**16**	**$52,807**	**$48,162**	**71,680**			**25**	**$0.055**	**$0.050**	**1.31**	**1.43**	

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs 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) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.

(7) Energy savings based on NEEA standardized per home kWh savings estimates.

Appendix 4. DSM Expense and Performance 2002–2008 (continued)

Program/Year		Participants (Number)	Total Costs: Utility Cost[c] (dollars)	Total Costs: Resource Cost[d] (dollars)	Savings and Demand Reduction: Annual Energy (kWh)	Savings and Demand Reduction: Average Demand[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 Benefit/Cost Ratio	Program Life Benefit/Cost Ratios[b]: Total Resource Benefit/Cost Ratio	
Oregon Residential Weatherization													
	2002	24	-$662	$23,971	4,580	0.00		25	$0.010	$0.389			(8)
	2003	0	-$943										(9)
	2004	4	$1,057	$1,057									
	2005	4	$612	$3,608	7,927	0.00		25	$0.006	$0.034			
	2006	0	$4,126	$4,126									(10)
	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			
	Total	**36**	**$15,389**	**$67,103**	**44,674**			**25**	**$0.026**	**$0.112**			(11)
Rebate Advantage													
	2003	73	$27,372	$79,399	227,434	0.03		45	$0.008	$0.022			(12)
	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			
	Total	**608**	**$358,563**	**$918,882**	**2,223,245**			**45**	**$0.010**	**$0.026**	**7.19**	**2.80**	
Window A/C Trade Up Pilot													
	2003	99	$6,687	$10,492	14,454	0.00		12	$0.051	$0.079			
	Total	**99**	**$6,687**	**$10,492**	**14,454**			**12**	**$0.051**	**$0.079**			

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs 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) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.

(8) Utility Cost reports reversal of $2778 asset from 2001 expense, this amount is included in levelized cost calculation.
In addition, Utility Cost also reports funds subsequently collected on bad loan writeoff expense. These funds are excluded from the annual levelized cost calculation.

(9) Utility Cost reflects collected funds on previous bad loan writeoffs.

(10) Utility Cost reflects only audit and administration costs; there was no further activity in 2006.

(11) Levelized cost calculation includes bad loan write-off expense and funds collected from previously written-off loans.

(12) Utility Cost restated in 2006 from $37,319 to reflect total expense.

Appendix 4. DSM Expense and Performance 2002–2008 (continued)

Program/Year		Participants (Number)	Total Costs: Utility Cost[c] (dollars)	Total Costs: Resource Cost[d] (dollars)	Savings and Demand Reduction: Annual Energy (kWh)	Savings and Demand Reduction: Average Demand[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 Benefit/Cost Ratio	Program Life Benefit/Cost Ratios[b]: Total Resource Benefit/Cost Ratio	
Residential - Weatherization Assistance for Qualified Customers (WAQC)													
WAQC—Idaho													
	2002	197	$235,048	$492,139									
	2003	208	$228,134	$483,369									(13)
	2004	269	$516,882	$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	$1,449,807	$2,231,086	2,958,024	0.34		25	$0.037	$0.056			
	2007	397	$1,290,017	$1,757,105	3,296,019	0.38		25	$0.029	$0.040			
	2008	439	$1,376,543	$1,755,749	4,064,301	0.46		25	$0.025	$0.032			
	Total	**2,620**	**$6,498,918**	**$9,506,354**	**14,769,332**			**25**	**$0.033**	**$0.048**	**2.17**	**1.50**	
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	$14,586	$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	0	$5,566										
	2007	11	$33,607	$41,700	42,108	0.00		25	$0.054	$0.074			
	2008	13	$42,932	$74,048	73,841	0.01		25	$0.040	$0.068			
	Total	**130**	**$188,067**	**$290,199**	**409,630**			**25**	**$0.033**	**$0.053**	**2.02**	**1.26**	
WAQC—BPA Supplemental													
	2002	75	$55,966	$118,255	311,347	0.04		25	$0.013	$0.028			(14)
	2003	57	$49,895	$106,915	223,591	0.03		25	$0.017	$0.036			
	2004	40	$49,885	$105,021	125,919	0.01		25	$0.041	$0.062			
	Total	**172**	**$155,746**	**$330,191**	**660,857**			**25**	**$0.020**	**$0.037**			

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs 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) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.

(13) Total Resource Cost restated in 2005 to include federal funding administered by CAP agencies. 2002–2003 savings not reported due to integration of fuel types.

(14) Beginning in 2005, BPA funds were no longer applied to CAP agency payments; BPA expense in subsequent years is reflected in the respective state expenses.

Appendix 4. DSM Expense and Performance 2002–2008 (continued)

Program/Year		Participants (Number)	Total Costs: Utility Cost[c] (dollars)	Total Costs: Resource Cost[d] (dollars)	Savings and Demand Reduction: Annual Energy (kWh)	Savings and Demand Reduction: Average Demand[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 Benefit/Cost Ratio	Program Life Benefit/Cost Ratios[b]: Total Resource Benefit/Cost Ratio
Commercial												
Air Care Plus Pilot												
	2003	4	$5,764	$9,061	33,976	0.00		10	$0.021	$0.033		
	2004	0	$344	$344								
	Total	**4**	**$6,108**	**$9,405**	**33,976**			**10**	**$0.022**	**$0.034**		
Building Efficiency												
	2004	0	$28,821	$28,821								
	2005	12	$194,066	$233,149	494,239	0.06	0.16	12	$0.043	$0.052		
	2006	40	$374,008	$463,770	704,541	0.08	0.34	12	$0.058	$0.072		
	2007	22	$669,032	$829,600	2,817,248	0.32	0.45	12	$0.015	$0.040		
	2008	60	$1,055,009	$1,673,268	6,598,123	0.75	0.96	12	$0.017	$0.028		
	Total	**134**	**$2,320,937**	**$3,228,609**	**10,614,151**			**12**	**$0.024**	**$0.026**	**2.14**	**1.55**
Easy Upgrades												
	2006	0	$31,819	$31,819								
	2007	104	$711,494	$1,882,035	5,183,640	0.59	0.78	12	$0.015	$0.040		
	2008	685	$2,992,261	$10,096,627	25,928,391	2.96	4.49	12	$0.013	$0.043		
	Total	**789**	**$3,735,574**	**$12,010,481**	**31,112,031**			**12**	**$0.013**	**$0.042**	**3.88**	**1.21**
Holiday Lighting Program												
	2008	14	$28,782	$73,108	259,092	0.03		10	$0.014	$0.035		
	Total	**14**	**$28,782**	**$73,108**	**259,092**			**10**	**$0.014**	**$0.035**	**2.85**	**1.12**

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs 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) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.

Appendix 4. DSM Expense and Performance 2002–2008 (continued)

Program/Year		Participants (Number)	Total Costs: Utility Cost[c] (dollars)	Total Costs: Resource Cost[d] (dollars)	Savings and Demand Reduction: Annual Energy (kWh)	Savings and Demand Reduction: Average Demand[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 Benefit/Cost Ratio	Program Life Benefit/Cost Ratios[b]: Total Resource Benefit/Cost Ratio	
Oregon Commercial Audits													
	2002	24	$5,200	$5,200									
	2003	21	$0	$4,000									
	2004	7	$0	$0									
	2005	7	$5,450	$5,450									
	2006	6											
	2007	8	$1,981	$1,981									
	2008	0	$58	$58									
	Total	**73**	**$12,689**	**$16,689**									(15)
Oregon School Efficiency													
	2005	0	$86	$86									
	2006	6	$24,379	$89,771	223,368	0.03		12	$0.012	$0.044			
	Total	**6**	**$24,465**	**$89,858**	**223,368**			**12**	**$0.012**	**$0.044**			
Industrial													
Custom Efficiency													
	2003	0	$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	3.62	12	$0.012	$0.026			
	2008	100	$4,045,671	$16,312,379	41,058,639	4.68	4.77	12	$0.011	$0.044			
	Total	**214**	**$10,074,442**	**$31,386,846**	**102,287,521**			**12**	**$0.018**	**$0.056**	**4.83**	**1.55**	

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs 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) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.

(15) Oregon statutory program. The company does not monitor customer implementation of audit recommendations and thus does not estimate savings for this program. Audit expense not involving outside contractor services are booked to general customer service.

Appendix 4. DSM Expense and Performance 2002–2008 (continued)

Program/Year	Participants (Number)	Total Costs: Utility Cost[c] (dollars)	Total Costs: Resource Cost[d] (dollars)	Savings and Demand Reduction: Annual Energy (kWh)	Savings and Demand Reduction: Average Demand[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 Benefit/Cost Ratio	Program Life Benefit/Cost Ratios[b]: Total Resource Benefit/Cost Ratio	
Irrigation												
Irrigation Efficiency Rewards												
2003	2	$41,089	$54,609	36,792	0.00	0.02	15	$0.106	$0.141			(16)
2004	33	$120,808	$402,978	802,812	0.09	0.45	15	$0.014	$0.048			(17)
2005	38	$150,577	$657,460	1,012,883	0.12	0.40	15	$0.014	$0.062			
2006	559	$2,779,620	$8,514,231	16,986,008	1.94	5.10	8	$0.024	$0.073			
2007	816	$2,001,961	$8,694,772	12,304,073	1.40	3.41	8	$0.024	$0.103			
2008	961	$2,103,702	$5,850,778	11,746,395	1.34	3.47	8	$0.026	$0.073			
Total	**2,409**	**$7,197,758**	**$24,174,827**	**42,888,963**			**8**	**$0.024**	**$0.082**	**5.49**	**1.64**	(18)
Other Programs												
Building Operator Training												
2003	71	$48,853	$48,853	1,825,000	0.21		5	$0.006	$0.006			(19)
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**			
Other Programs												
Commercial Education Initiative												
2005		$3,497	$3,497									
2006		$4,663	$4,663									
2007		$26,823	$26,823									
2008		$72,738	$72,738									
Total		**$107,721**	**$107,721**									

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs 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) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.

(16) Restated from $11,190 in prior reports.

(17) Originally reported expense and energy included accrued amounts, restated here to align with accounting records.

(18) Measure life is weighted life (based on energy savings) of custom option (15 years) and menu options (5 years).

(19) Originally reported expense and energy included accrued amounts: 2003 restated from $36,084, 2004 restated from $48,853.

Appendix 4. DSM Expense and Performance 2002–2008 (continued)

Program/Year	Participants (Number)	Total Costs: Utility Cost[c] (dollars)	Total Costs: Resource Cost[d] (dollars)	Savings and Demand Reduction: Annual Energy (kWh)	Savings and Demand Reduction: Average Demand[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 Benefit/Cost Ratio	Program Life Benefit/Cost Ratios[b]: Total Resource Benefit/Cost Ratio
Distribution Efficiency Initiative											
2005		$21,552	$43,969								
2006		$24,306	$24,306								
2007		$8,987									
2008		-$1,913	-$1,913								
Total		**$52,932**	**$66,362**								
DSM Direct Program Overhead											
2007		$56,909	$56,909								
2008		$169,911	$169,911								
Total		**$226,820**	**$226,820**								
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 Education Initiative											
2005		$7,498	$7,498								
2006		$56,727	$56,727								
2007		$0	$0								
2008		$150,917	$150,917								
Total		**$215,142**	**$215,142**								

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs 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) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.

Appendix 4. DSM Expense and Performance 2002–2008 (continued)

Program/Year		Participants (Number)	Total Costs: Utility Cost[c] (dollars)	Total Costs: Resource Cost[d] (dollars)	Savings and Demand Reduction: Annual Energy (kWh)	Savings and Demand Reduction: Average Demand[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 Benefit/Cost Ratio	Program Life Benefit/Cost Ratios[b]: Total Resource Benefit/Cost Ratio	
Local Energy Efficiency Funds													
	2003	56	$5,100	$5,100									
	2004	0	$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			
	Total	**541**	**$77,138**	**$126,384**	**221,958**			**10**	**$0.043**	**$0.070**			
Market Transformation													
NEEA													
	2002		$1,286,632	$1,286,632	13,251,644	1.51							
	2003		$1,292,748	$1,292,748	12,050,157	1.38							
	2004		$1,256,611	$1,256,611	13,545,896	1.55							
	2005		$476,891	$476,891	16,297,235	1.86							
	2006		$930,455	$930,455	22,337,477	2.55							
	2007		$893,340	$893,340	28,601,410	3.27							
	2008		$942,014	$942,014	32,671,465	3.73							(20)
	Total		**$7,078,690**	**$7,078,690**	**138,755,283**								

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs 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) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.

(20) Savings are preliminary estimates provided by the Northwest Energy Efficiency Alliance.

Appendix 4. DSM Expense and Performance 2002–2008 (continued)

Program/Year	Participants	Utility Cost[c]	Resource Cost[d]	Annual Energy	Average Demand[e]	Peak Demand[f]	Measure Life	Total Utility	Total Resource	Utility Benefit/Cost Ratio	Total Resource Benefit/Cost Ratio	
		Total Costs		Savings and Demand Reduction				Levelized Costs[a]		Program Life Benefit/Cost Ratios[b]		
	(Number)	(dollars)	(dollars)	(kWh)	(aMW)	(MW)	(Years)	($/kWh)	($/kWh)			
Annual Totals												
2002		**$1,932,520**	**$2,366,591**	**17,117,294**	**1.95**	**0.00**						
2003		**$2,566,229**	**$3,119,609**	**18,712,919**	**2.14**	**0.02**						
2004		**$3,827,213**	**$4,688,637**	**19,419,605**	**2.22**	**6.54**						
2005		**$6,523,348**	**$9,358,620**	**37,853,046**	**4.32**	**43.96**						
2006		**$11,174,181**	**$19,761,633**	**70,765,825**	**8.08**	**43.72**						
2007		**$14,896,816**	**$25,269,343**	**91,145,357**	**10.40**	**57.07**						
2008		**$20,213,215**	**$43,177,423**	**140,155,765**	**15.99**	**72.03**						
Total Direct Program		**$61,133,523**	**$107,741,856**	**395,169,810**								
Indirect Program Expense												
DSM Overhead and Other Indirect												
2002		$128,855										(21)
2003		-$41,543										(21)
2004		$142,337										
2005		$177,624										
2006		$309,832										
2007		$765,561										
2008		$980,305										
Total		**$2,462,971**										

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs 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) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.

(21) Analysis and indirect expense were not separated in the accounting for this reporting period.

Appendix 4. DSM Expense and Performance 2002–2008 (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	Average Demand[e]	Peak Demand[f]	Measure Life	Total Utility	Total Resource	Utility Benefit/Cost Ratio	Total Resource Benefit/Cost Ratio
	(Number)	*(dollars)*	*(dollars)*	*(kWh)*	*(aMW)*	*(MW)*	*(Years)*	*($/kWh)*	*($/kWh)*		
Total Expense											
2002		**$2,061,375**									
2003		**$2,524,686**									
2004		**$3,969,550**									
2005		**$6,700,972**									
2006		**$11,484,013**									
2007		**$15,662,377**									
2008		**$21,193,520**									
Total 2002–2008	**Total**	**$63,596,494**									

(a) Levelized Costs are based on financial inputs from Idaho Power's 2006 Integrated Resource Plan and calculations include line loss adjusted energy savings.

(b) Program Life Benefit/Cost Ratios are provided for active, non-statutory programs only.

(c) The Total Utility Cost is all costs 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) Summer Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season.



Appendix C — Technical Appendix

For the 2009 Integrated Resource Plan

December 2009

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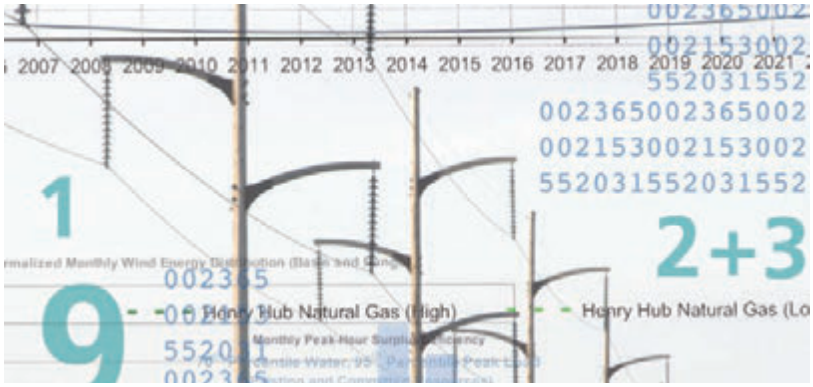
Appendix C — Technical Appendix

For the 2009 Integrated Resource Plan – December 2009



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INTRODUCTION

Appendix C—Technical Appendix contains some of the supporting and explanatory materials used to develop Idaho Power's *2009 Integrated Resource Plan* (IRP). The Technical Appendix begins with a reprint of the short-term and long-term resource action plans and follows with detailed information concerning various resource planning issues.

The main document, the IRP, contains a full narrative of the Idaho Power resource planning process. Additional information regarding the Idaho Power sales forecast is contained in *Appendix A—Sales and Load Forecast*, and details on Idaho Power's energy efficiency efforts are explained in *Appendix B—Demand-Side Management 2008 Annual Report*. The IRP, including the three appendices, was filed with the Idaho and Oregon public utility commissions in December 2009.

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
208-388-2483

NEAR- AND LONG-TERM ACTION PLAN

Near-Term Action Plan

Year	Action
2010	Present and gain acceptance of 2009 IRP with regulatory commissions File wind contract resulting from the 2012 Wind RFP with the IPUC File geothermal contract with the IPUC Irrigation Peak Rewards program increases from 160 MW to 220 MW FlexPeak Management program increases from 20 MW to 40 MW Langley Gulch CCCT construction begins
2011	Wind project construction begins Langley Gulch CCCT construction continues Irrigation Peak Rewards program increases from 220 MW to 250 MW FlexPeak Management program increases to from 40 MW to 45 MW File 2011 IRP with regulatory commissions
2012	Wind project on-line (approximately 150 MW) Langley Gulch CCCT on-line (300 MW) Geothermal project on-line (approximately 20 MW)
2013	Boardman to Hemingway construction begins Shoshone Falls Upgrade Project construction begins File 2013 IRP with regulatory commissions
2014	Shoshone Falls Upgrade Project construction continues
2015	Shoshone Falls Upgrade Project on-line (49 MW) Boardman to Hemingway completed (250 MW) File 2015 IRP with regulatory commissions
2016	Geothermal project on-line (approximately 20 MW)
2017	Boardman to Hemingway additional capacity for market purchases (175 MW) File 2017 IRP with regulatory commissions
2018	No action
2019	File 2019 IRP with regulatory commissions

Alternate Portfolio Near-Term Action Plan

Year	Action
2010	File 2009 IRP with regulatory commissions File wind contract (2012 Wind RFP) with the IPUC File geothermal contract with IPUC Irrigation Peak Rewards Program increases to 220 MW FlexPeak Management program increases to 40 MW Langley Gulch CCCT construction begins
2011	Wind project construction begins Langley Gulch CCCT construction Irrigation Peak Rewards Program increases to 250 MW FlexPeak Management program increases to 45 MW File 2011 IRP with regulatory commissions
2012	Wind project on line (approximately 150 MW) Langley Gulch CCCT on-line (300 MW) Geothermal generation on-line (approximately 20 MW) ***Natural gas generation resource one RFPs***
2013	File 2013 IRP with regulatory commissions
2014	Shoshone Falls upgrade construction

Year	Action
	Natural gas generation resource two RFPs
2015	Shoshone Falls upgrade on-line (50 MW)
	Natural gas generation resource one on-line
	File 2015 IRP with regulatory commissions
2016	Geothermal Generation on-line (approximately 20 MW)
2017	***Natural Gas generation resource two on-line***
	File 2017 IRP with commissions
2018	No action
2019	File 2019 IRP with commissions

Long-Term Action Plan

Year	Action
2020	Natural gas generation project on-line (approximately 100 MW)
2021	No action
2022	Wind project on-line (approximately 100 MW)
2023	No action
2024	Natural gas generation project on-line (approximately 200 MW)
2025	No action
2026	Natural gas generation project on-line (approximately 200 MW)
2027	Wind project on-line (approximately 400 MW)
2028	Natural gas generation project on-line (approximately 400 MW)
2029	Natural gas generation project on-line (approximately 500 MW)

PORTFOLIO ANALYSIS, RESULTS, AND SUPPORTING DOCUMENTATION

Initial Resource Portfolios (2010–2019)

	1-1 Solar		1-2 Gas Peaker		1-3 Gas Peaker & B2H[1]		1-4 B2H	
Year	Resource	MW	Resource	MW	Resource	MW	Resource	MW
2012	Wind*	150	Wind*	150	Wind*	150	Wind*	150
	CCCT (Langley Gulch)*	300	CCCT (Langley Gulch)*	300	CCCT (Langley Gulch)*	300	CCCT (Langley Gulch)*	300
	Geothermal*	20	Geothermal*	20	Geothermal*	20	Geothermal*	20
2015	Shoshone Falls	49	Shoshone Falls	49	Shoshone Falls	49	Shoshone Falls	49
	SCCT (Large Aero)	200	SCCT (Frame Peaker)	170	B2H	250	B2H	250
2016	Geothermal*	20	Geothermal*	20	Geothermal*	20	Geothermal*	20
2017	Solar PT w/St	100	SCCT (Frame Peaker)	170	SCCT (Large Aero)	100	B2H	175
2019	Solar PT w/St	100			SCCT (Large Aero)	100		

[1] B2H-Boardman to Hemingway
*Committed Resource

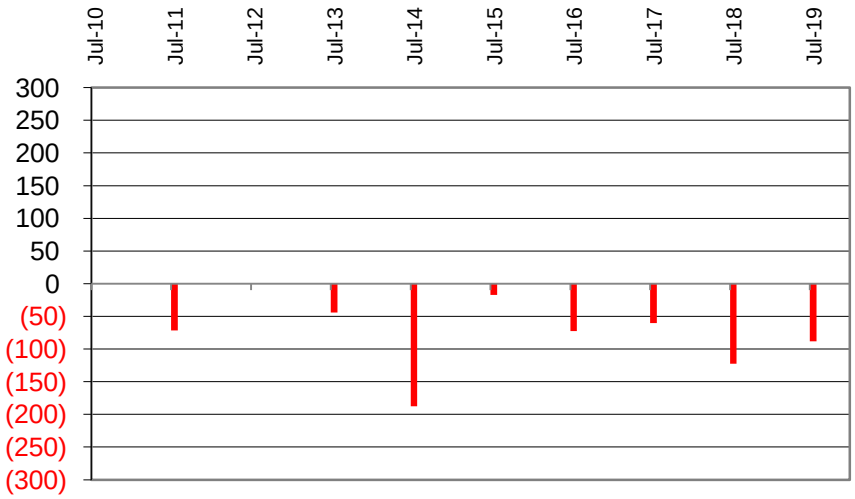
Initial Resource Portfolios (2020–2029)

	2-1 Nuclear/Green		2-2 Gateway West		2-3 IGCC		2-4 Wind & Peakers		2-5 Limited Curtailment	
Year	Resource	MW	Resource	MW	Resource	MW	Resource	MW	Resource	MW
2020	Solar PT w/St	100					SCCT (Large Aero)	100		
2021	Wind	100	Wind	100					Wind	100
2022	Solar PT w/St	100	Gateway West	200	Solar PT w/St	100	Wind	100	SCCT (Large Aero)	100
2023	Nuclear	270								
2024	Geothermal	52			IGCC w/Seq.	600	SCCT (Large Aero)	200		
2025	Solar PT w/St	100	Gateway West	200			Gateway West	100		
2026			Wind	100			SCCT (Large Aero)	200	SCCT (Large Aero)	100
2027	Geothermal	52	Gateway West	400	Solar PT w/St	100	Wind	400	Wind	200
									SCCT (Large Aero)	100
2028	Nuclear	400	Gateway West	600	SCCT (Large Aero)	400	SCCT (Large Aero)	400		
2029	Gateway West	250			Solar PT w/St	100	SCCT (Large Aero)	500		

1-1 Solar

RES	Type	Resource	Nameplate MW	Year	Energy	Peak	Cum. Energy	Cum. Peak	Cum. RES MW	Cum. RES MWh
				2010			0	0	0	-
RES	CR	Wind	150	2011			0	0	50	438,000
	CR	CCCT (Langley)	300	2012			0	0	50	438,000
RES	CR	Geothermal	20	2013			0	0	68	595,680
RES	NR	Shoshone Falls	49	2014	7.0	0.0	7	0	75	657,000
	NR	Large Aero	200	2015	100.0	200.0	107	200	75	657,000
RES	CR	Geothermal	20	2016			107	200	93	814,680
RES	NR	Solar PT w/St	100	2017	28.0	92.0	135	292	121	1,059,960
				2018			135	292	121	1,059,960
RES	NR	Solar PT w/St	100	2019	28.0	92.0	163	384	149	1,305,240
CR = Committed Resource						**Min**	**(91)**	**(188)**		
NR = New Resource						**STDEV**	**289**	**142**		
MP = Market Purchase						**AVG**	**505**	**107**		

Peak-Hour



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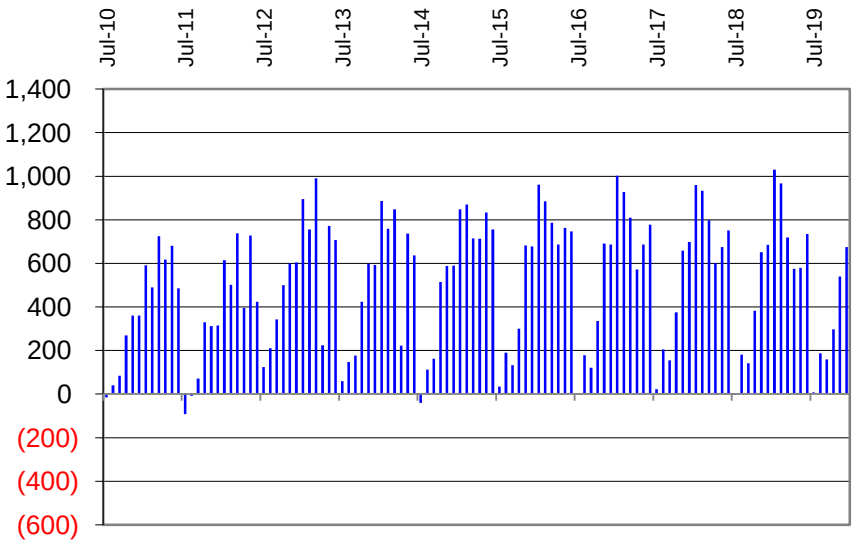
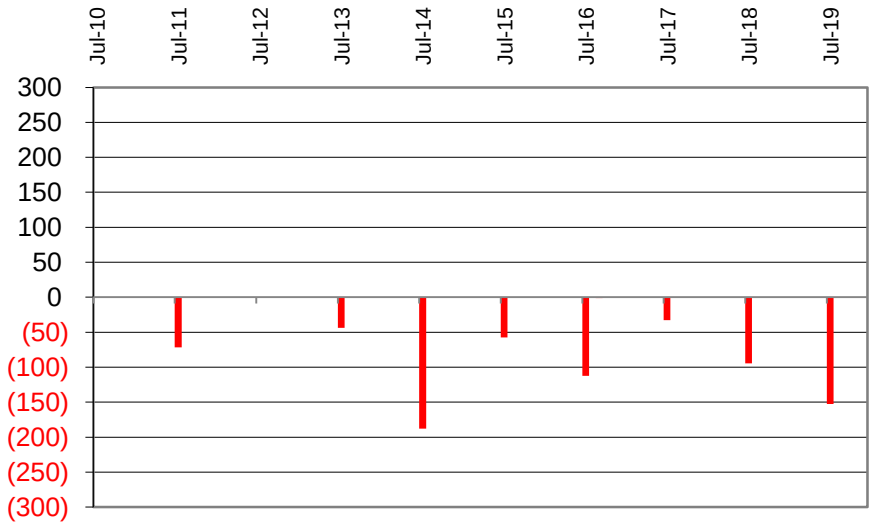


1-2 Gas Peaker

RES	Type	Resource	Nameplate MW	Year	Energy	Peak	Cum. Energy	Cum. Peak	Cum. RES MW	Cum. RES MWh
				2010			0	0	0	-
RES	CR	Wind	150	2011			0	0	50	438,000
	CR	CCCT (Langley)	300	2012			0	0	50	438,000
RES	CR	Geothermal	20	2013			0	0	68	595,680
RES	NR	Shoshone Falls	49	2014	7.0	0.0	7	0	75	657,000
	NR	Frame Peaker	170	2015	88.4	159.8	95.4	159.8	75	657,000
RES	CR	Geothermal	20	2016			95.4	159.8	93	814,680
	NR	Frame Peaker	170	2017	88.4	159.8	183.8	319.6	93	814,680
				2018			183.8	319.6	93	814,680
				2019			183.8	319.6	93	814,680
						Min	**(91)**	**(188)**		
						STDEV	**292**	**138**		
						AVG	**515**	**99**		

CR = Committed Resource
NR = New Resource
MP = Market Purchase

Peak-Hour



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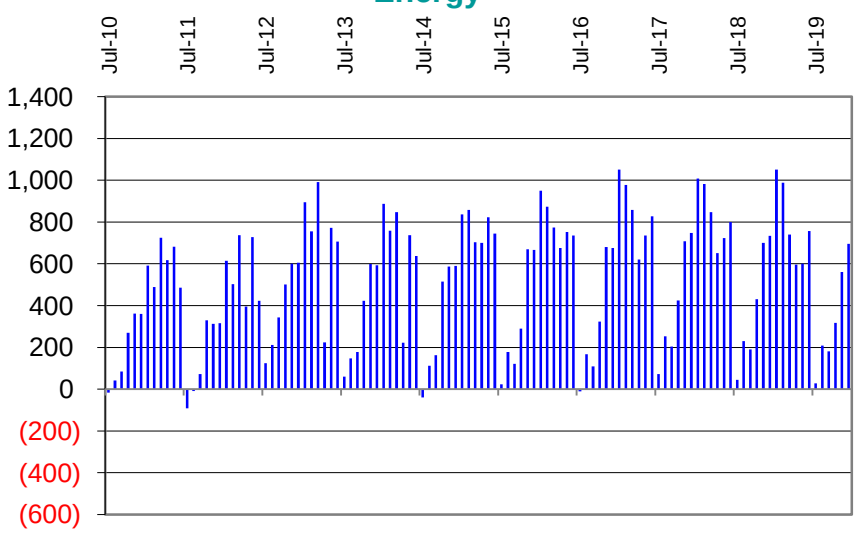
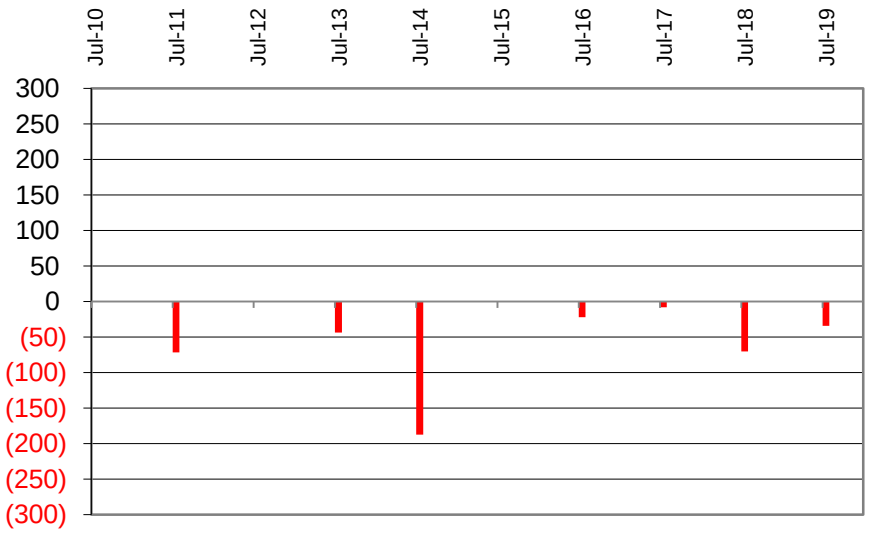


1-3 Gas Peaker & B2H

RES	Type	Resource	Nameplate MW	Year	Energy	Peak	Cum. Energy	Cum. Peak	Cum. RES MW	Cum. RES MWh
				2010			0	0	0	-
RES	CR	Wind	150	2011			0	0	50	438,000
	CR	CCCT (Langley)	300	2012			0	0	50	438,000
RES	CR	Geothermal	20	2013			0	0	68	595,680
RES	NR	Shoshone Falls	49	2014	7.0	0.0	7	0	75	657,000
	MP	B2H	250	2015	125.0	250.0	132	250	75	657,000
RES	CR	Geothermal	20	2016			132	250	93	814,680
	NR	Large Aero	100	2017	52.0	94.0	184	344	93	814,680
				2018			184	344	93	814,680
	NR	Large Aero	100	2019	52.0	94.0	236	438	93	814,680
						Min	**(91)**	**(188)**		
						STDEV	**294**	**163**		
						AVG	**527**	**133**		

CR = Committed Resource
NR = New Resource
MP = Market Purchase

Peak-Hour



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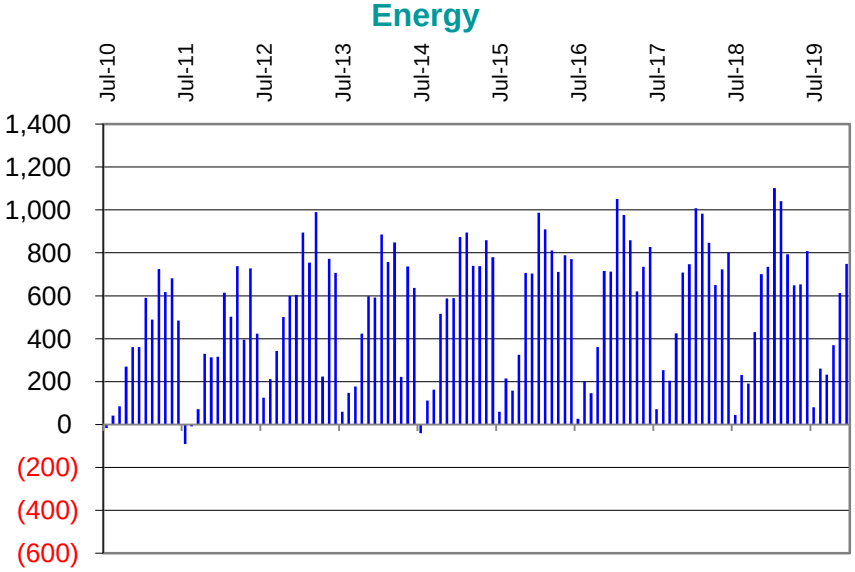
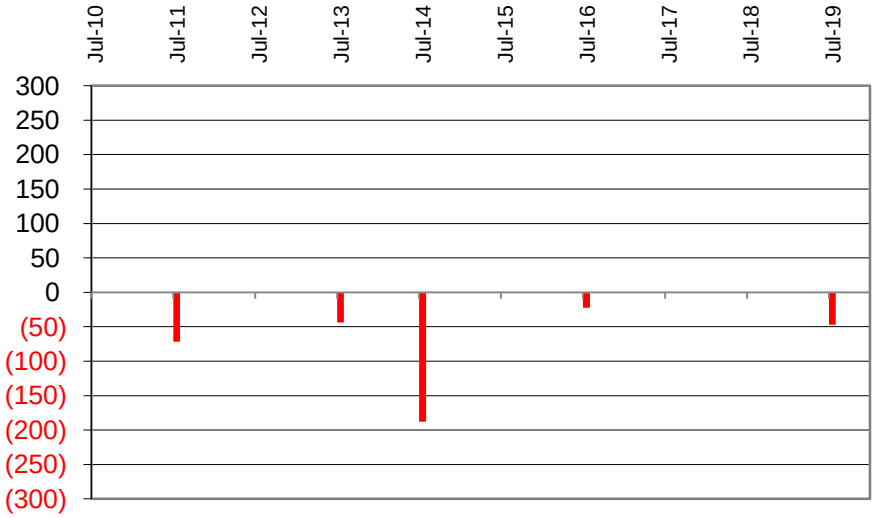


1-4 B2H

RES	Type	Resource	Nameplate MW	Year	Energy	Peak	Cum. Energy	Cum. Peak	Cum. RES MW	Cum. RES MWh
				2010			0	0	0	-
RES	CR	Wind	150	2011			0	0	50	438,000
	CR	CCCT (Langley)	300	2012			0	0	50	438,000
RES	CR	Geothermal	20	2013			0	0	68	595,680
RES	NR	Shoshone Falls	49	2014	7.0	0.0	7	0	75	657,000
	MP	B2H	250	2015	125.0	250.0	132	250	75	657,000
RES	CR	Geothermal	20	2016			132	250	93	814,680
	MP	B2H	175	2017	87.5	175.0	219.5	425	93	814,680
				2018			219.5	425	93	814,680
				2019			219.5	425	93	814,680
						Min	**(91)**	**(188)**		
						STDEV	**297**	**180**		
						AVG	**533**	**148**		

CR = Committed Resource
NR = New Resource
MP = Market Purchase

Peak-Hour



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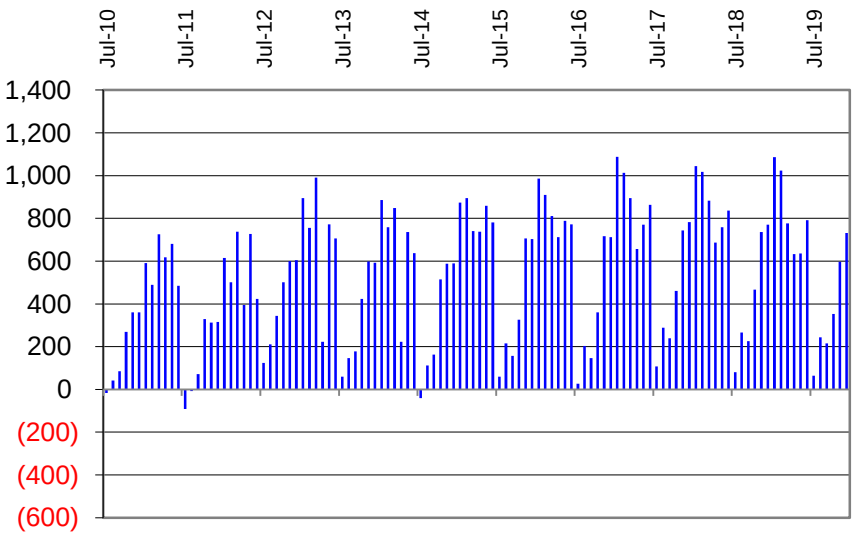
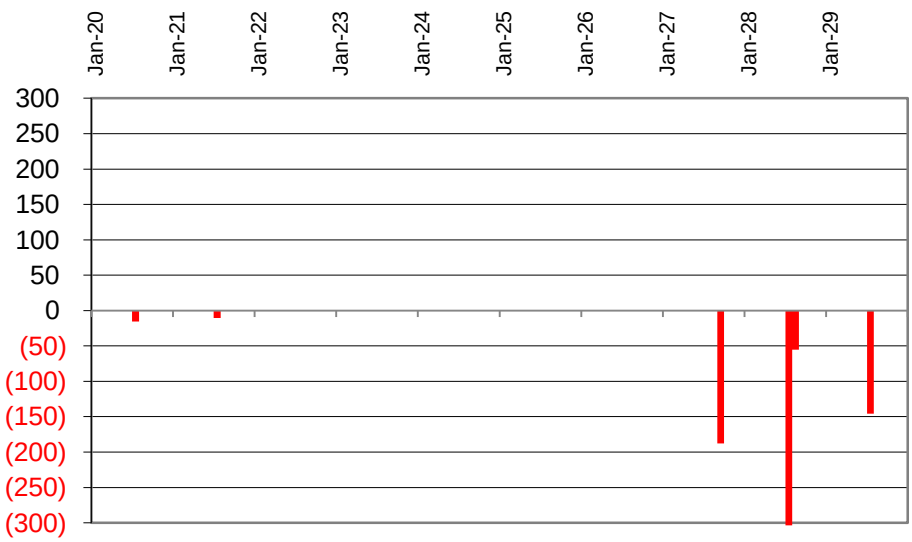


2-1 Nuclear/Green

RES	Type	Resource	Nameplate MW	Year	Energy	Peak	Cum. Energy	Cum. Peak	Cum. RES MW	Cum. RES MWh
RES	NR	Solar PT w/St	100	2020	28.0	92.0	28	92	28	245,280
RES	NR	Wind	100	2021	32.0	5.0	60	97	60	525,600
RES	NR	Solar PT w/St	100	2022	28.0	92.0	88	189	88	770,880
	NR	Nuclear	270	2023	270.0	270.0	358	459	88	770,880
RES	NR	Geothermal	52	2024	46.8	46.8	405	506	134.8	1,180,848
RES	NR	Solar PT w/St	100	2025	28.0	92.0	433	598	162.8	1,426,128
				2026			433	598	162.8	1,426,128
RES	NR	Geothermal	52	2027	46.8	46.8	480	645	209.6	1,836,096
	NR	Nuclear	400	2028	380.0	400.0	860	1045	209.6	1,836,096
		Gateway West	250	2029	125.0	250.0	985	1295	209.6	1,836,096
						Min	**(93)**	**(380)**		
						STDEV	**396**	**440**		
						AVG	**803**	**707**		

CR = Committed Resource
NR = New Resource
MP = Market Purchase

Peak-Hour



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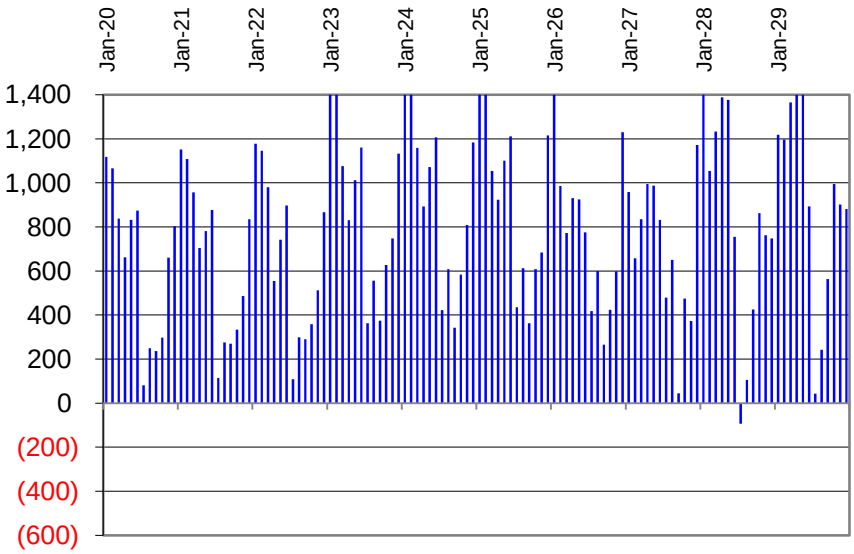
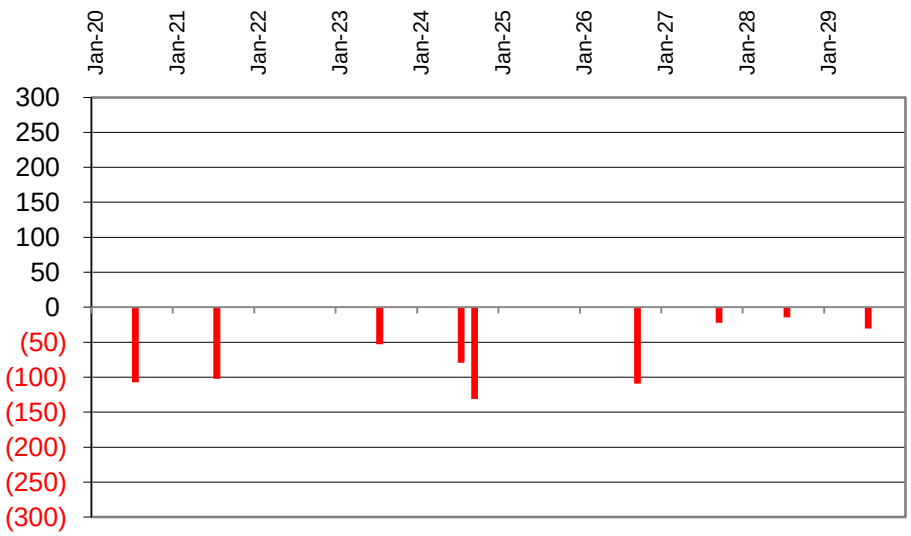


2-2 Gateway West

RES	Type	Resource	Nameplate MW	Year	Energy	Peak	Cum. Energy	Cum. Peak	Cum. RES MW	Cum. RES MWh
				2020			0	0	0	-
RES	NR	Wind	100	2021	32	5	32	5	32	280,320
		Gateway West	200	2022	100	200	132	205	32	280,320
				2023			132	205	32	280,320
				2024			132	205	32	280,320
		Gateway West	200	2025	100	200	232	405	32	280,320
RES	NR	Wind	100	2026	32	5	264	410	64	560,640
		Gateway West	400	2027	200	400	464	810	64	560,640
		Gateway West	600	2028	300	600	764	1410	64	560,640
				2029			764	1410	64	560,640
						Min	**(189)**	**(131)**		
						STDEV	**381**	**506**		
						AVG	**682**	**661**		

CR = Committed Resource
NR = New Resource
MP = Market Purchase

Peak-Hour



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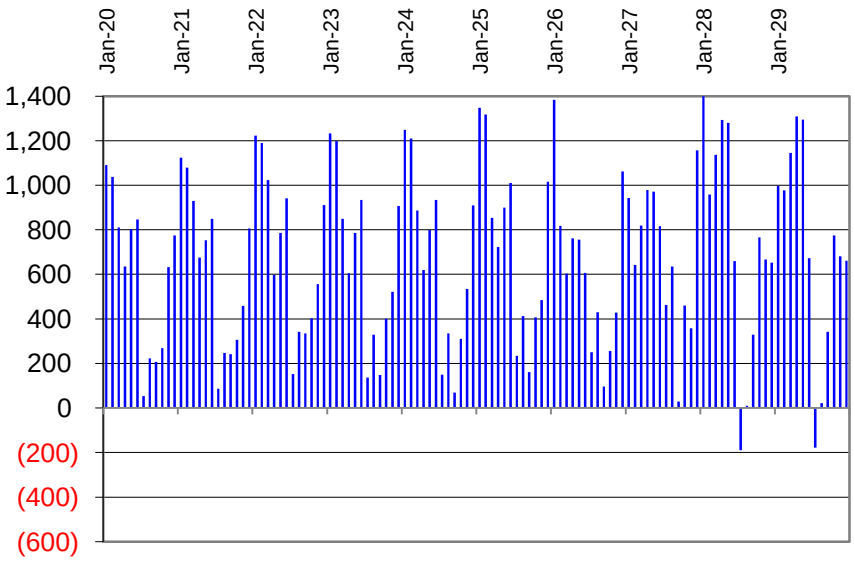
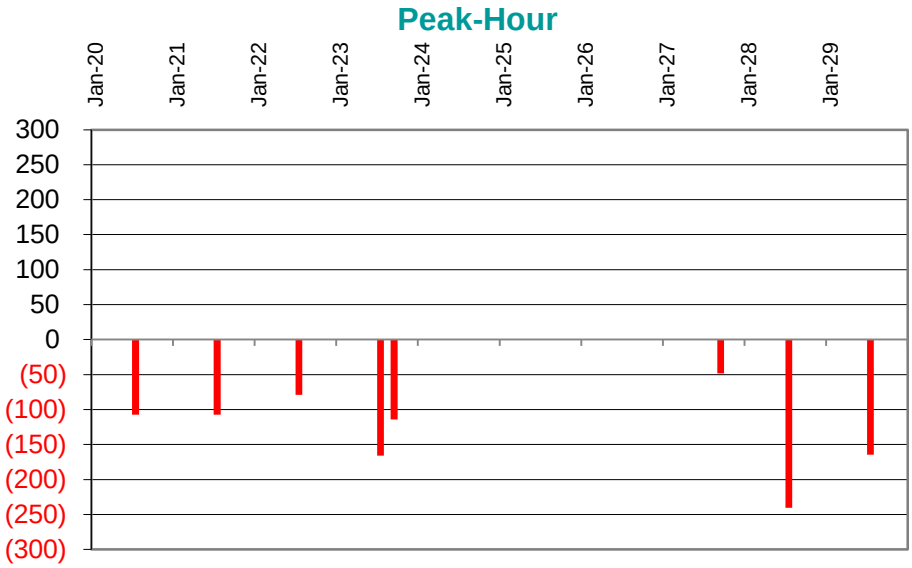
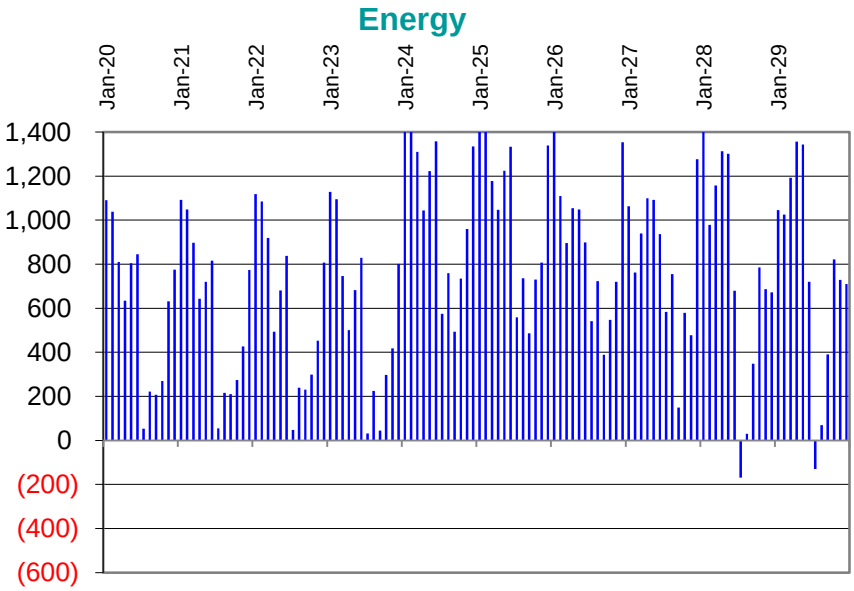


2-3 IGCC

RES	Type	Resource	Nameplate MW	Year	Energy	Peak	Cum. Energy	Cum. Peak	Cum. RES MW	Cum. RES MWh
				2020			0	0	0	-
				2021			0	0	0	-
RES	NR	Solar PT w/St	100	2022	28	92	28	92	28	245,280
				2023			28	92	28	245,280
	NR	IGCC w/Seq.	600	2024	528	600	556	692	28	245,280
				2025			556	692	28	245,280
				2026			556	692	28	245,280
RES	NR	Solar PT w/St	100	2027	28	92	584	784	56	490,560
	NR	Large Aero	400	2028	200	400	784	1184	56	490,560
RES	NR	Solar PT w/St	100	2029	28	92	812	1276	84	735,840
						Min	**(169)**	**(240)**		
						STDEV	**419**	**491**		
						AVG	**781**	**705**		

CR = Committed Resource
NR = New Resource
MP = Market Purchase



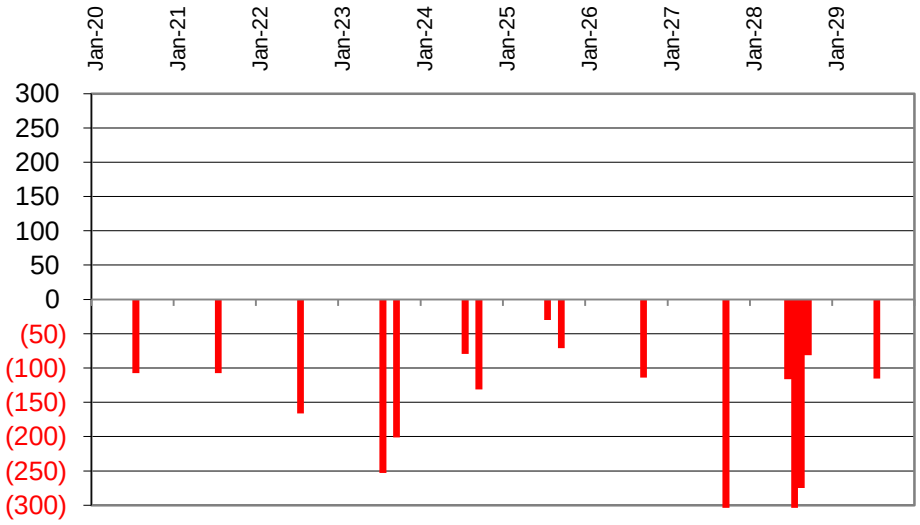


2-4 Wind & Peakers

RES	Type	Resource	Nameplate MW	Year	Energy	Peak	Cum. Energy	Cum. Peak	Cum. RES MW	Cum. RES MWh
	NR	Large Aero	100	2020			0	0	0	-
				2021			0	0	0	-
RES	NR	Wind	100	2022	30	5	30	5	30	262,800
				2023			30	5	30	262,800
	NR	Large Aero	200	2024	100	200	130	205	30	262,800
		Gateway West	100	2025	100	100	230	305	30	262,800
	NR	Large Aero	200	2026	50	100	280	405	30	262,800
RES	NR	Wind	400	2027	128	20	408	425	158	1,384,080
	NR	Large Aero	400	2028	200	400	608	825	158	1,384,080
	NR	Large Aero	500	2029	250	500	858	1325	158	1,384,080
						Min	**(345)**	**(599)**		
						STDEV	**384**	**460**		
						AVG	**648**	**504**		

CR = Committed Resource
NR = New Resource
MP = Market Purchase

Peak-Hour



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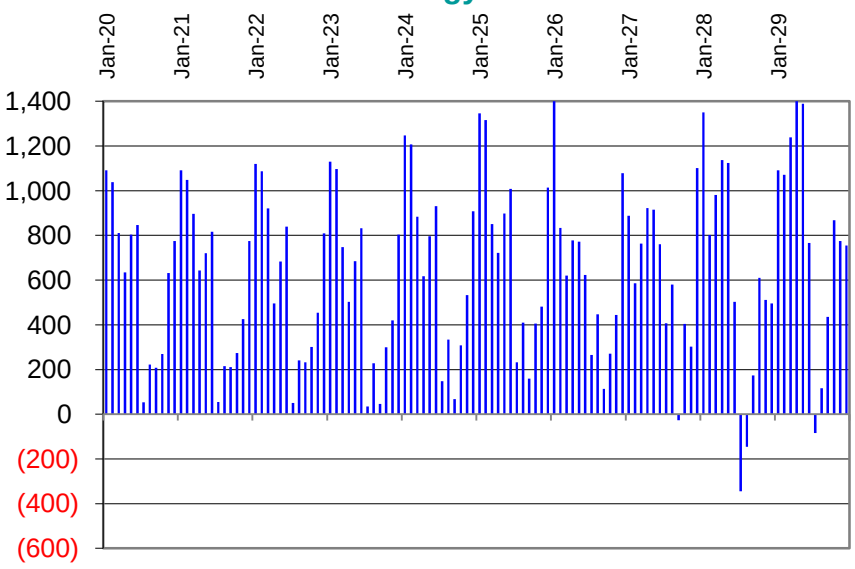
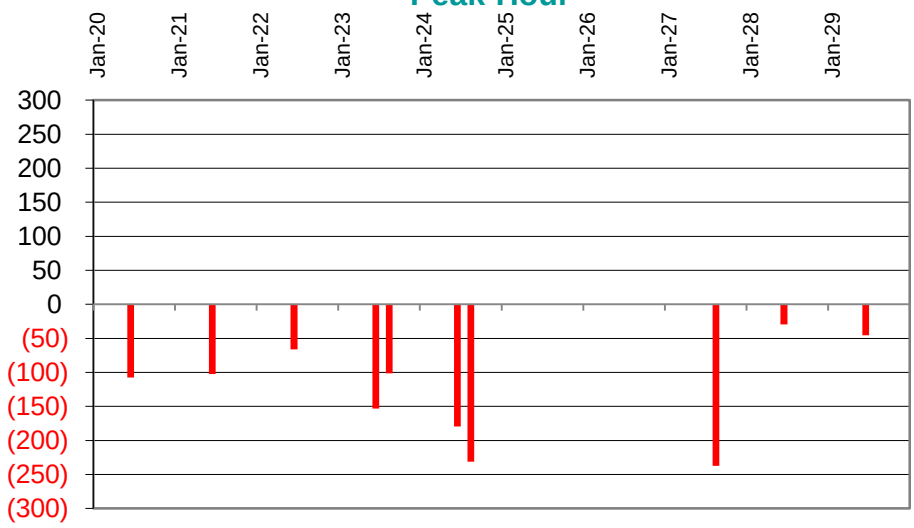


2-5 Limited Coal Curtailment

RES	Type	Resource	Nameplate MW	Year	Energy	Peak	Cum. Energy	Cum. Peak	Cum. RES MW	Cum. RES MWh
				2020			0	0	0	-
RES	NR	Wind	100	2021	32	5	32	5	32	280,320
	NR	Large Aero	100	2022	50	100	82	105	32	280,320
				2023			82	105	32	280,320
				2024			82	105	32	280,320
		Existing Coal	350	2025	152	380	234	485	32	280,320
	NR	Large Aero	100	2026	50	100	284	585	32	280,320
RES	NR	Wind	200	2027	64	10	348	595	96	840,960
	NR	Large Aero	100	2027	50	100	398	695	96	840,960
		Existing Coal	700	2028	350	700	748	1395	96	840,960
				2029			748	1395	96	840,960
						Min	**(205)**	**(237)**		
						STDEV	**371**	**510**		
						AVG	**647**	**632**		

CR = Committed Resource
NR = New Resource
MP = Market Purchase

Peak-Hour



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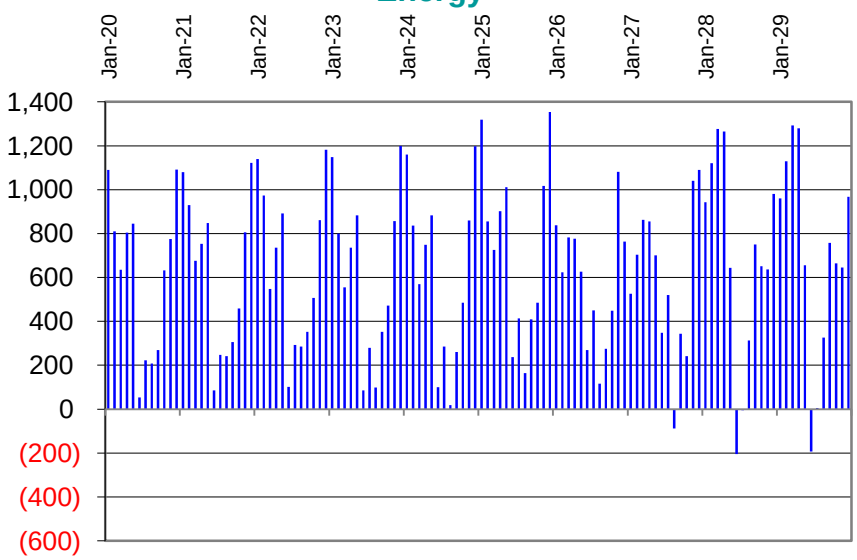
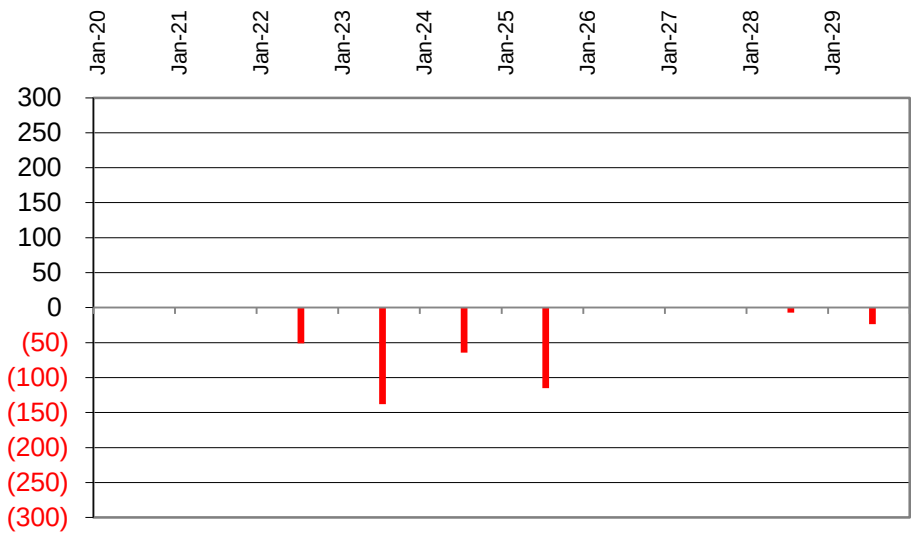


2-6 No Coal Curtailment

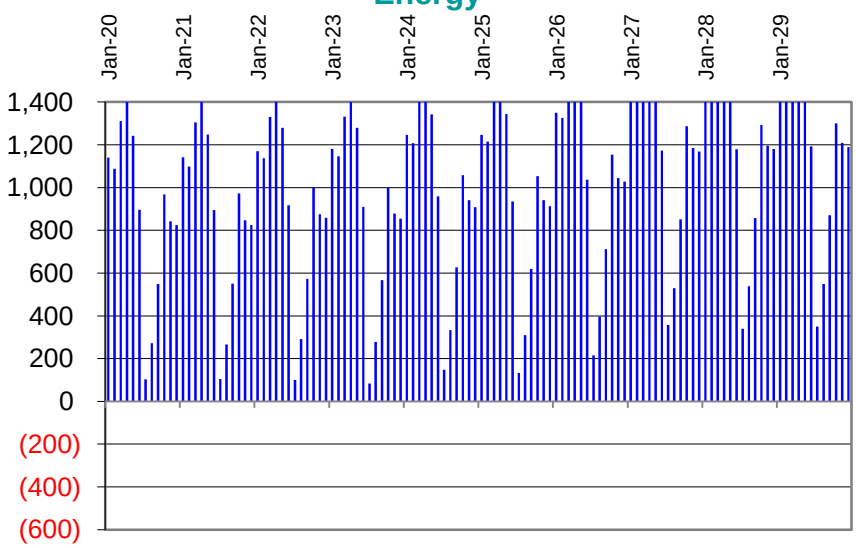
RES	Type	Resource	Nameplate MW	Year	Energy	Peak	Cum. Energy	Cum. Peak	Cum. RES MW	Cum. RES MWh
		Large Aero	100	2020	50	100	50	100	0	-
				2021			50	100	32	280,320
RES	NR	Wind	100	2022	30	5	80	105	32	280,320
				2023			80	105	32	280,320
		Large Aero	100	2024	50	100	130	205	32	280,320
				2025			130	205	32	280,320
	NR	Large Aero	200	2026	100	200	230	405	32	280,320
RES	NR	Wind	400	2027	128	20	358	425	96	840,960
				2027			358	425	96	840,960
				2028			358	425	96	840,960
				2029			358	425	96	840,960
						Min	**84**	**(138)**		
						STDEV	**432**	**245**		
						AVG	**1,029**	**550**		

CR = Committed Resource
NR = New Resource
MP = Market Purchase

Peak-Hour



Energy



Resource Portfolio Modeling Assumptions

Time Period	Figure Name	Coal Curtailment[1]	Carbon Adder[2]	NTTG Transmission Plan[3]	Only IPC Transmission Share of B2H[4]	Limited Coal Curtailment[5]
2010–2019	Base Case, Coal Curtailment *Used in first 10-year Portfolio Selection Process*	X			X	
2010–2019	Base Case, Coal Curtailment	X		X		
2010–2019	$43 CO2, No Coal Curtailment		X	X		
2010–2019	Current Operations, No Carbon, No Coal Curtailment			X		
2020–2029	Base Case, Coal Curtailment *Used in second 10-Year Portfolio Selection Process*	X		X		2-5 Only
2020–2029	$43 CO2, No Coal Curtailment		X	X		
2020–2029	Current Operations, No Carbon, No Coal Curtailment			X		

[1]Idaho Power coal plants are curtailed to comply with HR 2454

[2]$43 per ton added starting in 2012

[3]Includes all NTTG projects at estimated capacity estimate ratings

[4]Transmission paths in the Aurora model are unconstrained to levels of anticipated use by Idaho Power

[5]Coal curtailed to 2020 targets (partial HR 2454 compliance)

RESOURCE PORTFOLIO ANALYSIS
Base Case, Coal Curtailment (2010–2019)

Base Case—Coal Curtailment	1-1 Solar	1-2 Gas (Peaker)	1-3 Gas (Peaker & B2H)	1-4 B2H
Capital Costs 2009 ($ Total)	$ 1,264,351,176	$ 266,751,176	$ 249,551,176	$ 96,951,176
Capital Costs NPV ($ 20 Year)	$ 621,711,410	$ 239,909,076	$ 178,705,464	$ 107,198,820
Aurora NPV Portfolio Total Cost	$ 1,963,326,421	$ 2,066,337,264	$ 2,032,468,672	$ 2,063,765,789
NPV Total = Aurora + Capital	**$ 2,585,037,830**	**$ 2,306,246,340**	**$ 2,211,174,136**	**$ 2,170,964,609**
CO_2 Excess Emissions (Tons)	117,808	288,017	429,833	258,563
RES Excess Green Tags year 2019	684,156	193,596	193,596	193,596
Carbon Allowances Estimates	**117,808**	**288,017**	**429,833**	**258,563**
Boxer/Kerry Price Cap Proposal NPV	$ (263,462)	$ 1,467,059	$ 5,163,204	$ 1,839,437
2019 Res Position Estimates	**684,156**	**193,596**	**193,596**	**193,596**
RES NPV $ Estimates Yr 1–10				
Expected Value (Cost Reduction)	$ (46,921,264)	$ (37,338,255)	$ (37,338,255)	$ (37,338,255)
Transmission	$ 13,163,761	$ 10,977,415	$ 55,403,269	$ 94,451,794
Expected Portfolio Cost	**$ 2,551,016,864**	**$ 2,281,352,560**	**$ 2,234,402,354**	**$ 2,229,917,585**
Rank by Least Cost	**4**	**3**	**2**	**1**
Difference	**$ 321,099,279**	**$ 51,434,974**	**$ 4,484,769**	**$ -**
Risk Factors				
CO_2 $43 (Incremental)	$ 4,802,283	$ 13,851,809	$ 23,646,013	$ 12,957,638
RES NPV $ Estimates Yr 1–10				
High Value (Additional to Expected)	$ (55,685,534)	$ (41,902,289)	$ (41,902,289)	$ (41,902,289)
DSM 50% Realization (Cost Difference)	$ 51,876,928	$ 38,966,959	$ 71,495,131	$ 40,522,318
High Load Growth (Cost Difference)	$ 290,681,839	$ 288,768,701	$ 320,277,146	$ 289,732,784
Gas Price				
High NG Prices differential from Low	$ (36,516,721)	$ (40,577,759)	$ (7,744,434)	$ (38,094,952)
Transmission B2H				
With 3rd-Party Participation NPV			($16,726,745)	($46,086,195)
Total Risk Cost	**$ 255,158,795**	**$ 259,107,422**	**$ 349,044,823**	**$ 217,129,304**
Rank by Least Risk	**2**	**3**	**4**	**1**
Difference	**$ 38,029,491**	**$ 41,978,118**	**$ 131,915,519**	**$ -**
Portfolio Differences w/Cost Risk Adj				
High	$ 631,943,608	$ 352,444,685	$ 395,431,881	$ 259,031,593

RESOURCE PORTFOLIO ANALYSIS
Base Case, Coal Curtailment (2010–2019)

Base Case—Coal Curtailment	1-1 Solar	1-2 Gas Peaker	1-3 Gas Peaker & B2H	1-4 B2H
Capital Costs 2009 ($ Total)	$ 1,328,502,353	$ 363,702,353	$ 346,502,353	$ 193,902,353
Capital Costs NPV$ 20 Year	$ 621,711,410	$ 239,909,076	$ 178,705,464	$ 107,198,820
Aurora NPV Portfolio Total Cost	$ 1,976,455,828	$ 2,021,669,045	$ 2,017,973,554	$ 2,021,858,588
NPV Total = Aurora + Capital	**$ 2,598,167,238**	**$ 2,261,578,121**	**$ 2,196,679,018**	**$ 2,129,057,408**
CO_2 Excess Emissions (Tons)	(9,258)	57,787	213,135	73,737
RES Excess Green Tags year 2019	684,156	193,596	193,596	193,596
Carbon Allowances Needed Estimates	**(9,258)**	**57,787**	**213,135**	**73,737**
Boxer/Kerry Price Cap Proposal NPV	$ (263,462)	$ 1,467,059	$ 5,163,204	$ 1,839,437
2019 Res Position Estimates	**684,156**	**193,596**	**193,596**	**193,596**
RES NPV $ Estimates Yr 1–10				
Expected Value (Cost Reduction)	$ (46,921,264)	$ (37,338,255)	$ (37,338,255)	$ (37,338,255)
Transmission	$ 13,163,761	$ 10,977,415	$ 55,403,269	$ 94,451,794
Expected Portfolio Cost	**$ 2,564,146,272**	**$ 2,236,684,340**	**$ 2,219,907,236**	**$ 2,188,010,384**
Rank	**4**	**3**	**2**	**1**
Difference NPV 1–10 Years	**$ 376,135,888**	**$ 48,673,956**	**$ 31,896,852**	**$ -**
Risk Factors				
CO_2 $43 (Incremental)	$ (661,560)	$ 3,951,893	$ 14,327,997	$ 5,010,136
RES NPV $ Estimates Yr 1-10				
High Value (Additional to Expected)	$ (55,685,534)	$ (41,902,289)	$ (41,902,289)	$ (41,902,289)
DSM 50% Realization (Cost Difference)	$ 27,566,134	$ 88,116,160	$ 85,454,235	$ 87,129,172
High Load Growth (Cost Difference)	$ 267,685,288	$ 327,202,920	$ 325,597,765	$ 327,887,601
Gas Price				
High NG Prices differential from Low	$ (49,646,128)	$ 4,090,460	$ 6,750,684	$ 3,812,250
Transmission B2H				
No resell IPC Outbound NPV			($16,726,745)	($46,086,195)
No Third Party Participation 1–10 Years (Not Inlcuded in totals below)			*$211,215,269*	*$201,526,193*
11–20 Year Transmission Rev Req IPC Sells Outbound			*$47,299,585*	*$59,148,872*
11–20 Year Transmission Rev Req IPC Does Not Sell Outbound			*$67,755,614*	*$115,510,138.56*
11–20 Year Trans Rev Req IPC No Third Party Participation			*$600,050,525*	*$600,050,525.21*
Portfolio Differences w/Cost Risk Adj				
High	$ 621,079,622	$ 472,035,389	$ 447,300,789	$ 377,752,964
High w/Transmission	**$ 574,993,427**	**$ 425,949,195**	**$ 401,214,594**	**$ 377,752,964**
Low	$ 565,394,088	$ 430,133,100	$ 405,398,500	$ 335,850,675
Low w/Transmission	**$ 519,307,893**	**$ 384,046,905**	**$ 359,312,305**	**$ 335,850,675**
Rank	4	3	2	1

RESOURCE PORTFOLIO ANALYSIS
$43 CO_2, No Coal Curtailment (2010–2019)

$43 CO2—No Coal Curtailment	1-1 Solar	1-2 Gas Peaker	1-3 Gas Peaker & B2H	1-4 B2H
Capital Costs 2009 ($ Total)	$ 1,328,502,353	$ 363,702,353	$ 346,502,353	$ 193,902,353
Capital Costs NPV 20-Year	$ 621,711,410	$ 239,909,076	$ 178,705,464	$ 107,198,820
Aurora NPV Portfolio Total Cost	$ 3,613,437,405	$ 3,701,347,429	$ 3,703,473,275	$ 3,698,952,139
NPV Total = Aurora + Capital	**$ 4,235,148,815**	**$ 3,941,256,505**	**$ 3,882,178,739**	**$ 3,806,150,959**
CO_2 Excess Emissions (Tons)	7,758,441	7,705,353	8,323,589	7,584,025
RES Excess Green Tags year 2019	684,156	193,596	193,596	193,596
2019 Res Position	684,156	193,596	193,596	193,596
RES Net Valuation Estimates Yr 1–10 Expected Value (Cost Reduction)	$ (46,921,264)	$ (37,338,255)	$ (37,338,255)	$ (37,338,255)
Transmission B2H Fully Subscribed NPV	$ 13,163,761	$ 10,977,415	$ 55,403,269	$ 94,451,794
Expected Portfolio Cost	**$ 4,201,391,311**	**$ 3,914,895,665**	**$ 3,900,243,754**	**$ 3,863,264,498**
Rank	**4**	**3**	**2**	**1**
Difference	**$ 338,126,813**	**$ 51,631,167**	**$ 36,979,255**	**$ -**

RESOURCE PORTFOLIO ANALYSIS
Current Operations, No Carbon, No Coal Curtailment (2010–2019)

Current Operations, No carbon, No Curtailment	1-1 Solar	1-2 Gas Peaker	1-3 Gas Peaker & B2H	1-4 B2H
Capital Costs 2009 ($ Total)	$ 1,328,502,353	$ 363,702,353	$ 346,502,353	$ 193,902,353
Capital Costs NPV 20-Year	$ 621,711,410	$ 239,909,076	$ 178,705,464	$ 107,198,820
Aurora NPV Portfolio Total Cost	$ 1,907,178,616	$ 2,001,439,129	$ 2,000,008,019	$ 2,001,618,009
NPV Total = Aurora + Capital	**$ 2,528,890,026**	**$ 2,241,348,205**	**$ 2,178,713,483**	**$ 2,108,816,829**
CO_2 Excess Emissions (Tons)	5,272,549	5,312,589	5,453,587	5,364,722
RES Excess Green Tags year 2019	684,156	193,596	193,596	193,596
Carbon Allowances Needed Estimates	**5,272,549**	**5,312,589**	**5,453,587**	**5,364,722**
Boxer/Kerry Price Cap Proposal NPV	$ 127,454,073	$ 128,498,367	$ 131,857,808	$ 129,738,767
2019 Res Position	684,156	193,596	193,596	193,596
RES Net Valuation Estimates Yr 1–10 Expected Value (Cost Reduction)	$ (46,921,264)	$ (37,338,255)	$ (37,338,255)	$ (37,338,255)
Transmission B2H Fully Subscribed NPV	$ 13,163,761	$ 10,977,415	$ 55,403,269	$ 94,451,794
Expected Portfolio Cost	**$ 2,622,586,596**	**$ 2,343,485,731**	**$ 2,328,636,306**	**$ 2,295,669,136**
Rank	**4**	**3**	**2**	**1**
Difference	**$ 326,917,459**	**$ 47,816,595**	**$ 32,967,170**	**$ -**

RESOURCE PORTFOLIO ANALYSIS
Base Case, Coal Curtailment (2020–2029)

Base Case—Coal Curtailment	2-1 Nuclear Green	2-2 Gateway West	2-3 IGCC	2-4 Wind & Peakers	2-5 Limited Coal Curtailment
Capital Costs 2009 ($ Total)	$ 5,834,274,000	$ 355,600,000	$ 5,123,200,000	$ 1,957,200,000	$ 762,300,000
Capital Costs NPV$ 20 Year	$ 2,267,193,086	$ 150,871,393	$ 1,724,352,346	$ 479,620,560	$ 241,162,616
Aurora NPV Portfolio Total Cost	$ 948,612,021	$ 1,805,716,731	$ 1,106,374,123	$ 1,671,794,651	$ 1,461,869,774
NPV Total = Aurora + Capital	**$ 3,215,805,108**	**$ 1,956,588,124**	**$ 2,830,726,469**	**$ 2,151,415,212**	**$ 1,703,032,390**
CO_2 Excess Emissions (Tons)	6,186,401	7,268,164	6,401,005	8,328,556	26,657,888
RES Excess Green Tags year 2019	1,267,572	(7,884)	167,316	815,556	272,436
Carbon Allowances Needed Estimates	6,186,401	7,268,164	6,401,005	8,328,556	26,657,888
Boxer/Kerry Price Cap Proposal NPV	**$ (30,674,006)**	**$ (8,100,874)**	**$ (26,194,772)**	**$ 14,030,419**	**$ 396,574,720**
2029 Res Position Estimates	**1,267,572**	**(7,884)**	**167,316**	**815,556**	**272,436**
RES NPV $ Estimates Yr 1–10					
Expected Value (Cost Reduction)	$ (99,699,468)	$ (1,485,655)	$ 8,518,747	$ (17,665,567)	$ (6,796,825)
Transmission Estimate NPV	$ 849,733,630	$ 1,408,824,342	$768,798,180.04	$452,114,922	$207,800,668.18
Expected Portfolio Cost	**$ 3,935,165,264**	**$ 3,355,825,937**	**$ 3,581,848,625**	**$ 2,599,894,987**	**$ 2,300,610,952**
Rank by Least Cost	**5**	**3**	**4**	**2**	**1**
Difference	**$ 1,634,554,312**	**$ 1,055,214,985**	**$ 1,281,237,672**	**$ 299,284,034**	**$ -**
Risk Factors					
CO_2 $43 (Incremental)	$ 296,689,242	$ 320,631,927	$ 301,438,004	$ 344,097,492	$ 749,714,446
RES NPV $ Estimates Yr 11–20					
High Value (Additional to Expected)	$ (149,549,202)	$ (2,228,482)	$ 12,778,121	$ (26,498,351)	$ (10,195,238)
DSM 50% Realization (Cost Difference)	$ 110,191,842	$ 116,351,682	$ 113,762,113	$ 116,777,644	$ 24,354,437
High Load Growth (Cost Difference)	$ 465,800,512	$ 486,161,488	$ 473,734,605	$ 486,948,952	$ 392,322,637
Gas Price					
High NG Prices sensitivity	$ (83,134,652)	$ 199,963,861	$ (96,394,526)	$ 294,198,968	$ (97,212,291)
Transmission B2H					
Zero 3rd-Party Participation NPV					
Total Risk Cost	$ 639,997,742	$ 1,120,880,476	$ 805,318,318	$ 1,215,524,706	$ 1,058,983,991
Rank by Least Risk	**1**	**4**	**2**	**5**	**3**
Difference	**$ -**	**$ 480,882,734**	**$ 165,320,575**	**$ 575,526,964**	**$ 418,986,249**
Portfolio Differences w/Cost Risk Adj					
High	$ 2,424,101,255	$ 2,178,323,943	$ 2,073,777,869	$ 1,541,307,091	$ 1,069,179,229
High w/Transmission	**$ 2,424,101,255**	**$ 2,178,323,943**	**$ 2,073,777,869**	**$ 1,541,307,091**	**$ 1,069,179,229**
Low	$ 2,573,650,457	$ 2,180,552,425	$ 2,060,999,748	$ 1,567,805,441	$ 1,079,374,467
Low w/Transmission	**$ 2,573,650,457**	**$ 2,180,552,425**	**$ 2,060,999,748**	**$ 1,567,805,441**	**$ 1,079,374,467**
Rank	**5**	**4**	**3**	**2**	**1**

RESOURCE PORTFOLIO ANALYSIS
$43 CO_2, No Coal Curtailment (2020–2029)

$43 CO2—No Coal Curtailment	2-1 Nuclear/Green	2-2 Gateway West	2-3 IGCC	2-4 Wind & Peakers	2-5 Limited Coal Curtailment
Capital Costs 2009 ($ Total)	$ 5,834,274,000	$ 355,600,000	$ 5,123,200,000	$ 1,957,200,000	$ 762,300,000
Capital Costs NPV $20 Year	$ 2,267,193,086	$ 150,871,393	$ 1,724,352,346	$ 479,620,560	$ 241,162,616
Aurora NPV Portfolio Total Cost	$ 1,684,893,917	$ 2,689,899,037	$ 1,878,056,113	$ 2,646,447,583	$ 2,689,352,379
NPV Total = Aurora + Capital	**$ 3,952,087,004**	**$ 2,840,770,430**	**$ 3,602,408,459**	**$ 3,126,068,143**	**$ 2,930,514,994**
CO_2 Excess Emissions (Tons)	-	-	-	-	-
RES Excess Green Tags year 2019	1,267,572	(7,884)	167,316	815,556	272,436
Carbon Allowances Needed Estimates	-	-	-	-	-
Boxer/Kerry Price Cap Proposal NPV	**$ (30,674,006)**	**$ (8,100,874)**	**$ (26,194,772)**	**$ 14,030,419**	**$ 396,574,720**
2029 Res Position Estimates	**1,267,572**	**(7,884)**	**167,316**	**815,556**	**272,436**
RES NPV $ Estimates Yr 1–10 Expected Value (Cost Reduction)	$ (99,699,468)	$ (1,485,655)	$ 8,518,747	$ (17,665,567)	$ (6,796,825)
Transmission Estimate NPV	$ 849,733,630	$ 1,408,824,342	$768,798,180.04	$452,114,922	$207,800,668.18
Expected Portfolio Cost	**$ 4,671,447,160**	**$ 4,240,008,243**	**$ 4,353,530,615**	**$ 3,574,547,918**	**$ 3,528,093,556**
Rank by Least Cost	**5**	**3**	**4**	**2**	**1**
Difference	**$ 1,143,353,603**	**$ 711,914,687**	**$ 825,437,058**	**$ 46,454,362**	**$ -**

RESOURCE PORTFOLIO ANALYSIS
Current Operations, No Carbon, No Coal Curtailment (2020–2029)

Current Operations No carbon No curtailment	2-1 Nuclear/Green	2-2 Gateway West	2-3 IGCC	2-4 Wind & Peakers	2-5 Limited Coal Curtailment
Capital Costs 2009 ($ Total)	$ 5,834,274,000	$ 355,600,000	$ 5,123,200,000	$ 1,957,200,000	$ -
Capital Costs NPV $20 Year	$ 2,267,193,086	$ 150,871,393	$ 1,724,352,346	$ 479,620,560	$ -
Aurora NPV Portfolio Total Cost	$ 664,260,485	$ 1,331,464,010	$ 807,979,508	$ 1,251,035,806	$ -
NPV Total = Aurora + Capital	**$ 2,931,453,572**	**$ 1,482,335,403**	**$ 2,532,331,854**	**$ 1,730,656,367**	**$ -**
CO_2 Excess Emissions (Tons)	41,437,283	42,239,982	41,302,614	42,968,883	-
RES Excess Green Tags year 2019	1,267,572	(7,884)	167,316	815,556	-
Carbon Allowances Needed Estimates	41,437,283	42,239,982	41,302,614	42,968,883	-
Boxer/Kerry Price Cap Proposal NPV	**$ (30,674,006)**	**$ (8,100,874)**	**$ (26,194,772)**	**$ 14,030,419**	**$ 396,574,720**
2029 Res Position Estimates	**1,267,572**	**(7,884)**	**167,316**	**815,556**	**-**
RES NPV $ Estimates Yr 1–10 Expected Value (Cost Reduction)	$ (99,699,468)	$ (1,485,655)	$ 8,518,747	$ (17,665,567)	$ (6,796,825)
Transmission Estimate NPV	$ 849,733,630	$ 1,408,824,342	$768,798,180.04	$452,114,922	$207,800,668.18
Expected Portfolio Cost	**$ 3,650,813,728**	**$ 2,881,573,215**	**$ 3,283,454,009**	**$ 2,179,136,141**	**$ 597,578,562**
Rank by Least Cost	**5**	**3**	**4**	**2**	**1**
Difference	**$ 3,650,813,728**	**$ 2,881,573,215**	**$ 3,283,454,009**	**$ 2,179,136,141**	**$ 597,578,562**

2009 Integrated Resource Plan

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 2-5

Project	Capital Cost
Gateway 19% owned by IPCo (300/1600)	$ 337,500,000
300 Wind	Included in GW
1050 Existing Coal	

Annual Revenue Requirements

Existing Revenue Requirements	$	106,566,650
Existing Revenue Credits	$	(17,510,193)
Existing Net Revenue Requirements	$	89,056,456
New Project Capital	**$**	**337,500,000**
New Revenue Requirements for Project(s)	$	54,023,495
New Net Revenue Requirements	$	143,079,951

System Use (in MW)

Existing System Peak Demand	5,627
Future additional IPC Network Use	**300**
New System Demand—Including new uses	5,927

Point-To-Point Transmission Rate

a) Existing Rate—$/kW-yr	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr	$	24.14

Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)

Change in existing uses (increase > 100%)		100%
Existing uses adjusted at new rate b)	$	(9,198,010)

Network Transmission Revenue Requirements

a) Existing		
BPA Load Ratio Share	$	4,237,114
Long-Term PTP Revenue	$	7,375,757
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	70,700,764
b) Future - New Projects without additional participation		
BPA Load Ratio Share	$	6,028,365
Long-Term PTP Revenue	$	11,250,202
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	119,058,562
Net change	**$**	**48,357,798**

2009 Integrated Resource Plan

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 1-2

Project	Capital Cost
Two 170 MW Peakers at Langley	$ 22,000,000

Annual Revenue Requirements

Existing Revenue Requirements	$	106,566,650
Existing Revenue Credits	$	(17,510,193)
Existing Net Revenue Requirements	$	89,056,456
New Project Capital	**$**	**22,000,000**
New Revenue Requirements for Project(s)	$	3,521,532
New Net Revenue Requirements	$	92,577,988

System Use (in MW)

Existing System Peak Demand	5,627
Future additional IPC Network Use	**340**
New System Demand—Including new uses	5,967

Point-To-Point Transmission Rate

a) Existing Rate—$/kW-yr	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr	$	15.52

Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)

Change in existing uses (increase > 100%)		100%
Existing uses adjusted at new rate b)	$	344,857

Network Transmission Revenue Requirements

a) Existing		
BPA Load Ratio Share	$	4,237,114
Long-Term PTP Revenue	$	7,375,757
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	70,700,764
b) Future		
BPA Load Ratio Share	$	4,154,388
Long-Term PTP Revenue	$	7,230,494
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	74,450,284
Net change	**$**	**3,749,520**

2009 Integrated Resource Plan

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 1-3 with additional 3rd party subscription

Project	Capital Cost	
B2H 11% Owned by IPCo (250/2300)	$	65,217,391
Two 100MW Aeros at Langley	$	22,000,000

Annual Revenue Requirements

Existing Revenue Requirements	$	106,566,650
Existing Revenue Credits	$	(17,510,193)
Existing Net Revenue Requirements	$	89,056,456
New Project Capital	**$**	**87,217,391**
New Revenue Requirements for Project(s)	$	13,960,854
New Net Revenue Requirements	$	103,017,310

System Use (in MW)

Existing System Peak Demand	5,627
Future additional IPC Network Use	**450**
New System Demand—Including new uses	6,077

Point-To-Point Transmission Rate

a) Existing Rate—$/kW-yr	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr	$	16.95

Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)

Change in existing uses (increase > 100%)		100%
Existing uses adjusted at new rate b)	$	(1,244,978)

Network Transmission Revenue Requirements

a) Existing		
BPA Load Ratio Share	$	4,237,114
Long-Term PTP Revenue	$	7,375,757
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	70,700,764
b) Future - B2H with additional participation		
BPA Load Ratio Share	$	4,462,935
Long-Term PTP Revenue	$	7,900,174
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	83,911,380
Net change	**$**	**13,210,615**

2009 Integrated Resource Plan

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 1-3 without additional 3rd party subscription

Project	Capital Cost	
B2H 22% Owned by IPCo (500/2300)	$	130,434,783
Two 100MW Aeros at Langley	$	22,000,000

Annual Revenue Requirements

Existing Revenue Requirements	$	106,566,650
Existing Revenue Credits	$	(17,510,193)
Existing Net Revenue Requirements	$	89,056,456
New Project Capital	**$**	**152,434,783**
New Revenue Requirements for Project(s)	$	24,400,177
New Net Revenue Requirements	$	113,456,633

System Use (in MW)

Existing System Peak Demand	5,627
Future additional IPC Network Use	**450**
New System Demand—Including new uses	6,077

Point-To-Point Transmission Rate

a) Existing Rate—$/kW-yr	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr	$	18.67

Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)

Change in existing uses (increase > 100%)		100%
Existing uses adjusted at new rate b)	$	(3,145,545)

Network Transmission Revenue Requirements

a) Existing		
BPA Load Ratio Share	$	4,237,114
Long-Term PTP Revenue	$	7,375,757
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	70,700,764
b) Future - B2H without additional participation		
BPA Load Ratio Share	$	4,837,378
Long-Term PTP Revenue	$	8,700,743
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	93,175,690
Net change	**$**	**22,474,926**

2009 Integrated Resource Plan

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 1-4 with additional 3rd party subscription

Project	Capital Cost
B2H 19% owned by IPCo (425/2300)	$ 110,869,565
450 Market Purchase	included in B2H

Annual Revenue Requirements		
Existing Revenue Requirements	$	106,566,650
Existing Revenue Credits	$	(17,510,193)
Existing Net Revenue Requirements	$	89,056,456
New Project Capital	**$**	**110,869,565**
New Revenue Requirements for Project(s)	$	17,746,849
New Net Revenue Requirements	$	106,803,305

System Use (in MW)	
Existing System Peak Demand	5,627
Future additional IPC Network Use	**425**
New System Demand—Including new uses	6,052

Point-To-Point Transmission Rate		
a) Existing Rate—$/kW-yr	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr	$	17.65

Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)		
Change in existing uses (increase > 100%)		100%
Existing uses adjusted at new rate b)	$	(2,014,578)

Network Transmission Revenue Requirements		
a) Existing		
BPA Load Ratio Share	$	4,237,114
Long-Term PTP Revenue	$	7,375,757
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	70,700,764
b) Future - B2H with additional participation		
BPA Load Ratio Share	$	4,615,289
Long-Term PTP Revenue	$	8,224,350
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	87,220,844
Net change	**$**	**16,520,080**

2009 Integrated Resource Plan

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 1-4 without additional 3rd party subscription

Project	Capital Cost
B2H 37% owned by IPCo (850/2300)	$ 221,739,130
450 Market Purchase	included in B2H

Annual Revenue Requirements		
Existing Revenue Requirements	$	106,566,650
Existing Revenue Credits	$	(17,510,193)
Existing Net Revenue Requirements	$	89,056,456
New Project Capital	**$**	**221,739,130**
New Revenue Requirements for Project(s)	$	35,493,697
New Net Revenue Requirements	$	124,550,153

System Use (in MW)	
Existing System Peak Demand	5,627
Future additional IPC Network Use	**425**
New System Demand—Including new uses	6,052

Point-To-Point Transmission Rate		
a) Existing Rate—$/kW-yr	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr	$	20.58

Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)		
Change in existing uses (increase > 100%)		100%
Existing uses adjusted at new rate b)	$	(5,258,889)

Network Transmission Revenue Requirements		
a) Existing		
BPA Load Ratio Share	$	4,237,114
Long-Term PTP Revenue	$	7,375,757
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	70,700,764
b) Future - B2H without additional participation		
BPA Load Ratio Share	$	5,254,035
Long-Term PTP Revenue	$	9,590,940
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	102,962,357
Net change	**$**	**32,261,593**

2009 Integrated Resource Plan

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 2-1

Project	Capital Cost
Gateway 44% owned by IPCo (1020/2300)	$ 1,316,021,739
250 East Side Purchase	included in GW
670 MW Nuclear	included in GW
300 MW Solar	$ 7,500,000
104 MW Geothermal	$ 30,000,000

Annual Revenue Requirements

Existing Revenue Requirements	$	106,566,650
Existing Revenue Credits	$	(17,510,193)
Existing Net Revenue Requirements	$	89,056,456
New Project Capital	**$**	**1,353,521,739**
New Revenue Requirements for Project(s)	$	216,657,702
New Net Revenue Requirements	$	305,714,159

System Use (in MW)

Existing System Peak Demand	5,627
Future additional IPC Network Use	**1,424**
New System Demand—Including new uses	7,051

Point-To-Point Transmission Rate

a) Existing Rate—$/kW-yr	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr	$	43.36

Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)

Change in existing uses (increase > 100%)		100%
Existing uses adjusted at new rate b)	$	(30,458,820)

Network Transmission Revenue Requirements

a) Existing		
BPA Load Ratio Share	$	4,237,114
Long-Term PTP Revenue	$	7,375,757
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	70,700,764
b) Future - New Projects without additional participation		
BPA Load Ratio Share	$	10,321,179
Long-Term PTP Revenue	$	20,205,817
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	268,444,341
Net change	**$**	**197,743,576**

2009 Integrated Resource Plan

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 2-2

Project	Capital Cost
Gateway 60% owned by IPCo (900/1500)	$ 1,780,500,000
MSTI 47% owned by IPCo (700/1500)	$ 466,666,667
700 MW East Side Purchase (Wyoming)	included in GW
200 MW Wind	Included in GW

Annual Revenue Requirements

Existing Revenue Requirements	$	106,566,650
Existing Revenue Credits	$	(17,510,193)
Existing Net Revenue Requirements	$	89,056,456
New Project Capital	**$**	**2,247,166,667**
New Revenue Requirements for Project(s)	$	359,703,101
New Net Revenue Requirements	$	448,759,557

System Use (in MW)

Existing System Peak Demand	5,627
Future additional IPC Network Use	**1,600**
New System Demand—Including new uses	7,227

Point-To-Point Transmission Rate

a) Existing Rate—$/kW-yr	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr	$	62.10

Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)

Change in existing uses (increase > 100%)		100%
Existing uses adjusted at new rate b)	$	(51,188,896)

Network Transmission Revenue Requirements

a) Existing		
BPA Load Ratio Share	$	4,237,114
Long-Term PTP Revenue	$	7,375,757
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	70,700,764
b) Future - New Projects without additional participation		
BPA Load Ratio Share	$	14,527,165
Long-Term PTP Revenue	$	28,937,873
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	398,551,697
Net change	**$**	**327,850,933**

2009 Integrated Resource Plan

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 2-3

Project	Capital Cost	
Gateway 40% owned by IPCo (600/1500) (Aeolus-Hemingway)	$	1,187,000,000
300 MW Solar	$	7,500,000
400 Large Aero (simco Road)	$	32,000,000

Annual Revenue Requirements

Existing Revenue Requirements	$	106,566,650
Existing Revenue Credits	$	(17,510,193)
Existing Net Revenue Requirements	$	89,056,456
New Project Capital	**$**	**1,226,500,000**
New Revenue Requirements for Project(s)	$	196,325,382
New Net Revenue Requirements	$	285,381,838

System Use (in MW)

Existing System Peak Demand	5,627
Future additional IPC Network Use	**1,300**
New System Demand—Including new uses	6,927

Point-To-Point Transmission Rate

a) Existing Rate—$/kW-yr	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr	$	41.20

Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)

Change in existing uses (increase > 100%)		100%
Existing uses adjusted at new rate b)	$	(28,070,146)

Network Transmission Revenue Requirements

a) Existing		
BPA Load Ratio Share	$	4,237,114
Long-Term PTP Revenue	$	7,375,757
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	70,700,764
b) Future - New Projects without additional participation		
BPA Load Ratio Share	$	9,829,717
Long-Term PTP Revenue	$	19,199,644
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	249,609,655
Net change	**$**	**178,908,891**

2009 Integrated Resource Plan

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 2-4

Project	Capital Cost
Gateway 31% owned by IPCo (600/1600)	$ 675,000,000
500 Wind	Included in GW
100 MW East Side Purchase	included in GW
300 MW Aeros at Langley	$ 22,000,000
1100 MW Aeros At Simco	$ 102,000,000

Annual Revenue Requirements

Existing Revenue Requirements	$	106,566,650
Existing Revenue Credits	$	(17,510,193)
Existing Net Revenue Requirements	$	89,056,456
New Project Capital	**$**	**799,000,000**
New Revenue Requirements for Project(s)	$	127,895,622
New Net Revenue Requirements	$	216,952,078

System Use (in MW)

Existing System Peak Demand	5,627
Future additional IPC Network Use	**2,000**
New System Demand—Including new uses	7,627

Point-To-Point Transmission Rate

a) Existing Rate—$/kW-yr	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr	$	28.45

Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)

Change in existing uses (increase > 100%)		100%
Existing uses adjusted at new rate b)	$	(13,960,338)

Network Transmission Revenue Requirements

a) Existing		
BPA Load Ratio Share	$	4,237,114
Long-Term PTP Revenue	$	7,375,757
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	70,700,764
b) Future - New Projects without additional participation		
BPA Load Ratio Share	$	7,010,667
Long-Term PTP Revenue	$	13,256,220
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	189,942,369
Net change	**$**	**119,241,605**

2009 Integrated Resource Plan

Idaho Power Transmission Rate Approximation for 2009 IRP Analysis

Portfolio 2-5

Project	Capital Cost
Gateway 19% owned by IPCo (300/1600)	$ 337,500,000
300 Wind	Included in GW
1050 Existing Coal	

Annual Revenue Requirements

Existing Revenue Requirements	$	106,566,650
Existing Revenue Credits	$	(17,510,193)
Existing Net Revenue Requirements	$	89,056,456
New Project Capital	**$**	**337,500,000**
New Revenue Requirements for Project(s)	$	54,023,495
New Net Revenue Requirements	$	143,079,951

System Use (in MW)

Existing System Peak Demand	5,627
Future additional IPC Network Use	**300**
New System Demand—Including new uses	5,927

Point-To-Point Transmission Rate

a) Existing Rate—$/kW-yr	$	15.83
b) New Rate without 3rd-Party Use—$/kW-yr	$	24.14

Point-To-Point Revenue Adjustments (incremental change to Existing Revenue Credits)

Change in existing uses (increase > 100%)		100%
Existing uses adjusted at new rate b)	$	(9,198,010)

Network Transmission Revenue Requirements

a) Existing		
BPA Load Ratio Share	$	4,237,114
Long-Term PTP Revenue	$	7,375,757
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	70,700,764
b) Future - New Projects without additional participation		
BPA Load Ratio Share	$	6,028,365
Long-Term PTP Revenue	$	11,250,202
Legacy Contract Revenue	$	6,742,822
Assigned to IPC Retail Load Service	$	119,058,562
Net change	**$**	**48,357,798**

Loss of Load Expectation Summary Data—Preferred Portfolio (1-4 & 2-4)*

Year	Annual Preferred	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2010	0.66	0.00	0.00	0.00	0.00	0.01	0.10	0.43	0.06	0.06	0.00	0.00	0.01
2011	2.17	0.01	0.00	0.00	0.00	0.05	0.14	1.79	0.08	0.08	0.00	0.00	0.01
2012	1.57	0.01	0.00	0.00	0.00	0.02	0.85	0.48	0.11	0.06	0.00	0.00	0.01
2013	1.93	0.00	0.00	0.00	0.00	0.00	0.14	1.53	0.19	0.06	0.00	0.00	0.02
2014	1.91	0.00	0.00	0.00	0.00	0.01	0.26	1.36	0.21	0.06	0.00	0.00	0.02
2015	1.13	0.00	0.00	0.00	0.00	0.01	0.11	0.81	0.11	0.07	0.00	0.00	0.01
2016	1.48	0.00	0.00	0.00	0.00	0.03	0.10	1.15	0.13	0.05	0.00	0.00	0.01
2017	0.57	0.00	0.00	0.00	0.00	0.03	0.05	0.32	0.10	0.06	0.00	0.00	0.01
2018	0.69	0.00	0.00	0.00	0.00	0.02	0.03	0.47	0.09	0.05	0.00	0.00	0.01
2019	0.97	0.00	0.00	0.00	0.00	0.01	0.02	0.77	0.12	0.02	0.00	0.01	0.02
2020	0.71	0.00	0.00	0.00	0.00	0.02	0.02	0.64	0.02	0.01	0.00	0.00	0.00
2021	0.73	0.00	0.00	0.00	0.00	0.00	0.02	0.67	0.02	0.01	0.00	0.00	0.00
2022	1.05	0.00	0.00	0.00	0.00	0.00	0.03	0.97	0.02	0.01	0.00	0.00	0.00
2023	1.58	0.00	0.00	0.00	0.00	0.00	0.09	1.36	0.03	0.10	0.00	0.00	0.00
2024	0.83	0.00	0.00	0.00	0.00	0.00	0.01	0.79	0.00	0.03	0.00	0.00	0.00
2025	0.23	0.00	0.00	0.00	0.00	0.00	0.01	0.21	0.00	0.01	0.00	0.00	0.00
2026	0.14	0.00	0.00	0.00	0.00	0.00	0.07	0.05	0.00	0.02	0.00	0.00	0.00
2027	0.32	0.00	0.00	0.00	0.00	0.00	0.14	0.05	0.00	0.14	0.00	0.00	0.00
2028	3.22	0.00	0.00	0.00	0.00	0.00	0.24	2.89	0.09	0.01	0.00	0.00	0.00
2029	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

*With CBM @ 330 MW and 83 MW & 158 MW east-side purchases in 2013/2014 and 83 MW in 2028

Loss of Load Expectation Summary Data—Alternate Portfolio 1-2*

Year	Annual Preferred	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2014	1.91	0.00	0.00	0.00	0.00	0.01	0.26	1.36	0.21	0.06	0.00	0.00	0.02
2015	1.17	0.00	0.00	0.00	0.00	0.00	0.08	0.95	0.07	0.07	0.00	0.00	0.00
2016	1.68	0.00	0.00	0.00	0.00	0.01	0.12	1.34	0.14	0.08	0.00	0.00	0.00
2017	0.65	0.00	0.00	0.00	0.00	0.00	0.04	0.54	0.05	0.02	0.00	0.00	0.00
2018	0.99	0.00	0.00	0.00	0.00	0.00	0.07	0.81	0.07	0.03	0.00	0.00	0.00
2019	1.59	0.00	0.00	0.00	0.00	0.00	0.11	1.32	0.10	0.06	0.00	0.00	0.00

* With CBM @ 330 MW and 83 MW & 158 MW east-side purchases in 2013/2014
With CBM @ 330 MW and 83 east-side purchases in 2015 and beyond

Loss of Load Expectation Summary Data—Alternate Portfolio 2-5*

Year	Annual Preferred	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2019	0.97	0.00	0.00	0.00	0.00	0.01	0.02	0.77	0.12	0.02	0.00	0.01	0.02
2020	0.85	0.00	0.00	0.00	0.00	0.03	0.05	0.68	0.05	0.03	0.00	0.00	0.01
2021	0.93	0.00	0.00	0.00	0.00	0.04	0.06	0.71	0.07	0.05	0.00	0.00	0.01
2022	0.53	0.00	0.00	0.00	0.00	0.01	0.03	0.42	0.04	0.02	0.00	0.00	0.00
2023	0.75	0.00	0.00	0.00	0.00	0.02	0.08	0.57	0.05	0.03	0.00	0.00	0.00
2024	1.68	0.00	0.00	0.00	0.00	0.02	0.06	1.51	0.06	0.03	0.00	0.00	0.00
2025	1.31	0.00	0.00	0.00	0.00	0.02	0.08	1.09	0.07	0.05	0.00	0.00	0.00
2026	0.70	0.00	0.00	0.00	0.00	0.01	0.04	0.59	0.03	0.03	0.00	0.00	0.00
2027	0.34	0.00	0.00	0.00	0.00	0.00	0.04	0.28	0.01	0.01	0.00	0.00	0.00
2028	0.95	0.00	0.00	0.00	0.00	0.00	0.03	0.89	0.02	0.01	0.00	0.00	0.00
2029	0.48	0.00	0.00	0.00	0.00	0.00	0.03	0.41	0.01	0.02	0.00	0.00	0.00

*With CBM @ 330 MW and 83 MW purchases in 2020–2029

SALES AND LOAD FORECAST DATA

Average Annual Growth Rates (%)

	2010–2015	2010–2020	2010–2029
Sales			
Residential Sales	1.4	1.2	0.6
Commercial Sales	1.5	1.1	0.7
Irrigation Sales	-0.2	0.0	-0.5
Industrial Sales	3.5	1.8	1.0
Additional Firm Sales	3.4	1.5	2.3
Firm Sales	1.8	1.2	0.7
System Sales	1.8	1.2	0.7
Total Sales	1.8	1.2	0.7
Loads			
Residential Load	1.4	1.2	0.6
Commercial Load	1.5	1.1	0.7
Irrigation Load	-0.2	-0.1	-0.5
Industrial Load	3.3	1.7	1.0
Additional Firm Sales	3.4	1.5	2.3
Firm Load Losses	1.5	1.0	0.5
Firm Load	1.7	1.1	0.7
System Load	1.7	1.1	0.7
Total Load	1.7	1.1	0.7
Firm Requirement Load	1.7	1.1	0.6
Peaks			
Firm Peak	2.1	1.8	1.5
System Peak	2.1	1.8	1.5
Total Peak	2.1	1.8	1.5
Firm Requirement Peak	2.1	1.8	1.5
Winter Peak	0.3	0.3	0.0
Summer Peak	2.1	1.8	1.5
Customers			
Residential Customers	1.6	1.7	1.7
Commercial Customers	2.1	2.2	2.1
Irrigation Customers	1.5	1.4	1.4
Industrial Customers	1.3	1.2	1.1

Sales and Load Forecast

Average Load (Average Megawatts)—50th Percentile

	Jan. 2010	Feb. 2010	Mar. 2010	Apr. 2010	May. 2010	Jun. 2010	Jul. 2010	Aug. 2010	Sep. 2010	Oct. 2010	Nov. 2010	Dec. 2010
Residential	777	688	567	489	440	494	627	607	486	484	620	810
Commercial	458	436	402	388	390	436	503	486	427	407	432	487
Irrigation	1	1	6	74	258	523	599	483	315	47	3	3
Industrial	248	251	244	239	245	260	255	256	249	255	251	275
Additional Firm	152	160	155	150	158	144	147	156	172	182	189	193
Loss	159	148	131	128	144	184	214	198	160	129	142	170
Firm Load	1,796	1,684	1,505	1,469	1,635	2,039	2,345	2,186	1,808	1,505	1,636	1,938
Light Load	1,654	1,555	1,385	1,336	1,469	1,833	2,121	1,939	1,645	1,362	1,503	1,802
Heavy Load	1,918	1,780	1,592	1,565	1,778	2,190	2,521	2,380	1,938	1,617	1,743	2,045
System Load	1,796	1,684	1,505	1,469	1,635	2,039	2,345	2,186	1,808	1,505	1,636	1,938
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	1,796	1,684	1,505	1,469	1,635	2,039	2,345	2,186	1,808	1,505	1,636	1,938

Peak Load (Megawatts)—90th Percentile

	Jan. 2010	Feb. 2010	Mar. 2010	Apr. 2010	May. 2010	Jun. 2010	Jul. 2010	Aug. 2010	Sep. 2010	Oct. 2010	Nov. 2010	Dec. 2010
Energy Efficiency (MW)	-13	-13	-13	-14	-15	-16	-17	-16	-14	-13	-13	-13
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,416	2,356	2,045	1,860	2,692	3,284	3,439	3,131	2,965	2,052	2,253	2,593
System Peak (1 Hour)	2,416	2,356	2,045	1,860	2,692	3,284	3,439	3,131	2,965	2,052	2,253	2,593
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,416	2,356	2,045	1,860	2,692	3,284	3,439	3,131	2,965	2,052	2,253	2,593

Sales and Load Forecast

Average Load (Average Megawatts)—50th Percentile

	Jan. 2011	Feb. 2011	Mar. 2011	Apr. 2011	May. 2011	Jun. 2011	Jul. 2011	Aug. 2011	Sep. 2011	Oct. 2011	Nov. 2011	Dec. 2011
Residential	788	696	573	494	446	504	643	623	496	492	630	826
Commercial	464	442	408	393	395	444	513	495	435	413	439	497
Irrigation	1	1	6	74	259	526	603	486	317	47	3	3
Industrial	269	276	268	266	272	289	285	287	282	288	287	296
Additional Firm	206	205	197	191	186	160	153	161	177	182	190	193
Loss	165	153	136	133	148	189	219	203	164	133	146	174
Firm Load	1,892	1,773	1,588	1,551	1,706	2,112	2,416	2,255	1,871	1,556	1,695	1,989
Light Load	1,743	1,637	1,460	1,411	1,533	1,899	2,186	2,000	1,703	1,409	1,557	1,850
Heavy Load	2,021	1,875	1,679	1,653	1,855	2,268	2,615	2,438	2,006	1,673	1,805	2,099
System Load	1,892	1,773	1,588	1,551	1,706	2,112	2,416	2,255	1,871	1,556	1,695	1,989
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	1,892	1,773	1,588	1,551	1,706	2,112	2,416	2,255	1,871	1,556	1,695	1,989

Peak Load (Megawatts)—90th Percentile

	Jan. 2011	Feb. 2011	Mar. 2011	Apr. 2011	May. 2011	Jun. 2011	Jul. 2011	Aug. 2011	Sep. 2011	Oct. 2011	Nov. 2011	Dec. 2011
Energy Efficiency (MW)	-25	-25	-25	-26	-30	-33	-33	-32	-28	-26	-25	-25
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,520	2,440	2,133	1,937	2,777	3,361	3,538	3,177	3,013	2,096	2,304	2,627
System Peak (1 Hour)	2,520	2,440	2,133	1,937	2,777	3,361	3,538	3,177	3,013	2,096	2,304	2,627
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,520	2,440	2,133	1,937	2,777	3,361	3,538	3,177	3,013	2,096	2,304	2,627

Sales and Load Forecast

Average Load (Average Megawatts)—50th Percentile

	Jan. 2012	Feb. 2012	Mar. 2012	Apr. 2012	May. 2012	Jun. 2012	Jul. 2012	Aug. 2012	Sep. 2012	Oct. 2012	Nov. 2012	Dec. 2012
Residential	804	709	583	503	455	518	664	644	510	504	643	832
Commercial	474	451	416	401	404	456	527	508	445	422	448	506
Irrigation	1	1	6	74	256	521	598	483	315	47	3	3
Industrial	289	287	285	282	286	303	298	298	292	297	294	299
Additional Firm	205	202	197	191	186	160	153	160	177	188	197	201
Loss	169	156	139	135	151	192	223	207	167	136	149	177
Firm Load	1,941	1,805	1,626	1,586	1,738	2,151	2,464	2,299	1,906	1,594	1,735	2,018
Light Load	1,787	1,667	1,496	1,443	1,561	1,933	2,229	2,040	1,735	1,443	1,593	1,876
Heavy Load	2,073	1,907	1,720	1,700	1,877	2,310	2,666	2,486	2,056	1,703	1,848	2,139
System Load	1,941	1,805	1,626	1,586	1,738	2,151	2,464	2,299	1,906	1,594	1,735	2,018
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	1,941	1,805	1,626	1,586	1,738	2,151	2,464	2,299	1,906	1,594	1,735	2,018

Peak Load (Megawatts)—90th Percentile

	Jan. 2012	Feb. 2012	Mar. 2012	Apr. 2012	May. 2012	Jun. 2012	Jul. 2012	Aug. 2012	Sep. 2012	Oct. 2012	Nov. 2012	Dec. 2012
Energy Efficiency (MW)	-37	-36	-37	-39	-45	-48	-48	-47	-42	-38	-37	-37
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,561	2,441	2,168	1,953	2,821	3,462	3,614	3,235	3,055	2,131	2,342	2,648
System Peak (1 Hour)	2,561	2,441	2,168	1,953	2,821	3,462	3,614	3,235	3,055	2,131	2,342	2,648
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,561	2,441	2,168	1,953	2,821	3,462	3,614	3,235	3,055	2,131	2,342	2,648

Sales and Load Forecast

Average Load (Average Megawatts)—50th Percentile

	Jan. 2013	Feb. 2013	Mar. 2013	Apr. 2013	May. 2013	Jun. 2013	Jul. 2013	Aug. 2013	Sep. 2013	Oct. 2013	Nov. 2013	Dec. 2013
Residential	800	704	580	499	454	520	670	649	512	503	642	841
Commercial	480	457	422	407	411	465	538	518	453	429	455	514
Irrigation	1	1	6	73	254	518	595	479	313	47	3	3
Industrial	290	300	288	284	289	306	300	300	294	300	297	300
Additional Firm	205	205	198	191	186	179	189	185	184	189	197	201
Loss	169	157	139	136	151	194	226	209	169	137	150	178
Firm Load	1,947	1,823	1,632	1,591	1,745	2,181	2,519	2,342	1,926	1,604	1,745	2,037
Light Load	1,793	1,684	1,501	1,447	1,567	1,960	2,279	2,078	1,753	1,452	1,603	1,894
Heavy Load	2,068	1,928	1,735	1,696	1,884	2,357	2,708	2,532	2,078	1,714	1,859	2,160
System Load	1,947	1,823	1,632	1,591	1,745	2,181	2,519	2,342	1,926	1,604	1,745	2,037
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	1,947	1,823	1,632	1,591	1,745	2,181	2,519	2,342	1,926	1,604	1,745	2,037

Peak Load (Megawatts)—90th Percentile

	Jan. 2013	Feb. 2013	Mar. 2013	Apr. 2013	May. 2013	Jun. 2013	Jul. 2013	Aug. 2013	Sep. 2013	Oct. 2013	Nov. 2013	Dec. 2013
Energy Efficiency (MW)	-49	-49	-49	-52	-58	-63	-64	-62	-56	-50	-49	-50
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,521	2,450	2,145	1,911	2,845	3,506	3,703	3,288	3,112	2,140	2,341	2,594
System Peak (1 Hour)	2,521	2,450	2,145	1,911	2,845	3,506	3,703	3,288	3,112	2,140	2,341	2,594
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,521	2,450	2,145	1,911	2,845	3,506	3,703	3,288	3,112	2,140	2,341	2,594

Sales and Load Forecast

Average Load (Average Megawatts)—50th Percentile

	Jan. 2014	Feb. 2014	Mar. 2014	Apr. 2014	May. 2014	Jun. 2014	Jul. 2014	Aug. 2014	Sep. 2014	Oct. 2014	Nov. 2014	Dec. 2014
Residential	815	715	588	507	462	533	690	669	525	513	654	851
Commercial	485	461	426	412	416	472	547	526	460	435	460	519
Irrigation	1	1	6	72	253	516	593	478	312	46	3	3
Industrial	291	301	289	285	290	307	302	302	296	301	298	301
Additional Firm	206	205	198	192	187	179	189	186	185	190	198	202
Loss	172	159	141	137	152	196	229	212	171	138	152	180
Firm Load	1,970	1,842	1,648	1,604	1,759	2,203	2,551	2,372	1,948	1,623	1,766	2,055
Light Load	1,814	1,701	1,516	1,460	1,580	1,980	2,308	2,105	1,773	1,469	1,622	1,911
Heavy Load	2,092	1,947	1,752	1,710	1,900	2,381	2,743	2,583	2,089	1,734	1,892	2,169
System Load	1,970	1,842	1,648	1,604	1,759	2,203	2,551	2,372	1,948	1,623	1,766	2,055
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	1,970	1,842	1,648	1,604	1,759	2,203	2,551	2,372	1,948	1,623	1,766	2,055

Peak Load (Megawatts)—90th Percentile

	Jan. 2014	Feb. 2014	Mar. 2014	Apr. 2014	May. 2014	Jun. 2014	Jul. 2014	Aug. 2014	Sep. 2014	Oct. 2014	Nov. 2014	Dec. 2014
Energy Efficiency (MW)	-61	-61	-61	-64	-72	-78	-79	-76	-68	-62	-62	-61
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,555	2,470	2,172	1,933	2,875	3,557	3,766	3,351	3,154	2,157	2,367	2,637
System Peak (1 Hour)	2,555	2,470	2,172	1,933	2,875	3,557	3,766	3,351	3,154	2,157	2,367	2,637
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,555	2,470	2,172	1,933	2,875	3,557	3,766	3,351	3,154	2,157	2,367	2,637

Sales and Load Forecast

Average Load (Average Megawatts)—50th Percentile

	Jan. 2015	Feb. 2015	Mar. 2015	Apr. 2015	May. 2015	Jun. 2015	Jul. 2015	Aug. 2015	Sep. 2015	Oct. 2015	Nov. 2015	Dec. 2015
Residential	818	717	589	507	464	539	702	681	532	517	658	857
Commercial	488	463	429	414	419	477	554	532	465	438	464	523
Irrigation	1	1	6	73	253	518	595	480	314	47	3	3
Industrial	292	302	289	286	290	308	302	302	296	302	299	301
Additional Firm	206	205	198	192	187	179	189	186	185	190	198	202
Loss	172	159	141	137	153	197	232	214	172	139	152	181
Firm Load	1,977	1,846	1,652	1,608	1,765	2,218	2,574	2,394	1,963	1,632	1,774	2,067
Light Load	1,820	1,705	1,520	1,463	1,586	1,994	2,329	2,124	1,786	1,477	1,630	1,922
Heavy Load	2,100	1,952	1,756	1,714	1,919	2,382	2,768	2,607	2,104	1,743	1,901	2,181
System Load	1,977	1,846	1,652	1,608	1,765	2,218	2,574	2,394	1,963	1,632	1,774	2,067
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	1,977	1,846	1,652	1,608	1,765	2,218	2,574	2,394	1,963	1,632	1,774	2,067

Peak Load (Megawatts)—90th Percentile

	Jan. 2015	Feb. 2015	Mar. 2015	Apr. 2015	May. 2015	Jun. 2015	Jul. 2015	Aug. 2015	Sep. 2015	Oct. 2015	Nov. 2015	Dec. 2015
Energy Efficiency (MW)	-73	-73	-73	-76	-86	-92	-93	-90	-81	-74	-74	-73
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,544	2,463	2,168	1,920	2,898	3,604	3,819	3,388	3,196	2,164	2,372	2,629
System Peak (1 Hour)	2,544	2,463	2,168	1,920	2,898	3,604	3,819	3,388	3,196	2,164	2,372	2,629
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,544	2,463	2,168	1,920	2,898	3,604	3,819	3,388	3,196	2,164	2,372	2,629

Sales and Load Forecast

Average Load (Average Megawatts)—50th Percentile

	Jan. 2016	Feb. 2016	Mar. 2016	Apr. 2016	May. 2016	Jun. 2016	Jul. 2016	Aug. 2016	Sep. 2016	Oct. 2016	Nov. 2016	Dec. 2016
Residential	823	720	592	509	467	547	715	694	539	522	664	865
Commercial	490	466	431	416	421	482	561	537	468	440	467	527
Irrigation	1	1	6	72	253	517	595	479	314	46	3	3
Industrial	293	292	290	286	291	309	303	303	297	302	300	302
Additional Firm	204	201	197	191	186	178	189	185	184	189	197	201
Loss	173	159	141	137	153	198	234	216	173	140	153	182
Firm Load	1,985	1,839	1,657	1,612	1,770	2,231	2,595	2,414	1,975	1,640	1,784	2,079
Light Load	1,828	1,699	1,524	1,466	1,590	2,006	2,348	2,141	1,797	1,484	1,639	1,933
Heavy Load	2,120	1,943	1,752	1,718	1,925	2,396	2,808	2,610	2,117	1,762	1,900	2,194
System Load	1,985	1,839	1,657	1,612	1,770	2,231	2,595	2,414	1,975	1,640	1,784	2,079
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	1,985	1,839	1,657	1,612	1,770	2,231	2,595	2,414	1,975	1,640	1,784	2,079

Peak Load (Megawatts)—90th Percentile

	Jan. 2016	Feb. 2016	Mar. 2016	Apr. 2016	May. 2016	Jun. 2016	Jul. 2016	Aug. 2016	Sep. 2016	Oct. 2016	Nov. 2016	Dec. 2016
Energy Efficiency (MW)	-85	-82	-85	-88	-99	-106	-107	-104	-94	-87	-85	-84
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,541	2,461	2,170	1,913	2,921	3,649	3,871	3,428	3,237	2,170	2,381	2,631
System Peak (1 Hour)	2,541	2,461	2,170	1,913	2,921	3,649	3,871	3,428	3,237	2,170	2,381	2,631
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,541	2,461	2,170	1,913	2,921	3,649	3,871	3,428	3,237	2,170	2,381	2,631

Sales and Load Forecast

Average Load (Average Megawatts)—50th Percentile

	Jan. 2017	Feb. 2017	Mar. 2017	Apr. 2017	May. 2017	Jun. 2017	Jul. 2017	Aug. 2017	Sep. 2017	Oct. 2017	Nov. 2017	Dec. 2017
Residential	829	723	594	511	471	555	729	707	548	527	670	872
Commercial	493	466	433	417	424	487	567	542	472	443	470	529
Irrigation	1	1	6	72	252	518	595	480	314	47	3	3
Industrial	293	303	291	287	291	310	303	304	298	303	300	303
Additional Firm	204	203	197	191	186	178	188	185	184	188	196	200
Loss	173	160	142	138	154	199	236	218	174	140	154	183
Firm Load	1,994	1,857	1,662	1,616	1,778	2,247	2,619	2,435	1,989	1,649	1,794	2,090
Light Load	1,836	1,715	1,529	1,470	1,597	2,019	2,369	2,161	1,810	1,492	1,648	1,944
Heavy Load	2,129	1,963	1,758	1,732	1,920	2,413	2,834	2,634	2,133	1,772	1,911	2,217
System Load	1,994	1,857	1,662	1,616	1,778	2,247	2,619	2,435	1,989	1,649	1,794	2,090
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	1,994	1,857	1,662	1,616	1,778	2,247	2,619	2,435	1,989	1,649	1,794	2,090

Peak Load (Megawatts)—90th Percentile

	Jan. 2017	Feb. 2017	Mar. 2017	Apr. 2017	May. 2017	Jun. 2017	Jul. 2017	Aug. 2017	Sep. 2017	Oct. 2017	Nov. 2017	Dec. 2017
Energy Efficiency (MW)	-97	-96	-96	-101	-112	-120	-121	-117	-106	-99	-97	-97
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,540	2,458	2,173	1,909	2,945	3,695	3,925	3,471	3,278	2,178	2,391	2,636
System Peak (1 Hour)	2,540	2,458	2,173	1,909	2,945	3,695	3,925	3,471	3,278	2,178	2,391	2,636
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,540	2,458	2,173	1,909	2,945	3,695	3,925	3,471	3,278	2,178	2,391	2,636

Sales and Load Forecast

Average Load (Average Megawatts)—50th Percentile

	Jan. 2018	Feb. 2018	Mar. 2018	Apr. 2018	May. 2018	Jun. 2018	Jul. 2018	Aug. 2018	Sep. 2018	Oct. 2018	Nov. 2018	Dec. 2018
Residential	834	726	597	513	474	562	743	721	556	532	676	880
Commercial	495	468	435	419	427	492	573	548	476	446	472	533
Irrigation	1	1	6	72	252	518	596	480	315	47	3	3
Industrial	294	304	291	287	292	310	304	304	298	304	301	303
Additional Firm	204	203	196	190	185	177	188	184	183	188	196	200
Loss	174	160	142	138	154	201	238	220	176	141	155	184
Firm Load	2,002	1,862	1,667	1,620	1,784	2,262	2,643	2,457	2,003	1,659	1,804	2,104
Light Load	1,844	1,720	1,534	1,474	1,603	2,033	2,391	2,180	1,823	1,501	1,657	1,956
Heavy Load	2,127	1,969	1,763	1,736	1,927	2,429	2,859	2,658	2,161	1,772	1,922	2,231
System Load	2,002	1,862	1,667	1,620	1,784	2,262	2,643	2,457	2,003	1,659	1,804	2,104
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,002	1,862	1,667	1,620	1,784	2,262	2,643	2,457	2,003	1,659	1,804	2,104

Peak Load (Megawatts)—90th Percentile

	Jan. 2018	Feb. 2018	Mar. 2018	Apr. 2018	May. 2018	Jun. 2018	Jul. 2018	Aug. 2018	Sep. 2018	Oct. 2018	Nov. 2018	Dec. 2018
Energy Efficiency (MW)	-109	-108	-108	-113	-125	-134	-135	-131	-120	-110	-109	-109
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,537	2,455	2,176	1,904	2,969	3,742	3,978	3,514	3,319	2,186	2,400	2,642
System Peak (1 Hour)	2,537	2,455	2,176	1,904	2,969	3,742	3,978	3,514	3,319	2,186	2,400	2,642
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,537	2,455	2,176	1,904	2,969	3,742	3,978	3,514	3,319	2,186	2,400	2,642

Sales and Load Forecast

Average Load (Average Megawatts)—50th Percentile

	Jan. 2019	Feb. 2019	Mar. 2019	Apr. 2019	May. 2019	Jun. 2019	Jul. 2019	Aug. 2019	Sep. 2019	Oct. 2019	Nov. 2019	Dec. 2019
Residential	841	731	600	516	478	571	758	736	565	538	683	890
Commercial	497	469	437	421	430	497	580	553	480	449	475	536
Irrigation	1	1	6	73	253	520	598	481	316	47	3	3
Industrial	295	305	292	288	293	311	305	305	299	305	302	304
Additional Firm	201	200	194	188	184	176	186	183	182	186	194	198
Loss	175	161	142	138	155	202	240	222	177	142	156	185
Firm Load	2,009	1,867	1,670	1,624	1,791	2,277	2,667	2,480	2,017	1,667	1,813	2,115
Light Load	1,851	1,724	1,537	1,477	1,609	2,047	2,413	2,200	1,835	1,509	1,665	1,967
Heavy Load	2,135	1,974	1,776	1,731	1,935	2,462	2,868	2,682	2,176	1,782	1,931	2,243
System Load	2,009	1,867	1,670	1,624	1,791	2,277	2,667	2,480	2,017	1,667	1,813	2,115
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,009	1,867	1,670	1,624	1,791	2,277	2,667	2,480	2,017	1,667	1,813	2,115

Peak Load (Megawatts)—90th Percentile

	Jan. 2019	Feb. 2019	Mar. 2019	Apr. 2019	May. 2019	Jun. 2019	Jul. 2019	Aug. 2019	Sep. 2019	Oct. 2019	Nov. 2019	Dec. 2019
Energy Efficiency (MW)	-120	-120	-121	-125	-138	-148	-149	-145	-132	-122	-120	-121
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,539	2,455	2,180	1,904	2,994	3,789	4,034	3,561	3,358	2,193	2,411	2,654
System Peak (1 Hour)	2,539	2,455	2,180	1,904	2,994	3,789	4,034	3,561	3,358	2,193	2,411	2,654
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,539	2,455	2,180	1,904	2,994	3,789	4,034	3,561	3,358	2,193	2,411	2,654

Sales and Load Forecast

Average Load (Average Megawatts)—50th Percentile

	Jan. 2020	Feb. 2020	Mar. 2020	Apr. 2020	May. 2020	Jun. 2020	Jul. 2020	Aug. 2020	Sep. 2020	Oct. 2020	Nov. 2020	Dec. 2020
Residential	848	736	604	519	482	581	774	752	574	545	690	893
Commercial	498	472	438	423	431	502	586	558	484	451	477	539
Irrigation	1	1	6	73	253	521	600	483	317	47	4	3
Industrial	296	295	292	288	293	312	305	306	300	306	302	305
Additional Firm	201	198	194	188	183	175	186	182	181	186	193	197
Loss	176	161	143	139	155	204	243	224	178	143	157	186
Firm Load	2,021	1,862	1,676	1,629	1,799	2,295	2,694	2,505	2,035	1,678	1,823	2,122
Light Load	1,861	1,720	1,542	1,482	1,616	2,063	2,437	2,223	1,852	1,519	1,674	1,974
Heavy Load	2,146	1,968	1,782	1,736	1,956	2,465	2,897	2,728	2,181	1,793	1,953	2,240
System Load	2,021	1,862	1,676	1,629	1,799	2,295	2,694	2,505	2,035	1,678	1,823	2,122
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,021	1,862	1,676	1,629	1,799	2,295	2,694	2,505	2,035	1,678	1,823	2,122

Peak Load (Megawatts)—90th Percentile

	Jan. 2020	Feb. 2020	Mar. 2020	Apr. 2020	May. 2020	Jun. 2020	Jul. 2020	Aug. 2020	Sep. 2020	Oct. 2020	Nov. 2020	Dec. 2020
Energy Efficiency (MW)	-132	-127	-133	-137	-152	-162	-163	-159	-144	-134	-133	-132
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,547	2,448	2,188	1,907	3,018	3,837	4,091	3,612	3,401	2,202	2,422	2,666
System Peak (1 Hour)	2,547	2,448	2,188	1,907	3,018	3,837	4,091	3,612	3,401	2,202	2,422	2,666
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,547	2,448	2,188	1,907	3,018	3,837	4,091	3,612	3,401	2,202	2,422	2,666

Sales and Load Forecast

Average Load (Average Megawatts)—50th Percentile

	Jan. 2021	Feb. 2021	Mar. 2021	Apr. 2021	May. 2021	Jun. 2021	Jul. 2021	Aug. 2021	Sep. 2021	Oct. 2021	Nov. 2021	Dec. 2021
Residential	845	731	600	515	481	583	781	758	577	545	689	896
Commercial	498	470	439	423	433	506	591	562	487	453	479	541
Irrigation	1	1	6	72	252	520	599	482	316	47	4	3
Industrial	295	306	293	289	293	312	306	306	300	306	303	305
Additional Firm	200	200	193	188	183	175	186	182	181	186	193	197
Loss	175	161	142	138	155	204	244	225	179	143	157	186
Firm Load	2,016	1,869	1,674	1,625	1,797	2,301	2,706	2,516	2,040	1,679	1,825	2,129
Light Load	1,857	1,726	1,540	1,479	1,614	2,068	2,448	2,232	1,856	1,519	1,676	1,980
Heavy Load	2,153	1,976	1,770	1,732	1,954	2,471	2,909	2,740	2,187	1,804	1,944	2,247
System Load	2,016	1,869	1,674	1,625	1,797	2,301	2,706	2,516	2,040	1,679	1,825	2,129
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,016	1,869	1,674	1,625	1,797	2,301	2,706	2,516	2,040	1,679	1,825	2,129

Peak Load (Megawatts)—90th Percentile

	Jan. 2021	Feb. 2021	Mar. 2021	Apr. 2021	May. 2021	Jun. 2021	Jul. 2021	Aug. 2021	Sep. 2021	Oct. 2021	Nov. 2021	Dec. 2021
Energy Efficiency (MW)	-145	-144	-143	-149	-165	-176	-177	-172	-157	-146	-144	-144
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,508	2,435	2,171	1,878	3,034	3,877	4,133	3,633	3,442	2,202	2,418	2,633
System Peak (1 Hour)	2,508	2,435	2,171	1,878	3,034	3,877	4,133	3,633	3,442	2,202	2,418	2,633
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,508	2,435	2,171	1,878	3,034	3,877	4,133	3,633	3,442	2,202	2,418	2,633

Sales and Load Forecast

Average Load (Average Megawatts)—50th Percentile

	Jan. 2022	Feb. 2022	Mar. 2022	Apr. 2022	May. 2022	Jun. 2022	Jul. 2022	Aug. 2022	Sep. 2022	Oct. 2022	Nov. 2022	Dec. 2022
Residential	850	734	602	517	484	591	795	772	585	550	695	902
Commercial	499	471	440	424	434	510	596	567	490	454	480	544
Irrigation	1	1	6	72	251	518	597	480	315	47	4	3
Industrial	296	307	294	289	294	313	307	307	301	307	304	307
Additional Firm	200	200	193	187	183	175	185	182	181	185	193	197
Loss	176	161	142	138	155	205	246	227	180	143	157	187
Firm Load	2,022	1,872	1,677	1,628	1,801	2,312	2,726	2,535	2,051	1,686	1,833	2,139
Light Load	1,863	1,729	1,543	1,481	1,618	2,078	2,466	2,249	1,867	1,526	1,684	1,989
Heavy Load	2,160	1,980	1,774	1,735	1,958	2,483	2,949	2,741	2,199	1,813	1,953	2,258
System Load	2,022	1,872	1,677	1,628	1,801	2,312	2,726	2,535	2,051	1,686	1,833	2,139
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,022	1,872	1,677	1,628	1,801	2,312	2,726	2,535	2,051	1,686	1,833	2,139

Peak Load (Megawatts)—90th Percentile

	Jan. 2022	Feb. 2022	Mar. 2022	Apr. 2022	May. 2022	Jun. 2022	Jul. 2022	Aug. 2022	Sep. 2022	Oct. 2022	Nov. 2022	Dec. 2022
Energy Efficiency (MW)	-157	-155	-155	-161	-179	-190	-191	-186	-170	-159	-156	-155
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,504	2,431	2,174	1,875	3,055	3,921	4,183	3,676	3,483	2,208	2,426	2,641
System Peak (1 Hour)	2,504	2,431	2,174	1,875	3,055	3,921	4,183	3,676	3,483	2,208	2,426	2,641
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,504	2,431	2,174	1,875	3,055	3,921	4,183	3,676	3,483	2,208	2,426	2,641

Sales and Load Forecast

Average Load (Average Megawatts)—50th Percentile

	Jan. 2023	Feb. 2023	Mar. 2023	Apr. 2023	May. 2023	Jun. 2023	Jul. 2023	Aug. 2023	Sep. 2023	Oct. 2023	Nov. 2023	Dec. 2023
Residential	853	735	602	517	486	598	808	785	592	554	699	899
Commercial	500	470	441	424	436	514	601	570	492	456	482	544
Irrigation	1	1	6	72	251	519	597	481	316	47	4	3
Industrial	297	307	294	290	295	314	307	308	302	308	305	306
Additional Firm	198	198	192	186	182	173	184	181	180	184	191	195
Loss	176	161	142	138	156	206	247	229	181	144	158	187
Firm Load	2,026	1,872	1,678	1,627	1,805	2,324	2,746	2,553	2,062	1,692	1,837	2,134
Light Load	1,866	1,729	1,543	1,480	1,621	2,089	2,484	2,265	1,876	1,531	1,688	1,984
Heavy Load	2,164	1,980	1,774	1,744	1,949	2,496	2,971	2,761	2,211	1,818	1,958	2,263
System Load	2,026	1,872	1,678	1,627	1,805	2,324	2,746	2,553	2,062	1,692	1,837	2,134
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,026	1,872	1,678	1,627	1,805	2,324	2,746	2,553	2,062	1,692	1,837	2,134

Peak Load (Megawatts)—90th Percentile

	Jan. 2023	Feb. 2023	Mar. 2023	Apr. 2023	May. 2023	Jun. 2023	Jul. 2023	Aug. 2023	Sep. 2023	Oct. 2023	Nov. 2023	Dec. 2023
Energy Efficiency (MW)	-168	-167	-167	-174	-191	-204	-205	-200	-182	-170	-168	-169
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,496	2,424	2,172	1,867	3,077	3,965	4,234	3,716	3,523	2,212	2,431	2,628
System Peak (1 Hour)	2,496	2,424	2,172	1,867	3,077	3,965	4,234	3,716	3,523	2,212	2,431	2,628
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,496	2,424	2,172	1,867	3,077	3,965	4,234	3,716	3,523	2,212	2,431	2,628

Sales and Load Forecast

Average Load (Average Megawatts)—50th Percentile

	Jan. 2024	Feb. 2024	Mar. 2024	Apr. 2024	May. 2024	Jun. 2024	Jul. 2024	Aug. 2024	Sep. 2024	Oct. 2024	Nov. 2024	Dec. 2024
Residential	843	725	594	509	480	595	808	785	590	549	692	900
Commercial	499	472	439	424	437	516	605	573	493	456	482	545
Irrigation	1	1	6	71	248	514	593	477	314	46	4	3
Industrial	299	297	294	290	296	314	308	308	301	309	305	307
Additional Firm	198	195	191	186	181	173	184	180	179	184	191	195
Loss	175	159	141	137	155	206	247	228	180	143	157	187
Firm Load	2,015	1,849	1,666	1,617	1,797	2,319	2,744	2,552	2,057	1,687	1,830	2,136
Light Load	1,856	1,708	1,532	1,471	1,614	2,085	2,483	2,264	1,872	1,527	1,681	1,987
Heavy Load	2,140	1,954	1,771	1,724	1,941	2,507	2,951	2,760	2,219	1,803	1,950	2,265
System Load	2,015	1,849	1,666	1,617	1,797	2,319	2,744	2,552	2,057	1,687	1,830	2,136
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,015	1,849	1,666	1,617	1,797	2,319	2,744	2,552	2,057	1,687	1,830	2,136

Peak Load (Megawatts)—90th Percentile

	Jan. 2024	Feb. 2024	Mar. 2024	Apr. 2024	May. 2024	Jun. 2024	Jul. 2024	Aug. 2024	Sep. 2024	Oct. 2024	Nov. 2024	Dec. 2024
Energy Efficiency (MW)	-180	-173	-180	-185	-203	-218	-219	-214	-196	-181	-180	-181
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,428	2,408	2,135	1,819	3,087	3,998	4,262	3,718	3,562	2,207	2,412	2,565
System Peak (1 Hour)	2,428	2,408	2,135	1,819	3,087	3,998	4,262	3,718	3,562	2,207	2,412	2,565
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,428	2,408	2,135	1,819	3,087	3,998	4,262	3,718	3,562	2,207	2,412	2,565

Sales and Load Forecast

Average Load (Average Megawatts)—50th Percentile

	Jan. 2025	Feb. 2025	Mar. 2025	Apr. 2025	May. 2025	Jun. 2025	Jul. 2025	Aug. 2025	Sep. 2025	Oct. 2025	Nov. 2025	Dec. 2025
Residential	849	728	596	511	484	604	824	800	599	555	699	907
Commercial	499	468	440	424	438	520	610	577	496	458	482	547
Irrigation	1	1	6	71	246	512	589	474	312	46	4	3
Industrial	298	309	295	291	296	315	309	309	303	310	305	308
Additional Firm	198	197	191	185	181	173	184	180	179	184	191	194
Loss	175	160	141	137	155	207	249	230	181	144	158	188
Firm Load	2,021	1,863	1,669	1,619	1,801	2,330	2,764	2,571	2,070	1,696	1,838	2,147
Light Load	1,862	1,721	1,536	1,473	1,618	2,095	2,501	2,281	1,884	1,535	1,688	1,996
Heavy Load	2,147	1,970	1,774	1,726	1,945	2,519	2,972	2,800	2,219	1,812	1,969	2,265
System Load	2,021	1,863	1,669	1,619	1,801	2,330	2,764	2,571	2,070	1,696	1,838	2,147
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,021	1,863	1,669	1,619	1,801	2,330	2,764	2,571	2,070	1,696	1,838	2,147

Peak Load (Megawatts)—90th Percentile

	Jan. 2025	Feb. 2025	Mar. 2025	Apr. 2025	May. 2025	Jun. 2025	Jul. 2025	Aug. 2025	Sep. 2025	Oct. 2025	Nov. 2025	Dec. 2025
Energy Efficiency (MW)	-192	-191	-192	-198	-216	-232	-233	-227	-208	-193	-193	-192
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,432	2,384	2,143	1,824	3,109	4,042	4,312	3,766	3,604	2,214	2,422	2,586
System Peak (1 Hour)	2,432	2,384	2,143	1,824	3,109	4,042	4,312	3,766	3,604	2,214	2,422	2,586
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,432	2,384	2,143	1,824	3,109	4,042	4,312	3,766	3,604	2,214	2,422	2,586

Sales and Load Forecast

Average Load (Average Megawatts)—50th Percentile

	Jan. 2026	Feb. 2026	Mar. 2026	Apr. 2026	May. 2026	Jun. 2026	Jul. 2026	Aug. 2026	Sep. 2026	Oct. 2026	Nov. 2026	Dec. 2026
Residential	852	729	597	511	486	611	837	813	606	558	702	904
Commercial	499	468	440	424	439	524	615	581	499	459	483	548
Irrigation	1	1	6	71	247	513	591	476	313	46	4	3
Industrial	299	309	296	291	296	316	309	310	304	311	306	309
Additional Firm	196	196	189	184	180	171	182	179	178	182	189	192
Loss	176	159	141	137	155	208	251	232	182	144	158	187
Firm Load	2,023	1,862	1,669	1,619	1,802	2,343	2,785	2,590	2,082	1,700	1,842	2,144
Light Load	1,863	1,720	1,535	1,473	1,619	2,106	2,520	2,298	1,895	1,539	1,692	1,993
Heavy Load	2,149	1,969	1,774	1,725	1,960	2,516	2,994	2,820	2,232	1,817	1,973	2,262
System Load	2,023	1,862	1,669	1,619	1,802	2,343	2,785	2,590	2,082	1,700	1,842	2,144
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,023	1,862	1,669	1,619	1,802	2,343	2,785	2,590	2,082	1,700	1,842	2,144

Peak Load (Megawatts)—90th Percentile

	Jan. 2026	Feb. 2026	Mar. 2026	Apr. 2026	May. 2026	Jun. 2026	Jul. 2026	Aug. 2026	Sep. 2026	Oct. 2026	Nov. 2026	Dec. 2026
Energy Efficiency (MW)	-203	-203	-204	-210	-231	-246	-247	-241	-219	-205	-205	-203
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,421	2,375	2,142	1,817	3,128	4,087	4,364	3,808	3,646	2,218	2,427	2,577
System Peak (1 Hour)	2,421	2,375	2,142	1,817	3,128	4,087	4,364	3,808	3,646	2,218	2,427	2,577
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,421	2,375	2,142	1,817	3,128	4,087	4,364	3,808	3,646	2,218	2,427	2,577

Sales and Load Forecast

Average Load (Average Megawatts)—50th Percentile

	Jan. 2027	Feb. 2027	Mar. 2027	Apr. 2027	May. 2027	Jun. 2027	Jul. 2027	Aug. 2027	Sep. 2027	Oct. 2027	Nov. 2027	Dec. 2027
Residential	843	719	589	504	481	609	838	814	604	554	697	901
Commercial	498	466	440	424	438	526	618	583	500	459	484	548
Irrigation	1	1	6	70	245	509	587	473	311	46	4	3
Industrial	299	310	297	292	296	317	310	310	304	311	307	309
Additional Firm	195	194	188	182	178	170	181	178	177	180	187	190
Loss	174	158	140	136	154	207	251	232	182	144	157	187
Firm Load	2,010	1,849	1,659	1,608	1,793	2,339	2,785	2,590	2,078	1,694	1,836	2,139
Light Load	1,851	1,708	1,526	1,463	1,611	2,102	2,520	2,297	1,891	1,533	1,686	1,989
Heavy Load	2,146	1,955	1,755	1,714	1,949	2,512	2,995	2,820	2,228	1,821	1,956	2,257
System Load	2,010	1,849	1,659	1,608	1,793	2,339	2,785	2,590	2,078	1,694	1,836	2,139
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,010	1,849	1,659	1,608	1,793	2,339	2,785	2,590	2,078	1,694	1,836	2,139

Peak Load (Megawatts)—90th Percentile

	Jan. 2027	Feb. 2027	Mar. 2027	Apr. 2027	May. 2027	Jun. 2027	Jul. 2027	Aug. 2027	Sep. 2027	Oct. 2027	Nov. 2027	Dec. 2027
Energy Efficiency (MW)	-216	-214	-214	-222	-245	-260	-261	-255	-233	-218	-215	-215
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,354	2,336	2,111	1,772	3,138	4,120	4,394	3,815	3,684	2,210	2,411	2,513
System Peak (1 Hour)	2,354	2,336	2,111	1,772	3,138	4,120	4,394	3,815	3,684	2,210	2,411	2,513
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,354	2,336	2,111	1,772	3,138	4,120	4,394	3,815	3,684	2,210	2,411	2,513

Sales and Load Forecast

Average Load (Average Megawatts)—50th Percentile

	Jan. 2028	Feb. 2028	Mar. 2028	Apr. 2028	May. 2028	Jun. 2028	Jul. 2028	Aug. 2028	Sep. 2028	Oct. 2028	Nov. 2028	Dec. 2028
Residential	840	716	585	501	480	612	845	821	607	554	695	891
Commercial	497	469	440	423	440	529	623	586	502	459	484	548
Irrigation	1	1	6	69	242	504	581	468	308	45	3	3
Industrial	301	300	297	292	297	317	310	311	305	312	308	309
Additional Firm	193	190	186	181	177	169	179	176	175	179	186	189
Loss	174	157	140	135	154	207	251	232	182	144	157	186
Firm Load	2,005	1,833	1,654	1,600	1,789	2,338	2,790	2,594	2,079	1,693	1,834	2,126
Light Load	1,847	1,693	1,521	1,456	1,607	2,101	2,524	2,302	1,892	1,532	1,684	1,977
Heavy Load	2,142	1,937	1,749	1,716	1,932	2,511	3,019	2,806	2,229	1,820	1,954	2,254
System Load	2,005	1,833	1,654	1,600	1,789	2,338	2,790	2,594	2,079	1,693	1,834	2,126
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,005	1,833	1,654	1,600	1,789	2,338	2,790	2,594	2,079	1,693	1,834	2,126

Peak Load (Megawatts)—90th Percentile

	Jan. 2028	Feb. 2028	Mar. 2028	Apr. 2028	May. 2028	Jun. 2028	Jul. 2028	Aug. 2028	Sep. 2028	Oct. 2028	Nov. 2028	Dec. 2028
Energy Efficiency (MW)	-228	-218	-226	-235	-257	-274	-275	-269	-245	-230	-227	-228
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,315	2,299	2,094	1,745	3,152	4,156	4,430	3,835	3,724	2,208	2,405	2,469
System Peak (1 Hour)	2,315	2,299	2,094	1,745	3,152	4,156	4,430	3,835	3,724	2,208	2,405	2,469
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,315	2,299	2,094	1,745	3,152	4,156	4,430	3,835	3,724	2,208	2,405	2,469

Sales and Load Forecast

Average Load (Average Megawatts)—50th Percentile

	Jan. 2029	Feb. 2029	Mar. 2029	Apr. 2029	May. 2029	Jun. 2029	Jul. 2029	Aug. 2029	Sep. 2029	Oct. 2029	Nov. 2029	Dec. 2029
Residential	824	700	572	489	471	605	840	816	600	545	684	883
Commercial	496	463	438	421	439	532	626	588	502	460	484	548
Irrigation	1	1	6	68	237	496	572	460	303	45	3	3
Industrial	300	311	297	292	298	317	310	311	304	312	308	310
Additional Firm	191	190	185	180	175	167	178	175	174	177	184	187
Loss	172	155	138	133	152	206	250	231	180	142	156	184
Firm Load	1,984	1,820	1,636	1,584	1,772	2,322	2,775	2,580	2,064	1,682	1,819	2,116
Light Load	1,827	1,681	1,505	1,441	1,592	2,087	2,510	2,289	1,879	1,522	1,671	1,968
Heavy Load	2,108	1,925	1,731	1,698	1,914	2,493	3,003	2,791	2,227	1,797	1,938	2,244
System Load	1,984	1,820	1,636	1,584	1,772	2,322	2,775	2,580	2,064	1,682	1,819	2,116
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	1,984	1,820	1,636	1,584	1,772	2,322	2,775	2,580	2,064	1,682	1,819	2,116

Peak Load (Megawatts)—90th Percentile

	Jan. 2029	Feb. 2029	Mar. 2029	Apr. 2029	May. 2029	Jun. 2029	Jul. 2029	Aug. 2029	Sep. 2029	Oct. 2029	Nov. 2029	Dec. 2029
Energy Efficiency (MW)	-239	-238	-237	-247	-270	-288	-289	-282	-260	-241	-238	-240
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,209	2,250	2,042	1,676	3,155	4,181	4,445	3,818	3,761	2,197	2,376	2,367
System Peak (1 Hour)	2,209	2,250	2,042	1,676	3,155	4,181	4,445	3,818	3,761	2,197	2,376	2,367
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,209	2,250	2,042	1,676	3,155	4,181	4,445	3,818	3,761	2,197	2,376	2,367

Sales Load Forecast Annual Summary

Billed Sales (Megawatthours)—50th Percentile

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential	5,168,469	5,256,321	5,379,801	5,376,155	5,489,259	5,530,778	5,587,128	5,645,662	5,701,444	5,769,695
Commercial	3,829,818	3,890,483	3,980,186	4,047,917	4,100,296	4,133,788	4,163,623	4,192,537	4,221,347	4,249,770
Irrigation	1,698,888	1,708,444	1,695,280	1,683,869	1,677,836	1,683,905	1,682,258	1,683,643	1,685,914	1,689,596
Industrial	2,196,153	2,441,884	2,567,526	2,589,054	2,599,655	2,604,497	2,611,034	2,616,668	2,622,321	2,628,531
Additional Firm	1,428,995	1,604,959	1,621,276	1,687,195	1,689,907	1,689,231	1,683,727	1,678,357	1,676,318	1,657,486
Firm Sales	14,322,324	14,902,092	15,244,069	15,384,190	15,556,953	15,642,199	15,727,771	15,816,867	15,907,344	15,995,079
System Sales	14,322,324	14,902,092	15,244,069	15,384,190	15,556,953	15,642,199	15,727,771	15,816,867	15,907,344	15,995,079
Firm Off-System Sales	0	0	0	0	0	0	0	0	0	0
Total Sales	14,322,324	14,902,092	15,244,069	15,384,190	15,556,953	15,642,199	15,727,771	15,816,867	15,907,344	15,995,079

Generation Month Sales (Megawatthours)—50th Percentile

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential	5,174,855	5,264,992	5,396,714	5,384,048	5,492,013	5,534,546	5,608,557	5,649,355	5,705,977	5,774,417
Commercial	3,835,231	3,897,657	3,997,338	4,053,044	4,104,395	4,137,679	4,179,510	4,196,349	4,225,126	4,253,450
Irrigation	1,698,904	1,708,441	1,695,300	1,683,870	1,677,845	1,683,908	1,682,286	1,683,649	1,685,921	1,689,605
Industrial	2,211,419	2,457,547	2,569,645	2,589,952	2,600,158	2,605,016	2,611,732	2,616,883	2,622,847	2,628,952
Additional Firm	1,428,995	1,604,959	1,621,276	1,687,195	1,689,907	1,689,231	1,683,727	1,678,357	1,676,318	1,657,486
Firm Sales	14,349,404	14,933,595	15,280,274	15,398,109	15,564,319	15,650,380	15,765,812	15,824,593	15,916,190	16,003,910
System Sales	14,349,404	14,933,595	15,280,274	15,398,109	15,564,319	15,650,380	15,765,812	15,824,593	15,916,190	16,003,910
Firm Off-System Sales	0	0	0	0	0	0	0	0	0	0
Total Sales	14,349,404	14,933,595	15,280,274	15,398,109	15,564,319	15,650,380	15,765,812	15,824,593	15,916,190	16,003,910
Loss	1,392,659	1,434,513	1,465,382	1,472,316	1,488,589	1,496,524	1,507,986	1,513,222	1,521,803	1,531,196
Required Generation	15,742,063	16,368,108	16,745,656	16,870,425	17,052,907	17,146,904	17,273,798	17,337,815	17,437,993	17,535,105

Average Load (Average Megawatts)—50th Percentile

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential	591	601	614	615	627	632	638	645	651	659
Commercial	438	445	455	463	469	472	476	479	482	486
Irrigation	194	195	193	192	192	192	192	192	192	193
Industrial	252	281	293	296	297	297	297	299	299	300
Additional Firm	163	183	185	193	193	193	192	192	191	189
Loss	159	164	167	168	170	171	172	173	174	175
Firm Load	1,797	1,869	1,906	1,926	1,947	1,957	1,967	1,979	1,991	2,002
Light Load	1,635	1,700	1,735	1,752	1,771	1,781	1,789	1,801	1,811	1,821
Heavy Load	1,924	2,001	2,042	2,062	2,085	2,096	2,106	2,120	2,132	2,143
System Load	1,797	1,869	1,906	1,926	1,947	1,957	1,967	1,979	1,991	2,002
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0
Total Load	1,797	1,869	1,906	1,926	1,947	1,957	1,967	1,979	1,991	2,002

Peak Load (Megawatts)—90th Percentile

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Energy Efficiency (Mw)	-17	-33	-48	-64	-79	-93	-107	-121	-135	-149
Demand Response (Mw)	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	3,439	3,538	3,614	3,703	3,766	3,819	3,871	3,925	3,978	4,034
System Peak (1 Hour)	3,439	3,538	3,614	3,703	3,766	3,819	3,871	3,925	3,978	4,034
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0
Total Peak Load	3,439	3,538	3,614	3,703	3,766	3,819	3,871	3,925	3,978	4,034

Sales Load Forecast Annual Summary

Billed Sales (Megawatthours)—50th Percentile

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Residential	5,841,011	5,841,418	5,895,447	5,939,934	5,890,559	5,955,384	5,997,074	5,957,390	5,958,204	5,866,848
Commercial	4,276,547	4,293,464	4,313,307	4,329,757	4,334,101	4,350,602	4,365,073	4,370,462	4,379,409	4,379,364
Irrigation	1,695,341	1,691,409	1,685,309	1,686,379	1,673,258	1,663,734	1,668,126	1,656,601	1,638,789	1,612,185
Industrial	2,634,391	2,637,943	2,644,929	2,652,534	2,655,893	2,661,588	2,668,570	2,671,916	2,678,550	2,679,036
Additional Firm	1,657,426	1,651,857	1,650,315	1,636,705	1,638,050	1,632,964	1,619,435	1,605,524	1,595,267	1,578,775
Firm Sales	16,104,716	16,116,090	16,189,308	16,245,309	16,191,861	16,264,271	16,318,279	16,261,893	16,250,219	16,116,208
System Sales	16,104,716	16,116,090	16,189,308	16,245,309	16,191,861	16,264,271	16,318,279	16,261,893	16,250,219	16,116,208
Firm Off-System Sales	0	0	0	0	0	0	0	0	0	0
Total Sales	16,104,716	16,116,090	16,189,308	16,245,309	16,191,861	16,264,271	16,318,279	16,261,893	16,250,219	16,116,208

Generation Month Sales (Megawatthours)—50th Percentile

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Residential	5,858,867	5,844,921	5,898,281	5,936,364	5,912,615	5,957,991	5,994,165	5,957,221	5,969,571	5,866,154
Commercial	4,292,409	4,296,753	4,316,405	4,332,205	4,350,397	4,353,566	4,367,548	4,373,116	4,395,241	4,381,980
Irrigation	1,695,365	1,691,408	1,685,314	1,686,373	1,673,278	1,663,742	1,668,121	1,656,591	1,638,795	1,612,166
Industrial	2,634,963	2,638,631	2,645,784	2,652,260	2,656,430	2,662,466	2,668,880	2,672,483	2,678,356	2,679,387
Additional Firm	1,657,426	1,651,857	1,650,315	1,636,705	1,638,050	1,632,964	1,619,435	1,605,524	1,595,267	1,578,775
Firm Sales	16,139,031	16,123,569	16,196,100	16,243,907	16,230,769	16,270,729	16,318,149	16,264,935	16,277,230	16,118,462
System Sales	16,139,031	16,123,569	16,196,100	16,243,907	16,230,769	16,270,729	16,318,149	16,264,935	16,277,230	16,118,462
Firm Off-System Sales	0	0	0	0	0	0	0	0	0	0
Total Sales	16,139,031	16,123,569	16,196,100	16,243,907	16,230,769	16,270,729	16,318,149	16,264,935	16,277,230	16,118,462
Loss	1,544,406	1,541,615	1,548,045	1,552,690	1,549,724	1,552,855	1,557,457	1,551,223	1,551,830	1,534,338
Required Generation	17,683,437	17,665,184	17,744,145	17,796,597	17,780,493	17,823,583	17,875,606	17,816,158	17,829,060	17,652,801

Average Load (Average Megawatts)—50th Percentile

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Residential	667	667	673	678	673	680	684	680	680	670
Commercial	489	490	493	495	495	497	499	499	500	500
Irrigation	193	193	192	193	190	190	190	189	187	184
Industrial	300	301	302	303	302	304	305	305	305	306
Additional Firm	189	189	188	187	186	186	185	183	182	180
Loss	176	176	177	177	176	177	178	177	177	175
Firm Load	2,013	2,017	2,026	2,032	2,024	2,035	2,041	2,034	2,030	2,015
Light Load	1,831	1,834	1,843	1,848	1,841	1,851	1,856	1,850	1,846	1,833
Heavy Load	2,156	2,160	2,169	2,176	2,167	2,179	2,185	2,178	2,174	2,158
System Load	2,013	2,017	2,026	2,032	2,024	2,035	2,041	2,034	2,030	2,015
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0
Total Load	2,013	2,017	2,026	2,032	2,024	2,035	2,041	2,034	2,030	2,015

Peak Load (Megawatts)—90th Percentile

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Energy Efficiency (Mw)	-163	-177	-191	-205	-219	-233	-247	-261	-275	-289
Demand Response (Mw)	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	4,091	4,133	4,183	4,234	4,262	4,312	4,364	4,394	4,430	4,445
System Peak (1 Hour)	4,091	4,133	4,183	4,234	4,262	4,312	4,364	4,394	4,430	4,445
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0
Loss	0	0	0	0	0	0	0	0	0	0
Total Peak Load	4,091	4,133	4,183	4,234	4,262	4,312	4,364	4,394	4,430	4,445

Sales and Load Forecast

Average Load (Average Megawatts)—70th Percentile

	Jan. 2010	Feb. 2010	Mar. 2010	Apr. 2010	May. 2010	Jun. 2010	Jul. 2010	Aug. 2010	Sep. 2010	Oct. 2010	Nov. 2010	Dec. 2010
Residential	810	720	586	497	449	512	652	623	495	495	635	835
Commercial	468	447	407	395	397	441	509	490	429	409	436	493
Irrigation	1	1	7	99	309	577	626	500	332	52	4	3
Industrial	248	251	244	239	245	260	255	256	249	255	251	275
Additional Firm	152	160	155	150	158	144	147	156	172	182	189	193
Loss	164	153	134	132	151	192	220	202	163	131	144	174
Firm Load	1,844	1,730	1,533	1,512	1,709	2,126	2,409	2,226	1,838	1,525	1,658	1,972
Light Load	1,698	1,598	1,410	1,376	1,535	1,911	2,180	1,975	1,673	1,380	1,523	1,834
Heavy Load	1,969	1,829	1,622	1,612	1,858	2,283	2,590	2,424	1,971	1,639	1,766	2,081
System Load	1,844	1,730	1,533	1,512	1,709	2,126	2,409	2,226	1,838	1,525	1,658	1,972
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	1,844	1,730	1,533	1,512	1,709	2,126	2,409	2,226	1,838	1,525	1,658	1,972

Peak Load (Megawatts)—95th Percentile

	Jan. 2010	Feb. 2010	Mar. 2010	Apr. 2010	May. 2010	Jun. 2010	Jul. 2010	Aug. 2010	Sep. 2010	Oct. 2010	Nov. 2010	Dec. 2010
Energy Efficiency (MW)	-13	-13	-13	-14	-15	-16	-17	-16	-14	-13	-13	-13
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,455	2,402	2,103	1,871	2,761	3,318	3,460	3,138	2,978	2,088	2,302	2,695
System Peak (1 Hour)	2,455	2,402	2,103	1,871	2,761	3,318	3,460	3,138	2,978	2,088	2,302	2,695
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,455	2,402	2,103	1,871	2,761	3,318	3,460	3,138	2,978	2,088	2,302	2,695

Sales and Load Forecast

Average Load (Average Megawatts)—70th Percentile

	Jan. 2011	Feb. 2011	Mar. 2011	Apr. 2011	May. 2011	Jun. 2011	Jul. 2011	Aug. 2011	Sep. 2011	Oct. 2011	Nov. 2011	Dec. 2011
Residential	821	728	592	503	456	523	669	640	506	503	645	850
Commercial	475	452	413	400	403	450	519	499	436	415	442	503
Irrigation	1	1	7	99	309	580	630	503	334	52	4	3
Industrial	269	276	268	266	272	289	285	287	282	288	287	296
Additional Firm	206	205	197	191	186	160	153	161	177	182	190	193
Loss	170	158	139	137	155	197	226	207	167	135	148	178
Firm Load	1,941	1,820	1,616	1,595	1,781	2,200	2,482	2,296	1,902	1,577	1,716	2,024
Light Load	1,787	1,681	1,486	1,451	1,600	1,977	2,245	2,037	1,731	1,427	1,576	1,882
Heavy Load	2,073	1,924	1,709	1,700	1,937	2,362	2,685	2,483	2,039	1,695	1,828	2,136
System Load	1,941	1,820	1,616	1,595	1,781	2,200	2,482	2,296	1,902	1,577	1,716	2,024
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	1,941	1,820	1,616	1,595	1,781	2,200	2,482	2,296	1,902	1,577	1,716	2,024

Peak Load (Megawatts)—95th Percentile

	Jan. 2011	Feb. 2011	Mar. 2011	Apr. 2011	May. 2011	Jun. 2011	Jul. 2011	Aug. 2011	Sep. 2011	Oct. 2011	Nov. 2011	Dec. 2011
Energy Efficiency (MW)	-25	-25	-25	-26	-30	-33	-33	-32	-28	-26	-25	-25
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,559	2,486	2,191	1,948	2,846	3,395	3,560	3,185	3,027	2,133	2,353	2,733
System Peak (1 Hour)	2,559	2,486	2,191	1,948	2,846	3,395	3,560	3,185	3,027	2,133	2,353	2,733
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,559	2,486	2,191	1,948	2,846	3,395	3,560	3,185	3,027	2,133	2,353	2,733

Sales and Load Forecast

Average Load (Average Megawatts)—70th Percentile

	Jan. 2012	Feb. 2012	Mar. 2012	Apr. 2012	May. 2012	Jun. 2012	Jul. 2012	Aug. 2012	Sep. 2012	Oct. 2012	Nov. 2012	Dec. 2012
Residential	837	741	602	511	465	538	691	661	520	515	658	857
Commercial	485	462	421	408	412	461	533	512	447	424	452	513
Irrigation	1	1	7	98	307	576	625	499	332	52	4	3
Industrial	289	287	285	282	286	303	298	298	292	297	294	299
Additional Firm	205	202	197	191	186	160	153	160	177	188	197	201
Loss	174	161	142	140	158	201	230	211	170	138	151	180
Firm Load	1,990	1,853	1,655	1,630	1,814	2,239	2,531	2,341	1,937	1,615	1,756	2,053
Light Load	1,832	1,711	1,522	1,483	1,629	2,013	2,289	2,077	1,763	1,461	1,613	1,909
Heavy Load	2,125	1,958	1,750	1,747	1,959	2,405	2,738	2,532	2,090	1,725	1,871	2,176
System Load	1,990	1,853	1,655	1,630	1,814	2,239	2,531	2,341	1,937	1,615	1,756	2,053
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	1,990	1,853	1,655	1,630	1,814	2,239	2,531	2,341	1,937	1,615	1,756	2,053

Peak Load (Megawatts)—95th Percentile

	Jan. 2012	Feb. 2012	Mar. 2012	Apr. 2012	May. 2012	Jun. 2012	Jul. 2012	Aug. 2012	Sep. 2012	Oct. 2012	Nov. 2012	Dec. 2012
Energy Efficiency (MW)	-37	-36	-37	-39	-45	-48	-48	-47	-42	-38	-37	-37
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,600	2,487	2,225	1,964	2,891	3,496	3,636	3,242	3,069	2,168	2,391	2,756
System Peak (1 Hour)	2,600	2,487	2,225	1,964	2,891	3,496	3,636	3,242	3,069	2,168	2,391	2,756
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,600	2,487	2,225	1,964	2,891	3,496	3,636	3,242	3,069	2,168	2,391	2,756

Sales and Load Forecast

Average Load (Average Megawatts)—70th Percentile

	Jan. 2013	Feb. 2013	Mar. 2013	Apr. 2013	May. 2013	Jun. 2013	Jul. 2013	Aug. 2013	Sep. 2013	Oct. 2013	Nov. 2013	Dec. 2013
Residential	834	737	599	508	464	540	698	667	522	514	658	866
Commercial	492	468	428	414	419	471	545	522	455	431	459	520
Irrigation	1	1	7	98	305	572	622	496	330	52	4	3
Industrial	290	300	288	284	289	306	300	300	294	300	297	300
Additional Firm	205	205	198	191	186	179	189	185	184	189	197	201
Loss	174	162	142	140	158	202	233	213	172	139	152	182
Firm Load	1,997	1,872	1,661	1,635	1,821	2,270	2,587	2,385	1,957	1,625	1,767	2,073
Light Load	1,839	1,729	1,528	1,488	1,636	2,041	2,340	2,116	1,781	1,471	1,623	1,927
Heavy Load	2,121	1,979	1,766	1,743	1,967	2,454	2,781	2,579	2,111	1,736	1,883	2,198
System Load	1,997	1,872	1,661	1,635	1,821	2,270	2,587	2,385	1,957	1,625	1,767	2,073
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	1,997	1,872	1,661	1,635	1,821	2,270	2,587	2,385	1,957	1,625	1,767	2,073

Peak Load (Megawatts)—95th Percentile

	Jan. 2013	Feb. 2013	Mar. 2013	Apr. 2013	May. 2013	Jun. 2013	Jul. 2013	Aug. 2013	Sep. 2013	Oct. 2013	Nov. 2013	Dec. 2013
Energy Efficiency (MW)	-49	-49	-49	-52	-58	-63	-64	-62	-56	-50	-49	-50
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,560	2,496	2,203	1,922	2,915	3,541	3,726	3,296	3,127	2,177	2,389	2,703
System Peak (1 Hour)	2,560	2,496	2,203	1,922	2,915	3,541	3,726	3,296	3,127	2,177	2,389	2,703
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,560	2,496	2,203	1,922	2,915	3,541	3,726	3,296	3,127	2,177	2,389	2,703

Sales and Load Forecast

Average Load (Average Megawatts)—70th Percentile

	Jan. 2014	Feb. 2014	Mar. 2014	Apr. 2014	May. 2014	Jun. 2014	Jul. 2014	Aug. 2014	Sep. 2014	Oct. 2014	Nov. 2014	Dec. 2014
Residential	848	748	608	515	472	554	719	687	535	525	670	876
Commercial	497	472	432	418	424	478	554	530	461	437	464	526
Irrigation	1	1	7	97	303	570	620	495	329	52	4	3
Industrial	291	301	289	285	290	307	302	302	296	301	298	301
Additional Firm	206	205	198	192	187	179	189	186	185	190	198	202
Loss	176	163	143	141	160	204	236	216	174	140	154	183
Firm Load	2,020	1,891	1,677	1,649	1,836	2,294	2,620	2,416	1,980	1,644	1,788	2,091
Light Load	1,860	1,746	1,543	1,501	1,649	2,061	2,370	2,144	1,802	1,488	1,642	1,944
Heavy Load	2,146	1,999	1,783	1,758	1,983	2,479	2,817	2,631	2,123	1,757	1,916	2,206
System Load	2,020	1,891	1,677	1,649	1,836	2,294	2,620	2,416	1,980	1,644	1,788	2,091
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,020	1,891	1,677	1,649	1,836	2,294	2,620	2,416	1,980	1,644	1,788	2,091

Peak Load (Megawatts)—95th Percentile

	Jan. 2014	Feb. 2014	Mar. 2014	Apr. 2014	May. 2014	Jun. 2014	Jul. 2014	Aug. 2014	Sep. 2014	Oct. 2014	Nov. 2014	Dec. 2014
Energy Efficiency (MW)	-61	-61	-61	-64	-72	-78	-79	-76	-68	-62	-62	-61
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,594	2,516	2,230	1,944	2,946	3,593	3,789	3,359	3,169	2,193	2,415	2,748
System Peak (1 Hour)	2,594	2,516	2,230	1,944	2,946	3,593	3,789	3,359	3,169	2,193	2,415	2,748
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,594	2,516	2,230	1,944	2,946	3,593	3,789	3,359	3,169	2,193	2,415	2,748

Sales and Load Forecast

Average Load (Average Megawatts)—70th Percentile

	Jan. 2015	Feb. 2015	Mar. 2015	Apr. 2015	May. 2015	Jun. 2015	Jul. 2015	Aug. 2015	Sep. 2015	Oct. 2015	Nov. 2015	Dec. 2015
Residential	852	750	609	516	475	561	732	699	542	528	674	883
Commercial	500	475	435	421	427	484	561	536	466	440	468	530
Irrigation	1	1	7	97	304	572	622	496	330	52	4	3
Industrial	292	302	289	286	290	308	302	302	296	302	299	301
Additional Firm	206	205	198	192	187	179	189	186	185	190	198	202
Loss	177	164	144	141	160	206	238	218	175	141	155	184
Firm Load	2,028	1,896	1,682	1,653	1,842	2,310	2,645	2,438	1,994	1,652	1,797	2,103
Light Load	1,867	1,751	1,547	1,504	1,655	2,076	2,393	2,163	1,815	1,496	1,650	1,955
Heavy Load	2,154	2,004	1,788	1,762	2,003	2,480	2,843	2,655	2,138	1,766	1,925	2,219
System Load	2,028	1,896	1,682	1,653	1,842	2,310	2,645	2,438	1,994	1,652	1,797	2,103
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,028	1,896	1,682	1,653	1,842	2,310	2,645	2,438	1,994	1,652	1,797	2,103

Peak Load (Megawatts)—95th Percentile

	Jan. 2015	Feb. 2015	Mar. 2015	Apr. 2015	May. 2015	Jun. 2015	Jul. 2015	Aug. 2015	Sep. 2015	Oct. 2015	Nov. 2015	Dec. 2015
Energy Efficiency (MW)	-73	-73	-73	-76	-86	-92	-93	-90	-81	-74	-74	-73
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,583	2,509	2,226	1,931	2,970	3,640	3,843	3,396	3,211	2,200	2,421	2,742
System Peak (1 Hour)	2,583	2,509	2,226	1,931	2,970	3,640	3,843	3,396	3,211	2,200	2,421	2,742
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,583	2,509	2,226	1,931	2,970	3,640	3,843	3,396	3,211	2,200	2,421	2,742

Sales and Load Forecast

Average Load (Average Megawatts)—70th Percentile

	Jan. 2016	Feb. 2016	Mar. 2016	Apr. 2016	May. 2016	Jun. 2016	Jul. 2016	Aug. 2016	Sep. 2016	Oct. 2016	Nov. 2016	Dec. 2016
Residential	858	754	611	518	478	570	746	713	550	534	680	890
Commercial	502	478	437	423	430	489	568	542	470	443	471	534
Irrigation	1	1	7	97	303	572	622	496	330	52	4	3
Industrial	293	292	290	286	291	309	303	303	297	302	300	302
Additional Firm	204	201	197	191	186	178	189	185	184	189	197	201
Loss	178	164	144	142	161	207	241	220	176	142	156	186
Firm Load	2,037	1,889	1,687	1,657	1,848	2,324	2,667	2,459	2,007	1,661	1,807	2,115
Light Load	1,876	1,745	1,552	1,508	1,660	2,089	2,413	2,181	1,826	1,503	1,659	1,967
Heavy Load	2,175	1,996	1,784	1,767	2,010	2,496	2,886	2,659	2,152	1,785	1,925	2,232
System Load	2,037	1,889	1,687	1,657	1,848	2,324	2,667	2,459	2,007	1,661	1,807	2,115
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,037	1,889	1,687	1,657	1,848	2,324	2,667	2,459	2,007	1,661	1,807	2,115

Peak Load (Megawatts)—95th Percentile

	Jan. 2016	Feb. 2016	Mar. 2016	Apr. 2016	May. 2016	Jun. 2016	Jul. 2016	Aug. 2016	Sep. 2016	Oct. 2016	Nov. 2016	Dec. 2016
Energy Efficiency (MW)	-85	-82	-85	-88	-99	-106	-107	-104	-94	-87	-85	-84
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,580	2,507	2,228	1,924	2,993	3,686	3,895	3,437	3,252	2,207	2,430	2,745
System Peak (1 Hour)	2,580	2,507	2,228	1,924	2,993	3,686	3,895	3,437	3,252	2,207	2,430	2,745
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,580	2,507	2,228	1,924	2,993	3,686	3,895	3,437	3,252	2,207	2,430	2,745

Sales and Load Forecast

Average Load (Average Megawatts)—70th Percentile

	Jan. 2017	Feb. 2017	Mar. 2017	Apr. 2017	May. 2017	Jun. 2017	Jul. 2017	Aug. 2017	Sep. 2017	Oct. 2017	Nov. 2017	Dec. 2017
Residential	863	757	614	520	482	578	761	727	558	539	686	898
Commercial	505	478	439	425	433	494	574	547	474	445	474	537
Irrigation	1	1	7	97	303	572	622	496	331	52	4	3
Industrial	293	303	291	287	291	310	303	304	298	303	300	303
Additional Firm	204	203	197	191	186	178	188	185	184	188	196	200
Loss	179	165	145	142	161	209	243	222	177	142	156	187
Firm Load	2,046	1,908	1,693	1,662	1,856	2,340	2,692	2,481	2,022	1,670	1,817	2,127
Light Load	1,884	1,762	1,557	1,512	1,667	2,103	2,435	2,202	1,840	1,512	1,669	1,978
Heavy Load	2,185	2,017	1,790	1,781	2,005	2,513	2,913	2,684	2,167	1,795	1,936	2,256
System Load	2,046	1,908	1,693	1,662	1,856	2,340	2,692	2,481	2,022	1,670	1,817	2,127
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,046	1,908	1,693	1,662	1,856	2,340	2,692	2,481	2,022	1,670	1,817	2,127

Peak Load (Megawatts)—95th Percentile

	Jan. 2017	Feb. 2017	Mar. 2017	Apr. 2017	May. 2017	Jun. 2017	Jul. 2017	Aug. 2017	Sep. 2017	Oct. 2017	Nov. 2017	Dec. 2017
Energy Efficiency (MW)	-97	-96	-96	-101	-112	-120	-121	-117	-106	-99	-97	-97
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,578	2,504	2,231	1,920	3,018	3,733	3,949	3,480	3,293	2,215	2,439	2,751
System Peak (1 Hour)	2,578	2,504	2,231	1,920	3,018	3,733	3,949	3,480	3,293	2,215	2,439	2,751
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,578	2,504	2,231	1,920	3,018	3,733	3,949	3,480	3,293	2,215	2,439	2,751

Sales and Load Forecast

Average Load (Average Megawatts)—70th Percentile

	Jan. 2018	Feb. 2018	Mar. 2018	Apr. 2018	May. 2018	Jun. 2018	Jul. 2018	Aug. 2018	Sep. 2018	Oct. 2018	Nov. 2018	Dec. 2018
Residential	869	760	616	522	486	587	776	741	566	544	692	906
Commercial	507	480	441	427	435	499	581	553	477	449	477	540
Irrigation	1	1	7	97	303	573	623	497	331	52	4	3
Industrial	294	304	291	287	292	310	304	304	298	304	301	303
Additional Firm	204	203	196	190	185	177	188	184	183	188	196	200
Loss	179	165	145	142	162	210	245	224	179	143	157	188
Firm Load	2,054	1,914	1,698	1,666	1,863	2,356	2,717	2,504	2,035	1,680	1,827	2,141
Light Load	1,892	1,767	1,562	1,516	1,674	2,118	2,458	2,222	1,852	1,521	1,678	1,991
Heavy Load	2,183	2,023	1,796	1,786	2,013	2,530	2,940	2,708	2,196	1,795	1,946	2,270
System Load	2,054	1,914	1,698	1,666	1,863	2,356	2,717	2,504	2,035	1,680	1,827	2,141
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,054	1,914	1,698	1,666	1,863	2,356	2,717	2,504	2,035	1,680	1,827	2,141

Peak Load (Megawatts)—95th Percentile

	Jan. 2018	Feb. 2018	Mar. 2018	Apr. 2018	May. 2018	Jun. 2018	Jul. 2018	Aug. 2018	Sep. 2018	Oct. 2018	Nov. 2018	Dec. 2018
Energy Efficiency (MW)	-109	-108	-108	-113	-125	-134	-135	-131	-120	-110	-109	-109
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,576	2,501	2,233	1,915	3,042	3,780	4,003	3,523	3,334	2,223	2,448	2,759
System Peak (1 Hour)	2,576	2,501	2,233	1,915	3,042	3,780	4,003	3,523	3,334	2,223	2,448	2,759
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,576	2,501	2,233	1,915	3,042	3,780	4,003	3,523	3,334	2,223	2,448	2,759

Sales and Load Forecast

Average Load (Average Megawatts)—70th Percentile

	Jan. 2019	Feb. 2019	Mar. 2019	Apr. 2019	May. 2019	Jun. 2019	Jul. 2019	Aug. 2019	Sep. 2019	Oct. 2019	Nov. 2019	Dec. 2019
Residential	876	765	620	525	490	597	792	757	576	550	699	916
Commercial	510	482	443	429	439	504	587	558	481	451	479	544
Irrigation	1	1	7	97	303	574	625	498	332	52	4	3
Industrial	295	305	292	288	293	311	305	305	299	305	302	304
Additional Firm	201	200	194	188	184	176	186	183	182	186	194	198
Loss	180	166	145	143	163	212	248	227	180	144	158	189
Firm Load	2,062	1,918	1,701	1,670	1,871	2,373	2,743	2,528	2,050	1,689	1,836	2,153
Light Load	1,899	1,772	1,565	1,520	1,681	2,133	2,481	2,243	1,865	1,529	1,687	2,002
Heavy Load	2,191	2,028	1,808	1,780	2,021	2,565	2,949	2,734	2,211	1,805	1,956	2,283
System Load	2,062	1,918	1,701	1,670	1,871	2,373	2,743	2,528	2,050	1,689	1,836	2,153
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,062	1,918	1,701	1,670	1,871	2,373	2,743	2,528	2,050	1,689	1,836	2,153

Peak Load (Megawatts)—95th Percentile

	Jan. 2019	Feb. 2019	Mar. 2019	Apr. 2019	May. 2019	Jun. 2019	Jul. 2019	Aug. 2019	Sep. 2019	Oct. 2019	Nov. 2019	Dec. 2019
Energy Efficiency (MW)	-120	-120	-121	-125	-138	-148	-149	-145	-132	-122	-120	-121
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,578	2,501	2,238	1,915	3,067	3,827	4,060	3,570	3,374	2,230	2,459	2,773
System Peak (1 Hour)	2,578	2,501	2,238	1,915	3,067	3,827	4,060	3,570	3,374	2,230	2,459	2,773
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,578	2,501	2,238	1,915	3,067	3,827	4,060	3,570	3,374	2,230	2,459	2,773

Sales and Load Forecast

Average Load (Average Megawatts)—70th Percentile

	Jan. 2020	Feb. 2020	Mar. 2020	Apr. 2020	May. 2020	Jun. 2020	Jul. 2020	Aug. 2020	Sep. 2020	Oct. 2020	Nov. 2020	Dec. 2020
Residential	884	770	624	528	495	607	809	773	585	557	707	919
Commercial	511	485	444	431	441	509	594	563	486	454	481	547
Irrigation	1	1	8	97	304	576	627	500	334	52	4	3
Industrial	296	295	292	288	293	312	305	306	300	306	302	305
Additional Firm	201	198	194	188	183	175	186	182	181	186	193	197
Loss	181	166	146	143	163	213	250	229	182	145	159	190
Firm Load	2,074	1,915	1,707	1,676	1,879	2,392	2,772	2,554	2,068	1,699	1,846	2,160
Light Load	1,910	1,768	1,571	1,524	1,688	2,150	2,507	2,266	1,882	1,538	1,696	2,009
Heavy Load	2,203	2,023	1,815	1,786	2,043	2,568	2,980	2,781	2,217	1,816	1,978	2,280
System Load	2,074	1,915	1,707	1,676	1,879	2,392	2,772	2,554	2,068	1,699	1,846	2,160
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,074	1,915	1,707	1,676	1,879	2,392	2,772	2,554	2,068	1,699	1,846	2,160

Peak Load (Megawatts)—95th Percentile

	Jan. 2020	Feb. 2020	Mar. 2020	Apr. 2020	May. 2020	Jun. 2020	Jul. 2020	Aug. 2020	Sep. 2020	Oct. 2020	Nov. 2020	Dec. 2020
Energy Efficiency (MW)	-132	-127	-133	-137	-152	-162	-163	-159	-144	-134	-133	-132
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,586	2,494	2,246	1,918	3,092	3,876	4,118	3,621	3,417	2,239	2,470	2,786
System Peak (1 Hour)	2,586	2,494	2,246	1,918	3,092	3,876	4,118	3,621	3,417	2,239	2,470	2,786
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,586	2,494	2,246	1,918	3,092	3,876	4,118	3,621	3,417	2,239	2,470	2,786

Sales and Load Forecast

Average Load (Average Megawatts)—70th Percentile

	Jan. 2021	Feb. 2021	Mar. 2021	Apr. 2021	May. 2021	Jun. 2021	Jul. 2021	Aug. 2021	Sep. 2021	Oct. 2021	Nov. 2021	Dec. 2021
Residential	881	766	620	525	494	610	817	781	588	557	706	923
Commercial	512	483	446	431	442	513	599	567	488	455	483	549
Irrigation	1	1	8	97	303	574	626	499	333	52	4	3
Industrial	295	306	293	289	293	312	306	306	300	306	303	305
Additional Firm	200	200	193	188	183	175	186	182	181	186	193	197
Loss	181	166	145	143	163	214	252	230	182	145	159	190
Firm Load	2,070	1,922	1,705	1,673	1,878	2,398	2,785	2,565	2,073	1,700	1,848	2,167
Light Load	1,907	1,775	1,569	1,522	1,687	2,156	2,519	2,276	1,886	1,539	1,698	2,015
Heavy Load	2,211	2,032	1,804	1,783	2,042	2,576	2,994	2,794	2,222	1,828	1,969	2,287
System Load	2,070	1,922	1,705	1,673	1,878	2,398	2,785	2,565	2,073	1,700	1,848	2,167
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,070	1,922	1,705	1,673	1,878	2,398	2,785	2,565	2,073	1,700	1,848	2,167

Peak Load (Megawatts)—95th Percentile

	Jan. 2021	Feb. 2021	Mar. 2021	Apr. 2021	May. 2021	Jun. 2021	Jul. 2021	Aug. 2021	Sep. 2021	Oct. 2021	Nov. 2021	Dec. 2021
Energy Efficiency (MW)	-145	-144	-143	-149	-165	-176	-177	-172	-157	-146	-144	-144
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,547	2,481	2,229	1,889	3,109	3,916	4,160	3,642	3,458	2,239	2,466	2,754
System Peak (1 Hour)	2,547	2,481	2,229	1,889	3,109	3,916	4,160	3,642	3,458	2,239	2,466	2,754
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,547	2,481	2,229	1,889	3,109	3,916	4,160	3,642	3,458	2,239	2,466	2,754

Sales and Load Forecast

Average Load (Average Megawatts)—70th Percentile

	Jan. 2022	Feb. 2022	Mar. 2022	Apr. 2022	May. 2022	Jun. 2022	Jul. 2022	Aug. 2022	Sep. 2022	Oct. 2022	Nov. 2022	Dec. 2022
Residential	886	769	622	526	498	619	832	795	596	562	711	929
Commercial	513	484	447	432	444	517	604	572	491	457	485	552
Irrigation	1	1	8	97	301	572	624	497	332	52	4	3
Industrial	296	307	294	289	294	313	307	307	301	307	304	307
Additional Firm	200	200	193	187	183	175	185	182	181	185	193	197
Loss	181	166	146	143	163	215	253	232	183	146	160	191
Firm Load	2,077	1,926	1,709	1,675	1,883	2,411	2,806	2,585	2,085	1,708	1,857	2,178
Light Load	1,913	1,778	1,572	1,524	1,691	2,167	2,539	2,293	1,897	1,546	1,706	2,025
Heavy Load	2,218	2,036	1,807	1,786	2,047	2,589	3,036	2,796	2,235	1,836	1,978	2,298
System Load	2,077	1,926	1,709	1,675	1,883	2,411	2,806	2,585	2,085	1,708	1,857	2,178
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,077	1,926	1,709	1,675	1,883	2,411	2,806	2,585	2,085	1,708	1,857	2,178

Peak Load (Megawatts)—95th Percentile

	Jan. 2022	Feb. 2022	Mar. 2022	Apr. 2022	May. 2022	Jun. 2022	Jul. 2022	Aug. 2022	Sep. 2022	Oct. 2022	Nov. 2022	Dec. 2022
Energy Efficiency (MW)	-157	-155	-155	-161	-179	-190	-191	-186	-170	-159	-156	-155
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,543	2,477	2,232	1,886	3,131	3,961	4,210	3,685	3,500	2,245	2,474	2,763
System Peak (1 Hour)	2,543	2,477	2,232	1,886	3,131	3,961	4,210	3,685	3,500	2,245	2,474	2,763
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,543	2,477	2,232	1,886	3,131	3,961	4,210	3,685	3,500	2,245	2,474	2,763

Sales and Load Forecast

Average Load (Average Megawatts)—70th Percentile

	Jan. 2023	Feb. 2023	Mar. 2023	Apr. 2023	May. 2023	Jun. 2023	Jul. 2023	Aug. 2023	Sep. 2023	Oct. 2023	Nov. 2023	Dec. 2023
Residential	889	770	623	527	500	626	846	809	604	566	715	926
Commercial	514	484	447	432	446	521	610	576	494	458	486	552
Irrigation	1	1	8	97	301	573	624	498	333	52	4	3
Industrial	297	307	294	290	295	314	307	308	302	308	305	306
Additional Firm	198	198	192	186	182	173	184	181	180	184	191	195
Loss	182	166	146	143	164	216	255	234	184	146	160	190
Firm Load	2,081	1,926	1,709	1,674	1,887	2,424	2,827	2,604	2,096	1,714	1,862	2,173
Light Load	1,917	1,779	1,573	1,523	1,695	2,178	2,558	2,310	1,907	1,551	1,710	2,020
Heavy Load	2,223	2,036	1,808	1,795	2,039	2,603	3,059	2,816	2,247	1,842	1,983	2,304
System Load	2,081	1,926	1,709	1,674	1,887	2,424	2,827	2,604	2,096	1,714	1,862	2,173
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,081	1,926	1,709	1,674	1,887	2,424	2,827	2,604	2,096	1,714	1,862	2,173

Peak Load (Megawatts)—95th Percentile

	Jan. 2023	Feb. 2023	Mar. 2023	Apr. 2023	May. 2023	Jun. 2023	Jul. 2023	Aug. 2023	Sep. 2023	Oct. 2023	Nov. 2023	Dec. 2023
Energy Efficiency (MW)	-168	-167	-167	-174	-191	-204	-205	-200	-182	-170	-168	-169
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,535	2,470	2,230	1,878	3,153	4,006	4,261	3,726	3,540	2,249	2,479	2,751
System Peak (1 Hour)	2,535	2,470	2,230	1,878	3,153	4,006	4,261	3,726	3,540	2,249	2,479	2,751
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,535	2,470	2,230	1,878	3,153	4,006	4,261	3,726	3,540	2,249	2,479	2,751

Sales and Load Forecast

Average Load (Average Megawatts)—70th Percentile

	Jan. 2024	Feb. 2024	Mar. 2024	Apr. 2024	May. 2024	Jun. 2024	Jul. 2024	Aug. 2024	Sep. 2024	Oct. 2024	Nov. 2024	Dec. 2024
Residential	879	760	614	519	495	625	848	810	602	561	709	927
Commercial	513	485	446	432	447	524	613	578	495	459	486	553
Irrigation	1	1	8	96	299	569	620	494	330	51	4	3
Industrial	299	297	294	290	296	314	308	308	301	309	305	307
Additional Firm	198	195	191	186	181	173	184	180	179	184	191	195
Loss	180	164	144	142	163	216	255	234	184	145	159	191
Firm Load	2,071	1,903	1,698	1,665	1,880	2,420	2,827	2,604	2,091	1,709	1,855	2,176
Light Load	1,907	1,758	1,562	1,515	1,689	2,175	2,558	2,310	1,903	1,547	1,704	2,023
Heavy Load	2,200	2,011	1,805	1,775	2,031	2,616	3,040	2,816	2,256	1,827	1,976	2,307
System Load	2,071	1,903	1,698	1,665	1,880	2,420	2,827	2,604	2,091	1,709	1,855	2,176
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,071	1,903	1,698	1,665	1,880	2,420	2,827	2,604	2,091	1,709	1,855	2,176

Peak Load (Megawatts)—95th Percentile

	Jan. 2024	Feb. 2024	Mar. 2024	Apr. 2024	May. 2024	Jun. 2024	Jul. 2024	Aug. 2024	Sep. 2024	Oct. 2024	Nov. 2024	Dec. 2024
Energy Efficiency (MW)	-180	-173	-180	-185	-203	-218	-219	-214	-196	-181	-180	-181
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,467	2,454	2,193	1,830	3,164	4,039	4,290	3,728	3,580	2,244	2,461	2,688
System Peak (1 Hour)	2,467	2,454	2,193	1,830	3,164	4,039	4,290	3,728	3,580	2,244	2,461	2,688
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,467	2,454	2,193	1,830	3,164	4,039	4,290	3,728	3,580	2,244	2,461	2,688

Sales and Load Forecast

Average Load (Average Megawatts)—70th Percentile

	Jan. 2025	Feb. 2025	Mar. 2025	Apr. 2025	May. 2025	Jun. 2025	Jul. 2025	Aug. 2025	Sep. 2025	Oct. 2025	Nov. 2025	Dec. 2025
Residential	885	763	617	522	499	634	865	826	611	567	716	934
Commercial	514	483	447	433	448	528	618	582	498	461	487	556
Irrigation	1	1	7	95	297	566	617	491	329	51	4	3
Industrial	298	309	295	291	296	315	309	309	303	310	305	308
Additional Firm	198	197	191	185	181	173	184	180	179	184	191	194
Loss	181	165	145	142	163	217	257	235	185	146	160	192
Firm Load	2,078	1,918	1,702	1,668	1,885	2,433	2,849	2,624	2,104	1,718	1,863	2,186
Light Load	1,913	1,771	1,565	1,518	1,693	2,186	2,577	2,328	1,915	1,555	1,711	2,033
Heavy Load	2,207	2,028	1,809	1,778	2,036	2,629	3,063	2,857	2,256	1,836	1,996	2,307
System Load	2,078	1,918	1,702	1,668	1,885	2,433	2,849	2,624	2,104	1,718	1,863	2,186
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,078	1,918	1,702	1,668	1,885	2,433	2,849	2,624	2,104	1,718	1,863	2,186

Peak Load (Megawatts)—95th Percentile

	Jan. 2025	Feb. 2025	Mar. 2025	Apr. 2025	May. 2025	Jun. 2025	Jul. 2025	Aug. 2025	Sep. 2025	Oct. 2025	Nov. 2025	Dec. 2025
Energy Efficiency (MW)	-192	-191	-192	-198	-216	-232	-233	-227	-208	-193	-193	-192
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,471	2,430	2,201	1,835	3,186	4,084	4,341	3,776	3,622	2,251	2,471	2,710
System Peak (1 Hour)	2,471	2,430	2,201	1,835	3,186	4,084	4,341	3,776	3,622	2,251	2,471	2,710
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,471	2,430	2,201	1,835	3,186	4,084	4,341	3,776	3,622	2,251	2,471	2,710

Sales and Load Forecast

Average Load (Average Megawatts)—70th Percentile

	Jan. 2026	Feb. 2026	Mar. 2026	Apr. 2026	May. 2026	Jun. 2026	Jul. 2026	Aug. 2026	Sep. 2026	Oct. 2026	Nov. 2026	Dec. 2026
Residential	888	764	617	522	501	642	879	839	618	570	719	931
Commercial	514	482	447	433	449	532	623	586	501	462	488	557
Irrigation	1	1	8	96	297	567	618	493	330	51	4	3
Industrial	299	309	296	291	296	316	309	310	304	311	306	309
Additional Firm	196	196	189	184	180	171	182	179	178	182	189	192
Loss	181	165	144	142	163	218	259	237	186	147	160	191
Firm Load	2,080	1,918	1,701	1,668	1,887	2,446	2,871	2,644	2,117	1,723	1,866	2,183
Light Load	1,915	1,771	1,565	1,517	1,695	2,199	2,597	2,345	1,926	1,559	1,714	2,030
Heavy Load	2,210	2,028	1,809	1,778	2,052	2,627	3,087	2,879	2,269	1,841	2,000	2,304
System Load	2,080	1,918	1,701	1,668	1,887	2,446	2,871	2,644	2,117	1,723	1,866	2,183
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,080	1,918	1,701	1,668	1,887	2,446	2,871	2,644	2,117	1,723	1,866	2,183

Peak Load (Megawatts)—95th Percentile

	Jan. 2026	Feb. 2026	Mar. 2026	Apr. 2026	May. 2026	Jun. 2026	Jul. 2026	Aug. 2026	Sep. 2026	Oct. 2026	Nov. 2026	Dec. 2026
Energy Efficiency (MW)	-203	-203	-204	-210	-231	-246	-247	-241	-219	-205	-205	-203
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,460	2,421	2,199	1,828	3,206	4,129	4,393	3,818	3,664	2,254	2,475	2,702
System Peak (1 Hour)	2,460	2,421	2,199	1,828	3,206	4,129	4,393	3,818	3,664	2,254	2,475	2,702
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,460	2,421	2,199	1,828	3,206	4,129	4,393	3,818	3,664	2,254	2,475	2,702

Sales and Load Forecast

Average Load (Average Megawatts)—70th Percentile

	Jan. 2027	Feb. 2027	Mar. 2027	Apr. 2027	May. 2027	Jun. 2027	Jul. 2027	Aug. 2027	Sep. 2027	Oct. 2027	Nov. 2027	Dec. 2027
Residential	879	755	610	515	497	641	881	841	617	567	714	927
Commercial	513	481	447	433	449	534	627	589	502	462	489	558
Irrigation	1	1	7	95	295	563	614	489	328	51	4	3
Industrial	299	310	297	292	296	317	310	310	304	311	307	309
Additional Firm	195	194	188	182	178	170	181	178	177	180	187	190
Loss	180	164	144	141	162	218	260	237	185	146	160	191
Firm Load	2,067	1,905	1,692	1,658	1,878	2,443	2,873	2,644	2,113	1,716	1,861	2,179
Light Load	1,903	1,759	1,557	1,508	1,687	2,196	2,599	2,346	1,923	1,553	1,709	2,026
Heavy Load	2,207	2,014	1,790	1,767	2,042	2,624	3,089	2,880	2,265	1,845	1,982	2,299
System Load	2,067	1,905	1,692	1,658	1,878	2,443	2,873	2,644	2,113	1,716	1,861	2,179
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,067	1,905	1,692	1,658	1,878	2,443	2,873	2,644	2,113	1,716	1,861	2,179

Peak Load (Megawatts)—95th Percentile

	Jan. 2027	Feb. 2027	Mar. 2027	Apr. 2027	May. 2027	Jun. 2027	Jul. 2027	Aug. 2027	Sep. 2027	Oct. 2027	Nov. 2027	Dec. 2027
Energy Efficiency (MW)	-216	-214	-214	-222	-245	-260	-261	-255	-233	-218	-215	-215
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,393	2,382	2,168	1,783	3,216	4,163	4,424	3,825	3,703	2,247	2,460	2,639
System Peak (1 Hour)	2,393	2,382	2,168	1,783	3,216	4,163	4,424	3,825	3,703	2,247	2,460	2,639
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,393	2,382	2,168	1,783	3,216	4,163	4,424	3,825	3,703	2,247	2,460	2,639

Sales and Load Forecast

Average Load (Average Megawatts)—70th Percentile

	Jan. 2028	Feb. 2028	Mar. 2028	Apr. 2028	May. 2028	Jun. 2028	Jul. 2028	Aug. 2028	Sep. 2028	Oct. 2028	Nov. 2028	Dec. 2028
Residential	876	751	606	511	496	645	890	849	620	566	712	918
Commercial	513	484	447	432	451	538	632	592	504	462	489	557
Irrigation	1	1	7	94	292	558	608	484	325	50	4	3
Industrial	301	300	297	292	297	317	310	311	305	312	308	309
Additional Firm	193	190	186	181	177	169	179	176	175	179	186	189
Loss	179	163	143	140	162	218	260	238	185	146	160	189
Firm Load	2,063	1,889	1,687	1,650	1,875	2,443	2,879	2,650	2,114	1,715	1,859	2,166
Light Load	1,900	1,745	1,552	1,501	1,684	2,196	2,605	2,351	1,924	1,553	1,707	2,014
Heavy Load	2,203	1,996	1,784	1,769	2,025	2,624	3,115	2,866	2,266	1,844	1,980	2,297
System Load	2,063	1,889	1,687	1,650	1,875	2,443	2,879	2,650	2,114	1,715	1,859	2,166
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,063	1,889	1,687	1,650	1,875	2,443	2,879	2,650	2,114	1,715	1,859	2,166

Peak Load (Megawatts)—95th Percentile

	Jan. 2028	Feb. 2028	Mar. 2028	Apr. 2028	May. 2028	Jun. 2028	Jul. 2028	Aug. 2028	Sep. 2028	Oct. 2028	Nov. 2028	Dec. 2028
Energy Efficiency (MW)	-228	-218	-226	-235	-257	-274	-275	-269	-245	-230	-227	-228
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,354	2,345	2,152	1,756	3,231	4,199	4,460	3,846	3,743	2,245	2,454	2,595
System Peak (1 Hour)	2,354	2,345	2,152	1,756	3,231	4,199	4,460	3,846	3,743	2,245	2,454	2,595
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,354	2,345	2,152	1,756	3,231	4,199	4,460	3,846	3,743	2,245	2,454	2,595

Sales and Load Forecast

Average Load (Average Megawatts)—70th Percentile

	Jan. 2029	Feb. 2029	Mar. 2029	Apr. 2029	May. 2029	Jun. 2029	Jul. 2029	Aug. 2029	Sep. 2029	Oct. 2029	Nov. 2029	Dec. 2029
Residential	860	735	593	500	487	638	885	844	613	558	701	911
Commercial	512	478	446	431	450	540	635	594	504	463	489	558
Irrigation	1	1	7	93	288	550	599	477	320	50	4	3
Industrial	300	311	297	292	298	317	310	311	304	312	308	310
Additional Firm	191	190	185	180	175	167	178	175	174	177	184	187
Loss	177	161	141	138	160	216	259	236	184	145	158	188
Firm Load	2,042	1,877	1,670	1,634	1,859	2,429	2,866	2,637	2,100	1,704	1,844	2,157
Light Load	1,880	1,733	1,536	1,486	1,670	2,183	2,593	2,340	1,911	1,542	1,694	2,005
Heavy Load	2,169	1,985	1,766	1,751	2,008	2,608	3,101	2,852	2,265	1,821	1,965	2,287
System Load	2,042	1,877	1,670	1,634	1,859	2,429	2,866	2,637	2,100	1,704	1,844	2,157
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,042	1,877	1,670	1,634	1,859	2,429	2,866	2,637	2,100	1,704	1,844	2,157

Peak Load (Megawatts)—95th Percentile

	Jan. 2029	Feb. 2029	Mar. 2029	Apr. 2029	May. 2029	Jun. 2029	Jul. 2029	Aug. 2029	Sep. 2029	Oct. 2029	Nov. 2029	Dec. 2029
Energy Efficiency (MW)	-239	-238	-237	-247	-270	-288	-289	-282	-260	-241	-238	-240
Demand Response (MW)	0	0	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	2,248	2,296	2,100	1,687	3,234	4,225	4,475	3,828	3,780	2,234	2,424	2,493
System Peak (1 Hour)	2,248	2,296	2,100	1,687	3,234	4,225	4,475	3,828	3,780	2,234	2,424	2,493
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,248	2,296	2,100	1,687	3,234	4,225	4,475	3,828	3,780	2,234	2,424	2,493

Sales And Load Forecast Annual Summary

Billed Sales (Megawatthours)—70th Percentile

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential	5,328,002	5,418,985	5,545,564	5,544,988	5,661,123	5,705,655	5,765,013	5,826,541	5,885,328	5,956,603
Commercial	3,879,270	3,941,139	4,032,057	4,101,010	4,154,617	4,189,349	4,220,439	4,250,624	4,280,729	4,310,468
Irrigation	1,843,349	1,852,905	1,839,741	1,828,330	1,822,297	1,828,366	1,826,719	1,828,104	1,830,375	1,834,057
Industrial	2,196,153	2,441,884	2,567,526	2,589,054	2,599,655	2,604,497	2,611,034	2,616,668	2,622,321	2,628,531
Additional Firm	1,428,995	1,604,959	1,621,276	1,687,195	1,689,907	1,689,231	1,683,727	1,678,357	1,676,318	1,657,486
Firm Sales	14,675,769	15,259,872	15,606,163	15,750,577	15,927,598	16,017,097	16,106,932	16,200,294	16,295,071	16,387,145
System Sales	14,675,769	15,259,872	15,606,163	15,750,577	15,927,598	16,017,097	16,106,932	16,200,294	16,295,071	16,387,145
Firm Off-System Sales	0	0	0	0	0	0	0	0	0	0
Total Sales	14,675,769	15,259,872	15,606,163	15,750,577	15,927,598	16,017,097	16,106,932	16,200,294	16,295,071	16,387,145

Generation Month Sales (Megawatthours)—70th Percentile

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential	5,334,508	5,427,771	5,563,366	5,552,985	5,663,976	5,709,516	5,787,335	5,830,320	5,889,944	5,961,403
Commercial	3,884,769	3,948,400	4,049,553	4,106,225	4,158,805	4,193,329	4,236,696	4,254,529	4,284,602	4,314,243
Irrigation	1,843,364	1,852,901	1,839,761	1,828,330	1,822,306	1,828,368	1,826,747	1,828,110	1,830,382	1,834,065
Industrial	2,211,419	2,457,547	2,569,645	2,589,952	2,600,158	2,605,016	2,611,732	2,616,883	2,622,847	2,628,952
Additional Firm	1,428,995	1,604,959	1,621,276	1,687,195	1,689,907	1,689,231	1,683,727	1,678,357	1,676,318	1,657,486
Firm Sales	14,703,056	15,291,579	15,643,600	15,764,687	15,935,152	16,025,461	16,146,238	16,208,198	16,304,092	16,396,149
System Sales	14,703,056	15,291,579	15,643,600	15,764,687	15,935,152	16,025,461	16,146,238	16,208,198	16,304,092	16,396,149
Firm Off-System Sales	0	0	0	0	0	0	0	0	0	0
Total Sales	14,703,056	15,291,579	15,643,600	15,764,687	15,935,152	16,025,461	16,146,238	16,208,198	16,304,092	16,396,149
Loss	1,431,207	1,473,533	1,504,984	1,512,273	1,529,009	1,537,408	1,549,452	1,555,035	1,564,084	1,573,950
Required Generation	16,134,263	16,765,112	17,148,584	17,276,961	17,464,161	17,562,869	17,695,690	17,763,233	17,868,177	17,970,099

Average Load (Average Megawatts)—70th Percentile

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential	609	620	633	634	647	652	659	666	672	681
Commercial	443	451	461	469	475	479	482	486	489	492
Irrigation	210	212	209	209	208	209	208	209	209	209
Industrial	252	281	293	296	297	297	297	299	299	300
Additional Firm	163	183	185	193	193	193	192	192	191	189
Loss	163	168	171	173	175	176	176	178	179	180
Firm Load	1,842	1,914	1,952	1,972	1,994	2,005	2,015	2,028	2,040	2,051
Light Load	1,676	1,741	1,776	1,794	1,814	1,824	1,833	1,845	1,856	1,866
Heavy Load	1,972	2,049	2,091	2,112	2,135	2,147	2,157	2,172	2,184	2,196
System Load	1,842	1,914	1,952	1,972	1,994	2,005	2,015	2,028	2,040	2,051
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0
Total Load	1,842	1,914	1,952	1,972	1,994	2,005	2,015	2,028	2,040	2,051

Peak Load (Megawatts)—95th Percentile

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Energy Efficiency (Mw)	-17	-33	-48	-64	-79	-93	-107	-121	-135	-149
Demand Response (Mw)	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	3,460	3,560	3,636	3,726	3,789	3,843	3,895	3,949	4,003	4,060
System Peak (1 Hour)	3,460	3,560	3,636	3,726	3,789	3,843	3,895	3,949	4,003	4,060
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0
Total Peak Load	3,460	3,560	3,636	3,726	3,789	3,843	3,895	3,949	4,003	4,060

Sales And Load Forecast Annual Summary

Billed Sales (Megawatthours)—70th Percentile

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Residential	6,030,952	6,034,404	6,091,486	6,139,032	6,092,711	6,160,567	6,205,253	6,168,525	6,172,246	6,083,732
Commercial	4,338,582	4,356,860	4,378,082	4,395,931	4,401,688	4,419,613	4,435,517	4,442,344	4,452,730	4,454,123
Irrigation	1,839,802	1,835,870	1,829,770	1,830,840	1,817,719	1,808,195	1,812,587	1,801,062	1,783,250	1,756,646
Industrial	2,634,391	2,637,943	2,644,929	2,652,534	2,655,893	2,661,588	2,668,570	2,671,916	2,678,550	2,679,036
Additional Firm	1,657,426	1,651,857	1,650,315	1,636,705	1,638,050	1,632,964	1,619,435	1,605,524	1,595,267	1,578,775
Firm Sales	16,501,153	16,516,933	16,594,582	16,655,042	16,606,060	16,682,926	16,741,362	16,689,371	16,682,043	16,552,312
System Sales	16,501,153	16,516,933	16,594,582	16,655,042	16,606,060	16,682,926	16,741,362	16,689,371	16,682,043	16,552,312
Firm Off-System Sales	0	0	0	0	0	0	0	0	0	0
Total Sales	16,501,153	16,516,933	16,594,582	16,655,042	16,606,060	16,682,926	16,741,362	16,689,371	16,682,043	16,552,312

Generation Month Sales (Megawatthours)—70th Percentile

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Residential	6,049,707	6,037,977	6,094,385	6,135,523	6,115,664	6,163,222	6,202,384	6,168,388	6,184,488	6,083,052
Commercial	4,354,848	4,360,247	4,381,280	4,398,479	4,418,419	4,422,680	4,438,096	4,445,102	4,469,029	4,456,843
Irrigation	1,839,826	1,835,869	1,829,775	1,830,833	1,817,738	1,808,202	1,812,581	1,801,051	1,783,255	1,756,627
Industrial	2,634,963	2,638,631	2,645,784	2,652,260	2,656,430	2,662,466	2,668,880	2,672,483	2,678,356	2,679,387
Additional Firm	1,657,426	1,651,857	1,650,315	1,636,705	1,638,050	1,632,964	1,619,435	1,605,524	1,595,267	1,578,775
Firm Sales	16,536,770	16,524,581	16,601,540	16,653,801	16,646,300	16,689,534	16,741,377	16,692,548	16,710,395	16,554,683
System Sales	16,536,770	16,524,581	16,601,540	16,653,801	16,646,300	16,689,534	16,741,377	16,692,548	16,710,395	16,554,683
Firm Off-System Sales	0	0	0	0	0	0	0	0	0	0
Total Sales	16,536,770	16,524,581	16,601,540	16,653,801	16,646,300	16,689,534	16,741,377	16,692,548	16,710,395	16,554,683
Loss	1,587,760	1,585,325	1,592,238	1,597,369	1,595,017	1,598,504	1,603,588	1,597,833	1,599,044	1,581,886
Required Generation	18,124,531	18,109,906	18,193,778	18,251,170	18,241,317	18,288,039	18,344,965	18,290,381	18,309,439	18,136,570

Average Load (Average Megawatts)—70th Percentile

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Residential	689	689	696	700	696	704	708	704	704	694
Commercial	496	498	500	502	503	505	507	507	509	509
Irrigation	209	210	209	209	207	206	207	206	203	201
Industrial	300	301	302	303	302	304	305	305	305	306
Additional Firm	189	189	188	187	186	186	185	183	182	180
Loss	181	181	182	182	182	182	183	182	182	181
Firm Load	2,063	2,067	2,077	2,083	2,077	2,088	2,094	2,088	2,084	2,070
Light Load	1,877	1,881	1,889	1,895	1,889	1,899	1,905	1,899	1,896	1,883
Heavy Load	2,209	2,214	2,224	2,232	2,223	2,236	2,243	2,236	2,233	2,217
System Load	2,063	2,067	2,077	2,083	2,077	2,088	2,094	2,088	2,084	2,070
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0
Total Load	2,063	2,067	2,077	2,083	2,077	2,088	2,094	2,088	2,084	2,070

Peak Load (Megawatts)—95th Percentile

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Energy Efficiency (Mw)	-163	-177	-191	-205	-219	-233	-247	-261	-275	-289
Demand Response (Mw)	0	0	0	0	0	0	0	0	0	0
Firm Peak Load	4,118	4,160	4,210	4,261	4,290	4,341	4,393	4,424	4,460	4,475
System Peak (1 Hour)	4,118	4,160	4,210	4,261	4,290	4,341	4,393	4,424	4,460	4,475
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0
Loss	0	0	0	0	0	0	0	0	0	0
Total Peak Load	4,118	4,160	4,210	4,261	4,290	4,341	4,393	4,424	4,460	4,475

EXISTING RESOURCE DATA

Hydroelectric and Thermal Plant Data

Hydroelectric Power Plants	Nameplate kVA	Nameplate kW	Normal Rating kW (4)	Emergency Rating kW (5)
American Falls	102,600	92,340	92,340	108,850
Bliss	86,250	75,000	75,000	76,470
Brownlee	650,444	585,400	585,400	746,570
Cascade	13,800	12,420	12,420	14,800
Clear Lake	3,125	2,500 (1)	2,420	2,420
Hells Canyon	435,000	391,500	391,500	444,830
Lower Salmon	70,000	60,000	60,000	64,340
Malad–Lower	15,500	13,500	13,500	16,520
Malad–Upper	9,650	8,270	8,270	8,540
Milner	62,890	59,448	59,448	61,090
Oxbow	211,112	190,000	190,000	221,410
Shoshone Falls	14,900	12,500 (1)	12,500	14,040
Strike, C.J.	90,000	82,800	82,800	90,720
Swan Falls	28,600	27,170	24,170 (3)	24,170
Thousand Springs	11,000	8,800 (1)	6,380 (2)	6,380
Twin Falls	56,175	52,897	52,561	53,060
Upper Salmon "A"	18,000	18,000	18,000	18,930
Upper Salmon "B"	18,000	16,500	16,500	17,510
Total Hydro	1,897,046	1,709,045		

Thermal, Natural Gas, and Diesel Power Plants	Generator Nameplate Rating Gross kVA	Generator Nameplate Rating Gross kW	Net Dependable Capability (NDC) kW (6)
Bridger (IPC Share)	811,053	770,501	706,667
Boardman (IPC Share)	67,600	64,200	58,600
Valmy (IPC Share)	315,000	283,500	258,250
Total Thermal	1,193,653	1,118,201	1,023,517
Bennett Mountain	192,000	172,800	164,159
Evander Andrews Unit #1	189,994	170,955	170,955
Evander Andrews Unit #2	51,000	45,900	45,236
Evander Andrews Unit #3	51,000	45,900	45,236
Total Natural Gas	483,994	435,555	425,586
Salmon Diesel	6,880	5,000	5,500
Total IPC Generation	3,581,573	3,267,801	

(1) A power factor rating of 0.8 is assumed on four units (Clear Lake, Unit #2 at Shoshone Falls, and Units #1 and #2 at Thousand Springs) with a total kVA rating of 6,127 kVA on which there is no nameplate kW rating.

(2) The two smaller units, #1 and #2, both having nameplate ratings of 1.25 MVA and 1 MW, have been taken out of service due to reduced flows from the springs and penstock integrity.

(3) The Swan Falls units have been limited to 24,170 kW as a result of vibration issues.

(4) The Normal Rating is defined as 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) The Emergency Rating is defined as the maximum kW output of the facility with all units on-line. The Emergency Rating is based on allowable generator overloads and limited by auxiliary equipment ratings. To operate at the Emergency Rating, appropriate water conditions must exist and the FERC license requirements permit.

(6) Net Dependable Capacity (NDC) is defined in the NERC Generating Availability Data System (GADS) as Gross Dependable Capacity (GDC) less the unit capacity utilized for that unit's station service or auxiliaries. GDC is the Gross Maximum Capacity (GMC) modified for seasonal limitations over a specified period of time. The GDC and MDC (Maximum Dependable Capacity) 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.

Idaho Power Company
Qualifying Facilities
Cogeneration and Small Power Production Projects
Status as of June 1, 2009

Project			Contract On-line Date	Contract End Date
Hydro Projects				
Barber Dam	Hydro	3.70	Apr-1989	Apr-2024
Birch Creek	Hydro	0.05	Nov-1984	Oct-2019
Black Canyon #3	Hydro	0.14	Apr-1984	Apr-2019
Blind Canyon	Hydro	1.50	Dec-1994	Dec-2014
Box Canyon	Hydro	0.36	Feb-1984	Feb-2019
Briggs Creek	Hydro	0.60	Oct-1985	Oct-2020
Bypass	Hydro	9.96	Jun-1988	Jun-2023
Canyon Springs	Hydro	0.13	Oct-1984	Non firm
Cedar Draw	Hydro	1.55	Jun-1984	May-2019
Clear Springs Trout	Hydro	0.52	Nov-1983	Oct-2018
Crystal Springs	Hydro	2.44	Apr-1986	Mar-2021
Curry Cattle Company	Hydro	0.22	Jun-1983	Jun-2018
Dietrich Drop	Hydro	4.50	Aug-1988	Aug-2023
Elk Creek	Hydro	2.00	May-1986	May-2021
Falls River	Hydro	9.10	Aug-1993	Aug-2028
Faulkner Ranch	Hydro	0.87	Aug-1987	Aug-2022
Fisheries Development Co	Hydro	0.26	Jul-1990	Non firm
Geo Bon #2	Hydro	0.93	Nov-1986	Nov-2021
Hailey CSPP	Hydro	0.06	Jun-1985	Jun-2020
Hazelton A	Hydro	7.70	Jun-1990	Jun-2010
Hazelton B	Hydro	7.60	May-1993	Apr-2028
Horseshoe Bend Hydroelectric	Hydro	9.50	Sep-1995	Sep-2030
Jim Knight	Hydro	0.34	Jun-1985	Jun-2020
Kasel and Witherspoon	Hydro	0.90	Mar-1984	Feb-2019
Koyle Small Hydro	Hydro	1.25	Apr-1984	Mar-2019
Lateral # 10	Hydro	2.06	May-1985	Apr-2020
Lemoyne	Hydro	0.08	Jun-1985	Jun-2020
Little Wood Rvr Res	Hydro	2.85	Feb-1985	Feb-2020
Littlewood - Arkoosh	Hydro	0.87	Aug-1986	Jul-2021
Low Line Midway Hydro	Hydro	7.97	Aug-2007	Aug-2027
Lowline #2	Hydro	2.79	Apr-1988	Apr-2023
Lowline Canal	Hydro	2.50	May-1985	Apr-2005
Magic Reservoir	Hydro	9.07	Jun-1989	May-2024
Malad River	Hydro	0.62	May-1984	Apr-2019
Marco Ranches	Hydro	1.20	Aug-1985	Jul-2020
Mile 28	Hydro	1.50	Jun-1994	May-2029
Mitchell Butte	Hydro	2.09	May-1989	May-2024
Mora Drop	Hydro	1.90	Oct-2006	Estimated
Mud Creek S&S	Hydro	0.52	Feb-1982	Feb-2017
Mud Creek White	Hydro	0.21	Jan-1986	Jan-2021
Owyhee Dam CSPP	Hydro	5.00	Aug-1985	Aug-2015
Pigeon Cove	Hydro	1.89	Oct-1984	Oct-2019
Pristine Springs	Hydro	0.13	May-2005	Apr-2015
Pristine Springs #3	Hydro	0.20	May-2005	Apr-2015
Reynolds Irrigation	Hydro	0.26	May-1986	May-2021
Rim View	Hydro	0.20	Nov-2000	Non firm
Rock Creek #1	Hydro	2.05	Sep-1983	Sep-2018
Rock Creek #2	Hydro	1.90	Apr-1989	Mar-2024
Sagebrush	Hydro	0.43	Sep-1985	Aug-2020
Sahko Hydro	Hydro	0.50	Jun-2006	Non firm
Schaffner	Hydro	0.53	Aug-1986	Jul-2021
Shingle Creek	Hydro	0.22	Aug-1983	Jul-2018
Shoshone #2	Hydro	0.58	May-1996	Apr-2031
Shoshone CSPP	Hydro	0.37	Jun-1982	Jun-2017
Snake River Pottery	Hydro	0.07	Nov-1984	Nov-2019
Snedigar	Hydro	0.54	Jan-1985	Dec-2019
Tiber Dam	Hydro	7.50	Jun-2004	May-2024
Trout—Co	Hydro	0.24	Dec-1986	Nov-2021
Tunnel #1	Hydro	7.00	Jun-1993	May-2028
White Water Ranch	Hydro	0.16	Aug-1985	Jul-2020
Wilson Lake Hydro	Hydro	8.40	May-1993	May-2028
Total Hydro Nameplate MW rating		**140.55**		
Thermal Projects				
Magic Valley	Natural Gas	10.00	Nov-1996	Nov-2016
Magic West	Natural Gas	10.00	Dec-1996	Nov-2016
Simplot Pocatello	Cogen	12.00	Mar-2006	Feb-2016
TASCO—Nampa	Natural Gas	2.00	Sep-2003	Aug-2008
TASCO—Twin Falls	Natural Gas	3.00	Aug-2001	Aug-2006
Total Thermal Nameplate MW rating		**37.00**		
Biomass Projects				
Bettencourt Dry Creek Biofactory	Biomass	2.25	Aug-2008	Non-firm
Big Sky West Dairy Digester	Biomass	1.50	Jan-2009	Jan-2029
CO-GEN CO	Biomass	9.40	Jul-2008	Jul-09
Hidden Hollow Landfill Gas	Biomass	3.20	Oct-2006	Jul-2009
Pocatello Waste	Biomass	0.46	Dec-1985	Dec-2020
Tamarack CSPP	Biomass	5.00	Jun-1983	May-2018
Vaagen Brothers Lumber Inc	Biomass	4.50	Sep-1995	Aug-2010
Total Biomass Nameplate MW rating		**26.31**		
Wind Projects				
Bennett Creek Wind Farm	Wind	19.80	Dec-2008	Dec. 2028
Burley Butte Wind	Wind	10.50	Sep-2010	Estimated
Cassia Farm	Wind	10.50	Feb. 2009	Feb-2029
Cassia Gulch	Wind	18.90	Feb. 2009	Feb. 2029
Fossil Gulch Wind	Wind	10.50	Sep-2005	Sep-2025
Golden Valley Wind	Wind	12.00	Sep-2010	Estimated
Horseshoe Bend Wind Park	Wind	9.00	Feb-2006	Feb-2026
Hot Springs Wind Farm	Wind	19.80	Mar-2008	Mar-2028
Lava Beds Wind	Wind	18.00	Sep-2010	Estimated
Magic Wind Park	Wind	19.50	Sep-2010	Estimated
Milner Dam Wind	Wind	19.50	Sep-2010	Estimated
Notch Butte Wind	Wind	18.00	Sep-2010	Estimated
Oregon Trail Wind	Wind	13.50	Sep-2010	Estimated
Pilgrim Stage Station Wind	Wind	10.50	Sep-2010	Estimated
Salmon Falls Wind	Wind	19.50	Sep-2010	Estimated
Thousand Springs Wind	Wind	12.00	Sep-2010	Estimated
Tuana Gulch Wind	Wind	10.50	Sep-2010	Estimated
Total Wind Nameplate MW rating		**252.00**		
Geothermal Projects				
None				
Total Geothermal Nameplate MW rating		**0.00**		
Total Nameplate MW rating		**456.86**		

Cogeneration and Small Power Production Project (CSPP) Generation Information

The above is a summary of the Nameplate rating for the CSPP projects under contract with Idaho Power. 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. The application of this information to the portfolio of CSPP projects resulted in the average annual MW from CSPP projects being 150 MW beginning in 2011. Projects listed in this appendix are included in the CSPP forecast and were signed and approved contracts as of June 1, 2009.

Idaho Power Company

Power Purchase Agreements

Status as of June 1, 2009

Project		MW	Contract On-Line Date	Contract End Date
Wind Projects				
Elkhorn Wind Project	Wind	101	Dec-2007	Dec-2027
Total Wind Nameplate MW Rating*		**101**		
Geothermal Projects				
Raft River Unit #1	Geothermal	13	Apr-2008	Apr-2033
Total Geothermal Nameplate MW Rating*		**13**		
Total Nameplate MW Rating		**114**		

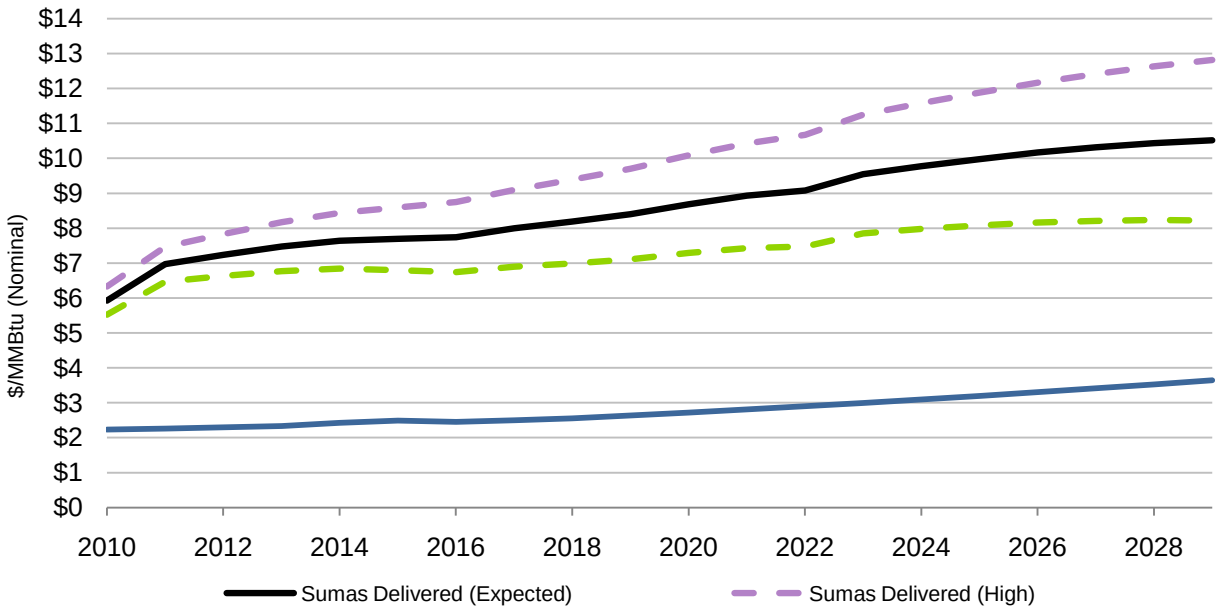
*The above is a summary of the nameplate ratings for the Power Purchase Agreements under contract with Idaho Power. Nameplate ratings of the actual generation units is not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy the projects will produce.

FUEL DATA

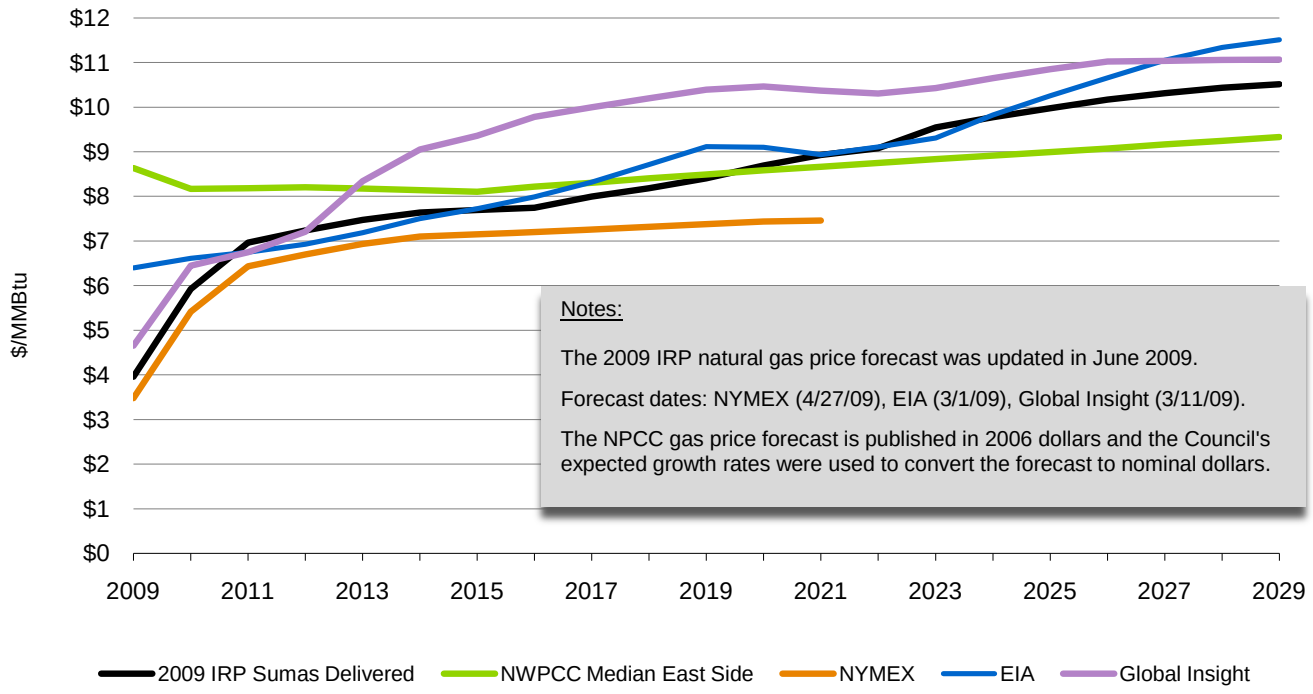
Gas and Coal Forecast—Data and Graphs

Year	Henry Hub	Sumas	Sumas Delivered (Expected)	Sumas Delivered (High)	Sumas Delivered (Low)	Regional Coal
2010	$5.81	$5.41	$5.93	$6.33	$5.53	$2.23
2011	$6.75	$6.44	$6.97	$7.47	$6.47	$2.26
2012	$7.10	$6.70	$7.23	$7.83	$6.63	$2.30
2013	$7.23	$6.93	$7.47	$8.17	$6.77	$2.34
2014	$7.32	$7.10	$7.64	$8.44	$6.84	$2.43
2015	$7.42	$7.15	$7.69	$8.59	$6.79	$2.49
2016	$7.51	$7.20	$7.74	$8.74	$6.74	$2.46
2017	$7.81	$7.45	$7.99	$9.09	$6.89	$2.50
2018	$8.05	$7.64	$8.19	$9.39	$6.99	$2.55
2019	$8.31	$7.86	$8.40	$9.70	$7.10	$2.63
2020	$8.64	$8.14	$8.69	$10.09	$7.29	$2.72
2021	$8.93	$8.38	$8.93	$10.43	$7.43	$2.81
2022	$9.10	$8.48	$9.08	$10.68	$7.48	$2.90
2023	$9.65	$8.95	$9.55	$11.25	$7.85	$3.00
2024	$9.96	$9.18	$9.78	$11.58	$7.98	$3.10
2025	$10.26	$9.37	$9.98	$11.88	$8.08	$3.20
2026	$10.57	$9.55	$10.17	$12.17	$8.17	$3.30
2027	$10.85	$9.70	$10.31	$12.41	$8.21	$3.41
2028	$11.14	$9.81	$10.43	$12.63	$8.23	$3.53
2029	$11.43	$9.90	$10.52	$12.82	$8.22	$3.65

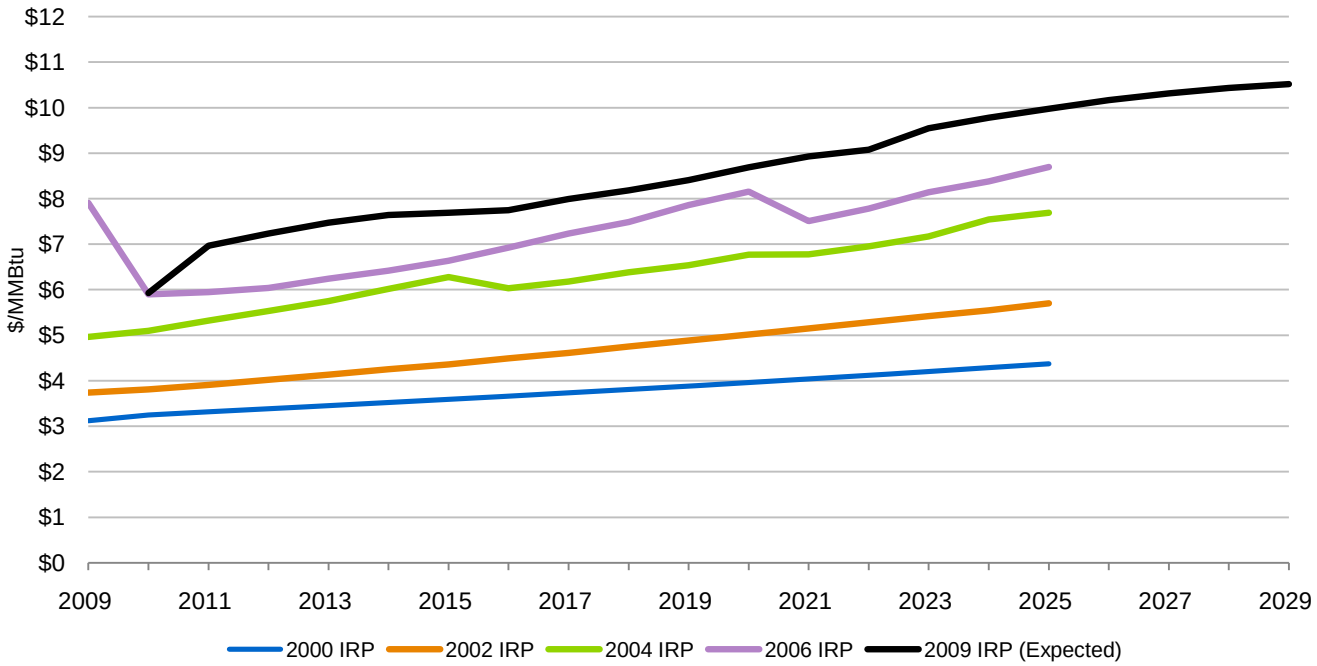
Natural Gas and Coal Price Forecast



Natural Gas Price Forecast—Comparison to Other Forecasts



Natural Gas Price Forecast—Comparison to Previous Integrated Resource Plans



SUPPLY-SIDE RESOURCE DATA

Key Financial and Forecast Assumptions

Financing Cap Structure and Cost	
Composition	
Debt	50.54%
Preferred	0.00%
Common	49.46%
Total	100.00%
Cost	
Debt	5.65%
Preferred	0.00%
Common	10.60%
Average Weighted Cost	8.10%

Financial Assumptions and Factors	
Plant Operating (Book) Life	30 Years
Discount Rate (aka WACC)	6.98%
Composite Tax Rate	39.10%
Deferred Rate	35.00%
General O&M Esc Rate	3.00%
Emission Adder Esc Rate	2.50%
Annual Prop Tax Rate (% of Invest)	0.29%
Prop Tax Esc Rate	3.00%
Annual Insurance Prems (% of Invest)	0.31%
Insurance Esc Rate	2.00%
AFUDC Rate (Annual)	7.00%
Prod Tax Credits Esc Rate	3.00%

Tax Credits (2009 $)	
Wind, Geothermal and Closed Loop Biomass	$21/MWh first 10 years of operation
Open Loop Biomass, Hydro and In-Stream Generation	$10/ MWh first 10 years of operation
Solar Investment Tax Credit (ITC)	30% of depreciable investment

Emissions Limits (pounds per MWh by technology)

(adders are brought into the analysis beginning in 2012)

	GHG	Nox	Mercury
Small Aeroderavative SCCT	1,190	0.12000	0.00000
Large Aeroderavative SCCT	1,071	0.10800	0.00000
Large Frame SCCT	1,119	0.11280	0.00000
Reciprocating Engines	1,071	0.10800	0.00000
CCCT 1x1	809	0.08160	0.00000
CCCT 2x1	809	0.08160	0.00000
Combined Heat and Power (CHP)	809	0.08160	0.00000
Distributed Generation—Gas Fired	1,071	0.10800	0.00000
Pulverized Coal	1,886	0.44160	0.00002
IGCC	1,797	0.21036	0.00002
IGCC w/ Carbon Sequestration	309	0.42560	0.00002
Biomass—Landfill Gas	0	1.70000	0.00000
Biomass—Aneorobic Digesters	0	1.70000	0.00000

Emission Adder Rates

(adders are brought into the analysis beginning in 2012)

GHG	$40 per ton (2009 $)
NOX	$2,600 per ton during May–September
Mercury	$1,443/oz in years 2012–2017; $1,731/oz in year 2018 and beyond

Fuel Forecast Base Case (Nominal, $ per MMBtu)

Year	Gas	Generic	Nuclear
2009	3.96	1.83	0.65
2010	5.93	2.23	0.65
2011	6.97	2.26	0.66
2012	7.23	2.30	0.66
2013	7.47	2.34	0.67
2014	7.64	2.43	0.67
2015	7.69	2.49	0.67
2016	7.74	2.46	0.68
2017	7.99	2.50	0.68
2018	8.19	2.55	0.69
2019	8.40	2.63	0.69
2020	8.69	2.72	0.69
2021	8.93	2.81	0.70
2022	9.08	2.90	0.70
2023	9.55	3.00	0.71
2024	9.78	3.10	0.71
2025	9.98	3.20	0.72
2026	10.17	3.30	0.72
2027	10.31	3.41	0.72
2028	10.43	3.53	0.73
2029	10.52	3.65	0.73
2030	10.55	3.77	0.74
2031	10.73	3.69	0.74
2032	10.84	3.77	0.75
2033	10.96	3.85	0.75
2034	11.07	3.93	0.75
2035	11.19	4.01	0.76
2036	11.30	4.09	0.76
2037	11.42	4.16	0.77
2038	11.53	4.24	0.77

Cost Inputs and Operating Assumptions Resource Cost Analysis
(All Costs in 2009 Dollars)

	Plant Capacity (MW)	Overnight Plant Capital $/kW [1,2]	Overnight Transmission Capital $/kW	Overnight Total Capital $/kW	Total Investment $/kW [2]	Fixed O&M $/kW [3]	Variable O&M $/MWh	Emission Adders $/MWh	Heat Rate (btus/kWH)
Distributed Generation- Gas Fired	15	$0	$163	$163	$0	$3	$1	$26	12,000
Simple Cycle CT - Industrial Frame	170	$470	$29	$499	$529	$4	$2	$27	10,000
Boardman to Hemingway	225	$0	$700	$700	$0	$0	$0	$0	0
Simple Cycle CT - Large Aeroderivative	100	$700	$63	$763	$806	$3	$3	$24	8,400
Reciprocating Engines	25	$673	$100	$773	$815	$10	$7	$24	9,700
Simple Cycle CT - Small Aeroderivative	47	$850	$77	$927	$982	$3	$3	$27	9,200
Gateway West	275	$0	$1,000	$1,000	$0	$0	$0	$0	0
CCCT (2x1) F Class	540	$1,050	$99	$1,149	$0	$5	$1	$18	6,800
CHP/Co-Generation	47	$1,200	$133	$1,333	$0	$0	$3	$18	9,200
CCCT (1x1) F Class	270	$1,200	$93	$1,293	$0	$7	$1	$18	6,800
Wind	100	$1,275	$503	$1,778	$1,887	$35	$1	$0	0
Shoshone Falls Upgrade	64	$1,779	$200	$1,979	$2,195	$2	$0	$0	0
In-Stream Generation	1	$2,839	$442	$3,281	$3,398	$112	$0	$0	0
Solar - Parabolic Dish Engine	100	$3,400	$10	$3,410	$3,739	$56	$0	$0	0
Solar - Water Steam Power Tower	100	$3,400	$10	$3,410	$3,772	$56	$0	$0	0
Solar - Parabolic Trough	100	$4,200	$10	$4,210	$4,856	$55	$0	$0	0
Biomass - Digesters	1	$4,100	$348	$4,448	$0	$54	$16	$0	12,407
Biomass - Landfill Gas	2	$4,100	$348	$4,448	$0	$22	$16	$0	11,556
Conventional Scrubbed Coal	750	$3,500	$675	$4,175	$4,547	$23	$5	$43	9,200
Low Drop/Small Hydro New	10	$4,312	$400	$4,712	$5,436	$14	$3	$0	0
Solar - Molten Salt Power Tower, 6.9 Hours Energy Storage	100	$4,900	$10	$4,910	$5,602	$55	$0	$0	0
IGCC	600	$4,025	$675	$4,700	$5,735	$32	$3	$41	8,765
Solar - Flat Plate PV	1	$6,300	$0	$6,300	$6,411	$25	$0	$0	0
IGCC with Carbon Sequestration	600	$4,900	$675	$5,575	$6,803	$38	$5	$8	10,500
Solar - Parabolic Trough, 6 hours Energy Storage	100	$6,300	$10	$6,310	$7,279	$72	$0	$0	0
Solar - Concentrating PV	1	$7,500	$0	$7,500	$7,768	$50	$0	$0	0
Advanced Nuclear	1,100	$5,000	$538	$5,538	$0	$146	$5	$0	10,400
Geothermal	26	$7,200	$331	$7,531	$0	$75	$5	$0	0

[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).

Levelized Resource Cost Tables

30-Year Levelized Cost of Production (at stated capacity factors)

	Cost of Capital	Non-Fuel O&M [1]	Fuel	Wholesale Energy	Emission Adders	Total Cost per MWh	Capacity Factor
Shoshone Falls Upgrade - Hydro (64 MW)	$62	$0	$0	$0	$0	$62	36%
Wind (100 MW)	$60	$20	$0	$0	$0	$80	32%
Biomass - Landfill Gas (2 MW)	$62	$21	$0	$0	$0	$83	80%
Combined Cycle CT 2x1 (540 MW)	$22	$5	$58	$0	$18	$103	65%
Geothermal (26 MW)	$92	$15	$0	$0	$0	$107	92%
Combined Cycle CT 1x1 (270 MW)	$25	$6	$58	$0	$18	$107	65%
Transmission @ 65% - Boardman to Hemingway (225 MW)	$13	$1	$0	$113	$0	$126	65%
Combined Heat and Power (47 MW)	$18	$6	$86	$0	$18	$128	90%
Transmission @ 65% - Gateway West (275 MW)	$18	$2	$0	$113	$0	$132	65%
Biomass - Digesters (1 MW)	$66	$69	$0	$0	$0	$136	75%
Solar - Salt Power Tower (100 MW)	$89	$50	$0	$0	$0	$139	28%
Transmission @ 25.7% - Boardman to Hemingway (225 MW)	$32	$3	$0	$113	$0	$147	26%
Pulverized Coal (750 MW)	$68	$16	$26	$0	$43	$153	88%
Low Drop/Small Hydro New (10 MW)	$140	$14	$0	$0	$0	$154	45%
IGCC with Carbon Sequestration (600 MW)	$96	$21	$30	$0	$8	$155	85%
Solar - Parabolic Dish Engine (100 MW)	$89	$67	$0	$0	$0	$156	19%
Transmission @ 25.7% - Gateway West (275 MW)	$45	$4	$0	$113	$0	$162	26%
IGCC (600 MW)	$81	$17	$25	$0	$41	$163	85%
Advanced Nuclear (1,100 MW)	$114	$44	$7	$0	$0	$165	85%
Solar - Parabolic Trough, with Energy Storage (100 MW)	$115	$66	$0	$0	$0	$181	28%
Solar - Parabolic Trough No Storage (100 MW)	$117	$73	$0	$0	$0	$191	18%
Solar - Water Steam Power Tower (100 MW)	$113	$85	$0	$0	$0	$198	15%
Simple Cycle CT - Large Aero (100 MW)	$93	$17	$71	$0	$24	$205	10%
Distributed Generation - Gas Fired (15 MW)	$68	$23	$102	$0	$26	$218	3%
Solar - Concentrating PV (1 MW)	$159	$70	$0	$0	$0	$229	22%
Solar - Flat Plate PV (1 MW)	$174	$60	$0	$0	$0	$234	17%
Simple Cycle CT - Industrial Frame (170 MW)	$102	$21	$85	$0	$27	$234	6%
In-Stream Generation (1 MW)	$157	$90	$0	$0	$0	$247	22%
Transmission @ 6% - Boardman to Hemingway (225 MW)	$135	$12	$0	$113	$0	$260	6%
Simple Cycle CT - Small Aero (47 MW)	$142	$22	$78	$0	$27	$268	8%
Transmission @ 6% - Gateway West (275 MW)	$193	$17	$0	$113	$0	$323	6%
Reciprocating Engines (25 MW)	$157	$49	$109	$0	$24	$339	6%

[1] Non Fuel O&M includes fixed and variable costs, property taxes, and production tax credits.

30 Year Levelized Capacity (Fixed) Cost per kW

	Cost of Capital	Non-Fuel O&M	Fuel	Emission Adders	Total Cost per kW
Distributed Generation - Gas Fired (15 MW)	$1	$0	$0	$0	$2
Simple Cycle CT - Industrial Frame (170 MW)	$4	$1	$0	$0	$5
Transmission - Boardman to Hemingway (275 MW)	$6	$1	$0	$0	$6
Simple Cycle CT - Large Aero (100 MW)	$7	$1	$0	$0	$8
Reciprocating Engines (25 MW)	$7	$2	$0	$0	$9
Transmission - Gateway West (275 MW)	$8	$1	$0	$0	$9
Simple Cycle CT - Small Aero (47 MW)	$8	$1	$0	$0	$9
Combined Cycle CT 2x1 (540 MW)	$11	$1	$0	$0	$12
Combined Heat and Power (47 MW)	$12	$1	$0	$0	$13
Combined Cycle CT 1x1 (270 MW)	$12	$2	$0	$0	$14
Shoshone Falls Upgrade - Hydro (64 MW)	$16	$2	$0	$0	$18
Wind (100 MW)	$14	$5	$0	$0	$19
Solar - Parabolic Dish Engine (100 MW)	$12	$9	$0	$0	$21
Solar - Water Steam Power Tower (100 MW)	$12	$9	$0	$0	$21
Solar - Parabolic Trough No Storage (100 MW)	$16	$10	$0	$0	$25
Solar - Flat Plate PV (1 MW)	$21	$7	$0	$0	$28
Solar - Salt Power Tower (100 MW)	$18	$10	$0	$0	$28
Solar - Concentrating PV (1 MW)	$25	$11	$0	$0	$36
Solar - Parabolic Trough, with Energy Storage (100 MW)	$24	$13	$0	$0	$37
In-Stream Generation (1 MW)	$25	$16	$0	$0	$41
Biomass - Landfill Gas (2 MW)	$36	$6	$0	$0	$42
Biomass - Digesters (1 MW)	$36	$10	$0	$0	$46
Pulverized Coal (750 MW)	$43	$6	$0	$0	$49
Low Drop/Small Hydro New (10 MW)	$46	$5	$0	$0	$51
IGCC (600 MW)	$50	$8	$0	$0	$58
IGCC with Carbon Sequestration (600 MW)	$60	$9	$0	$0	$69
Geothermal (26 MW)	$62	$15	$0	$0	$76
Advanced Nuclear (1,100 MW)	$71	$23	$0	$0	$93

The Comprehensive Aquifer Management Plan (CAMP) Process and Potential to Impact Power Generation

The CAMP Process

The Eastern Snake Plain Aquifer (ESPA) serves nearly one million acres of ground water irrigated land, cities, industries, and thousands of domestic wells. Above American Falls, the ESPA supports spring discharge that provides natural flow for irrigated lands in the Magic Valley. The ESPA has experienced serious declines that began in the late 1970s and appear to be ongoing. Those declines have impacted spring discharge to the Snake River, including springs that provide irrigation water and flows of cold water that support fish hatcheries from Twin Falls to Hagerman. Flow from the ESPA also provides a significant portion of the flow in the Snake River at King Hill and below.

Declining spring discharge has created numerous water shortages resulting in water calls pitting senior spring and surface water users against junior ground water appropriators. Many of those water calls are still pending or have been only partially resolved through orders from the director of the Idaho Department of Water Resources (IDWR). Continued declines in spring flows are likely to exacerbate these ongoing conflicts over water use on the Eastern Snake River Plain (ESRP).

The 2007 Idaho Legislature tasked the Idaho Water Resource Board (IWRB) with developing an ESPA Comprehensive Aquifer Management Plan (CAMP). The charge of the legislature was to "establish public policy as a settlement framework for future management of the ESPA." To meet legislative goals, the IWRB established a 15-member committee representing various water user groups and other parties interested in the management of the ESPA. The goal of the committee was to develop an aquifer management plan to "sustain the economic viability and social and environmental health of the Easter Snake Plain by adaptively managing a balance between water use and supplies."

Table CAMP-1. Phase I Measures Included in the CAMP

Measure	Target (Acft)
Ground Water to Surface Water Conversions	100,000
Managed Aquifer Recharge	100,000
Demand Reduction	
Surface Water Conservation	50,000
Crop Mix Modification	5,000
Rotating Fallowing, Dry-Year Lease, CREP	40,000
Weather Modification	50,000

The committee met monthly starting in May 2007 continuing through September 2008. The CAMP committee first established a goal of producing an annual 600,000 acre-feet adjustment in the water budget of the ESRP. This water balance adjustment was adopted as the long-term hydrologic target; however, committee members recognized this adjustment would be achieved only after many years of implementation. The committee adopted an interim plan called Phase I that targets an annual water budget change of 200,000–300,000 acre-feet/year. The committee's goal is to have Phase I fully implemented in 10 years. Table CAMP-1 shows the measures anticipated under Phase I. The Phase I plan includes the implementation of a variety of measures to change the overall water budget of the ESRP.

CAMP was submitted to the 2009 Idaho Legislature for approval. Upon legislative approval of the plan, the IWRB began a process of selecting an implementation committee. The charge of that committee will be to "assist the Board in the prioritization, development, implementation, and monitoring and evaluation of management actions." The implementation committee will also develop a mechanism to fund measures implemented under CAMP. The successful implementation of any CAMP-recommended measure is dependent upon securing a long-term funding source. As such, the specific practices, their extent or location is unknown at this time. Additionally, some practices are likely to change as the feasibility and impact of specific practices is evaluated over the next five years. The legislative approval of CAMP was only the first step in implementing management practices on the ESPA.

Idaho Power recognizes the potential for declining spring flow below Milner Dam to impact generation capabilities. Idaho Power also recognizes the potential for management practices recommended and implemented through CAMP to impact generation capabilities. Those impacts could be either positive or negative. As such, Idaho Power has been an active member of the CAMP committee. Idaho Power was represented at every CAMP committee meeting, and the company representatives participated in several sub-committees. Idaho Power also developed the appropriate modeling techniques to assess the potential impacts of CAMP on river flows and spring discharge. The results of the modeling was provided to the CAMP committee and used during the decision-making process. Idaho Power has also suggested management alternatives and has agreed to provide technical and material support for a pilot weather modification program in the upper Snake River basin.

CAMP committee members recognize that the failure of proposed management practices to increase aquifer levels or improve spring discharge to the Snake River could result in continued legal action against junior ground water appropriators. Implementation of CAMP was not to supplant the need for litigation but to manage the aquifer such that water calls would be lessened. Ground water appropriators could be subjected to increased mitigation requirements or potential curtailment if CAMP fails to produce desired results.

Potential Impact of CAMP Implementation on Idaho Power

The implementation of CAMP practices impact hydropower generation in three different ways.

1) Managed recharge can increase spring discharge below Milner Dam, but those increases can occur only if water is diverted above Milner Dam and directed onto the ESRP and recharged to the aquifer. Conversions of ground water supplied irrigated land to surface supplied can also improve spring flow, but would require diversions of water from the Snake River above Milner Dam as well. Diversion for managed recharge and conversion projects have the potential to reduce the volume of water passing through numerous Idaho Power projects. Those diversions may have a negative impact to hydropower production on those facilities located between Milner Dam and King Hill. Additionally, while most of the water diverted for these projects comes back to the river as spring discharge, up to 10% of the water remains in the aquifer as long-term storage. These practices essentially shift water from one compartment, surface water, to another compartment, ground water. The net effect on the overall water budget is zero, but the diversions from the Snake River can have negative impacts to hydropower production.

2) Weather modification and practices that reduce consumptive use of ground water can increase water flowing through those generation facilities located on the Snake River above King Hill. These measures actually change the water budget by reducing consumptive demand or by increasing water supply in the basin. They can increase spring flow or tributary flow into the

Snake River, but, unlike managed recharge or conversion projects, they require no diversions from the Snake River. These projects increase flows in the Snake River and could potentially benefit power generation.

3) Practices described in 1) and 2) are likely to be implemented in some combination. The relative extent of those practices will ultimately determine whether the impact is positive or negative for hydropower production. Diversions and increases in spring discharge may eventually balance, but the first five to ten years of implementation may produce a net negative effect on hydropower production.

The actual impact to hydropower production resulting from the implementation of the CAMP plan is uncertain. The availability of funding could drastically alter the implementation of the CAMP Phase I plan and long-standing water calls may eventually trump any plan proffered. Changing economic conditions may also alter decisions made by agriculture producers and their participation in current mitigation plans and other programs, such as the Conservation Reserve Enhancement Program (CREP). In evaluating the potential impacts of CAMP on hydropower production, the Phase I targets provide a basis for modeling and evaluation.

Modeled CAMP Scenario

Idaho Power developed modeling capabilities to help determine the potential impacts of CAMP on spring discharge and flows in the Snake River. Idaho Power modeled several different scenarios for the CAMP committee. The modeling incorporates the Enhanced Snake Plain Aquifer Model (ESPAM) and the Snake River Planning Modeling (SRPM). The modeling also incorporates information on canal capacities and sets limits for managed recharge, system conversions, and demand reduction activities. The modeling also includes estimates on increased water from weather-modification activities.

The scenario modeled for the IRP was the Phase I implementation plan proposed in CAMP. The parameters entered into the model were done to try and match the goals of the Phase I plan. Table CAMP-2 compares the results of the Phase I CAMP with the modeled results. The modeled scenario provides close approximation of the planned Phase I and allows for the examination of the impacts of CAMP on spring discharge and flows in the Snake River.

Table CAMP-2. CAMP Phase I Goals and Results of Modeling

Action	CAMP Goal (Average thousand acre-feet/year)	Modeled (Average thousand acre-feet/year)
Ground to Surface Water Conversions	100	81
Managed Recharge	100	140**
Demand Reduction	95*	45
Weather Modification	50	50

*Some demand reduction includes the purchase of subordination agreements from spring owners that cannot be modeled, but would have no impact on spring flows or Snake River Flows.

**This recharge also includes approximately 20 KAF/yr recharge on the Wood River system.

The SRPM uses a variety of data inputs to determine water availability for irrigation diversions as well as providing information on reservoir storage and river flows. The model allows for present conditioning of historic data. In other words, it applies today's level of development (irrigation diversions and storage), reach gains, and diversions to historic water availability. The model is currently calibrated to

run from 1928 through 2005. This mode of operation allows for the comparison of a base case scenario to a variety of management scenarios. This provides a perspective on the degree to which different management scenarios may impact reservoir storage and river flows.

Table CAMP-3. Average Difference Between the CAMP Scenario and the Base Case Scenario for Flow at King Hill

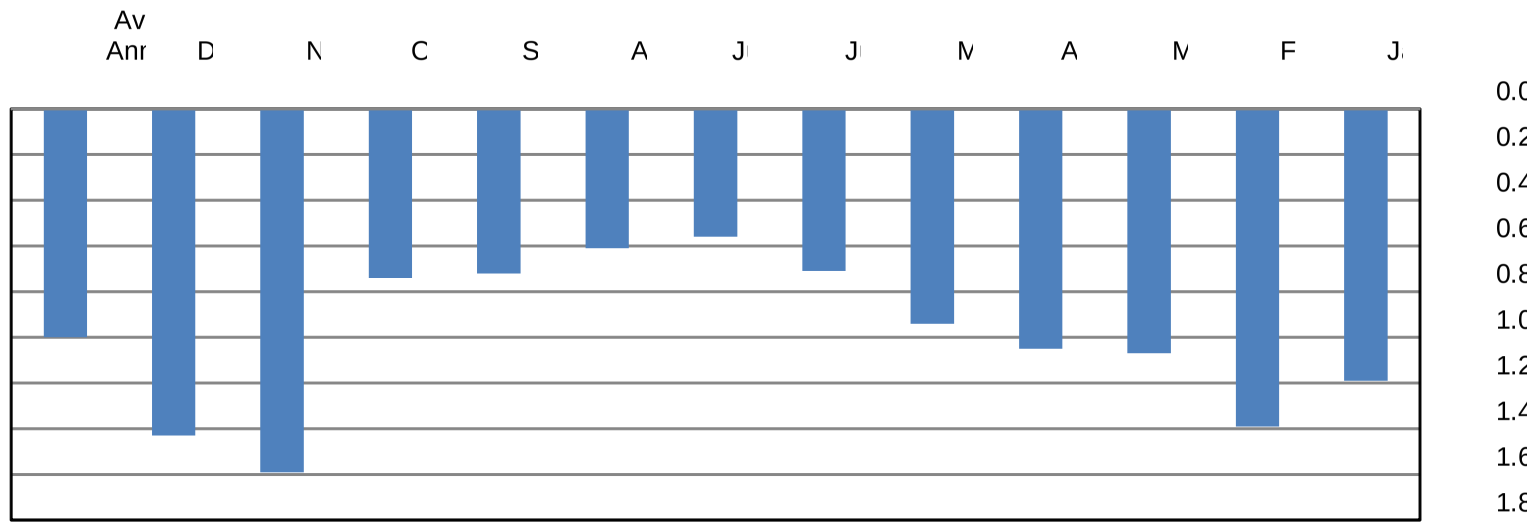
July (acre-feet)	December (acre-feet)	Yearly (acre-feet)
7,700	10,900	66,600

A comparison was made for the months of July and December and total yearly flows for the base case scenario and the CAMP scenario. July and December were selected because they are critical months for power generation. The comparison of modeled data was for the King Hill gage on the Snake River (Table CAMP-3). The average flows for July increased 7,670 acre-feet/month, and December flows increased 10,880 acre-feet/month. The yearly average flows increased by 66,580 acre-feet/year, which is about 1% of the yearly average flow at the King Hill gage. These small increases reflect the nature of changes in the water budget for the upper Snake Basin as proposed through CAMP. The CAMP Phase I plan contains only 95,000 acft in new or additional water to the system. CAMP may increase spring discharge tributary to the Snake River, but those increases are dependent upon large diversion from the Snake River for managed recharge or system conversions. The overall increase in Snake River flow is dependent upon a reduction in consumptive use of water or increases related to water modification activities.

Brownlee Reservoir Inflow Record (Million Acre-Feet)
Record Used for 2009 IRP Modeling of Idaho Power Hydropower System

CY	Brownlee April–July Inflow Volume (MAF)	Brownlee Annual Inflow Volume (MAF)	CY	Brownlee April–July Inflow Volume (MAF)	Brownlee Annual Inflow Volume (MAF)
1928	6.8	14.8	1967	4.9	11.3
1929	3.5	9.3	1968	3.5	10.8
1930	2.8	8.3	1969	6.9	15.4
1931	2.3	7.2	1970	6.3	14.9
1932	4.8	10.2	1971	10.4	22.9
1933	4.3	9.4	1972	7.8	20.2
1934	2.4	7.5	1973	4.0	11.3
1935	3.0	7.9	1974	9.7	20.1
1936	5.1	10.4	1975	8.2	17.6
1937	3.0	8.5	1976	7.3	16.3
1938	7.1	13.8	1977	2.2	7.8
1939	3.9	10.0	1978	5.2	11.9
1940	4.3	10.8	1979	4.0	10.8
1941	3.8	10.2	1980	6.1	13.2
1942	5.0	11.2	1981	4.4	11.5
1943	9.3	19.0	1982	9.4	21.2
1944	3.4	9.6	1983	10.0	23.6
1945	4.9	11.7	1984	11.4	24.4
1946	6.9	15.5	1985	5.5	13.5
1947	5.3	12.5	1986	8.4	20.6
1948	5.9	12.6	1987	3.0	9.2
1949	5.4	12.5	1988	2.7	7.9
1950	6.6	14.8	1989	4.4	10.7
1951	6.6	16.2	1990	3.1	8.6
1952	10.4	19.3	1991	2.9	8.2
1953	6.1	13.7	1992	2.0	6.8
1954	5.6	12.6	1993	6.3	13.0
1955	3.5	9.9	1994	2.8	8.5
1956	7.9	17.6	1995	6.9	14.2
1957	7.9	16.2	1996	8.3	19.1
1958	7.5	15.2	1997	10.1	24.0
1959	3.9	10.4	1998	8.6	17.6
1960	4.3	10.8	1999	7.9	17.8
1961	3.2	8.7	2000	4.6	12.1
1962	4.9	11.1	2001	2.6	7.8
1963	4.7	11.6	2002	3.5	8.8
1964	5.8	13.1	2003	3.7	9.2
1965	8.5	20.0	2004	3.2	8.8
1966	3.6	9.9	2005	3.6	8.8

Note: Based on Idaho Department of Water Resources computed Snake River Basin record for 1928–2005.



Normalized Monthly Wind Energy Distri

30	43	48	22	22	18	17	21	28	32	32	42	36
A	Dec	Nov	Oct	Sep	Aug	Jul	Jun	May	Apr	Mar	Feb	Jan
Ar												

Estimated Monthly Output (aMW)

1.00	1.43	1.59	0.74	0.72	0.61	0.56	0.71	0.94	1.05	1.07	1.39	1.19
A	Dec	Nov	Oct	Sep	Aug	Jul	Jun	May	Apr	Mar	Feb	Jan
Ar												

Normalized Monthly Wind Energy Distri

30	Flat M
30%	Annual Ca
100	Project Size (M

Monthly Wind Distribution Pro

DEMAND-SIDE RESOURCE DATA

Cost-Effectiveness

Most of Idaho Power's energy efficiency programs are preliminarily identified through the integrated resource planning process. A change for the *2009 Integrated Resource Plan* IRP is that a majority of the anticipated new energy efficiency future commitments come through additional measures added into existing programs as opposed to new program offerings.

Idaho Power considers cost-effectiveness to be the primary screening tool prior to demand-side management (DSM) program implementation. Idaho Power primarily 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.

In the IRP process, specific programs or potential energy savings are screened by sector to determine if the levelized cost of the potential programs is less than supply-side resource alternatives. If the DSM programs are shown to be less costly than supply-side resources as measured by the levelized cost, the potential program is included in the resource plan. Generally, the hourly shaped energy savings are used to compare DSM programs with other supply-side and transmission alternatives.

Prior to the actual implementation of energy efficiency or demand response programs, Idaho Power creates cost-effectiveness models to assess whether a specific potential program design will be cost-effective from the perspective of Idaho Power and its customers. Incorporated into the cost-effectiveness models are inputs from various sources in order to use the most current and reliable information available. Idaho Power uses a cost-effectiveness model to perform sensitivity analyses in order to determine the appropriate program design. The remaining inputs used in the cost-effectiveness models are obtained from the IRP process.

When possible, Idaho Power uses actual data and experiences from other companies in the region, or throughout the country, to help identify specific program parameters. The regional program review is typically accomplished through discussions with other utilities' program managers and research staff.

Idaho Power also uses electric industry research organizations, such as E Source, Edison Electrical Institute (EEI), Consortium for Energy Efficiency (CEE), American Council for an Energy Efficient Economy (ACEEE), Advanced Load Control Alliance (ALCA), Association of Energy Service Professionals (AESP), Energy Insights, and others, to identify similar programs and expected results. For other assumptions, including estimated costs, savings, and net-to-gross ratio estimates, Idaho Power relies on sources, such as the Northwest Power and Conservation Council (NPCC), the Regional Technical Forum (RTF), Northwest Energy Efficiency Alliance (NEEA), E Source, the Database for Energy Efficiency Resources (DEER), the Energy Trust of Oregon (ETO), Bonneville Power Administration (BPA), third-party consultants, and other regional utilities.

The financial assumptions used in the analysis are consistent with the 2009 IRP, including the discount rate and inflation rate. The IRP is also the source of the DSM alternative costs, which is 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 or forward market prices as determined by the AURORAxmp® Electric Market Model. The avoided capital cost is based on a 170 MW natural gas-fired, simple-cycle combustion turbine.

Idaho Power relies on the Electric Power Research Institute End Use Technical Assessment Guide (TAG) and the California Standard Practice Manual for the cost-effectiveness methodology. As defined in the TAG and California Standard Practice Manual, the TRC and UC tests are most similar to supply-side tests and provide a useful basis to compare demand-side and supply-side resources.

Idaho Power determines cost-effectiveness on a program basis and on a measure-by-measure basis where applicable. To be consistent with the IRP, demand response program B/C ratios for the residential A/C Cool Credit, Irrigation Peak Rewards, and the commercial and industrial FlexPeak program are calculated over a 20-year period. In order for a program to be considered cost-effective, the program must have B/C ratios greater than one for both the TRC and UC tests.

Idaho Power may choose to launch a pilot or limited-scale program to evaluate estimates or assumptions in the cost-effectiveness model. Pilot programs are designed to measure actual program experiences, including program expenses, savings, and participation. Following implementation of a program, the cost-effectiveness models are reviewed as data from actual program activity becomes available. The program design may be reexamined after program implementation.

Alternate Costs

The prices of avoided energy throughout the 20-year planning period were simulated using the Preferred Portfolio module within the AuroraAxmp model. The Preferred Portfolio module takes into consideration the energy capacity and resource costs of the current preferred mix of IRP resources along with regional transmission resources in the Western Electricity Coordinating Council (WECC) region to project forward electric market prices. The forward prices are placed into five homogenous pricing categories that follow the pattern of heavy and light load pricing throughout each year of the planning period. The resulting categories are:

- *Summer On-Peak (SONP)*—Average of Idaho Power variable energy and operating costs of a 170 MW simple-cycle combustion turbine, 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 through August

- *Summer Off-Peak (SOFP)*—Average of light load prices from June through 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. During the SONP, additional purchases from the regional power market are not an option due to currently existing transmission constraints. The marginal resource Idaho Power is trying to avoid with DSM efforts for SONP hours is the construction of simple-cycle combustion turbine. The estimated levelized capacity cost of building a new simple-cycle combustion turbine is approximately $63/kW over a 30-year expected plant life. For demand response or direct load control DSM programs operating during the summer peak, the $63/kW becomes the cost threshold for program cost-effectiveness.

The avoided capacity value is spread across the annual SONP hours to value the energy efficiency savings occurring during the hours. The total SONP vary between 512 to 528 hours depending on the calendar. 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 energy prices over the 20-year planning period that were used to screen new energy efficiency and demand response programs for cost-effectiveness. The cost-effectiveness analysis for measures that have a life longer than 20 years, which is typical for weatherization and building shell measures, prices are escalated at three percent.

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 through DSM-7 show the forecast impact of energy efficiency by customer class for existing programs, new energy efficiency commitments, and the total combined impact.

Table DSM-8 shows the annual forecast of utility costs or the costs to administer the new programs and measures to meet the forecast new energy efficiency amounts.

Table DSM-9 shows the 20-year flow of resource costs that combines the program participant costs with the costs to administer the program.

Table DSM-10 outlines the 20-year flow of avoided generation and the benefits attributed to energy efficiency programs.

Table DSM-11 summarizes the cost-effectiveness analysis for new programs and measures through the 20-year IRP planning period.

Table DSM-12 shows the annual forecast impact from all demand response programs.

Tables DSM-13 through DSM-15 show the 20-year flow of utility costs, total resource costs, and value of avoided generation for demand response programs, similar to those presented for new energy efficiency programs.

Table DSM-16 summarizes the cost-effectiveness for demand response programs and the forecast impact through the IRP planning horizon.

Table DSM-1. IRP Financials

DSM Analysis Assumptions	
Avoided Capacity Costs	
Simple-Cycle Combined Turbine	$63/kW
Financial Assumptions	
Weighted Average Cost of Capital (2008 Year Ending After Tax)	6.98%
Financial Escalation Factor	3.00%
Transmission Losses	
Non-summer Secondary Losses	10.90%
Summer Peak Loss	13.00%

Table DSM-2. DSM Alternate Costs by Pricing Period

Year	Summer On-Peak (SONP)	Summer Mid-Peak (SMP)	Summer Off-Peak (SOFP)	Non-Summer Mid-Peak (NSMP)	Non-Summer Off-Peak (NSOFP)
2010	$61.23	$45.22	$33.70	$46.50	$34.94
2011	$71.70	$53.51	$40.04	$55.00	$42.05
2012	$98.56	$83.99	$73.25	$84.85	$72.70
2013	$103.52	$85.83	$76.66	$84.95	$73.38
2014	$105.93	$88.03	$78.54	$87.74	$75.23
2015	$107.21	$90.65	$80.59	$91.35	$77.69
2016	$108.48	$93.77	$82.08	$93.03	$79.60
2017	$111.77	$95.65	$84.94	$95.19	$82.20
2018	$114.49	$97.48	$86.37	$97.66	$84.64
2019	$117.51	$100.97	$88.40	$99.54	$86.87
2020	$121.19	$102.07	$89.30	$101.54	$89.17
2021	$124.46	$104.48	$91.76	$104.64	$91.87
2022	$126.83	$108.43	$95.56	$109.05	$95.67
2023	$132.46	$111.36	$98.73	$111.23	$98.70
2024	$135.69	$113.45	$100.73	$114.15	$101.27
2025	$138.67	$117.06	$104.45	$117.50	$104.31
2026	$141.54	$120.25	$107.38	$121.00	$107.28
2027	$144.00	$122.37	$109.98	$123.58	$110.04
2028	$146.24	$126.81	$113.72	$126.09	$112.90

[1]Estimated variable operations and management costs of a 170 MW capacity simple-cycle combined turbine.

Table DSM-3. DSM Alternate Cost Summer Pricing Periods (June 1 to 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 Costs Non-Summer Pricing Periods (September 1 to 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. DSM Existing Energy Efficiency Forecast 2010–2029 (aMW with transmission losses)

Year	Industrial	Commercial	Irrigation	Residential	Total
2010	4.9	5.3	1.3	2.7	14.2
2011	9.7	11.0	2.5	4.5	27.8
2012	14.2	17.2	3.7	6.0	41.1
2013	18.6	23.4	4.7	7.5	54.2
2014	23.0	29.7	5.6	9.0	67.3
2015	27.5	35.9	6.2	10.3	79.8
2016	31.9	42.1	6.9	11.5	92.4
2017	36.3	48.4	7.5	12.8	105.0
2018	40.8	54.6	8.2	14.0	117.6
2019	45.2	60.8	8.9	15.3	130.1
2020	49.6	67.0	9.5	16.5	142.7
2021	54.1	73.3	10.2	17.8	155.3
2022	58.5	79.5	10.8	19.0	167.9
2023	62.9	85.7	11.5	20.3	180.4
2024	67.4	92.0	12.2	21.6	193.0
2025	71.8	98.2	12.8	22.8	205.6
2026	76.2	104.4	13.5	24.1	218.2
2027	80.6	110.6	14.1	25.3	230.7
2028	85.1	116.9	14.8	26.6	243.3
2029	89.5	123.1	15.4	27.8	255.9

Table DSM-6. New 2009 IRP Energy Efficiency Resources 2010–2029 (aMW with transmission losses)

Year	Residential	Commercial	Industrial	Total
2010	0.9	0.9	1.0	2.8
2011	2.1	1.8	3.1	7.0
2012	3.4	2.9	6.1	12.4
2013	4.9	4.0	9.3	18.2
2014	6.4	5.3	12.7	24.4
2015	8.0	6.6	16.2	30.8
2016	9.6	8.0	19.9	37.5
2017	11.3	9.5	23.5	44.3
2018	12.9	11.1	27.3	51.3
2019	14.6	12.8	31.0	58.4
2020	16.3	14.5	34.9	65.7
2021	17.7	16.4	38.8	72.9
2022	19.2	18.3	42.7	80.2
2023	20.7	20.2	46.7	87.6
2024	22.2	22.3	50.8	95.3
2025	23.7	24.4	54.9	103.0
2026	25.3	26.7	59.0	110.9
2027	26.9	29.0	63.2	119.0
2028	28.5	31.3	67.4	127.2
2029	28.5	31.3	67.4	127.2

Table DSM-7. Total Energy Efficiency Forecasted Impact Existing and New 2010–2029 (aMW with transmission losses)

Year	Industrial	Commercial	Irrigation	Residential	Total
2010	5.5	5.6	1.1	3.3	15.5
2011	12.9	12.8	2.5	6.6	34.8
2012	20.3	20.1	3.7	9.5	53.5
2013	27.9	27.5	4.7	12.4	72.5
2014	35.7	35.0	5.6	15.4	91.7
2015	43.7	42.5	6.2	18.2	110.7
2016	51.8	50.2	6.9	21.1	129.9
2017	59.9	57.9	7.5	24.0	149.3
2018	68.0	65.7	8.2	26.9	168.9
2019	76.2	73.6	8.9	29.9	188.6
2020	84.5	81.6	9.5	32.8	208.4
2021	92.8	89.6	10.2	35.5	228.2
2022	101.2	97.7	10.8	38.2	248.0
2023	109.6	106.0	11.5	41.0	268.1
2024	118.1	114.2	12.2	43.7	288.3
2025	126.6	122.6	12.8	46.5	308.6
2026	135.2	131.1	13.5	49.4	329.1
2027	143.8	139.6	14.1	52.2	349.7
2028	152.5	148.2	14.8	55.1	370.5
2029	156.9	154.4	15.4	56.3	383.1

Table DSM-8. New Energy Efficiency Utility Costs 2010–2029

Year	Residential	Commercial	Industrial	Total All Sectors
2010	$2,185,803	$859,845	$1,297,023	$4,342,671
2011	$3,060,477	$969,777	$3,319,561	$7,349,814
2012	$3,508,588	$1,067,687	$4,314,247	$8,890,522
2013	$3,811,045	$1,158,161	$4,446,834	$9,416,040
2014	$4,058,383	$1,243,199	$4,658,622	$9,960,205
2015	$4,267,066	$1,325,522	$4,841,031	$10,433,618
2016	$4,406,327	$1,405,619	$4,871,784	$10,683,730
2017	$4,546,267	$1,484,206	$4,939,369	$10,969,841
2018	$4,672,279	$1,561,790	$5,011,687	$11,245,755
2019	$4,768,785	$1,638,743	$5,080,622	$11,488,151
2020	$4,867,634	$1,715,345	$5,146,344	$11,729,324
2021	$4,481,009	$1,791,806	$5,195,678	$11,468,493
2022	$4,584,723	$1,868,290	$5,269,358	$11,722,371
2023	$4,690,963	$1,944,923	$5,330,311	$11,966,196
2024	$4,799,793	$2,021,803	$5,376,699	$12,198,295
2025	$4,911,279	$2,099,010	$5,438,122	$12,448,410
2026	$5,025,489	$2,176,602	$5,496,960	$12,699,051
2027	$5,142,493	$2,254,627	$5,536,118	$12,933,238
2028	$5,262,362	$2,333,121	$5,594,501	$13,189,985
2029	$0	$0	$0	$0
20-Year NPV	**$42,646,505**	**$15,206,640**	**$46,583,003**	**$104,436,148**

Table DSM-9. New Energy Efficiency Total Resource Costs 2010–2029

Year	Residential	Commercial	Industrial	Total All Sectors
2010	$2,357,175	$3,636,527	$1,711,236	$7,704,938
2011	$3,639,396	$4,162,005	$4,382,424	$12,183,825
2012	$4,212,132	$4,635,110	$5,698,932	$14,546,174
2013	$4,594,083	$5,075,432	$5,877,320	$15,546,835
2014	$4,904,362	$5,492,750	$6,160,444	$16,557,556
2015	$5,166,365	$5,896,996	$6,404,797	$17,468,157
2016	$5,339,158	$6,291,431	$6,448,457	$18,079,045
2017	$5,512,736	$6,679,287	$6,540,755	$18,732,777
2018	$5,668,296	$7,062,878	$6,639,234	$19,370,408
2019	$5,785,396	$7,443,906	$6,733,149	$19,962,451
2020	$5,905,291	$7,823,649	$6,822,723	$20,551,663
2021	$5,395,175	$8,203,079	$6,890,478	$20,488,732
2022	$5,520,874	$8,582,945	$6,990,439	$21,094,258
2023	$5,649,585	$8,963,830	$7,073,439	$21,686,855
2024	$5,781,384	$9,346,187	$7,137,028	$22,264,599
2025	$5,916,347	$9,730,368	$7,220,494	$22,867,209
2026	$6,054,554	$10,116,647	$7,300,456	$23,471,657
2027	$6,196,088	$10,505,234	$7,354,203	$24,055,525
2028	$6,341,030	$10,896,288	$7,433,417	$24,670,736
2029	$0	$0	$0	$0
20-Year NPV	**$51,412,498**	**$68,482,366**	**$61,693,447**	**$181,588,312**

Table DSM-10. New Energy Efficiency Resource Avoided Energy Costs 2010–2029

Year	Residential	Commercial	Industrial	Total All Sectors
2010	$3,709,589	$5,626,728	$6,044,209	$15,380,526
2011	$6,188,004	$6,805,914	$16,575,769	$29,569,686
2012	$8,371,989	$7,983,345	$22,875,049	$39,230,383
2013	$9,735,242	$8,899,982	$24,155,131	$42,790,356
2014	$10,921,698	$9,823,463	$25,955,488	$46,700,648
2015	$12,019,828	$10,765,480	$27,660,310	$50,445,619
2016	$12,895,163	$11,721,993	$28,532,458	$53,149,614
2017	$13,807,371	$12,710,756	$29,672,368	$56,190,494
2018	$14,673,960	$13,730,128	$30,880,008	$59,284,096
2019	$15,459,304	$14,790,279	$32,112,014	$62,361,597
2020	$16,257,717	$15,899,087	$33,376,505	$65,533,308
2021	$17,119,736	$17,068,181	$34,601,987	$68,789,905
2022	$18,070,545	$18,292,292	$36,035,764	$72,398,601
2023	$18,998,401	$19,550,317	$37,398,739	$75,947,457
2024	$19,943,721	$20,866,846	$38,707,298	$79,517,864
2025	$20,959,811	$22,253,164	$40,189,732	$83,402,707
2026	$22,003,968	$23,702,308	$41,703,823	$87,410,099
2027	$23,035,571	$25,219,078	$43,124,470	$91,379,118
2028	$24,124,351	$26,825,849	$44,782,746	$95,732,947
2029	$24,876,318	$26,875,246	$44,782,746	$96,534,310
20-Year NPV	**$142,492,125**	**$143,365,937**	**$301,075,029**	**$586,933,090**

Table DSM-11. New Energy Efficiency Cost Effectiveness Summary

	Impact		20-Year NPV Costs			Utility Costs		Total Resource Costs	
	2029 Load (aMW)	20-Year Energy (kWh)	Utility	Resource	Avoided Energy	Benefit/Cost Ratio	Levelized ($/kWh)	Benefit/Cost Ratio	Levelized ($/kWh)
Residential	29	1,096,775,152	$42,646,505	$51,412,498	$142,492,125	3.3	$0.039	2.8	$0.047
Commercial	31	1,042,951,839	$15,206,640	$68,482,366	$143,365,937	9.4	$0.015	2.1	$0.066
Industrial	67	2,391,084,888	$46,583,003	$61,693,447	$301,075,029	6.5	$0.019	4.9	$0.026
Total	**127**	**4,530,811,879**	**$104,436,148**	**$181,588,312**	**$586,933,090**	**5.6**	**$0.023**	**3.2**	**$0.040**

Table DSM-12. Total Existing and New Demand Response Forecasted Impacts 2010–2029 (MW with transmission losses)

Year	Residential	Irrigation	Commercial	Total
2010	50.6	220.0	39.6	310.2
2011	50.6	250.0	45.2	345.8
2012	50.6	260.0	56.5	367.1
2013	50.6	260.0	56.5	367.1
2014	50.6	260.0	56.5	367.1
2015	50.6	260.0	56.5	367.1
2016	50.6	260.0	56.5	367.1
2017	50.6	260.0	56.5	367.1
2018	50.6	260.0	56.5	367.1
2019	50.6	260.0	56.5	367.1
2020	50.6	260.0	56.5	367.1
2021	50.6	260.0	56.5	367.1
2022	50.6	260.0	56.5	367.1
2023	50.6	260.0	56.5	367.1
2024	50.6	260.0	56.5	367.1
2025	50.6	260.0	56.5	367.1
2026	50.6	260.0	56.5	367.1
2027	50.6	260.0	56.5	367.1
2028	50.6	260.0	56.5	367.1
2029	50.6	260.0	56.5	367.1

Table DSM-13. Demand Response Utility Costs 2010–2029

Year	Residential	Commercial/Industrial	Irrigation	Total All Sectors
2010	$3,520,710	$2,081,025	$10,799,032	$16,400,767
2011	$1,352,143	$2,760,783	$11,038,020	$15,150,946
2012	$1,396,152	$3,415,100	$11,223,562	$16,034,815
2013	$1,371,927	$3,448,853	$11,247,225	$16,068,005
2014	$1,417,031	$3,482,066	$11,274,667	$16,173,763
2015	$1,760,923	$3,489,626	$11,306,566	$16,557,115
2016	$1,817,247	$3,498,355	$11,343,682	$16,659,284
2017	$1,813,491	$3,507,347	$11,368,382	$16,689,220
2018	$1,872,482	$3,516,609	$11,456,834	$16,845,925
2019	$1,869,268	$3,526,148	$11,434,099	$16,829,515
2020	$1,967,417	$3,535,973	$11,451,335	$16,954,725
2021	$2,000,416	$3,546,093	$11,482,018	$17,028,527
2022	$2,105,980	$3,556,517	$11,528,664	$17,191,161
2023	$2,141,187	$3,567,254	$11,565,121	$17,273,562
2024	$2,252,091	$3,578,312	$11,593,138	$17,423,542
2025	$2,289,700	$3,589,703	$11,636,912	$17,516,315
2026	$2,407,865	$3,601,435	$11,676,627	$17,685,927
2027	$2,446,881	$3,613,519	$11,705,625	$17,766,024
2028	$2,572,782	$3,625,966	$11,840,660	$18,039,408
2029	$2,614,977	$3,638,786	$11,840,660	$18,094,423
20-Year NPV	**$21,020,406**	**$35,339,272**	**$120,389,467**	**$176,749,144**

Table DSM-14. Demand Response Total Resource Costs 2010–2029

Year	Residential	Commercial/Industrial	Irrigation	Total All Sectors
2010	$3,520,710	$2,081,025	$10,799,032	$16,400,767
2011	$1,352,143	$2,760,783	$11,038,020	$15,150,946
2012	$1,396,152	$3,415,100	$11,223,562	$16,034,815
2013	$1,371,927	$3,448,853	$11,247,225	$16,068,005
2014	$1,417,031	$3,482,066	$11,274,667	$16,173,763
2015	$1,760,923	$3,489,626	$11,306,566	$16,557,115
2016	$1,817,247	$3,498,355	$11,343,682	$16,659,284
2017	$1,813,491	$3,507,347	$11,368,382	$16,689,220
2018	$1,872,482	$3,516,609	$11,456,834	$16,845,925
2019	$1,869,268	$3,526,148	$11,434,099	$16,829,515
2020	$1,967,417	$3,535,973	$11,451,335	$16,954,725
2021	$2,000,416	$3,546,093	$11,482,018	$17,028,527
2022	$2,105,980	$3,556,517	$11,528,664	$17,191,161
2023	$2,141,187	$3,567,254	$11,565,121	$17,273,562
2024	$2,252,091	$3,578,312	$11,593,138	$17,423,542
2025	$2,289,700	$3,589,703	$11,636,912	$17,516,315
2026	$2,407,865	$3,601,435	$11,676,627	$17,685,927
2027	$2,446,881	$3,613,519	$11,705,625	$17,766,024
2028	$2,572,782	$3,625,966	$11,840,660	$18,039,408
2029	$2,614,977	$3,638,786	$11,840,660	$18,094,423
20-Year NPV	**$21,020,406**	**$35,339,272**	**$120,389,467**	**$176,749,144**

Table DSM-15. Demand Response Avoided Capacity Costs 2010–2029

Year	Residential	Commercial/Industrial	Irrigation	Total All Sectors
2010	$3,108,304	$2,636,945	$16,262,282	$22,107,531
2011	$3,117,340	$3,042,059	$17,125,711	$23,285,110
2012	$3,140,508	$3,893,616	$17,405,016	$24,439,140
2013	$3,144,787	$3,910,432	$17,456,605	$24,511,824
2014	$3,146,863	$3,918,590	$17,481,633	$24,547,086
2015	$3,147,966	$3,922,926	$17,494,936	$24,565,828
2016	$3,149,066	$3,927,247	$17,508,191	$24,584,503
2017	$3,151,905	$3,938,404	$17,542,418	$24,632,727
2018	$3,154,249	$3,947,614	$17,570,675	$24,672,538
2019	$3,156,852	$3,957,844	$17,602,057	$24,716,752
2020	$3,160,032	$3,970,342	$17,640,402	$24,770,776
2021	$3,162,847	$3,981,405	$17,674,340	$24,818,592
2022	$3,164,891	$3,989,438	$17,698,985	$24,853,315
2023	$3,169,750	$4,008,532	$17,757,562	$24,935,844
2024	$3,172,541	$4,019,498	$17,791,203	$24,983,242
2025	$3,175,111	$4,029,598	$17,822,188	$25,026,896
2026	$3,177,585	$4,039,320	$17,852,014	$25,068,919
2027	$3,179,706	$4,047,657	$17,877,590	$25,104,953
2028	$3,181,640	$4,055,256	$17,900,902	$25,137,798
2029	$3,185,424	$4,070,128	$17,900,902	$25,156,455
20-Year NPV	**$33,417,991**	**$39,982,107**	**$185,238,997**	**$258,639,09**

Table DSM-16. Demand Response Cost-Effectiveness Summary

	Impact		20-Year NPV Costs			Total Resource Costs	
	2029 Load (aMW)	20-Year Energy (kWh)	Utility	Resource	Avoided Energy	Benefit/Cost Ratio	Levelized ($/kWh)
Residential	51	555,495	$21,020,406	$21,020,406	$33,417,991	1.6	$38
Commercial/Industrial	56	573,775	$35,339,272	$35,339,272	$39,982,107	1.1	$62
Irrigation	260	2,748,954	$120,389,467	$120,389,467	$185,238,997	1.5	$44
Total	**367**	**3,878,225**	**$176,749,144**	**$176,749,144**	**$258,639,094**	**1.5**	**$46**

Monthly Average Energy	2010												2011											
Load and Resource Balance	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Nov-11**	**Dec-11**
Load Forecast (70th%)—Aug 2009	(1,857)	(1,743)	(1,546)	(1,526)	(1,724)	(2,143)	(2,426)	(2,242)	(1,853)	(1,538)	(1,671)	(1,985)	(1,966)	(1,845)	(1,641)	(1,621)	(1,811)	(2,232)	(2,515)	(2,328)	(1,930)	(1,602)	(1,741)	(2,049)
Existing DSM (Energy Efficiency)	13	13	13	14	15	16	17	16	14	13	13	13	25	25	25	26	30	33	33	32	28	26	25	25
Load Forecast (70th%) w/Existing DSM	(1,844)	(1,730)	(1,533)	(1,512)	(1,709)	(2,126)	(2,409)	(2,226)	(1,838)	(1,525)	(1,658)	(1,972)	(1,941)	(1,820)	(1,616)	(1,595)	(1,781)	(2,200)	(2,482)	(2,296)	(1,902)	(1,577)	(1,716)	(2,024)
Existing Resources																								
Coal (w/Curtailment)	919	919	861	628	587	919	924	924	924	922	924	924	924	924	924	685	712	905	928	928	928	927	928	928
Hydro (70th%)—HCC	610	598	620	697	848	667	477	378	425	434	364	475	669	532	620	697	848	667	477	378	425	434	363	475
Hydro (70th%)—Other	221	296	250	248	329	341	252	248	240	227	210	216	221	296	250	248	328	340	252	247	240	227	210	215
Sho-Ban Water Lease	0	0	0	0	0	0	71	0	0	0	0	0	0	0	0	0	0	0	71	0	0	0	0	0
Total Hydro (70th%)	831	894	870	945	1,177	1,008	801	626	665	661	574	691	890	828	869	945	1,176	1,007	800	625	664	661	574	690
CSPP (PURPA)	64	68	67	92	137	146	145	136	117	119	112	120	102	118	125	144	184	194	180	169	160	139	114	120
Power Purchase Agreements																								
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana - Jefferson (83 MW)	0	0	0	0	0	48	48	46	0	0	0	0	0	0	0	0	0	48	45	48	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	29	28	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	42	42	0	0	0	0	0	0	0	0	0	0	42	42	0	0	0	0
Total Power Purchase Agreements	44	43	44	45	40	95	166	159	39	45	42	54	44	43	44	45	40	95	134	133	39	45	42	54
Firm Pacific NW Import Capability (Actuals Through Sept 2010)	270	325	238	310	301	241	123	187	177	44	364	309	342	389	372	387	343	237	117	183	175	127	363	307
Gas Peakers	224	0	0	0	0	240	233	233	0	0	0	233	224	0	0	0	0	240	224	242	0	0	0	233
Existing Resource Subtotal	**2,350**	**2,249**	**2,079**	**2,019**	**2,242**	**2,648**	**2,391**	**2,264**	**1,920**	**1,791**	**2,016**	**2,330**	**2,525**	**2,302**	**2,334**	**2,206**	**2,455**	**2,678**	**2,384**	**2,281**	**1,966**	**1,899**	**2,022**	**2,332**
Monthly Surplus/Deficit	**506**	**518**	**546**	**507**	**533**	**522**	**(19)**	**38**	**82**	**266**	**358**	**358**	**584**	**482**	**718**	**611**	**674**	**478**	**(98)**	**(15)**	**65**	**322**	**306**	**308**

2006 IRP Resources	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Nov-11**	**Dec-11**
2012 Wind RFP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Langley Gulch	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	**506**	**518**	**546**	**507**	**533**	**522**	**(19)**	**38**	**82**	**266**	**358**	**358**	**584**	**482**	**718**	**611**	**674**	**478**	**(98)**	**(15)**	**65**	**322**	**306**	**308**

2009 IRP DSM	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Nov-11**	**Dec-11**
Industrial	1	1	1	1	1	1	1	1	1	1	1	1	3	3	3	3	3	3	3	3	3	3	3	3
Comercial	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2
Residential	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2
Total New DSM Average Energy	3	3	3	3	3	3	3	3	3	3	3	3	7	7	7	7	7	7	7	7	7	7	7	7
Remaining Monthly Surplus/Deficit	**509**	**521**	**549**	**510**	**536**	**525**	**(16)**	**41**	**85**	**269**	**361**	**361**	**591**	**489**	**725**	**618**	**681**	**485**	**(91)**	**(8)**	**72**	**329**	**313**	**315**

2009 IRP Resources	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Nov-11**	**Dec-11**
2015 Boardman–Hemingway Transmission																								
2015 Shoshone Falls Upgrade (49 MW)																								
2017 Boardman–Hemingway Transmission																								
2020 Large Aero (100 MW)																								
2022 Wind (100 MW)																								
2024 Large Aero (2 X 100 MW)																								
2025 Gateway West Transmission																								
2026 Large Aero (2 X 100 MW)																								
2027 Wind (2 X 200 MW)																								
2028 Large Aero (4 X 100 MW)																								
2029 Large Aero (5 X 100 MW)																								
Monthly Surplus/Deficit	**509**	**521**	**549**	**510**	**536**	**525**	**(16)**	**41**	**85**	**269**	**361**	**361**	**591**	**489**	**725**	**618**	**681**	**485**	**(91)**	**(8)**	**72**	**329**	**313**	**315**

Monthly Average Energy	2012												2013											
Load and Resource Balance	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**
Load Forecast (70th%)—Aug 2009	(2,027)	(1,890)	(1,692)	(1,669)	(1,858)	(2,287)	(2,579)	(2,388)	(1,979)	(1,652)	(1,793)	(2,090)	(2,046)	(1,921)	(1,710)	(1,687)	(1,879)	(2,334)	(2,650)	(2,446)	(2,013)	(1,675)	(1,816)	(2,122)
Existing DSM (Energy Efficiency)	37	37	37	39	45	48	48	47	42	38	37	37	49	49	49	52	58	63	64	62	55	50	49	50
Load Forecast (70th%) w/Existing DSM	(1,990)	(1,853)	(1,655)	(1,630)	(1,814)	(2,239)	(2,531)	(2,341)	(1,937)	(1,615)	(1,756)	(2,053)	(1,997)	(1,872)	(1,661)	(1,635)	(1,821)	(2,270)	(2,587)	(2,385)	(1,957)	(1,625)	(1,767)	(2,073)
Existing Resources																								
Coal (w/Curtailment)	928	939	898	543	718	881	934	934	934	768	934	934	934	934	833	0	490	934	940	940	766	646	940	940
Hydro (70th%)—HCC	686	511	619	697	848	667	477	377	425	434	363	475	685	514	615	696	848	666	477	377	424	433	364	474
Hydro (70th%)—Other	220	296	249	250	328	340	252	247	240	227	210	215	220	296	249	250	328	339	251	246	239	227	210	215
Sho-Ban Water Lease	0	0	0	0	0	0	71	0	0	0	0	0	0	0	0	0	0	0	72	0	0	0	0	0
Total Hydro (70th%)	906	807	869	946	1,176	1,006	800	624	664	661	573	690	905	810	864	946	1,176	1,006	799	623	664	660	574	689
CSPP (PURPA)	102	118	125	144	184	194	180	169	160	139	114	120	102	118	125	144	184	194	180	169	160	139	114	120
Power Purchase Agreements																								
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana - Jefferson (83 MW)	0	0	0	0	0	0	45	48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	44	43	44	45	40	47	92	91	39	45	42	54	44	43	44	45	40	47	47	43	39	45	42	54
Firm Pacific NW Import Capability (Actuals Through Sept 2010)	340	387	396	287	363	233	114	180	172	172	361	305	337	384	449	388	366	229	110	178	170	222	358	302
Gas Peakers	224	0	0	0	0	240	224	242	0	0	0	224	233	0	0	0	0	231	233	242	0	0	0	224
Existing Resource Subtotal	**2,543**	**2,294**	**2,332**	**1,965**	**2,481**	**2,602**	**2,344**	**2,241**	**1,969**	**1,785**	**2,025**	**2,326**	**2,555**	**2,290**	**2,315**	**1,523**	**2,256**	**2,641**	**2,310**	**2,195**	**1,798**	**1,712**	**2,029**	**2,328**
Monthly Surplus/Deficit	**554**	**441**	**677**	**335**	**667**	**363**	**(187)**	**(100)**	**32**	**170**	**269**	**274**	**558**	**418**	**654**	**(113)**	**435**	**371**	**(277)**	**(189)**	**(159)**	**87**	**262**	**256**
2006 IRP Resources	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**
2012 Wind RFP	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
Langley Gulch	0	0	0	0	0	0	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251
Geothermal	0	0	0	0	0	0	0	0	0	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	**602**	**489**	**725**	**383**	**715**	**411**	**112**	**199**	**331**	**488**	**587**	**592**	**876**	**737**	**972**	**205**	**753**	**689**	**41**	**129**	**159**	**405**	**580**	**574**
2009 IRP DSM	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**
Industrial	6	6	6	6	6	6	6	6	6	6	6	6	9	9	9	9	9	10	10	10	9	9	9	9
Comercial	3	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	4	4	4	4
Residential	4	4	4	4	4	3	3	3	4	4	4	4	5	5	5	5	5	4	4	4	5	5	5	5
Total New DSM Average Energy	12	12	12	12	12	12	12	12	12	12	12	12	18	18	18	18	18	18	18	18	18	18	18	18
Remaining Monthly Surplus/Deficit	**614**	**502**	**737**	**396**	**727**	**423**	**125**	**211**	**343**	**501**	**600**	**604**	**895**	**755**	**991**	**223**	**772**	**707**	**59**	**147**	**177**	**423**	**598**	**592**
2009 IRP Resources	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**
2015 Boardman–Hemingway Transmission																								
2015 Shoshone Falls Upgrade (49 MW)																								
2017 Boardman–Hemingway Transmission																								
2020 Large Aero (100 MW)																								
2022 Wind (100 MW)																								
2024 Large Aero (2 X 100 MW)																								
2025 Gateway West Transmission																								
2026 Large Aero (2 X 100 MW)																								
2027 Wind (2 X 200 MW)																								
2028 Large Aero (4 X 100 MW)																								
2029 Large Aero (5 X 100 MW)																								
Monthly Surplus/Deficit	**614**	**502**	**737**	**396**	**727**	**423**	**125**	**211**	**343**	**501**	**600**	**604**	**895**	**755**	**991**	**223**	**772**	**707**	**59**	**147**	**177**	**423**	**598**	**592**

Monthly Average Energy	2014												2015											
Load and Resource Balance	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**
Load Forecast (70th%)—Aug 2009	(2,081)	(1,952)	(1,739)	(1,714)	(1,908)	(2,371)	(2,699)	(2,492)	(2,048)	(1,706)	(1,850)	(2,152)	(2,101)	(1,969)	(1,755)	(1,730)	(1,928)	(2,402)	(2,737)	(2,528)	(2,075)	(1,727)	(1,870)	(2,176)
Existing DSM (Energy Efficiency)	61	61	61	64	72	78	79	76	68	62	62	61	73	73	73	76	86	92	93	90	81	74	74	73
Load Forecast (70th%) w/Existing DSM	(2,020)	(1,891)	(1,677)	(1,649)	(1,836)	(2,294)	(2,620)	(2,416)	(1,980)	(1,644)	(1,788)	(2,091)	(2,028)	(1,896)	(1,682)	(1,653)	(1,842)	(2,310)	(2,645)	(2,438)	(1,994)	(1,652)	(1,797)	(2,103)
Existing Resources																								
Coal (w/Curtailment)	940	932	715	0	491	880	940	940	765	646	940	940	938	938	491	490	490	906	938	938	646	444	938	938
Hydro (70th%)—HCC	684	529	597	695	846	665	475	376	423	432	364	472	683	535	588	694	845	664	474	375	422	430	364	471
Hydro (70th%)—Other	219	295	248	249	327	338	249	243	238	226	209	213	218	295	247	247	326	336	248	242	237	225	209	213
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	903	824	845	944	1,173	1,003	725	619	661	658	573	685	901	830	835	941	1,171	1,000	722	617	659	655	573	683
CSPP (PURPA)	102	118	125	144	184	194	180	169	160	139	114	120	102	118	125	144	184	194	180	169	160	139	114	120
Power Purchase Agreements																								
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana - Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	44	43	44	45	40	47	47	43	39	45	42	54	44	43	44	45	40	47	47	43	39	45	42	54
Firm Pacific NW Import Capability (Actuals Through Sept 2010)	335	381	447	390	334	226	106	174	168	322	356	299	202	379	446	290	335	222	103	172	167	214	354	297
Gas Peakers	233	0	0	0	0	231	233	233	0	0	0	233	233	0	0	0	0	240	233	233	0	0	0	233
Existing Resource Subtotal	**2,557**	**2,299**	**2,175**	**1,523**	**2,222**	**2,581**	**2,231**	**2,178**	**1,793**	**1,809**	**2,026**	**2,330**	**2,420**	**2,309**	**1,941**	**1,910**	**2,220**	**2,609**	**2,223**	**2,172**	**1,671**	**1,497**	**2,022**	**2,325**
Monthly Surplus/Deficit	**537**	**408**	**498**	**(127)**	**387**	**288**	**(389)**	**(238)**	**(187)**	**166**	**238**	**240**	**392**	**414**	**259**	**256**	**377**	**299**	**(421)**	**(266)**	**(324)**	**(155)**	**225**	**222**
2006 IRP Resources	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**
2012 Wind RFP	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
Langley Gulch	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251
Geothermal	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	**855**	**727**	**816**	**191**	**705**	**606**	**(71)**	**80**	**131**	**484**	**556**	**558**	**710**	**732**	**577**	**575**	**695**	**618**	**(103)**	**52**	**(6)**	**163**	**543**	**540**
2009 IRP DSM	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**
Industrial	13	13	13	13	13	13	13	13	13	13	13	13	16	16	16	16	16	17	17	17	16	16	16	16
Comercial	5	5	5	5	5	5	5	5	5	5	5	5	7	7	7	7	7	7	7	7	7	7	7	7
Residential	7	7	7	7	7	6	6	6	7	7	7	7	8	8	8	8	8	7	7	7	8	8	8	8
Total New DSM Average Energy	24	24	24	24	24	24	24	24	24	24	25	24	31	31	31	31	31	31	31	31	31	31	31	31
Remaining Monthly Surplus/Deficit	**879**	**751**	**841**	**216**	**729**	**630**	**(47)**	**105**	**156**	**508**	**580**	**583**	**741**	**763**	**608**	**605**	**726**	**648**	**(72)**	**83**	**25**	**194**	**575**	**571**
2009 IRP Resources	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**
2015 Boardman–Hemingway Transmission																		250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)																						0	0	3
2017 Boardman–Hemingway Transmission																								
2020 Large Aero (100 MW)																								
2022 Wind (100 MW)																								
2024 Large Aero (2 X 100 MW)																								
2025 Gateway West Transmission																								
2026 Large Aero (2 X 100 MW)																								
2027 Wind (2 X 200 MW)																								
2028 Large Aero (4 X 100 MW)																								
2029 Large Aero (5 X 100 MW)																								
Monthly Surplus/Deficit	**879**	**751**	**841**	**216**	**729**	**630**	**(47)**	**105**	**156**	**508**	**580**	**583**	**741**	**763**	**608**	**605**	**726**	**898**	**178**	**333**	**275**	**444**	**825**	**824**

Monthly Average Energy	2016												2017											
Load and Resource Balance	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**
Load Forecast (70th%)—Aug 2009	(2,122)	(1,974)	(1,771)	(1,746)	(1,948)	(2,430)	(2,774)	(2,562)	(2,101)	(1,747)	(1,892)	(2,200)	(2,142)	(2,004)	(1,789)	(1,762)	(1,968)	(2,460)	(2,813)	(2,599)	(2,128)	(1,769)	(1,914)	(2,225)
Existing DSM (Energy Efficiency)	85	85	84	88	99	106	107	104	94	87	85	84	97	96	96	101	112	120	121	117	106	99	97	97
Load Forecast (70th%) w/Existing DSM	(2,037)	(1,889)	(1,687)	(1,657)	(1,848)	(2,324)	(2,667)	(2,459)	(2,007)	(1,661)	(1,807)	(2,115)	(2,046)	(1,908)	(1,693)	(1,662)	(1,856)	(2,340)	(2,692)	(2,481)	(2,022)	(1,670)	(1,817)	(2,127)
Existing Resources																								
Coal (w/Curtailment)	937	947	560	366	418	909	937	937	645	443	937	937	937	937	560	398	298	909	937	937	645	443	882	937
Hydro (70th%)—HCC	682	531	590	693	844	663	473	374	420	429	363	471	681	551	567	692	843	662	472	373	419	427	364	469
Hydro (70th%)—Other	218	295	246	246	326	335	246	241	236	225	208	212	217	295	246	245	325	334	245	240	236	224	207	211
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	899	826	836	939	1,170	998	719	615	657	654	571	683	898	846	813	937	1,168	996	717	612	655	651	572	681
CSPP (PURPA)	102	118	125	144	184	194	180	169	160	139	114	120	102	118	125	144	184	194	180	169	160	139	114	120
Power Purchase Agreements																								
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana - Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	44	43	44	45	40	47	47	43	39	45	42	54	44	43	44	45	40	47	47	43	39	45	42	54
Firm Pacific NW Import Capability (Actuals Through Sept 2010)	330	376	445	387	336	219	99	169	165	234	351	295	328	374	444	193	335	215	94	166	162	252	349	294
Gas Peakers	224	0	0	0	0	240	224	242	0	0	0	233	224	0	0	0	0	240	224	242	0	0	0	224
Existing Resource Subtotal	**2,535**	**2,311**	**2,010**	**1,881**	**2,148**	**2,608**	**2,206**	**2,175**	**1,665**	**1,514**	**2,016**	**2,321**	**2,531**	**2,319**	**1,985**	**1,716**	**2,025**	**2,601**	**2,199**	**2,169**	**1,660**	**1,529**	**1,959**	**2,309**
Monthly Surplus/Deficit	**499**	**422**	**323**	**224**	**300**	**284**	**(461)**	**(284)**	**(342)**	**(147)**	**209**	**205**	**486**	**411**	**293**	**55**	**169**	**262**	**(493)**	**(312)**	**(361)**	**(141)**	**142**	**182**
2006 IRP Resources	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**
2012 Wind RFP	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
Langley Gulch	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251
Geothermal	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Geothermal	0	0	0	0	0	0	0	0	0	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Remaining Monthly Surplus/Deficit	**817**	**740**	**641**	**542**	**618**	**602**	**(143)**	**34**	**(24)**	**191**	**547**	**543**	**823**	**749**	**630**	**392**	**506**	**599**	**(156)**	**25**	**(24)**	**196**	**480**	**519**
2009 IRP DSM	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**
Industrial	20	20	20	20	20	20	20	20	20	20	20	20	23	23	23	23	23	24	24	24	23	23	23	23
Comercial	8	8	8	8	8	8	8	8	8	8	8	8	9	9	9	9	10	10	10	10	9	9	9	10
Residential	10	10	10	10	10	9	9	9	10	10	10	10	12	12	12	12	12	10	10	10	12	12	12	12
Total New DSM Average Energy	38	37	37	37	38	37	37	37	38	38	38	37	44	44	44	44	45	44	44	44	44	44	44	45
Remaining Monthly Surplus/Deficit	**855**	**777**	**679**	**579**	**656**	**639**	**(105)**	**71**	**14**	**228**	**584**	**580**	**868**	**793**	**675**	**437**	**551**	**643**	**(112)**	**69**	**20**	**241**	**524**	**564**
2009 IRP Resources	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	6	31	12	0	14	17	0	0	0	0	0	3	6	31	12	0	14	17	0	0	0	0	0	3
2017 Boardman–Hemingway Transmission													175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)																								
2022 Wind (100 MW)																								
2024 Large Aero (2 X 100 MW)																								
2025 Gateway West Transmission																								
2026 Large Aero (2 X 100 MW)																								
2027 Wind (2 X 200 MW)																								
2028 Large Aero (4 X 100 MW)																								
2029 Large Aero (5 X 100 MW)																								
Monthly Surplus/Deficit	**1,111**	**1,059**	**941**	**830**	**920**	**907**	**145**	**321**	**264**	**478**	**834**	**833**	**1,299**	**1,249**	**1,112**	**862**	**990**	**1,086**	**313**	**494**	**445**	**666**	**949**	**992**

Monthly Average Energy	2018												2019											
Load and Resource Balance	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**
Load Forecast (70th%)—Aug 2009	(2,163)	(2,022)	(1,806)	(1,779)	(1,989)	(2,490)	(2,852)	(2,635)	(2,155)	(1,790)	(1,936)	(2,250)	(2,183)	(2,038)	(1,822)	(1,795)	(2,009)	(2,521)	(2,892)	(2,673)	(2,182)	(1,811)	(1,957)	(2,274)
Existing DSM (Energy Efficiency)	109	108	108	113	125	134	135	131	120	110	109	109	120	120	120	125	138	148	149	145	132	122	121	121
Load Forecast (70th%) w/Existing DSM	(2,054)	(1,914)	(1,698)	(1,666)	(1,863)	(2,356)	(2,717)	(2,504)	(2,035)	(1,680)	(1,827)	(2,141)	(2,062)	(1,918)	(1,701)	(1,670)	(1,871)	(2,373)	(2,743)	(2,528)	(2,050)	(1,689)	(1,836)	(2,153)
Existing Resources																								
Coal (w/Curtailment)	937	937	560	319	288	899	934	934	642	440	879	934	937	937	460	180	168	879	934	934	642	284	746	934
Hydro (70th%)—HCC	680	558	558	691	842	661	471	372	418	426	364	468	679	564	549	689	841	659	470	371	417	425	364	468
Hydro (70th%)—Other	216	295	245	244	324	333	243	238	235	223	207	211	216	295	244	244	323	331	242	237	234	223	207	210
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	896	853	802	935	1,166	993	714	610	653	649	571	679	894	859	793	933	1,164	991	712	608	650	648	571	678
CSPP (PURPA)	102	118	125	144	184	194	180	169	160	139	114	120	102	118	125	144	184	194	180	169	160	139	114	120
Power Purchase Agreements																								
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana - Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	44	43	44	45	40	47	47	43	39	45	42	54	44	43	44	45	40	47	47	43	39	45	42	54
Firm Pacific NW Import Capability (Actuals Through Sept 2010)	279	371	441	301	336	211	90	164	160	266	348	292	324	369	440	385	336	208	86	161	159	312	344	260
Gas Peakers	233	0	0	0	0	240	224	242	0	0	0	224	233	0	0	0	0	231	233	242	0	0	0	224
Existing Resource Subtotal	**2,490**	**2,323**	**1,972**	**1,744**	**2,014**	**2,584**	**2,189**	**2,162**	**1,653**	**1,539**	**1,955**	**2,302**	**2,533**	**2,327**	**1,862**	**1,687**	**1,892**	**2,549**	**2,192**	**2,157**	**1,650**	**1,427**	**1,817**	**2,269**
Monthly Surplus/Deficit	**435**	**409**	**274**	**78**	**151**	**228**	**(528)**	**(342)**	**(382)**	**(141)**	**128**	**161**	**471**	**408**	**161**	**17**	**21**	**177**	**(551)**	**(371)**	**(400)**	**(262)**	**(19)**	**116**
2006 IRP Resources	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**
2012 Wind RFP	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
Langley Gulch	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251
Geothermal	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Geothermal	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Remaining Monthly Surplus/Deficit	**773**	**747**	**612**	**415**	**488**	**565**	**(190)**	**(5)**	**(45)**	**196**	**465**	**499**	**808**	**746**	**498**	**354**	**358**	**514**	**(214)**	**(34)**	**(62)**	**75**	**319**	**454**
2009 IRP DSM	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**
Industrial	27	27	27	27	27	28	28	28	27	27	27	27	31	31	31	31	31	32	32	32	31	31	31	31
Comercial	11	11	11	11	11	11	11	11	11	11	11	11	13	13	13	13	13	13	13	13	13	13	13	13
Residential	13	13	13	13	13	12	12	12	13	13	13	13	15	15	15	15	15	13	13	13	15	15	15	15
Total New DSM Average Energy	51	51	51	51	52	51	51	51	52	51	51	52	59	58	59	58	59	58	58	58	59	58	59	59
Remaining Monthly Surplus/Deficit	**824**	**798**	**663**	**467**	**540**	**616**	**(139)**	**46**	**7**	**247**	**517**	**550**	**866**	**804**	**556**	**413**	**417**	**572**	**(155)**	**25**	**(4)**	**134**	**377**	**512**
2009 IRP Resources	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	6	31	12	0	14	17	0	0	0	0	0	3	6	31	12	0	14	17	0	0	0	0	0	3
2017 Boardman–Hemingway Transmission	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)																								
2022 Wind (100 MW)																								
2024 Large Aero (2 X 100 MW)																								
2025 Gateway West Transmission																								
2026 Large Aero (2 X 100 MW)																								
2027 Wind (2 X 200 MW)																								
2028 Large Aero (4 X 100 MW)																								
2029 Large Aero (5 X 100 MW)																								
Monthly Surplus/Deficit	**1,256**	**1,254**	**1,100**	**892**	**979**	**1,059**	**286**	**471**	**432**	**672**	**942**	**978**	**1,298**	**1,261**	**993**	**838**	**856**	**1,015**	**270**	**450**	**421**	**559**	**802**	**941**

Monthly Average Energy	2020												2021											
Load and Resource Balance	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**
Load Forecast (70th%)—Aug 2009	(2,207)	(2,047)	(1,840)	(1,813)	(2,031)	(2,554)	(2,934)	(2,712)	(2,211)	(1,833)	(1,980)	(2,293)	(2,215)	(2,065)	(1,848)	(1,821)	(2,043)	(2,574)	(2,961)	(2,738)	(2,230)	(1,847)	(1,992)	(2,311)
Existing DSM (Energy Efficiency)	132	132	132	137	152	162	163	159	144	134	133	132	145	144	143	149	165	176	177	172	157	146	144	144
Load Forecast (70th%) w/Existing DSM	(2,074)	(1,915)	(1,707)	(1,676)	(1,879)	(2,392)	(2,772)	(2,554)	(2,068)	(1,699)	(1,846)	(2,160)	(2,070)	(1,922)	(1,705)	(1,673)	(1,878)	(2,398)	(2,785)	(2,565)	(2,073)	(1,700)	(1,848)	(2,167)
Existing Resources																								
Coal (w/Curtailment)	937	937	487	180	338	926	934	934	642	284	773	934	937	937	578	180	248	898	934	934	644	284	563	934
Hydro (70th%)—HCC	677	561	551	688	839	658	468	370	416	423	364	468	676	571	538	687	838	657	467	368	415	422	364	468
Hydro (70th%)—Other	220	295	244	244	322	330	241	236	232	222	210	210	219	294	243	243	322	330	240	235	231	221	210	209
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	897	855	794	932	1,162	989	709	606	648	645	574	677	895	865	781	931	1,160	987	707	603	646	643	574	677
CSPP (PURPA)	102	118	125	144	184	194	180	169	160	139	114	120	102	118	125	144	184	194	180	169	160	139	114	120
Power Purchase Agreements																								
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana - Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	44	43	44	45	40	47	47	43	39	45	42	54	44	43	44	45	40	47	47	43	39	45	42	54
Firm Pacific NW Import Capability (Actuals Through Sept 2010)	330	376	445	387	336	219	99	169	165	234	351	295	330	376	445	387	336	219	99	169	165	234	351	295
Gas Peakers	233	0	0	0	0	240	233	233	0	0	0	233	224	0	0	0	0	240	242	233	0	0	0	233
Existing Resource Subtotal	**2,542**	**2,330**	**1,895**	**1,688**	**2,060**	**2,615**	**2,203**	**2,154**	**1,653**	**1,346**	**1,855**	**2,313**	**2,531**	**2,340**	**1,973**	**1,687**	**1,968**	**2,585**	**2,209**	**2,151**	**1,653**	**1,344**	**1,645**	**2,312**
Monthly Surplus/Deficit	**468**	**415**	**187**	**12**	**181**	**223**	**(569)**	**(400)**	**(415)**	**(353)**	**9**	**152**	**461**	**418**	**268**	**14**	**90**	**187**	**(575)**	**(414)**	**(420)**	**(356)**	**(204)**	**144**
2006 IRP Resources	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**
2012 Wind RFP	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
Langley Gulch	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251
Geothermal	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Geothermal	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Remaining Monthly Surplus/Deficit	**805**	**752**	**525**	**350**	**518**	**561**	**(232)**	**(63)**	**(77)**	**(16)**	**346**	**490**	**799**	**756**	**605**	**351**	**428**	**524**	**(238)**	**(77)**	**(82)**	**(19)**	**134**	**482**
2009 IRP DSM	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**
Industrial	35	34	35	34	35	36	36	36	34	34	35	35	39	38	38	38	39	40	40	40	38	38	38	38
Comercial	14	14	14	14	15	15	15	15	14	14	15	14	16	16	16	16	16	17	17	17	16	16	16	16
Residential	17	17	17	17	17	15	15	15	17	17	17	17	18	18	18	18	18	16	16	16	18	18	18	18
Total New DSM Average Energy	66	66	66	66	66	66	66	66	66	66	66	66	73	73	73	73	74	73	73	73	73	73	73	73
Remaining Monthly Surplus/Deficit	**871**	**818**	**591**	**415**	**584**	**626**	**(166)**	**3**	**(12)**	**50**	**412**	**555**	**872**	**828**	**677**	**424**	**501**	**597**	**(165)**	**(4)**	**(9)**	**54**	**207**	**555**
2009 IRP Resources	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	6	31	12	0	14	17	0	0	0	0	0	3	6	31	12	0	14	17	0	0	0	0	0	3
2017 Boardman–Hemingway Transmission	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)	56	0	0	0	0	58	56	56	0	0	0	56	54	0	0	0	0	58	58	56	0	0	0	56
2022 Wind (100 MW)																								
2024 Large Aero (2 X 100 MW)																								
2025 Gateway West Transmission																								
2026 Large Aero (2 X 100 MW)																								
2027 Wind (2 X 200 MW)																								
2028 Large Aero (4 X 100 MW)																								
2029 Large Aero (5 X 100 MW)																								
Monthly Surplus/Deficit	**1,359**	**1,274**	**1,028**	**840**	**1,023**	**1,126**	**315**	**484**	**413**	**475**	**838**	**1,039**	**1,357**	**1,285**	**1,115**	**849**	**940**	**1,097**	**318**	**477**	**416**	**479**	**632**	**1,039**

Monthly Average Energy	2022												2023											
Load and Resource Balance	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**
Load Forecast (70th%)—Aug 2009	(2,234)	(2,081)	(1,864)	(1,836)	(2,062)	(2,601)	(2,997)	(2,771)	(2,254)	(1,867)	(2,013)	(2,333)	(2,249)	(2,093)	(1,876)	(1,849)	(2,078)	(2,627)	(3,032)	(2,804)	(2,278)	(1,884)	(2,029)	(2,341)
Existing DSM (Energy Efficiency)	157	155	155	161	179	190	191	186	170	159	156	155	168	167	167	174	191	204	205	200	182	170	168	169
Load Forecast (70th%) w/Existing DSM	(2,077)	(1,926)	(1,709)	(1,675)	(1,883)	(2,411)	(2,806)	(2,585)	(2,085)	(1,708)	(1,857)	(2,178)	(2,081)	(1,926)	(1,709)	(1,674)	(1,887)	(2,424)	(2,827)	(2,604)	(2,096)	(1,714)	(1,862)	(2,173)
Existing Resources																								
Coal (w/Curtailment)	937	937	578	0	180	898	934	934	644	284	563	934	937	937	403	0	180	898	934	934	464	284	526	934
Hydro (70th%)—HCC	675	577	529	686	837	656	466	367	414	420	364	468	674	579	525	685	836	655	465	366	412	418	364	468
Hydro (70th%)—Other	219	294	242	243	321	329	239	235	229	220	209	208	218	294	242	242	320	328	238	234	228	219	209	208
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	894	871	771	929	1,158	985	705	602	642	640	573	676	892	873	766	927	1,156	982	703	600	640	638	573	676
CSPP (PURPA)	102	118	125	144	184	194	180	169	160	139	114	120	102	118	125	144	184	194	180	169	160	139	114	120
Power Purchase Agreements																								
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana - Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	44	43	44	45	40	47	47	43	39	45	42	54	44	43	44	45	40	47	47	43	39	45	42	54
Firm Pacific NW Import Capability (Actuals Through Sept 2010)	330	376	445	387	336	219	99	169	165	234	351	295	330	376	445	387	336	219	99	169	165	234	351	295
Gas Peakers	224	0	0	0	0	240	224	242	0	0	0	242	233	0	0	0	0	240	224	242	0	0	0	224
Existing Resource Subtotal	**2,530**	**2,346**	**1,964**	**1,505**	**1,898**	**2,583**	**2,189**	**2,159**	**1,650**	**1,342**	**1,644**	**2,320**	**2,537**	**2,348**	**1,783**	**1,503**	**1,896**	**2,581**	**2,187**	**2,157**	**1,468**	**1,339**	**1,607**	**2,302**
Monthly Surplus/Deficit	**453**	**420**	**255**	**(171)**	**16**	**172**	**(617)**	**(426)**	**(435)**	**(367)**	**(212)**	**142**	**456**	**422**	**74**	**(172)**	**9**	**157**	**(640)**	**(447)**	**(628)**	**(375)**	**(255)**	**129**
2006 IRP Resources	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**
2012 Wind RFP	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
Langley Gulch	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251
Geothermal	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Geothermal	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Remaining Monthly Surplus/Deficit	**790**	**757**	**592**	**167**	**353**	**510**	**(279)**	**(89)**	**(97)**	**(29)**	**125**	**480**	**793**	**759**	**411**	**166**	**346**	**495**	**(303)**	**(110)**	**(291)**	**(37)**	**83**	**467**
2009 IRP DSM	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**
Industrial	43	42	42	42	43	44	44	44	42	42	42	42	46	46	46	46	47	48	48	48	46	46	46	47
Comercial	18	18	18	18	18	19	19	19	18	18	18	18	20	20	20	20	20	21	21	21	20	20	20	20
Residential	20	20	20	20	20	17	17	17	20	20	20	20	21	21	21	21	21	19	19	19	21	21	21	21
Total New DSM Average Energy	81	80	80	80	81	80	80	80	80	80	80	80	88	87	87	88	88	88	87	88	88	88	88	88
Remaining Monthly Surplus/Deficit	**871**	**838**	**672**	**247**	**434**	**590**	**(199)**	**(9)**	**(17)**	**51**	**205**	**560**	**881**	**847**	**498**	**253**	**434**	**582**	**(215)**	**(22)**	**(203)**	**50**	**170**	**555**
2009 IRP Resources	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	6	31	12	0	14	17	0	0	0	0	0	3	6	31	12	0	14	17	0	0	0	0	0	3
2017 Boardman–Hemingway Transmission	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)	54	0	0	0	0	58	54	58	0	0	0	58	56	0	0	0	0	58	54	58	0	0	0	54
2022 Wind (100 MW)	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
2024 Large Aero (2 X 100 MW)																								
2025 Gateway West Transmission																								
2026 Large Aero (2 X 100 MW)																								
2027 Wind (2 X 200 MW)																								
2028 Large Aero (4 X 100 MW)																								
2029 Large Aero (5 X 100 MW)																								
Monthly Surplus/Deficit	**1,388**	**1,326**	**1,141**	**704**	**905**	**1,122**	**311**	**506**	**440**	**508**	**662**	**1,078**	**1,400**	**1,335**	**967**	**710**	**905**	**1,114**	**295**	**493**	**254**	**507**	**627**	**1,068**

Monthly Average Energy	2024												2025											
Load and Resource Balance	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**
Load Forecast (70th%)—Aug 2009	(2,250)	(2,082)	(1,877)	(1,851)	(2,083)	(2,638)	(3,046)	(2,817)	(2,287)	(1,891)	(2,034)	(2,356)	(2,269)	(2,109)	(1,893)	(1,866)	(2,101)	(2,664)	(3,082)	(2,851)	(2,312)	(1,911)	(2,056)	(2,378)
Existing DSM (Energy Efficiency)	180	179	180	185	203	218	219	214	196	181	180	181	192	191	192	198	216	232	233	227	208	193	193	192
Load Forecast (70th%) w/Existing DSM	(2,071)	(1,903)	(1,698)	(1,665)	(1,880)	(2,420)	(2,827)	(2,604)	(2,091)	(1,709)	(1,855)	(2,176)	(2,078)	(1,918)	(1,702)	(1,668)	(1,885)	(2,433)	(2,849)	(2,624)	(2,104)	(1,718)	(1,863)	(2,186)
Existing Resources																								
Coal (w/Curtailment)	937	937	403	0	180	898	934	934	374	184	526	934	937	937	285	0	180	898	934	934	374	184	374	934
Hydro (70th%)—HCC	673	561	542	684	835	654	463	365	411	416	364	468	672	576	524	683	834	638	462	364	410	414	364	468
Hydro (70th%)—Other	218	294	241	242	320	327	237	233	227	218	208	207	217	294	241	242	319	323	236	232	226	218	207	206
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	890	854	783	926	1,154	980	700	598	638	635	572	675	889	869	764	924	1,152	961	698	596	636	632	572	674
CSPP (PURPA)	102	118	125	144	184	194	180	169	160	139	114	120	102	118	125	144	184	194	180	169	160	139	114	120
Power Purchase Agreements																								
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana - Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	44	43	44	45	40	47	47	43	39	45	42	54	44	43	44	45	40	47	47	43	39	45	42	54
Firm Pacific NW Import Capability (Actuals Through Sept 2010)	330	376	445	387	336	219	99	169	165	234	351	295	330	376	445	387	336	219	99	169	165	234	351	295
Gas Peakers	233	0	0	0	0	231	233	242	0	0	0	224	233	0	0	0	0	231	233	233	0	0	0	233
Existing Resource Subtotal	**2,535**	**2,329**	**1,800**	**1,501**	**1,894**	**2,569**	**2,194**	**2,155**	**1,376**	**1,236**	**1,606**	**2,301**	**2,534**	**2,344**	**1,663**	**1,500**	**1,892**	**2,550**	**2,192**	**2,144**	**1,374**	**1,233**	**1,454**	**2,309**
Monthly Surplus/Deficit	**465**	**426**	**102**	**(164)**	**14**	**149**	**(634)**	**(449)**	**(716)**	**(473)**	**(249)**	**126**	**456**	**426**	**(39)**	**(168)**	**8**	**118**	**(657)**	**(480)**	**(730)**	**(485)**	**(409)**	**123**
2006 IRP Resources	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**
2012 Wind RFP	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
Langley Gulch	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251
Geothermal	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Geothermal	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Remaining Monthly Surplus/Deficit	**802**	**763**	**439**	**173**	**352**	**487**	**(296)**	**(111)**	**(378)**	**(136)**	**88**	**463**	**794**	**763**	**299**	**169**	**345**	**455**	**(320)**	**(142)**	**(393)**	**(147)**	**(72)**	**461**
2009 IRP DSM	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**
Industrial	50	50	50	50	50	52	52	52	51	50	50	51	54	54	54	54	54	56	56	56	54	54	55	54
Comercial	22	22	22	22	22	23	23	23	22	22	22	22	24	24	24	24	24	25	25	25	24	24	24	24
Residential	23	23	23	23	23	20	20	20	23	23	23	23	24	25	24	25	24	22	22	21	24	25	24	24
Total New DSM Average Energy	95	95	95	95	95	95	95	95	96	95	95	96	103	103	103	103	103	103	103	103	103	103	104	103
Remaining Monthly Surplus/Deficit	**897**	**858**	**535**	**268**	**447**	**582**	**(201)**	**(16)**	**(282)**	**(41)**	**184**	**559**	**897**	**866**	**402**	**272**	**448**	**558**	**(217)**	**(39)**	**(290)**	**(45)**	**32**	**564**
2009 IRP Resources	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	6	31	12	0	14	17	0	0	0	0	0	3	6	31	12	0	14	17	0	0	0	0	0	3
2017 Boardman–Hemingway Transmission	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)	56	0	0	0	0	56	56	58	0	0	0	54	56	0	0	0	0	56	56	56	0	0	0	56
2022 Wind (100 MW)	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
2024 Large Aero (2 X 100 MW)	112	0	0	0	0	111	112	116	0	0	0	108	112	0	0	0	0	111	112	112	0	0	0	112
2025 Gateway West Transmission													100	100	100	100	100	100	100	100	100	100	100	100
2026 Large Aero (2 X 100 MW)																								
2027 Wind (2 X 200 MW)																								
2028 Large Aero (4 X 100 MW)																								
2029 Large Aero (5 X 100 MW)																								
Monthly Surplus/Deficit	**1,529**	**1,346**	**1,004**	**725**	**918**	**1,223**	**423**	**615**	**175**	**416**	**641**	**1,180**	**1,628**	**1,454**	**971**	**829**	**1,019**	**1,299**	**508**	**685**	**267**	**512**	**589**	**1,292**

Monthly Average Energy	2026												2027											
Load and Resource Balance	**Jan-26**	**Feb-26**	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**	**Jan-27**	**Feb-27**	**Mar-27**	**Apr-27**	**May-27**	**Jun-27**	**Jul-27**	**Aug-27**	**Sep-27**	**Oct-27**	**Nov-27**	**Dec-27**
Load Forecast (70th%)—Aug 2009	(2,283)	(2,120)	(1,905)	(1,877)	(2,118)	(2,692)	(3,118)	(2,885)	(2,336)	(1,928)	(2,071)	(2,387)	(2,283)	(2,119)	(1,906)	(1,879)	(2,123)	(2,703)	(3,134)	(2,899)	(2,346)	(1,934)	(2,076)	(2,394)
Existing DSM (Energy Efficiency)	203	203	203	210	231	246	247	241	219	205	205	203	216	214	214	222	245	260	261	255	233	218	215	215
Load Forecast (70th%) w/Existing DSM	(2,080)	(1,918)	(1,701)	(1,668)	(1,887)	(2,446)	(2,871)	(2,644)	(2,117)	(1,723)	(1,866)	(2,183)	(2,067)	(1,905)	(1,692)	(1,658)	(1,878)	(2,443)	(2,873)	(2,644)	(2,113)	(1,716)	(1,861)	(2,179)
Existing Resources																								
Coal (w/Curtailment)	937	395	0	0	0	463	934	934	284	0	284	934	285	0	0	0	0	463	934	934	5	0	0	816
Hydro (70th%)—HCC	670	578	519	681	832	637	461	363	409	412	364	468	669	576	519	680	831	636	459	362	408	402	364	468
Hydro (70th%)—Other	217	293	240	242	318	321	235	231	226	217	207	210	217	293	240	241	317	320	235	231	225	217	206	210
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	887	871	759	923	1,151	958	696	594	634	629	571	678	886	869	759	921	1,149	956	694	592	633	618	571	678
CSPP (PURPA)	102	118	125	144	184	194	180	169	160	139	114	120	102	118	125	144	184	194	180	169	160	139	114	120
Power Purchase Agreements																								
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana - Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	44	43	44	45	40	47	47	43	39	45	42	54	44	43	44	45	40	47	47	43	39	45	42	54
Firm Pacific NW Import Capability (Actuals Through Sept 2010)	330	376	445	387	336	219	99	169	165	234	351	295	330	376	445	387	336	219	99	169	165	234	351	295
Gas Peakers	233	0	0	0	0	240	233	233	0	0	0	233	224	0	0	0	0	240	242	233	0	0	0	233
Existing Resource Subtotal	**2,532**	**1,804**	**1,373**	**1,499**	**1,711**	**2,121**	**2,189**	**2,142**	**1,282**	**1,047**	**1,362**	**2,313**	**1,870**	**1,407**	**1,373**	**1,497**	**1,709**	**2,119**	**2,196**	**2,140**	**1,002**	**1,036**	**1,078**	**2,195**
Monthly Surplus/Deficit	**452**	**(114)**	**(328)**	**(169)**	**(177)**	**(325)**	**(682)**	**(501)**	**(835)**	**(676)**	**(504)**	**130**	**(197)**	**(498)**	**(320)**	**(161)**	**(170)**	**(324)**	**(677)**	**(504)**	**(1,111)**	**(680)**	**(782)**	**17**
2006 IRP Resources	**Jan-26**	**Feb-26**	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**	**Jan-27**	**Feb-27**	**Mar-27**	**Apr-27**	**May-27**	**Jun-27**	**Jul-27**	**Aug-27**	**Sep-27**	**Oct-27**	**Nov-27**	**Dec-27**
2012 Wind RFP	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
Langley Gulch	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251
Geothermal	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Geothermal	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Remaining Monthly Surplus/Deficit	**790**	**223**	**9**	**168**	**161**	**13**	**(345)**	**(164)**	**(497)**	**(339)**	**(167)**	**467**	**140**	**(160)**	**18**	**177**	**168**	**14**	**(339)**	**(167)**	**(774)**	**(343)**	**(445)**	**354**
2009 IRP DSM	**Jan-26**	**Feb-26**	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**	**Jan-27**	**Feb-27**	**Mar-27**	**Apr-27**	**May-27**	**Jun-27**	**Jul-27**	**Aug-27**	**Sep-27**	**Oct-27**	**Nov-27**	**Dec-27**
Industrial	59	58	59	58	59	61	61	61	58	58	59	59	63	62	62	62	63	65	65	65	63	63	63	63
Comercial	26	26	26	26	27	27	27	27	26	26	27	26	29	29	28	28	29	30	30	30	29	29	29	29
Residential	26	26	26	26	26	23	23	23	26	26	26	26	28	28	28	28	27	24	24	24	28	28	28	28
Total New DSM Average Energy	111	111	111	111	112	111	111	111	111	110	112	111	119	119	118	118	120	119	119	119	119	119	119	119
Remaining Monthly Surplus/Deficit	**901**	**334**	**120**	**279**	**272**	**123**	**(234)**	**(53)**	**(387)**	**(228)**	**(55)**	**578**	**260**	**(42)**	**136**	**295**	**288**	**133**	**(220)**	**(48)**	**(655)**	**(224)**	**(326)**	**473**
2009 IRP Resources	**Jan-26**	**Feb-26**	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**	**Jan-27**	**Feb-27**	**Mar-27**	**Apr-27**	**May-27**	**Jun-27**	**Jul-27**	**Aug-27**	**Sep-27**	**Oct-27**	**Nov-27**	**Dec-27**
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	6	31	12	0	14	17	0	0	0	0	0	3	6	31	12	0	14	17	0	0	0	0	0	3
2017 Boardman–Hemingway Transmission	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)	56	0	0	0	0	58	56	56	0	0	0	56	54	0	0	0	0	58	58	56	0	0	0	56
2022 Wind (100 MW)	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
2024 Large Aero (2 X 100 MW)	112	0	0	0	0	116	112	112	0	0	0	112	108	0	0	0	0	116	116	112	0	0	0	112
2025 Gateway West Transmission	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
2026 Large Aero (2 X 100 MW)	112	0	0	0	0	116	112	112	0	0	0	112	108	0	0	0	0	116	116	112	0	0	0	112
2027 Wind (2 X 200 MW)													64	64	64	64	64	64	64	64	64	64	64	64
2028 Large Aero (4 X 100 MW)																								
2029 Large Aero (5 X 100 MW)																								
Monthly Surplus/Deficit	**1,744**	**923**	**689**	**836**	**843**	**987**	**603**	**783**	**170**	**329**	**502**	**1,418**	**1,156**	**611**	**769**	**916**	**923**	**1,060**	**691**	**852**	**(34)**	**397**	**295**	**1,377**

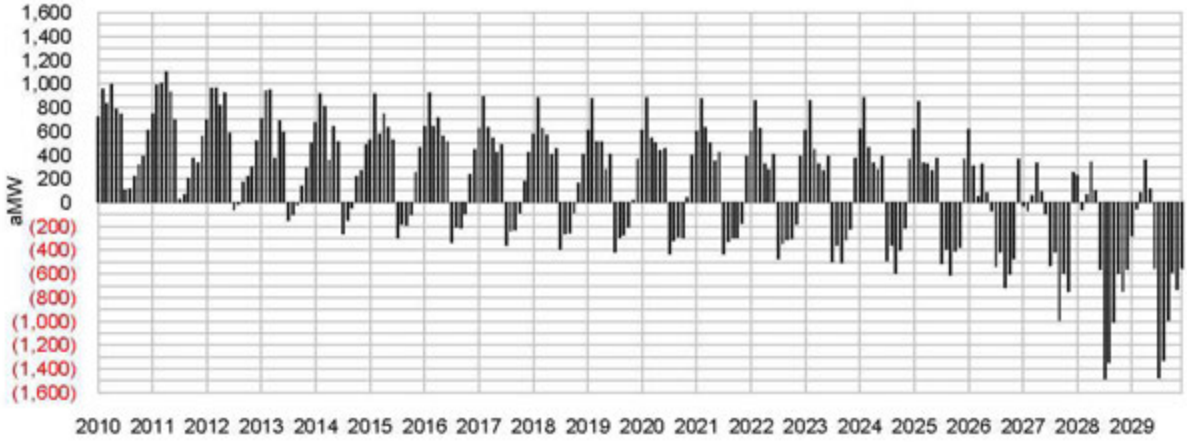
Monthly Average Energy	2028												2029											
Load and Resource Balance	**Jan-28**	**Feb-28**	**Mar-28**	**Apr-28**	**May-28**	**Jun-28**	**Jul-28**	**Aug-28**	**Sep-28**	**Oct-28**	**Nov-28**	**Dec-28**	**Jan-29**	**Feb-29**	**Mar-29**	**Apr-29**	**May-29**	**Jun-29**	**Jul-29**	**Aug-29**	**Sep-29**	**Oct-29**	**Nov-29**	**Dec-29**
Load Forecast (70th%)—Aug 2009	(2,291)	(2,115)	(1,912)	(1,885)	(2,132)	(2,717)	(3,154)	(2,919)	(2,359)	(1,946)	(2,085)	(2,394)	(2,280)	(2,115)	(1,907)	(1,881)	(2,129)	(2,716)	(3,155)	(2,920)	(2,359)	(1,945)	(2,083)	(2,397)
Existing DSM (Energy Efficiency)	228	226	225	235	257	274	275	269	245	230	227	228	239	238	237	247	270	288	289	282	260	241	239	240
Load Forecast (70th%) w/Existing DSM	(2,063)	(1,889)	(1,687)	(1,650)	(1,875)	(2,443)	(2,879)	(2,650)	(2,114)	(1,715)	(1,859)	(2,166)	(2,042)	(1,877)	(1,670)	(1,634)	(1,859)	(2,429)	(2,866)	(2,637)	(2,100)	(1,704)	(1,844)	(2,157)
Existing Resources																								
Coal (w/Curtailment)	537	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro (70th%)—HCC	668	570	523	679	830	635	458	360	407	400	364	468	667	576	514	678	829	634	457	359	406	398	364	468
Hydro (70th%)—Other	216	292	239	241	317	320	234	229	225	216	206	210	216	292	239	241	316	319	233	229	224	216	205	209
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	884	862	762	920	1,147	954	692	590	631	616	570	677	883	868	753	918	1,145	953	690	588	629	613	569	677
CSPP (PURPA)	102	118	125	144	184	194	180	169	160	139	114	120	102	118	125	144	184	194	180	169	160	139	114	120
Power Purchase Agreements																								
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana - Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	44	43	44	45	40	47	47	43	39	45	42	54	44	43	44	45	40	47	47	43	39	45	42	54
Firm Pacific NW Import Capability (Actuals Through Sept 2010)	330	376	445	387	336	219	99	169	165	234	351	295	330	376	445	387	336	219	99	169	165	234	351	295
Gas Peakers	224	0	0	0	0	240	224	242	0	0	0	224	233	0	0	0	0	240	224	242	0	0	0	224
Existing Resource Subtotal	**2,120**	**1,400**	**1,376**	**1,495**	**1,707**	**1,655**	**1,242**	**1,213**	**995**	**1,034**	**1,078**	**1,370**	**1,591**	**1,406**	**1,367**	**1,494**	**1,705**	**1,653**	**1,240**	**1,211**	**993**	**1,031**	**1,077**	**1,369**
Monthly Surplus/Deficit	**57**	**(489)**	**(311)**	**(155)**	**(168)**	**(789)**	**(1,637)**	**(1,438)**	**(1,119)**	**(682)**	**(781)**	**(797)**	**(451)**	**(471)**	**(303)**	**(140)**	**(154)**	**(776)**	**(1,626)**	**(1,426)**	**(1,107)**	**(673)**	**(767)**	**(787)**

2006 IRP Resources	Jan-28	Feb-28	Mar-28	Apr-28	May-28	Jun-28	Jul-28	Aug-28	Sep-28	Oct-28	Nov-28	Dec-28	Jan-29	Feb-29	Mar-29	Apr-29	May-29	Jun-29	Jul-29	Aug-29	Sep-29	Oct-29	Nov-29	Dec-29
2012 Wind RFP	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
Langley Gulch	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251	251
Geothermal	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Geothermal	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Remaining Monthly Surplus/Deficit	**394**	**(152)**	**27**	**183**	**169**	**(451)**	**(1,300)**	**(1,100)**	**(782)**	**(344)**	**(443)**	**(459)**	**(114)**	**(134)**	**35**	**198**	**184**	**(439)**	**(1,288)**	**(1,089)**	**(769)**	**(336)**	**(430)**	**(450)**

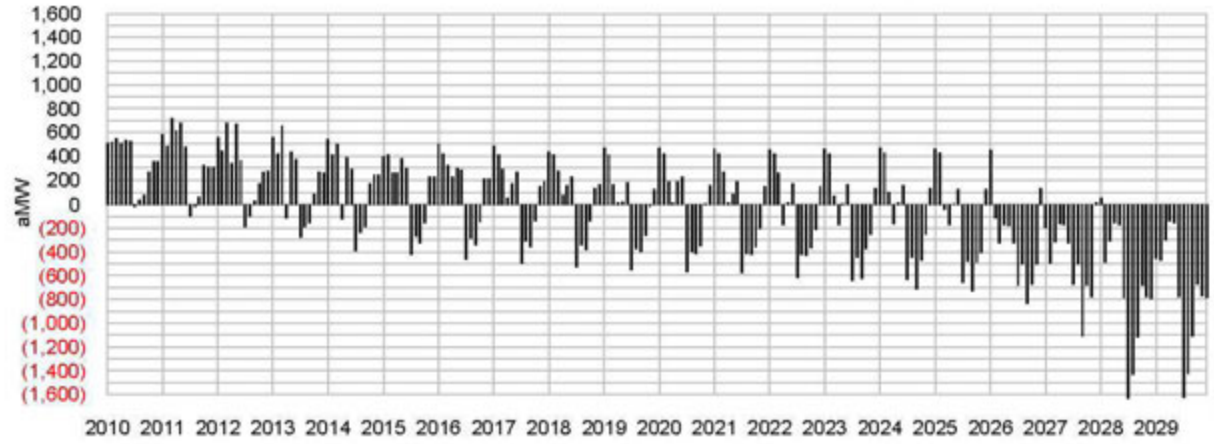
2009 IRP DSM	Jan-28	Feb-28	Mar-28	Apr-28	May-28	Jun-28	Jul-28	Aug-28	Sep-28	Oct-28	Nov-28	Dec-28	Jan-29	Feb-29	Mar-29	Apr-29	May-29	Jun-29	Jul-29	Aug-29	Sep-29	Oct-29	Nov-29	Dec-29
Industrial	67	66	66	67	67	69	69	69	67	67	67	67	67	66	66	67	67	69	69	69	67	66	67	67
Comercial	31	31	31	31	31	32	32	32	31	31	31	31	31	31	31	31	31	32	32	32	31	31	31	31
Residential	29	29	30	29	29	26	26	26	29	29	29	29	29	29	30	29	29	26	26	26	29	30	29	29
Total New DSM Average Energy	128	127	127	127	128	127	127	127	127	127	127	128	127	127	127	127	128	127	127	127	128	127	127	128
Remaining Monthly Surplus/Deficit	**522**	**(25)**	**153**	**310**	**297**	**(324)**	**(1,173)**	**(973)**	**(655)**	**(217)**	**(316)**	**(331)**	**14**	**(7)**	**161**	**325**	**311**	**(311)**	**(1,161)**	**(962)**	**(641)**	**(209)**	**(303)**	**(322)**

2009 IRP Resources	Jan-28	Feb-28	Mar-28	Apr-28	May-28	Jun-28	Jul-28	Aug-28	Sep-28	Oct-28	Nov-28	Dec-28	Jan-29	Feb-29	Mar-29	Apr-29	May-29	Jun-29	Jul-29	Aug-29	Sep-29	Oct-29	Nov-29	Dec-29
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	6	31	12	0	14	17	0	0	0	0	0	3	6	31	12	0	14	17	0	0	0	0	0	3
2017 Boardman–Hemingway Transmission	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)	54	0	0	0	0	58	54	58	0	0	0	54	56	0	0	0	0	58	54	58	0	0	0	54
2022 Wind (100 MW)	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
2024 Large Aero (2 X 100 MW)	108	0	0	0	0	116	108	116	0	0	0	108	112	0	0	0	0	116	108	116	0	0	0	108
2025 Gateway West Transmission	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
2026 Large Aero (2 X 100 MW)	108	0	0	0	0	116	108	116	0	0	0	108	112	0	0	0	0	116	108	116	0	0	0	108
2027 Wind (2 X 200 MW)	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64	64
2028 Large Aero (4 X 100 MW)	215	0	0	0	0	231	215	232	0	0	0	215	224	0	0	0	0	231	215	232	0	0	0	215
2029 Large Aero (5 X 100 MW)													280	0	0	0	0	289	269	290	0	0	0	269
Monthly Surplus/Deficit	**1,633**	**627**	**786**	**931**	**932**	**834**	**(68)**	**171**	**(34)**	**404**	**305**	**777**	**1,424**	**645**	**794**	**946**	**946**	**1,136**	**213**	**472**	**(20)**	**412**	**319**	**1,055**

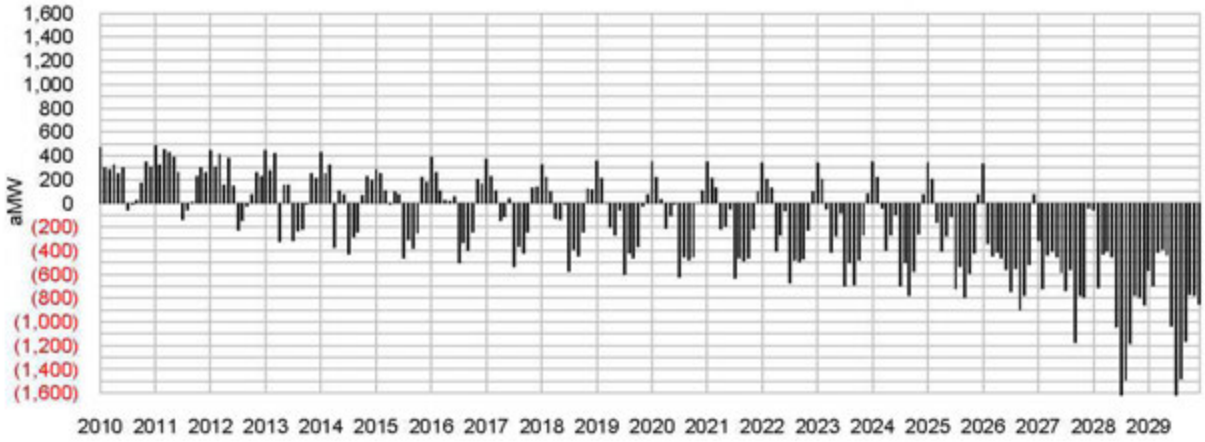
Monthly Average Energy Surpluses and Deficits with Existing Resources
(50th Percentile Water and 50th Percentile Load)



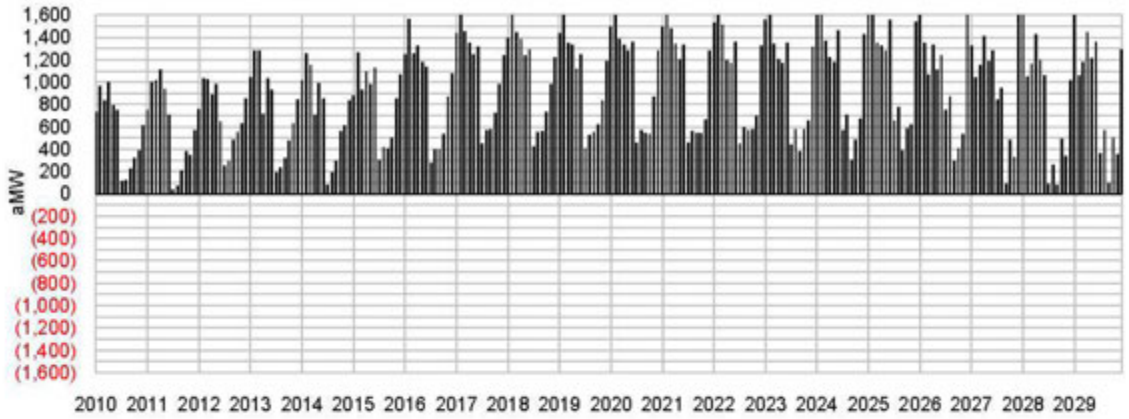
Monthly Average Energy Surpluses and Deficits with Existing Resources
(70th Percentile Water and 70th Percentile Load)



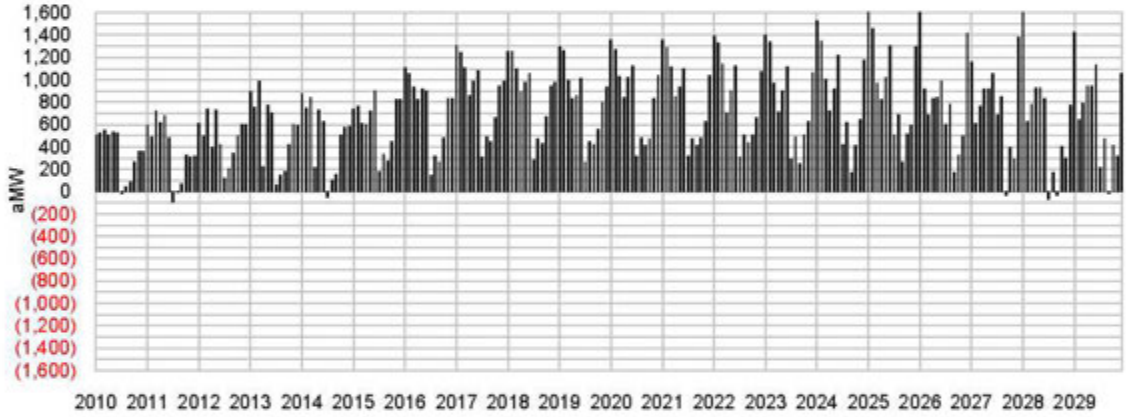
Monthly Average Energy Surpluses and Deficits with Existing Resources
(90th Percentile Water and 70th Percentile Load)



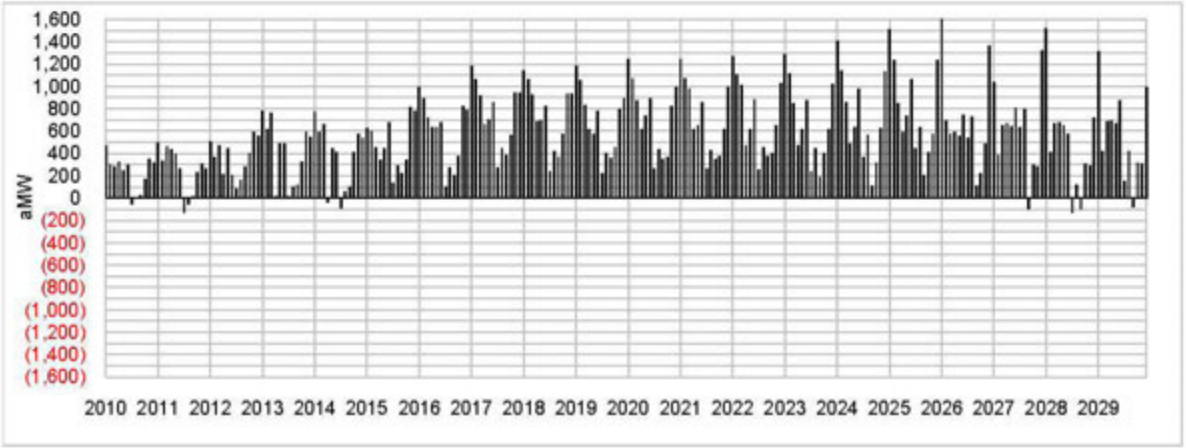
Monthly Average Energy Surpluses and Deficits with 2009 IRP Resources
(50th Percentile Water and 50th Percentile Load)



Monthly Average Energy Surpluses and Deficits with 2009 IRP Resources
(70th Percentile Water and 70th Percentile Load)



Monthly Average Energy Surpluses and Deficits with 2009 IRP Resources
(90th Percentile Water and 70th Percentile Load)



Peak-Hour	2010												2011											
Load and Resource Balance	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Nov-10**	**Dec-10**	**Jan-11**	**Feb-11**	**Mar-11**	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Nov-11**	**Dec-11**
Load Forecast (95th%)—w/EE DSM	(2,455)	(2,402)	(2,103)	(1,871)	(2,761)	(3,318)	(3,460)	(3,138)	(2,978)	(2,088)	(2,302)	(2,695)	(2,559)	(2,486)	(2,191)	(1,948)	(2,846)	(3,395)	(3,560)	(3,185)	(3,027)	(2,133)	(2,353)	(2,733)
Existing DSM (Irrigation Timer)	0	0	0	0	0	8	8	0	0	0	0	0	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	59	59	51	0	0	0	0	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,455)	(2,402)	(2,103)	(1,871)	(2,761)	(3,259)	(3,401)	(3,088)	(2,978)	(2,088)	(2,302)	(2,695)	(2,559)	(2,486)	(2,191)	(1,948)	(2,846)	(3,338)	(3,503)	(3,134)	(3,027)	(2,133)	(2,353)	(2,733)
Existing Resources																								
Coal (w/Curtailment)	963	963	963	676	621	963	967	967	967	967	967	967	967	967	967	680	790	967	972	972	972	972	972	972
Hydro (90th%)—HCC	1,131	945	670	690	1,181	1,106	1,040	945	1,035	835	600	785	1,107	900	670	690	1,179	1,110	1,035	945	1,090	780	600	785
Hydro (90th%)—Other	203	207	196	213	289	306	246	236	217	210	198	204	203	206	196	213	289	306	246	236	216	210	198	204
Sho-Ban Water Lease	0	0	0	0	0	0	42	0	0	0	0	0	0	0	0	0	0	0	47	0	0	0	0	0
Total Hydro	1,335	1,152	866	903	1,470	1,413	1,328	1,181	1,252	1,045	798	989	1,310	1,106	866	903	1,467	1,416	1,328	1,181	1,306	990	798	989
CSPP (PURPA)	43	42	46	70	121	129	133	124	102	82	58	55	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements																								
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	83	83	83	0	0	0	0	0	0	0	0	0	83	83	83	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	50	50	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	75	75	0	0	0	0	0	0	0	0	0	0	75	75	0	0	0	0
Total Power Purchase Agreements	15	15	15	15	15	98	223	223	15	15	15	15	15	15	15	15	15	98	173	173	15	15	15	15
Firm Pacific NW Import Capability	99	229	212	205	414	302	122	255	291	0	535	443	216	346	288	270	406	287	105	247	287	73	530	440
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**2,871**	**2,816**	**2,518**	**2,286**	**3,057**	**3,321**	**3,190**	**3,166**	**3,042**	**2,526**	**2,789**	**2,885**	**2,976**	**2,901**	**2,606**	**2,363**	**3,223**	**3,322**	**3,135**	**3,121**	**3,106**	**2,548**	**2,790**	**2,887**
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(212)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(17)**	**(368)**	**(13)**	**0**	**0**	**0**	**0**

2006 IRP Resources	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
2012 Wind RFP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Langley Gulch	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(212)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(17)**	**(368)**	**(13)**	**0**	**0**	**0**	**0**

2009 IRP DSM	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
Commercial (FlexPeak)	0	0	0	0	0	40	40	40	0	0	0	0	0	0	0	0	0	45	45	45	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	212	212	0	0	0	0	0	0	0	0	0	0	244	244	0	0	0	0	0
Energy Efficiency Peak Reduction	3	3	3	3	3	3	3	3	3	3	3	3	7	7	7	7	7	7	7	7	7	7	7	7
Total New DSM Peak Reduction	3	3	3	3	3	254	254	42	3	3	3	3	7	7	7	7	7	296	296	52	7	7	7	7
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(71)**	**0**	**0**	**0**	**0**	**0**

2009 IRP Resources	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
2015 Boardman–Hemingway Transmission																								
2015 Shoshone Falls Upgrade (49 MW)																								
2017 Boardman–Hemingway Transmission																								
2020 Large Aero (100 MW)																								
2022 Wind (100 MW)																								
2024 Large Aero (2 X 100 MW)																								
2025 Gateway West Transmission																								
2026 Large Aero (2 X 100 MW)																								
2027 Wind (2 X 200 MW)																								
2028 Large Aero (4 X 100 MW)																								
2029 Large Aero (5 X 100 MW)																								
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(71)**	**0**	**0**	**0**	**0**	**0**

Peak-Hour	2012												2013											
Load and Resource Balance	**Jan-12**	**Feb-12**	**Mar-12**	**Apr-12**	**May-12**	**Jun-12**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**
Load Forecast (95th%)—w/EE DSM	(2,600)	(2,487)	(2,225)	(1,964)	(2,891)	(3,496)	(3,636)	(3,242)	(3,069)	(2,168)	(2,391)	(2,756)	(2,560)	(2,496)	(2,203)	(1,922)	(2,915)	(3,541)	(3,726)	(3,296)	(3,127)	(2,177)	(2,389)	(2,703)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,600)	(2,487)	(2,225)	(1,964)	(2,891)	(3,440)	(3,579)	(3,192)	(3,069)	(2,168)	(2,391)	(2,756)	(2,560)	(2,496)	(2,203)	(1,922)	(2,915)	(3,484)	(3,669)	(3,246)	(3,127)	(2,177)	(2,389)	(2,703)
Existing Resources																								
Coal (w/Curtailment)	972	972	933	663	751	972	978	978	978	798	978	978	978	978	907	0	744	978	983	983	789	670	983	983
Hydro (90th%)—HCC	1,106	897	670	690	1,170	1,056	1,035	945	1,090	780	510	785	1,116	870	670	670	1,170	1,060	1,034	945	1,035	780	600	870
Hydro (90th%)—Other	203	206	196	213	289	306	245	235	216	210	198	203	202	206	195	213	289	306	245	234	216	210	198	203
Sho-Ban Water Lease	0	0	0	0	0	0	48	0	0	0	0	0	0	0	0	0	0	0	48	0	0	0	0	0
Total Hydro	1,308	1,103	866	903	1,459	1,363	1,328	1,180	1,306	990	708	988	1,319	1,076	865	883	1,459	1,366	1,327	1,179	1,251	990	798	1,073
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements																								
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	83	83	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	15	15	15	15	15	15	98	98	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Firm Pacific NW Import Capability	254	348	317	160	396	263	97	240	284	102	528	437	197	377	290	254	389	248	87	234	278	106	525	443
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**3,017**	**2,904**	**2,601**	**2,236**	**3,166**	**3,166**	**3,059**	**3,045**	**3,109**	**2,403**	**2,704**	**2,889**	**2,977**	**2,913**	**2,547**	**1,647**	**3,151**	**3,161**	**2,969**	**2,960**	**2,859**	**2,279**	**2,795**	**2,985**
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(274)**	**(521)**	**(147)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(276)**	**0**	**(324)**	**(700)**	**(286)**	**(268)**	**0**	**0**	**0**

2006 IRP Resources	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	0	0	0	0	0	0	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Geothermal	0	0	0	0	0	0	0	0	0	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(266)**	**(213)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(373)**	**0**	**0**	**0**	**0**	**0**

2009 IRP DSM	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	12	12	12	12	12	12	12	12	12	12	12	12	18	18	18	18	18	18	18	18	18	18	18	18
Total New DSM Peak Reduction	12	12	12	12	12	323	323	69	12	12	12	12	18	18	18	18	18	329	329	75	18	18	18	18
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(44)**	**0**	**0**	**0**	**0**	**0**

2009 IRP Resources	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
2015 Boardman–Hemingway Transmission																								
2015 Shoshone Falls Upgrade (49 MW)																								
2017 Boardman–Hemingway Transmission																								
2020 Large Aero (100 MW)																								
2022 Wind (100 MW)																								
2024 Large Aero (2 X 100 MW)																								
2025 Gateway West Transmission																								
2026 Large Aero (2 X 100 MW)																								
2027 Wind (2 X 200 MW)																								
2028 Large Aero (4 X 100 MW)																								
2029 Large Aero (5 X 100 MW)																								
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(44)**	**0**	**0**	**0**	**0**	**0**

Peak-Hour	2014												2015											
Load and Resource Balance	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**Oct-15**	**Nov-15**	**Dec-15**
Load Forecast (95th%)—w/EE DSM	(2,594)	(2,516)	(2,230)	(1,944)	(2,946)	(3,593)	(3,789)	(3,359)	(3,169)	(2,193)	(2,415)	(2,748)	(2,583)	(2,509)	(2,226)	(1,931)	(2,970)	(3,640)	(3,843)	(3,396)	(3,211)	(2,200)	(2,421)	(2,742)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,594)	(2,516)	(2,230)	(1,944)	(2,946)	(3,536)	(3,732)	(3,308)	(3,169)	(2,193)	(2,415)	(2,748)	(2,583)	(2,509)	(2,226)	(1,931)	(2,970)	(3,583)	(3,786)	(3,346)	(3,211)	(2,200)	(2,421)	(2,742)
Existing Resources																								
Coal (w/Curtailment)	983	983	803	0	728	913	983	983	789	670	983	983	982	982	586	676	725	936	982	982	671	470	982	982
Hydro (90th%)—HCC	1,122	845	670	585	1,135	1,066	1,005	945	1,035	595	600	870	1,098	845	670	585	1,187	1,104	1,035	945	1,035	780	600	870
Hydro (90th%)—Other	202	205	195	213	288	305	243	232	215	209	197	202	201	204	194	212	287	296	240	230	214	209	197	201
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro	1,323	1,050	865	798	1,422	1,371	1,248	1,177	1,250	804	797	1,072	1,299	1,049	864	797	1,473	1,400	1,275	1,175	1,249	989	797	1,071
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements																								
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Firm Pacific NW Import Capability	222	444	523	356	380	237	79	218	276	308	523	439	236	432	517	223	381	242	71	196	267	131	525	439
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**3,011**	**2,959**	**2,676**	**1,663**	**3,090**	**3,090**	**2,882**	**2,941**	**2,856**	**2,295**	**2,793**	**2,980**	**3,000**	**2,944**	**2,452**	**2,206**	**3,139**	**3,146**	**2,900**	**2,916**	**2,728**	**2,103**	**2,793**	**2,978**
Monthly Surplus/Deficit	**0**	**0**	**0**	**(281)**	**0**	**(447)**	**(850)**	**(367)**	**(313)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(437)**	**(886)**	**(430)**	**(483)**	**(97)**	**0**	**0**

2006 IRP Resources	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(119)**	**(522)**	**(40)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(110)**	**(558)**	**(102)**	**(156)**	**0**	**0**	**0**

2009 IRP DSM	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	24	24	24	24	24	24	24	24	24	24	25	24	31	31	31	31	31	31	31	31	31	31	31	31
Total New DSM Peak Reduction	24	24	24	24	24	335	335	81	24	24	25	24	31	31	31	31	31	341	341	87	31	31	31	31
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(188)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(217)**	**(15)**	**(125)**	**0**	**0**	**0**

2009 IRP Resources	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
2015 Boardman–Hemingway Transmission																		250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)																						0	0	1
2017 Boardman–Hemingway Transmission																								
2020 Large Aero (100 MW)																								
2022 Wind (100 MW)																								
2024 Large Aero (2 X 100 MW)																								
2025 Gateway West Transmission																								
2026 Large Aero (2 X 100 MW)																								
2027 Wind (2 X 200 MW)																								
2028 Large Aero (4 X 100 MW)																								
2029 Large Aero (5 X 100 MW)																								
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(188)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Peak-Hour	2016												2017											
Load and Resource Balance	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**
Load Forecast (95th%)—w/EE DSM	(2,580)	(2,507)	(2,228)	(1,924)	(2,993)	(3,686)	(3,895)	(3,437)	(3,252)	(2,207)	(2,430)	(2,745)	(2,578)	(2,504)	(2,231)	(1,920)	(3,018)	(3,733)	(3,949)	(3,480)	(3,293)	(2,215)	(2,439)	(2,751)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,580)	(2,507)	(2,228)	(1,924)	(2,993)	(3,629)	(3,838)	(3,386)	(3,252)	(2,207)	(2,430)	(2,745)	(2,578)	(2,504)	(2,231)	(1,920)	(3,018)	(3,676)	(3,893)	(3,429)	(3,293)	(2,215)	(2,439)	(2,751)
Existing Resources																								
Coal (w/Curtailment)	980	980	586	602	635	936	980	980	671	470	980	980	980	980	586	569	543	936	980	980	671	470	908	980
Hydro (90th%)—HCC	1,115	835	585	780	1,181	1,117	1,035	945	1,035	780	600	870	1,117	845	585	785	1,184	1,060	1,005	945	1,085	780	600	870
Hydro (90th%)—Other	200	203	193	212	286	294	238	226	213	208	196	201	200	202	192	211	285	292	237	223	212	207	196	200
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro	1,315	1,038	778	992	1,467	1,411	1,273	1,171	1,248	988	796	1,071	1,317	1,047	777	996	1,469	1,353	1,242	1,168	1,297	987	796	1,070
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements																								
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	15	15	15	15	15	15	15	15	15	15	15	15												
Firm Pacific NW Import Capability	219	451	400	259	376	229	65	190	265	141	524	440	215	431	404	0	370	219	58	182	262	150	524	440
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**2,997**	**2,951**	**2,249**	**2,363**	**3,038**	**3,144**	**2,891**	**2,905**	**2,725**	**2,112**	**2,790**	**2,977**	**2,980**	**2,925**	**2,237**	**2,060**	**2,927**	**3,061**	**2,838**	**2,879**	**2,756**	**2,105**	**2,701**	**2,960**
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(485)**	**(948)**	**(481)**	**(526)**	**(95)**	**0**	**0**	**0**	**0**	**0**	**0**	**(91)**	**(615)**	**(1,054)**	**(550)**	**(537)**	**(110)**	**0**	**0**
2006 IRP Resources	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Geothermal	0	0	0	0	0	0	0	0	0	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(158)**	**(620)**	**(154)**	**(199)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(267)**	**(707)**	**(203)**	**(190)**	**0**	**0**	**0**
2009 IRP DSM	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	38	37	37	37	38	37	37	37	38	38	38	37	44	44	44	44	45	44	44	44	44	44	44	45
Total New DSM Peak Reduction	38	37	37	37	38	348	348	94	38	38	38	37	44	44	44	44	45	355	355	101	44	44	44	45
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(272)**	**(60)**	**(161)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(352)**	**(102)**	**(145)**	**0**	**0**	**0**
2009 IRP Resources	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	2	2	0	0	3	10	0	0	0	0	0	1	2	2	0	0	3	10	0	0	0	0	0	1
2017 Boardman–Hemingway Transmission													175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)																								
2022 Wind (100 MW)																								
2024 Large Aero (2 X 100 MW)																								
2025 Gateway West Transmission																								
2026 Large Aero (2 X 100 MW)																								
2027 Wind (2 X 200 MW)																								
2028 Large Aero (4 X 100 MW)																								
2029 Large Aero (5 X 100 MW)																								
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(22)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Peak-Hour	2018												2019											
Load and Resource Balance	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**
Load Forecast (95th%)—w/EE DSM	(2,576)	(2,501)	(2,233)	(1,915)	(3,042)	(3,780)	(4,003)	(3,523)	(3,334)	(2,223)	(2,448)	(2,759)	(2,578)	(2,501)	(2,238)	(1,915)	(3,067)	(3,827)	(4,060)	(3,570)	(3,374)	(2,230)	(2,459)	(2,773)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,576)	(2,501)	(2,233)	(1,915)	(3,042)	(3,723)	(3,947)	(3,472)	(3,334)	(2,223)	(2,448)	(2,759)	(2,578)	(2,501)	(2,238)	(1,915)	(3,067)	(3,770)	(4,003)	(3,520)	(3,374)	(2,230)	(2,459)	(2,773)
Existing Resources																								
Coal (w/Curtailment)	980	980	586	376	525	936	977	977	671	470	908	977	977	977	486	237	405	916	977	977	671	314	775	977
Hydro (90th%)—HCC	1,113	845	585	585	1,175	1,041	1,005	945	1,080	780	510	870	1,114	845	700	585	1,173	1,039	1,005	945	1,035	760	600	1,187
Hydro (90th%)—Other	199	201	192	211	284	290	230	222	208	207	195	200	198	201	191	211	284	287	227	221	207	206	195	200
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro	1,312	1,046	777	796	1,460	1,331	1,235	1,167	1,288	987	705	1,070	1,313	1,046	891	796	1,457	1,326	1,232	1,166	1,242	966	795	1,387
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements																								
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements																								
Firm Pacific NW Import Capability	218	426	406	166	363	206	54	179	256	161	525	439	222	432	300	335	355	193	48	174	249	189	520	312
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**2,978**	**2,919**	**2,239**	**1,833**	**2,893**	**3,026**	**2,823**	**2,872**	**2,741**	**2,116**	**2,612**	**2,956**	**2,980**	**2,922**	**2,147**	**1,863**	**2,762**	**2,988**	**2,815**	**2,866**	**2,688**	**1,967**	**2,564**	**3,146**
Monthly Surplus/Deficit	**0**	**0**	**0**	**(82)**	**(150)**	**(697)**	**(1,123)**	**(601)**	**(593)**	**(107)**	**0**	**0**	**0**	**0**	**(91)**	**(52)**	**(305)**	**(783)**	**(1,188)**	**(654)**	**(686)**	**(263)**	**0**	**0**

2006 IRP Resources	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(350)**	**(776)**	**(253)**	**(246)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(435)**	**(841)**	**(306)**	**(339)**	**0**	**0**	**0**

2009 IRP DSM	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	51	51	51	51	52	51	51	51	52	51	51	52	59	58	59	58	59	58	58	58	59	58	59	59
Total New DSM Peak Reduction	51	51	51	51	52	362	362	108	52	51	51	52	59	58	59	58	59	369	369	115	59	58	59	59
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(414)**	**(146)**	**(194)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(66)**	**(472)**	**(191)**	**(280)**	**0**	**0**	**0**

2009 IRP Resources	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	2	2	0	0	3	10	0	0	0	0	0	1	2	2	0	0	3	10	0	0	0	0	0	1
2017 Boardman–Hemingway Transmission	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)																								
2022 Wind (100 MW)																								
2024 Large Aero (2 X 100 MW)																								
2025 Gateway West Transmission																								
2026 Large Aero (2 X 100 MW)																								
2027 Wind (2 X 200 MW)																								
2028 Large Aero (4 X 100 MW)																								
2029 Large Aero (5 X 100 MW)																								
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(47)**	**0**	**0**	**0**	**0**	**0**

Peak-Hour	2020												2021											
Load and Resource Balance	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**
Load Forecast (95th%)—w/EE DSM	(2,586)	(2,494)	(2,246)	(1,918)	(3,092)	(3,876)	(4,118)	(3,621)	(3,417)	(2,239)	(2,470)	(2,786)	(2,547)	(2,481)	(2,229)	(1,889)	(3,109)	(3,916)	(4,160)	(3,642)	(3,458)	(2,239)	(2,466)	(2,754)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,586)	(2,494)	(2,246)	(1,918)	(3,092)	(3,819)	(4,061)	(3,570)	(3,417)	(2,239)	(2,470)	(2,786)	(2,547)	(2,481)	(2,229)	(1,889)	(3,109)	(3,860)	(4,103)	(3,592)	(3,458)	(2,239)	(2,466)	(2,754)
Existing Resources																								
Coal (w/Curtailment)	977	977	513	237	575	977	977	977	671	314	802	977	977	977	605	237	485	935	977	977	673	314	592	977
Hydro (90th%)—HCC	925	965	700	585	1,181	1,035	1,005	945	1,035	505	600	785	1,064	845	700	585	1,178	1,035	1,050	945	1,035	690	600	870
Hydro (90th%)—Other	198	200	190	210	283	286	224	220	205	206	194	199	197	200	190	210	282	282	222	219	204	205	193	198
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro	1,123	1,165	890	795	1,463	1,321	1,229	1,165	1,240	711	794	984	1,261	1,045	890	795	1,461	1,317	1,272	1,164	1,239	895	793	1,068
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements																								
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements																								
Firm Pacific NW Import Capability	452	287	309	339	375	191	41	159	244	481	522	436	243	394	292	313	350	189	34	146	228	269	522	439
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**3,019**	**2,896**	**2,182**	**1,866**	**2,958**	**3,042**	**2,805**	**2,849**	**2,682**	**2,004**	**2,592**	**2,868**	**2,949**	**2,883**	**2,257**	**1,840**	**2,841**	**2,995**	**2,840**	**2,835**	**2,667**	**1,976**	**2,382**	**2,955**
Monthly Surplus/Deficit	**0**	**0**	**(64)**	**(53)**	**(134)**	**(777)**	**(1,256)**	**(721)**	**(736)**	**(235)**	**0**	**0**	**0**	**0**	**0**	**(50)**	**(268)**	**(865)**	**(1,263)**	**(757)**	**(791)**	**(262)**	**(84)**	**0**
2006 IRP Resources	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(429)**	**(908)**	**(373)**	**(388)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(518)**	**(915)**	**(409)**	**(444)**	**0**	**0**	**0**
2009 IRP DSM	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	66	66	66	66	66	66	66	66	66	66	66	66	73	73	73	73	74	73	73	73	73	73	73	73
Total New DSM Peak Reduction	66	66	66	66	66	376	376	122	66	66	66	66	73	73	73	73	74	383	383	129	73	73	73	73
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(53)**	**(532)**	**(251)**	**(323)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(134)**	**(532)**	**(280)**	**(371)**	**0**	**0**	**0**
2009 IRP Resources	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	2	2	0	0	3	10	0	0	0	0	0	1	2	2	0	0	3	10	0	0	0	0	0	1
2017 Boardman–Hemingway Transmission	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
2022 Wind (100 MW)																								
2024 Large Aero (2 X 100 MW)																								
2025 Gateway West Transmission																								
2026 Large Aero (2 X 100 MW)																								
2027 Wind (2 X 200 MW)																								
2028 Large Aero (4 X 100 MW)																								
2029 Large Aero (5 X 100 MW)																								
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(7)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(7)**	**0**	**0**	**0**	**0**	**0**

Peak-Hour	2022												2023											
Load and Resource Balance	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**
Load Forecast (95th%)—w/EE DSM	(2,543)	(2,477)	(2,232)	(1,886)	(3,131)	(3,961)	(4,210)	(3,685)	(3,500)	(2,245)	(2,474)	(2,763)	(2,535)	(2,470)	(2,230)	(1,878)	(3,153)	(4,006)	(4,261)	(3,726)	(3,540)	(2,249)	(2,479)	(2,751)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,543)	(2,477)	(2,232)	(1,886)	(3,131)	(3,904)	(4,154)	(3,634)	(3,500)	(2,245)	(2,474)	(2,763)	(2,535)	(2,470)	(2,230)	(1,878)	(3,153)	(3,949)	(4,205)	(3,675)	(3,540)	(2,249)	(2,479)	(2,751)
Existing Resources																								
Coal (w/Curtailment)	977	977	605	0	417	935	977	977	673	314	592	977	977	977	430	0	417	935	977	977	493	314	555	977
Hydro (90th%)—HCC	1,056	815	700	585	1,177	1,035	1,040	945	1,035	750	600	785	1,048	815	785	585	1,104	1,035	1,005	945	1,035	700	600	785
Hydro (90th%)—Other	197	199	189	210	282	279	217	218	204	204	193	198	196	198	188	209	281	277	214	218	203	204	192	197
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro	1,252	1,014	889	795	1,458	1,314	1,257	1,163	1,239	954	793	983	1,244	1,013	973	794	1,385	1,312	1,219	1,163	1,238	904	792	982
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements																								
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements																								
Firm Pacific NW Import Capability	248	445	296	311	345	185	28	142	222	216	522	439	248	433	210	303	341	176	23	142	217	270	521	439
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**2,945**	**2,902**	**2,260**	**1,600**	**2,766**	**2,988**	**2,820**	**2,830**	**2,660**	**1,982**	**2,380**	**2,870**	**2,937**	**2,890**	**2,083**	**1,592**	**2,687**	**2,977**	**2,776**	**2,830**	**2,474**	**1,986**	**2,342**	**2,868**
Monthly Surplus/Deficit	**0**	**0**	**0**	**(287)**	**(365)**	**(916)**	**(1,334)**	**(804)**	**(840)**	**(263)**	**(94)**	**0**	**0**	**0**	**(148)**	**(287)**	**(465)**	**(972)**	**(1,428)**	**(845)**	**(1,066)**	**(263)**	**(137)**	**0**

2006 IRP Resources	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**(17)**	**(569)**	**(987)**	**(456)**	**(492)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(118)**	**(625)**	**(1,081)**	**(498)**	**(719)**	**0**	**0**	**0**

2009 IRP DSM	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	81	80	80	80	81	80	80	80	80	80	80	80	88	87	87	88	88	88	87	88	88	88	88	88
Total New DSM Peak Reduction	81	80	80	80	81	391	390	137	80	80	80	80	88	87	87	88	88	398	398	144	88	88	88	88
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(178)**	**(596)**	**(320)**	**(412)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(30)**	**(227)**	**(683)**	**(354)**	**(631)**	**0**	**0**	**0**

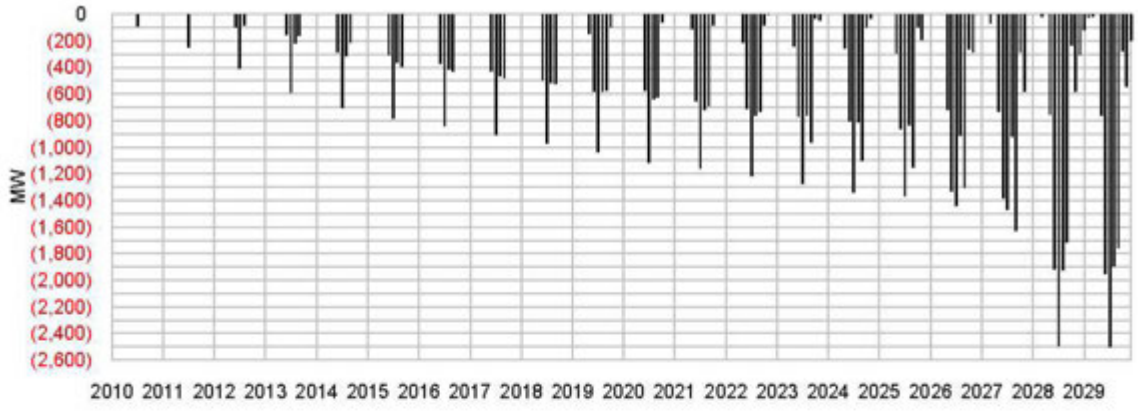
2009 IRP Resources	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**Oct-23**	**Nov-23**	**Dec-23**
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	2	2	0	0	3	10	0	0	0	0	0	1	2	2	0	0	3	10	0	0	0	0	0	1
2017 Boardman–Hemingway Transmission	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
2022 Wind (100 MW)	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
2024 Large Aero (2 X 100 MW)																								
2025 Gateway West Transmission																								
2026 Large Aero (2 X 100 MW)																								
2027 Wind (2 X 200 MW)																								
2028 Large Aero (4 X 100 MW)																								
2029 Large Aero (5 X 100 MW)																								
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(66)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(153)**	**0**	**(101)**	**0**	**0**	**0**

Peak-Hour	2024												2025											
Load and Resource Balance	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**
Load Forecast (95th%)—w/EE DSM	(2,467)	(2,454)	(2,193)	(1,830)	(3,164)	(4,039)	(4,290)	(3,728)	(3,580)	(2,244)	(2,461)	(2,688)	(2,471)	(2,430)	(2,201)	(1,835)	(3,186)	(4,084)	(4,341)	(3,776)	(3,622)	(2,251)	(2,471)	(2,710)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,467)	(2,454)	(2,193)	(1,830)	(3,164)	(3,983)	(4,234)	(3,678)	(3,580)	(2,244)	(2,461)	(2,688)	(2,471)	(2,430)	(2,201)	(1,835)	(3,186)	(4,027)	(4,284)	(3,726)	(3,622)	(2,251)	(2,471)	(2,710)
Existing Resources																								
Coal (w/Curtailment)	977	977	430	0	417	935	977	977	403	214	555	977	977	977	311	0	417	935	977	977	403	214	403	977
Hydro (90th%)—HCC	1,043	780	700	585	1,175	1,039	1,005	945	1,035	615	600	785	968	775	700	585	1,173	1,035	1,005	945	1,035	574	600	785
Hydro (90th%)—Other	195	198	188	209	281	275	212	217	202	204	191	197	195	197	187	208	280	266	211	216	201	203	190	196
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro	1,238	978	888	794	1,455	1,314	1,217	1,162	1,237	819	791	982	1,162	972	887	793	1,454	1,301	1,216	1,161	1,236	777	790	981
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements																								
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements																								
Firm Pacific NW Import Capability	186	470	258	255	336	172	19	133	209	366	519	445	266	431	267	261	327	169	13	137	205	466	520	443
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**2,869**	**2,891**	**2,046**	**1,544**	**2,754**	**2,974**	**2,771**	**2,820**	**2,375**	**1,897**	**2,339**	**2,874**	**2,873**	**2,847**	**1,935**	**1,549**	**2,743**	**2,959**	**2,763**	**2,823**	**2,370**	**1,955**	**2,188**	**2,872**
Monthly Surplus/Deficit	**0**	**0**	**(148)**	**(286)**	**(410)**	**(1,009)**	**(1,463)**	**(858)**	**(1,204)**	**(347)**	**(121)**	**0**	**0**	**0**	**(266)**	**(286)**	**(443)**	**(1,068)**	**(1,521)**	**(903)**	**(1,252)**	**(295)**	**(283)**	**0**
2006 IRP Resources	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**(63)**	**(661)**	**(1,115)**	**(510)**	**(857)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(95)**	**(721)**	**(1,173)**	**(556)**	**(904)**	**0**	**0**	**0**
2009 IRP DSM	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	95	95	95	95	95	95	95	95	96	95	95	96	103	103	103	103	103	103	103	103	103	103	104	103
Total New DSM Peak Reduction	95	95	95	95	95	406	406	152	96	95	95	96	103	103	103	103	103	413	413	159	103	103	104	103
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**(256)**	**(709)**	**(358)**	**(761)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(307)**	**(760)**	**(396)**	**(801)**	**0**	**0**	**0**
2009 IRP Resources	**Jan-24**	**Feb-24**	**Mar-24**	**Apr-24**	**May-24**	**Jun-24**	**Jul-24**	**Aug-24**	**Sep-24**	**Oct-24**	**Nov-24**	**Dec-24**	**Jan-25**	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	2	2	0	0	3	10	0	0	0	0	0	1	2	2	0	0	3	10	0	0	0	0	0	1
2017 Boardman–Hemingway Transmission	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
2022 Wind (100 MW)	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
2024 Large Aero (2 X 100 MW)	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
2025 Gateway West Transmission													100	100	100	100	100	100	100	100	100	100	100	100
2026 Large Aero (2 X 100 MW)																								
2027 Wind (2 X 200 MW)																								
2028 Large Aero (4 X 100 MW)																								
2029 Large Aero (5 X 100 MW)																								
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(31)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

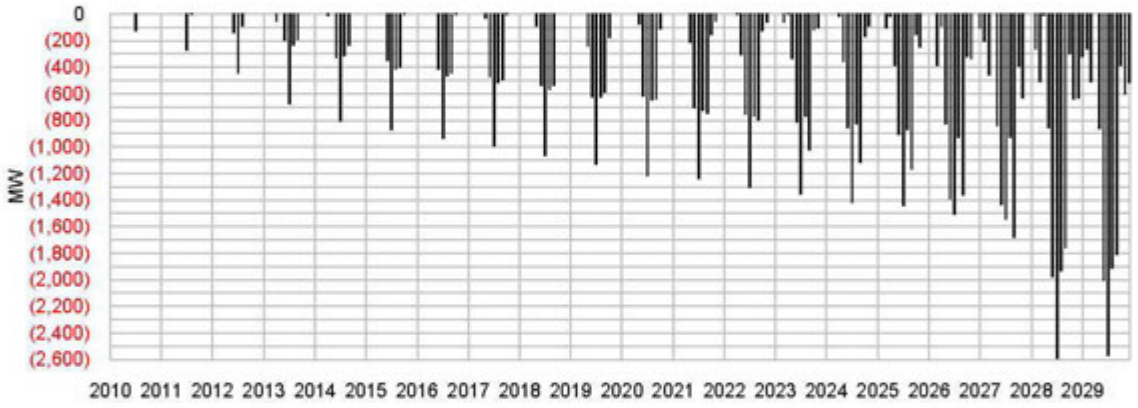
Peak-Hour	2026												2027											
Load and Resource Balance	**Jan-26**	**Feb-26**	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**	**Jan-27**	**Feb-27**	**Mar-27**	**Apr-27**	**May-27**	**Jun-27**	**Jul-27**	**Aug-27**	**Sep-27**	**Oct-27**	**Nov-27**	**Dec-27**
Load Forecast (95th%)—w/EE DSM	(2,460)	(2,421)	(2,199)	(1,828)	(3,206)	(4,129)	(4,393)	(3,818)	(3,664)	(2,254)	(2,475)	(2,702)	(2,393)	(2,382)	(2,168)	(1,783)	(3,216)	(4,163)	(4,424)	(3,825)	(3,703)	(2,247)	(2,460)	(2,639)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,460)	(2,421)	(2,199)	(1,828)	(3,206)	(4,072)	(4,336)	(3,768)	(3,664)	(2,254)	(2,475)	(2,702)	(2,393)	(2,382)	(2,168)	(1,783)	(3,216)	(4,106)	(4,367)	(3,774)	(3,703)	(2,247)	(2,460)	(2,639)
Existing Resources																								
Coal (w/Curtailment)	977	421	0	0	0	500	977	977	313	0	313	977	311	0	0	0	0	500	977	977	34	0	0	846
Hydro (90th%)—HCC	895	775	700	585	1,173	1,035	1,005	904	1,035	628	605	785	965	690	755	585	1,123	1,035	1,005	945	1,035	632	600	785
Hydro (90th%)—Other	194	196	186	208	280	261	208	214	201	202	190	195	193	196	186	208	280	241	208	213	200	202	189	195
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro	1,089	971	886	793	1,452	1,296	1,213	1,119	1,236	830	795	980	1,158	886	941	793	1,402	1,276	1,213	1,158	1,235	834	789	980
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements																								
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements																								
Firm Pacific NW Import Capability	329	412	389	131	329	172	6	125	187	364	522	444	193	504	180	210	327	165	2	126	183	343	523	449
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**2,863**	**2,271**	**1,745**	**1,419**	**2,326**	**2,521**	**2,754**	**2,769**	**2,262**	**1,693**	**2,104**	**2,872**	**2,130**	**1,856**	**1,591**	**1,498**	**2,274**	**2,494**	**2,750**	**2,810**	**1,979**	**1,675**	**1,786**	**2,745**
Monthly Surplus/Deficit	**0**	**(150)**	**(454)**	**(409)**	**(879)**	**(1,551)**	**(1,582)**	**(999)**	**(1,402)**	**(561)**	**(371)**	**0**	**(263)**	**(526)**	**(577)**	**(285)**	**(942)**	**(1,613)**	**(1,618)**	**(965)**	**(1,724)**	**(572)**	**(674)**	**0**
2006 IRP Resources	**Jan-26**	**Feb-26**	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**	**Jan-27**	**Feb-27**	**Mar-27**	**Apr-27**	**May-27**	**Jun-27**	**Jul-27**	**Aug-27**	**Sep-27**	**Oct-27**	**Nov-27**	**Dec-27**
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Remaining Monthly Surplus/Deficit	**0**	**0**	**(107)**	**(62)**	**(532)**	**(1,203)**	**(1,235)**	**(651)**	**(1,055)**	**(214)**	**(24)**	**0**	**0**	**(178)**	**(230)**	**0**	**(594)**	**(1,265)**	**(1,270)**	**(617)**	**(1,376)**	**(224)**	**(326)**	**0**
2009 IRP DSM	**Jan-26**	**Feb-26**	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**	**Jan-27**	**Feb-27**	**Mar-27**	**Apr-27**	**May-27**	**Jun-27**	**Jul-27**	**Aug-27**	**Sep-27**	**Oct-27**	**Nov-27**	**Dec-27**
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	111	111	111	111	112	111	111	111	111	110	112	111	119	119	118	118	120	119	119	119	119	119	119	119
Total New DSM Peak Reduction	111	111	111	111	112	421	421	167	111	110	112	111	119	119	118	118	120	429	429	175	119	119	119	119
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**(420)**	**(782)**	**(813)**	**(484)**	**(944)**	**(103)**	**0**	**0**	**0**	**(59)**	**(111)**	**0**	**(474)**	**(836)**	**(841)**	**(442)**	**(1,257)**	**(105)**	**(207)**	**0**
2009 IRP Resources	**Jan-26**	**Feb-26**	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**	**Jan-27**	**Feb-27**	**Mar-27**	**Apr-27**	**May-27**	**Jun-27**	**Jul-27**	**Aug-27**	**Sep-27**	**Oct-27**	**Nov-27**	**Dec-27**
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	2	2	0	0	3	10	0	0	0	0	0	1	2	2	0	0	3	10	0	0	0	0	0	1
2017 Boardman–Hemingway Transmission	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
2022 Wind (100 MW)	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
2024 Large Aero (2 X 100 MW)	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
2025 Gateway West Transmission	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
2026 Large Aero (2 X 100 MW)	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
2027 Wind (2 X 200 MW)													20	20	20	20	20	20	20	20	20	20	20	20
2028 Large Aero (4 X 100 MW)																								
2029 Large Aero (5 X 100 MW)																								
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(207)**	**0**	**0**	**0**

Peak-Hour	2028												2029											
Load and Resource Balance	**Jan-28**	**Feb-28**	**Mar-28**	**Apr-28**	**May-28**	**Jun-28**	**Jul-28**	**Aug-28**	**Sep-28**	**Oct-28**	**Nov-28**	**Dec-28**	**Jan-29**	**Feb-29**	**Mar-29**	**Apr-29**	**May-29**	**Jun-29**	**Jul-29**	**Aug-29**	**Sep-29**	**Oct-29**	**Nov-29**	**Dec-29**
Load Forecast (95th%)—w/EE DSM	(2,354)	(2,345)	(2,152)	(1,756)	(3,231)	(4,199)	(4,460)	(3,846)	(3,743)	(2,245)	(2,454)	(2,595)	(2,248)	(2,296)	(2,100)	(1,687)	(3,234)	(4,225)	(4,475)	(3,828)	(3,780)	(2,234)	(2,424)	(2,493)
Existing DSM (Irrigation Timer)	0	0	0	0	0	6	6	0	0	0	0	0	0	0	0	0	0	6	6	0	0	0	0	0
Existing DSM (AC Cool Credit)	0	0	0	0	0	51	51	51	0	0	0	0	0	0	0	0	0	51	51	51	0	0	0	0
Total Existing Demand Response	0	0	0	0	0	57	57	51	0	0	0	0	0	0	0	0	0	57	57	51	0	0	0	0
Peak-Hour Load Forecast w/Existing DSM	(2,354)	(2,345)	(2,152)	(1,756)	(3,231)	(4,143)	(4,403)	(3,795)	(3,743)	(2,245)	(2,454)	(2,595)	(2,248)	(2,296)	(2,100)	(1,687)	(3,234)	(4,169)	(4,419)	(3,778)	(3,780)	(2,234)	(2,424)	(2,493)
Existing Resources																								
Coal (w/Curtailment)	563	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro (90th%)—HCC	962	775	700	575	1,171	1,035	1,005	860	1,035	571	600	785	893	775	700	575	1,170	1,035	1,005	945	1,035	625	600	785
Hydro (90th%)—Other	193	195	185	207	279	239	206	211	200	201	189	194	197	199	184	207	279	237	206	210	199	201	188	193
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro	1,155	970	885	782	1,450	1,274	1,211	1,071	1,235	772	789	979	1,090	974	884	782	1,449	1,272	1,211	1,155	1,234	826	788	978
CSPP (PURPA)	52	51	54	79	129	138	141	132	110	82	58	55	52	51	54	79	129	138	141	132	110	82	58	55
Power Purchase Agreements																								
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
PPL Montana—Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
East Side Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements																								
Firm Pacific NW Import Capability	157	333	220	195	324	163	0	120	176	462	518	454	117	280	169	135	321	159	0	129	170	333	526	463
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416
Subtotal	**2,343**	**1,770**	**1,575**	**1,472**	**2,319**	**1,991**	**1,769**	**1,739**	**1,936**	**1,733**	**1,781**	**1,904**	**1,675**	**1,721**	**1,523**	**1,412**	**2,315**	**1,985**	**1,768**	**1,832**	**1,931**	**1,657**	**1,788**	**1,912**
Monthly Surplus/Deficit	**(11)**	**(576)**	**(577)**	**(284)**	**(912)**	**(2,152)**	**(2,634)**	**(2,056)**	**(1,806)**	**(512)**	**(673)**	**(691)**	**(573)**	**(575)**	**(577)**	**(276)**	**(919)**	**(2,184)**	**(2,651)**	**(1,946)**	**(1,850)**	**(576)**	**(636)**	**(581)**
2006 IRP Resources	**Jan-28**	**Feb-28**	**Mar-28**	**Apr-28**	**May-28**	**Jun-28**	**Jul-28**	**Aug-28**	**Sep-28**	**Oct-28**	**Nov-28**	**Dec-28**	**Jan-29**	**Feb-29**	**Mar-29**	**Apr-29**	**May-29**	**Jun-29**	**Jul-29**	**Aug-29**	**Sep-29**	**Oct-29**	**Nov-29**	**Dec-29**
2012 Wind RFP	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Geothermal	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Remaining Monthly Surplus/Deficit	**0**	**(228)**	**(229)**	**0**	**(565)**	**(1,804)**	**(2,287)**	**(1,709)**	**(1,459)**	**(165)**	**(325)**	**(344)**	**(225)**	**(228)**	**(229)**	**0**	**(572)**	**(1,836)**	**(2,303)**	**(1,598)**	**(1,502)**	**(229)**	**(288)**	**(233)**
2009 IRP DSM	**Jan-28**	**Feb-28**	**Mar-28**	**Apr-28**	**May-28**	**Jun-28**	**Jul-28**	**Aug-28**	**Sep-28**	**Oct-28**	**Nov-28**	**Dec-28**	**Jan-29**	**Feb-29**	**Mar-29**	**Apr-29**	**May-29**	**Jun-29**	**Jul-29**	**Aug-29**	**Sep-29**	**Oct-29**	**Nov-29**	**Dec-29**
Commercial (FlexPeak)	0	0	0	0	0	57	57	57	0	0	0	0	0	0	0	0	0	57	57	57	0	0	0	0
Irrigation Peak Rewards	0	0	0	0	0	254	254	0	0	0	0	0	0	0	0	0	0	254	254	0	0	0	0	0
Energy Efficiency Peak Reduction	128	127	127	127	128	127	127	127	127	127	127	128	127	127	127	127	128	127	127	127	128	127	127	128
Total New DSM Peak Reduction	128	127	127	127	128	438	438	184	127	127	127	128	127	127	127	127	128	438	438	184	128	127	127	128
Remaining Monthly Surplus/Deficit	**0**	**(101)**	**(103)**	**0**	**(437)**	**(1,366)**	**(1,849)**	**(1,525)**	**(1,331)**	**(38)**	**(198)**	**(216)**	**(98)**	**(101)**	**(103)**	**0**	**(444)**	**(1,398)**	**(1,866)**	**(1,415)**	**(1,374)**	**(102)**	**(161)**	**(106)**
2009 IRP Resources	**Jan-28**	**Feb-28**	**Mar-28**	**Apr-28**	**May-28**	**Jun-28**	**Jul-28**	**Aug-28**	**Sep-28**	**Oct-28**	**Nov-28**	**Dec-28**	**Jan-29**	**Feb-29**	**Mar-29**	**Apr-29**	**May-29**	**Jun-29**	**Jul-29**	**Aug-29**	**Sep-29**	**Oct-29**	**Nov-29**	**Dec-29**
2015 Boardman–Hemingway Transmission	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
2015 Shoshone Falls Upgrade (49 MW)	2	2	0	0	3	10	0	0	0	0	0	1	2	2	0	0	3	10	0	0	0	0	0	1
2017 Boardman–Hemingway Transmission	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175	175
2020 Large Aero (100 MW)	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
2022 Wind (100 MW)	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
2024 Large Aero (2 X 100 MW)	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
2025 Gateway West Transmission	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
2026 Large Aero (2 X 100 MW)	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
2027 Wind (2 X 200 MW)	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
2028 Large Aero (4 X 100 MW)	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
2029 Large Aero (5 X 100 MW)													500	500	500	500	500	500	500	500	500	500	500	500
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**(399)**	**(75)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

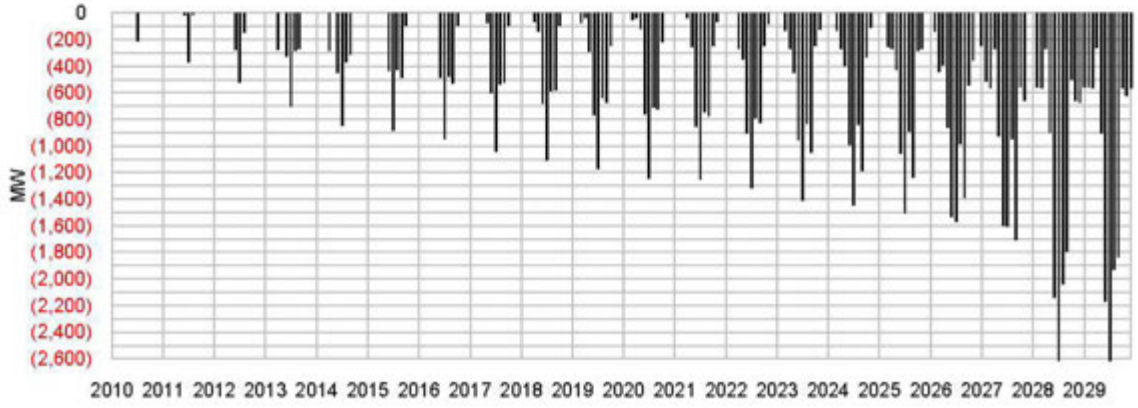
Peak Hour Deficits with Existing Resources
(50th Percentile Water and 90th Percentile Load)



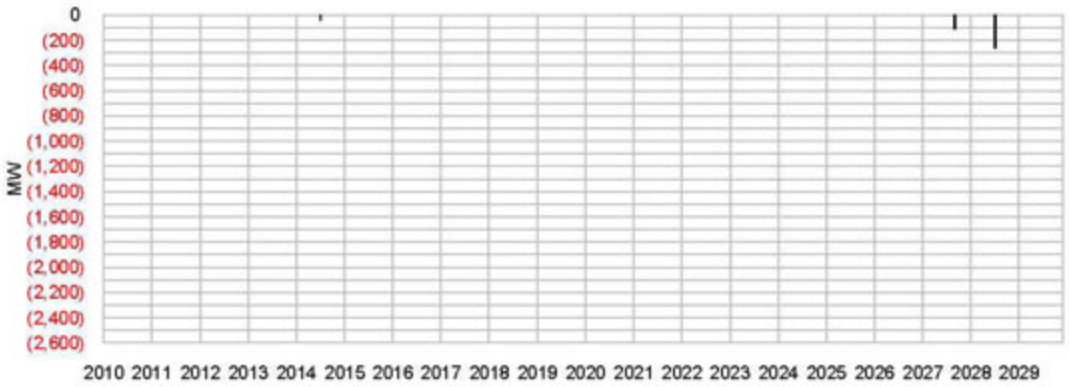
Peak Hour Deficits with Existing Resources
(70th Percentile Water and 95th Percentile Load)



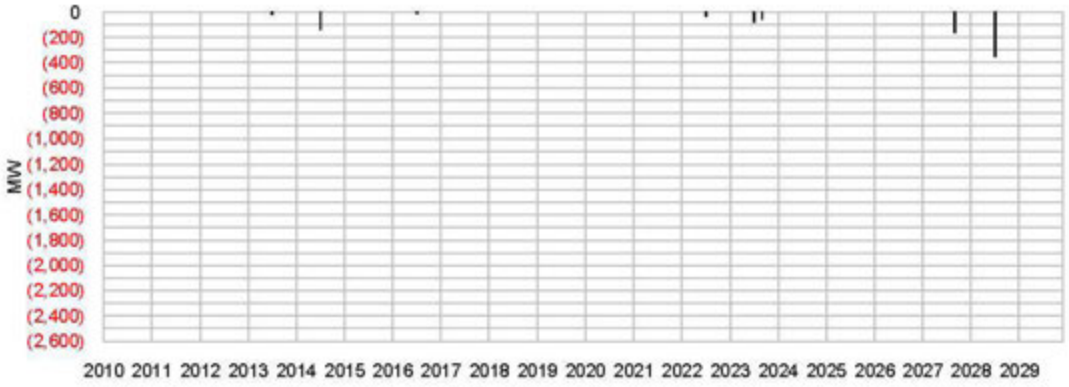
Peak Hour Deficits with Existing Resources
(90th Percentile Water and 95th Percentile Load)



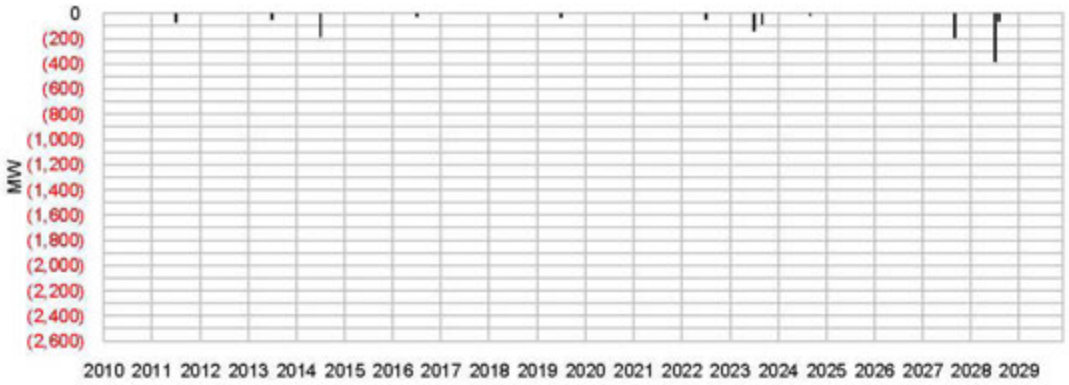
Peak Hour Deficits with 2009 IRP Resources
(50th Percentile Water and 90th Percentile Load)



Peak Hour Deficits with 2009 IRP Resources
(70th Percentile Water and 95th Percentile Load)



Peak Hour Deficits with Existing Resources
(90th Percentile Water and 95th Percentile Load)



2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

50th Percentile Water, 50th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2010	HCC	290.8	405.9	352.8	427.6	424.6	352.3	250.0	179.7	225.7	191.8	152.2	250.8	291.1
OXBOW	2010	HCC	118.0	169.0	154.4	185.9	173.0	143.8	106.1	78.9	101.9	88.6	69.3	105.6	124.2
HELLS CANYON	2010	HCC	232.4	335.5	311.2	375.4	356.1	292.1	210.3	155.4	199.1	174.8	138.0	209.3	248.4
1000 SPRINGS	2010	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2010	ROR	24.1	26.5	23.6	57.7	80.4	86.4	79.2	60.2	36.4	16.8	0.0	19.9	42.7
BLISS	2010	ROR	49.7	52.2	45.5	52.0	49.6	43.3	37.5	35.4	38.9	40.6	39.8	48.9	44.4
C.J. STRIKE	2010	ROR	67.0	68.6	60.2	68.7	65.8	53.6	41.0	39.3	46.8	51.9	52.7	64.2	56.6
CASCADE	2010	ROR	1.5	2.6	4.7	7.6	7.3	11.8	6.9	10.1	9.1	2.7	2.2	1.5	5.7
CLEAR LAKE	2010	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2010	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2010	ROR	35.9	37.2	30.2	35.7	34.3	29.2	24.6	22.4	24.9	26.3	25.3	34.4	30.0
MILNER	2010	ROR	42.4	45.2	28.4	41.0	34.5	17.6	9.4	0.0	0.0	0.0	5.0	36.7	21.6
SHOSHONE FALLS	2010	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	10.4	10.5	11.3	12.0	12.0	11.7
SWAN FALLS	2010	ROR	21.5	22.0	19.7	22.1	21.1	17.5	14.1	13.3	15.2	16.7	17.1	20.8	18.4
TWIN FALLS	2010	ROR	42.4	44.3	28.9	40.8	35.3	21.9	14.0	6.6	6.6	7.3	9.5	37.3	24.5
UPPER MALAD	2010	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2010	ROR	19.1	18.8	13.7	19.1	19.1	18.8	15.3	13.8	15.4	16.4	15.6	19.1	17.0
UPPER SALMON 3&4	2010	ROR	17.7	17.7	16.5	16.8	17.4	17.3	14.3	13.0	14.4	15.2	14.6	17.7	16.0
HCC TOTAL			**641.2**	**910.4**	**818.4**	**988.9**	**953.7**	**788.2**	**566.4**	**414.0**	**526.6**	**455.2**	**359.5**	**565.7**	**663.7**
ROR TOTAL			**360.5**	**374.8**	**311.1**	**401.3**	**403.7**	**355.3**	**295.0**	**251.9**	**246.6**	**233.4**	**221.3**	**339.8**	**315.9**
TOTAL			**1001.7**	**1285.2**	**1129.5**	**1390.2**	**1357.3**	**1143.5**	**861.4**	**665.9**	**773.2**	**688.6**	**580.8**	**905.5**	**979.5**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2011	HCC	290.8	405.7	352.7	427.5	424.5	352.2	249.9	179.6	225.3	192.1	152.0	250.7	291.0
OXBOW	2011	HCC	118.0	169.0	154.3	185.9	173.0	143.8	106.0	78.9	101.7	88.7	69.2	105.5	124.1
HELLS CANYON	2011	HCC	232.3	335.4	311.1	375.3	356.1	292.1	210.2	155.2	198.7	175.0	137.9	209.3	248.3
1000 SPRINGS	2011	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2011	ROR	23.9	26.4	23.3	57.5	79.8	85.9	78.7	59.9	36.3	16.7	0.0	19.8	42.4
BLISS	2011	ROR	49.7	52.1	45.5	52.0	49.6	43.2	37.4	35.4	38.9	40.6	39.8	48.9	44.4
C.J. STRIKE	2011	ROR	67.0	68.5	60.2	68.7	65.7	53.6	40.9	39.2	46.7	51.8	52.7	64.1	56.5
CASCADE	2011	ROR	1.5	2.6	4.7	7.6	7.3	11.8	6.9	10.1	9.1	2.7	2.2	1.5	5.7
CLEAR LAKE	2011	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2011	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2011	ROR	35.9	37.2	30.2	35.7	34.3	29.2	24.6	22.4	24.9	26.3	25.3	34.4	30.0
MILNER	2011	ROR	42.3	45.2	28.4	41.0	34.5	17.6	9.4	0.0	0.0	0.0	5.0	36.7	21.5
SHOSHONE FALLS	2011	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	10.4	10.4	11.3	12.0	12.0	11.7
SWAN FALLS	2011	ROR	21.5	22.0	19.7	22.1	21.1	17.5	14.0	13.2	15.2	16.7	17.1	20.7	18.4
TWIN FALLS	2011	ROR	42.4	44.3	28.9	40.8	35.3	21.9	14.0	6.6	6.6	7.3	9.5	37.3	24.5
UPPER MALAD	2011	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2011	ROR	19.1	18.8	13.7	19.1	19.1	18.8	15.3	13.8	15.4	16.4	15.6	19.1	17.0
UPPER SALMON 3&4	2011	ROR	17.7	17.7	16.5	16.8	17.4	17.3	14.2	13.0	14.4	15.2	14.5	17.7	16.0
HCC TOTAL			**641.1**	**910.1**	**818.1**	**988.7**	**953.5**	**788.1**	**566.1**	**413.7**	**525.7**	**455.8**	**359.1**	**565.5**	**663.4**
ROR TOTAL			**360.2**	**374.5**	**310.8**	**401.1**	**403.0**	**354.7**	**294.1**	**251.4**	**246.3**	**233.2**	**221.2**	**339.5**	**315.5**
TOTAL			**1001.3**	**1284.6**	**1128.9**	**1389.8**	**1356.5**	**1142.8**	**860.2**	**665.1**	**771.9**	**689.0**	**580.3**	**905.0**	**978.9**

2009 Integrated Resource Plan
Average Megawatt Hydro Output from PDR580
50th Percentile Water, 50th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2012	HCC	290.7	405.7	352.6	427.4	424.4	352.1	249.8	179.5	225.0	192.3	152.0	250.6	291.2
OXBOW	2012	HCC	118.0	169.0	154.3	185.8	173.0	143.7	106.0	78.9	101.5	88.8	69.2	105.5	124.2
HELLS CANYON	2012	HCC	232.2	335.4	311.1	375.3	356.0	292.0	210.2	155.2	198.4	175.1	137.9	209.2	248.5
1000 SPRINGS	2012	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2012	ROR	23.9	26.3	21.9	57.4	79.6	85.4	78.3	59.4	35.9	16.6	0.0	19.7	42.1
BLISS	2012	ROR	49.7	52.1	45.5	51.9	49.6	43.2	37.4	35.4	38.9	40.5	39.8	48.9	44.4
C.J. STRIKE	2012	ROR	67.0	68.5	60.2	68.6	65.7	53.5	40.9	39.2	46.7	51.8	52.6	64.1	56.5
CASCADE	2012	ROR	1.5	2.6	4.7	7.6	7.3	11.8	6.9	10.1	9.1	2.7	2.2	1.5	5.7
CLEAR LAKE	2012	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2012	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2012	ROR	35.9	37.2	30.2	35.7	34.2	29.2	24.5	22.4	24.8	26.3	25.3	34.3	30.0
MILNER	2012	ROR	42.3	45.2	28.4	41.0	34.5	17.6	9.4	0.0	0.0	0.0	5.0	36.7	21.6
SHOSHONE FALLS	2012	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	10.4	10.4	11.2	12.0	12.0	11.7
SWAN FALLS	2012	ROR	21.5	22.0	19.7	22.1	21.1	17.5	14.0	13.2	15.2	16.7	17.1	20.5	18.4
TWIN FALLS	2012	ROR	42.4	44.3	28.9	40.8	35.3	21.9	14.0	6.6	6.6	7.3	9.5	37.3	24.5
UPPER MALAD	2012	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2012	ROR	19.1	18.8	13.7	19.1	19.1	18.8	15.2	13.7	15.4	16.4	15.6	19.1	17.0
UPPER SALMON 3&4	2012	ROR	17.7	17.7	16.5	16.8	17.4	17.3	14.2	13.0	14.4	15.2	14.5	17.7	16.0
HCC TOTAL			**640.9**	**910.1**	**818.0**	**988.5**	**953.3**	**787.8**	**566.0**	**413.6**	**524.9**	**456.2**	**359.1**	**565.3**	**664.0**
ROR TOTAL			**360.2**	**374.4**	**309.4**	**400.8**	**402.7**	**354.1**	**293.5**	**250.8**	**245.8**	**232.9**	**221.1**	**339.1**	**315.2**
TOTAL			**1001.1**	**1284.5**	**1127.4**	**1389.3**	**1355.9**	**1141.9**	**859.5**	**664.4**	**770.7**	**689.1**	**580.2**	**904.4**	**979.2**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2013	HCC	290.5	405.6	352.5	427.3	424.3	352.0	249.7	179.4	225.0	192.0	152.2	250.5	290.8
OXBOW	2013	HCC	117.9	168.9	154.2	185.8	172.9	143.7	105.9	78.8	101.5	88.6	69.3	105.4	124.0
HELLS CANYON	2013	HCC	232.1	335.3	311.0	375.2	355.9	291.9	210.0	155.1	198.3	174.8	138.1	209.1	248.2
1000 SPRINGS	2013	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2013	ROR	23.8	26.3	21.8	57.3	79.3	84.9	78.0	59.2	35.6	16.6	0.0	19.6	42.0
BLISS	2013	ROR	49.7	52.1	45.5	51.9	49.6	43.2	37.3	35.4	38.9	40.5	39.8	48.8	44.3
C.J. STRIKE	2013	ROR	66.9	68.5	60.2	68.6	65.7	53.5	40.8	39.2	46.7	51.7	52.6	64.1	56.5
CASCADE	2013	ROR	1.5	2.6	4.7	7.6	7.3	11.8	6.9	10.1	9.1	2.7	2.2	1.5	5.7
CLEAR LAKE	2013	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2013	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2013	ROR	35.8	37.2	30.2	35.6	34.2	29.1	24.5	22.3	24.8	26.3	25.2	34.3	29.9
MILNER	2013	ROR	42.2	45.2	28.4	41.0	34.5	17.6	9.4	0.0	0.0	0.0	5.0	36.7	21.5
SHOSHONE FALLS	2013	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	10.4	10.4	11.2	12.0	12.0	11.7
SWAN FALLS	2013	ROR	21.5	22.0	19.7	22.1	21.1	17.5	14.0	13.2	15.2	16.7	17.1	20.5	18.4
TWIN FALLS	2013	ROR	42.4	44.3	28.9	40.8	35.3	21.9	14.0	6.6	6.6	7.3	9.5	37.3	24.5
UPPER MALAD	2013	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2013	ROR	19.1	18.8	13.7	19.1	19.1	18.8	15.2	13.7	15.4	16.3	15.6	19.1	17.0
UPPER SALMON 3&4	2013	ROR	17.7	17.7	16.5	16.8	17.4	17.3	14.2	12.9	14.4	15.2	14.5	17.7	16.0
HCC TOTAL			**640.5**	**909.8**	**817.7**	**988.3**	**953.0**	**787.6**	**565.6**	**413.3**	**524.8**	**455.4**	**359.6**	**565.0**	**663.0**
ROR TOTAL			**359.8**	**374.4**	**309.3**	**400.6**	**402.4**	**353.5**	**293.0**	**250.4**	**245.5**	**232.7**	**221.0**	**338.9**	**314.7**
TOTAL			**1000.3**	**1284.2**	**1127.0**	**1388.9**	**1355.4**	**1141.1**	**858.6**	**663.7**	**770.2**	**688.1**	**580.6**	**903.9**	**977.8**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

50th Percentile Water, 50th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2014	HCC	281.9	405.0	352.0	426.8	423.7	351.4	235.7	178.9	224.0	192.4	152.1	250.0	288.5
OXBOW	2014	HCC	117.7	168.7	154.0	185.6	172.7	143.5	100.0	78.6	101.0	88.8	69.2	105.2	123.4
HELLS CANYON	2014	HCC	233.5	334.9	310.6	374.8	355.5	291.5	198.5	154.7	197.3	175.1	137.9	208.7	247.0
1000 SPRINGS	2014	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2014	ROR	23.4	26.0	21.5	57.2	78.9	83.6	71.1	56.5	34.1	16.2	0.0	19.0	40.7
BLISS	2014	ROR	49.8	52.0	45.3	51.8	49.5	43.0	33.7	35.2	38.7	40.4	39.6	48.7	43.9
C.J. STRIKE	2014	ROR	66.8	68.3	60.2	68.4	65.5	53.3	36.1	39.0	46.5	51.6	52.4	63.8	55.9
CASCADE	2014	ROR	1.5	2.6	4.7	7.6	7.3	11.8	6.9	10.1	9.1	2.7	2.2	1.5	5.7
CLEAR LAKE	2014	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2014	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2014	ROR	35.7	37.1	30.2	35.5	34.1	29.0	21.3	22.2	24.7	26.2	25.1	34.2	29.6
MILNER	2014	ROR	42.0	45.2	28.4	41.0	34.5	17.6	0.0	0.0	0.0	0.0	5.0	35.5	20.6
SHOSHONE FALLS	2014	ROR	12.0	12.0	12.0	12.0	12.0	12.0	10.0	10.4	10.4	11.2	12.0	12.0	11.5
SWAN FALLS	2014	ROR	21.4	21.9	19.6	22.0	21.0	17.5	12.6	13.2	15.2	16.5	17.1	20.4	18.2
TWIN FALLS	2014	ROR	42.2	44.3	28.9	40.8	35.3	21.9	6.2	6.5	6.6	7.3	9.5	36.6	23.7
UPPER MALAD	2014	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2014	ROR	19.1	18.8	13.7	19.1	19.1	18.7	12.8	13.7	15.3	16.3	15.5	19.1	16.7
UPPER SALMON 3&4	2014	ROR	17.7	17.7	16.5	16.8	17.4	17.2	12.1	12.9	14.3	15.1	14.5	17.7	15.8
HCC TOTAL			**633.1**	**908.6**	**816.6**	**987.2**	**951.9**	**786.4**	**534.2**	**412.2**	**522.2**	**456.3**	**359.2**	**563.9**	**658.9**
ROR TOTAL			**358.8**	**373.6**	**308.7**	**400.0**	**401.5**	**351.5**	**249.5**	**247.1**	**243.3**	**231.7**	**220.4**	**335.8**	**309.7**
TOTAL			**991.9**	**1282.2**	**1125.3**	**1387.2**	**1353.3**	**1137.9**	**783.7**	**659.3**	**765.5**	**688.0**	**579.6**	**899.7**	**968.6**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2015	HCC	281.4	404.5	351.5	426.3	423.2	350.9	235.2	178.5	219.0	192.5	152.3	249.4	287.8
OXBOW	2015	HCC	117.5	168.5	153.8	185.4	172.5	143.3	99.8	78.4	100.5	88.7	69.3	105.0	123.2
HELLS CANYON	2015	HCC	233.1	334.5	310.1	374.4	355.1	291.1	198.1	154.3	197.2	175.0	138.0	208.2	246.7
1000 SPRINGS	2015	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2015	ROR	23.1	25.9	21.3	57.6	78.3	82.3	68.7	53.6	33.5	16.2	0.0	17.5	39.9
BLISS	2015	ROR	49.8	51.9	45.2	51.7	49.3	42.9	33.5	35.1	38.6	40.3	39.5	48.4	43.8
C.J. STRIKE	2015	ROR	66.6	68.1	60.2	68.3	65.3	53.2	35.9	38.8	46.3	51.4	52.3	62.5	55.6
CASCADE	2015	ROR	1.5	2.6	4.7	7.6	7.3	11.8	6.9	10.1	9.1	2.7	2.2	1.5	5.7
CLEAR LAKE	2015	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2015	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2015	ROR	35.6	37.0	30.2	35.4	34.0	28.9	21.2	22.1	24.6	26.1	25.0	33.6	29.4
MILNER	2015	ROR	41.7	45.2	28.4	41.0	34.5	17.6	0.0	0.0	0.0	0.0	5.0	34.0	20.5
SHOSHONE FALLS	2015	ROR	12.0	12.0	12.0	12.0	12.0	12.0	10.0	10.3	10.4	11.1	12.0	12.0	11.5
SWAN FALLS	2015	ROR	21.4	21.9	19.6	21.9	21.0	17.5	12.5	13.1	15.1	16.4	17.0	20.3	18.1
TWIN FALLS	2015	ROR	42.0	44.2	28.9	40.7	35.3	21.8	6.2	6.5	6.5	7.2	9.5	34.9	23.5
UPPER MALAD	2015	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2015	ROR	19.1	18.8	13.7	19.1	19.1	18.6	12.7	13.6	15.2	16.2	15.4	19.1	16.7
UPPER SALMON 3&4	2015	ROR	17.7	17.7	16.5	16.8	17.4	17.2	12.0	12.8	14.2	15.1	14.4	17.7	15.8
HCC TOTAL			**632.0**	**907.5**	**815.4**	**986.1**	**950.7**	**785.3**	**533.1**	**411.2**	**516.7**	**456.2**	**359.6**	**562.6**	**657.6**
ROR TOTAL			**357.7**	**373.0**	**308.4**	**399.9**	**400.4**	**349.7**	**246.3**	**243.4**	**241.9**	**230.9**	**219.8**	**328.8**	**307.9**
TOTAL			**989.7**	**1280.5**	**1123.8**	**1386.0**	**1351.1**	**1135.0**	**779.4**	**654.6**	**758.6**	**687.1**	**579.4**	**891.4**	**965.5**

2009 Integrated Resource Plan
Average Megawatt Hydro Output from PDR580
50th Percentile Water, 50th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2016	HCC	280.9	404.0	351.0	425.8	422.7	350.4	234.7	170.8	217.8	192.5	152.5	248.9	287.0
OXBOW	2016	HCC	117.3	168.3	153.6	185.2	172.3	143.1	99.6	78.2	99.9	88.6	69.4	104.8	123.1
HELLS CANYON	2016	HCC	232.7	334.0	309.7	374.0	354.7	290.7	197.7	153.4	196.0	174.8	138.2	207.8	246.5
1000 SPRINGS	2016	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2016	ROR	22.8	25.9	20.7	57.2	77.5	81.6	67.8	52.2	33.4	16.2	0.0	17.6	39.4
BLISS	2016	ROR	49.9	51.7	45.1	51.6	49.2	42.8	33.5	35.0	38.5	40.1	39.4	48.2	43.7
C.J. STRIKE	2016	ROR	66.0	67.9	60.2	68.1	65.1	53.0	35.7	38.7	46.1	51.2	52.1	62.3	55.5
CASCADE	2016	ROR	1.5	2.6	4.7	7.6	7.3	11.8	6.9	10.1	9.1	2.7	2.2	1.5	5.7
CLEAR LAKE	2016	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2016	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2016	ROR	35.5	36.9	30.2	35.3	33.9	28.8	21.1	22.0	24.5	26.0	24.9	33.5	29.4
MILNER	2016	ROR	41.6	45.2	28.4	41.0	34.5	17.6	0.0	0.0	0.0	0.0	5.0	34.0	20.5
SHOSHONE FALLS	2016	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.9	10.3	10.3	11.1	12.0	12.0	11.5
SWAN FALLS	2016	ROR	21.3	21.8	19.5	21.9	21.0	17.5	12.5	13.1	15.1	16.4	17.0	20.1	18.1
TWIN FALLS	2016	ROR	41.4	44.2	28.9	40.7	35.2	21.8	6.1	6.4	6.5	7.2	9.5	34.9	23.5
UPPER MALAD	2016	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2016	ROR	19.1	18.8	13.7	19.1	19.1	18.6	12.6	13.5	15.2	16.1	15.3	19.1	16.7
UPPER SALMON 3&4	2016	ROR	17.7	17.7	16.5	16.8	17.4	17.1	12.0	12.7	14.2	15.0	14.3	17.7	15.7
HCC TOTAL			**630.9**	**906.3**	**814.3**	**985.0**	**949.6**	**784.2**	**532.0**	**402.4**	**513.7**	**455.9**	**360.1**	**561.5**	**656.6**
ROR TOTAL			**356.0**	**372.4**	**307.6**	**399.1**	**399.1**	**348.5**	**244.8**	**241.4**	**241.3**	**230.2**	**219.2**	**328.2**	**307.0**
TOTAL			**986.9**	**1278.7**	**1121.9**	**1384.1**	**1348.7**	**1132.7**	**776.8**	**643.8**	**754.9**	**686.1**	**579.3**	**889.7**	**963.6**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2017	HCC	280.3	403.5	350.5	425.3	422.2	349.9	234.2	170.2	216.4	192.8	152.3	248.9	286.3
OXBOW	2017	HCC	117.0	168.1	153.4	184.9	172.1	142.8	99.3	77.9	99.2	88.7	69.3	104.7	122.7
HELLS CANYON	2017	HCC	232.2	333.7	309.3	373.5	354.3	290.3	197.3	152.9	194.6	174.9	138.0	207.7	245.8
1000 SPRINGS	2017	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2017	ROR	22.8	25.9	20.6	57.7	76.8	81.3	67.6	52.0	33.4	16.3	4.4	17.5	39.8
BLISS	2017	ROR	49.9	51.6	45.0	51.4	49.1	42.7	33.4	34.9	38.4	40.0	39.2	48.1	43.6
C.J. STRIKE	2017	ROR	65.9	67.8	60.2	67.9	65.0	52.8	35.5	38.5	46.0	51.1	51.9	62.1	55.3
CASCADE	2017	ROR	1.5	2.6	4.7	7.6	7.3	11.8	6.9	10.1	9.1	2.7	2.2	1.5	5.7
CLEAR LAKE	2017	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2017	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2017	ROR	35.4	36.8	30.1	35.2	33.8	28.7	21.0	21.9	24.4	25.9	24.8	33.4	29.2
MILNER	2017	ROR	41.6	45.2	28.4	41.0	34.5	17.6	0.0	0.0	0.0	0.0	5.0	34.0	20.5
SHOSHONE FALLS	2017	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.9	10.2	10.3	11.1	12.0	12.0	11.5
SWAN FALLS	2017	ROR	21.3	21.8	19.5	21.8	20.9	17.5	12.4	13.0	15.0	16.3	16.9	20.0	18.0
TWIN FALLS	2017	ROR	41.4	44.2	28.9	40.7	35.2	21.8	6.1	6.4	6.4	7.2	9.5	34.8	23.4
UPPER MALAD	2017	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2017	ROR	19.1	18.8	13.7	19.1	19.1	18.5	12.5	13.4	15.1	16.0	15.3	19.1	16.6
UPPER SALMON 3&4	2017	ROR	17.7	17.7	16.5	16.8	17.4	17.0	11.9	12.7	14.1	14.9	14.2	17.7	15.7
HCC TOTAL			**629.5**	**905.3**	**813.2**	**983.7**	**948.5**	**783.0**	**530.8**	**401.0**	**510.2**	**456.4**	**359.6**	**561.3**	**654.8**
ROR TOTAL			**355.8**	**372.1**	**307.3**	**399.0**	**398.0**	**347.6**	**243.9**	**240.5**	**240.6**	**229.7**	**222.9**	**327.5**	**306.6**
TOTAL			**985.3**	**1277.4**	**1120.5**	**1382.7**	**1346.5**	**1130.6**	**774.7**	**641.5**	**750.8**	**686.1**	**582.5**	**888.8**	**961.4**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

50th Percentile Water, 50th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2018	HCC	279.9	402.9	350.0	424.8	421.7	349.3	233.7	169.5	215.4	192.8	152.6	248.3	285.8
OXBOW	2018	HCC	116.8	167.9	153.2	184.7	171.9	142.6	99.1	77.6	98.6	88.6	69.3	104.5	122.5
HELLS CANYON	2018	HCC	231.9	333.2	308.9	373.1	353.9	289.8	196.8	152.3	193.5	174.7	138.1	207.3	245.4
1000 SPRINGS	2018	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2018	ROR	22.6	25.8	20.4	57.6	76.1	80.8	67.6	52.0	33.5	16.3	4.5	17.4	39.6
BLISS	2018	ROR	49.9	51.5	44.8	51.3	49.0	42.6	33.2	34.7	38.2	39.9	39.1	48.0	43.5
C.J. STRIKE	2018	ROR	65.7	67.6	60.1	67.7	64.8	52.6	35.4	38.3	45.8	50.9	51.8	61.9	55.1
CASCADE	2018	ROR	1.5	2.6	4.7	7.6	7.3	11.8	6.9	10.1	9.1	2.7	2.2	1.5	5.7
CLEAR LAKE	2018	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2018	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2018	ROR	35.3	36.7	30.0	35.1	33.7	28.6	20.9	21.8	24.3	25.8	24.7	33.3	29.1
MILNER	2018	ROR	41.6	45.2	28.4	41.0	34.5	17.6	0.0	0.0	0.0	0.0	5.0	34.0	20.5
SHOSHONE FALLS	2018	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.8	10.2	10.2	11.0	12.0	12.0	11.4
SWAN FALLS	2018	ROR	21.2	21.7	19.4	21.8	20.9	17.4	12.4	13.0	15.0	16.3	16.9	20.0	18.0
TWIN FALLS	2018	ROR	41.3	44.1	28.9	40.7	35.2	21.8	6.1	6.4	6.4	7.1	9.5	34.8	23.4
UPPER MALAD	2018	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2018	ROR	19.1	18.8	13.7	19.1	19.1	18.4	12.4	13.3	15.0	16.0	15.2	19.1	16.6
UPPER SALMON 3&4	2018	ROR	17.7	17.7	16.5	16.8	17.4	17.0	11.8	12.6	14.0	14.9	14.2	17.7	15.7
HCC TOTAL			**628.6**	**904.0**	**812.1**	**982.6**	**947.4**	**781.7**	**529.6**	**399.4**	**507.4**	**456.1**	**360.0**	**560.1**	**653.7**
ROR TOTAL			**355.1**	**371.4**	**306.6**	**398.5**	**396.9**	**346.5**	**243.2**	**239.8**	**239.9**	**229.1**	**222.6**	**327.0**	**305.9**
TOTAL			**983.7**	**1275.4**	**1118.7**	**1381.1**	**1344.3**	**1128.2**	**772.8**	**639.2**	**747.2**	**685.2**	**582.6**	**887.1**	**959.6**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2019	HCC	279.4	402.4	349.5	424.3	421.1	348.8	233.1	169.3	214.7	193.0	152.4	247.9	285.4
OXBOW	2019	HCC	116.6	167.7	153.0	184.5	171.7	142.4	98.9	77.5	98.2	88.6	69.2	104.3	122.3
HELLS CANYON	2019	HCC	231.5	332.8	308.5	372.7	353.5	289.4	196.4	152.2	192.7	174.8	137.9	206.9	245.0
1000 SPRINGS	2019	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2019	ROR	22.6	25.8	20.3	57.8	76.1	80.9	67.7	51.9	33.5	16.4	4.6	17.5	39.7
BLISS	2019	ROR	49.8	51.4	44.7	51.2	48.8	42.5	33.1	34.6	38.2	39.9	39.0	47.9	43.4
C.J. STRIKE	2019	ROR	65.5	67.4	59.9	67.6	64.6	52.5	35.2	38.1	45.6	50.7	51.6	61.8	54.9
CASCADE	2019	ROR	1.5	2.6	4.7	7.6	7.3	11.8	6.9	10.1	9.1	2.7	2.2	1.5	5.7
CLEAR LAKE	2019	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2019	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2019	ROR	35.2	36.6	29.9	35.0	33.6	28.5	20.8	21.7	24.2	25.7	24.6	33.2	29.0
MILNER	2019	ROR	41.6	45.2	28.4	41.0	34.5	17.6	0.0	0.0	0.0	0.0	5.0	34.0	20.5
SHOSHONE FALLS	2019	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.8	10.1	10.2	11.0	12.0	12.0	11.4
SWAN FALLS	2019	ROR	21.2	21.7	19.4	21.7	20.8	17.4	12.3	12.9	14.9	16.2	16.8	20.0	17.9
TWIN FALLS	2019	ROR	41.3	44.1	28.9	40.6	35.1	21.7	6.0	6.3	6.4	7.1	9.5	34.8	23.4
UPPER MALAD	2019	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2019	ROR	19.1	18.8	13.7	19.1	19.1	18.3	12.4	13.3	14.9	15.9	15.1	19.1	16.5
UPPER SALMON 3&4	2019	ROR	17.7	17.7	16.5	16.8	17.4	16.9	11.8	12.5	14.0	14.8	14.1	17.7	15.6
HCC TOTAL			**627.5**	**902.9**	**811.0**	**981.5**	**946.2**	**780.6**	**528.4**	**399.0**	**505.5**	**456.4**	**359.5**	**559.1**	**652.7**
ROR TOTAL			**354.7**	**371.0**	**306.1**	**398.2**	**396.2**	**346.0**	**242.7**	**238.9**	**239.4**	**228.6**	**222.0**	**326.8**	**305.4**
TOTAL			**982.2**	**1273.9**	**1117.1**	**1379.7**	**1342.4**	**1126.6**	**771.1**	**637.9**	**744.8**	**685.0**	**581.5**	**885.9**	**958.1**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

50th Percentile Water, 50th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2020	HCC	278.8	401.9	349.0	423.8	420.6	348.2	232.6	169.3	213.7	193.4	152.6	247.3	285.3
OXBOW	2020	HCC	116.4	167.5	152.8	184.3	171.5	142.2	98.7	77.5	97.6	88.6	69.3	104.1	122.3
HELLS CANYON	2020	HCC	231.0	332.4	308.1	372.3	353.0	289.0	196.0	152.2	191.6	174.8	138.1	206.4	244.9
1000 SPRINGS	2020	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2020	ROR	22.7	25.9	20.2	57.3	76.1	80.8	67.7	51.9	33.5	16.7	4.7	17.6	39.6
BLISS	2020	ROR	49.7	51.3	44.6	51.1	48.7	42.4	33.0	34.5	38.1	39.8	38.9	47.7	43.3
C.J. STRIKE	2020	ROR	65.3	67.3	59.7	67.4	64.5	52.3	35.0	37.9	45.5	50.5	51.4	61.6	54.8
CASCADE	2020	ROR	1.5	2.6	4.7	7.6	7.3	11.8	6.9	10.1	9.1	2.7	2.2	1.5	5.7
CLEAR LAKE	2020	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2020	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2020	ROR	35.1	36.5	29.8	34.9	33.5	28.4	20.7	21.6	24.1	25.6	24.5	33.1	29.0
MILNER	2020	ROR	41.6	45.2	28.4	41.0	34.5	17.6	0.0	0.0	0.0	0.0	5.0	34.0	20.5
SHOSHONE FALLS	2020	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.7	10.1	10.1	10.9	12.0	12.0	11.4
SWAN FALLS	2020	ROR	21.1	21.7	19.3	21.7	20.8	17.3	12.2	12.9	14.9	16.2	16.8	19.9	17.9
TWIN FALLS	2020	ROR	41.3	44.1	28.9	40.6	35.1	21.7	6.0	6.3	6.3	7.0	9.5	34.7	23.4
UPPER MALAD	2020	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2020	ROR	19.1	18.8	13.7	19.1	19.1	18.2	12.3	13.2	14.8	15.8	15.0	19.2	16.5
UPPER SALMON 3&4	2020	ROR	17.7	17.7	16.5	16.8	17.4	16.8	11.7	12.5	13.9	14.7	14.0	17.7	15.6
HCC TOTAL			**626.2**	**901.8**	**809.9**	**980.4**	**945.1**	**779.4**	**527.3**	**399.0**	**502.9**	**456.8**	**360.0**	**557.8**	**652.5**
ROR TOTAL			**354.3**	**370.8**	**305.5**	**397.3**	**395.9**	**345.2**	**241.9**	**238.4**	**238.7**	**228.1**	**221.5**	**326.3**	**305.0**
TOTAL			**980.5**	**1272.6**	**1115.4**	**1377.7**	**1341.0**	**1124.6**	**769.2**	**637.4**	**741.6**	**684.9**	**581.5**	**884.1**	**957.5**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2021	HCC	278.3	401.4	348.5	423.4	420.1	347.8	232.1	169.3	213.0	193.4	152.8	246.8	284.6
OXBOW	2021	HCC	116.2	167.2	152.6	184.1	171.3	142.0	98.5	77.5	97.2	88.6	69.4	103.9	122.0
HELLS CANYON	2021	HCC	230.6	332.0	307.7	371.9	352.6	288.6	195.6	152.2	190.8	174.7	138.2	206.0	244.3
1000 SPRINGS	2021	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2021	ROR	22.8	26.0	20.1	57.2	75.7	80.4	67.7	52.0	33.6	16.8	4.7	17.6	39.6
BLISS	2021	ROR	49.6	51.1	44.5	51.0	48.6	42.2	32.8	34.3	37.9	39.7	38.7	47.6	43.1
C.J. STRIKE	2021	ROR	65.2	67.1	59.6	67.2	64.3	52.1	34.8	37.8	45.3	50.4	51.2	61.4	54.6
CASCADE	2021	ROR	1.5	2.6	4.7	7.6	7.3	11.8	6.9	10.1	9.1	2.7	2.2	1.5	5.7
CLEAR LAKE	2021	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2021	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2021	ROR	35.0	36.4	29.7	34.8	33.4	28.3	20.6	21.5	24.0	25.5	24.4	33.0	28.8
MILNER	2021	ROR	41.6	45.2	28.4	41.0	34.5	17.6	0.0	0.0	0.0	0.0	5.0	34.0	20.5
SHOSHONE FALLS	2021	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.7	10.0	10.1	10.9	12.0	12.0	11.4
SWAN FALLS	2021	ROR	21.1	21.6	19.3	21.6	20.5	17.3	12.2	12.8	14.8	16.1	16.7	19.9	17.8
TWIN FALLS	2021	ROR	41.2	44.1	28.9	40.6	35.1	21.6	6.0	6.3	6.3	7.0	9.5	34.7	23.3
UPPER MALAD	2021	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2021	ROR	19.1	18.8	13.7	19.1	19.1	18.2	12.2	13.1	14.8	15.7	14.9	19.2	16.5
UPPER SALMON 3&4	2021	ROR	17.7	17.7	16.5	16.8	17.4	16.8	11.6	12.4	13.8	14.6	14.0	17.7	15.6
HCC TOTAL			**625.1**	**900.6**	**808.8**	**979.4**	**943.9**	**778.4**	**526.2**	**399.0**	**501.0**	**456.7**	**360.4**	**556.7**	**651.0**
ROR TOTAL			**354.0**	**370.3**	**305.1**	**396.7**	**394.8**	**344.2**	**241.2**	**237.7**	**238.1**	**227.6**	**220.8**	**325.9**	**304.2**
TOTAL			**979.1**	**1270.9**	**1113.9**	**1376.1**	**1338.7**	**1122.6**	**767.4**	**636.7**	**739.1**	**684.3**	**581.2**	**882.6**	**955.2**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

50th Percentile Water, 50th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2022	HCC	280.6	396.6	348.0	422.9	419.6	347.2	231.6	169.2	212.3	193.4	152.7	246.8	284.2
OXBOW	2022	HCC	117.3	165.6	152.3	183.9	171.1	141.8	98.3	77.4	96.8	88.5	69.3	103.9	121.8
HELLS CANYON	2022	HCC	232.8	328.7	307.3	371.5	352.3	288.2	195.1	152.0	189.9	174.5	138.1	206.0	244.0
1000 SPRINGS	2022	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2022	ROR	22.9	26.0	20.0	57.2	75.1	79.6	67.4	52.0	33.6	17.0	4.8	17.7	39.5
BLISS	2022	ROR	49.5	51.0	44.3	50.9	48.5	42.1	32.7	34.2	37.8	39.6	38.6	47.5	43.0
C.J. STRIKE	2022	ROR	65.0	66.9	59.4	67.0	64.1	52.1	34.7	37.6	45.1	50.2	51.0	61.2	54.4
CASCADE	2022	ROR	1.5	2.6	4.7	7.6	7.3	11.8	6.9	10.1	9.1	2.7	2.2	1.5	5.7
CLEAR LAKE	2022	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2022	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2022	ROR	34.9	36.3	29.6	34.7	33.3	28.3	20.5	21.4	23.9	25.4	24.3	32.9	28.7
MILNER	2022	ROR	41.6	45.2	28.4	41.0	34.5	17.6	0.0	0.0	0.0	0.0	5.0	34.0	20.5
SHOSHONE FALLS	2022	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.7	10.0	10.0	10.9	12.0	12.0	11.4
SWAN FALLS	2022	ROR	21.1	21.6	19.2	21.6	20.4	17.2	12.1	12.8	14.8	16.1	16.5	19.8	17.7
TWIN FALLS	2022	ROR	41.2	44.0	28.9	40.5	35.1	21.6	5.9	6.2	6.3	7.0	9.5	34.7	23.3
UPPER MALAD	2022	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2022	ROR	19.1	18.8	13.8	19.1	19.1	18.1	12.1	13.0	14.7	15.6	14.9	19.2	16.4
UPPER SALMON 3&4	2022	ROR	17.7	17.7	16.5	16.8	17.4	16.7	11.6	12.3	13.8	14.6	13.9	17.7	15.5
HCC TOTAL			**630.7**	**890.9**	**807.6**	**978.3**	**943.0**	**777.2**	**525.0**	**398.6**	**498.9**	**456.4**	**360.1**	**556.7**	**650.0**
ROR TOTAL			**353.7**	**369.8**	**304.5**	**396.2**	**393.7**	**343.0**	**240.3**	**237.0**	**237.5**	**227.3**	**220.2**	**325.5**	**303.6**
TOTAL			**984.4**	**1260.7**	**1112.1**	**1374.5**	**1336.7**	**1120.2**	**765.3**	**635.6**	**736.4**	**683.7**	**580.3**	**882.2**	**953.5**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2023	HCC	289.6	394.0	347.5	422.4	419.0	346.7	231.1	168.7	211.0	193.6	152.6	246.2	284.3
OXBOW	2023	HCC	117.8	164.6	152.1	183.7	170.9	141.6	98.1	77.2	96.2	88.5	69.2	103.6	121.6
HELLS CANYON	2023	HCC	231.9	326.9	306.8	371.1	351.9	287.8	194.7	151.6	188.7	174.6	137.9	205.5	243.4
1000 SPRINGS	2023	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2023	ROR	22.9	25.8	19.9	57.0	75.1	79.6	67.3	52.1	33.6	16.9	4.9	17.8	39.5
BLISS	2023	ROR	49.3	50.9	44.2	50.7	48.4	42.0	32.6	34.1	37.7	39.5	38.5	47.4	42.9
C.J. STRIKE	2023	ROR	64.8	66.7	59.2	66.9	63.9	52.1	34.5	37.4	44.9	50.0	50.8	61.1	54.3
CASCADE	2023	ROR	1.5	2.6	4.7	7.6	7.3	11.8	6.9	10.1	9.1	2.7	2.2	1.5	5.7
CLEAR LAKE	2023	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2023	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2023	ROR	34.9	36.2	29.5	34.7	33.2	28.2	20.4	21.3	23.8	25.3	24.2	32.8	28.7
MILNER	2023	ROR	41.6	45.2	28.4	41.0	34.5	17.6	0.0	0.0	0.0	0.0	5.0	34.0	20.5
SHOSHONE FALLS	2023	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.6	10.0	10.0	10.8	12.0	12.0	11.4
SWAN FALLS	2023	ROR	21.0	21.5	19.1	21.6	20.4	17.2	12.1	12.8	14.7	16.1	16.4	19.8	17.7
TWIN FALLS	2023	ROR	41.2	44.0	28.9	40.5	35.0	21.6	5.9	6.2	6.2	6.9	9.5	34.6	23.2
UPPER MALAD	2023	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2023	ROR	19.1	18.8	13.8	19.1	19.1	18.1	12.1	12.9	14.6	15.6	14.8	19.2	16.4
UPPER SALMON 3&4	2023	ROR	17.7	17.7	16.5	16.8	17.4	16.7	11.5	12.3	13.7	14.5	13.8	17.7	15.5
HCC TOTAL			**639.3**	**885.5**	**806.4**	**977.2**	**941.7**	**776.1**	**523.9**	**397.5**	**495.9**	**456.7**	**359.7**	**555.3**	**649.3**
ROR TOTAL			**353.2**	**369.1**	**303.9**	**395.7**	**393.2**	**342.8**	**239.6**	**236.6**	**236.7**	**226.5**	**219.6**	**325.2**	**303.0**
TOTAL			**992.5**	**1254.6**	**1110.3**	**1372.9**	**1334.9**	**1118.9**	**763.5**	**634.1**	**732.6**	**683.2**	**579.3**	**880.5**	**952.4**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

50th Percentile Water, 50th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2024	HCC	280.5	394.2	347.0	421.9	418.5	346.1	230.6	168.3	209.8	193.7	152.8	245.7	283.5
OXBOW	2024	HCC	117.3	164.7	151.9	183.5	170.7	141.4	97.8	77.0	95.5	88.4	69.3	103.4	121.5
HELLS CANYON	2024	HCC	232.8	327.0	306.4	370.7	351.5	287.3	194.3	151.2	187.5	174.4	138.0	205.1	243.4
1000 SPRINGS	2024	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2024	ROR	23.0	25.8	19.9	56.9	74.4	79.1	67.4	52.1	33.7	17.1	5.0	17.8	39.4
BLISS	2024	ROR	49.2	50.8	44.1	50.6	48.2	41.8	32.4	33.9	37.5	39.3	38.3	47.3	42.7
C.J. STRIKE	2024	ROR	64.6	66.6	59.0	66.7	63.8	52.1	34.3	37.3	44.8	49.9	50.6	60.9	54.2
CASCADE	2024	ROR	1.5	2.6	4.7	7.6	7.3	11.8	6.9	10.1	9.1	2.7	2.2	1.5	5.7
CLEAR LAKE	2024	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2024	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2024	ROR	34.8	36.1	29.4	34.5	33.1	28.1	20.3	21.2	23.7	25.2	24.1	32.7	28.6
MILNER	2024	ROR	41.6	45.2	28.4	41.0	34.5	17.6	0.0	0.0	0.0	0.0	5.0	34.0	20.5
SHOSHONE FALLS	2024	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.6	9.9	10.0	10.8	12.0	12.0	11.4
SWAN FALLS	2024	ROR	21.0	21.5	19.1	21.5	20.3	17.1	12.0	12.7	14.6	16.0	16.4	19.7	17.6
TWIN FALLS	2024	ROR	41.2	44.0	28.9	40.5	35.0	21.6	5.8	6.1	6.2	6.9	9.5	34.6	23.3
UPPER MALAD	2024	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2024	ROR	19.1	18.8	13.8	19.1	19.1	18.0	12.0	12.9	14.5	15.5	14.7	19.2	16.4
UPPER SALMON 3&4	2024	ROR	17.7	17.7	16.5	16.8	17.4	16.6	11.4	12.2	13.6	14.4	13.8	17.7	15.5
HCC TOTAL			**630.6**	**885.9**	**805.3**	**976.1**	**940.6**	**774.8**	**522.7**	**396.5**	**492.8**	**456.5**	**360.1**	**554.2**	**648.4**
ROR TOTAL			**352.9**	**368.8**	**303.5**	**395.0**	**392.0**	**341.7**	**238.8**	**235.8**	**236.1**	**226.0**	**219.1**	**324.7**	**302.6**
TOTAL			**983.5**	**1254.7**	**1108.8**	**1371.1**	**1332.6**	**1116.5**	**761.5**	**632.3**	**728.8**	**682.5**	**579.2**	**878.9**	**950.9**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2025	HCC	291.5	388.7	346.5	421.3	418.0	345.6	230.1	167.8	208.4	194.0	152.9	245.2	283.3
OXBOW	2025	HCC	118.7	162.7	151.7	183.3	170.5	141.1	97.6	76.8	94.7	88.5	69.3	103.2	121.2
HELLS CANYON	2025	HCC	233.7	323.2	306.0	370.2	351.1	286.9	193.9	150.8	186.0	174.5	138.1	204.7	242.6
1000 SPRINGS	2025	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2025	ROR	23.1	25.8	19.8	57.0	74.1	78.7	67.2	52.0	33.7	17.1	5.1	17.9	39.4
BLISS	2025	ROR	49.1	50.7	44.0	50.5	48.1	41.7	32.3	33.8	37.4	39.2	38.2	47.1	42.6
C.J. STRIKE	2025	ROR	64.5	66.4	58.9	66.5	63.6	51.4	34.2	37.1	44.6	49.7	50.5	60.7	53.9
CASCADE	2025	ROR	1.5	2.6	4.7	7.6	7.3	11.8	6.9	10.1	9.1	2.7	2.2	1.5	5.7
CLEAR LAKE	2025	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2025	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2025	ROR	34.7	36.1	29.3	34.5	33.0	28.0	20.3	21.1	23.6	25.1	24.0	32.6	28.5
MILNER	2025	ROR	41.6	45.2	28.4	41.0	34.5	17.6	0.0	0.0	0.0	0.0	5.0	34.0	20.5
SHOSHONE FALLS	2025	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.5	9.9	9.9	10.7	12.0	12.0	11.3
SWAN FALLS	2025	ROR	20.9	21.4	19.1	21.5	20.3	17.0	12.0	12.6	14.6	16.0	16.3	19.7	17.6
TWIN FALLS	2025	ROR	41.1	43.9	28.9	40.5	35.0	21.5	5.8	6.1	6.2	6.8	9.5	34.6	23.2
UPPER MALAD	2025	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2025	ROR	19.1	18.8	13.8	19.1	19.1	17.9	11.9	12.8	14.4	15.4	14.6	19.2	16.3
UPPER SALMON 3&4	2025	ROR	17.7	17.7	16.5	16.8	17.4	16.6	11.4	12.1	13.6	14.4	13.7	17.7	15.5
HCC TOTAL			**643.9**	**874.6**	**804.2**	**974.8**	**939.5**	**773.6**	**521.6**	**395.4**	**489.1**	**457.0**	**360.3**	**553.1**	**647.1**
ROR TOTAL			**352.5**	**368.3**	**303.1**	**394.8**	**391.3**	**340.1**	**238.2**	**235.0**	**235.5**	**225.3**	**218.6**	**324.3**	**301.8**
TOTAL			**996.4**	**1242.9**	**1107.3**	**1369.6**	**1330.8**	**1113.7**	**759.8**	**630.4**	**724.6**	**682.3**	**578.9**	**877.4**	**948.8**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

50th Percentile Water, 50th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2026	HCC	290.8	388.4	346.0	420.8	417.5	342.2	229.6	167.3	207.2	194.0	153.1	244.7	282.6
OXBOW	2026	HCC	118.4	162.6	151.5	183.1	170.3	139.8	97.4	76.5	94.1	88.4	69.4	103.0	120.9
HELLS CANYON	2026	HCC	233.1	323.0	305.6	369.9	350.7	284.3	193.5	150.4	184.8	174.3	138.2	204.2	242.0
1000 SPRINGS	2026	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2026	ROR	23.2	25.8	19.7	56.9	73.6	78.2	67.0	52.0	33.7	17.1	5.1	18.1	39.3
BLISS	2026	ROR	49.0	50.6	43.8	50.4	48.0	41.5	32.2	33.7	37.3	39.1	38.1	47.0	42.5
C.J. STRIKE	2026	ROR	64.3	66.2	58.7	66.4	63.4	51.3	34.0	36.9	44.4	49.5	50.3	60.6	53.7
CASCADE	2026	ROR	1.5	2.6	4.7	7.6	7.3	11.8	6.9	10.1	9.1	2.7	2.2	1.5	5.7
CLEAR LAKE	2026	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2026	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2026	ROR	34.6	36.0	29.2	34.4	32.9	27.9	20.2	21.0	23.5	25.0	23.9	32.5	28.4
MILNER	2026	ROR	41.6	45.2	28.4	41.0	34.5	17.6	0.0	0.0	0.0	0.0	5.0	34.0	20.5
SHOSHONE FALLS	2026	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.5	9.8	9.9	10.7	12.0	12.0	11.3
SWAN FALLS	2026	ROR	20.9	21.4	19.0	21.4	20.2	17.0	11.9	12.6	14.5	15.9	16.3	19.6	17.5
TWIN FALLS	2026	ROR	41.1	43.9	28.9	40.4	34.9	21.5	5.8	6.1	6.1	6.8	9.5	34.5	23.2
UPPER MALAD	2026	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2026	ROR	19.1	18.8	13.8	19.1	19.1	17.8	11.8	12.7	14.4	15.4	14.5	19.2	16.3
UPPER SALMON 3&4	2026	ROR	17.7	17.7	16.5	16.8	17.4	16.5	11.3	12.1	13.5	14.3	13.6	17.7	15.4
HCC TOTAL			**642.3**	**874.0**	**803.1**	**973.8**	**938.4**	**766.3**	**520.5**	**394.2**	**486.0**	**456.7**	**360.7**	**551.9**	**645.5**
ROR TOTAL			**352.2**	**367.9**	**302.4**	**394.2**	**390.2**	**339.0**	**237.3**	**234.4**	**234.8**	**224.7**	**218.0**	**324.0**	**301.1**
TOTAL			**994.5**	**1241.9**	**1105.5**	**1368.0**	**1328.6**	**1105.3**	**757.8**	**628.6**	**720.8**	**681.4**	**578.7**	**875.9**	**946.6**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2027	HCC	290.9	387.0	345.5	420.4	417.0	329.5	229.1	166.9	206.0	194.1	153.0	244.6	281.2
OXBOW	2027	HCC	118.5	162.1	151.3	182.9	170.0	134.8	97.2	76.3	93.5	88.3	69.3	102.9	120.3
HELLS CANYON	2027	HCC	233.3	322.0	305.2	369.5	350.3	274.5	193.1	150.0	183.5	174.2	138.0	204.2	240.8
1000 SPRINGS	2027	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2027	ROR	23.3	25.9	19.7	56.8	73.4	77.7	66.7	52.0	33.3	17.0	5.1	18.2	39.2
BLISS	2027	ROR	48.9	50.4	43.7	50.3	47.9	41.4	32.0	33.5	37.1	39.0	38.0	46.9	42.4
C.J. STRIKE	2027	ROR	64.1	66.0	58.5	66.2	63.2	51.1	33.8	36.7	44.3	49.3	50.1	60.4	53.5
CASCADE	2027	ROR	1.5	2.6	4.7	7.6	7.3	11.8	6.9	10.1	9.1	2.7	2.2	1.5	5.7
CLEAR LAKE	2027	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2027	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2027	ROR	34.5	35.9	29.1	34.3	32.8	27.8	20.1	20.9	23.4	24.9	23.8	32.4	28.3
MILNER	2027	ROR	41.6	45.2	28.4	41.0	34.5	17.6	0.0	0.0	0.0	0.0	5.0	34.0	20.5
SHOSHONE FALLS	2027	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.4	9.8	9.8	10.6	12.0	12.0	11.3
SWAN FALLS	2027	ROR	20.8	21.3	19.0	21.4	20.2	17.0	11.9	12.5	14.5	15.9	16.2	19.6	17.5
TWIN FALLS	2027	ROR	41.1	43.9	28.9	40.4	34.9	21.4	5.7	6.0	6.1	6.8	9.5	34.5	23.1
UPPER MALAD	2027	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2027	ROR	19.1	18.8	13.8	19.1	19.1	17.8	11.8	12.6	14.3	15.3	14.5	19.2	16.3
UPPER SALMON 3&4	2027	ROR	17.7	17.7	16.5	16.8	17.4	16.4	11.3	12.0	13.4	14.3	13.6	17.7	15.4
HCC TOTAL			**642.7**	**871.1**	**802.0**	**972.8**	**937.3**	**738.8**	**519.4**	**393.2**	**482.9**	**456.6**	**360.3**	**551.7**	**642.3**
ROR TOTAL			**351.8**	**367.4**	**302.0**	**393.7**	**389.6**	**337.9**	**236.3**	**233.5**	**233.7**	**224.0**	**217.5**	**323.7**	**300.4**
TOTAL			**994.5**	**1238.5**	**1104.0**	**1366.5**	**1326.8**	**1076.7**	**755.7**	**626.7**	**716.6**	**680.6**	**577.8**	**875.4**	**942.7**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

50th Percentile Water, 50th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2028	HCC	293.2	382.4	345.0	419.9	416.5	329.0	228.6	166.4	204.8	194.1	153.2	244.1	280.9
OXBOW	2028	HCC	119.6	160.5	151.1	182.7	169.9	134.6	97.0	76.1	92.8	88.2	69.4	102.7	120.2
HELLS CANYON	2028	HCC	235.4	318.8	304.8	369.1	349.9	274.1	192.6	149.6	182.3	174.0	138.2	203.8	240.6
1000 SPRINGS	2028	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2028	ROR	23.3	25.9	19.6	56.7	73.5	77.5	66.3	51.9	32.7	16.9	5.1	18.3	39.0
BLISS	2028	ROR	48.7	50.3	43.6	50.1	47.8	41.3	31.9	33.4	37.0	38.8	37.8	46.8	42.3
C.J. STRIKE	2028	ROR	64.0	65.9	58.4	66.0	63.1	50.9	33.6	36.5	44.1	49.2	49.9	60.2	53.4
CASCADE	2028	ROR	1.5	2.6	4.7	7.6	7.3	11.8	6.9	10.1	9.1	2.7	2.2	1.5	5.7
CLEAR LAKE	2028	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2028	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2028	ROR	34.4	35.8	29.0	34.1	32.7	27.7	19.9	20.8	23.3	24.8	23.8	32.3	28.2
MILNER	2028	ROR	41.6	45.2	28.4	41.0	34.5	17.6	0.0	0.0	0.0	0.0	5.0	34.0	20.5
SHOSHONE FALLS	2028	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.4	9.7	9.8	10.6	12.0	12.0	11.3
SWAN FALLS	2028	ROR	20.8	21.3	18.9	21.3	20.1	16.9	11.8	12.5	14.4	15.8	16.2	19.5	17.4
TWIN FALLS	2028	ROR	41.0	43.9	28.9	40.4	34.9	21.4	5.7	6.0	6.0	6.7	9.5	34.5	23.2
UPPER MALAD	2028	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2028	ROR	19.1	18.8	13.8	19.1	19.2	17.7	11.7	12.5	14.2	15.2	14.4	19.2	16.2
UPPER SALMON 3&4	2028	ROR	17.7	17.7	16.5	16.8	17.4	16.3	11.2	11.9	13.4	14.2	13.5	17.7	15.3
HCC TOTAL			**648.2**	**861.7**	**800.9**	**971.7**	**936.2**	**737.7**	**518.2**	**392.1**	**479.8**	**456.3**	**360.8**	**550.6**	**641.7**
ROR TOTAL			**351.3**	**367.1**	**301.5**	**392.9**	**389.4**	**337.0**	**235.1**	**232.7**	**232.4**	**223.1**	**216.9**	**323.3**	**299.9**
TOTAL			**999.5**	**1228.8**	**1102.4**	**1364.6**	**1325.6**	**1074.7**	**753.3**	**624.8**	**712.2**	**679.4**	**577.7**	**873.9**	**941.6**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2029	HCC	293.5	380.7	344.5	419.3	416.0	328.5	228.1	166.0	203.6	194.3	153.1	243.6	280.2
OXBOW	2029	HCC	119.7	159.9	150.9	182.5	169.7	134.3	96.8	75.9	92.2	88.3	69.3	102.5	119.8
HELLS CANYON	2029	HCC	235.7	317.6	304.4	368.6	349.5	273.7	192.2	149.2	181.1	174.1	138.0	203.3	240.0
1000 SPRINGS	2029	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2029	ROR	23.3	25.9	19.6	56.7	73.4	77.4	66.3	51.8	32.0	16.7	5.0	18.4	38.9
BLISS	2029	ROR	48.6	50.2	43.5	50.0	47.6	40.8	31.8	33.3	36.9	38.7	37.7	46.6	42.1
C.J. STRIKE	2029	ROR	63.8	65.7	58.2	65.8	62.9	50.1	33.4	36.4	43.9	49.0	49.8	60.0	53.2
CASCADE	2029	ROR	1.5	2.6	4.7	7.6	7.3	11.8	6.9	10.1	9.1	2.7	2.2	1.5	5.7
CLEAR LAKE	2029	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2029	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2029	ROR	34.3	35.7	28.9	34.1	32.6	27.6	19.8	20.7	23.2	24.7	23.7	32.2	28.1
MILNER	2029	ROR	41.6	45.2	28.4	41.0	34.5	17.6	0.0	0.0	0.0	0.0	5.0	34.0	20.5
SHOSHONE FALLS	2029	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.4	9.7	9.7	10.6	12.0	12.0	11.3
SWAN FALLS	2029	ROR	20.5	21.2	18.9	21.3	20.1	16.5	11.7	12.5	14.4	15.8	16.1	19.5	17.3
TWIN FALLS	2029	ROR	41.0	43.8	28.9	40.3	34.8	21.4	5.7	6.0	6.0	6.7	9.5	34.5	23.1
UPPER MALAD	2029	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2029	ROR	19.1	18.8	13.8	19.1	19.2	17.6	11.6	12.5	14.1	15.1	14.4	19.2	16.2
UPPER SALMON 3&4	2029	ROR	17.7	17.7	16.5	16.8	17.4	16.3	11.1	11.9	13.3	14.2	13.5	17.7	15.3
HCC TOTAL			**648.9**	**858.2**	**799.8**	**970.4**	**935.1**	**736.5**	**517.1**	**391.1**	**476.9**	**456.7**	**360.4**	**549.4**	**640.0**
ROR TOTAL			**350.6**	**366.5**	**301.1**	**392.5**	**388.7**	**335.0**	**234.4**	**232.3**	**231.0**	**222.4**	**216.4**	**322.9**	**299.0**
TOTAL			**999.5**	**1224.7**	**1100.9**	**1362.9**	**1323.8**	**1071.5**	**751.5**	**623.4**	**707.8**	**679.1**	**576.8**	**872.3**	**939.0**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

70th Percentile Water, 70th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2010	HCC	269.4	261.7	270.0	311.6	382.5	301.2	224.9	160.6	180.8	186.9	156.0	211.5	243.0
OXBOW	2010	HCC	114.3	112.4	115.2	127.3	153.6	121.0	95.1	73.3	82.4	83.2	69.5	88.5	102.9
HELLS CANYON	2010	HCC	225.9	223.8	234.6	258.1	312.3	244.8	187.7	144.0	161.7	164.0	138.1	175.4	205.8
1000 SPRINGS	2010	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2010	ROR	0.0	14.3	13.6	37.0	71.4	87.1	80.8	59.2	34.1	15.7	0.0	0.0	34.5
BLISS	2010	ROR	39.3	45.2	40.2	38.3	42.0	41.1	36.8	35.0	38.0	39.5	37.9	38.2	39.2
C.J. STRIKE	2010	ROR	50.9	56.0	53.0	49.4	53.5	48.1	39.8	38.3	45.6	50.8	50.1	50.3	48.8
CASCADE	2010	ROR	0.0	0.0	2.6	1.5	4.8	7.6	6.9	10.1	9.0	2.2	1.4	1.4	4.0
CLEAR LAKE	2010	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2010	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2010	ROR	24.4	30.5	25.6	23.3	28.3	28.5	24.1	22.0	24.4	25.7	24.3	24.5	25.4
MILNER	2010	ROR	9.0	26.9	12.6	4.9	17.0	17.6	9.4	0.0	0.0	0.0	3.5	6.5	8.8
SHOSHONE FALLS	2010	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	10.4	10.4	11.2	12.0	12.0	11.7
SWAN FALLS	2010	ROR	16.7	18.3	17.6	16.9	17.5	15.8	13.6	13.0	14.7	16.1	16.2	16.2	16.0
TWIN FALLS	2010	ROR	12.2	28.6	16.0	8.8	20.2	21.9	14.0	6.5	6.5	7.3	8.7	10.1	13.3
UPPER MALAD	2010	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2010	ROR	15.1	18.9	13.8	14.5	18.3	18.3	14.9	13.4	15.0	15.9	14.8	15.1	15.6
UPPER SALMON 3&4	2010	ROR	14.1	17.7	15.1	13.6	16.9	16.9	14.0	12.7	14.1	14.8	13.9	14.1	14.8
HCC TOTAL			**609.6**	**597.9**	**619.8**	**697.0**	**848.4**	**667.0**	**507.7**	**377.9**	**424.8**	**434.1**	**363.6**	**475.4**	**551.7**
ROR TOTAL			**220.9**	**296.1**	**249.8**	**248.0**	**328.8**	**340.8**	**293.0**	**248.0**	**240.2**	**227.4**	**210.3**	**215.7**	**259.6**
TOTAL			**830.5**	**894.0**	**869.6**	**945.0**	**1177.2**	**1007.8**	**800.7**	**625.9**	**665.0**	**661.5**	**573.9**	**691.1**	**811.3**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2011	HCC	299.4	230.8	269.9	311.5	382.4	301.1	224.8	160.5	180.7	186.8	155.9	211.3	243.1
OXBOW	2011	HCC	124.8	100.5	115.2	127.3	153.5	121.0	95.1	73.3	82.4	83.2	69.5	88.4	102.9
HELLS CANYON	2011	HCC	244.6	200.6	234.5	258.0	312.2	244.7	187.6	143.9	161.7	164.0	138.0	175.3	205.5
1000 SPRINGS	2011	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2011	ROR	0.0	14.2	13.5	37.5	71.0	86.7	80.8	58.7	34.0	15.7	0.0	0.0	34.4
BLISS	2011	ROR	39.3	45.2	40.2	38.2	41.9	41.0	36.8	35.0	38.0	39.5	37.9	38.1	39.2
C.J. STRIKE	2011	ROR	50.9	56.0	52.9	49.4	53.5	48.0	39.8	38.2	45.5	50.7	50.1	50.2	48.7
CASCADE	2011	ROR	0.0	0.0	2.6	1.5	4.8	7.6	6.9	10.1	9.0	2.2	1.4	1.4	4.0
CLEAR LAKE	2011	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2011	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2011	ROR	24.4	30.5	25.6	23.3	28.2	28.5	24.1	22.0	24.3	25.7	24.3	24.5	25.4
MILNER	2011	ROR	9.0	26.9	12.6	4.9	17.0	17.6	9.4	0.0	0.0	0.0	3.5	6.4	8.8
SHOSHONE FALLS	2011	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	10.4	10.4	11.2	12.0	12.0	11.7
SWAN FALLS	2011	ROR	16.7	18.3	17.6	16.9	17.5	15.8	13.6	12.9	14.7	16.1	16.2	16.2	16.0
TWIN FALLS	2011	ROR	12.2	28.6	16.0	8.8	20.2	21.9	14.0	6.5	6.5	7.3	8.7	10.1	13.3
UPPER MALAD	2011	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2011	ROR	15.1	18.9	13.8	14.5	18.3	18.3	14.9	13.4	15.0	15.9	14.8	15.1	15.6
UPPER SALMON 3&4	2011	ROR	14.1	17.7	15.1	13.6	16.9	16.9	14.0	12.7	14.0	14.8	13.9	14.1	14.8
HCC TOTAL			**668.8**	**531.9**	**619.6**	**696.8**	**848.1**	**666.8**	**507.5**	**377.7**	**424.7**	**434.0**	**363.4**	**475.0**	**551.5**
ROR TOTAL			**220.9**	**296.0**	**249.6**	**248.4**	**328.2**	**340.2**	**293.0**	**247.3**	**239.8**	**227.3**	**210.3**	**215.4**	**259.4**
TOTAL			**889.7**	**827.9**	**869.2**	**945.2**	**1176.3**	**1007.0**	**800.5**	**625.0**	**664.5**	**661.3**	**573.7**	**690.4**	**810.9**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580
70th Percentile Water, 70th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2012	HCC	306.3	220.9	269.8	311.4	382.3	301.0	224.7	160.4	180.6	186.7	155.8	211.1	242.8
OXBOW	2012	HCC	128.1	96.6	115.1	127.3	153.5	121.0	95.0	73.2	82.4	83.1	69.4	88.3	102.8
HELLS CANYON	2012	HCC	251.1	193.1	234.4	258.0	312.2	244.6	187.5	143.8	161.6	163.9	137.9	175.1	205.4
1000 SPRINGS	2012	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2012	ROR	0.0	14.2	13.5	39.1	70.9	86.4	80.6	58.3	33.8	15.8	0.0	0.0	34.4
BLISS	2012	ROR	39.3	45.2	40.1	38.2	41.9	41.0	36.7	35.0	38.0	39.5	37.9	38.1	39.2
C.J. STRIKE	2012	ROR	50.8	55.9	52.9	49.3	53.5	48.0	39.7	38.1	45.5	50.7	50.0	50.2	48.7
CASCADE	2012	ROR	0.0	0.0	2.6	1.5	4.8	7.6	6.9	10.1	9.0	2.2	1.4	1.4	4.0
CLEAR LAKE	2012	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2012	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2012	ROR	24.4	30.5	25.6	23.2	28.2	28.5	24.1	21.9	24.3	25.6	24.3	24.4	25.4
MILNER	2012	ROR	8.9	26.9	12.6	4.9	17.0	17.6	9.4	0.0	0.0	0.0	3.5	6.4	8.9
SHOSHONE FALLS	2012	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	10.4	10.4	11.2	12.0	12.0	11.7
SWAN FALLS	2012	ROR	16.5	18.3	17.6	16.9	17.5	15.8	13.6	12.9	14.7	16.1	16.2	16.2	16.0
TWIN FALLS	2012	ROR	12.1	28.6	16.0	8.8	20.2	21.9	14.0	6.5	6.5	7.3	8.7	10.0	13.3
UPPER MALAD	2012	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2012	ROR	15.1	18.9	13.8	14.4	18.3	18.3	14.9	13.4	15.0	15.8	14.8	15.0	15.6
UPPER SALMON 3&4	2012	ROR	14.1	17.7	15.1	13.5	16.9	16.8	13.9	12.7	14.0	14.8	13.9	14.1	14.8
HCC TOTAL			**685.5**	**510.6**	**619.3**	**696.7**	**847.9**	**666.6**	**507.2**	**377.4**	**424.5**	**433.7**	**363.1**	**474.5**	**550.9**
ROR TOTAL			**220.4**	**295.9**	**249.5**	**249.6**	**328.1**	**339.8**	**292.5**	**246.7**	**239.6**	**227.2**	**210.2**	**215.1**	**259.4**
TOTAL			**905.9**	**806.5**	**868.8**	**946.3**	**1176.0**	**1006.4**	**799.7**	**624.1**	**664.1**	**660.9**	**573.3**	**689.6**	**810.3**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2013	HCC	306.2	222.3	267.7	311.3	382.2	300.9	224.6	160.3	180.5	186.4	156.1	210.9	242.7
OXBOW	2013	HCC	128.1	97.3	114.3	127.2	153.5	120.9	95.0	73.2	82.3	83.0	69.6	88.2	102.8
HELLS CANYON	2013	HCC	251.0	194.5	232.9	257.9	312.1	244.6	187.4	143.7	161.5	163.6	138.1	174.9	205.3
1000 SPRINGS	2013	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2013	ROR	0.0	14.2	13.4	39.0	70.8	86.1	80.2	57.3	33.6	15.8	0.0	0.0	34.3
BLISS	2013	ROR	39.3	45.2	40.1	38.2	41.9	41.0	36.7	35.0	38.0	39.4	37.8	38.1	39.2
C.J. STRIKE	2013	ROR	50.6	55.8	52.9	49.3	53.4	47.9	39.7	38.1	45.5	50.7	50.0	50.1	48.6
CASCADE	2013	ROR	0.0	0.0	2.6	1.5	4.8	7.6	6.9	10.1	9.0	2.2	1.4	1.4	4.0
CLEAR LAKE	2013	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2013	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2013	ROR	24.4	30.5	25.6	23.2	28.2	28.4	24.1	21.9	24.3	25.6	24.2	24.4	25.4
MILNER	2013	ROR	8.9	26.9	12.6	4.9	17.0	17.6	9.4	0.0	0.0	0.0	3.5	6.3	8.8
SHOSHONE FALLS	2013	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	10.4	10.4	11.2	12.0	12.0	11.7
SWAN FALLS	2013	ROR	16.5	18.3	17.6	16.9	17.5	15.8	13.6	12.9	14.7	16.1	16.2	16.2	16.0
TWIN FALLS	2013	ROR	12.0	28.6	16.0	8.8	20.2	21.9	14.0	6.5	6.5	7.3	8.7	10.0	13.3
UPPER MALAD	2013	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2013	ROR	15.1	18.9	13.8	14.4	18.3	18.3	14.9	13.4	15.0	15.8	14.8	15.0	15.6
UPPER SALMON 3&4	2013	ROR	14.1	17.7	15.1	13.5	16.9	16.8	13.9	12.7	14.0	14.8	13.8	14.0	14.8
HCC TOTAL			**685.3**	**514.1**	**614.9**	**696.4**	**847.7**	**666.4**	**507.0**	**377.2**	**424.2**	**433.0**	**363.8**	**474.0**	**550.8**
ROR TOTAL			**220.1**	**295.8**	**249.4**	**249.5**	**327.9**	**339.3**	**292.1**	**245.7**	**239.4**	**227.1**	**209.9**	**214.8**	**258.9**
TOTAL			**905.4**	**809.9**	**864.3**	**945.9**	**1175.6**	**1005.7**	**799.1**	**622.9**	**663.6**	**660.1**	**573.7**	**688.8**	**809.7**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

70th Percentile Water, 70th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2014	HCC	305.7	228.2	259.2	310.8	381.6	300.4	210.5	159.9	179.9	185.9	156.0	209.9	240.8
OXBOW	2014	HCC	127.9	100.3	111.1	127.0	153.2	120.7	89.0	73.0	82.0	82.8	69.5	87.8	102.1
HELLS CANYON	2014	HCC	250.6	200.3	226.6	257.5	311.6	244.2	175.8	143.3	161.0	163.2	138.0	174.2	203.9
1000 SPRINGS	2014	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2014	ROR	0.0	14.0	12.6	38.6	70.5	85.4	74.3	55.6	33.0	15.8	0.0	0.0	33.4
BLISS	2014	ROR	39.1	45.2	40.0	38.1	41.8	40.9	33.1	34.8	37.8	39.3	37.7	37.9	38.8
C.J. STRIKE	2014	ROR	50.4	55.5	52.7	49.1	53.3	47.8	34.9	37.9	45.3	50.5	49.8	49.8	48.0
CASCADE	2014	ROR	0.0	0.0	2.6	1.5	4.8	7.6	6.9	10.1	9.0	2.2	1.4	1.4	4.0
CLEAR LAKE	2014	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2014	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2014	ROR	24.2	30.5	25.5	23.1	28.1	28.3	20.9	21.8	24.2	25.5	24.1	24.2	25.0
MILNER	2014	ROR	8.7	26.9	12.6	4.9	17.0	17.6	0.0	0.0	0.0	0.0	3.5	6.0	8.0
SHOSHONE FALLS	2014	ROR	12.0	12.0	12.0	12.0	12.0	12.0	10.0	10.3	10.3	11.1	12.0	12.0	11.5
SWAN FALLS	2014	ROR	16.4	18.2	17.5	16.9	17.5	15.7	12.1	12.8	14.7	16.0	16.1	16.2	15.8
TWIN FALLS	2014	ROR	11.9	28.6	16.0	8.8	20.2	21.8	6.2	6.5	6.5	7.2	8.7	9.8	12.6
UPPER MALAD	2014	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2014	ROR	14.9	18.9	13.8	14.3	18.2	18.2	12.4	13.3	14.9	15.8	14.7	14.8	15.3
UPPER SALMON 3&4	2014	ROR	14.0	17.7	15.0	13.5	16.8	16.8	11.8	12.6	14.0	14.7	13.8	13.9	14.5
HCC TOTAL			**684.2**	**528.8**	**596.9**	**695.3**	**846.4**	**665.3**	**475.3**	**376.2**	**422.8**	**431.9**	**363.5**	**471.9**	**546.8**
ROR TOTAL			**218.8**	**295.2**	**248.0**	**248.6**	**327.1**	**338.0**	**249.3**	**243.1**	**238.1**	**226.3**	**209.3**	**213.3**	**254.2**
TOTAL			**903.0**	**824.0**	**844.9**	**943.9**	**1173.5**	**1003.3**	**724.6**	**619.3**	**660.9**	**658.2**	**572.8**	**685.2**	**801.0**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2015	HCC	305.2	230.6	255.1	310.2	381.1	299.8	210.0	159.4	179.3	185.1	156.3	209.4	240.2
OXBOW	2015	HCC	127.7	101.5	109.5	126.8	153.0	120.5	88.8	72.7	81.8	82.4	69.6	87.6	101.8
HELLS CANYON	2015	HCC	250.2	202.7	223.6	257.0	311.2	243.7	175.4	142.9	160.4	162.4	138.2	173.7	203.5
1000 SPRINGS	2015	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2015	ROR	0.0	14.0	12.2	38.0	70.0	84.4	73.2	55.0	32.8	15.6	0.0	0.0	33.0
BLISS	2015	ROR	39.0	45.2	39.9	37.9	41.6	40.7	33.0	34.7	37.7	39.2	37.6	37.8	38.6
C.J. STRIKE	2015	ROR	50.2	55.5	52.5	48.9	53.1	47.6	34.7	37.7	45.1	50.3	49.6	49.6	47.8
CASCADE	2015	ROR	0.0	0.0	2.6	1.5	4.8	7.6	6.9	10.1	9.0	2.2	1.4	1.4	4.0
CLEAR LAKE	2015	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2015	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2015	ROR	24.1	30.5	25.4	23.0	28.0	28.3	20.8	21.7	24.1	25.4	24.0	24.1	24.9
MILNER	2015	ROR	8.7	26.9	12.6	4.9	17.0	17.6	0.0	0.0	0.0	0.0	3.5	6.0	8.0
SHOSHONE FALLS	2015	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.9	10.3	10.3	11.1	12.0	12.0	11.5
SWAN FALLS	2015	ROR	16.3	18.2	17.5	16.8	17.5	15.7	12.1	12.8	14.6	16.0	16.1	16.1	15.8
TWIN FALLS	2015	ROR	11.9	28.6	15.9	8.7	20.1	21.8	6.1	6.4	6.4	7.2	8.7	9.8	12.5
UPPER MALAD	2015	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2015	ROR	14.8	18.9	13.8	14.3	18.1	18.1	12.4	13.2	14.8	15.7	14.6	14.8	15.3
UPPER SALMON 3&4	2015	ROR	13.9	17.7	14.9	13.4	16.7	16.7	11.8	12.5	13.9	14.6	13.7	13.8	14.4
HCC TOTAL			**683.1**	**534.8**	**588.2**	**694.0**	**845.3**	**664.0**	**474.2**	**375.0**	**421.5**	**429.9**	**364.1**	**470.7**	**545.6**
ROR TOTAL			**218.1**	**295.2**	**247.0**	**247.2**	**325.8**	**336.4**	**247.6**	**241.8**	**237.1**	**225.5**	**208.7**	**212.7**	**253.2**
TOTAL			**901.2**	**830.0**	**835.2**	**941.2**	**1171.1**	**1000.4**	**721.8**	**616.8**	**658.6**	**655.4**	**572.8**	**683.4**	**798.8**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

70th Percentile Water, 70th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2016	HCC	304.6	229.0	256.0	309.7	380.6	299.2	209.5	159.0	178.8	184.6	155.9	209.3	239.8
OXBOW	2016	HCC	127.5	100.8	109.8	126.6	152.8	120.3	88.6	72.5	81.5	82.2	69.4	87.6	101.7
HELLS CANYON	2016	HCC	249.8	201.2	224.2	256.6	310.9	243.3	175.0	142.5	160.0	162.0	137.9	173.6	203.1
1000 SPRINGS	2016	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2016	ROR	0.0	14.0	12.0	37.6	70.3	84.1	72.7	54.5	32.9	15.7	0.0	0.0	32.8
BLISS	2016	ROR	38.9	45.2	39.7	37.8	41.5	40.6	32.8	34.6	37.5	39.1	37.4	37.7	38.5
C.J. STRIKE	2016	ROR	50.0	55.5	52.4	48.8	52.9	47.4	34.5	37.5	44.9	50.1	49.5	49.5	47.7
CASCADE	2016	ROR	0.0	0.0	2.6	1.5	4.8	7.6	6.9	10.1	9.0	2.2	1.4	1.4	4.0
CLEAR LAKE	2016	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2016	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2016	ROR	24.0	30.4	25.3	22.9	27.9	28.2	20.7	21.6	24.0	25.3	23.9	24.0	24.8
MILNER	2016	ROR	8.7	26.9	12.6	4.9	17.0	17.6	0.0	0.0	0.0	0.0	3.5	6.0	8.0
SHOSHONE FALLS	2016	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.9	10.2	10.2	11.1	12.0	12.0	11.4
SWAN FALLS	2016	ROR	16.3	18.2	17.4	16.8	17.5	15.6	12.0	12.8	14.6	15.9	16.0	16.1	15.8
TWIN FALLS	2016	ROR	11.8	28.5	15.9	8.7	20.1	21.8	6.1	6.4	6.4	7.2	8.7	9.7	12.5
UPPER MALAD	2016	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2016	ROR	14.8	18.9	13.8	14.2	18.1	18.0	12.3	13.2	14.7	15.6	14.5	14.7	15.2
UPPER SALMON 3&4	2016	ROR	13.8	17.7	14.9	13.3	16.7	16.6	11.7	12.5	13.8	14.5	13.6	13.8	14.4
HCC TOTAL			**681.9**	**531.0**	**590.0**	**692.9**	**844.2**	**662.8**	**473.1**	**374.0**	**420.3**	**428.8**	**363.2**	**470.5**	**544.6**
ROR TOTAL			**217.5**	**295.0**	**246.3**	**246.3**	**325.7**	**335.4**	**246.3**	**240.8**	**236.4**	**224.9**	**208.0**	**212.2**	**252.6**
TOTAL			**899.4**	**826.0**	**836.3**	**939.2**	**1169.9**	**998.2**	**719.4**	**614.8**	**656.6**	**653.7**	**571.2**	**682.7**	**797.2**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2017	HCC	304.1	237.1	245.2	309.1	380.0	298.7	209.0	158.5	178.3	183.9	156.3	208.8	239.1
OXBOW	2017	HCC	127.2	104.9	105.7	126.4	152.6	120.1	88.4	72.3	81.3	81.8	69.6	87.4	101.5
HELLS CANYON	2017	HCC	249.4	209.2	216.2	256.2	310.4	242.9	174.6	142.1	159.5	161.3	138.2	173.2	202.8
1000 SPRINGS	2017	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2017	ROR	0.0	14.0	11.9	37.3	70.3	83.5	71.7	54.0	32.6	15.6	0.0	0.0	32.7
BLISS	2017	ROR	38.7	45.2	39.6	37.7	41.4	40.5	32.7	34.4	37.4	39.0	37.3	37.5	38.4
C.J. STRIKE	2017	ROR	49.8	55.5	52.2	48.6	52.7	47.3	34.3	37.3	44.7	50.0	49.3	49.3	47.5
CASCADE	2017	ROR	0.0	0.0	2.6	1.5	4.8	7.6	6.9	10.1	9.0	2.2	1.4	1.4	4.0
CLEAR LAKE	2017	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2017	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2017	ROR	23.9	30.3	25.2	22.8	27.8	28.1	20.6	21.5	23.9	25.2	23.8	23.9	24.7
MILNER	2017	ROR	8.7	26.9	12.6	4.9	17.0	17.6	0.0	0.0	0.0	0.0	3.5	6.0	8.0
SHOSHONE FALLS	2017	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.8	10.2	10.2	11.0	12.0	12.0	11.4
SWAN FALLS	2017	ROR	16.2	18.2	17.4	16.7	17.5	15.6	12.0	12.7	14.5	15.9	16.0	16.0	15.7
TWIN FALLS	2017	ROR	11.8	28.5	15.9	8.7	20.1	21.7	6.1	6.4	6.4	7.1	8.6	9.7	12.5
UPPER MALAD	2017	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2017	ROR	14.7	18.9	13.8	14.1	18.0	18.0	12.2	13.1	14.7	15.5	14.5	14.6	15.1
UPPER SALMON 3&4	2017	ROR	13.8	17.7	14.8	13.3	16.6	16.6	11.6	12.4	13.8	14.5	13.6	13.7	14.3
HCC TOTAL			**680.7**	**551.2**	**567.1**	**691.7**	**843.0**	**661.7**	**472.0**	**372.9**	**419.1**	**427.0**	**364.1**	**469.4**	**543.4**
ROR TOTAL			**216.8**	**294.9**	**245.7**	**245.4**	**325.1**	**334.4**	**244.6**	**239.5**	**235.6**	**224.2**	**207.5**	**211.4**	**251.7**
TOTAL			**897.5**	**846.1**	**812.8**	**937.1**	**1168.1**	**996.1**	**716.6**	**612.4**	**654.6**	**651.2**	**571.6**	**680.8**	**795.1**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

70th Percentile Water, 70th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2018	HCC	303.7	239.9	240.7	308.6	379.5	298.2	208.5	158.0	177.8	183.4	156.3	208.3	238.6
OXBOW	2018	HCC	127.1	106.3	104.0	126.1	152.4	119.9	88.1	72.1	81.0	81.6	69.6	87.1	101.3
HELLS CANYON	2018	HCC	249.0	212.0	212.8	255.8	310.0	242.5	174.2	141.7	159.0	160.9	138.2	172.8	202.4
1000 SPRINGS	2018	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2018	ROR	0.0	14.0	11.7	37.1	70.4	83.1	71.1	53.7	32.6	15.6	0.0	0.0	32.5
BLISS	2018	ROR	38.6	45.2	39.5	37.6	41.3	40.2	32.5	34.3	37.3	38.9	37.2	37.4	38.3
C.J. STRIKE	2018	ROR	49.6	55.5	52.0	48.4	52.5	47.1	34.1	37.0	44.6	49.8	49.1	49.1	47.3
CASCADE	2018	ROR	0.0	0.0	2.6	1.5	4.8	7.6	6.9	10.1	9.0	2.2	1.4	1.4	4.0
CLEAR LAKE	2018	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2018	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2018	ROR	23.8	30.2	25.1	22.7	27.7	27.8	20.5	21.4	23.8	25.1	23.8	23.8	24.6
MILNER	2018	ROR	8.7	26.9	12.6	4.9	17.0	17.6	0.0	0.0	0.0	0.0	3.5	6.0	8.0
SHOSHONE FALLS	2018	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.8	10.1	10.1	11.0	12.0	12.0	11.4
SWAN FALLS	2018	ROR	16.2	18.2	17.3	16.5	17.4	15.5	11.9	12.6	14.4	15.8	15.9	16.0	15.6
TWIN FALLS	2018	ROR	11.8	28.5	15.8	8.7	20.0	21.7	6.0	6.3	6.3	7.1	8.6	9.7	12.4
UPPER MALAD	2018	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2018	ROR	14.6	18.9	13.8	14.0	17.9	17.7	12.1	13.0	14.6	15.4	14.4	14.5	15.0
UPPER SALMON 3&4	2018	ROR	13.7	17.7	14.7	13.2	16.5	16.4	11.6	12.3	13.7	14.4	13.6	13.6	14.3
HCC TOTAL			**679.8**	**558.2**	**557.5**	**690.5**	**841.8**	**660.6**	**470.8**	**371.8**	**417.8**	**425.9**	**364.1**	**468.2**	**542.2**
ROR TOTAL			**216.2**	**294.8**	**244.8**	**244.4**	**324.4**	**332.6**	**243.2**	**238.2**	**234.8**	**223.5**	**207.0**	**210.8**	**250.8**
TOTAL			**896.0**	**853.0**	**802.3**	**934.9**	**1166.2**	**993.2**	**714.0**	**610.0**	**652.6**	**649.4**	**571.1**	**679.0**	**793.0**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2019	HCC	303.1	242.3	236.7	308.1	379.0	297.6	208.0	157.6	177.3	182.9	156.3	208.1	238.1
OXBOW	2019	HCC	126.8	107.6	102.4	125.9	152.2	119.6	87.9	71.9	80.8	81.4	69.6	87.0	101.1
HELLS CANYON	2019	HCC	248.6	214.5	209.8	255.4	309.6	242.1	173.8	141.2	158.6	160.5	138.2	172.6	202.0
1000 SPRINGS	2019	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2019	ROR	0.0	14.0	11.6	37.1	70.1	82.7	70.6	53.3	32.1	15.5	0.0	0.0	32.3
BLISS	2019	ROR	38.5	45.2	39.3	37.4	41.1	40.1	32.4	34.2	37.2	38.8	37.1	37.3	38.2
C.J. STRIKE	2019	ROR	49.6	55.5	51.8	48.2	52.4	46.9	33.9	36.8	44.4	49.6	48.9	49.0	47.2
CASCADE	2019	ROR	0.0	0.0	2.6	1.5	4.8	7.6	6.9	10.1	9.0	2.2	1.4	1.4	4.0
CLEAR LAKE	2019	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2019	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2019	ROR	23.7	30.1	25.0	22.7	27.6	27.7	20.4	21.3	23.7	25.0	23.8	23.7	24.5
MILNER	2019	ROR	8.7	26.9	12.6	4.9	17.0	17.6	0.0	0.0	0.0	0.0	3.5	6.0	8.0
SHOSHONE FALLS	2019	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.7	10.1	10.1	10.9	12.0	12.0	11.4
SWAN FALLS	2019	ROR	16.1	18.2	17.3	16.4	17.4	15.4	11.8	12.5	14.4	15.8	15.9	15.9	15.6
TWIN FALLS	2019	ROR	11.7	28.4	15.8	8.6	20.0	21.6	6.0	6.3	6.3	7.0	8.6	9.7	12.4
UPPER MALAD	2019	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2019	ROR	14.5	18.9	13.8	14.0	17.8	17.7	12.0	12.9	14.5	15.4	14.4	14.4	15.0
UPPER SALMON 3&4	2019	ROR	13.6	17.7	14.7	13.2	16.4	16.3	11.5	12.3	13.6	14.4	13.5	13.5	14.2
HCC TOTAL			**678.5**	**564.4**	**548.9**	**689.4**	**840.7**	**659.3**	**469.7**	**370.7**	**416.7**	**424.8**	**364.1**	**467.7**	**541.1**
ROR TOTAL			**215.6**	**294.6**	**244.2**	**243.8**	**323.5**	**331.5**	**241.9**	**237.2**	**233.7**	**222.8**	**206.6**	**210.2**	**250.1**
TOTAL			**894.1**	**859.0**	**793.1**	**933.2**	**1164.1**	**990.8**	**711.6**	**607.9**	**650.4**	**647.6**	**570.7**	**677.9**	**791.2**

2009 Integrated Resource Plan
Average Megawatt Hydro Output from PDR580
70th Percentile Water, 70th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2020	HCC	302.6	240.8	237.5	307.6	378.4	297.1	207.4	157.1	176.8	182.3	156.3	208.1	237.7
OXBOW	2020	HCC	126.6	106.8	102.7	125.7	152.0	119.4	87.7	71.6	80.6	81.1	69.6	87.0	100.9
HELLS CANYON	2020	HCC	248.2	213.0	210.4	255.0	309.2	241.7	173.3	140.8	158.2	159.9	138.2	172.6	201.7
1000 SPRINGS	2020	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2020	ROR	4.7	14.1	11.5	37.1	69.7	82.2	70.2	53.0	31.0	15.2	4.1	0.0	32.8
BLISS	2020	ROR	38.4	45.1	39.2	37.3	41.0	39.9	32.3	34.0	37.0	38.6	37.0	37.1	38.0
C.J. STRIKE	2020	ROR	49.4	55.5	51.7	48.1	52.2	46.7	33.7	36.6	44.2	49.5	48.8	48.8	47.1
CASCADE	2020	ROR	0.0	0.0	2.6	1.5	4.8	7.6	6.9	10.1	9.0	2.2	1.4	1.4	4.0
CLEAR LAKE	2020	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2020	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2020	ROR	23.6	30.0	24.9	22.7	27.5	27.6	20.3	21.2	23.6	24.9	23.7	23.6	24.4
MILNER	2020	ROR	8.7	26.9	12.6	4.9	17.0	17.6	0.0	0.0	0.0	0.0	3.5	6.0	8.0
SHOSHONE FALLS	2020	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.7	10.0	10.0	10.9	12.0	12.0	11.4
SWAN FALLS	2020	ROR	16.1	18.2	17.2	16.4	17.3	15.4	11.8	12.5	14.3	15.7	15.8	15.9	15.5
TWIN FALLS	2020	ROR	11.7	28.4	15.8	8.6	19.9	21.6	6.0	6.3	6.3	7.0	8.5	9.6	12.4
UPPER MALAD	2020	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2020	ROR	14.4	18.9	13.8	14.0	17.7	17.6	12.0	12.8	14.5	15.3	14.3	14.4	15.0
UPPER SALMON 3&4	2020	ROR	13.6	17.7	14.6	13.2	16.4	16.3	11.4	12.2	13.6	14.3	13.5	13.5	14.2
HCC TOTAL			**677.4**	**560.6**	**550.6**	**688.3**	**839.5**	**658.2**	**468.4**	**369.5**	**415.6**	**423.3**	**364.1**	**467.7**	**540.2**
ROR TOTAL			**219.8**	**294.5**	**243.6**	**243.6**	**322.4**	**330.4**	**241.0**	**236.1**	**231.9**	**221.8**	**210.1**	**209.6**	**250.1**
TOTAL			**897.2**	**855.1**	**794.2**	**931.9**	**1161.8**	**988.6**	**709.4**	**605.6**	**647.5**	**645.1**	**574.2**	**677.3**	**790.4**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2021	HCC	302.1	244.8	231.5	307.1	377.9	296.6	207.0	156.6	176.4	181.7	156.3	208.1	237.1
OXBOW	2021	HCC	126.4	108.9	100.4	125.5	151.8	119.2	87.5	71.4	80.4	80.8	69.6	87.0	100.7
HELLS CANYON	2021	HCC	247.7	217.1	205.8	254.6	308.8	241.3	172.9	140.4	157.8	159.4	138.2	172.6	201.3
1000 SPRINGS	2021	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2021	ROR	4.8	14.1	11.4	37.3	69.7	82.3	69.6	52.5	30.6	15.1	4.2	0.0	32.7
BLISS	2021	ROR	38.2	44.9	39.1	37.2	40.9	39.8	32.2	33.9	36.9	38.5	36.9	37.0	37.9
C.J. STRIKE	2021	ROR	49.2	55.5	51.5	47.9	52.0	46.5	33.5	36.4	44.1	49.3	48.6	48.6	46.9
CASCADE	2021	ROR	0.0	0.0	2.6	1.5	4.8	7.6	6.9	10.1	9.0	2.2	1.4	1.4	4.0
CLEAR LAKE	2021	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2021	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2021	ROR	23.5	29.9	24.8	22.7	27.4	27.5	20.2	21.1	23.5	24.8	23.6	23.5	24.3
MILNER	2021	ROR	8.7	26.9	12.6	4.9	17.0	17.6	0.0	0.0	0.0	0.0	3.5	6.0	8.0
SHOSHONE FALLS	2021	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.7	10.0	10.0	10.9	12.0	12.0	11.4
SWAN FALLS	2021	ROR	16.0	18.2	17.2	16.3	17.3	15.3	11.8	12.5	14.3	15.7	15.8	15.8	15.5
TWIN FALLS	2021	ROR	11.7	28.4	15.7	8.6	19.9	21.6	5.9	6.2	6.2	7.0	8.5	9.6	12.3
UPPER MALAD	2021	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2021	ROR	14.4	18.9	13.8	14.0	17.7	17.5	11.9	12.8	14.4	15.2	14.3	14.3	14.9
UPPER SALMON 3&4	2021	ROR	13.5	17.7	14.5	13.2	16.3	16.2	11.4	12.1	13.5	14.2	13.4	13.4	14.1
HCC TOTAL			**676.2**	**570.8**	**537.7**	**687.2**	**838.4**	**657.1**	**467.4**	**368.4**	**414.6**	**421.9**	**364.1**	**467.7**	**539.1**
ROR TOTAL			**219.2**	**294.2**	**242.9**	**243.4**	**321.9**	**329.8**	**239.8**	**235.0**	**230.9**	**221.1**	**209.7**	**208.9**	**249.3**
TOTAL			**895.4**	**865.0**	**780.6**	**930.6**	**1160.3**	**986.9**	**707.2**	**603.4**	**645.5**	**643.0**	**573.8**	**676.6**	**788.5**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

70th Percentile Water, 70th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2022	HCC	301.6	247.2	227.5	306.5	377.3	296.0	206.4	156.2	175.9	180.9	156.4	208.1	236.6
OXBOW	2022	HCC	126.2	110.2	98.8	125.3	151.6	119.0	87.2	71.2	80.2	80.5	69.6	87.0	100.5
HELLS CANYON	2022	HCC	247.3	219.6	202.8	254.1	308.4	240.9	172.4	140.0	157.4	158.7	138.3	172.6	200.9
1000 SPRINGS	2022	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2022	ROR	5.0	14.2	11.3	37.3	69.5	82.3	69.7	52.5	29.3	14.8	4.3	0.0	32.6
BLISS	2022	ROR	38.1	44.8	39.0	37.0	40.7	39.5	32.0	33.8	36.8	38.4	36.8	36.9	37.8
C.J. STRIKE	2022	ROR	49.1	55.5	51.3	47.7	51.9	46.3	33.3	36.4	43.9	49.1	48.4	48.4	46.7
CASCADE	2022	ROR	0.0	0.0	2.6	1.5	4.8	7.6	6.9	10.1	9.0	2.2	1.4	1.4	4.0
CLEAR LAKE	2022	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2022	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2022	ROR	23.4	29.8	24.7	22.7	27.3	27.4	20.1	21.0	23.4	24.8	23.5	23.4	24.2
MILNER	2022	ROR	8.7	26.9	12.6	4.9	17.0	17.6	0.0	0.0	0.0	0.0	3.5	6.0	8.0
SHOSHONE FALLS	2022	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.6	10.0	10.0	10.8	12.0	12.0	11.4
SWAN FALLS	2022	ROR	16.0	18.2	17.1	16.3	17.2	15.3	11.7	12.4	14.2	15.6	15.7	15.8	15.4
TWIN FALLS	2022	ROR	11.7	28.3	15.7	8.6	19.9	21.5	5.9	6.2	6.2	6.9	8.5	9.6	12.3
UPPER MALAD	2022	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2022	ROR	14.3	18.9	13.8	14.0	17.6	17.4	11.8	12.7	14.3	15.2	14.2	14.2	14.8
UPPER SALMON 3&4	2022	ROR	13.4	17.7	14.5	13.2	16.2	16.1	11.3	12.0	13.4	14.2	13.4	13.4	14.0
HCC TOTAL			**675.1**	**577.0**	**529.1**	**685.9**	**837.2**	**655.9**	**466.0**	**367.4**	**413.5**	**420.1**	**364.3**	**467.7**	**538.0**
ROR TOTAL			**218.9**	**294.0**	**242.3**	**243.0**	**321.0**	**328.9**	**239.0**	**234.5**	**228.9**	**220.2**	**209.2**	**208.4**	**248.6**
TOTAL			**894.0**	**871.0**	**771.4**	**928.9**	**1158.2**	**984.8**	**705.0**	**601.9**	**642.4**	**640.3**	**573.5**	**676.1**	**786.7**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2023	HCC	301.0	248.1	225.3	305.9	376.8	295.5	205.7	155.7	175.4	180.1	156.4	208.1	236.1
OXBOW	2023	HCC	126.0	110.7	98.0	125.1	151.3	118.8	87.0	71.0	80.0	80.1	69.6	87.0	100.3
HELLS CANYON	2023	HCC	246.9	220.5	201.2	253.7	308.0	240.4	171.9	139.6	157.0	158.0	138.2	172.6	200.5
1000 SPRINGS	2023	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2023	ROR	5.1	14.2	11.2	37.5	69.3	82.1	69.7	52.4	28.9	14.8	4.5	0.0	32.6
BLISS	2023	ROR	38.0	44.7	38.8	36.9	40.6	39.4	31.9	33.6	36.6	38.2	36.6	36.8	37.6
C.J. STRIKE	2023	ROR	48.9	55.5	51.1	47.5	51.7	46.2	33.1	36.3	43.7	48.9	48.2	48.3	46.5
CASCADE	2023	ROR	0.0	0.0	2.6	1.5	4.8	7.6	6.9	10.1	9.0	2.2	1.4	1.4	4.0
CLEAR LAKE	2023	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2023	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2023	ROR	23.3	29.7	24.6	22.6	27.2	27.1	20.0	20.9	23.3	24.7	23.4	23.3	24.1
MILNER	2023	ROR	8.7	26.9	12.6	4.9	17.0	17.6	0.0	0.0	0.0	0.0	3.5	6.0	8.0
SHOSHONE FALLS	2023	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.6	9.9	9.9	10.8	12.0	12.0	11.3
SWAN FALLS	2023	ROR	15.9	18.2	17.1	16.2	17.2	15.2	11.6	12.4	14.2	15.6	15.7	15.7	15.4
TWIN FALLS	2023	ROR	11.7	28.3	15.7	8.5	19.9	21.5	5.8	6.2	6.2	6.9	8.5	9.6	12.3
UPPER MALAD	2023	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2023	ROR	14.2	18.9	13.8	13.9	17.5	17.2	11.7	12.6	14.2	15.1	14.2	14.2	14.8
UPPER SALMON 3&4	2023	ROR	13.3	17.7	14.4	13.1	16.2	15.9	11.2	12.0	13.4	14.1	13.3	13.3	14.0
HCC TOTAL			**673.9**	**579.3**	**524.5**	**684.7**	**836.0**	**654.7**	**464.6**	**366.3**	**412.4**	**418.2**	**364.2**	**467.7**	**536.9**
ROR TOTAL			**218.3**	**293.8**	**241.6**	**242.4**	**320.3**	**327.7**	**238.2**	**233.8**	**227.8**	**219.5**	**208.8**	**207.9**	**247.9**
TOTAL			**892.2**	**873.1**	**766.1**	**927.1**	**1156.3**	**982.4**	**702.8**	**600.1**	**640.1**	**637.7**	**573.0**	**675.6**	**784.9**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

70th Percentile Water, 70th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2024	HCC	300.5	240.6	233.4	305.4	376.2	294.9	205.1	155.2	175.0	179.3	156.2	208.1	235.8
OXBOW	2024	HCC	125.7	106.8	101.1	124.9	151.1	118.6	86.7	70.8	79.7	79.7	69.5	87.0	100.1
HELLS CANYON	2024	HCC	246.4	213.1	207.1	253.3	307.5	240.0	171.4	139.2	156.6	157.2	138.1	172.6	200.2
1000 SPRINGS	2024	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2024	ROR	5.2	14.3	11.1	37.6	69.4	82.2	69.3	52.2	28.5	14.7	4.5	0.0	32.4
BLISS	2024	ROR	37.8	44.6	38.7	36.8	40.5	39.1	31.8	33.5	36.5	38.1	36.5	36.6	37.5
C.J. STRIKE	2024	ROR	48.7	55.5	51.0	47.4	51.5	45.8	33.0	36.1	43.5	48.7	48.1	48.1	46.4
CASCADE	2024	ROR	0.0	0.0	2.6	1.5	4.8	7.6	6.9	10.1	9.0	2.2	1.4	1.4	4.0
CLEAR LAKE	2024	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2024	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2024	ROR	23.2	29.6	24.6	22.5	27.1	26.9	19.9	20.8	23.2	24.6	23.3	23.2	24.0
MILNER	2024	ROR	8.7	26.9	12.6	4.9	17.0	17.6	0.0	0.0	0.0	0.0	3.5	6.0	8.0
SHOSHONE FALLS	2024	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.5	9.9	9.9	10.7	12.0	12.0	11.3
SWAN FALLS	2024	ROR	15.9	18.2	17.0	16.2	17.1	15.4	11.6	12.4	14.2	15.5	15.6	15.7	15.4
TWIN FALLS	2024	ROR	11.7	28.3	15.6	8.5	19.8	21.5	5.8	6.1	6.1	6.8	8.4	9.5	12.3
UPPER MALAD	2024	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2024	ROR	14.1	18.9	13.8	13.9	17.4	17.0	11.6	12.5	14.1	15.0	14.1	14.1	14.7
UPPER SALMON 3&4	2024	ROR	13.3	17.7	14.4	13.1	16.1	15.8	11.2	11.9	13.3	14.0	13.2	13.3	13.9
HCC TOTAL			**672.6**	**560.5**	**541.6**	**683.6**	**834.8**	**653.5**	**463.2**	**365.2**	**411.2**	**416.2**	**363.8**	**467.7**	**536.1**
ROR TOTAL			**217.8**	**293.7**	**241.1**	**242.2**	**319.6**	**326.8**	**237.3**	**232.9**	**226.7**	**218.5**	**208.1**	**207.2**	**247.4**
TOTAL			**890.4**	**854.2**	**782.7**	**925.8**	**1154.3**	**980.3**	**700.5**	**598.1**	**637.9**	**634.7**	**571.9**	**674.9**	**783.5**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2025	HCC	300.0	246.5	225.0	304.9	375.7	282.8	204.6	154.8	174.5	178.3	156.5	208.1	234.3
OXBOW	2025	HCC	125.5	110.0	97.8	124.7	150.9	116.9	86.5	70.6	79.5	79.2	69.6	87.0	99.8
HELLS CANYON	2025	HCC	246.1	219.1	200.8	252.9	307.1	238.7	170.9	138.8	156.1	156.3	138.2	172.6	199.7
1000 SPRINGS	2025	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2025	ROR	5.3	14.4	11.1	37.8	69.1	80.7	69.1	52.0	28.6	14.8	4.4	0.0	32.4
BLISS	2025	ROR	37.7	44.5	38.6	36.6	40.4	38.8	31.6	33.4	36.4	38.0	36.4	36.5	37.4
C.J. STRIKE	2025	ROR	48.5	55.5	50.8	47.2	51.5	45.3	32.8	35.9	43.4	48.6	47.9	47.9	46.2
CASCADE	2025	ROR	0.0	0.0	2.6	1.5	4.8	7.6	6.9	10.1	9.0	2.2	1.4	1.4	4.0
CLEAR LAKE	2025	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2025	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2025	ROR	23.1	29.5	24.6	22.4	27.0	26.5	19.8	20.7	23.1	24.5	23.2	23.1	23.9
MILNER	2025	ROR	8.7	26.9	12.6	4.9	17.0	17.6	0.0	0.0	0.0	0.0	3.5	6.0	8.0
SHOSHONE FALLS	2025	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.5	9.8	9.8	10.7	12.0	12.0	11.3
SWAN FALLS	2025	ROR	15.8	18.2	17.0	16.1	17.1	15.2	11.5	12.3	14.2	15.5	15.6	15.6	15.3
TWIN FALLS	2025	ROR	11.7	28.2	15.6	8.5	19.8	20.7	5.8	6.1	6.1	6.8	8.4	9.5	12.2
UPPER MALAD	2025	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2025	ROR	14.0	18.9	13.8	13.8	17.3	16.8	11.6	12.4	14.0	14.9	14.0	14.0	14.6
UPPER SALMON 3&4	2025	ROR	13.2	17.7	14.4	13.0	16.0	15.6	11.1	11.8	13.2	14.0	13.2	13.2	13.8
HCC TOTAL			**671.6**	**575.6**	**523.6**	**682.5**	**833.6**	**638.4**	**462.0**	**364.2**	**410.1**	**413.8**	**364.3**	**467.7**	**533.7**
ROR TOTAL			**217.2**	**293.5**	**240.8**	**241.6**	**318.9**	**322.7**	**236.4**	**231.9**	**226.2**	**218.2**	**207.5**	**206.5**	**246.4**
TOTAL			**888.8**	**869.1**	**764.4**	**924.1**	**1152.5**	**961.1**	**698.4**	**596.1**	**636.3**	**632.0**	**571.8**	**674.2**	**780.1**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580
70th Percentile Water, 70th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2026	HCC	299.5	247.4	222.9	304.3	375.1	282.2	204.0	154.3	174.0	177.5	156.4	208.1	233.7
OXBOW	2026	HCC	125.3	110.4	97.0	124.4	150.7	116.7	86.2	70.3	79.3	78.8	69.5	87.0	99.6
HELLS CANYON	2026	HCC	245.6	220.0	199.2	252.5	306.7	238.2	170.5	138.3	155.7	155.5	138.1	172.6	199.3
1000 SPRINGS	2026	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2026	ROR	5.5	14.5	11.1	38.5	68.9	80.8	68.8	52.0	28.7	14.8	4.4	4.4	32.8
BLISS	2026	ROR	37.6	44.3	38.4	36.5	40.2	38.7	31.5	33.2	36.2	37.8	36.2	36.4	37.2
C.J. STRIKE	2026	ROR	48.3	55.5	50.6	47.0	51.3	44.3	32.6	35.8	43.2	48.4	47.7	47.7	46.0
CASCADE	2026	ROR	0.0	0.0	2.6	1.5	4.8	7.6	6.9	10.1	9.0	2.2	1.4	1.4	4.0
CLEAR LAKE	2026	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2026	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2026	ROR	23.0	29.4	24.6	22.3	26.9	26.5	19.7	20.6	23.0	24.4	23.1	23.0	23.8
MILNER	2026	ROR	8.7	26.9	12.6	4.9	17.0	17.6	0.0	0.0	0.0	0.0	3.5	6.0	8.0
SHOSHONE FALLS	2026	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.5	9.8	9.8	10.6	12.0	12.0	11.3
SWAN FALLS	2026	ROR	15.8	18.1	16.9	16.1	17.1	14.9	11.4	12.2	14.1	15.4	15.5	15.6	15.2
TWIN FALLS	2026	ROR	11.7	28.2	15.6	8.5	19.8	20.7	5.7	6.0	6.0	6.8	8.4	9.5	12.1
UPPER MALAD	2026	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2026	ROR	14.0	18.9	13.8	13.7	17.3	16.7	11.5	12.4	14.0	14.9	13.9	13.9	14.5
UPPER SALMON 3&4	2026	ROR	13.1	17.6	14.4	12.9	16.0	15.5	11.0	11.8	13.1	13.9	13.1	13.1	13.8
HCC TOTAL			**670.4**	**577.8**	**519.1**	**681.2**	**832.4**	**637.1**	**460.7**	**362.9**	**408.9**	**411.8**	**364.0**	**467.7**	**532.6**
ROR TOTAL			**216.9**	**293.1**	**240.3**	**241.7**	**318.2**	**321.2**	**235.3**	**231.3**	**225.5**	**217.4**	**206.7**	**210.3**	**246.1**
TOTAL			**887.3**	**870.9**	**759.4**	**922.9**	**1150.6**	**958.3**	**696.0**	**594.2**	**634.4**	**629.2**	**570.7**	**678.0**	**778.7**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2027	HCC	299.0	246.7	222.7	303.8	374.6	281.7	203.4	153.7	173.5	169.2	156.6	208.1	232.7
OXBOW	2027	HCC	125.1	110.1	96.9	124.2	150.5	116.5	86.0	70.0	79.1	78.3	69.6	87.0	99.4
HELLS CANYON	2027	HCC	245.2	219.4	199.0	252.1	306.3	237.8	170.0	137.8	155.3	154.1	138.2	172.6	198.8
1000 SPRINGS	2027	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2027	ROR	5.6	14.5	11.1	38.7	68.9	80.8	68.8	51.9	28.8	14.9	4.4	4.7	32.8
BLISS	2027	ROR	37.5	44.2	38.3	36.4	40.1	38.6	31.5	33.1	36.1	37.7	36.2	36.3	37.1
C.J. STRIKE	2027	ROR	48.2	55.5	50.5	46.8	51.1	44.2	32.4	35.6	43.0	48.3	47.5	47.6	45.8
CASCADE	2027	ROR	0.0	0.0	2.6	1.5	4.8	7.6	6.9	10.1	9.0	2.2	1.4	1.4	4.0
CLEAR LAKE	2027	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2027	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2027	ROR	22.9	29.3	24.6	22.2	26.8	26.4	19.6	20.5	22.9	24.3	23.0	22.9	23.7
MILNER	2027	ROR	8.7	26.9	12.6	4.9	17.0	17.6	0.0	0.0	0.0	0.0	3.5	6.0	8.0
SHOSHONE FALLS	2027	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.4	9.7	9.8	10.6	12.0	12.0	11.3
SWAN FALLS	2027	ROR	15.7	18.1	16.9	16.0	17.0	14.8	11.4	12.2	14.1	15.4	15.5	15.5	15.2
TWIN FALLS	2027	ROR	11.7	28.2	15.6	8.4	19.7	20.6	5.7	6.0	6.0	6.7	8.4	9.5	12.1
UPPER MALAD	2027	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2027	ROR	13.9	18.9	13.8	13.6	17.2	16.6	11.4	12.3	13.9	14.8	13.8	13.8	14.5
UPPER SALMON 3&4	2027	ROR	13.1	17.5	14.4	12.8	15.9	15.4	11.0	11.7	13.1	13.8	13.0	13.0	13.7
HCC TOTAL			**669.3**	**576.2**	**518.6**	**680.1**	**831.3**	**636.0**	**459.4**	**361.5**	**407.9**	**401.6**	**364.4**	**467.7**	**530.9**
ROR TOTAL			**216.5**	**292.8**	**240.1**	**241.1**	**317.4**	**320.5**	**234.8**	**230.5**	**225.1**	**216.9**	**206.2**	**210.0**	**245.6**
TOTAL			**885.8**	**869.0**	**758.7**	**921.2**	**1148.6**	**956.5**	**694.2**	**592.0**	**633.0**	**618.5**	**570.6**	**677.7**	**776.5**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

70th Percentile Water, 70th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2028	HCC	298.4	244.0	224.8	303.2	374.0	281.2	202.8	153.1	173.0	168.4	156.5	208.1	232.3
OXBOW	2028	HCC	124.9	108.8	97.7	124.0	150.3	116.3	85.7	69.8	78.8	77.9	69.6	87.0	99.2
HELLS CANYON	2028	HCC	244.8	216.8	200.6	251.6	305.9	237.4	169.5	137.3	154.9	153.4	138.1	172.6	198.5
1000 SPRINGS	2028	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2028	ROR	5.7	14.5	10.9	38.9	68.8	80.7	68.7	51.8	28.8	15.0	4.4	4.9	32.8
BLISS	2028	ROR	37.3	44.1	38.2	36.2	40.0	38.4	31.4	32.8	36.0	37.6	36.2	36.2	37.0
C.J. STRIKE	2028	ROR	48.0	55.5	50.3	46.7	51.0	44.0	32.2	35.3	42.9	48.1	47.4	47.4	45.7
CASCADE	2028	ROR	0.0	0.0	2.6	1.5	4.8	7.6	6.9	10.1	9.0	2.2	1.4	1.4	4.0
CLEAR LAKE	2028	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2028	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2028	ROR	22.8	29.2	24.5	22.1	26.7	26.2	19.5	20.4	22.8	24.1	22.9	22.8	23.6
MILNER	2028	ROR	8.7	26.9	12.6	4.9	17.0	17.6	0.0	0.0	0.0	0.0	3.5	6.0	8.0
SHOSHONE FALLS	2028	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.4	9.7	9.7	10.6	12.0	12.0	11.3
SWAN FALLS	2028	ROR	15.7	18.0	16.8	16.0	17.0	14.8	11.3	12.1	14.2	15.3	15.4	15.5	15.2
TWIN FALLS	2028	ROR	11.7	28.1	15.6	8.4	19.7	20.6	5.7	6.0	6.0	6.7	8.3	9.4	12.1
UPPER MALAD	2028	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2028	ROR	13.8	18.9	13.8	13.5	17.1	16.5	11.3	12.2	13.8	14.7	13.8	13.8	14.4
UPPER SALMON 3&4	2028	ROR	13.0	17.5	14.3	12.8	15.8	15.3	10.9	11.6	13.0	13.8	13.0	13.0	13.6
HCC TOTAL			**668.1**	**569.6**	**523.1**	**678.8**	**830.1**	**634.9**	**458.0**	**360.2**	**406.7**	**399.7**	**364.2**	**467.7**	**530.0**
ROR TOTAL			**215.9**	**292.4**	**239.3**	**240.8**	**316.8**	**319.6**	**234.0**	**229.4**	**224.6**	**216.3**	**205.8**	**209.7**	**245.1**
TOTAL			**884.0**	**862.0**	**762.4**	**919.6**	**1146.9**	**954.5**	**692.0**	**589.6**	**631.3**	**616.0**	**570.0**	**677.4**	**775.1**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2029	HCC	297.9	246.4	220.8	302.7	373.5	280.6	202.3	152.7	172.6	167.6	156.4	208.1	231.7
OXBOW	2029	HCC	124.7	110.0	96.1	123.8	150.1	116.0	85.5	69.6	78.6	77.5	69.5	87.0	99.0
HELLS CANYON	2029	HCC	244.4	219.3	197.5	251.2	305.5	236.9	169.0	136.9	154.5	152.7	138.0	172.6	198.1
1000 SPRINGS	2029	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2029	ROR	5.9	14.6	10.9	39.1	68.7	80.7	68.6	51.7	28.9	15.0	4.3	5.1	32.9
BLISS	2029	ROR	37.2	44.0	38.1	36.2	39.9	38.3	31.3	32.7	35.9	37.5	36.2	36.1	36.9
C.J. STRIKE	2029	ROR	47.8	55.5	50.1	46.5	50.8	43.8	32.0	35.2	42.7	47.9	47.2	47.2	45.5
CASCADE	2029	ROR	0.0	0.0	2.6	1.5	4.8	7.6	6.9	10.1	9.0	2.2	1.4	1.4	4.0
CLEAR LAKE	2029	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2029	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2029	ROR	22.8	29.1	24.3	22.0	26.6	26.1	19.4	20.2	22.6	24.0	22.8	22.7	23.5
MILNER	2029	ROR	8.7	26.9	12.6	4.9	17.0	17.6	0.0	0.0	0.0	0.0	3.5	6.0	8.0
SHOSHONE FALLS	2029	ROR	12.0	12.0	12.0	12.0	12.0	12.0	9.3	9.7	9.7	10.5	12.0	12.0	11.3
SWAN FALLS	2029	ROR	15.6	18.0	16.8	15.9	16.9	14.7	11.2	12.0	14.1	15.3	15.4	15.4	15.1
TWIN FALLS	2029	ROR	11.7	28.1	15.6	8.4	19.6	20.6	5.6	5.9	5.9	6.7	8.3	9.4	12.0
UPPER MALAD	2029	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2029	ROR	13.8	18.9	13.8	13.5	17.0	16.5	11.3	12.1	13.7	14.6	13.7	13.7	14.3
UPPER SALMON 3&4	2029	ROR	13.0	17.4	14.2	12.7	15.8	15.3	10.8	11.6	12.9	13.7	12.9	12.9	13.6
HCC TOTAL			**667.0**	**575.7**	**514.4**	**677.7**	**829.0**	**633.5**	**456.8**	**359.2**	**405.6**	**397.8**	**363.9**	**467.7**	**528.7**
ROR TOTAL			**215.7**	**292.2**	**238.7**	**240.5**	**316.0**	**319.1**	**233.1**	**228.6**	**223.8**	**215.6**	**205.2**	**209.2**	**244.4**
TOTAL			**882.7**	**867.9**	**753.1**	**918.2**	**1145.0**	**952.6**	**689.9**	**587.8**	**629.4**	**613.4**	**569.1**	**676.9**	**773.1**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

90th Percentile Water, 70th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2010	HCC	259.6	199.2	173.4	242.2	266.2	213.5	210.2	146.5	166.2	149.9	158.2	195.8	198.4
OXBOW	2010	HCC	111.7	88.9	77.7	100.7	110.1	88.0	88.5	66.6	75.6	68.5	69.7	81.5	85.6
HELLS CANYON	2010	HCC	219.9	176.4	158.7	204.6	226.2	177.0	173.9	130.9	148.1	135.3	138.0	161.2	170.8
1000 SPRINGS	2010	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2010	ROR	0.0	0.0	5.7	33.7	71.3	83.8	83.5	54.7	25.7	9.2	0.0	0.0	30.8
BLISS	2010	ROR	35.8	36.3	34.7	34.2	38.2	37.9	36.0	33.9	36.5	38.4	36.5	36.4	36.2
C.J. STRIKE	2010	ROR	45.6	45.8	45.3	42.7	45.4	41.3	36.4	35.6	42.8	47.9	46.3	45.8	43.4
CASCADE	2010	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
CLEAR LAKE	2010	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2010	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2010	ROR	22.9	23.5	21.6	21.3	25.8	25.7	23.5	21.3	23.2	24.9	23.4	23.4	23.4
MILNER	2010	ROR	6.4	6.8	2.0	0.0	8.8	13.1	9.4	0.0	0.0	0.0	1.8	5.5	4.5
SHOSHONE FALLS	2010	ROR	12.0	12.0	10.2	8.0	12.0	12.0	12.0	9.7	7.3	9.5	11.5	12.0	10.7
SWAN FALLS	2010	ROR	15.3	15.2	15.3	14.6	15.3	14.6	12.7	12.1	14.2	15.4	15.3	15.2	14.6
TWIN FALLS	2010	ROR	9.8	9.7	6.4	4.3	12.0	16.9	13.2	6.0	3.8	5.8	7.5	9.4	8.7
UPPER MALAD	2010	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2010	ROR	13.9	14.5	13.1	12.9	16.4	16.1	14.4	12.9	14.1	15.3	14.1	14.2	14.3
UPPER SALMON 3&4	2010	ROR	13.1	13.6	12.4	12.2	15.3	15.0	13.5	12.3	13.3	14.3	13.3	13.4	13.5
HCC TOTAL			**591.2**	**464.5**	**409.8**	**547.5**	**602.5**	**478.5**	**472.6**	**344.0**	**389.9**	**353.7**	**365.9**	**438.5**	**454.9**
ROR TOTAL			**203.4**	**206.5**	**195.8**	**213.0**	**288.9**	**306.5**	**288.3**	**235.7**	**216.5**	**210.4**	**198.5**	**204.0**	**230.8**
TOTAL			**794.6**	**671.0**	**605.6**	**760.5**	**891.4**	**785.0**	**760.9**	**579.7**	**606.4**	**564.1**	**564.4**	**642.5**	**685.7**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2011	HCC	259.4	199.0	173.3	242.2	266.1	213.5	210.1	146.4	166.1	149.8	158.1	195.6	198.3
OXBOW	2011	HCC	111.6	88.8	77.6	100.7	110.1	88.0	88.5	66.6	75.6	68.5	69.6	81.5	85.6
HELLS CANYON	2011	HCC	219.8	176.3	158.6	204.6	226.1	177.0	173.8	130.8	148.0	135.2	137.9	161.0	170.8
1000 SPRINGS	2011	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2011	ROR	0.0	0.0	5.7	33.7	71.3	83.8	83.2	54.7	25.7	9.2	0.0	0.0	30.8
BLISS	2011	ROR	35.8	36.2	34.7	34.2	38.2	37.8	36.0	33.9	36.5	38.3	36.5	36.3	36.2
C.J. STRIKE	2011	ROR	45.5	45.8	45.3	42.7	45.4	41.3	36.4	35.6	42.7	47.9	46.3	45.7	43.4
CASCADE	2011	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
CLEAR LAKE	2011	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2011	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2011	ROR	22.8	23.5	21.6	21.3	25.8	25.7	23.4	21.3	23.2	24.9	23.3	23.4	23.3
MILNER	2011	ROR	6.4	6.7	2.0	0.0	8.8	13.1	9.4	0.0	0.0	0.0	1.8	5.5	4.5
SHOSHONE FALLS	2011	ROR	12.0	12.0	10.2	8.0	12.0	12.0	12.0	9.7	7.3	9.5	11.5	12.0	10.7
SWAN FALLS	2011	ROR	15.2	15.2	15.3	14.6	15.3	14.6	12.7	12.1	14.2	15.4	15.3	15.2	14.6
TWIN FALLS	2011	ROR	9.8	9.7	6.4	4.3	12.0	16.9	13.2	5.9	3.8	5.8	7.5	9.4	8.7
UPPER MALAD	2011	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2011	ROR	13.8	14.5	13.1	12.9	16.4	16.1	14.4	12.9	14.1	15.3	14.1	14.2	14.3
UPPER SALMON 3&4	2011	ROR	13.0	13.6	12.4	12.2	15.3	15.0	13.5	12.3	13.3	14.3	13.3	13.4	13.5
HCC TOTAL			**590.8**	**464.1**	**409.5**	**547.5**	**602.2**	**478.5**	**472.4**	**343.8**	**389.7**	**353.5**	**365.6**	**438.1**	**454.7**
ROR TOTAL			**202.9**	**206.3**	**195.8**	**213.0**	**288.9**	**306.4**	**287.9**	**235.6**	**216.4**	**210.3**	**198.4**	**203.8**	**230.6**
TOTAL			**793.7**	**670.4**	**605.3**	**760.5**	**891.1**	**784.9**	**760.3**	**579.4**	**606.1**	**563.8**	**564.0**	**641.9**	**685.3**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

90th Percentile Water, 70th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2012	HCC	259.2	198.8	173.2	242.2	266.0	213.5	209.9	146.3	166.0	149.4	158.4	195.4	198.2
OXBOW	2012	HCC	111.5	88.7	77.6	100.7	110.1	88.0	88.4	66.5	75.5	68.2	69.7	81.4	85.5
HELLS CANYON	2012	HCC	219.6	176.1	158.6	204.6	226.1	177.0	173.8	130.7	147.9	134.8	138.1	160.9	170.7
1000 SPRINGS	2012	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2012	ROR	0.0	0.0	5.7	33.7	71.2	83.9	82.9	54.4	25.7	9.2	0.0	0.0	30.7
BLISS	2012	ROR	35.7	36.2	34.7	34.2	38.2	37.8	36.0	33.9	36.5	38.3	36.4	36.3	36.2
C.J. STRIKE	2012	ROR	45.4	45.7	45.3	42.7	45.4	41.2	36.3	35.5	42.7	47.8	46.2	45.6	43.3
CASCADE	2012	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
CLEAR LAKE	2012	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2012	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2012	ROR	22.8	23.4	21.5	21.3	25.8	25.6	23.4	21.3	23.2	24.9	23.3	23.4	23.3
MILNER	2012	ROR	6.3	6.7	2.0	0.0	8.8	13.1	9.4	0.0	0.0	0.0	1.8	5.4	4.5
SHOSHONE FALLS	2012	ROR	12.0	12.0	10.2	8.0	12.0	12.0	12.0	9.7	7.3	9.5	11.4	12.0	10.7
SWAN FALLS	2012	ROR	15.2	15.2	15.2	14.6	15.3	14.6	12.7	12.1	14.2	15.4	15.3	15.2	14.6
TWIN FALLS	2012	ROR	9.7	9.6	6.4	4.3	12.0	16.9	13.2	5.9	3.8	5.8	7.5	9.3	8.7
UPPER MALAD	2012	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2012	ROR	13.8	14.4	13.1	12.9	16.4	16.1	14.4	12.9	14.1	15.3	14.1	14.2	14.3
UPPER SALMON 3&4	2012	ROR	13.0	13.5	12.4	12.2	15.2	14.9	13.5	12.2	13.3	14.3	13.2	13.3	13.4
HCC TOTAL			**590.3**	**463.6**	**409.4**	**547.5**	**602.1**	**478.5**	**472.1**	**343.5**	**389.4**	**352.4**	**366.2**	**437.7**	**454.4**
ROR TOTAL			**202.5**	**205.8**	**195.6**	**213.0**	**288.8**	**306.2**	**287.5**	**235.1**	**216.4**	**210.2**	**198.0**	**203.4**	**230.3**
TOTAL			**792.8**	**669.4**	**605.0**	**760.5**	**890.9**	**784.7**	**759.6**	**578.6**	**605.8**	**562.6**	**564.2**	**641.1**	**684.7**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2013	HCC	259.0	198.7	189.3	230.3	265.9	213.5	209.9	146.2	165.9	149.3	158.3	195.2	198.5
OXBOW	2013	HCC	111.4	88.6	82.0	96.2	110.0	88.0	88.4	66.5	75.5	68.2	69.7	81.3	85.5
HELLS CANYON	2013	HCC	219.4	176.0	167.3	195.8	226.0	177.0	173.7	130.6	147.8	134.7	138.0	160.7	170.6
1000 SPRINGS	2013	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2013	ROR	0.0	0.0	5.7	33.8	71.2	84.0	82.5	54.0	25.7	9.2	0.0	0.0	30.7
BLISS	2013	ROR	35.7	36.1	34.6	34.2	38.1	37.8	35.9	33.8	36.4	38.3	36.4	36.3	36.1
C.J. STRIKE	2013	ROR	45.4	45.6	45.2	42.6	45.3	41.2	36.3	35.4	42.6	47.8	46.2	45.6	43.2
CASCADE	2013	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
CLEAR LAKE	2013	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2013	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2013	ROR	22.8	23.4	21.5	21.3	25.8	25.6	23.4	21.2	23.2	24.9	23.3	23.3	23.3
MILNER	2013	ROR	6.2	6.6	2.0	0.0	8.8	13.1	9.4	0.0	0.0	0.0	1.8	5.3	4.4
SHOSHONE FALLS	2013	ROR	12.0	12.0	10.2	8.0	12.0	12.0	12.0	9.7	7.3	9.5	11.4	12.0	10.7
SWAN FALLS	2013	ROR	15.2	15.4	15.2	14.6	15.3	14.5	12.7	12.1	14.2	15.4	15.3	15.4	14.6
TWIN FALLS	2013	ROR	9.7	9.6	6.4	4.3	12.0	16.9	13.2	5.9	3.8	5.8	7.5	9.3	8.7
UPPER MALAD	2013	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2013	ROR	13.8	14.4	13.1	12.9	16.4	16.1	14.3	12.9	14.1	15.2	14.1	14.2	14.3
UPPER SALMON 3&4	2013	ROR	13.0	13.5	12.4	12.2	15.2	14.9	13.5	12.2	13.3	14.2	13.2	13.3	13.4
HCC TOTAL			**589.8**	**463.3**	**438.6**	**522.3**	**601.8**	**478.5**	**472.0**	**343.3**	**389.2**	**352.2**	**366.0**	**437.2**	**454.6**
ROR TOTAL			**202.4**	**205.7**	**195.4**	**213.0**	**288.6**	**306.2**	**286.9**	**234.4**	**216.2**	**210.0**	**198.0**	**203.4**	**230.2**
TOTAL			**792.2**	**669.0**	**634.0**	**735.3**	**890.4**	**784.7**	**758.9**	**577.7**	**605.4**	**562.2**	**564.0**	**640.6**	**684.8**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

90th Percentile Water, 70th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2014	HCC	258.4	198.0	202.7	211.8	265.4	213.5	195.8	145.7	165.4	148.2	158.6	194.8	196.6
OXBOW	2014	HCC	111.2	88.4	88.5	89.1	109.8	88.0	82.4	66.2	75.3	67.7	69.8	81.1	84.8
HELLS CANYON	2014	HCC	219.0	175.4	180.1	182.2	225.6	177.0	162.1	130.2	147.4	133.7	138.2	160.4	169.3
1000 SPRINGS	2014	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2014	ROR	0.0	0.0	5.6	33.8	71.0	83.5	76.9	52.4	25.6	9.4	0.0	0.0	30.0
BLISS	2014	ROR	35.5	36.0	34.5	34.0	38.0	37.6	32.3	33.7	36.3	38.1	36.3	36.1	35.7
C.J. STRIKE	2014	ROR	45.2	45.5	45.1	42.5	45.2	41.0	31.5	35.2	42.5	47.6	46.0	45.4	42.7
CASCADE	2014	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
CLEAR LAKE	2014	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2014	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2014	ROR	22.8	23.3	21.4	21.2	25.7	25.5	20.3	21.1	23.1	24.8	23.2	23.2	23.0
MILNER	2014	ROR	6.2	6.4	2.0	0.0	8.8	13.1	0.0	0.0	0.0	0.0	1.8	5.2	3.6
SHOSHONE FALLS	2014	ROR	12.0	12.0	10.2	8.0	12.0	12.0	8.9	9.6	7.2	9.4	11.4	12.0	10.4
SWAN FALLS	2014	ROR	15.4	15.4	15.2	14.5	15.3	14.5	11.1	12.0	14.1	15.3	15.2	15.4	14.4
TWIN FALLS	2014	ROR	9.4	9.3	6.4	4.3	11.9	16.9	5.3	5.9	3.7	5.7	7.4	9.1	7.9
UPPER MALAD	2014	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2014	ROR	13.8	14.3	13.0	12.9	16.3	16.0	11.9	12.8	14.0	15.2	14.0	14.0	14.0
UPPER SALMON 3&4	2014	ROR	13.0	13.5	12.3	12.2	15.2	14.9	11.4	12.1	13.2	14.2	13.2	13.2	13.2
HCC TOTAL			**588.6**	**461.8**	**471.3**	**483.1**	**600.7**	**478.5**	**440.3**	**342.1**	**388.0**	**349.6**	**366.6**	**436.3**	**450.7**
ROR TOTAL			**201.9**	**204.8**	**194.8**	**212.5**	**287.8**	**305.1**	**243.3**	**232.0**	**215.4**	**209.4**	**197.3**	**202.3**	**225.6**
TOTAL			**790.5**	**666.6**	**666.1**	**695.6**	**888.5**	**783.6**	**683.6**	**574.1**	**603.4**	**559.0**	**563.9**	**638.6**	**676.4**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2015	HCC	258.0	197.5	207.5	204.3	264.8	213.5	195.3	145.1	165.0	147.5	158.5	194.8	196.1
OXBOW	2015	HCC	111.0	88.1	90.9	86.2	109.6	88.0	82.2	65.9	75.1	67.3	69.7	81.1	84.6
HELLS CANYON	2015	HCC	218.6	175.0	184.7	176.5	225.2	177.0	161.6	129.6	147.0	133.0	138.1	160.4	168.9
1000 SPRINGS	2015	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2015	ROR	0.0	0.0	5.5	34.3	70.6	80.5	74.1	51.0	25.1	9.4	0.0	0.0	29.4
BLISS	2015	ROR	35.4	35.9	34.4	33.9	37.9	37.1	32.1	33.6	36.0	38.0	36.2	36.0	35.5
C.J. STRIKE	2015	ROR	45.0	45.3	44.9	42.3	45.0	40.5	31.3	35.0	42.3	47.4	45.8	45.2	42.5
CASCADE	2015	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
CLEAR LAKE	2015	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2015	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2015	ROR	22.7	23.2	21.3	21.1	25.6	25.3	20.1	21.0	22.9	24.7	23.1	23.1	22.8
MILNER	2015	ROR	5.9	6.0	2.0	0.0	8.8	10.5	0.0	0.0	0.0	0.0	1.8	5.0	3.3
SHOSHONE FALLS	2015	ROR	12.0	12.0	10.1	7.9	12.0	12.0	8.9	9.6	7.2	9.4	11.3	12.0	10.4
SWAN FALLS	2015	ROR	15.3	15.3	15.1	14.4	15.2	14.4	11.0	12.0	14.1	15.3	15.2	15.4	14.4
TWIN FALLS	2015	ROR	9.4	9.3	6.3	4.2	11.9	15.1	5.3	5.9	3.7	5.7	7.4	9.0	7.8
UPPER MALAD	2015	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2015	ROR	13.7	14.2	12.9	12.8	16.2	15.8	11.8	12.7	13.9	15.1	13.9	14.0	13.9
UPPER SALMON 3&4	2015	ROR	12.9	13.4	12.2	12.1	15.1	14.7	11.3	12.0	13.1	14.1	13.1	13.1	13.1
HCC TOTAL			**587.6**	**460.6**	**483.1**	**467.0**	**599.5**	**478.5**	**439.1**	**340.6**	**387.0**	**347.8**	**366.3**	**436.3**	**449.6**
ROR TOTAL			**200.9**	**203.7**	**193.8**	**212.1**	**286.7**	**296.0**	**239.6**	**230.0**	**214.0**	**208.8**	**196.6**	**201.5**	**223.7**
TOTAL			**788.5**	**664.3**	**676.9**	**679.1**	**886.2**	**774.5**	**678.7**	**570.6**	**601.0**	**556.6**	**562.9**	**637.8**	**673.4**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

90th Percentile Water, 70th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2016	HCC	257.5	197.1	183.8	234.3	264.3	213.5	194.8	144.5	164.5	146.4	158.8	194.1	196.2
OXBOW	2016	HCC	110.8	87.9	79.4	97.6	109.4	88.0	82.0	65.7	74.9	66.8	69.8	80.8	84.4
HELLS CANYON	2016	HCC	218.2	174.6	162.4	198.7	224.7	177.0	161.2	129.1	146.7	132.0	138.3	159.8	168.6
1000 SPRINGS	2016	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2016	ROR	0.0	0.0	5.4	34.6	70.6	79.1	73.7	48.2	25.1	9.2	0.0	0.0	28.9
BLISS	2016	ROR	35.3	35.7	34.2	33.8	37.7	37.1	31.8	33.3	35.9	37.9	36.2	35.9	35.4
C.J. STRIKE	2016	ROR	44.8	45.1	44.7	42.1	44.8	40.3	31.2	34.8	42.1	47.3	45.7	45.0	42.3
CASCADE	2016	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
CLEAR LAKE	2016	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2016	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2016	ROR	22.5	23.1	21.2	21.0	25.5	25.1	20.0	20.9	22.8	24.6	23.0	23.0	22.7
MILNER	2016	ROR	5.9	5.9	2.0	0.0	8.8	10.5	0.0	0.0	0.0	0.0	1.8	5.0	3.3
SHOSHONE FALLS	2016	ROR	12.0	12.0	10.1	7.9	12.0	12.0	8.9	9.6	7.2	9.4	11.3	12.0	10.4
SWAN FALLS	2016	ROR	15.2	15.3	15.1	14.4	15.1	14.4	11.0	11.9	14.0	15.3	15.4	15.3	14.4
TWIN FALLS	2016	ROR	9.4	9.3	6.3	4.2	11.9	15.0	5.3	5.8	3.7	5.7	7.3	9.0	7.7
UPPER MALAD	2016	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2016	ROR	13.6	14.2	12.8	12.7	16.2	15.6	11.7	12.6	13.8	15.0	13.8	13.9	13.8
UPPER SALMON 3&4	2016	ROR	12.8	13.3	12.2	12.1	15.0	14.6	11.2	12.0	13.0	14.0	13.0	13.1	13.0
HCC TOTAL			**586.5**	**459.6**	**425.6**	**530.6**	**598.3**	**478.5**	**438.0**	**339.3**	**386.0**	**345.2**	**366.9**	**434.7**	**449.1**
ROR TOTAL			**200.1**	**203.0**	**193.1**	**211.9**	**286.1**	**293.8**	**238.5**	**226.3**	**213.2**	**208.1**	**196.3**	**200.9**	**222.7**
TOTAL			**786.6**	**662.6**	**618.7**	**742.5**	**884.4**	**772.3**	**676.5**	**565.6**	**599.2**	**553.3**	**563.2**	**635.6**	**671.8**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2017	HCC	257.0	196.6	185.4	231.0	263.8	213.5	194.2	143.9	164.0	145.6	158.3	193.8	195.6
OXBOW	2017	HCC	110.6	87.7	80.2	96.4	109.2	88.0	81.7	65.4	74.6	66.4	69.6	80.7	84.2
HELLS CANYON	2017	HCC	217.8	174.2	163.9	196.2	224.3	177.0	160.8	128.5	146.2	131.3	137.8	159.6	168.1
1000 SPRINGS	2017	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2017	ROR	0.0	0.0	5.4	34.8	70.5	78.5	73.6	45.9	24.9	9.2	0.0	0.0	28.7
BLISS	2017	ROR	35.1	35.6	34.1	33.7	37.6	36.9	31.5	33.1	35.8	37.8	36.0	35.7	35.2
C.J. STRIKE	2017	ROR	44.6	44.9	44.5	41.9	44.6	40.1	31.0	34.6	41.9	47.1	45.7	44.9	42.1
CASCADE	2017	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
CLEAR LAKE	2017	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2017	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2017	ROR	22.5	23.0	21.1	20.9	25.4	24.9	19.9	20.8	22.7	24.5	22.9	22.9	22.6
MILNER	2017	ROR	5.9	5.9	2.0	0.0	8.8	10.5	0.0	0.0	0.0	0.0	1.8	5.0	3.3
SHOSHONE FALLS	2017	ROR	12.0	12.0	10.1	7.8	12.0	12.0	8.8	9.5	7.1	9.3	11.3	12.0	10.3
SWAN FALLS	2017	ROR	15.2	15.2	15.0	14.3	15.1	14.3	10.9	11.8	13.9	15.3	15.3	15.3	14.3
TWIN FALLS	2017	ROR	9.4	9.3	6.3	4.2	11.8	15.0	5.2	5.8	3.6	5.6	7.3	9.0	7.7
UPPER MALAD	2017	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2017	ROR	13.5	14.1	12.7	12.6	16.1	15.5	11.6	12.5	13.8	14.9	13.7	13.8	13.7
UPPER SALMON 3&4	2017	ROR	12.8	13.3	12.1	12.0	15.0	14.5	11.2	11.9	13.0	14.0	13.0	13.0	13.0
HCC TOTAL			**585.4**	**458.5**	**429.5**	**523.6**	**597.2**	**478.5**	**436.7**	**337.8**	**384.8**	**343.3**	**365.7**	**434.1**	**447.9**
ROR TOTAL			**199.6**	**202.4**	**192.4**	**211.3**	**285.3**	**292.3**	**237.4**	**223.1**	**212.4**	**207.4**	**195.8**	**200.3**	**221.7**
TOTAL			**785.0**	**660.9**	**621.9**	**734.9**	**882.5**	**770.8**	**674.1**	**560.9**	**597.2**	**550.7**	**561.5**	**634.4**	**669.7**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

90th Percentile Water, 70th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2018	HCC	256.4	196.1	188.2	226.2	263.3	209.2	193.7	143.4	163.5	144.5	158.6	193.3	194.7
OXBOW	2018	HCC	110.3	87.5	81.6	94.5	108.9	86.2	81.5	65.1	74.4	65.9	69.7	80.5	83.8
HELLS CANYON	2018	HCC	217.3	173.7	166.5	192.7	223.9	173.6	160.4	128.1	145.8	130.3	138.0	159.1	167.4
1000 SPRINGS	2018	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2018	ROR	0.0	0.0	5.3	35.1	70.1	77.6	66.8	45.8	25.0	9.1	0.0	0.0	28.1
BLISS	2018	ROR	35.0	35.5	34.0	33.6	37.5	36.7	31.5	33.0	35.6	37.6	35.9	35.7	35.1
C.J. STRIKE	2018	ROR	44.5	44.6	44.4	41.8	44.5	39.8	30.8	34.4	41.7	46.9	45.7	44.9	42.0
CASCADE	2018	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
CLEAR LAKE	2018	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2018	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2018	ROR	22.4	22.8	21.0	20.8	25.3	24.7	19.8	20.7	22.6	24.4	22.8	22.8	22.5
MILNER	2018	ROR	5.9	5.9	2.0	0.0	8.8	10.5	0.0	0.0	0.0	0.0	1.8	5.0	3.3
SHOSHONE FALLS	2018	ROR	12.0	12.0	10.0	7.8	12.0	12.0	8.8	9.5	7.1	9.3	11.2	12.0	10.3
SWAN FALLS	2018	ROR	15.1	15.1	15.0	14.3	15.0	14.1	10.8	11.8	13.9	15.2	15.3	15.2	14.2
TWIN FALLS	2018	ROR	9.4	9.2	6.2	4.2	11.8	15.0	5.2	5.7	0.0	5.6	7.3	9.0	7.4
UPPER MALAD	2018	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2018	ROR	13.5	14.0	12.7	12.5	16.0	15.3	11.6	12.4	13.7	14.9	13.7	13.7	13.7
UPPER SALMON 3&4	2018	ROR	12.7	13.2	12.0	11.9	14.9	14.3	11.1	11.8	12.9	13.9	12.9	12.9	12.9
HCC TOTAL			**584.0**	**457.3**	**436.3**	**513.4**	**596.0**	**469.0**	**435.6**	**336.6**	**383.7**	**340.7**	**366.3**	**432.9**	**446.0**
ROR TOTAL			**199.1**	**201.4**	**191.7**	**211.1**	**284.3**	**290.1**	**230.1**	**222.3**	**208.2**	**206.6**	**195.4**	**199.9**	**220.1**
TOTAL			**783.1**	**658.7**	**628.0**	**724.5**	**880.3**	**759.1**	**665.7**	**558.9**	**591.8**	**547.3**	**561.7**	**632.8**	**666.1**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2019	HCC	256.0	195.6	190.5	222.0	262.7	208.7	193.1	142.9	163.1	143.5	158.9	192.8	194.2
OXBOW	2019	HCC	110.1	87.3	82.7	92.9	108.7	86.0	81.3	64.9	74.2	65.3	69.8	80.3	83.6
HELLS CANYON	2019	HCC	216.9	173.3	168.8	189.5	223.5	173.1	159.9	127.6	145.4	129.3	138.2	158.7	167.0
1000 SPRINGS	2019	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2019	ROR	0.0	0.0	5.3	35.4	69.9	77.0	64.6	45.4	24.9	9.2	0.0	0.0	27.8
BLISS	2019	ROR	34.9	35.3	33.9	33.4	37.4	36.5	31.2	32.8	35.5	37.5	35.8	35.6	35.0
C.J. STRIKE	2019	ROR	44.3	44.4	44.2	41.6	44.3	39.6	30.6	34.4	41.5	46.7	45.5	44.9	41.8
CASCADE	2019	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
CLEAR LAKE	2019	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2019	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2019	ROR	22.2	22.7	20.9	20.7	25.2	24.6	19.7	20.6	22.5	24.3	22.7	22.7	22.4
MILNER	2019	ROR	5.9	5.9	2.0	0.0	8.8	9.6	0.0	0.0	0.0	0.0	1.8	5.0	3.2
SHOSHONE FALLS	2019	ROR	12.0	12.0	10.0	7.7	12.0	12.0	8.8	9.4	7.0	9.2	11.2	12.0	10.3
SWAN FALLS	2019	ROR	15.1	15.1	15.0	14.2	15.0	14.1	10.8	11.7	13.8	15.2	15.2	15.2	14.2
TWIN FALLS	2019	ROR	9.3	9.2	6.2	4.1	11.8	14.0	5.2	5.7	0.0	5.6	7.2	9.0	7.3
UPPER MALAD	2019	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2019	ROR	13.4	13.9	12.6	12.5	15.9	15.3	11.5	12.4	13.6	14.8	13.6	13.6	13.6
UPPER SALMON 3&4	2019	ROR	12.6	13.1	12.0	11.9	14.8	14.3	11.0	11.8	12.8	13.8	12.8	12.9	12.8
HCC TOTAL			**583.0**	**456.2**	**442.0**	**504.4**	**594.8**	**467.8**	**434.3**	**335.4**	**382.6**	**338.1**	**366.9**	**431.8**	**444.8**
ROR TOTAL			**198.3**	**200.7**	**191.2**	**210.6**	**283.5**	**287.1**	**227.1**	**221.4**	**207.3**	**206.0**	**194.6**	**199.6**	**219.0**
TOTAL			**781.3**	**656.9**	**633.2**	**715.0**	**878.3**	**754.9**	**661.4**	**556.8**	**589.9**	**544.1**	**561.5**	**631.4**	**663.9**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

90th Percentile Water, 70th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2020	HCC	255.5	195.1	193.3	217.3	262.2	208.1	192.7	142.3	162.6	142.7	158.8	192.2	193.6
OXBOW	2020	HCC	109.9	87.1	84.0	91.1	108.5	85.8	81.1	64.6	74.0	64.9	69.7	80.0	83.4
HELLS CANYON	2020	HCC	216.5	172.9	171.4	186.0	223.1	172.7	159.5	127.1	145.0	128.5	138.1	158.3	166.6
1000 SPRINGS	2020	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2020	ROR	0.0	0.0	5.3	35.7	69.8	76.9	62.6	44.6	23.6	9.3	0.0	0.0	27.4
BLISS	2020	ROR	34.8	35.2	33.7	33.3	37.2	36.4	31.1	32.7	35.4	37.4	35.6	35.5	34.9
C.J. STRIKE	2020	ROR	44.1	44.2	44.0	41.4	44.1	39.4	30.5	34.4	41.3	46.5	45.3	44.7	41.6
CASCADE	2020	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
CLEAR LAKE	2020	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2020	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2020	ROR	22.1	22.6	20.8	20.6	25.1	24.5	19.6	20.5	22.3	24.2	22.6	22.6	22.3
MILNER	2020	ROR	5.9	5.9	2.0	0.0	8.8	9.6	0.0	0.0	0.0	0.0	1.8	5.0	3.2
SHOSHONE FALLS	2020	ROR	12.0	12.0	9.9	7.7	12.0	12.0	8.7	9.4	7.0	9.2	11.1	12.0	10.2
SWAN FALLS	2020	ROR	15.0	15.0	15.0	14.2	14.9	14.0	10.8	11.7	13.8	15.4	15.2	15.1	14.2
TWIN FALLS	2020	ROR	9.3	9.2	6.1	4.1	11.8	13.9	5.1	5.7	0.0	5.5	7.2	9.0	7.2
UPPER MALAD	2020	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2020	ROR	13.3	13.8	12.5	12.4	15.8	15.2	11.4	12.3	13.5	14.7	13.5	13.6	13.5
UPPER SALMON 3&4	2020	ROR	12.6	13.0	11.9	11.8	14.7	14.2	11.0	11.7	12.7	13.8	12.8	12.8	12.7
HCC TOTAL			**581.9**	**455.1**	**448.7**	**494.4**	**593.7**	**466.6**	**433.3**	**334.0**	**381.5**	**336.1**	**366.6**	**430.5**	**443.6**
ROR TOTAL			**197.7**	**200.0**	**190.3**	**210.3**	**282.7**	**286.2**	**224.5**	**220.2**	**205.2**	**205.7**	**193.9**	**199.0**	**218.0**
TOTAL			**779.6**	**655.1**	**639.0**	**704.7**	**876.4**	**752.8**	**657.8**	**554.2**	**586.7**	**541.8**	**560.5**	**629.5**	**661.7**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2021	HCC	254.9	194.6	193.5	215.8	261.7	207.6	192.2	141.7	158.6	141.6	158.7	192.2	192.8
OXBOW	2021	HCC	109.7	86.8	84.2	90.5	108.3	85.5	80.9	64.3	73.8	64.4	69.7	80.0	83.2
HELLS CANYON	2021	HCC	216.0	172.5	171.7	184.8	222.6	172.3	159.1	126.6	144.4	127.5	138.0	158.2	166.2
1000 SPRINGS	2021	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2021	ROR	0.0	0.0	5.2	36.0	69.7	76.3	60.6	44.3	23.5	9.4	0.0	0.0	27.2
BLISS	2021	ROR	34.7	35.1	33.6	33.2	37.2	36.3	30.9	32.5	35.2	37.2	35.5	35.4	34.7
C.J. STRIKE	2021	ROR	44.0	44.0	43.9	41.2	44.0	39.2	30.3	34.2	41.2	46.4	45.2	44.5	41.5
CASCADE	2021	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
CLEAR LAKE	2021	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2021	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2021	ROR	22.0	22.6	20.7	20.5	25.0	24.3	19.5	20.4	22.2	24.1	22.5	22.5	22.2
MILNER	2021	ROR	5.9	5.9	2.0	0.0	8.8	8.5	0.0	0.0	0.0	0.0	1.8	5.0	3.1
SHOSHONE FALLS	2021	ROR	12.0	12.0	9.9	7.6	12.0	12.0	8.7	9.3	6.9	9.1	11.1	12.0	10.2
SWAN FALLS	2021	ROR	15.0	15.0	15.0	14.1	14.9	14.0	10.7	11.6	13.7	15.3	15.1	15.1	14.1
TWIN FALLS	2021	ROR	9.3	9.2	6.1	4.0	11.8	12.1	5.1	5.6	0.0	5.5	7.2	9.0	7.1
UPPER MALAD	2021	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2021	ROR	13.2	13.8	12.4	12.3	15.8	15.0	11.3	12.2	13.4	14.6	13.4	13.5	13.4
UPPER SALMON 3&4	2021	ROR	12.5	13.0	11.8	11.7	14.7	14.1	10.9	11.6	12.6	13.7	12.7	12.7	12.7
HCC TOTAL			**580.6**	**453.9**	**449.4**	**491.1**	**592.5**	**465.4**	**432.2**	**332.6**	**376.7**	**333.5**	**366.4**	**430.4**	**442.1**
ROR TOTAL			**197.2**	**199.7**	**189.7**	**209.7**	**282.3**	**281.9**	**221.7**	**218.9**	**204.3**	**205.0**	**193.3**	**198.4**	**216.9**
TOTAL			**777.8**	**653.6**	**639.1**	**700.8**	**874.8**	**747.3**	**653.9**	**551.5**	**581.0**	**538.5**	**559.7**	**628.8**	**659.1**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

90th Percentile Water, 70th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2022	HCC	254.4	194.2	195.8	211.6	261.2	207.0	191.7	141.2	158.1	140.9	158.7	191.7	192.3
OXBOW	2022	HCC	109.5	86.6	85.3	88.9	108.1	85.3	80.6	64.1	73.5	64.0	69.6	79.8	82.9
HELLS CANYON	2022	HCC	215.6	172.1	173.9	181.7	222.2	171.8	158.7	126.2	143.9	126.8	137.9	157.8	165.7
1000 SPRINGS	2022	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2022	ROR	0.0	0.0	5.2	36.3	69.5	75.6	56.8	44.2	23.3	9.5	0.0	0.0	26.8
BLISS	2022	ROR	34.6	34.9	33.5	33.0	37.2	35.7	30.8	32.4	35.1	37.1	35.4	35.2	34.6
C.J. STRIKE	2022	ROR	43.8	43.8	43.7	41.1	43.8	38.7	30.1	34.0	41.0	46.3	45.0	44.4	41.3
CASCADE	2022	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
CLEAR LAKE	2022	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2022	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2022	ROR	21.9	22.5	20.6	20.4	24.9	24.2	19.4	20.3	22.1	23.9	22.4	22.4	22.1
MILNER	2022	ROR	5.9	5.9	2.0	0.0	8.8	8.5	0.0	0.0	0.0	0.0	1.8	5.0	3.1
SHOSHONE FALLS	2022	ROR	12.0	12.0	9.8	7.6	12.0	12.0	8.7	9.3	6.9	9.1	11.0	12.0	10.2
SWAN FALLS	2022	ROR	14.9	14.9	15.0	14.1	14.8	13.7	10.6	11.5	13.6	15.3	15.1	15.1	14.0
TWIN FALLS	2022	ROR	9.3	9.1	6.1	4.0	11.8	12.0	5.1	5.6	0.0	5.5	7.1	8.9	7.0
UPPER MALAD	2022	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2022	ROR	13.1	13.7	12.3	12.2	15.7	15.0	11.2	12.1	13.3	14.5	13.4	13.4	13.3
UPPER SALMON 3&4	2022	ROR	12.4	12.9	11.8	11.7	14.6	14.0	10.8	11.6	12.6	13.6	12.6	12.7	12.6
HCC TOTAL			**579.5**	**452.9**	**455.0**	**482.2**	**591.4**	**464.1**	**431.0**	**331.5**	**375.5**	**331.7**	**366.2**	**429.3**	**441.0**
ROR TOTAL			**196.5**	**198.8**	**189.1**	**209.5**	**281.6**	**279.5**	**217.2**	**218.2**	**203.6**	**204.5**	**192.6**	**197.8**	**215.8**
TOTAL			**776.0**	**651.7**	**644.1**	**691.7**	**873.0**	**743.6**	**648.2**	**549.7**	**579.0**	**536.2**	**558.8**	**627.1**	**656.8**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2023	HCC	254.0	193.7	196.9	209.0	260.7	206.6	191.1	140.7	157.6	139.8	159.0	191.2	191.8
OXBOW	2023	HCC	109.3	86.4	85.9	87.9	107.9	85.1	80.4	63.9	73.3	63.5	69.7	79.6	82.7
HELLS CANYON	2023	HCC	215.2	171.7	174.9	179.7	221.8	171.4	158.3	125.7	143.5	125.8	138.1	157.4	165.3
1000 SPRINGS	2023	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2023	ROR	0.0	0.0	5.1	36.5	69.6	74.3	54.2	44.0	23.3	9.6	0.0	0.0	26.5
BLISS	2023	ROR	34.4	34.8	33.3	32.9	37.2	35.5	30.7	32.3	34.9	37.0	35.2	35.1	34.4
C.J. STRIKE	2023	ROR	43.6	43.7	43.5	40.9	43.6	38.3	29.9	33.9	40.8	46.3	44.9	44.2	41.1
CASCADE	2023	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
CLEAR LAKE	2023	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2023	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2023	ROR	21.8	22.4	20.5	20.3	24.8	24.1	19.2	20.2	22.0	23.8	22.3	22.3	22.0
MILNER	2023	ROR	5.9	5.9	2.0	0.0	8.8	8.5	0.0	0.0	0.0	0.0	1.8	5.0	3.1
SHOSHONE FALLS	2023	ROR	12.0	12.0	9.8	7.5	12.0	12.0	8.7	9.3	6.9	9.0	11.0	12.0	10.2
SWAN FALLS	2023	ROR	14.9	14.9	15.0	14.1	14.8	13.7	10.6	11.5	13.6	15.2	15.0	15.1	14.0
TWIN FALLS	2023	ROR	9.2	9.1	6.0	4.0	11.8	12.0	5.1	5.6	0.0	5.4	7.1	8.9	7.0
UPPER MALAD	2023	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2023	ROR	13.1	13.6	12.3	12.1	15.6	14.9	11.1	12.0	13.2	14.5	13.3	13.3	13.2
UPPER SALMON 3&4	2023	ROR	12.4	12.8	11.7	11.6	14.5	13.9	10.7	11.5	12.5	13.6	12.6	12.6	12.5
HCC TOTAL			**578.5**	**451.8**	**457.7**	**476.6**	**590.3**	**463.1**	**429.8**	**330.3**	**374.4**	**329.1**	**366.8**	**428.2**	**439.8**
ROR TOTAL			**195.9**	**198.3**	**188.3**	**209.0**	**281.2**	**277.3**	**213.9**	**217.5**	**202.9**	**204.1**	**192.0**	**197.2**	**214.9**
TOTAL			**774.4**	**650.1**	**646.0**	**685.6**	**871.5**	**740.4**	**643.7**	**547.8**	**577.2**	**533.2**	**558.8**	**625.4**	**654.7**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

90th Percentile Water, 70th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2024	HCC	253.5	193.2	193.8	211.8	260.2	206.0	190.6	140.2	157.2	139.0	158.9	190.6	191.3
OXBOW	2024	HCC	109.0	86.2	84.4	88.9	107.6	84.9	80.2	63.7	73.1	63.1	69.7	79.4	82.5
HELLS CANYON	2024	HCC	214.8	171.2	172.1	181.7	221.4	171.0	157.8	125.3	143.1	125.1	138.0	157.0	164.9
1000 SPRINGS	2024	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2024	ROR	0.0	0.0	5.1	36.8	69.8	73.0	53.1	43.9	23.3	9.7	0.0	0.0	26.3
BLISS	2024	ROR	34.3	34.7	33.2	32.8	37.2	35.4	30.5	32.1	34.8	36.8	35.1	35.0	34.3
C.J. STRIKE	2024	ROR	43.4	43.5	43.3	40.7	43.4	38.3	29.9	33.7	40.7	46.2	44.7	44.0	41.0
CASCADE	2024	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
CLEAR LAKE	2024	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2024	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2024	ROR	21.7	22.3	20.4	20.2	24.7	24.0	19.1	20.1	21.9	23.7	22.2	22.2	21.9
MILNER	2024	ROR	5.9	5.9	2.0	0.0	8.8	7.7	0.0	0.0	0.0	0.0	1.8	5.0	3.1
SHOSHONE FALLS	2024	ROR	12.0	12.0	9.7	7.5	12.0	12.0	8.7	9.2	6.8	9.0	11.0	12.0	10.2
SWAN FALLS	2024	ROR	14.8	14.9	15.0	14.1	14.7	13.7	10.5	11.4	13.5	15.2	15.0	15.0	14.0
TWIN FALLS	2024	ROR	9.2	9.1	6.0	3.9	11.8	11.9	5.1	5.5	0.0	5.4	7.1	8.9	7.0
UPPER MALAD	2024	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2024	ROR	13.0	13.5	12.2	12.1	15.5	14.7	11.0	12.0	13.1	14.4	13.2	13.3	13.2
UPPER SALMON 3&4	2024	ROR	12.3	12.8	11.6	11.5	14.5	13.8	10.6	11.4	12.4	13.5	12.5	12.5	12.4
HCC TOTAL			**577.3**	**450.6**	**450.3**	**482.4**	**589.2**	**461.9**	**428.6**	**329.2**	**373.3**	**327.2**	**366.6**	**427.0**	**438.8**
ROR TOTAL			**195.2**	**197.8**	**187.6**	**208.7**	**280.8**	**274.6**	**212.2**	**216.5**	**202.2**	**203.6**	**191.4**	**196.6**	**214.0**
TOTAL			**772.5**	**648.4**	**637.9**	**691.1**	**870.0**	**736.5**	**640.8**	**545.7**	**575.5**	**530.8**	**558.0**	**623.6**	**652.7**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2025	HCC	253.0	192.7	195.7	208.2	259.6	205.5	190.1	139.8	156.7	137.9	159.1	190.1	190.8
OXBOW	2025	HCC	108.8	86.0	85.4	87.5	107.4	84.7	80.0	63.4	72.9	62.6	69.8	79.1	82.3
HELLS CANYON	2025	HCC	214.4	170.8	174.0	179.0	221.0	170.6	157.4	124.9	142.7	124.1	138.2	156.5	164.5
1000 SPRINGS	2025	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2025	ROR	0.0	0.0	5.1	36.9	69.8	69.4	51.8	43.6	23.1	9.8	0.0	0.0	25.9
BLISS	2025	ROR	34.2	34.5	33.1	32.6	37.2	34.0	30.4	32.0	34.6	36.7	35.0	34.8	34.1
C.J. STRIKE	2025	ROR	43.3	43.3	43.2	40.6	43.3	38.3	29.8	33.5	40.6	46.0	44.5	43.8	40.8
CASCADE	2025	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
CLEAR LAKE	2025	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2025	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2025	ROR	21.6	22.2	20.3	20.1	24.6	22.9	19.0	20.0	21.8	23.6	22.1	22.1	21.7
MILNER	2025	ROR	5.9	5.9	2.0	0.0	8.8	7.7	0.0	0.0	0.0	0.0	1.8	5.0	3.1
SHOSHONE FALLS	2025	ROR	12.0	12.0	9.7	7.5	12.0	12.0	8.7	9.2	6.8	9.0	10.9	12.0	10.1
SWAN FALLS	2025	ROR	14.8	14.9	15.0	14.0	14.7	13.2	10.5	11.4	13.5	15.1	14.9	14.9	13.9
TWIN FALLS	2025	ROR	9.2	9.1	6.0	3.9	11.8	11.9	5.1	5.5	0.0	5.3	7.0	8.8	7.0
UPPER MALAD	2025	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2025	ROR	12.9	13.5	12.1	12.0	15.4	13.9	11.0	11.9	13.0	14.3	13.1	13.2	13.0
UPPER SALMON 3&4	2025	ROR	12.2	12.7	11.6	11.5	14.4	13.1	10.6	11.4	12.4	13.4	12.4	12.5	12.3
HCC TOTAL			**576.2**	**449.5**	**455.1**	**474.7**	**587.9**	**460.8**	**427.5**	**328.1**	**372.2**	**324.6**	**367.1**	**425.7**	**437.6**
ROR TOTAL			**194.7**	**197.2**	**187.2**	**208.2**	**280.4**	**266.5**	**210.6**	**215.7**	**201.5**	**202.9**	**190.5**	**195.8**	**212.7**
TOTAL			**770.9**	**646.7**	**642.3**	**682.9**	**868.3**	**727.3**	**638.1**	**543.8**	**573.6**	**527.5**	**557.6**	**621.5**	**650.2**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

90th Percentile Water, 70th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2026	HCC	252.5	192.2	196.4	206.2	259.1	205.0	189.6	139.3	156.3	136.8	159.1	190.0	190.3
OXBOW	2026	HCC	108.6	85.8	85.7	86.7	107.2	84.5	79.8	63.2	72.7	62.1	69.7	79.1	82.1
HELLS CANYON	2026	HCC	214.0	170.4	174.6	177.5	220.6	170.1	157.0	124.4	142.3	123.0	138.0	156.4	164.0
1000 SPRINGS	2026	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2026	ROR	0.0	0.0	5.0	37.1	69.8	69.3	50.5	43.3	23.1	9.9	0.0	0.0	25.8
BLISS	2026	ROR	34.0	34.4	32.9	32.5	37.2	33.8	30.2	31.8	34.5	36.6	34.9	34.7	34.0
C.J. STRIKE	2026	ROR	43.1	43.2	43.0	40.5	43.1	38.3	29.6	33.3	40.4	45.9	44.3	43.7	40.7
CASCADE	2026	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
CLEAR LAKE	2026	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2026	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2026	ROR	21.5	22.0	20.2	20.0	24.5	22.7	18.9	19.8	21.7	23.5	22.0	21.9	21.6
MILNER	2026	ROR	5.9	5.9	2.0	0.0	8.8	5.4	0.0	0.0	0.0	0.0	1.8	5.0	2.9
SHOSHONE FALLS	2026	ROR	12.0	12.0	9.7	7.4	12.0	12.0	8.7	9.1	6.7	8.9	10.9	12.0	10.1
SWAN FALLS	2026	ROR	14.8	14.8	15.0	14.0	14.6	13.1	10.4	11.3	13.4	15.1	14.9	14.9	13.9
TWIN FALLS	2026	ROR	9.2	9.0	5.9	3.9	11.8	9.9	5.1	5.5	0.0	5.3	7.0	8.8	6.8
UPPER MALAD	2026	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2026	ROR	12.8	13.4	12.0	11.9	15.4	13.8	10.9	11.8	13.0	14.2	13.1	13.1	12.9
UPPER SALMON 3&4	2026	ROR	12.2	12.6	11.5	11.4	14.3	13.0	10.5	11.3	12.3	13.4	12.4	12.4	12.3
HCC TOTAL			**575.1**	**448.4**	**456.7**	**470.4**	**586.8**	**459.6**	**426.4**	**326.9**	**371.2**	**321.9**	**366.8**	**425.5**	**436.4**
ROR TOTAL			**194.1**	**196.4**	**186.3**	**207.8**	**279.9**	**261.4**	**208.5**	**214.4**	**200.8**	**202.5**	**190.1**	**195.2**	**211.5**
TOTAL			**769.2**	**644.8**	**643.0**	**678.2**	**866.7**	**721.0**	**634.9**	**541.3**	**571.9**	**524.4**	**556.9**	**620.7**	**648.0**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2027	HCC	252.0	191.7	197.0	204.1	258.6	204.4	189.1	138.8	155.8	136.1	159.0	189.5	189.8
OXBOW	2027	HCC	108.4	85.5	86.1	85.9	107.0	84.2	79.6	63.0	72.4	61.7	69.7	78.9	81.9
HELLS CANYON	2027	HCC	213.5	170.0	175.3	175.9	220.1	169.7	156.6	124.0	141.9	122.3	138.0	156.0	163.6
1000 SPRINGS	2027	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2027	ROR	0.0	0.0	5.0	37.4	69.9	67.6	50.4	42.7	23.1	10.0	0.0	0.0	25.6
BLISS	2027	ROR	33.9	34.3	32.8	32.4	37.2	32.4	30.1	31.7	34.4	36.4	34.7	34.6	33.7
C.J. STRIKE	2027	ROR	42.9	43.0	42.8	40.5	42.9	38.1	29.4	33.1	40.4	45.7	44.2	43.5	40.5
CASCADE	2027	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
CLEAR LAKE	2027	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2027	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2027	ROR	21.4	22.0	20.1	19.9	24.4	20.8	18.8	19.7	21.6	23.4	21.9	21.9	21.3
MILNER	2027	ROR	5.9	5.9	2.0	0.0	8.8	0.0	0.0	0.0	0.0	0.0	1.8	5.0	2.4
SHOSHONE FALLS	2027	ROR	12.0	12.0	9.6	7.4	12.0	9.3	8.7	9.1	6.7	8.9	10.8	12.0	9.9
SWAN FALLS	2027	ROR	14.7	14.8	15.0	14.0	14.6	13.1	10.4	11.2	13.4	15.0	14.8	14.8	13.8
TWIN FALLS	2027	ROR	9.2	9.0	5.9	3.8	11.8	5.6	5.1	5.4	0.0	5.3	6.9	8.8	6.4
UPPER MALAD	2027	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2027	ROR	12.7	13.3	11.9	11.8	15.3	12.3	10.8	11.7	12.9	14.1	13.0	13.0	12.7
UPPER SALMON 3&4	2027	ROR	12.1	12.6	11.4	11.3	14.3	11.7	10.4	11.2	12.2	13.3	12.3	12.3	12.1
HCC TOTAL			**573.9**	**447.2**	**458.4**	**465.9**	**585.6**	**458.3**	**425.3**	**325.8**	**370.1**	**320.1**	**366.7**	**424.4**	**435.3**
ROR TOTAL			**193.4**	**196.0**	**185.6**	**207.6**	**279.7**	**241.0**	**207.8**	**213.0**	**200.4**	**201.8**	**189.2**	**194.6**	**209.3**
TOTAL			**767.3**	**643.2**	**644.0**	**673.5**	**865.3**	**699.3**	**633.1**	**538.8**	**570.4**	**521.9**	**555.9**	**619.0**	**644.5**

2009 Integrated Resource Plan

Average Megawatt Hydro Output from PDR580

90th Percentile Water, 70th Percentile Load

Abbreviations:
HCC - Hells Canyon Complex
ROR - Run of River

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2028	HCC	251.5	191.2	197.7	202.1	258.1	203.9	188.6	138.3	155.4	134.9	159.3	189.0	189.2
OXBOW	2028	HCC	108.2	85.3	86.4	85.1	106.8	84.0	79.3	62.8	72.2	61.1	69.8	78.7	81.7
HELLS CANYON	2028	HCC	213.1	169.5	176.0	174.4	219.7	169.3	156.1	123.5	141.5	121.3	138.2	155.6	163.2
1000 SPRINGS	2028	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2028	ROR	0.0	0.0	5.0	37.6	70.0	66.4	49.6	41.6	23.0	10.0	0.0	0.0	25.3
BLISS	2028	ROR	33.8	34.1	32.7	32.2	37.2	32.3	30.0	31.6	34.2	36.3	34.6	34.4	33.6
C.J. STRIKE	2028	ROR	42.7	42.8	42.6	40.5	42.7	37.8	29.2	33.0	40.4	45.5	44.0	43.4	40.4
CASCADE	2028	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
CLEAR LAKE	2028	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2028	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2028	ROR	21.3	21.8	20.0	19.8	24.3	20.6	18.6	19.5	21.5	23.3	21.8	21.7	21.2
MILNER	2028	ROR	5.9	5.9	2.0	0.0	8.8	0.0	0.0	0.0	0.0	0.0	1.8	5.0	2.5
SHOSHONE FALLS	2028	ROR	12.0	12.0	9.6	7.3	12.0	9.3	8.7	9.0	6.7	8.8	10.8	12.0	9.9
SWAN FALLS	2028	ROR	14.7	14.7	15.0	14.0	14.6	13.0	10.3	11.1	13.3	14.9	14.8	14.8	13.8
TWIN FALLS	2028	ROR	9.2	9.0	5.9	3.8	11.8	5.6	5.1	5.4	0.0	5.2	6.9	8.8	6.4
UPPER MALAD	2028	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2028	ROR	12.7	13.2	11.9	11.7	15.2	12.2	10.7	11.5	12.8	14.1	12.9	12.9	12.6
UPPER SALMON 3&4	2028	ROR	12.0	12.5	11.4	11.2	14.2	11.6	10.3	11.1	12.1	13.2	12.2	12.3	12.0
HCC TOTAL			**572.8**	**446.0**	**460.1**	**461.6**	**584.5**	**457.2**	**424.0**	**324.6**	**369.0**	**317.3**	**367.3**	**423.3**	**434.1**
ROR TOTAL			**192.9**	**195.1**	**185.2**	**207.2**	**279.3**	**238.9**	**206.2**	**211.0**	**199.7**	**201.0**	**188.6**	**194.0**	**208.3**
TOTAL			**765.7**	**641.1**	**645.3**	**668.8**	**863.8**	**696.1**	**630.2**	**535.6**	**568.7**	**518.3**	**555.9**	**617.3**	**642.5**

Resource	YEAR	TYPE	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVE. MW
BROWNLEE	2029	HCC	251.0	190.8	197.1	201.6	257.5	203.4	188.1	137.8	154.9	133.9	159.2	188.5	188.7
OXBOW	2029	HCC	108.0	85.1	86.2	84.9	106.6	83.8	79.1	62.5	72.0	60.6	69.7	78.4	81.4
HELLS CANYON	2029	HCC	212.7	169.1	175.5	174.0	219.3	168.9	155.7	123.1	141.0	120.3	138.0	155.2	162.8
1000 SPRINGS	2029	ROR	6.5	6.5	6.1	6.1	5.4	5.8	6.0	6.3	6.5	6.6	6.6	6.6	6.2
AMERICAN FALLS	2029	ROR	4.3	4.1	4.9	37.9	70.2	65.4	49.6	41.1	23.0	10.1	0.0	0.0	26.0
BLISS	2029	ROR	33.6	34.0	32.5	32.1	37.1	32.2	29.8	31.4	34.1	36.2	34.5	34.3	33.5
C.J. STRIKE	2029	ROR	42.6	42.7	42.5	40.4	42.6	37.6	29.1	32.8	40.2	45.5	43.9	43.3	40.2
CASCADE	2029	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
CLEAR LAKE	2029	ROR	1.9	1.8	1.7	1.6	1.5	1.4	1.5	1.6	1.6	1.8	1.8	1.8	1.7
LOWER MALAD	2029	ROR	12.1	12.5	12.8	13.0	12.6	11.6	12.2	12.6	13.1	13.2	12.2	12.1	12.5
LOWER SALMON	2029	ROR	21.2	21.7	19.9	19.7	24.2	20.5	18.5	19.4	21.4	23.2	21.7	21.6	21.1
MILNER	2029	ROR	5.9	5.9	2.0	0.0	8.8	0.0	0.0	0.0	0.0	0.0	1.8	5.0	2.4
SHOSHONE FALLS	2029	ROR	12.0	12.0	9.5	7.3	12.0	9.2	8.7	9.0	6.6	8.8	10.8	12.0	9.8
SWAN FALLS	2029	ROR	14.6	14.7	14.9	14.0	14.6	13.0	10.3	11.1	13.2	14.9	14.7	14.7	13.7
TWIN FALLS	2029	ROR	9.2	9.0	5.8	3.8	11.8	5.5	5.1	5.3	0.0	5.2	6.9	8.7	6.4
UPPER MALAD	2029	ROR	6.8	7.0	7.1	7.2	7.5	7.1	7.0	7.0	7.2	6.7	6.8	6.8	7.0
UPPER SALMON 1&2	2029	ROR	12.6	13.1	11.8	11.7	15.1	12.1	10.6	11.5	12.7	14.0	12.8	12.9	12.6
UPPER SALMON 3&4	2029	ROR	12.0	12.4	11.3	11.2	14.1	11.6	10.2	11.0	12.1	13.2	12.2	12.2	12.0
HCC TOTAL			**571.7**	**445.0**	**458.8**	**460.5**	**583.3**	**456.1**	**422.9**	**323.4**	**367.8**	**314.8**	**366.9**	**422.1**	**432.9**
ROR TOTAL			**196.6**	**198.7**	**184.2**	**207.2**	**279.0**	**237.2**	**205.6**	**209.8**	**199.0**	**200.8**	**188.1**	**193.4**	**208.4**
TOTAL			**768.3**	**643.7**	**643.0**	**667.7**	**862.3**	**693.3**	**628.5**	**533.2**	**566.8**	**515.6**	**555.0**	**615.5**	**641.3**

OREGON ORDER UM 1056 PLANNING CRITERIA

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 09 2007.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

Adopted IRP Guidelines

Guideline 1: Substantive Requirements

a. All resources must be evaluated on a consistent and comparable basis.

- *All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.*
- *Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.*
- *Consistent assumptions and methods should be used for evaluation of all resources.*
- *The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.*

b. Risk and uncertainty must be considered.

- *At a minimum, utilities should address the following sources of risk and uncertainty:*
  1. *Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.*
  2. *Natural gas utilities: demand (peak, swing and base-load), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.*
- *Utilities should identify in their plans any additional sources of risk and uncertainty.*

c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and

associated risks and uncertainties for the utility and its customers.[1]

- *The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.*

- *Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.*

- *To address risk, the plan should include, at a minimum:*

  1. *Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.*

  2. *Discussion of the proposed use and impact on costs and risks of physical and financial hedging.*

- *The utility should explain in its plan how its resource choices appropriately balance cost and risk.*

d. *The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.*

Guideline 2: Procedural Requirements.

a. *The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.*

[1] We sometimes refer to this portfolio as the "best cost/risk portfolio."

b. *While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.*

c. *The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.*

Guideline 3: Plan Filing, Review, and Updates.

a. *A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.*

b. *The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.*

c. *Commission staff and parties should complete their comments and recommendations within six months of IRP filing.*

d. *The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.*

e. *The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.*

f. *Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.*

g. *Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:*

- *Describes what actions the utility has taken to implement the plan;*
- *Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and*
- *Justifies any deviations from the acknowledged action plan.*

Guideline 4: Plan Components.

At a minimum, the plan must include the following elements:

a. *An explanation of how the utility met each of the substantive and procedural requirements;*

b. *Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;*

c. *For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;*

d. *For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;*

e. *Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;*

f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;

g. Identification of key assumptions about the future(e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;

h. Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;

i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;

j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;

k. Analysis of the uncertainties associated with each portfolio evaluated;

l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;

m. Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and

n. An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.

Guideline 5: Transmission.

Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote

locations, acquiring alternative fuel supplies, and improving reliability.

Guideline 6: Conservation.

a. *Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.*

b. *To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.*

c. *To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:*

   - *Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and*

   - *Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.*

Guideline 7: Demand Response.

Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).

Guideline 8: Environmental Costs.

Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential CO_2 regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.

Guideline 9: Direct Access Loads.

An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.

Guideline 10: Multi-state Utilities.

Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.

Guideline 11: Reliability.

Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.

Guideline 12: Distributed Generation.

Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.

Guideline 13: Resource Acquisition.

a. *An electric utility should, in its IRP:*

   - *Identify its proposed acquisition strategy for each resource in its action plan.*
   - *Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.*
   - *Identify any Benchmark Resources it plans to consider in competitive bidding.*

b. *Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.*

SUMMARY OF NORTHWEST UTILITY PLANNING CRITERIA

Utility	Planning Criteria
Avista Corporation	*Peak Load*—The maximum one-hour obligation, including operating reserves, on the expected average coldest day in January and the average hottest day in August.[1] *Peak Resource Capability*—The maximum one-hour generation capability of company resources, including net contract contribution, at the time of the one-hour system peak, and excluding resources that are on maintenance during peak load periods.[1] *Planning Reserve*—Set at a level equal to 15 percent planning reserve margin during the company's peak load hour.[1] *Confidence Interval*—Ninety percent confidence interval based on the monthly variability of load and the 10th percentile of monthly historical hydro energy. This results in a 10 percent chance of load exceeding the planning criteria for each month. In other words, there is a 10 percent chance that the company would need to purchase energy from the market in any given month.[1]
Bonneville Power Administration	*Load Forecast*—Based upon normal weather conditions.[2] *Hydro Conditions*—Firm hydro energy and capacity estimates based on 1937 critical water conditions.[2] *Hydro Energy*—Based on current generation capability under average monthly river discharge. Uses operating year (OY) 1937 water conditions (the 12-month period from August 1936 through July 1937) to estimate the firm hydro energy capability in low water conditions.[2] *Federal Firm Energy Surplus Analysis*—Defined as the amount of generation that can be produced in excess of firm loads using 1937 critical water conditions.[2] *Hydroelectric Capacity*—The monthly instantaneous capacity of hydroelectric projects is defined as the full-gate-flow maximum generation at mid-month reservoir elevation using 1929 through 1998 historical water conditions.[2]
Idaho Power Company	*Hydro Conditions*—70th percentile hydro conditions based upon historical data from 1928 through 2005.[3] *Load Forecast*—Based upon 50th percentile weather conditions. [3] *Monthly Average Energy*—Based on 70th percentile water and 70th percentile average load conditions.[3] *Capacity*—Based on monthly peak-hour Northwest transmission deficit assuming 90th percentile water, 70th percentile average load and 95th percentile peak-hour load conditions.[3]
Northwest Power and Conservation Council	*Utilizes a fully probabilistic model*—Prospective plans are tested against 20 years of future conditions. The test process uses random simulations of the principal sources of uncertainty, including hydro conditions, regional electric loads, fuel prices, CO_2 control requirements, import and export markets, resource availability, and other factors. The Council's analytical process creates a two-dimensional mathematical surface defined by portfolio cost and portfolio risk. A subset of resource portfolios along the mathematical cost–risk frontier are selected for further consideration. The preferred portfolio is selected from the set of finalist portfolios using qualitative criteria.[4]

[1] 2009 Integrated Resource Plan, Avista Utilities, August 2009, Chapter 2.

[2] 2009 Pacific Northwest Loads and Resources Study, Bonneville Power Administration, July 2009, Sections 2 & 4.

[3] 2009 Integrated Resource Plan, Idaho Power Company, December 2009.

[4] Draft Sixth Northwest Power Plan, Northwest Power and Conservation Council, September 2009.

Utility	Planning Criteria
PacifiCorp	*Thermal*—Maximum dependable capacity for peak-hour assessment. Energy assessments used maximum dependable capacity de-rated for forced outages and maintenance.[5]
	Hydro Conditions—Critical water conditions. For peak hour assessment, decision support software is used to shape critical hydro energy to estimate maximum capability sustainable for one hour.[5]
	Loads—Average energy requirements based upon normal weather conditions.[5]
	Planning Reserve—Planning reserve margin of 12 percent assumed for energy and peak-hour assessments.[5]
Portland General Electric Company (PGE)	*Hydro Conditions*—Normal hydro conditions.[6]
	Loads—PGE identifies annual energy needs under a reference case (i.e., expected or most likely) and high-load and low-load forecasts, assuming normal weather conditions.[6]
	Capacity—PGE evaluates peaking needs by comparing the annual one-hour maximum load inclusive of 12 percent reserves (6 percent operating margin, 6 percent planning margin), calculated on a 1-in-2 or average basis, to the capability of energy-producing resources. Reports both the winter and the summer peak loads.[6]
Puget Sound Energy	*Loads*—For capacity, power demand was estimated at normal winter minimum temperature (23° F) plus a 15 percent planning margin. Five different economic growth scenarios were modeled in the resource plan.[7]
	Hydro—For capacity resource need, hydro projects assumed at full capacity output.[7]
	Thermal—For capacity resource need, thermal projects assumed at full capacity output.[7]

[5] 2008 Integrated Resource Plan, PacifiCorp, May 28, 2009, Chapter 5.

[6] PGE 2009 Integrated Resource Plan, Portland General Electric, November 2009, Chapter 3.

[7] Integrated Resource Plan, Puget Sound Energy, July 2009, Chapters 5 & 8.

IRP ADVISORY COUNCIL ROSTER

Customer Representatives

AARP	Maribeth Connell
Agricultural Representative	Sid Erwin
Boise State University	John Gardner/Todd Haynes
Heinz Frozen Foods	Steve Munn
Idaho Retailers	Pam Eaton
Industrial Customers of Idaho Power	David Hawk
INL	Tom Moriarty
Micron	John Velikoff
Simplot	Don Sturtevant

Public Interest Representatives

Idaho Conservation League	Betsy Bridge
Idaho Department of Commerce	Don Dietrich/Lane Packwood
Idaho Office of Energy Resources	Paul Kjellander
Idaho State House of Representatives	Representative Fred Wood
Idaho State Senate	Senator Russ Fulcher
Northwest Power and Conservation Council	Jim Yost/Shirley Lindstrom
Snake River Alliance	Ken Miller
Twin Falls Canal Company	Vince Alberdi, Retired General Manager

Regulatory Commission Representatives

Idaho PUC	Rick Sterling
Oregon PUC	Kelcey Brown

Consultant/Facilitator

The Cadmus Group, Inc.	Brian Hedman

ATTACHMENT N-2
IDAHO POWER COMPANY'S 2011 INTEGRATED RESOURCE PLAN (DOCKET LC 53)



2011 Integrated Resource Plan

June 2011

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Printed on recycled paper

2011 Integrated Resource Plan

June 2011



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Acknowledgement

Resource planning is a continuous process that Idaho Power Company constantly works to improve. Idaho Power prepares and publishes an Integrated Resource Plan (IRP) every two years and expects the experience gained over the next few years will lead to modifications in the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the 2011 IRP. Idaho Power values the knowledgeable input, comments, and discussion provided by the IRP Advisory Council, and the comments provided by other concerned citizens and customers.

It takes approximately one year for a dedicated team of individuals at Idaho Power to prepare the IRP. The IRP team is comprised of individuals that represent many different departments within the company. IRP team members are responsible for preparing forecasts, working with the IRP Advisory Council (IRPAC) 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 its customers and other interested parties. You can learn more about Idaho Power's resource planning process at www.idahopower.com.

Safe Harbor Statement

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

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1. SUMMARY

Introduction



Idaho Power's IRP is updated every two years.

The *2011 Integrated Resource Plan* (IRP) is Idaho Power's 10th resource plan prepared to fulfill the regulatory requirements and guidelines established by the Idaho Public Utilities Commission (IPUC) and the Public Utility Commission of Oregon (OPUC).

The 2011 IRP assumes that during the planning period (2011–2030), Idaho Power will continue to be responsible for acquiring resources sufficient to serve all of its retail customers in its mandated Idaho and Oregon service areas and that the company will continue to operate as a vertically integrated electric utility. In developing this plan, Idaho Power has worked with the IRP Advisory Council (IRPAC), which is comprised of major stakeholders representing the environmental community, major industrial customers, irrigation customers, state legislators, public utility commission representatives, and others. There are four primary goals of Idaho Power's planning process.

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
4. Involve the public in the planning process in a meaningful way

Idaho Power is responsible for providing safe and reliable electrical service to its service area, which includes most of southern Idaho and a portion of eastern Oregon. In addition to operating under the regulatory oversight of the IPUC and the OPUC, Idaho Power is a public utility under the jurisdiction of the Federal Energy Regulatory Commission (FERC) and is obligated to plan for and expand its transmission system to provide requested firm transmission service to third parties and to construct and place in service sufficient transmission capacity to reliably deliver resources to network

Highlights

- The 2011 IRP expected-case load forecast projects peak-hour load will grow 69 megawatts (MW) annually (1.8 percent) and average-system load will increase annually 29 average megawatts (aMW) (1.4 percent) over the 20-year planning period.
- In 2011, Idaho Power's demand response programs are expected to reduce peak-hour load by 330 MW.
- Idaho Power's ability to import additional amounts of energy from the Pacific Northwest is limited by constraints on the existing transmission system.

customers[1] and the company's retail customers.[2] The 2011 IRP evaluates only the need for additional transmission capacity necessary to serve retail customers. The total capacity of proposed transmission line projects may be larger than identified in the IRP in order to accommodate third-party requests and network customer obligations for capacity on the same transmission path.

The number of customers in Idaho Power's service area is expected to increase from approximately 492,000 in 2010 to over 650,000 by the end of the planning period in 2030. Even with the recent recession, population growth in Idaho Power's service area will require the company to add physical resources to meet the energy demands of its growing customer base.

With hydroelectric generation as the foundation of its energy production, Idaho Power has an obligation to serve customer loads regardless of the water conditions that may occur. In light of public input and regulatory support of the more conservative planning criteria used in the 2002 IRP, Idaho Power will continue to emphasize a resource plan based on worse-than-median stream flows. The IRP uses more conservative planning criteria than median water planning, but the criteria are less conservative than critical water planning. Further discussion of Idaho Power's planning criteria can be found in Chapter 8.

Idaho Power extended the planning horizon in the 2006 IRP to 20 years. Prior Idaho Power IRPs used a 10-year planning horizon, but with the increased need for resources with long construction lead times, the need for a 20-year resource plan to support *Public Utility Regulatory Policies Act of 1978* (PURPA) contract negotiations, and support from the IRPAC, Idaho Power decided to extend the planning horizon of the 2006 and future resource plans to 20 years.

Planning for the future is necessary to meet the needs of Idaho Power's customers today and tomorrow. While the 2011 IRP addresses Idaho Power's long-term resource needs, the company plans for the near-term in accordance with the *Energy Risk Management Policy and Standards* that were collaboratively developed in 2002 between Idaho Power, the IPUC staff, and interested customers (IPUC Case No. IPC-E-01-16). While the IRP has a planning horizon of 20 years and is updated every two years, the *Energy Risk Management Policy and Standards* focuses on an 18-month period and is updated every month.

Public Advisory Process

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 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 2011 IRP, Idaho Power hosted a field trip covering wind, hydroelectric, and natural gas resources, two portfolio-design workshops, and nine monthly IRPAC meetings. The IRPAC meetings served as an open forum for discussions related to the development of the IRP. The IRPAC members and the public have made significant contributions to this plan. A list of the 2011 IRPAC members can be found in *Appendix C—Technical Appendix*.

Idaho Power believes working with members of the IRPAC and the public is a rewarding process, 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

[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.

made by Idaho Power. Idaho Power encourages IRPAC members and members of the public to submit comments expressing their views regarding the 2011 IRP and the planning process in general.

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

IRP Methodology

The preparation of Idaho Power's 2011 IRP begins with updating the forecast of future customer demand. Existing resources, the ability to import electricity, and the performance of existing demand-side management (DSM) programs are then accounted for in the load and resource balance. The next step involves evaluating new DSM programs and the expansion of existing programs. Finally, Idaho Power evaluates portfolios of supply-side resources designed to eliminate any remaining deficits.

Idaho Power primarily uses a financial analysis to compare various resource portfolios to determine the preferred portfolio. Idaho Power attempts to financially value the costs and benefits of each resource type. Traditional resources have fixed and variable costs and a market value for the delivered energy, and Idaho Power includes both the costs and the value when evaluating resources. The cost of any necessary transmission upgrades and the value of renewable energy certificates (REC) are also accounted for in the analysis.

Two resources identified in the 2009 IRP are considered committed resources in the 2011 IRP—1) the 300-megawatt (MW) Langley Gulch combined-cycle combustion turbine (CCCT) that is expected to be available in the summer of 2012, and 2) a 49-MW upgrade of the Shoshone Falls Hydroelectric Project in 2015.

For the 2011 IRP, the 20-year planning period was divided into two, 10-year segments. Dividing the planning period into these two segments prevents near-term resource decisions from being influenced by the availability of resources that are dependent on technological advancements in the second 10 years.

In the first 10-year period (2011–2020), nine resource portfolios were examined. Each resource portfolio was designed to substantially meet the energy and capacity deficits identified in the load and resource balance.

For the second 10-year period (2021–2030), the preferred resource portfolio from the first 10-year period was coupled with each of the 10 portfolios analyzed for the second period. Using the preferred portfolio from the first 10-year period ensures all the portfolios in the second 10-year period are analyzed consistently.

Demand-Side Management

Energy efficiency programs from both the existing portfolio and new program opportunities included in the 2011 IRP are forecast to reduce average load by 233 average megawatts (aMW) by 2030. New energy efficiency opportunities come from a combination of new measures and program expansions. The cost to acquire energy efficiency will vary between an average of 3.6 cents per kilowatt hour (kWh) for existing programs to 5.1 cents per kWh for new program activities and measures for the 2011 IRP.

Demand response programs for the 2011 IRP are targeted to reduce peak summer load by 351 MW by summer 2016. Demand response resources have an average levelized cost of $48 per kilowatt (kW) over the IRP planning period. Demand response programs as peaking resources have grown dramatically in the past few years. The large increase comes from the introduction of the FlexPeak Management

program, which targets commercial and industrial customers, and the transition of the Irrigation Peak Rewards program into a dispatchable, direct load-control program as part of the 2011 IRP.

Details on Idaho Power's existing and proposed DSM programs can be found in Chapter 4 and in *Appendix B–2010 Demand-Side Management Annual Report*. An explanation of the methodologies used to incorporate prior and forecast energy efficiency impacts into the load forecast can be found in *Appendix A–Sales and Load Forecast.*

Supply-Side Resource Costs

The 2011 IRP forecasts load growth in Idaho Power's service area and identifies supply-side resources and demand-side measures necessary to meet the future needs of customers. Recent cost increases have significantly impacted the cost of new supply-side resources, especially when compared to the cost of the existing resources in Idaho Power's generation portfolio. Figure 1.1 shows the 2010 costs in dollars per megawatt hour (MWh) for Idaho Power's existing hydroelectric resources, coal generation facilities, and power purchased from the Elkhorn Valley Wind Project. In addition, Figure 1.1 shows the estimated cost of energy from new resources considered in the 2011 IRP. Existing resource costs are based on 2010 actual costs of capital, fuel, and non-fuel operating and maintenance (O&M). New resource costs are 30-year levelized estimates (based on expected annual generation), which include capital, fuel, non-fuel O&M, and the expected-case carbon adder.

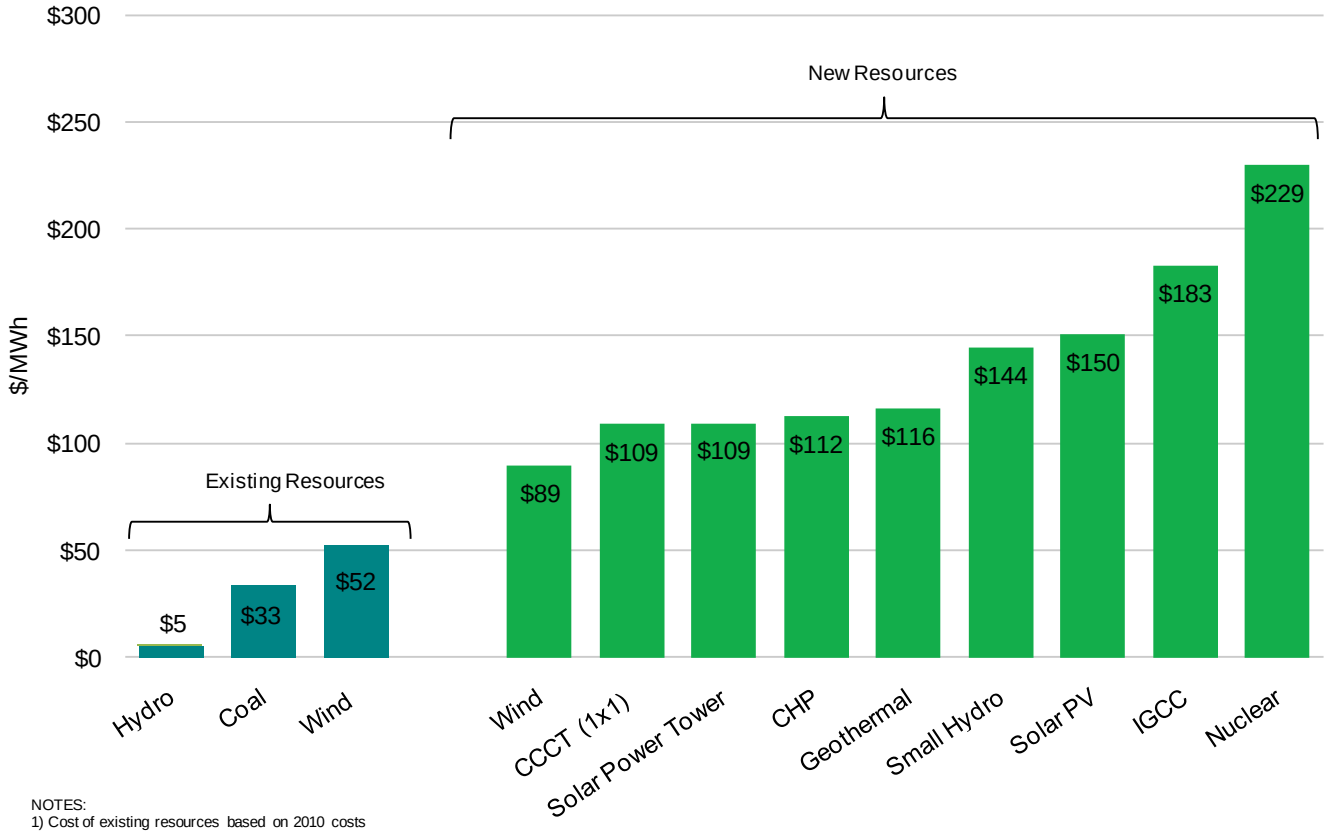


Figure 1.1 Cost of existing and new supply-side resources

While it is important to evaluate the costs presented in Figure 1.1, these figures represent only a part of the total resource cost. In preparing the IRP, Idaho Power must also consider the value that each type of resource provides in conjunction with the other 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. The low capital cost and dispatch capability of a simple-cycle combustion turbine (SCCT) resource makes it a good choice for meeting capacity needs, as long as it is needed for only short durations to meet peak-hour load. A geothermal resource typically provides maximum generation during peak load periods, but because it is non-dispatchable and generally provides constant generation year round (baseload), it is considered a better energy resource. Wind is also a good source of energy; however, it provides almost no peak-hour capacity due to the variable and intermittent nature of the generation.

Figure 1.2 shows the 30-year levelized capital cost in dollars per MW of peak-hour capacity for many of the supply-side resources evaluated in the 2011 IRP. This metric provides useful information on the value of each resource type in terms of providing peak-hour capacity. Idaho Power's peak loads typically occur between 3:00 p.m. and 7:00 p.m. on hot summer days; the expected capacity factor for each resource type during this time period is also shown in Figure 1.2.

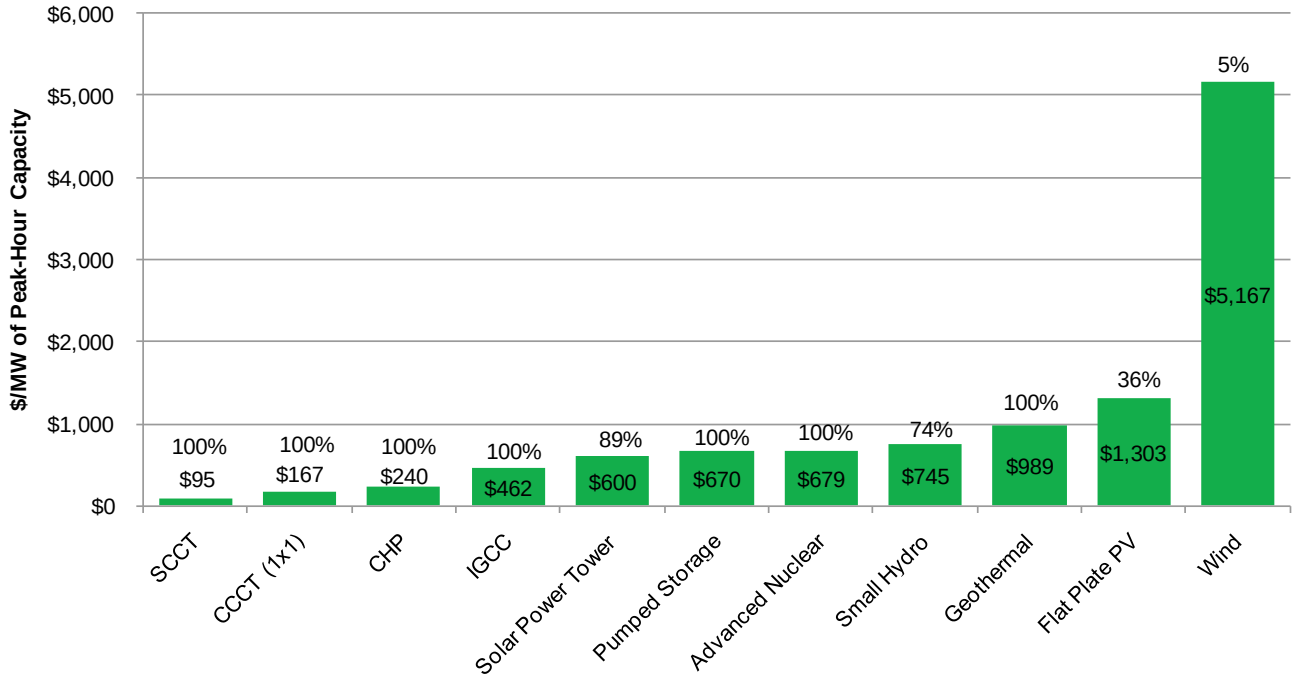


Figure 1.2 30-year levelized capital cost of peak-hour capacity

Resources capable of providing 100 percent of nameplate capacity during peak load periods have an obvious cost advantage when compared to resources with lower peak-hour capacity factors, such as wind. Because wind can be counted only to provide 5 percent of nameplate capacity during the peak-hour, 20 MW of nameplate wind would need to be built to get one MW of peak-hour capacity. A complete discussion of the cost of capacity and the total cost of the resources analyzed in the 2011 IRP is presented in Chapter 6, and details of the calculations used to prepare Figure 1.2 are presented in *Appendix C–Technical Appendix*.

Greenhouse Gas Emissions

Idaho Power owns and operates 17 hydroelectric projects, 2 natural gas-fired plants, 1 diesel-powered plant, and shares ownership in 3 coal-fired facilities. Idaho Power's carbon dioxide (CO_2) emissions levels have historically been well below the national average for the 100 largest electric utilities in the United States, both in terms of total CO_2 emissions (tons) and CO_2 emissions intensity (pounds [lbs] per MWh), based on the report of 2008 CO_2 emissions presented in *Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States,*

released in June 2010 by the Ceres investor coalition, the Natural Resources Defense Council, Public Service Enterprise Group, and Portland Gas & Electric (PG&E) Corporation.

In September 2009, Idaho Power's Board of Directors approved guidelines to establish a goal to reduce the CO_2 emissions intensity of the company's utility operations. The guidelines are intended to prepare the company for potential legislative and or regulatory restrictions on greenhouse gas (GHG) emissions, while minimizing the cost of complying with such reductions on Idaho Power's customers.

The guidelines establish a goal to reduce Idaho Power's resource portfolio's average CO_2 emissions intensity for the 2010 through 2013 time period to a level of 10–15 percent below the company's 2005 CO_2 emissions intensity of 1,194 lbs per MWh. Since Idaho Power's CO_2 emissions intensity fluctuates with stream flows and the production levels of existing and anticipated renewable resources, the company has adopted an average intensity reduction goal to be achieved over several years.

At present, 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, as well as additional information on Idaho Power's CO_2 emissions, is currently reported on the company's website at www.idahopower.com/NewsCommunity/OurEnvironment/co2Intensity.cfm. Information related to Idaho Power's CO_2 emissions is also available through the Carbon Disclosure Project at www.cdproject.net.

Idaho Power's annual CO_2 emissions intensity for 2009 and 2010 were 1,003 lbs per MWh and 1,065 lbs per MWh respectively, both below the 2005 CO_2 emissions intensity level. Idaho Power's average CO_2 intensity for the goal period-to-date, January 2010–April 2011, is 949 lbs of CO_2 per MWh. This reduction in intensity relative to the 2010 level reflects an increase in hydroelectric generation, as a result of the current water conditions, and reduced coal-fired generation. For the 2010–2013 time period, Idaho Power fully expects to achieve its goal of reducing its CO_2 emissions intensity from company-owned resources (relative to the 2005 level of 1,194 lbs CO_2 per MWh) by more than 15 percent.

The guidelines are intended to reduce Idaho Power's near-term CO_2 emissions intensity levels in a manner that minimizes the cost of the reductions on the company's customers. The 2011 IRP attempts to quantify the cost and longer term impacts of carbon regulations by including a carbon adder that is applied to all resources that emit CO_2. Additional details regarding the assumptions and analysis are presented in Chapter 6 and Chapter 9 of the 2011 IRP.

Preferred Resource Portfolio

The preferred portfolio for the 2011 IRP presented in Table 1.1 was constructed by combining the preferred portfolio for the first 10 years of the planning horizon (2011–2020) with the preferred portfolio for the second 10-year period (2021–2030). In addition to the committed resources (Langley Gulch and the Shoshone Falls upgrade) the preferred resource portfolio includes 450 MW of market purchases beginning in 2016 with the completion of the Boardman to Hemingway transmission line. The total west-to-east transfer capacity reserved on Boardman to Hemingway by Idaho Power is expected to be 450 MW.

The preferred portfolio for the second 10-year period (2021–2030) represents a balanced strategy of adding a mixture of renewable resources along with natural gas-fired baseload and peaking resources. Although the resources in the preferred portfolio for the second 10-year period were analyzed without the addition of the Gateway West transmission project, Idaho Power plans to continue permitting the Gateway West project because of uncertainty associated with the location of resources planned so far in the future and the long lead time required to permit high-voltage transmission projects.

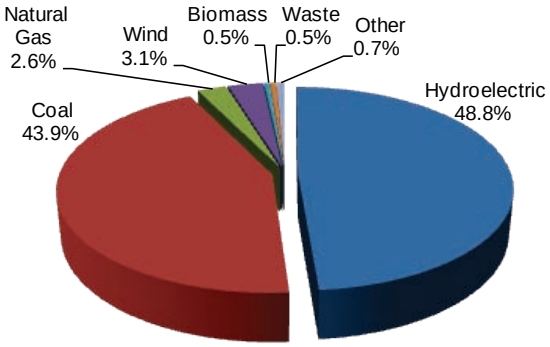
Table 1.1 Preferred portfolios

1–3 Boardman to Hemingway (2011–2020)			2–6 Balanced 1 (2021–2030)		
Year	**Resource**	**MW**	**Year**	**Resource**	**MW**
2011			2021	Geothermal	52
2012	CCCT (Langley Gulch)*	300	2022	SCCT	170
2013	Solar Demonstration Project		2023		
2014			2024	Solar Power Tower	50
2015	Shoshone Falls Upgrade*	49	2025	CCCT	300
2016	Boardman to Hemingway	450	2026		
2017			2027		
2018			2028	Small Hydro	60
2019			2029	SCCT	170
2020			2030		

*Committed resource

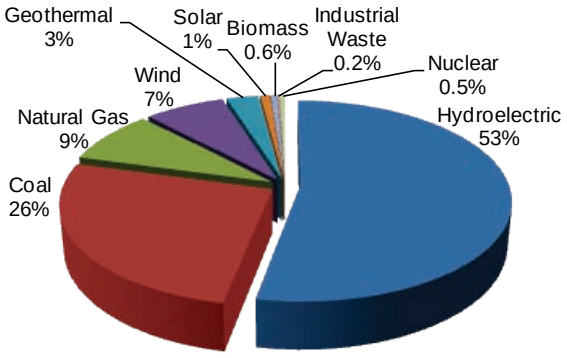
Idaho Power relies primarily on company-owned hydroelectric and coal-fired generation facilities along with purchased power to supply the energy needed to serve customers. Because Idaho Power's annual hydroelectric generation varies depending on water conditions in the Snake River, the percentage of each energy source also changes year-to-year.

Figure 1.3 shows Idaho Power's "fuel mix" by resource type for 2010, and Figure 1.4 estimates the company's fuel mix in 2030 based on the implementation of the preferred portfolio. In 2030, Idaho Power's hydroelectric resources are the predominate resource and provide over 50 percent of the mix. Generation from coal-fired resources becomes a smaller part of the mix, being replaced by natural gas and a mixture of renewable resources. In preparing Figures 1.3 and 1.4, market purchases were assumed to be comprised of the estimated Pacific Northwest energy market fuel mix for 2010 and 2030.



NOTE: 2010 Market Purchases are 6% of Idaho Power's energy sources, and the fuel mix is modeled in this graph using the Northwest Power Pool (NWPP) system mix for 2010.

Figure 1.3 2010 fuel mix



NOTE: 2030 Market Purchases are 13% of Idaho Power's energy sources, and the fuel mix is modeled in this chart using the AURORA Washington system mix for 2030.

Figure 1.4 2030 fuel mix

Idaho Power anticipates the resources in the second 10-year period will be reconsidered in the 2013 IRP and subsequent plans as more certainty regarding carbon regulations and a federal renewable electricity standard (RES) become available. Future uncertainty requires alternate portfolios be considered in the resource planning process. Further details regarding the preferred portfolio and the alternate portfolios can be found in Chapter 10.

Near-Term Action Plan

The Langley Gulch CCCT is currently under construction and is expected to be completed by summer 2012. Idaho Power also anticipates beginning preliminary design work for the Shoshone Falls Upgrade

Project in 2012, which is expected to be completed in 2015. Idaho Power is also continuing to work with federal and state agencies, FERC, other transmission providers, and the public on the Boardman to Hemingway and Gateway West transmission projects. Major milestones associated with these resources and programs are presented in Table 1.2.

Table 1.2 Near-term action plan milestones

Year	Action
2011	Langley Gulch CCCT construction continues
	File 2011 IRP with regulatory commissions
	Demand response programs expected to provide 330 MW of load reduction
	Continue the Boardman to Hemingway permitting process
	Continue the Gateway West NEPA permitting process
	Prepare and issue an RFP for the Solar Demonstration Project
2012	Langley Gulch CCCT on line (300 MW)
	Evaluate responses to the Solar Demonstration Project and file a Certificate of Public Convenience and Necessity (CPCN)
	Complete design work on the Shoshone Falls Upgrade Project and issue RFP
	Continue Boardman to Hemingway permitting process
	Continue the Gateway West NEPA permitting process
	Solar Demonstration Project on line in late 2012/early 2013
2013	Issue RFP for Boardman to Hemingway construction
	Shoshone Falls Upgrade Project construction begins
	File 2013 IRP with regulatory commissions
	Continue the Gateway West NEPA permitting process
2014	Shoshone Falls Upgrade Project construction continues
	Boardman to Hemingway construction begins
	Secure 83 MW PPA for summer 2015 from the east side
2015	Shoshone Falls Upgrade Project on line (49 MW)
	File 2015 IRP with regulatory commissions
2016	Boardman to Hemingway construction completed (450 MW)
2017	File 2017 IRP with regulatory commissions
2018	
2019	File 2019 IRP with regulatory commissions
2020	

Public Policy Issues

The 2011 IRP was completed using computer modeling and other analytical methods. However, certain public policy questions exist that cannot be directly examined through analytical methods. Idaho Power has presented these issues to the IRPAC for discussion, but the nature of issues typically precludes a strong majority opinion from IRPAC members. The public policy issues presented to the IRPAC are discussed in the following sections.

New Large Loads

Locally, Idaho Power and its customers face internal conflicts created by traditional rate determination and the cost difference between existing resources and future resources. New customers that connect to Idaho Power's system benefit from energy rates based on the low-cost of existing resources that are embedded in current rates. However, Idaho Power's existing resources and transmission system are fully used, and new customers require the addition of generation, transmission, and distribution resources. Because new resources are more expensive than Idaho Power's existing portfolio, each new customer

dilutes the existing resource base and increases the cost to all customers. Accordingly, for a number of years, Idaho Power has attempted to balance the impact on both the new customer and existing customers through an intermediate period by using blocked contracts that provide for an element of marginal-cost pricing.

In addition, Idaho Power's ability to serve new large loads is limited as growth in summertime peak demand continues to drive the need for additional resources. New businesses are attracted to southern Idaho due in part to Idaho Power's low rates, which have consistently been some of the lowest in the nation. When a new large customer makes a request for service, Idaho Power must include restrictions in the contract limiting the customer's usage during peak summer months. These restrictions typically last for several years until new resources can be planned for and built, and many new large customers are unable or unwilling to accept these terms.

For the 2011 IRP, an analysis was performed to determine the cost of building additional natural gas-fired peaking capacity that could be used to serve new large loads. The analysis assumes 80 MW of capacity from a SCCT is added to Idaho Power's resource portfolio in 2014. The analysis also assumes the additional capacity is built and no new large load materializes.

The results show the net present value of the revenue requirement associated with the fixed and variable cost of adding the additional 80 MW of capacity would be $60 million. In addition to positioning the company to serve new large loads, which will promote local economic development and create jobs, this additional capacity will be able to assist with integrating wind generation and, when opportunities exist, make profitable surplus sales to help offset the fixed costs of ownership. *Appendix C–Technical Appendix* contains additional details regarding the analysis.

Idaho Power recognizes the ability to serve new large loads has an impact on Idaho's economy. Because of this, and the results of the analysis mentioned above, Idaho Power is proposing an additional 80 MW of peak-hour load be added to Idaho Power's load and resource balance beginning with the 2013 IRP. By adding this additional peak-hour load to the load and resource balance, the additional capacity will come from a diverse set of resources identified in the IRP process, perhaps at a lower cost, and not specifically from the construction of a single new resource.

Asset Ownership

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

Emissions Offsets

Depending on market conditions and future regulations, it may be possible to purchase emissions or carbon offsets for less than the cost of a carbon allowance. Some members of the IRPAC have suggested it would be prudent for Idaho Power to hedge carbon emissions risk by purchasing emissions offsets prior to the formal passage of carbon legislation. However, there are differing opinions among IRPAC members. The principal reason cited for not purchasing offsets today is the uncertainty associated with whether carbon offsets purchased today will meet future carbon control requirements and regulations. In addition, recent draft federal legislation has limited the amount of offsets that may be used to meet reduction targets.

Uncertainty in the future regulation of carbon is evidenced in the recent collapse of the Chicago Climate Exchange (CCX). CCX was established in 2003 as the sole voluntary GHG reduction and offset trading platform for North America and Brazil. In December 2010, CCX ceased trading due to the complete market free-fall of their carbon emissions product. However, CCX continues generation of their carbon financial instrument (CFI) product as a strictly voluntary GHG emissions offset system.

Idaho Power plans to continue to follow developments related to carbon offsets and options in the event either becomes a viable alternative. The company could potentially reduce the large financial exposure of possible carbon regulation for the cost of the option premium. Idaho Power believes it should be able to recover the cost of purchasing emissions offset options as well as the cost of any emissions offsets purchased.

Technology Risk and Joint Development

In the 2011 IRP, several resource options dependent on developing technology have been evaluated in various portfolios. Carbon capture and sequestration, integrated gasification combined-cycle (IGCC), advanced nuclear, and numerous storage technologies are not yet commercially available; however, the technology may become available during the 20-year planning horizon evaluated in the IRP. This raises the question of whether Idaho Power should participate in development efforts related to any of these technologies prior to them becoming commercially available.

Idaho Power believes that, as a medium-sized utility, it would be impractical to lead the development work on any particular technology. However, as certain technologies are identified that show promise as being beneficial to Idaho Power and its customers, the company may choose to participate in development efforts. Idaho Power's participation would most likely be part of a larger group-effort to develop a technology jointly with other utilities with similar needs.

Similarly, certain existing and emerging resource technologies are available only in large sizes—larger than what Idaho Power could or would consider developing alone. If opportunities become available to jointly develop large resources, Idaho Power plans to evaluate them on a case-by-case basis. A similar strategy has been used in the past and resulted in Idaho Power's joint ownership of three coal-fired resources.

Solar Demonstration Project

While solar technology continues to be more expensive than other alternatives, the cost of solar resources continues to decrease while the cost of most other resource options has increased. In addition to providing RECs, solar resources typically deliver energy during the time of day when Idaho Power's customer demand is high.

Idaho Power's 2009 IRP discussed the advantages and disadvantages of several solar demonstration project options, including a utility-scale project located near an existing substation and a distributed rooftop program. During the preparation of the 2009 IRP, a substantial amount of support was expressed by IRPAC members and the public for some type of a local project.

Idaho Power has continued to evaluate the benefits of developing a solar photovoltaic (PV) demonstration project and the topic was again discussed with the IRPAC as part of preparing the 2011 IRP. Several IRPAC members expressed support for the project to include a research and development component as well as continued support for developing a solar rooftop program.

As the cost continues to decline, Idaho Power believes solar PV resources will become more prevalent in the future, and it will be important for the company to have operating experience and be able to determine what specific type of PV technology provides the most value for Idaho Power customers.

With that in mind, Idaho Power intends to make a more detailed proposal that would allow the company to invest in a small-scale solar PV resource.

Idaho Power anticipates issuing a request for proposal (RFP) before the end of 2011 to design and construct a 500-kW–1-MW solar PV resource to be located in Idaho Power's service area. A portion of the facility would be devoted to testing new PV panel technologies, inverters, and other mounting and tracking systems. Idaho Power would also offer to collaborate with the Center for Advanced Energy Studies (CAES) on relevant research into solar technologies.

Proposals would be evaluated by mid-2012, and if a successful bidder is identified, the company would then file a request with the IPUC for a CPCN. If approved, it is anticipated the facility could be on line as early as the end of 2012.

Based on the 2011 IRP cost estimate for a solar PV resource of $3,750 per kW, the expected cost of the project could be $2–$4 million and would require approximately 5–10 acres of land. While the proposed size of this project is small relative to what might be considered a utility-scale project, Idaho Power believes it will provide useful data and give the company experience owning and operating this type of resource. It will also allow the company to better evaluate the advantages and disadvantages of utility-scale solar PV projects and distributed rooftop programs.

Idaho Power views this proposal as a demonstration project because of its small size and its primary purpose being to collect information on how solar PV resources integrate with the company's other system resources. In addition to providing valuable information on solar integration, the demonstration project will provide an opportunity for Idaho Power to expand green power program options for customers.

Idaho Power's REC Management Plan details the company's intent to continue selling RECs in the near term until they are needed to meet a federal RES. In general, a majority of Idaho Power's customers support this policy, as 95 percent of the revenue from the sale of RECs is returned to customers to keep rates low. However, there is a growing segment of customers who desire, and are willing, to pay a premium for, green energy. Idaho Power believes it is important to provide additional options for these customers, and the solar demonstration project presents an opportunity to expand the available offerings.

In addition to the benefits already identified, Idaho Power is required to build a 500-kilovolt (kV) solar PV project within the next several years under the State of Oregon's Solar PV Pilot Program. The company is currently working with the OPUC to determine if this facility would have to be built in Oregon, which may impact the structure of the RFP. Additional details on the Oregon Solar PV Pilot Program can be found in Chapter 3.

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2. Political, Regulatory, and Operational Issues

Idaho Power is a regulated utility. On the federal level, Idaho Power is subject to the rules and regulation of FERC. On the state level Idaho Power is subject to the IPUC and OPUC because the company has customers in both Idaho and Oregon, with approximately 95 percent of Idaho Power's customers located in the state of Idaho. The following sections describe some of the federal and state regulatory issues facing Idaho Power.



The IPUC regulates Idaho Power in Idaho.

Idaho Energy Plan

In 2006, the Idaho State Legislature directed the Interim Committee on Energy, Environment, and Technology to develop a state energy plan that provides for the state's power generation needs and protects the health and safety of Idaho citizens. In January 2007, the committee completed the *2007 Idaho Energy Plan* and concluded that all Idaho energy systems have performed very well, with retail electric and natural gas prices remaining some of the lowest in the country.

The committee also recognized that Idaho's reliance on low-cost coal plants may become a source of risk in the future due to the economic impact of potential federal regulation of carbon and mercury (Hg) emissions. To address these concerns, the committee recommended increasing investments in energy conservation and in-state renewable resources. In a resource priority policy statement, the committee stated, "When acquiring resources, Idaho and Idaho utilities should give priority to: 1) conservation, energy efficiency, and demand response; and 2) renewable resources; recognizing that these alone may not fulfill Idaho's growing energy requirements." The committee further stated, "…energy suppliers must continue to have access to conventional energy resources to keep Idaho's energy costs as low as possible."

Idaho Strategic Energy Alliance

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

Highlights

- Idaho Power continues to operate the Hells Canyon Complex under annual licenses issued by FERC until a new license is issued.
- The 2011 IRP assumes a federal RES will be enacted in the future.
- Idaho Power is preparing an updated wind integration study in association with the 2011 IRP.

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

- Conservation and energy efficiency
- Wind
- Geothermal
- Hydroelectric power
- Carbon issues
- Baseload resources
- Economic/financial development
- Forestry
- Biogas
- Biofuel
- Solar
- Transmission
- Communication and outreach

Idaho Power representatives serve on many of these task forces. The alliance is governed by a board of directors comprised of representatives from Idaho stakeholders and industry experts. The workings of the alliance are overseen by the Governor's Council, a group of the governor's cabinet members.

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 is actively pursuing the relicensing of the Hells Canyon Complex and the Swan Falls hydroelectric project.

Idaho Power's most significant ongoing relicensing effort is the Hells Canyon Complex. The Hells Canyon Complex provides approximately two-thirds of Idaho Power's hydroelectric generating capacity and 40 percent of the company's total generating capacity. The current license for the Hells Canyon Complex expired at the end of July 2005. Until the new, multi-year license is issued, Idaho Power continues to operate the project under an annual license issued by FERC.

The Hells Canyon Complex license application was filed in July 2003 and accepted by FERC for filing in December 2003. FERC is now processing the application consistent with the requirements of the *Federal Power Act of 1920*, as amended (FPA); the *National Environmental Policy Act of 1969*, as amended (NEPA); the *Endangered Species Act of 1978* (ESA); and other applicable federal laws.

The license for the Swan Falls project expired in June 2010. In March 2005, Idaho Power issued a Formal Consultation Package (FCP) to the public relating to environmental studies designed to determine project effects for the relicensing of the project. In September 2007, Idaho Power submitted a draft license application to FERC for public review and comment. The draft application was based on the results of environmental studies along with agency and public consultation. Idaho Power filed a final license application for the Swan Falls hydroelectric project with FERC in June 2008, and FERC issued its Final Environmental Impact Statement (FEIS) in August 2010.

Relicensing costs of $134 million and $5 million for the Hells Canyon Complex and Swan Falls projects, respectively, were recorded by Idaho Power as of March 2011. Administrative work on relicensing is expected to continue until new licenses are issued in 2012 for Swan Falls and 2014 for the Hells Canyon Complex. Once new licenses are issued, further costs will be incurred to comply with the terms of the new licenses. Given the new licenses for Swan Falls and the Hells Canyon Complex have not been issued, and discussions on the PM&E packages are still being conducted, it is not possible to estimate the final total cost.

Relicensing activities include: 1) coordination of 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, reservoir contours and volumes; 5) study and data analysis; 6) preparing all necessary reports, exhibits, and filings; 7) responding to requests for additional information from FERC; and 8) legal consultation. This estimate includes costs for all areas of Idaho Power related to the relicensing effort.

Failure to relicense any of the existing hydroelectric projects at a reasonable cost will create upward pressure on the current electric rates of Idaho Power customers. The relicensing process also has the potential to decrease available capacity and increase the cost of a project's generation through additional operating constraints and requirements for environmental protection, mitigation, and enhancement (PM&E) measures imposed as a condition for 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 was assumed as part of the 2011 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 is dependent on the state water rights held by the company for these projects. The long-term sustainability of the Snake River Basin stream flows, including tributary spring flows and the regional aquifer system, is crucial for Idaho Power to be able 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 are expected to impact Idaho Power's hydroelectric generation in the near term, but the company cannot predict the ultimate outcome of the legal and administrative water-rights proceedings. Idaho Power's ongoing participation in water-rights issues is intended to guarantee that sufficient water is available for use at the company's hydroelectric projects on the Snake River.

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

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 hydroelectric facility. 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 agreement placed the portion of the company's water rights beyond those 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 that the court resolve issues associated with Idaho Power's water rights and the application and effect of the trust provisions of the Swan Falls Agreement. In addition, Idaho Power asked the court to determine whether the agreement subordinated the company's hydroelectric water rights to aquifer recharge.

A settlement signed in 2009 reaffirmed the Swan Falls Agreement and resolved the litigation by clarifying that the water rights held in trust by the state are subject to subordination to future upstream beneficial uses, including aquifer recharge. It 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 are actively involved in those discussions. The settlement also recognizes water-management measures that enhance aquifer levels, springs, and river flows—such as aquifer-recharge projects—that benefit both agricultural development and hydroelectric generation. Both parties anticipate water-management measures will be developed in the implementation of the Eastern Snake River Plain Aquifer, Comprehensive Aquifer Management Plan (ESPA CAMP) as approved by the Idaho Water Resource Board.

Idaho Power actively participates in proceedings associated with the ESPA CAMP. Given the high degree of interconnection between ESPA and the Snake River, Idaho Power recognizes the importance of aquifer-management planning in promoting the long-term sustainability of the Snake River.

The company hopes implementation of the ESPA CAMP will restore aquifer levels and tributary spring flows to the Snake River. It is assumed in the 2011 IRP that CAMP measures specified under Phase I of the plan are implemented. Phase I recommendations, to be implemented over a 5–10-year period, consist of a combination of ground-water to surface-water conversions, managed aquifer recharge, demand reduction programs, and weather-modification programs designed to produce an increase in average annual aquifer discharge between 200,000 and 300,000 acre feet. Additional funding mechanisms are being explored to implement measures outlined in the ESPA CAMP.

Further discussion of the ESPA CAMP is included in *Appendix C—Technical Appendix*. The Phase I measures with associated target water volumes are shown in Table 2.1.

Table 2.1 Phase I measures

Measure	Target (acre-feet)
Ground water to surface water conversions	100,000
Managed aquifer recharge	100,000
Demand reduction	0
Surface-water conservation	50,000
Crop mix modification	5,000
Rotating fallowing, dry-year lease, conservation reserve enhancement program (CREP)	40,000
Weather modifications	50,000

Wind Integration Study

Total installed wind-generation capacity continues to expand in Idaho and the Pacific Northwest. A recent surge in wind development in southern Idaho by independent power producers has heightened concerns over Idaho Power's ability to integrate additional wind resources beyond the 395 MW currently online. The cost of integrating additional intermittent wind resources and the potential impact on system reliability is of primary concern. As a result of these concerns, Idaho Power is updating its study in association with the 2011 IRP.

The objective of the updated study is to assess the costs incurred in modifying operations of dispatchable generating resources in order to allow them to respond to the variable and intermittent nature of wind resources such that the reliable delivery of electrical power to customers is unaffected. Idaho Power considers the assessment of these costs an important part of efforts to ensure the price paid to acquire wind energy is fair to independent developers and Idaho Power customers. Although the purpose of the study is to estimate the cost of integrating wind, the actual impact of integrating large amounts of wind generation on a day-to-day basis will create ongoing operational and reliability issues for Idaho Power's system dispatchers.

Idaho Power has been concerned about wind integration issues since late 2010 when 771 MW of requests for PPAs by wind developers were made under PURPA. Initial efforts were focused on determining the value of the energy from these PURPA contracts, and in early 2011, Idaho Power entered into a contract with PLEXOS Solutions, LLC, for technical support in determining the cost of integrating wind and the impact on system reliability.

The study is designed to investigate the impact and cost of integrating wind on Idaho Power's system by modeling a range of wind build-out cases (600 MW, 800 MW, 1,200 MW, and 1,600 MW) and comparing the system operation and cost of these cases against a base case. The concept behind this approach is that a set of dispatchable generating resources is operated differently in the wind build-out cases to provide balancing reserves necessary for responding to the intermittency and variability associated with wind generation. These reserves, necessary to maintain system reliability, are provided at a cost.

An important consideration for the study, as well as wind integration in practice, is the designation of the set of resources responsible for integrating wind. For the updated study, Idaho Power's existing resources capable of providing balancing reserves includes the hydroelectric units of the Hells Canyon Complex, the coal-fired units at the Jim Bridger and North Valmy power plants, the company's fleet of SCCTs located in Mountain Home, Idaho, and the Langley Gulch CCCT expected to be commercially available in July 2012. In addition, the study will evaluate the benefits of the proposed Boardman to Hemingway transmission line project (planned for 2016) on the cost of integrating wind generation.

In March 2011, Idaho Power held a public workshop for interested stakeholders where the proposed study methodology was explained and input on the design of the study was solicited. The company anticipates holding a second public workshop in conjunction with the completion of the study in July 2011, and a final study report is expected to be released shortly thereafter.

Fixed Cost Adjustment

Under the fixed cost adjustment (FCA), rates are annually adjusted up or down to recover or refund the difference between the fixed costs authorized by the IPUC and the fixed costs that Idaho Power actually received the previous year through energy sales. This mechanism removes the financial disincentive that exists when Idaho Power invests in DSM resources. The FCA Pilot is currently limited to the residential and small commercial classes in recognition of the fact that, for these customers, a high percentage of fixed costs are recovered through energy charges.

On October 1, 2009, the company filed an application with the IPUC to convert the FCA to an ongoing and permanent rate schedule. On April 29, 2010, the IPUC issued Order No. 31063 extending the original 3-year FCA Pilot for an additional two years, effective January 1, 2010.

During the 4-year period that the FCA (Schedule 54) has been in effect, Idaho Power has made progress in promoting energy efficiency and DSM activities. During the term of the FCA Pilot, the company has increased the number of DSM programs it offers and substantially increased both its investment in DSM activities and the MWh savings obtained via DSM. Results from the first four years of the pilot indicate

the true-up mechanism is working as intended and operating to mitigate the unintended adverse effects of DSM by ensuring that the fixed costs the IPUC authorized the company to recover are being recovered via the FCA mechanism.

As part of a general rate case filed with the IPUC on June 1, 2011, the company has again requested to convert the FCA to an ongoing and permanent rate schedule. The company believes the FCA has proved to be an effective rate mechanism for removing the financial disincentives that exist when Idaho Power invests in DSM resources and if made permanent will continue to serve in the best interests of its customers.

Renewable Energy Certificates

To promote the construction of renewable resources, a system was created that separates renewable generation into two parts, 1) the electrical energy produced by a renewable resource, and 2) the renewable attributes of that generation. These renewable attributes are referred to as RECs or green tags. The entity that holds a REC has the right to make claims about the environmental benefits associated with the renewable energy from the project. One REC is issued for each MWh of electricity generated by a qualified resource. Electricity that is split from the REC is no longer considered renewable and cannot be marketed as renewable by the entity that purchases the electricity.

A REC must be retired once it has been used for either regulatory compliance or to substantiate a claim regarding renewable energy. Once a REC is retired, it cannot be sold or transferred to another party. The same REC may not be claimed by more than one entity, including any environmental claims made pursuant to electricity coming from renewable energy resources, environmental labeling, or disclosure requirements. State renewable portfolio standards (RPS) also typically specify a "shelf life" for RECs so they cannot be banked indefinitely.

Renewable Portfolio Standards

Under the state of Oregon's RPS, Idaho Power is classified as a "smaller utility" because the company's Oregon customers represent less than 3 percent of Oregon's total retail electric sales. As a smaller utility, Idaho Power will have to meet a 10 percent RPS requirement beginning in 2025.

While the state of Idaho does not have an RPS, Idaho Power believes a federal RES, requiring Idaho Power to retire RECs for compliance, will be passed by Congress in the future. Idaho Power believes it is prudent to continue acquiring RECs associated with renewable resources to minimize the impact when a federal RES is implemented.

For the 2011 IRP, the portfolios being analyzed are designed to substantially comply with the *Renewable Electricity Promotion Act of 2010* (S. 3813) introduced in Congress in September 2010, by Senator Jeff Bingaman (D–New Mexico). Under the proposed bill, an initial renewable requirement of 3 percent would begin in 2012 and would increase to 15 percent by 2021.

REC Management Plan

Idaho Power's acquisition of RECs has created an issue regarding the disposition of the RECs until either a state RPS or federal RES requirement exists. Two options exist: 1) retire RECs, which would allow Idaho Power to represent to customers that renewable energy is being delivered to them, or 2) sell RECs and use the proceeds to reduce customer rates.

This issue was debated by the IRPAC during the preparation of both the 2009 IRP and the 2011 IRP. In general, environmental representatives felt future RECs should be retired while customer representatives felt they should be sold so that the value could be returned to customers.

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

Federal Energy Legislation

Idaho Power is subject to a broad range of federal, state, regional, and local laws and regulations designed to protect, restore, and enhance the quality of the environment, including air, water, and solid waste. Current and pending legislation relates to, among other items, climate change, GHG emissions and air quality, RES, Hg and other emissions, hazardous wastes, and polychlorinated biphenyls (PCB). Environmental laws and regulations may, among other things, increase the cost of operating power generation plants and constructing new facilities, require that Idaho Power install additional pollution control devices at existing generating plants, or require that Idaho Power discontinue operating certain power generation plants.

Federal Climate Change Legislation



Future federal climate-change legislation could affect regulated utilities, such as Idaho Power.

For the past several years, Congress has considered comprehensive federal energy legislation requiring reductions in GHG emissions. Proposed GHG regulations target the reduction of carbon and other GHG emissions nationwide. The most recent and prominent bills that have been proposed are 1) the *American Clean Energy and Security Act of 2009* (Waxman–Markey), sponsored by Representatives Henry A. Waxman and Edward J. Markey; 2) the *Clean Energy Jobs and American Power Act of 2009* (Boxer–Kerry), sponsored by Senators Barbara Boxer and John Kerry in the Senate; and 3) the *American Power Act of 2010* (Kerry–Lieberman), sponsored by Senators John Kerry and Joe Lieberman.

In June 2009, the US House of Representatives narrowly passed the Waxman–Markey bill. The draft bill included a GHG emissions reduction goal of 3 percent below 2005 levels by 2012, 17 percent by 2020, 42 percent by 2030, and more than 80 percent by 2050. The Waxman–Markey bill proposed to accomplish the reductions under a cap-and-trade system that would establish a limit or cap on the total amount of GHG emissions. Although the Waxman–Markey bill passed in the House of Representatives, it did not pass in the Senate.

Under a cap-and-trade system, utilities would be allocated emissions allowances that would be decreased over time to achieve a total emissions reduction goal. A certain amount of allowances would also be auctioned as part of establishing a market where allowances could be bought and sold. In effect, a buyer would be paying a charge for polluting, while a seller would be rewarded for having reduced emissions by more than was required. The theory is those who can reduce emissions most economically will do so, achieving the pollution reduction at the lowest possible cost to society.

In September 2009, the Boxer–Kerry bill was introduced in the Senate. The draft bill included a GHG emissions reduction goal of 20 percent below 2005 levels by 2020. The Boxer–Kerry bill did not include a federal RES provision.

In May 2010, the Kerry–Lieberman bill was introduced in the Senate. The proposed legislation included a cap-and-trade system for reducing GHG emissions by 17 percent in 2020 and by over 80 percent in 2050. None of the proposed federal climate change legislation has been able to gain enough support to be passed by both the House of Representatives and the Senate.

In the summer of 2011, the Environmental Protection Agency (EPA) plans to begin regulating GHG emissions. However, some members of Congress are currently working to remove EPA's authority to regulate GHGs through legislative action and budget cuts.

Environmental Protection Agency

Idaho Power co-owns three coal-fired power plants and owns two natural gas-fired combustion turbine power plants that are subject to air-quality regulation. The coal-fired plants are Jim Bridger (one-third interest) located in Wyoming; Boardman (10 percent interest) located in Oregon; and Valmy (50 percent interest) located in Nevada. The natural gas-fired plants, Danskin and Bennett Mountain, are located in Idaho. In addition, Idaho Power is currently in the process of constructing the Langley Gulch power plant, a natural gas-fired CCCT generating plant with a nameplate capacity of approximately 300 MW.

The *Clean Air Act* (CAA) establishes controls on the emissions from stationary sources like those owned by Idaho Power. The EPA adopts many of the standards and regulations under the CAA, while states have the primary responsibility for implementation and administration of these air-quality programs. Idaho Power continues to actively monitor, evaluate, and work on air-quality issues pertaining to federal and state Hg emissions rules, possible legislative amendment of the CAA, Regional Haze–Best Available Retrofit Technology (RH BART), National Ambient Air Quality Standards (NAAQS), and New Source Review (NSR) permitting.

Regional Haze–Best Retrofit Technology

In accordance with federal regional haze rules, coal-fired utility boilers are subject to RH BART if they were built between 1962 and 1977 and affect any Class I areas. This includes all four units at the Jim Bridger plant and the Boardman plant. The two units at the Valmy plant were constructed after 1977 and are not subject to the federal regional haze rule. The Wyoming Department of Environmental Quality (WDEQ) and the Oregon Department of Environmental Quality (ODEQ) have conducted assessments of the Jim Bridger and Boardman plants pursuant to the RH BART process. These states have also evaluated the need for additional controls at Jim Bridger and Boardman to achieve reasonable progress toward a long-term strategy beyond RH BART to reduce regional haze in Class I areas to natural conditions by the year 2064.

On November 3, 2010, PacifiCorp, the majority owner and operator of the Jim Bridger plant, and the WDEQ signed a settlement agreement under which PacifiCorp agreed to install selective catalytic reduction (SCR) technology, alternative add-on nitrogen oxide (NO_x) controls, or otherwise achieve a 0.07 pounds-per-million British thermal units (MMBtu) 30-day rolling average NO_x emissions rate by December 31, 2015, for Unit 3 and December 31, 2016, for Unit 4. In addition, PacifiCorp has agreed to install SCR technology, alternative add-on NO_x controls, or otherwise achieve a 0.07 pounds-per-MMBtu 30-day rolling average NO_x emissions rate by December 31, 2021, for Unit 2 and December 31, 2022, for Unit 1. The settlement agreement is conditioned on the EPA ultimately approving those portions of the Wyoming Regional Haze State Implementation Plan that are consistent with the terms of the settlement agreement. In light of the settlement agreement, WDEQ issued a revised RH BART permit for Jim Bridger on November 24, 2010.

In August 2010, Portland General Electric (PGE), the majority owner and operator of the Boardman plant, submitted a new plan to the ODEQ that would cease coal-fired operations at the Boardman plant in 2020, but contemplated additional emissions reductions relative to PGE's previous 2020 closure plan.

Following an extensive public process, in December 2010, the Oregon Environmental Quality Commission approved PGE's August and October 2010 plan to cease coal-fired operations at the Boardman plant no later than December 31, 2020. The new rules implementing the plan are expected to contain the following measures:

- Install new low-NO_x burners and modified overfire air ports by July 2011 to comply with BART standards for NO_x
- Conduct pilot studies for the dry sorbent-injection system to verify that set sulfur dioxide (SO_2) limits for 2014 and 2018, are achievable
- Install a dry sorbent-injection system by July 2014, to comply with BART standards for SO_2
- Repeal the ODEQ's 2009 BART rule, which would have allowed continued operation of the Boardman plant through at least 2040 with installation of a more expensive suite of emissions controls
- Permanent cessation of coal-fired operation no later than December 31, 2020

National Ambient Air Quality Standards

In July 1997, the EPA adopted new NAAQS for ozone (8-hour ozone standard) and fine particulate matter of less than 2.5 micrometers in diameter (PM2.5 standard). In December 2006, the EPA revised the NAAQS for PM2.5. This new standard is the subject of a legal challenge by a number of groups. However, all counties in Idaho, Nevada, Oregon, and Wyoming—where Idaho Power's power plants operate currently—were designated as meeting attainment with the revised PM2.5 NAAQS.

In January 2010, the EPA adopted a new NAAQS for NO_2 at a level of 100 parts-per-billion averaged over a 1-hour period. In addition, in June 2010, the EPA adopted a new NAAQS for SO_2 at a level of 75 parts-per-billion averaged over a 1-hour period. The EPA has not yet designated areas as attaining or not attaining these new standards. Idaho Power is unable to predict what impact the adoption and implementation of these standards may have on its operations.

Hazardous Air Pollutants–Maximum Achievable Control Standard

On March 16, 2011, EPA issued proposed rules to reduce emissions of Hazardous Air Pollutants (HAP) from coal- and oil-fired electric utility steam-generating units. These rules target certain heavy metals, acid gases, organics, dioxins, and furans. EPA grouped these HAPs into the following categories; Hg, non-Hg HAP metals, acid gases, organics, and dioxins/furans. Of these groups, all but organics and dioxin/furan have numerical limits that must be met. Two of the groups (non-Hg HAP metals and acid gases) allow for "surrogate" pollutants to be used to demonstrate compliance with the limits. To demonstrate compliance with organic HAPs and dioxin/furans, the EPA has proposed Work Practice Standards.

Continuous emissions-monitoring systems of Hg have been installed on all the coal-fired units at the Jim Bridger, Boardman, and Valmy plants, and tests to confirm the accuracy of the data being collected are underway. In 2008, the state of Oregon adopted an Hg rule requiring the Boardman plant to reduce Hg emissions by 90 percent or meet an emissions rate of 0.6 pounds-per-trillion Btus by July 2012. Idaho Power continues to monitor Wyoming and Nevada actions related to Hg emissions. Idaho Power is unable to predict at this time what actions the EPA or the other states may take to reduce Hg emissions from their coal-fired power plants. In April 2010, the US District Court for the District of

Columbia approved, by consent decree, a timetable that would require the EPA to propose a standard to control Hg emissions from coal-fired power plants by May 2011 and to finalize it by November 2011.

Clean Air Transport Rule

In July 2009, the EPA proposed its Clean Air Transport Rule (Transport Rule), which would require new reductions in SO_2 and NO_x emissions from large stationary sources, including power plants, located in 31 states and the District of Columbia beginning in 2012. The Transport Rule is intended to help states attain NAAQS set in 1997 for ozone and fine particulate-matter emissions. This rule replaces the Bush administration‘s Clean Air Interstate Rule (CAIR), which was vacated in July 2008 and rescinded by a federal court because it failed to effectively address pollution from upwind states that is hampering efforts by downwind states to comply with ozone and PM NAAQS.

Idaho Power does not own generating units in states identified by the Transport Rule and thus will not be directly impacted; however, the company intends to monitor amendments to the Transport Rule closely, particularly since there is some indication that the 2014 revisions to the Transport Rule will extend the geographic scope of impacted states.

Coal Combustion Residuals

Coal Combustion Residuals (CCRs), including coal ash, are the byproducts from the combustion of coal in power plants. CCRs are currently considered exempt wastes under an amendment to the *Resource Conservation and Recovery Act of 1976* (RCRA); however, in 2010, the EPA proposed to regulate CCRs for the first time. The EPA is considering two possible options for the management of CCRs. Both options fall under the RCRA.

Under the first option, the EPA would list these residual materials as special wastes subject to regulation under Subtitle C of RCRA with requirements from the point of generation to disposition, including the closure of disposal units. Under the second option, the EPA would regulate CCRs as nonhazardous waste under Subtitle D of RCRA and establish minimum nationwide standards for the disposal of CCRs. A final ruling is expected in 2012.

3. IDAHO POWER TODAY

Customer Load and Growth



An Idaho Power employee installs a new Smart Meter.

In 1990, Idaho Power served approximately 292,000 general business customers. Today, Idaho Power serves more than 492,000 general business customers in Idaho and Oregon. Firm peak-hour load has increased from 2,052 MW in 1990 to over 3,000 MW in 2006–2009. In June 2008, the peak-hour load reached 3,214 MW, which is the system peak-hour record. Idaho Power's successful demand reduction programs, along with weather conditions and the general decline in economic activity, lowered Idaho Power's peak demand in both 2009 and 2010.

Average firm load (excluding Astaris/FMC) increased from nearly 1,200 aMW in 1990 to over 1,800 aMW in 2008. 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 3,276 MW. The 641-MW increase in capacity represents enough generation to serve approximately 100,000 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 300-MW Langley Gulch CCCT. The highly efficient, natural gas-fired power plant is being constructed in the western Treasure Valley in Payette County, Idaho. Construction began in August 2010, and the plant is expected to be operational in July 2012.

The data in Table 3.1 suggests each new customer adds approximately 6.5 kW to the peak-hour load and about 1.5 average kilowatts (akW) to average load. In actuality, residential, commercial, and irrigation customers generally contribute more to the peak-hour load, whereas industrial customers contribute more to average load. Industrial customers generally have a more consistent load shape, whereas residential, commercial, and irrigation customers have a load shape with greater daily and seasonal variation.

Since 1990, Idaho Power has added about 200,000 new customers. The simple peak-hour and average-energy calculations mentioned earlier suggest the additional 200,000 customers require over 1,100 MW of additional peak-hour capacity and about 600 aMW of energy.

Highlights

- Idaho Power had over 492,000 retail customers at the end of 2010.
- The 300-MW Langley Gulch natural gas-fired CCCT is expected to begin operating in July 2012.
- Since 2003, Idaho Power has been operating a cloud-seeding program that increases snow accumulation and provides increased generation at the company's hydroelectric facilities.

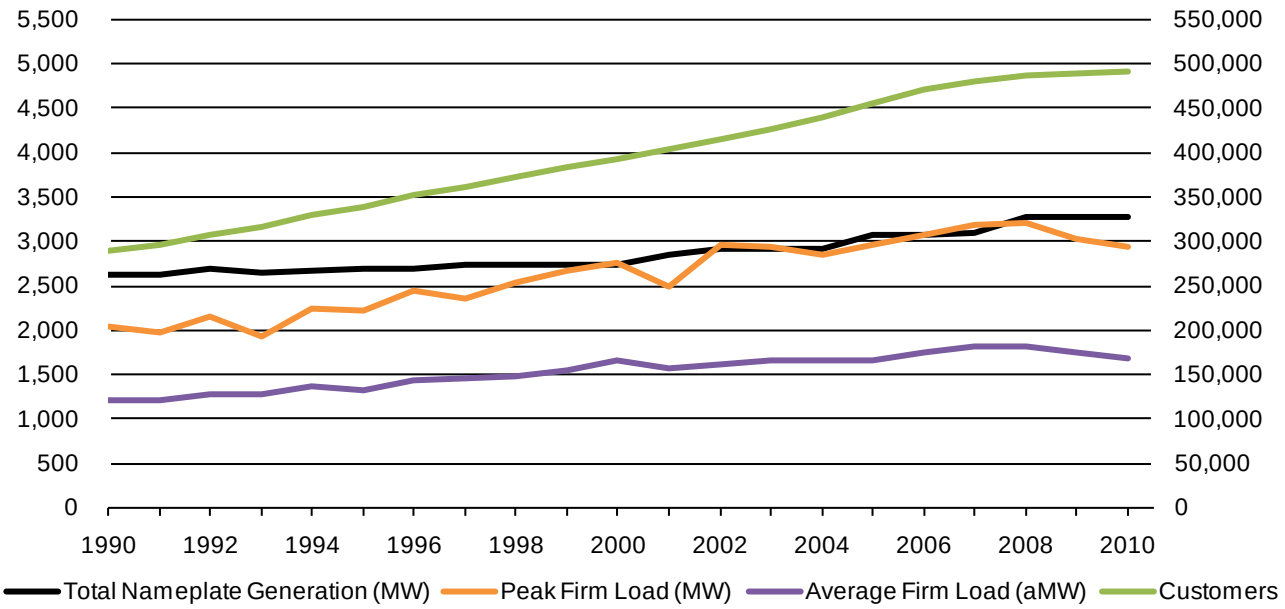

Figure 3.1 Historical capacity, load, and customer data

Table 3.1 Historical capacity, load, and customer data

Year	Total Nameplate Generation (MW)	Peak Firm Load (MW)	Average Firm Load (aMW)	Customers
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	1,744	489,927
2010	3,276	2,930	1,680	492,073

Idaho Power anticipates adding approximately 8,000 customers each year throughout the planning period. The expected-case load forecast predicts that summer peak-hour load requirements are expected to grow at about 69 MW per year, and the average energy requirement is forecast to grow at 29 aMW

per year. More detailed customer and load forecast information is presented in Chapter 6 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 173-MW Bennett Mountain plant every 3 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 near-term and long-term action plans to meet the requirements of Idaho Power's load growth are discussed in Chapter 10.

The generation costs per kW included in Chapter 6 help put forecast customer growth in perspective. Load research data indicates the average residential customer requires about 1.5 kW of baseload generation and 5.0–5.5 kW of peak-hour generation. Baseload generation capital costs are about $1,200 per kW for a natural gas-fired CCCT, such as Idaho Power's Langley Gulch plant, and peak-hour generation capital costs are about $750 per kW for a natural gas-fired SCCT, such as the Danskin and Bennett Mountain projects. The capital costs do not include fuel or any other operation and maintenance expenses.

Based on the capital cost estimates, each new residential customer requires about $1,800 of capital investment for 1.5 kW of baseload generation, plus an additional $4,000 for 5.0–5.5 kW of peak-hour capacity, leading to a total generation capital cost of $5,800. Other capital expenditures for transmission, distribution, customer systems, and other administrative costs are not included in the $5,800 capital generation requirement. A residential customer growth rate of 8,000 new customers per year translates into nearly $50 million of new generation plant capital each year to serve the baseload and peak energy requirements of the new residential customers.

2010 Energy Sources

Idaho Power relies primarily on company-owned hydroelectric and coal-fired generation facilities and long-term PPAs to supply the energy needed to serve customers. Idaho Power's annual hydroelectric generation varies depending on water conditions in the Snake River. Market purchases and sales are used to balance supply and demand throughout the year. The next sections provide specific details on Idaho Power's sources of energy in 2010 followed by a description of Idaho Power's existing and committed resources.

In 2010, 86 percent of Idaho Power's supply of electricity came from company-owned generation resources. In above-average water years, Idaho Power's low-cost hydroelectric plants are typically the company's largest source of electricity. Figure 3.2 shows Idaho Power's electricity sources for 2010, including generation from company-owned resources and purchased power. Market purchases are electric power purchases from other utilities in the wholesale electric market.

Long-term power purchases are electric power contracts with independent power producers and firm PPAs with other utilities and can typically be identified by resource type. In 2010, Idaho Power purchased 1,399,661 MWh of electricity through long-term PPAs that are shown by resource type in Figure 3.3. Long-term power purchases that cannot be identified by resource type are shown as "other" in the chart.

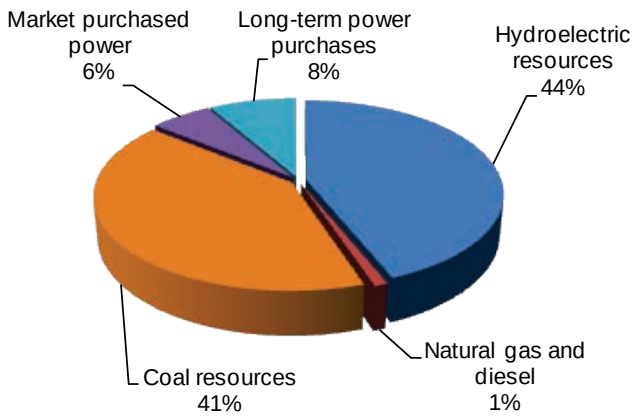

Figure 3.2 2010 energy sources

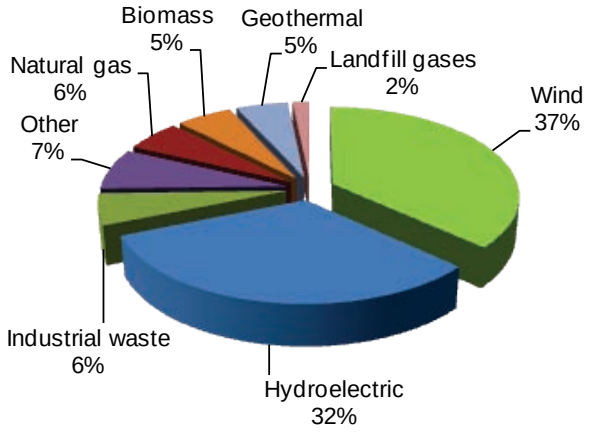

Figure 3.3 2010 long-term power purchases by resource type

Electricity delivered to retail customers includes electricity generated by Idaho Power-owned resources and energy purchased from others. Electricity produced by resources typically considered to be renewable, such as wind, biomass, geothermal, etc., is not counted as renewable energy delivered to retail customers in a given year, unless Idaho Power retires an equivalent number of RECs in that year.

In December 2009, Idaho Power filed with the IPUC a REC Management Plan that detailed Idaho Power's plans to continue to acquire long-term rights to RECs in anticipation of a federal RES, but to sell RECs in the near-term and return the customers' share of the proceeds through the PCA mechanism.

Table 3.2 shows Idaho Powers' energy sources and the subsequent electricity delivered to retail customers in 2010. Because Idaho Power sells electricity to other utilities and to retail customers, not all electricity purchased or generated by Idaho Power is delivered to its retail customers. Table 3.2 shows that no wind or geothermal generation was delivered to retail customers in 2010, the RECs associated with this generation were sold to others who have purchased the right to claim the renewable attributes of that generation. However, if Idaho Power had retired the RECs associated with this generation, the company would have been able to claim the renewable energy had been delivered to customers. Idaho Power also has several small hydroelectric projects that qualify under the state of Nevada's RPS, and RECs from these projects were sold to NV Energy in 2010. Idaho Power's Green Power Program retired 23,056 RECs in 2010, this energy can be reported as renewable energy delivered to customers.

Table 3.2 Electricity delivered to customers (2010)

Resource by Type (MWh)	Generation	RECs Sold[1]	RECs Purchased and Retired[2]	Delivered to Customers
Hydroelectric	7,344,433	-188,336		7,156,097
Coal	6,863,870			6,863,870
Natural Gas & Diesel	159,586			159,586
Purchased Power	1,992,584	573,438	-23,056	2,542,966
Wind	313,256	-313,256		0
Geothermal	71,846	-71,846		0
Renewable (Green Power Program)	0		23,056	23,056
Total	**16,745,575**	**0**	**0**	**16,745,575**

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

[2] Idaho Power's Green Power Program retired 23,056 RECs in 2010; this energy is reported as renewable energy delivered to customers enrolled in the Green Power Program.

Existing Supply-Side Resources

To identify the need and timing of future resources, Idaho Power prepares a load and resource balance that accounts for forecast load growth and generation from all of the company's existing resources and planned purchases. The load and resource balance worksheets showing Idaho Power's existing and committed resources for average energy and peak-hour load are presented in *Appendix C–Technical Appendix*. Table 3.3 shows all of Idaho Power's existing resources, nameplate capacities, and general locations.

Table 3.3 Existing Resources

Resource	Type	Generator Nameplate Capacity (MW)	Location
American Falls	Hydro	92.3	Upper Snake
Bliss	Hydro	75.0	Mid-Snake
Brownlee	Hydro	585.4	Hells Canyon
C.J. Strike	Hydro	82.8	Mid-Snake
Cascade	Hydro	12.4	North Fork Payette
Clear Lake	Hydro	2.5	South Central Idaho
Hells Canyon	Hydro	391.5	Hells Canyon
Lower Malad	Hydro	13.5	South Central Idaho
Lower Salmon	Hydro	60.0	Mid-Snake
Milner	Hydro	59.4	Upper Snake
Oxbow	Hydro	190.0	Hells Canyon
Shoshone Falls	Hydro	12.5	Upper Snake
Swan Falls	Hydro	27.2	Mid-Snake
Thousand Springs	Hydro	8.8	South Central Idaho
Twin Falls	Hydro	52.9	Mid-Snake
Upper Malad	Hydro	8.3	South Central Idaho
Upper Salmon A	Hydro	18.0	Mid-Snake
Upper Salmon B	Hydro	17.0	Mid-Snake
Boardman	Coal	64.2	North Central Oregon
Jim Bridger	Coal	770.5	Southwest Wyoming
Valmy	Coal	283.5	North Central Nevada
Bennett Mountain	Natural Gas	172.8	Southwest Idaho
Danskin	Natural Gas	270.9	Southwest Idaho
Salmon Diesel	Diesel	5.0	Eastern Idaho
Total Existing Nameplate Capacity		**3,276.4**	

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

Hydroelectric Facilities

Idaho Power operates 17 hydroelectric projects located on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,709 MW and 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 Hells Canyon Complex in the Hells Canyon reach of the Snake River. The Hells Canyon Complex consists of Brownlee, Oxbow, and Hells Canyon

dams and the associated generation facilities. In a normal water year, the three plants provide approximately 68 percent of Idaho Power's annual hydroelectric generation and approximately 35 percent of the total energy generated. Water storage in Brownlee Reservoir also enables the Hells Canyon Complex projects to provide the major portion of Idaho Power's peaking and load-following capability.

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

Brownlee Reservoir is the only Hells Canyon Complex reservoir—and Idaho Power's only reservoir—with significant active storage. Brownlee Reservoir has 101 vertical feet of active storage capacity, which equals approximately one million acre-feet of water. Both Oxbow and Hells Canyon reservoirs have significantly smaller active storage capacities—approximately 0.5 percent and 1.0 percent of Brownlee Reservoir's volume, respectively.

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

Brownlee Dam is one of several Pacific Northwest dams that are 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 (ACOE) 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 (BOR) periodically releases water from BOR storage reservoirs in the upper Snake River in an effort to augment flows in the lower Snake River to help anadromous fish migrate past the Federal Columbia River Power System (FCRPS) projects. The periodic releases are part of the flow augmentation implemented by the 2000 FCRPS biological opinion. The flow augmentation water travels through Idaho Power's Mid-Snake projects and eventually through the Hells Canyon Complex before reaching the FCRPS projects.

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

Maintaining constant flows to protect the fall Chinook spawning contributes to the need for additional generation resources during the fall months. The fall Chinook operations result in lower reservoir elevations in Brownlee Reservoir, which reduce the power production capability of the project. The reduced power production may necessitate Idaho Power's acquisition of power from other sources to meet customer load.

Mid-Snake Projects

Idaho Power's hydroelectric facilities upstream from the Hells Canyon Complex include the American Falls, Milner, Twin Falls, Shoshone Falls, Clear Lake, Thousand Springs, Upper and Lower Malad, Upper and Lower Salmon, Bliss, C.J. Strike, Swan Falls, and Cascade projects. Although the Mid-Snake projects of Upper and Lower Salmon, Bliss, and C.J. Strike typically follow run-of-river operations, the Lower Salmon, Bliss, and C.J. Strike plants provide a limited amount of peaking and load-following capability. When possible, the projects are operated within FERC license requirements to coincide with the daily system peak demand. All of the other upstream plants are operated as run-of-river projects.

Idaho Power has completed a study to identify the effects of load-following operations at the Lower Salmon and Bliss power plants on the Bliss Rapids snail, a species listed as threatened under the ESA.

The study was part of a 2004 settlement agreement with the US Fish and Wildlife Service (FWS) to license the Upper Salmon, Lower Salmon, Bliss, and C.J. Strike hydroelectric projects. During the study, Idaho Power operated the Bliss and Lower Salmon facilities under both run-of-river 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 FWS was completed in March 2010. The plan identifies appropriate protection measures to be implemented by Idaho Power, including monitoring snail populations in the Snake River and associated springs. By implementing the protection and monitoring measures, the company will be able to operate the Lower Salmon and Bliss projects in load-following mode while protecting the stability and viability of the Bliss Rapids snail. Idaho Power has filed license amendment applications with FERC for both projects that would allow load-following operations to resume.

Water Lease Agreements

Idaho Power views the lease of water for delivery through its hydroelectric system as a potentially cost-effective power-supply alternative. This approach is particularly attractive for water-lease agreements that allow the company to request delivery as needed. Acquiring water through leases also helps the company to improve water quality and temperature conditions in the Snake River as part of ongoing relicensing efforts associated with the Hells Canyon Complex.

The company signed rental agreements in 2009 and 2010 with Water District 63 in the Boise River system to lease 13,500 and 15,400 acre feet of storage water released in December 2009 and January 2011, respectively.

In 2011, Idaho Power signed a lease agreement with Water District 1 (WD 1) in the upper Snake River system for 25,000 acre feet of storage water for release during summer 2011. The company is participating in development discussions with the WD 1 Rental Pool Committee and the upper Snake advisory committee, the Committee of Nine, regarding a supplemental rental pool for use by the company for releases below Milner Dam.

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

In 2011, the company is pursuing an extension of the Shoshone–Bannock lease for two additional years, 2014 and 2015. The company plans to schedule delivery of the water between July and October of each

year during the term of the lease. The Shoshone–Bannock agreement was executed in part to offset the impact of drought and changing water-use patterns in southern Idaho and to provide additional generation in summer months when customer demand is high. Idaho Power intends to continue to pursue water-lease opportunities as part of its regular operations.

Cloud Seeding

In 2003, Idaho Power implemented a cloud-seeding program to increase snow accumulation in the south fork of the Payette River watershed. In 2008, Idaho Power expanded its program by enhancing an existing program operated by a coalition of counties and other stakeholders in the upper Snake River system above Milner Dam.

Idaho Power seeds clouds by introducing silver iodide into winter storms. This process increases precipitation from passing winter storm systems. If a storm has a combination of an abundance of super-cooled liquid water vapor and appropriate temperatures, the conditions are optimal for cloud seeding to increase precipitation.

Idaho Power uses two methods to seed clouds: 1) install ground generators at high elevations, or 2) attach special flares to modified airplanes. Either method successfully releases silver iodide into passing storms. Minute water particles within the clouds freeze on contact with the silver iodide particles and eventually grow and fall to the ground as snow.

Silver iodide has been used as a seeding agent in numerous western states for decades without any known harmful effects. Analyses conducted by Idaho Power since 2003, indicate the annual snowpack in the Payette River basin increased between 5 and 15 percent (depending on the year). Idaho Power estimates cloud seeding will provide an additional 120,000 to 180,000 acre-feet of water for the Hells Canyon Complex. Studies conducted by the Desert Research Institute from 2003 to 2005 support the effectiveness of Idaho Power's program.



Cloud seeding station in the Payette basin.

For the 2010–2011 winter season, the program included 10, remote-controlled, ground-based generators and one airplane for operations in the Payette Basin. The program in the Upper Snake River Basin included 15, remote-controlled, ground-based generators operated by Idaho Power and 25, manual, ground-based generators operated by the coalition. Idaho Power provides meteorological data and weather forecasting to guide the coalition's operations.

Thermal Facilities

Jim Bridger

Idaho Power owns one-third, or 706 MW (net dependable capacity), of the Jim Bridger coal-fired power plant located near Rock Springs, Wyoming. The plant consists of four generating units. After adjustment for routine scheduled maintenance periods and estimated forced outages, the annual energy generating capability of Idaho Power's share of the plant is approximately 625 aMW. PacifiCorp has two-thirds ownership and is the operator of the Jim Bridger facility.

North Valmy

Idaho Power owns 50 percent, or 260.5 MW (net dependable capacity) of the North Valmy coal-fired power plant located near Winnemucca, Nevada. The plant consists of two generating units. After adjusting for routine scheduled maintenance periods and estimated forced outages, the annual energy generating capability of Idaho Power's share of the North Valmy plant is approximately 220 aMW. NV Energy has 50 percent ownership and is the operator of the North Valmy facility.

Boardman

Idaho Power owns 10 percent, or 58.5 MW (net dependable capacity), of the Boardman coal-fired power plant located near Boardman, Oregon. The plant consists of a single generating unit. After adjusting for routine scheduled maintenance periods and estimated forced outages, the annual energy generating capability of Idaho Power's share of the Boardman plant is approximately 50 aMW. PGE has 65 percent ownership, Bank of America Leasing has 15 percent ownership, and Power Resources Cooperative (PRC) has 10 percent ownership. As the majority partner of the plant, PGE is the operator of the Boardman facility.

The 2011 IRP assumes Idaho Power's share of Boardman plant will not be available after December 31, 2020. The estimated date is the result of an agreement reached between the ODEQ and PGE, related to compliance with RH BART rules on particulate matter, SO_2, and NO_x emissions. Both ODEQ and PGE are waiting for formal approval from the EPA.

At the end of 2010, the net-book value of Idaho Power's share of the Boardman facility was approximately $19.3 million. In order to continue operating the plant until 2020, the addition of new emissions controls will likely be required. Idaho Power's share of the additional capital cost for the new equipment is estimated to range from $1 million to $37 million depending on the final ruling from the EPA. Until the EPA formally approves the agreement, it would be difficult to estimate the net book value of Idaho Power's share of the plant in 2020.

Peaking Facilities

Danskin

Idaho Power owns and operates the Danskin plant, a 271-MW natural gas-fired project. The plant consists of one, 179-MW Siemens 501F SCCT and two, 46-MW Siemens–Westinghouse W251B12A combustion turbines. The 12-acre facility was initially constructed in 2001, and 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 plant operates as 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 near the Danskin plant in Mountain Home, Idaho. The Bennett Mountain plant also operates as needed to support system load.

Salmon Diesel

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

Solar Facilities

In 1994, a 25-kW solar PV array with 90 individual panels was installed on the rooftop of Idaho Power's corporate headquarters in Boise, Idaho. The company also maintains a remote, off-grid, 80-kW solar PV array for the US Air Force near Grasmere, Idaho.

Idaho Power uses small PV panels in its daily operations to supply power to equipment used for monitoring water quality, measuring stream flows, and operating-cloud seeding equipment. In addition to these solar PV installations, Idaho Power participates in the Solar 4R Schools Program; owns a mobile solar trailer that can be used to supply power for concerts, radio remotes, and other events; and has a 200-watt (W) solar water pump used for demonstrations and the promotion of solar PV technology.

Net Metering Program

Idaho Power's net metering program allows customers to install small-scale, renewable generation projects on their property and connect to Idaho Power's system. Under the program, net energy generated beyond what the customer uses is sold back to Idaho Power. A majority of the program's participants are solar projects. Currently, there are 130 solar PV installations under this program with a total capacity of 607 kW.

Oregon Solar Photovoltaic Pilot Program

In 2009, the Oregon Legislature passed 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 its customers in Oregon. Under the pilot program, Idaho Power will acquire up to 400 kW of installed capacity from solar PV systems with a nameplate capacity of less than or equal to 10 kW. In July 2010, approximately 200 kW was allocated, and the remaining 200 kW will be offered during the next enrollment period in October 2011.

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

Power Purchase Agreements

Elkhorn Valley Wind Project

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

Raft River Geothermal Project

In January 2008, the IPUC approved a PPA for 13 MW of nameplate generation from the Raft River Geothermal Power Plant (Unit 1) located in southern Idaho. The Raft River project began commercial operations in October 2007 under a PURPA contract with Idaho Power that was canceled when the new PPA was approved by the IPUC. For the first 10 years (2008–2017) of the agreement, Idaho Power is entitled to 75 percent of the RECs from the project for generation that exceeds 10 aMW monthly.

For the second 10 years of the agreement (2018–2027), Idaho Power is entitled to 51 percent of the total 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 is under development and is expected to begin commercial operations in 2012. Under the PPA, Idaho Power receives all the 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 newly constructed 18-MW power plant at Arrowrock Dam on the Boise River; and in exchange, Idaho Power provides Clatskanie PUD energy of 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, 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. Individual states were tasked with establishing the PPA terms and conditions, including price, that each state's utilities are required to pay as part of the PURPA agreements. Because Idaho Power operates in both Idaho and Oregon, the company must adhere to both the IPUC rules and regulations for all PURPA facilities located in the state of Idaho, and the OPUC rules and regulations for all PURPA facilities located in the state of Oregon. The rules and regulations are similar, but not identical, for the two states. Because Idaho Power cannot accurately predict the level of future PURPA development, only signed contracts are accounted for in Idaho Power's resource planning process.

Generation from PURPA contracts has to be forecasted early in the IRP planning process to update the load and resource balance. The forecast used in the 2011 IRP was completed in September 2010 and did not include approximately 500 MW of wind contracts that were signed in late 2010. Because Idaho Power's future resource needs are driven by capacity requirements and not energy, the exclusion of these new contracts does not have a material impact on the 2011 IRP. At the 5-percent peak-hour capacity factor used for wind resources for planning purposes, the 500 MW of PURPA wind contracts represent only 25 MW of capacity for peak-hour planning.

As of March 31, 2011, Idaho Power had 127 PURPA contracts with independent developers for approximately 1,190 MW of nameplate capacity. The PURPA generation facilities consist of low-head hydroelectric projects on various irrigation canals, cogeneration projects at industrial facilities, wind projects, anaerobic digesters, landfill gas, wood-burning facilities, solar projects, and various other small, renewable-power projects. Of the 127 contracts, 91 were on line as of March 31, 2011, with a cumulative nameplate rating of approximately 491 MW. Figure 3.4 shows the total nameplate capacity of each resource type under contract. Figure 3.4 includes 294 MW from 13 PURPA wind contracts that were recently disapproved by the IPUC. Additional details on these contracts are presented in the next section.

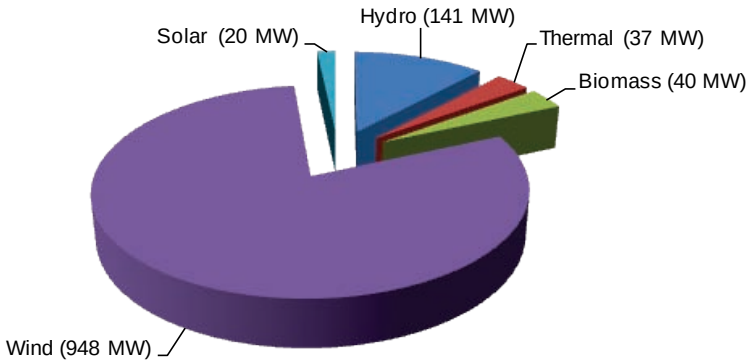

Figure 3.4 PURPA contracts by resource type

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 that Idaho Power is required to include in PURPA contracts.

In November 2010, Idaho Power and other investor-owned utilities in Idaho filed a joint petition asking the IPUC to examine certain issues related to PURPA (IPUC Case No. GNR-E-10-04 and GNR-E-11-01). These issues include the disaggregation of larger, utility-scale projects in order to qualify for the published avoided cost rate and the methods used to calculate the published rate. As of June 2011, this case was not resolved, and the outcome may impact some of the existing PURPA contracts for projects not yet constructed as well as future PURPA project development.

On June 8, 2011, the IPUC issued Order 32262 in this case. The order recognized that the disaggregation issue could not be solved without simultaneously addressing pricing and other issues related to PURPA. In addition, the order established that the published avoided cost rate is available for only wind and solar projects with a nameplate rating of less than 100 kW. For all other resource types, the eligibility cap will remain at 10 aMW. The order goes on to state that the next phase of the case will be a thorough review of the energy pricing methods to be used for PURPA. The order requests the parties in the case meet no later than July 8, 2011, to establish a schedule to process the next phase of the case.

In addition to Order 32262, on June 8, 2011, the IPUC issued separate orders disapproving 13 PURPA wind contracts that Idaho Power had filed requesting IPUC approval. Idaho Power expects some of the counterparties to these contracts to request the IPUC reconsider these orders. The parties have 21 days from the date of the order to file the request for reconsideration, at which time the IPUC will take requests under consideration and issue additional rulings. Rulings on the reconsideration process and other orders in the case will not be complete by the June 30, 2011, IRP filing deadline.

Wholesale Contracts

Idaho Power currently has one, fixed-term, off-system sales contract to supply 6 aMW to the Raft River Rural Electric Cooperative. The Raft River Cooperative is the electric distribution utility serving Idaho Power's former customers in Nevada. The agreement was established as a full-requirements contract after being approved by FERC and the Public Utilities Commission of Nevada. This contract has been renewed annually for several years; however, it is expected to expire at the end of September 2011.

Idaho Power continues to use its transmission capacity on the Jefferson line to import power from Montana during the summer months. At present, Idaho Power purchases 83 MW during summertime heavy-load hours from PPL EnergyPlus, LLC. Although the purchase agreement expires in 2012,

Idaho Power plans to continue to use the available transmission capacity during the summer months as needed until the Boardman to Hemingway transmission line is completed.

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 these purchases. Reliance on regional markets has benefited Idaho Power customers during times of low prices as the cost of purchases, revenue from surplus sales, and fuel expenses are shared with customers through the PCA.

Committed Supply-Side Resources

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

Langley Gulch

The need for a new baseload power plant was identified in Idaho Power's 2004 and 2006 IRPs. The initial decision was to construct a coal-fired baseload resource, but regulatory, price, and environmental issues led Idaho Power to reconsider the coal resource and instead select a natural gas-fired CCCT. Idaho Power completed the competitive bidding process in early 2009 and selected a 300 MW CCCT project near New Plymouth, Idaho to meet the resource need.

The Langley Gulch project is expected to begin delivering energy in time to meet summer peaking needs in July 2012. The Langley Gulch project will require the construction of short segments of 138-kV and 230-kV transmission lines to connect to the existing system in order to deliver energy and provide capacity support to Idaho Power customers in Idaho and Oregon.

Shoshone Falls Upgrade Project

In August 2006, Idaho Power filed a license amendment application with FERC to upgrade the Shoshone Falls Hydroelectric 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 upgrade project involves replacing the two smaller units with a single, 50-MW unit that will result in a net upgrade of 49 MW.

In July 2010, FERC issued a license amendment for the project. This amendment allows two years to begin construction and five years to complete the project. For the 2011 IRP, Idaho Power is planning on the additional capacity from the Shoshone Falls upgrade being available in October 2015. When the project is completed, Idaho Power expects the additional generation from the upgrade will qualify for RECs that can be used to satisfy federal RES requirements.

While previous evaluations of the Shoshone Falls upgrade have been done under median water conditions, some uncertainty exists regarding future Snake River streamflows that would not only impact the Shoshone Falls project, but all of Idaho Power's Snake River hydroelectric projects. Because of the benefits and additional value provided by the Shoshone Falls Upgrade Project, it is included in the 2011 IRP as a committed resource. Idaho Power will continue to pursue this project in conjunction with the resolution of water issues in the state of Idaho. Prior to filing for a CPCN with the IPUC, Idaho Power plans to update the economic analysis of the project, taking into account the most current forecasts of forward market prices, REC prices, and any unresolved water issues.

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4. DEMAND-SIDE RESOURCES



Idaho Power's Long Valley Operations Center in Lake Fork was granted LEED gold status due in part to its energy-efficient design.

DSM customer programs are an essential component of Idaho Power's resource strategy. Idaho Power works with customers to promote energy efficiency and produce the same output or provide the same level of service with lower energy consumption. Through demand response programs, Idaho Power provides incentives to customers to identify applications where a short-term load reduction can be timed to coincide with peak energy consumption when all other resources, including transmission capacity to purchase energy, 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. Energy efficiency and demand response programs are offered to all four major customer classes: residential, irrigation, commercial, and industrial.

Market transformation, an additional program category, targets energy savings through engaging and influencing large national and regional organizations to promote energy efficiency. Idaho Power has collaborated with other regional utilities and organizations in funding the Northwest Energy Efficiency Alliance (NEEA) market transformation promotional activities since 2001. Due to the indirect nature of savings from market transformation, NEEA impacts are not accounted for in resource planning.

Cost-effectiveness analyses, which indicate whether the benefits of avoided power generation costs exceed the costs of offering an energy efficiency or demand response program, are published annually, and the most recent analysis can be found in the *Demand-Side Management 2010 Annual Report Supplement 1: Cost Effectiveness*. Each program in the existing portfolio of demand-side resources are reviewed as part of the IRP process for their potential impact over the 20-year IRP planning horizon. The resulting forecast of energy savings and demand-reduction potential, along with prior program performance, is then incorporated into the load forecast process. For a description of this process, see *Appendix A–Sales and Load Forecast.*

In addition to reviewing the existing portfolio of DSM resources, new opportunities for demand-side resources are evaluated for inclusion into the existing portfolio of programs and their impacts are

Highlights

- Energy Efficiency efforts from both the existing portfolio and program expansion will provide 233 aMW of system reduction over the 20-year planning period avoiding over $1.1 billion in power supply costs in 2011 dollars.
- Total peak summer capacity of the demand response program portfolio is targeted at 330 MW in 2011 and increases to 351 MW by 2016.
- Demand response programs will cost $48 per kW, and new energy efficiency will cost 5.1 cents per kWh over the IRP planning period.

forecasted. Idaho Power adopts all new demand-side resources when they are determined to be cost-effective. Energy efficiency resources are consistently one of the least-cost resources available for Idaho Power's resource stack.

All cost-effectiveness analyses for DSM forecasts for both the existing portfolio and new acquisition accounted for in the 2011 IRP are either presented as a summary in the IRP or in more detail in *Appendix C–Technical Appendix*. *Appendix B–Demand-Side Management 2010 Annual Report* contains a detailed description of Idaho Power's 2010 energy efficiency program portfolio along with historical program performance.

Energy Efficiency Program Portfolio Analysis

Each energy efficiency program currently offered to customers as part of the existing portfolio is reviewed to forecast average demand reduction. The forecast of potential programs over the IRP planning horizon considers where the program is in its life cycle (i.e., ramping up or ramping down). Also, recent program participation trends, future changes in codes and standards that will affect program measures, along with program design changes are taken into consideration.

Idaho Power placed primary emphasis on the first five years (2011–2015) when reviewing program potential; then future program performance was assumed to be held constant at 2015 levels unless known codes and standards or other mitigating circumstances justified ramping the program down early. Many unknown factors may affect program participation for the second 10 years, including multiple changes in codes and standards or technology. Therefore, programs included in the 2020 portfolio are ramped down by the end of the 20-year IRP planning period.

Historical demand-side reductions are assumed to influence customer energy-usage behavior and are accounted for in the 2011 IRP load forecast methodologies. Therefore, the current portfolio is analyzed starting in 2011 and looks at 2011–2030 impacts only. The program performance forecast assumes customers will not replace existing efficiency measures with less-efficient measures once useful life expires, and the forecasted impact of energy efficiency programs accumulates from year-to-year. For example, in 2015, Idaho Power assumes all efficient measures installed during 2011–2014 are still in place, along with incremental 2015 energy savings.

Annual savings are measured in MWh; for the IRP analysis they are divided by 8,760 hours (hours in a year), or corresponding monthly hours, to convert to average annual or monthly demand reduction (aMW) to compare with supply-side resources. All forecasts are prepared in terms of generation equivalency and include line losses of 10.9 percent, which accounts for energy lost as a result of transmitting energy between the generation source and the customer.

Table 4.1 shows the forecast impact of the current portfolio of energy efficiency programs for 2011, 2015, 2020, and 2030, in terms of average demand reduction (aMW) by customer class. In 2015, the forecast reduction for 2011–2015 programs will be 69 aMW; by the year 2020, the reduction across all customer classes increases to 133 aMW. By the end of the IRP planning horizon in 2030, 191 aMW of reduction is forecast to come from the current energy efficiency portfolio, with 80 percent of that reduction coming from programs serving commercial and industrial customers. Detailed year-by-year forecast values can be found in *Appendix C–Technical Appendix*.

Table 4.1 Energy efficiency current portfolio forecasted impacts (2011–2030)

	2015 (aMW)	2020 (aMW)	2025 (aMW)	2030 (aMW)
Industrial	23	46	61	66
Irrigation	5	8	11	11
Commercial	30	60	80	86
Residential	11	20	26	28
Total	**69**	**133**	**178**	**191**

Table 4.2 shows the forecast cost-effectiveness of the current portfolio of energy efficiency programs. The table shows the net-present-value analysis of the 20-year forecast of utility costs, resource costs, and avoided energy. Utility costs are the costs to administer the energy efficiency programs, while total resource costs account for both the utility costs and the customer investment in efficiency technologies and measures offered through the programs. Utility costs and total resource costs were estimated based on 2010 program performance for industrial, commercial, and residential classes and a three-year average performance for irrigation to allow for annual fluctuations between custom- and menu-driven irrigation efficiency. Avoided energy is the benefit of the programs calculated by valuing energy savings against the avoided generation costs of Idaho Power's existing portfolio of generation resources.

Table 4.2 Existing energy efficiency portfolio cost-effectiveness summary

	2030 Load Impact (aMW)	Utility Costs (20-Year NPV*)	Resource Costs (20-Year NPV)	Avoided Energy Costs (20-Year NPV)	Utility Cost: Benefit/Cost Ratio	Utility Levelized Costs ($/kWh)	Total Resource Cost: Benefit/Cost Ratio	Total Resource Cost Levelized Costs ($/kWh)
Industrial	66	$49,398,586	$96,635,806	$257,704,824	5.2	$0.015	2.7	$0.028
Irrigation	11	$14,229,458	$38,651,984	$43,667,373	3.1	$0.023	1.1	$0.061
Commercial	86	$60,885,631	$119,966,128	$335,208,357	5.5	$0.014	2.8	$0.027
Residential	28	$60,023,978	$103,519,281	$181,086,911	3.0	$0.040	1.7	$0.069
Total	**191**	**$184,537,652**	**$358,773,200**	**$817,667,465**	**4.4**	**$0.019**	**2.3**	**$0.036**

*Net present value (NPV)

The value of avoided energy over the 20-year investment in the energy efficiency measures was more than twice the total resource cost when comparing benefits and costs. This resulted in an overall benefit cost ratio of 2.3. The levelized cost to reduce energy demand by 191 aMW is 3.6 cents per kWh from a total resource cost perspective. Figure 6.9 in Chapter 6 compares energy efficiency program costs with Idaho Power's other supply-side resource options from an energy perspective.

New Energy Efficiency Resources

During each IRP planning period, Idaho Power uses various resources, including existing portfolio program expansion, new program development, potential studies, Northwest Power and Conservation Council (NPCC) research, and Idaho Power's Energy Efficiency Advisory Group (EEAG), to determine how future energy efficiency and demand response programs can fulfill future resource needs.
New energy efficiency opportunities are evaluated through a cost-effectiveness analysis similar to the existing programs. Forecasting assumptions for new residential efficiency for the 2011 IRP were aided by the planning model that was developed by Nexant Inc., from the *2009 Demand Side Management Potential Study*.

Along with identifying new opportunities for energy efficiency it is also important to identify the barriers that may face new program measures and expansions. One challenge the company will continue

to face going forward is to increase the understanding of behaviors and decisions that residential customers make in regards to energy efficiency investments and providing the correct level of incentive to motivate them while maintaining cost-effectiveness. Much of the expansion to residential programs analyzed for the 2011 IRP include measures requiring increased customer investments, such as improved weatherization in electric home and multi-family housing. It will become increasingly important to understand the purchasing decisions of prior participants and continue forward with Idaho Power's efforts of targeted marketing and demographic analysis to work to overcome customers' investment barriers. Ongoing process evaluations of energy efficiency programs will also continue to be an important source of information for understanding customer participation in programs and for developing strategies to increase participation and program delivery. Examples of past process evaluations for energy efficiency programs can be found in the *Demand-Side Management 2010 Annual Report Supplement 2: Evaluation*.

Industrial Efficiency

Efficiency projects, through the Custom Efficiency program, which provides efficiency projects to large commercial and industrial customers continues to exceed expectations and has performed well since the program began providing incentives in 2004. Projects can include any combination of approved custom measures and process improvements that show energy efficiency enhancements. Some of the most common projects include measures, such as higher-efficiency lighting, fans, compressed air, and pumps.

Program changes, including moving some smaller lighting projects of less than 100,000 annual kWh of savings to other programs, will allow increased capacity for more custom projects over the next few years. This will lead to an increased expansion of 13 aMW over the 20-year IRP planning horizon. The increased efficiency will cost approximately 2.6 cents per kWh.

Commercial Efficiency

Program changes in the commercial and industrial efficiency programs in 2011 will shift some lighting projects into the Easy Upgrades prescriptive program that previously would have paid through the Custom Efficiency program. These potential savings were not accounted for in the original commercial program portfolio forecast and will result in an additional 6.6 aMW of average demand reduction potential over the IRP planning horizon.

Residential Efficiency

New residential efficiency includes expanded weatherization measures identified in the *Idaho Power Demand-Side Management Potential Study*, published in 2009, along with growth in incentives for heat pumps for electrically heated homes, and expansion of existing programs into the multi-family sector. During 2011 and 2012, plans are being made to add additional weatherization measures to Idaho Power's Home Improvement Program, which currently provides incentives for increasing levels of attic insulation. The additional measures are also expected to be made available to multi-family housing and will focus on windows, infiltration, and HVAC duct sealing. These program additions for electrically heated homes are forecasted to add 20.1 aMW of savings to the program over the IRP planning horizon.

Increased incentives for air-source heat pumps in 2011 will encourage customers to transition from electric, forced-air furnaces and will add 0.3 aMW of average demand reduction to the program. Weatherization Solutions for Eligible Customers, a weatherization program for income-qualified customers, will be expanded to eastern Idaho in 2011. Idaho Power forecasts the new targeted area will provide 2 aMW of increased program reduction over the IRP planning horizon.

Table 4.3 shows the forecast combined contribution in reduced average consumption over the IRP planning horizon. In 2015, the new and expanded energy efficiency programs will reduce average loads by 13 aMW; in 2020, average loads will be reduced by 25 aMW. The full 20-year capacity of the program additions and changes is 42 aMW of average demand reduction.

Table 4.3 New energy efficiency portfolio forecasted impacts (2011–2030)

	2015 (aMW)	2020 (aMW)	2025 (aMW)	2030 (aMW)
Industrial	7	10	12	13
Commercial	2	5	6	7
Residential	4	10	16	23
Total	**13**	**25**	**35**	**42**

Table 4.4 presents a summary of the cost and cost-effectiveness of new energy efficiency efforts. The overall benefit/cost ratio for all new energy efficiency measures is 3.2 at a levelized total resource cost of 5.1 cents per kWh. Additional details on annual costs and benefits can be found in *Appendix C–Technical Appendix*.

Table 4.4 New energy efficiency portfolio cost-effectiveness summary

	2030 Load Impact (aMW)	Utility Costs (20-Year NPV)	Resource Costs (20-Year NPV)	Avoided Energy Costs (20-Year NPV)	Utility Cost: Benefit/Cost Ratio	Utility Levelized Costs ($/kWh)	Total Resource Cost: Benefit/Cost Ratio	Total Resource Cost: Levelized Costs ($/kWh)
Industrial	13	$10,293,124	$20,135,886	$56,034,905	5.4	$0.013	2.8	$0.026
Commercial	7	$4,468,872	$8,607,815	$25,770,482	5.8	$0.013	3.0	$0.025
Residential	23	$35,582,870	$69,027,549	$228,851,046	6.4	$0.045	3.3	$0.086
Total	**42**	**$50,344,865**	**$97,771,250**	**$310,656,434**	**6.2**	**$0.026**	**3.2**	**$0.051**

Demand Response Resources

The goal of demand response programs at Idaho Power is to reduce summer peak load during periods of extremely high demand and minimize or delay the need to build new supply-side resources. Demand response programs were first implemented in summer 2004 when a 6.1-MW peak-hour load reduction was measured. Idaho Power's demand response portfolio has grown since that time, and 330 MW of peak-hour load reduction has been targeted for summer 2011. Three programs 1) A/C Cool Credit, 2) Irrigation Peak Rewards, and 3) FlexPeak Management allow residential, irrigation, commercial, and industrial customers to participate in potential peak-hour load reduction efforts. A complete description of the demand response programs can be found in *Appendix B–Demand-Side Management 2010 Annual Report*.



An Idaho Power customer representative discusses the Irrigation Peak Rewards program with a farmer.

An analysis that focused on the optimal level of demand response resources along with the costs and the most effective method of utilization was conducted as part of the 2011 IRP. The conclusions drawn from this analysis were that 1) there is a defined optimal amount of demand response for Idaho Power's

system; 2) in conjunction with each IRP, Idaho Power will update the targets for demand response; 3) the program managers will work to align program design with system needs; 4) stakeholders will be involved in this process; and 5) program designs and pricing options will be reassessed. In this analysis, the costs from an energy perspective for demand response was compared to the energy costs of owning and operating an SCCT. The results of this analysis indicated actual program energy costs were inherently more because of the limitations on the number of hours the programs could be operated (60 hours) and the limited time of the year when the programs were available. The program continues to be less expensive than an SCCT from a capacity perspective, which is how the program cost-effectiveness is determined. However, from an energy perspective, it is among the most expensive resources evaluated in the IRP.

Because of the results of the analysis, Idaho Power filed with the IPUC Case No. IPC-E-10-46 asking for significant changes to the Irrigation Peak Rewards program, including a method of paying participants with a variable component based on the level of use. The levels of demand response determined for the 2011 IRP analysis is 330 MW for summer 2011, 310 MW in 2012 when the Langley Gulch plant comes on line, and 315 MW in 2013 and 2014. In 2015, the demand response level used in the IRP analysis is 321 MW and then 351 MW from 2016 through the end of the planning period. Demand response, because of its limited availability, cannot continually satisfy all of the load and resource balance deficits throughout the IRP planning period; rather, the goal of setting the appropriate levels of demand response is to delay the addition of new supply-side resources.

Table 4.5 presents a summary of the cost-effectiveness of the demand response programs. The Irrigation Peak Rewards program is forecast to provide 260 MW of peak-hour load reduction. The A/C Cool Credit program is expected to have 40,000 residential customer participants and is expected to provide a peak-hour load reduction of 51 MW. The FlexPeak Management program is forecast to provide 40 MW of reduction and is controlled by EnerNoc, Inc., a third-party program administrator.

Table 4.5 Demand response cost-effectiveness summary

	2030 Load Impact (MW)	Resource Costs (20-Year NPV)	Avoided Energy Costs (20-Year NPV)	Total Resource Cost: Benefit/Cost Ratio	Total Resource Cost: Levelized Costs ($/kW)
Commercial/Industrial	40	$29,797,258	$46,640,850	1.6	$65
Irrigation	260	$122,250,426	$238,224,468	2.0	$45
Residential	51	$25,242,292	$52,905,340	2.1	$46
Total/Summary	**351**	**$177,289,977**	**$337,770,659**	**1.9**	**$48**

Across the demand response portfolio, the value of reduced demand compared with building a supply-side capacity resource is nearly twice the value of the cost to run the programs. The benefit/cost ratio is 1.9 with a levelized cost of $48 per kW. Detailed annual forecast costs and benefits of demand response resources are presented in *Appendix C–Technical Appendix*.

5. SUPPLY-SIDE 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. The company has done that; today, demand-side programs are an essential component of Idaho Power's resource strategy. The following sections describe the supply-side resources considered when Idaho Power developed the resource portfolios for the 2011 IRP. Not all supply-side resources described in this section were included in the preliminary resource portfolios, but every resource described was considered.



A vintage generator still in operation at Idaho Power's Thousand Springs power plant.

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 2011 IRP, renewable resources were included in all portfolios analyzed to meet proposed federal RES legislation. Renewable resources are discussed in general terms in the following sections.

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. 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 is 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 300ºFahrenheit (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

Highlights

- The cost of solar PV technology has continued to decline as technology improvements have improved efficiency and the supply of PV panels has increased. The 2011 IRP cost estimate for solar PV is $3,750 per kW.
- Idaho Power continues the permitting process for the Boardman to Hemingway and Gateway West transmission projects that will provide additional access to the regional electricity market.
- The 2011 IRP assumes advanced nuclear, IGCC, and carbon capture and sequestration technologies will not be available until the 2020s.

(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 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 Neal Hot Springs geothermal project located in eastern Oregon. The capital cost estimate used in the IRP for geothermal resources is $6,250 per kW, and the 30-year levelized cost of production is $117 per MWh.

Wind

A typical wind project consists of an array of wind turbines ranging in size from 1–3 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.

The Pacific Northwest and Intermountain regions are good areas for the development of wind resources, as evidenced by the number of existing and planned projects. However, wind resources present challenges for utilities due to the variable and intermittent nature of the generation. Therefore, planning new wind resources requires estimates of the expected annual energy and peak-hour capacity. For the 2011 IRP, Idaho Power used an annual average capacity factor of 32 percent and a capacity factor of 5 percent for peak-hour planning.

Cost estimates and operating parameters used for wind generation in the IRP are based on data from independent developers and cost information obtained from the 2012 Wind RFP issued by Idaho Power. The 2012 Wind RFP did not ultimately result in the identification of a successful bidder due in large part to a recent surge in PURPA wind development in southern Idaho. The capital cost estimate used in the IRP for wind resources is $1,450 per kW, and the 30-year levelized cost of production is $89 per MWh, which includes a cost for wind integration. In 2008, the IPUC approved a settlement stipulation establishing a wind integration cost of $6.50 per MWh, which was less than Idaho Power's estimated cost to integrate wind.

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, such as run-of-river and projects requiring small or no impoundments, does not have the same level of environmental and permitting issues as large hydroelectric, the IRPAC expressed an interest in evaluating small hydroelectric in the 2011 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 the state of 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 $4,000 per kW and the 30-year levelized cost of production is $144 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.

For pumped storage to be economical, there must be a significant differential in the price of electricity between peak and off-peak times in order 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 30-year levelized cost of production is $155 per MWh.

Solar

The primary types of solar technology are solar thermal and PV. Solar thermal technologies use mirrors to focus the sun's rays onto a central receiver or a "collector" to collect thermal energy that can be used to make steam and power a turbine that creates electricity. PV panels absorb 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.

On cloudy days, solar thermal generation will not produce power. However, thermal storage using molten salt functions as an energy storage system allowing solar thermal generation plants to generate electricity after the sun sets or during brief cloudy periods, generally for 3–7 hours. PV technology uses panels that convert the sun's rays directly to electricity. 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 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 United States.

There are several types of solar thermal technologies, including power tower, parabolic dish engine, and parabolic trough. In designing initial portfolios that included solar resources, Idaho Power chose the power tower technology because of its lower overall cost. The company also selected the solar PV technology because of the increased availability of PV panels and the recent declining cost trend.

Power Tower

Power tower technology uses thousands of small, flat, two-axis mirrors, called heliostats, to reflect the sun's rays onto a boiler at the top of a central tower. The concentrated sunlight strikes the boiler's pipes, heating the water inside to 1,000°F. The high-temperature steam is then piped from the boiler to a turbine where electricity is generated. The power tower technology can use molten salt as a storage medium to store energy. It has a storage time of 6.9 hours that has been used to evaluate this resource

in the IRP. The capital cost estimate used in the IRP for the power tower technology with storage is $3,220 per kW, and the 30-year levelized cost of production is $109 per MWh.

Photovoltaic

Solar PV panels absorb 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, creating 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.

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 RPS requirements, have made PV resources more cost competitive with other renewable and conventional generating technologies. The capital cost estimate used in the IRP for PV resources is $3,750 per kW, and the 30-year levelized cost of production, based on a 17-percent annual capacity factor, is $150 per MWh. 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.

Natural Gas-Fired Resources

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

CCCT and SCCT resources are typically sited near existing gas pipelines, which is the case for Idaho Power's existing gas resources. However, the capacity of the existing gas pipeline system is almost fully allocated. Therefore, the 2011 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, thus 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, including 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. At the time the natural gas price forecast was prepared for the IRP, natural gas prices were considerably higher than they are today. In fact, the low natural gas price case is a more accurate reflection of the current forward market for natural gas.

The capital cost estimate used in the IRP for CCCT resources is $1,120 per kW, and the 30-year levelized cost of production at a 65-percent annual capacity factor is $108 per MWh with the carbon adder and $98 per MWh without the adder. If a CCCT were run at a 90-percent annual capacity factor, the 30-year levelized cost would be $100 per MWh with the carbon adder and $90 per MWh without the adder.

Simple-Cycle Combustion Turbines

Simple-cycle, natural gas-turbine technology involves pressurizing air that then heats 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 80–200 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. Peak summertime electricity demand continues to grow significantly within Idaho Power's service area, and SCCT generating resources have been built 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 2011 IRP evaluated two different 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 $1,050 per kW, and an industrial-frame unit is $610 per kW. Because of the higher efficiency of the aeroderivative unit, it is assumed to have an annual capacity factor of 8 percent, while the industrial-frame unit is expected to have an annual capacity factor of only 6 percent.

Based on these annual capacity factors, the 30-year levelized cost of production (including the estimated cost of carbon emissions) is $319 per MWh for the small, aeroderivative unit and $316 per MWh for the industrial-frame unit. These levelized costs are nearly identical as the higher efficiency of the small aeroderivative unit offsets the slightly higher capital cost. If an SCCT resource is identified in the IRP preferred portfolio, Idaho Power would evaluate these two technologies in greater detail prior to issuing an RFP in order to determine which technology provided the greatest benefit.

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 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 provides a competitive advantage that will 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.

Although a CHP resource was not identified in the 2011 IRP preferred portfolio, Idaho Power is committed to continuing its investigation into CHP opportunities on a case-by-case basis. While the actual cost of a CHP resource may be less as previous discussed, the capital-cost estimate used in the IRP for CHP is $1,860 per kW, and the 30-year levelized cost of production, evaluated at an annual capacity factor of 93 percent, is $111 per MWh, which also accounts for the assumed cost of carbon emissions.

Several IRPAC members noted that, when considering the total societal benefit of a project, using CHP projects to produce both electrical energy and useful heat results in an overall reduction of CO_2 and other emissions. The 2011 IRP assumes emissions costs are associated with a new facility because it would be owned and operated by Idaho Power. For the next IRP, Idaho Power plans to raise this issue with the IRPAC early in the process to determine if it would be appropriate to remove some or all of the emissions cost adders from CHP resources.

Idaho Power's commitment to continue investigating CHP projects is evidenced by an agreement signed in October 2009 with the IOER and the Amalgamated Sugar Company (TASCO), one of Idaho Power's large industrial customers. The agreement establishes the framework for a feasibility study for a CHP resource as large as 100 MW to be performed at TASCO's Nampa, Idaho facility. The TASCO facility currently uses coal to produce steam, and switching to natural gas as a fuel source would result in reduced CO_2 emissions and improve air quality in the Treasure Valley. The results of the first phase of the study looks promising, and a second, more detailed study is expected to be completed by June 2011.

Distributed Generation

In September 2010, Idaho Power received a proposal to implement and manage a distributed generation program that would use existing emergency generators owned by some of Idaho Power's largest customers. The proposal included a load-shed option and a grid-synchronized option. Both options were analyzed as part of the 2011 IRP.

In the resource stack cost analysis, the load-shed option had a cost of almost $8,500 per MWh, and the grid-synchronized option was over $10,000 per MWh. These costs are high due to the limited amount of generation these programs are expected to produce and, therefore, must also be analyzed to determine the value they provide when included with Idaho Power's other generation resources.

The load-shed option was evaluated for the first 10-year period in the IRP (2011–2020). In portfolio 1-9, this program was assumed to be available beginning in 2012. To ascertain the marginal value of the program, the other resources in portfolio 1-9 were identical to portfolio 1-4 which contained simple-cycle peaking resources. It was not necessary to evaluate the grid synchronization option because of the higher costs associated with the program.

The results of the analysis of the load-shed option showed that the distributed generation portfolio (portfolio 1-9) had a higher NPV cost of $5.6 million for the 10-year period compared to the simple-cycle portfolio under the base case assumptions used in the IRP. Idaho Power will continue to evaluate distributed generation programs in the future; however, at this time the company does not intend to pursue the implementation of a distributed generation program.

Conventional Coal Resources

Conventional coal-fired generation is a mature technology and has been the primary source of commercial power production in the United States for many decades. Traditional pulverized-coal plants have been a significant part of Idaho Power's generation mix since the early 1970s. Idaho Power currently has over 1,100 MW of coal resources that are jointly owned with other utility partners who operate the facilities. Idaho Power's coal resources are located in the neighboring states of Wyoming (Jim Bridger), Nevada (Valmy), and Oregon (Boardman).

A pulverized-coal facility uses coal ground into a dust-like consistency and burned to heat water and produce steam to drive a steam turbine and generator. Emissions controls at coal plants have become increasingly important in recent years, and many units in the region have been upgraded to include the latest scrubber and low-NO_x burner technology to help reduce harmful emissions and particulates. Coal has the highest ratio of carbon-to-hydrogen of all fossil fuels, and significant research is being done to develop carbon capture and sequestration technology that can be economically added to existing coal facilities.

Though coal-fired power plants require significant capital commitments to develop, coal resources take advantage of a low-cost fuel and provide reliable and dispatchable energy. Coal supplies are abundant in the Intermountain Region and are sufficient to fuel Idaho Power's existing plants for many years to come.

In 2007, Idaho Power decided not to pursue the development of a coal-fired resource identified in the 2006 IRP. In addition to considering the cost of a coal-based resource, the company considered the uncertainty surrounding the regulation of carbon emissions and the ability to permit a new coal resource. Idaho Power continues to evaluate other coal-fired resource opportunities, including efficiency improvements at its jointly owned facilities as well as monitoring the development of clean coal technologies. However, due to the uncertainty regarding future carbon regulations, conventional coal resources were not included in any of the portfolios analyzed in the 2011 IRP.

Integrated Gasification Combined-Cycle and Carbon Sequestration

IGCC is an evolving coal-based technology designed to substantially reduce CO_2 emissions. If the cost 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. For the 2011 IRP, Idaho Power is assuming this technology will not be available until the year 2024. The capital cost estimate used in the IRP for IGCC with carbon sequestration is $3,776 per kW, and the 30-year levelized cost of production, evaluated at an annual capacity factor of 85 percent, is $191 per MWh.

Advanced Nuclear

The nuclear power industry has been working to develop and improve reactor technology for some time. In Idaho Power's 2006 IRP, an advanced nuclear resource was included in the preferred portfolio in the year 2023, based on the assumption that an advanced-design reactor would be built on the Idaho National Laboratory (INL) site in eastern Idaho. Updated information from INL suggests the plant, if built, would be located near an industrial manufacturing hub with a high baseload energy need, most likely outside of Idaho. High capital cost coupled with a great amount of uncertainty in the actual cost of building an advanced reactor prevented a nuclear resource from being included in the preferred portfolio in Idaho Power's 2011 IRP.

The recent earthquake and tsunami in Japan, and the impact on the nuclear reactors located there, have created a global concern over the safety of nuclear power generation. While there will undoubtedly be new design and safety measures implemented, it is difficult to know the impact this disaster will have on the future of nuclear power generation.

For the 2011 IRP, an advanced nuclear resource was assumed to not be commercially available until 2023. Additionally, if the IRP identified a nuclear resource in the preferred portfolio, Idaho Power would plan to partner with other utilities in a plant built around a smaller modular design with Idaho Power's share being approximately 250 MW. Similar to the 2009 IRP, the capital cost of an advanced nuclear reactor is considerable, and the IRP risk analysis continues to account for a great amount of uncertainty in the actual cost. The capital cost estimate used in the IRP for an advanced nuclear resource is $3,820 per kW, and the 30-year levelized cost of production, evaluated at an annual capacity factor of 85 percent, is $229 per MWh.

Transmission

Idaho Power is responsible for providing safe and reliable electrical service to its service area, which includes most of southern Idaho and a portion of eastern Oregon. In addition to operating under the regulatory oversight of the IPUC and the OPUC, Idaho Power is a public utility under the jurisdiction of FERC, and under its Open Access Transmission Tariff (OATT), is required to expand its transmission system to provide requested firm transmission service and to construct and place in service sufficient capacity to reliably deliver electrical resources to customers.



The Hemingway Substation is located in southwestern Idaho.

Idaho Power's transmission system is currently limited in its ability to transmit energy from markets or new resources to load centers in Idaho and eastern Oregon. Because of the need to access markets, improve reliability, integrate new resources, and facilitate renewable resource development in the region, Idaho Power has considered two major transmission projects for a number of years ; they are both included in the 2011 IRP—Boardman to Hemingway and Gateway West. These two projects were

also evaluated in Idaho Power's 2009 IRP and sub-regional and regional transmission planning processes.

For the 2011 IRP, one portfolio requiring Boardman to Hemingway capacity was analyzed for the first 10 years of the planning horizon (2011–2020). In the second 10 years (2021–2030), one portfolio included additional capacity to the Pacific Northwest and another included additional capacity to the east side of Idaho Power's system. These two portfolios were designed to evaluate the cost of market purchases on either side of Idaho Power's system. The Gateway West project was included in portfolios for the second 10-year period when current constraints required the addition of new transmission capacity for resources to be added in southern Idaho, east of the Treasure Valley load center. However, the amount of Gateway West capacity is different in each portfolio, depending on other included resources.

Idaho Power faces increasing demands for transmission capacity in the coming decade. Additional requirements include the forecast growth of existing network customers, including Bonneville Power Administration's (BPA) southern Idaho contracts. The development of wind and other renewable resources in response to state RPS requirements is anticipated to further increase the demand for transmission capacity between the Intermountain Region and the Pacific Northwest.

The concept of "right sizing" a transmission project, or building the project to an appropriate potential, has been carefully considered. There are many factors involved in the decision process prior to proposing a solution to the identified requirements, including planning horizon perspectives. The Boardman to Hemingway and Gateway West projects have been designed to appropriately size the transmission line and allow phased construction to meet Idaho Power's needs as well as satisfy requests from third parties for capacity on the same path. A more detailed description of each project is presented in the following sections.

Boardman to Hemingway

The proposed Boardman to Hemingway project involves constructing, operating, and maintaining a new, single-circuit, 500-kV transmission line approximately 300 miles in length. The proposed route is between northeast Oregon and southwest Idaho. The new line will provide many benefits, including 1) greater access to the Pacific Northwest electric market to serve homes, farms, and businesses in Idaho Power's service area; 2) improved system reliability and reduced capacity limitations on the Pacific Northwest's transmission system as demand for energy continues to grow; and 3) assurance of Idaho Power's ability to meet customers' existing and future energy needs in Idaho and Oregon.

The project is expected to be completed and in service in 2016. The overhead, 500-kV, high-voltage transmission line will connect a future substation near Boardman, Oregon, to the Hemingway Substation, located near Melba, Idaho. The proposed transmission line will connect with other transmission lines on either end of the project to convey electricity on a regional scale. Figure 5.1 shows a map of the region with the proposed route of the new line.

In the 2006 IRP, Idaho Power anticipated the new line would interconnect at the McNary substation; however, there is insufficient room at the existing McNary substation for major transmission expansion options. A number of utilities are also considering a northeast Oregon (NEO) substation to provide future interconnectivity of regional projects. The exact location and in-service date for the NEO substation is unknown at this time. The proposed Boardman to Hemingway project is not dependent on completion of the NEO substation project or any of the other transmission proposals to satisfy Idaho Power's load-serving need or other existing service requests.

The Boardman to Hemingway project will use a bundled-conductor design capable of a thermal continuous rating of about 3,000 MW. However, due to reliability standards and the Western Electricity

Coordinating Council's (WECC) rating process, the initial implementation of the Boardman to Hemingway project is likely to result in an Idaho to Northwest path increase of 1,300 MW from east-to-west (exports into the Pacific Northwest), on completion of the Gateway West Project and about 850 MW from west-to-east (imports into Idaho Power's balancing authority area). The ratings are subject to technical peer review and will be revisited as other regional projects continue to develop. As additional projects reinforce the transmission network, additional capacity rating increases of the Boardman to Hemingway project may occur.

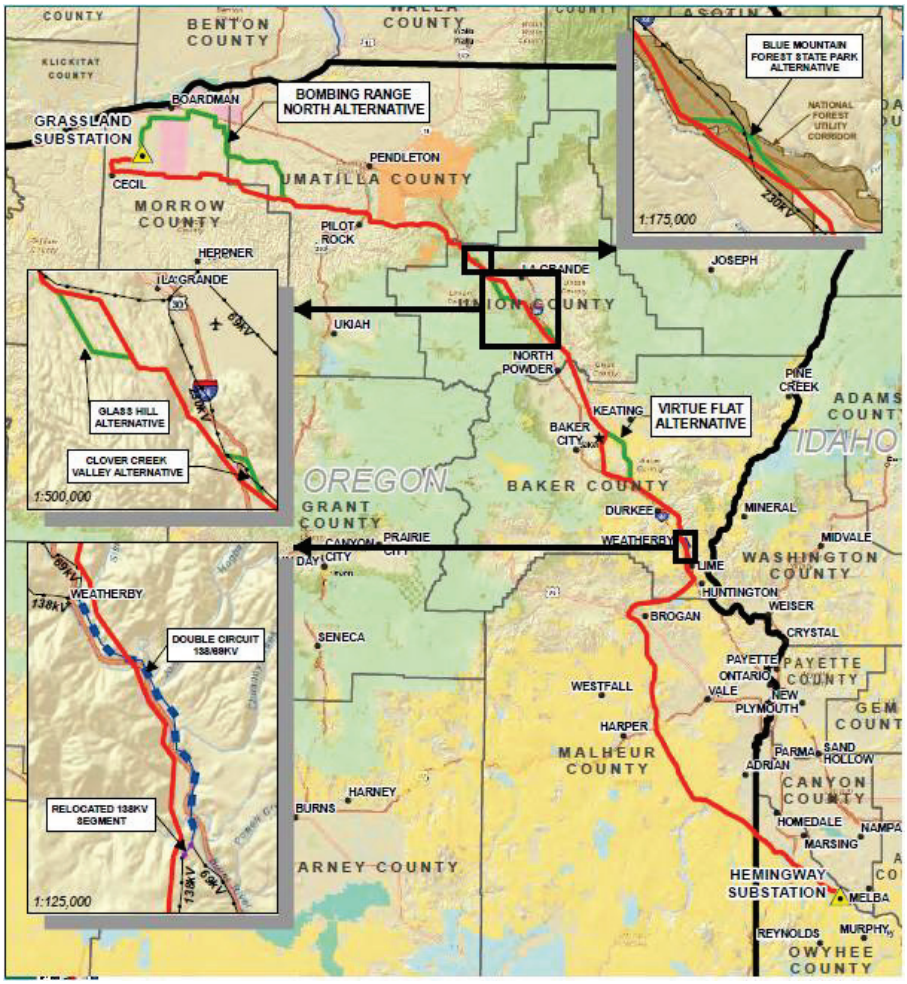

Figure 5.1 Boardman to Hemingway line project map

The Boardman to Hemingway project capacity or sizing considerations and termination locations were developed in the public review process conducted by the Northern Tier Transmission Group (NTTG) and the regional planning phase of the project's WECC rating process. During the review process, it was determined a 230-kV project was too small to meet Idaho Power's overall resource planning needs and would underuse a substantial and valuable transmission corridor. A project operating voltage of 500 kV was selected to match the existing Pacific Northwest transmission grid. A 765-kV line designed with a thermal capacity of approximately 7,000 MW would not achieve a greater rating than the proposed 500-kV project, but would be nearly twice the cost. Because of the higher cost, no further consideration was given to a 765-kV transmission line.

Idaho Power received more than 4,000 MW of requests to commence transmission service between 2005 and 2014 on the Idaho–Northwest transmission path. Of the 4,000 MW of service requests, only 133 MW were granted up through 2007 due to the limited available transmission capacity of the existing system. In the 2006 IRP, Idaho Power identified a need for 225 MW of energy imports from the

Pacific Northwest to Idaho Power's system. The 2009 IRP analyzed various levels of imports, and the final preferred portfolio included 425 MW of capacity on Boardman to Hemingway. The updated analysis in the 2011 IRP indicates 450 MW of capacity is needed on the line to meet Idaho Power's needs.

The Boardman to Hemingway project is important for the development of renewable resources as northeast Oregon has the potential for both wind and geothermal resource development. In 2007, Idaho Power and Horizon Wind Energy developed the first phase of the 101-MW Elkhorn Valley Wind Project in Union County, Oregon, and Idaho Power purchases the output from the facility under a long-term PPA. Firm transmission capacity existed for the first 66 MW of the wind project. The remaining 34 MW of output from the Elkhorn project may face curtailment during times of transmission congestion. Further renewable resource development in northeast Oregon will require additional transmission resources.

Idaho Power is committed to working with communities to identify proposed and alternate routes for the Boardman to Hemingway project. The initial process of identifying a route began in late 2007 when Idaho Power submitted documents to the Bureau of Land Management (BLM), the US Forest Service (USFS), and the Oregon Department of Energy (ODOE).

Following public scoping meetings held in October 2008, the agencies received public input requesting Idaho Power conduct more extensive outreach as part of identifying a route for the new transmission line. In response, Idaho Power initiated the Community Advisory Process (CAP) to engage communities from Boardman, Oregon to Melba, Idaho in siting the Boardman to Hemingway project. The CAP enlisted project advisory team members in five geographic regions within the project area. The members were familiar with the local areas and issues and understand the topography, recreation, wildlife, and view-shed issues; they collaboratively worked with Idaho Power to identify and recommend potential line routes. Idaho Power has been working with communities in the CAP since spring 2009. The CAP process was completed in July 2010; however, Idaho Power continues to meet with landowners and work with local communities as the project moves forward through the local-, state-, and federal-review processes.

Additional information about the Boardman to Hemingway project can be found at http://www.boardmantohemingway.com.

Updated Cost Estimate

The 2011 IRP contains an updated cost estimate for the Boardman to Hemingway line. Idaho Power worked with two primary contractors, Pike Energy Solutions and Tetra Tech EC, Inc., to prepare the updated estimate. The new estimate also updates Idaho Power's internal costs in addition to the estimates provided by Pike Energy Solutions and Tetra Tech EC, Inc. As a result of the analysis, the updated cost estimate increased from the 2009 IRP estimate of $634 million to $820 million.

Pike Energy Solutions provided the line and stations engineering and construction costs for the project and Tetra Tech EC, Inc. provided the environmental permitting and mitigation cost estimates for the project. In addition, Idaho Power included estimated costs for internal labor hours, right-of-way overheads, property taxes, allowance for funds used during construction (AFUDC), and contingency estimates in support of the entire project. The detailed estimate included in *Appendix C–Technical Appendix* shows the combination of third-party cost estimates provided by Pike Engineering Solutions, Tetra Tech EC, Inc., and estimates for Idaho Power's internal costs.

The updated costs show significant increases in material prices and construction costs, primarily due to increased material and labor prices and line-route modifications to move the routing away from agricultural land. The AFUDC estimate has also increased due to a projected rate increase of 5 percent

to 7.5 percent. Property taxes were not included in the 2009 IRP estimate and have now been included in the updated estimate.

For the 2011 IRP, the contingency estimate has been reduced from 30 percent to 20 percent because of the higher level of project definition and detail and increased level of confidence in the line location and the engineering and design aspects of the project. The contingency estimate is consistent with Idaho Power's estimating practices and industry standards for contingency estimating. The updated cost estimate does not include any estimated impacts of future inflation that may occur following the date of the estimate; however, the IRP analysis assumes a general inflation rate of 3 percent, which is applied consistently to all resources.

The results of the 2011 IRP analysis indicate the Boardman to Hemingway transmission line will be a well-used resource that benefits Idaho Power's retail and transmission customers, as well as consumers and generators in both the Pacific Northwest and the Intermountain Region. The capital cost of the Boardman to Hemingway project, as measured on a dollars-per-kW-of-capacity basis, has the lowest capital cost of any supply-side resource 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 1,150 miles of new transmission lines from the planned Windstar substation near Glenrock, Wyoming to the Hemingway substation near Melba, Idaho. The project is being designed so multiple construction phases can provide transmission segments as needs materialize. Some segments of the Gateway West project are planned to be in service in the 2015–2017 timeframe. Numerous routes under consideration are shown in Figure 5.2.

The two transmission projects, Boardman to Hemingway and Gateway West, are complementary and will provide an upgraded transmission path from the Pacific Northwest across Idaho and into eastern Wyoming with an additional transmission connection to the population center along the Wasatch Front in Utah through Rocky Mountain Power's Gateway South project.

Significant renewable resource development potential exists in Wyoming and southern and eastern Idaho. Idaho Power's transmission system is currently limited in its ability to transmit energy from new resources from the east to the major load centers in Idaho. Gateway West will provide new transmission capacity to integrate and deliver any such selected resources in addition to meeting third-party transmission service requests under Idaho Power's OATT.

The Gateway West project is currently undergoing an extensive and ongoing public involvement process to identify proposed and alternate routes. The outreach work is being done in conjunction with the NEPA process related to environmental studies, as well as local jurisdictions for permitting. The project as proposed in Idaho includes two separate 500-kV lines between the Populus substation in southeast Idaho, and the Hemingway Substation in southwestern Idaho, with connection in central Idaho between the Midpoint Substation and the proposed Cedar Hill substation.

Phase 1 is expected to provide between 700 MW and 1,500 MW of additional transfer capacity across Idaho. The fully completed project would provide a total of 3,000 MW of additional transfer capacity. Similarly, the project extending east from the Populus substation into eastern Wyoming is expected to provide Phase 1 capacity improvements of approximately 700 to 1,500 MW, with the full build-out capacity increase being greater than 2,000 MW east of Jim Bridger and 3,000 MW between the Populus substation and Jim Bridger.

The project cost and capacity is expected to be shared between Idaho Power and Rocky Mountain Power based on load service requirements and third-party transmission service request obligations. Additional information about the Gateway West project can be found at www.gatewaywestproject.com.

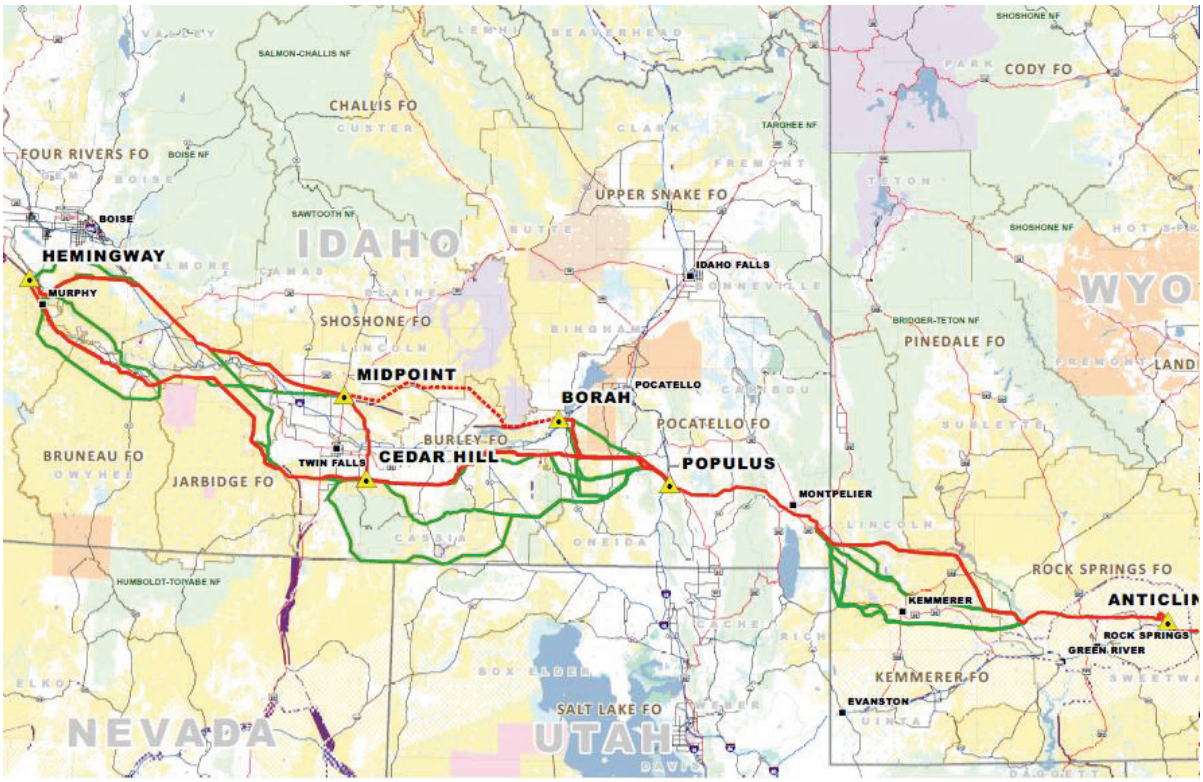

Figure 5.2 Gateway West line project map

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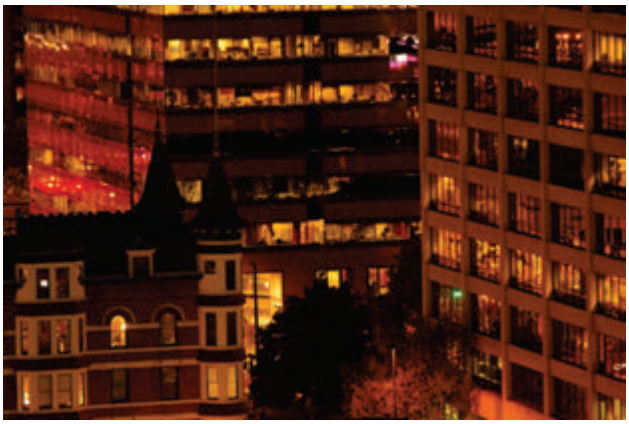
6. Planning Period Forecasts

The IRP process requires Idaho Power prepare numerous forecasts that can be grouped into four main categories, 1) load forecasts, 2) a generation forecast, 3) fuel price forecasts, and 4) financial assumptions. 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 2011 IRP.



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

Load Forecast

Historically, Idaho Power has been a summer peaking utility with peak loads driven by irrigation pumps and air conditioning in the months of June, July, and August. For a number of years, the growth rate of peak-hour load has exceeded the growth of average monthly load. However, both measures are important in planning for future resources and are part of the load forecast prepared for the 2011 IRP.

The expected-case (median) load forecasts for peak-hour and average energy represent Idaho Power's most probable outcome for load growth during the planning period. However, the actual path of future electricity sales will not precisely follow the path suggested by the expected-case forecast. Therefore, Idaho Power prepared four additional load forecasts, 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-growth and low-growth scenarios provide boundaries on each side of the expected-case forecast and historical load variability potential on future load due to demographic, economic, and other non-weather-related influences. The 70th percentile and 90th percentile load forecast scenarios were developed to assist Idaho Power's review of the resource requirements that would result from higher loads due to adverse weather conditions.

Idaho Power prepares a sales and load forecast each year as part of the company's annual financial forecast. The economic forecast is based on a forecast of national and regional economic activity developed by Moody's Analytics, Inc., a national econometric consulting firm. Moody's Analytics,

Highlights

- Idaho Power's summer peak load record of 3,214 MW was set in June 2008.
- Idaho Power's customers set a new winter system peak record of 2,528 MW on December 10, 2009, during several days of below-normal temperatures.
- The 2011 IRP assumes an expected-case carbon adder of $20 per ton starting in 2015.
- For the first time, the IRP load forecast includes the expected impact of electric vehicles.
- The 2011 IRP average system load forecast is lower than the 2009 IRP average system load forecast in all years of the forecast period.

Inc.'s July 2010 macroeconomic forecast strongly influenced the 2011 IRP load forecast. The national, state, metropolitan statistical area (MSA), and county econometric projections are tailored to Idaho Power's service area using an economic database developed by an outside consultant. Specific demographic projections are also developed for the service area from national and local census data. National economic drivers from Moody's Analytics, Inc., are also used in developing the 2011 IRP load forecast. The forecast of the number of households, employment projections, and retail electricity prices, along with historical customer consumption patterns, are used to develop customer forecasts and load projections.

Weather Impacts

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

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

Weather conditions are the primary factor affecting the load forecast on the hourly, daily, weekly, monthly, and seasonal time horizon. Economic and demographic conditions affect the load forecast over the long-term time horizon.

Economic Impacts

The national recession that began in 2008 underscores the effects of the national and local economy on energy use in Idaho Power's service area. The severity of the recession resulted in a collapse in new residential customer growth from the addition of 15,000 new residential customers each year prior to the recession, to approximately 2,000 new customers added each year at the present. Commercial and industrial customer energy use contracted and overall system energy use declined by 3.5 percent in 2009, followed by a 1.2 percent decline in 2010—the first time overall energy use has declined since the energy crisis of 2001.

Increased population in Idaho Power's service area—due to migration to Idaho from other states—is expected to continue throughout the planning period and has been included in the load forecast model. Idaho Power also continues to receive requests from prospective new large-load customers attracted to southern Idaho due to the relatively low electric rates. In addition, the economic conditions in surrounding states may encourage some manufacturers to consider moving operations to Idaho.

The number of households in Idaho is projected to grow at an annual average rate of 1.2 percent during the 20-year forecast period. Growth in the number of households within individual counties in Idaho Power's service area differs from statewide household growth patterns. Service area household projections are derived from individual, county-specific household forecasts. Growth in the number of households within Idaho Power's service area, combined with estimated consumption per household and considerations made for DSM measures, results in a 1.5-percent residential load growth rate.

The number of residential customers in Idaho Power's service area is expected to increase 1.4 percent annually from approximately 409,000 at the end of 2010 to nearly 536,000 by the end of the planning period in 2030.

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 1.4 percent (over the period 2011 through 2030) is comprised of residential load growth of 1.5 percent, commercial load growth of 1.3 percent, irrigation load growth of 0.3 percent, industrial load growth of 1.7 percent, and additional firm load growth of 2.0 percent.

The 2011 IRP average system load forecast is lower than the 2009 IRP average system load forecast in all years of the forecast period. The slowdown in the national and service-area economy caused load growth to slow significantly. In addition, the significant increase in assumed DSM combined with retail electricity price assumptions that incorporate estimates of assumed carbon legislation serve to decrease the forecast of average loads. Significant factors and considerations that influenced the outcome of the 2011 IRP load forecast include the following:

- The electricity price forecast used to prepare the sales and load forecast in the 2009 IRP reflected the fixed and variable costs of integrating the resources identified in the 2006 IRP preferred portfolio, including the expected costs of carbon emissions. When compared to the electricity price forecast used to prepare the 2011 IRP sales and load forecast, the 2009 IRP price forecast yielded significantly higher future prices. The price forecast difference is primarily the result of differing carbon cost assumptions between the two forecasts. The 2009 IRP retail electricity price forecast assumed a carbon tax scenario (from the 2006 IRP) and the 2011 IRP electricity price forecast assumed a cap-and-trade carbon scenario (from the 2009 IRP). Under the cap-and-trade carbon scenario in the 2009 IRP, Idaho Power curtailed coal resources to comply with target emissions levels.
- The sales and load forecast reflects the increased expected demand for energy and peak capacity of Idaho Power's newest special-contract customer, Hoku Materials, located in Pocatello, Idaho. At the time this forecast was completed (August 2010), Hoku Materials was planning to begin operation in January 2011 and reach full capacity by April 2011. The IRP sales and load forecast assumes that Hoku Materials will consume 74 aMW of energy each year and have a peak demand of 82 MW (each measure excluding line losses) once continuous operation is reached in 2013.
- The load forecast used for the 2011 IRP reflects a recovery in the service-area economy following a severe recession in 2008 and 2009, as well as a much smaller impact of carbon regulation on future energy rates charged to Idaho Power customers. The collapse in the housing sector in 2008 and 2009 dramatically slowed the growth in the number of new households and residential customers being added to Idaho Power's service area. In addition, the number of commercial customers being added also slowed dramatically as a result of the economic downturn. However, by 2012, residential and commercial customer growth is expected to slowly recover; by 2015, customer additions are forecast to approach the growth that occurred prior to the housing bubble (2000–2004). The cost of carbon impact on the 2011 IRP load forecast was not material because of the cap-and-trade assumption used in the 2009 IRP, which was the basis for carbon costs in the 2011 IRP load forecast.
- In this year's forecast, an additional customer referred to as "Special" was included in the additional firm load category even though a long-term contract had not yet been fully executed.

At the time this forecast was prepared (August 2010), several interested parties had taken significant steps toward the ultimate development and location of their businesses within Idaho Power's service area. It was determined that the real possibility of the new large load was significant enough for it to be imprudent of the company to ignore the possible impact. The anticipated load of the new "Special" contract has been included in this forecast based on discussions with the interested parties. The existing special contracts and the new "Special" contract together make up the additional firm load category.

- There continues to be significant uncertainty associated with the industrial and special contract sales forecasts. The forecast uncertainty is due to the number of parties that contact Idaho Power and express interest in locating production operations within Idaho Power's service area and the unknown magnitude of the energy and peak demand requirements. The current sales and load forecast reflects only those customers that have a high probability of locating in the service area or have made financial commitments and whose facilities are actually being constructed at this time. Therefore, the large numbers of businesses that have contacted Idaho Power and shown interest, but have not made commitments, are not included in the current sales and load forecast.
- In another improvement to this year's forecast, Idaho Power used Itron, Inc.'s residential Statistically Adjusted End-Use (SAE) model to prepare the long-term residential sales forecast. Recently, many utilities have adopted Itron, Inc.'s SAE modeling approach to include greater end-use information into the forecast process.
- Existing energy efficiency program performance is estimated and included in the sales and load forecast base, lowering the energy and peak demand forecast. However, the impact of demand response programs is accounted for in the load and resource balance. 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*.
- A somewhat higher irrigation sales forecast compared to earlier forecasts (prior to 2009 IRP) due to a substantial increase in weather-adjusted irrigation sales in 2007 and 2008 (6% in 2007 and 8% in 2008). High commodity prices appear to be the primary reason behind the irrigation sales increase. Farmers have taken advantage of the commodities market by planting all available acreage. In addition, the conversion of hand-lines to electrically operated pivots may explain a part of the increased energy consumption. In recent years, the increased labor costs associated with moving hand-lines has triggered the substitution of labor with electrically operated pivots.

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 (including Astaris historically) and the Raft River Rural Electric Cooperative wholesale agreement. Idaho Power uses the 95th percentile forecast as the basis for peak-hour planning in the IRP. The 95th percentile forecast is based on 95th percentile average peak-day temperatures to forecast monthly peak-hour load.

Idaho Power's system peak-hour load record, 3,214 MW, was recorded on Monday, June 30, 2008, at 3:00 p.m. The previous year's summer peak demand was 3,193 MW and occurred on Friday, July 13, 2007, at 4:00 p.m. Summertime peak-hour load growth accelerated in the previous decade as air conditioning became standard in nearly all new residential home construction and new commercial buildings. The growth in peak demand slowed considerably in 2008 and 2009 due to a severe recession that brought new home and new business construction to a standstill. Demand response programs operating in the summertime have also served to reduce peak demand. The 2011 IRP load forecast projects peak-hour load to grow by approximately 69 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.

Figure 6.1 and Table 6.1 summarize three forecast outcomes of Idaho Power's estimate of annual system peak load considering median, 90th percentile, and 95th percentile weather impacts on the expected (median) peak forecast. The 95th percentile forecast uses the 95th percentile peak-day average temperature to determine monthly peak-hour demand. The planning criteria for determining the need for peak-hour capacity assumes the 95th percentile peak-day temperature conditions.

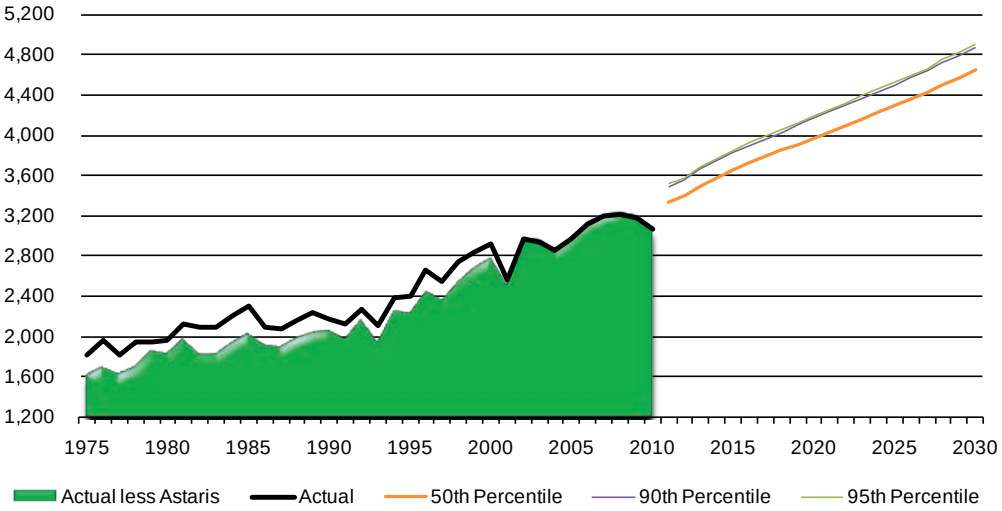


Figure 6.1 Peak-hour load growth forecast (MW)

Table 6.1 Load forecast—peak-hour (MW)

Year	Median	90th Percentile	95th Percentile
2010 (Actual)	2,930	2,930	2,930
2011	3,334	3,494	3,515
2012	3,392	3,555	3,577
2013	3,496	3,662	3,684
2014	3,577	3,747	3,770
2015	3,657	3,831	3,854
2016	3,725	3,902	3,925
2017	3,787	3,967	3,991
2018	3,847	4,031	4,056
2019	3,911	4,098	4,123
2020	3,973	4,164	4,190
2021	4,034	4,229	4,254
2022	4,098	4,296	4,323
2023	4,165	4,367	4,394
2024	4,229	4,435	4,462
2025	4,291	4,501	4,529
2026	4,358	4,571	4,599
2027	4,419	4,635	4,664
2028	4,498	4,718	4,747
2029	4,569	4,792	4,822
2030	4,643	4,870	4,901
Growth Rate (2011–2030)	**1.8%**	**1.8%**	**1.8%**

The median or expected-case peak-hour load forecast predicts peak-hour load will grow from 3,334 MW in 2011 to 4,643 MW in 2030, an average annual compound growth rate of 1.8 percent. The projected average annual compound growth rate of the 95th percentile peak forecast is 1.8 percent. In the 95th percentile forecast, summer peak-hour load is expected to increase from 3,515 MW in 2011 to 4,901 MW in 2030. Historical peak-hour loads as well as the three forecast scenarios are shown in Figure 6.1.

Idaho Power's winter peak-hour load record was 2,528 MW, recorded on Thursday, 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 the variability of peak day temperatures 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 a series of four load forecasts that reflect a range of load uncertainty resulting from differing economic growth and weather-related assumptions. Figure 6.2 and Table 6.2 show the results of the four forecasts used in the 2011 IRP to estimate the boundaries of annual system load growth over the planning period. There is approximately a 90-percent probability that Idaho Power's load growth will exceed the low-load growth forecast, a 50-percent probability of load growth exceeding the expected-case forecast, a 30-percent probability of load growth exceeding the 70th percentile forecast, and approximately a 10-percent probability that load growth will exceed the high-growth forecast. The projected 20-year average annual compound growth rate in the expected-load forecast is 1.4 percent.

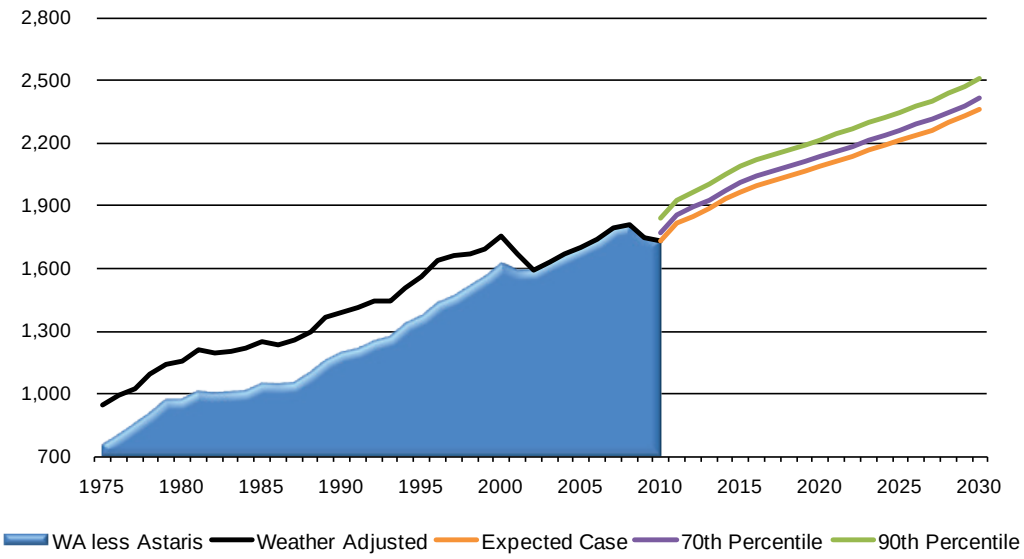


Figure 6.2 Average monthly load growth forecast (aMW)

Table 6.2 Load forecast—average monthly energy (aMW)

Year	Median	70th Percentile	Low	High
2011	1,819	1,860	1,793	1,878
2012	1,852	1,893	1,814	1,936
2013	1,890	1,931	1,836	1,987
2014	1,932	1,974	1,866	2,043
2015	1,970	2,013	1,894	2,094
2016	1,998	2,042	1,913	2,135
2017	2,023	2,067	1,927	2,170
2018	2,045	2,090	1,940	2,203
2019	2,070	2,115	1,956	2,238
2020	2,090	2,136	1,970	2,271
2021	2,114	2,160	1,983	2,303
2022	2,139	2,186	2,000	2,338
2023	2,166	2,214	2,019	2,375
2024	2,189	2,237	2,036	2,410
2025	2,214	2,263	2,051	2,443
2026	2,241	2,290	2,070	2,480
2027	2,263	2,313	2,084	2,511
2028	2,298	2,349	2,113	2,560
2029	2,329	2,380	2,133	2,598
2030	2,362	2,414	2,158	2,642
Growth Rate (2011–2030)	**1.4%**	**1.4%**	**1.0%**	**1.8%**

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

Additional Firm Load

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

A special contract also allows Idaho Power to provide requested service consistent with system capability and reliability. Idaho Power currently has four special-contract customers recognized as firm-load customers. These special-contract customers are Micron Technology, Simplot Fertilizer, INL, and Hoku Materials. In addition, the company has a term sales contract with Raft River Rural Electric Cooperative. Raft River is not required to meet the 20-MW electric service minimum.

It is difficult to predict when a new special-contract customer will begin taking service from Idaho Power. However, because of the magnitude of their load and subsequent impact on system resources, it is important to anticipate such load if a customer of that size is considered imminent. In this year's forecast, the company has included the anticipated load of an additional special-contract customer referred to as "Special" in the additional firm load category even though a long-term special contract had

not yet been fully executed. At the time this forecast was prepared (August 2010), several interested parties had taken significant steps toward the ultimate development and location of their businesses within Idaho Power's service area. It was determined that the real possibility of the new large load was significant enough that it would be imprudent of the company to ignore the possible impact. The anticipated load of the new "Special" contract has been included in this forecast based on discussions with the interested parties. The existing special-contract customers and the new "Special" contract together make up the additional firm-load category.

Micron Technology

Micron Technology is currently Idaho Power's largest individual customer and employs approximately 5,000 workers in the Boise MSA. Electricity sales to Micron Technology moved considerably downward in 2009 and 2010 as Micron phased out its 200-millimeter (mm) dynamic random access memory (DRAM) operations at its Boise facility. The company continues to operate its 300-mm research and development fabrication facility in Boise and performs a variety of other activities, including product design and support, quality assurance, systems integration and related manufacturing, corporate, and general services. Once establishing a new floor for energy consumption at the facility at about a quarter less energy use than in recent years, 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 United States. The future electricity usage at the plant is expected to grow at a slow pace throughout the planning period (2011–2030). The primary driver of long-term electricity sales growth at Simplot Fertilizer is Moody's Analytics, Inc., forecast of gross product in the pesticide, fertilizer, and other agricultural chemical manufacturing segment for the Pocatello MSA.

Hoku Materials

The sales and load forecast reflects the increased expected demand for energy and peak capacity of Idaho Power's newest special-contract customer, Hoku Materials, located in Pocatello, Idaho. At the time this forecast was completed (August 2010) Hoku Materials was planning to begin operation in January 2011 and reach full capacity by April 2011. The IRP sales and load forecast assumes that Hoku Materials will consume 74 aMW of energy each year and have a peak demand of 82 MW (each measure excluding line losses) once continuous operation is reached in 2013. In the time since the IRP load forecast was prepared, Hoku Materials has delayed the ramp up of its operations; however, this delay is not expected to impact the results of the 2011 IRP.

"Special" Contract

In this year's forecast, an additional customer referred to in this document as "Special" was included in the additional firm-load category even though a long-term contract had not yet been fully executed. At the time this forecast was prepared (August 2010), several interested parties had taken significant steps toward the ultimate development and location of their businesses within the Idaho Power service area. It was determined that the real possibility of the new large load was significant enough that it would be imprudent of the company to ignore the possible impact.

Planning Scenarios

The timing and necessity of future generation resources are based on a 20-year forecast of surpluses and deficits for monthly average load (energy) and peak-hour load. For both of these areas, one set of criteria has been chosen for planning purposes; however, additional scenarios have been analyzed to provide a comparison.

Table 6.3 provides a summary of the six planning scenarios analyzed for the 2011 IRP, and the criteria used for planning purposes are shown in bold. Median water and median load forecast scenarios were included to enable comparison of the 2011 IRP with plans developed during the 1990s. The median forecast is no longer used for resource planning, although the median forecast is used to set retail rates and avoided cost rates during regulatory proceedings. The planning criteria used to prepare Idaho Power's 2011 IRP are consistent with the criteria used in the 2009 IRP.

Table 6.3 Planning criteria for average monthly and peak-hour load

Average monthly load/energy (aMW)	50th Percentile Water, 50th Percentile Average Load **70th Percentile Water, 70th Percentile Average Load** 90th Percentile Water, 70th Percentile Average Load
Peak-hour load (MW)	50th Percentile Water, 90th Percentile Peak-Hour Load 70th Percentile Water, 95th Percentile Peak-Hour Load **90th Percentile Water, 95th Percentile Peak-Hour Load**

The planning criteria used for energy or average load are 70th percentile water and 70th percentile average load. In addition, 50th percentile water and 50th percentile average load conditions are analyzed to represent a median condition, and 90th percentile water and 70th percentile average load are analyzed to examine the effects of low water conditions.

Peak-hour load planning criteria consist of 90th percentile water and 95th percentile peak-hour load conditions, coupled with Idaho Power's ability to import additional energy on its transmission system. A median condition of 50th percentile water and 50th percentile peak-hour load are also analyzed, as well as 70th percentile water and 95th percentile peak-hour load. Peak-hour load planning criteria are more stringent than average load planning criteria because Idaho Power's ability to import additional energy is typically limited during peak-hour load periods. Surpluses and deficits for the average and peak-hour load scenarios can be found in *Appendix C–Technical Appendix*.

Existing Resources

To identify the need and timing of future resources, Idaho Power prepares a load and resource balance, which accounts for forecast load growth and generation from all of the company's existing resources and planned purchases. Updated load and resource balance worksheets showing Idaho Power's existing and committed resources for average energy and peak-hour load are shown in *Appendix C–Technical Appendix*. The following sections describe recent events or changes accounted for in the load and resource balance regarding Idaho Power's hydroelectric, thermal, and transmission resources.



Brownlee Dam is part of the Hells Canyon Complex.

Hydroelectric Resources

For the 2011 IRP, Idaho Power continues the practice of using 70th percentile streamflow conditions for the Snake River Basin as the basis for the projections of monthly average hydroelectric generation. The 70th percentile means that 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 that 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.

The 50th, 70th, and 90th percentile streamflow forecasts used in the IRP are derived from a streamflow planning model developed by the Idaho Department of Water Resources (IDWR). The IDWR streamflow planning model is used by Idaho Power to produce a normalized hydrologic record for the Snake River Basin from 1928 through 2009. The normalized model accounts for current hydroelectric conditions and historical hydroelectric development with regard to groundwater discharge to the river, water management facilities, irrigation facilities, and operations.

Prior to the 2009 IRP, Idaho Power assumed the representative streamflow conditions calculated from the normalized record were static through the IRP planning period. For example, the practice was to assume that a 70th percentile year in 2010 is identical to a 70th percentile year in 2015. A review of Snake River Basin streamflow trends suggests that persistent decline documented in the 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. However, Idaho Power hydrologists believe the positive effect of the new water associated with the CAMP measures is likely to be temporary, and, over time, the water-use practices driving the steady decline over recent years is expected to resume and result in a return to declining basin outflows that is assumed to persist through at least the first 10 years of the 2011 IRP planning horizon. The declining basin outflows for this IRP are assumed to continue through 2023, with no further decline assumed for the remainder of the planning period through 2030. The expected year-to-year decline in annual hydroelectric generation is less than 0.5 percent. Idaho Power plans to revisit assumptions on the projected date at which basin hydrologic conditions equilibrate as a standard part of forecasting hydroelectric generation for future IRPs.

River temperature is an important concern that can affect the timing of Snake River streamflows. Various federal agencies involved in salmon migration studies continue to support efforts to shift delivery of flow augmentation water from the Upper Snake River and Boise River basins from the traditional months of July and August to the spring months of April, May, and June. The objective of the streamflow augmentation is to more closely mimic the timing of the naturally occurring flow conditions. Reported biological opinions indicate the shift in water delivery is most likely to take place during worse-than-median water years.

Because worse-than-median water is assumed in the IRP, and the importance of July as a resource-constrained month, Idaho Power incorporated the shifted delivery of flow augmentation water from the Upper Snake River and Boise River basins for the 2009 IRP and continues to incorporate the modified flow augmentation for the 2011 IRP. Augmentation water delivered from the Payette River Basin is assumed to remain in July and August. Based on resource planning analyses, monthly average hydroelectric generation for July under the 70th percentile streamflow condition is projected to decline by approximately 115 aMW as a result of the water being shifted out of the month of July.

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 Hells Canyon Complex as run-of-river plants. The generation model mathematically manages reservoir storage in the Hells Canyon Complex to meet the remaining system load, while adhering to the operating constraints on the level of Brownlee Reservoir and outflows from the Hells Canyon project. For peak-hour analysis, a review of historical operations was performed to yield relationships between monthly energy production and achieved one-hour peak generation. The projected peak-hour capabilities for the IRP were derived to be consistent with the observed relationships.

A representative measure of the streamflow condition for any given year is the volume of inflow to Brownlee Reservoir during the April–July runoff period. Figure 6.3 shows historical April–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 of the report, these declines are assumed to equilibrate beyond 2023.

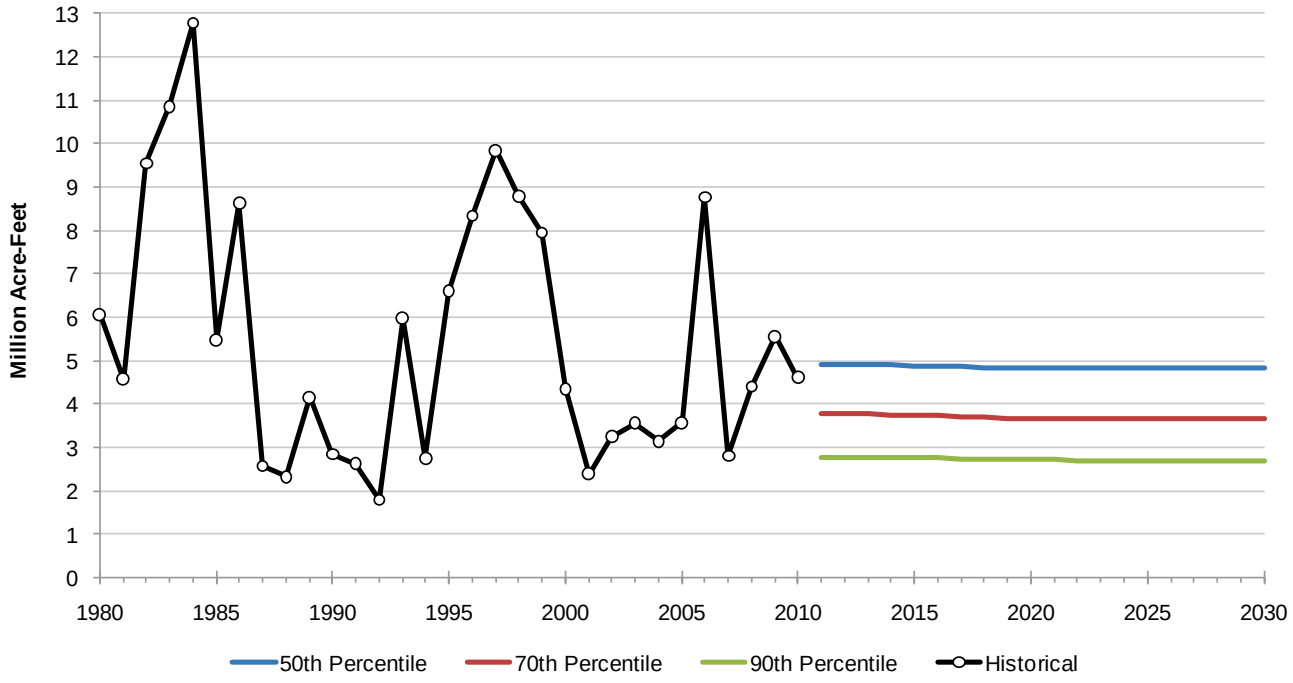


Figure 6.3 Brownlee historical and forecast inflows

Idaho Power recognizes the need to remain apprised of scientific advancements concerning climate change on the regional and global scale. Idaho Power believes there is too much uncertainty to predict the scale and timing of hydrologic effects due to climate change. Therefore, no adjustments related to climate change have been made in the 2011 IRP.

Coal Resources

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

capacity, minus 6 percent to account for forced outages. A summary of the expected coal price forecast is included in *Appendix C–Technical Appendix*.

Plant modifications required to maintain compliance with air-quality standards are projected for the Boardman plant in 2011, 2014, and 2018, and for the Jim Bridger plant in 2015, 2016, 2021, and 2022. The total effect of the air-quality modifications is a reduction in coal-fired generation of less than 1 percent.

The 2011 IRP assumes Idaho Power's share of the Boardman plant will not be available after December 31, 2020. The estimated date is the result of an agreement reached between the ODEQ and PGE, related to compliance with RH BART rules on particulate matter, SO_2, and NO_x emissions. Both ODEQ and PGE are waiting for formal approval from the EPA.

Planned Upgrades at Jim Bridger

Turbine upgrades are continuing at the Jim Bridger plant with the replacement of the high-pressure/intermediate-pressure turbine on unit 2 planned for 2013. The high-pressure/intermediate-pressure turbine on unit 1 was upgraded in 2010. Upgrades of the high-pressure/intermediate-pressure turbines on units 3 and 4 and upgrades to the low-pressure turbines on all four units are currently being evaluated.

Natural Gas Resources

Idaho Power owns and operates four natural gas-fired SCCTs. These resources are typically operated during high-load occurrences in summer and winter months. The monthly average energy forecast for the SCCTs is based on the assumption that the generators are operated at full capacity for heavy-load hours during the months of January, June, July, August, and December, producing on average approximately 230 aMW of gas-fired generation for the selected months. With respect to peak-hour output, the SCCTs are assumed capable of producing on-demand peak capacity of 416 MW. While this dispatchable capacity is assumed achievable for all months, it is most critical to system reliability during summer and winter peak-load months.

Idaho Power is currently constructing the Langley Gulch CCCT, which is expected to be commercially available in July 2012. Because of its higher efficiency rating, Langley Gulch is expected to be dispatched more frequently and for longer runtimes than the existing SCCTs. For the 2011 IRP, Langley Gulch is forecast to contribute 251 aMW of energy per month, with on-demand peaking capacity of 300 MW.

Transmission Resources

Transmission capacity limitations are an important factor in Idaho Power's ability to reliably serve peak-hour load. Idaho Power uses spot-market purchases when the company's generating resources and firm purchases are inadequate to meet peak-hour load requirements, and transmission capacity limitations restrict Idaho Power's ability to import additional energy.

From the load and generation forecasts, a determination can be made regarding the need for, and the magnitude of, the off-system market purchases needed to serve system load. The projected off-system market purchases are added to all other committed transmission obligations to determine if the additional imported energy will exceed the operational limits of the transmission system. The analysis assumes that all off-system market purchases will come from the Pacific Northwest.

During Idaho Power's peak-hour load periods, off-system market purchases from the east and south have historically proven to be unavailable or very expensive. Many of the utilities to the east and south of Idaho Power also experience a summer peak, and the weather conditions that drive Idaho Power's summer peak-hour load are often similar across the Intermountain Region. Therefore, Idaho Power does not typically rely on imports from the Intermountain Region for planning purposes.

For the 2011 IRP, Idaho Power has restricted its transmission analysis to the scenario assuming 90th percentile streamflows, 70th percentile load, and 95th percentile peak-hour load. The 95th percentile peak-hour load planning criterion means that there is a 1-in-20 chance that Idaho Power will be required to initiate more drastic measures, such as curtailing load, if attempts to acquire energy and transmission access from the spot market are unsuccessful.

Idaho Power used the results of the transmission analysis to establish a capacity target for planning purposes. The capacity target identifies the amount of additional generation, demand response programs, or transmission resources that must be added to Idaho Power's system to avoid capacity deficits.

On a yearly basis, Idaho Power's transmission capacity is reserved for the company's retail customers based on annual load and resource forecasts. Although transmission resources are owned by Idaho Power, the unreserved transmission capacity may be purchased by other parties due to FERC's open access requirements. Idaho Power must reserve the use of its own transmission system under FERC's open access rules. Often, Snake River flow forecasts for the remainder of the year are not known with a high degree of accuracy until May or June, and late spring is often too late to acquire firm transmission capacity for the summer months.

Natural Gas Price Forecast

Future natural gas price assumptions significantly influence the financial results of the operational modeling used to evaluate and rank resource portfolios. The 2011 IRP natural gas price forecast uses several outside public and private forecast sources to develop a composite future yearly Henry Hub price curve. The forecast sources include the NPCC, the New York Mercantile Exchange (NYMEX), the Natural Gas Exchange, the Energy Information Administration (EIA), and Moody's Analytics, Inc.

The individual annual forecasts from the outside sources are evaluated and weighted to calculate the composite forecast. The weighting is based on a combination of Idaho Power's expectation of price, the reasonableness of the forecasts when compared with others, and the current forward price of actual contracts being executed on various exchanges. In the near-term forecast horizon, greater weight is given to actual commitment contracts being executed on the NYMEX compared to longer-term forecasts that are weighted more heavily towards projected prices without underlying financial trades (EIA, Moody's, Inc.).

Regional price variability from the Henry Hub can be significant. Idaho Power uses a price adjustment (basis) based on the cost of delivering natural gas from the Sumas trading hub to model natural gas prices in southwest Idaho. The Sumas price adjustment incorporates the Pacific Northwest regional price variation from Henry Hub and the transportation charges from Northwest Pipeline Corporation to deliver natural gas to Idaho Power's service area. The 2011 IRP assumes existing pipeline transport capacity is sufficient to serve only existing demand. The cost of new gas resources includes an additional transportation cost to account for the cost of constructing new pipeline capacity. This additional cost is approximately twice the current tariff rate. Figure 6.5 shows the major natural gas pipeline transportation paths in the Pacific Northwest.

The Henry Hub price, including the Sumas Basis, is shaped monthly to reflect the normal seasonal supply and demand price variation. The gas price forecast in all future years receives the same monthly price shaping. Sumas gas prices can have high seasonal spot price variability, especially in the winter months, and the Sumas price volatility is not included in the regional adjustment. Idaho Power's geographic position between Sumas gas and Rockies gas allows Idaho Power to access two independent gas markets that may not have high-price correlation. Also, Idaho Power hedges a portion of its short- and mid-term gas planned for use in the resource portfolio. This hedging activity is intended to reduce the spot and seasonal-price volatility of natural gas costs incurred by customers.

The 2011 IRP analyzes three gas price scenarios as shown in Figure 6.4. The expected-case forecast has a 20-year levelized cost of $7.92 per MMBtu, while the high case is $9.82 per MMBtu and the low case is $6.01 per MMBtu. At the time the natural gas price forecast was prepared for the IRP, natural gas prices were considerably higher than they are today. In fact, the low natural gas price case is a more accurate reflection of the current forward market for natural gas.

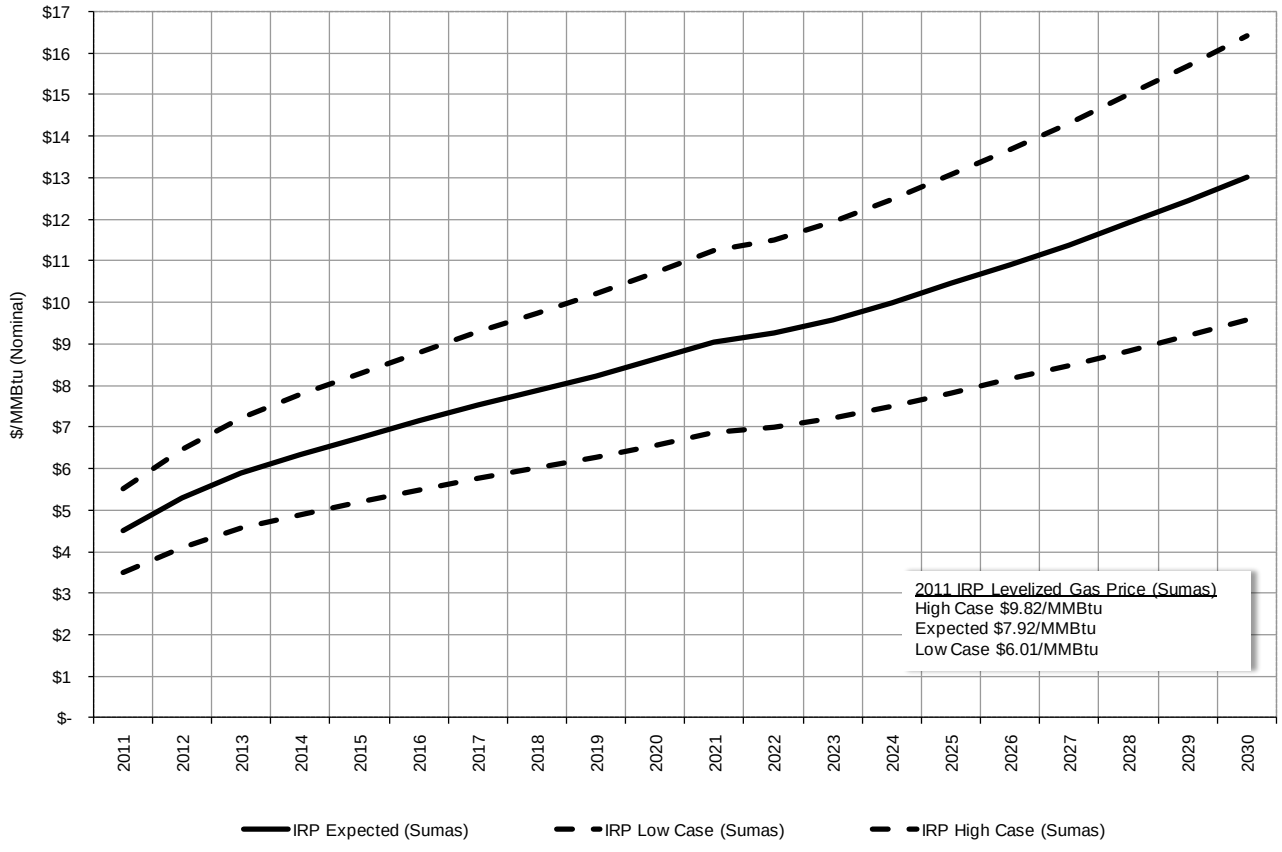


Figure 6.4 Natural gas price forecast

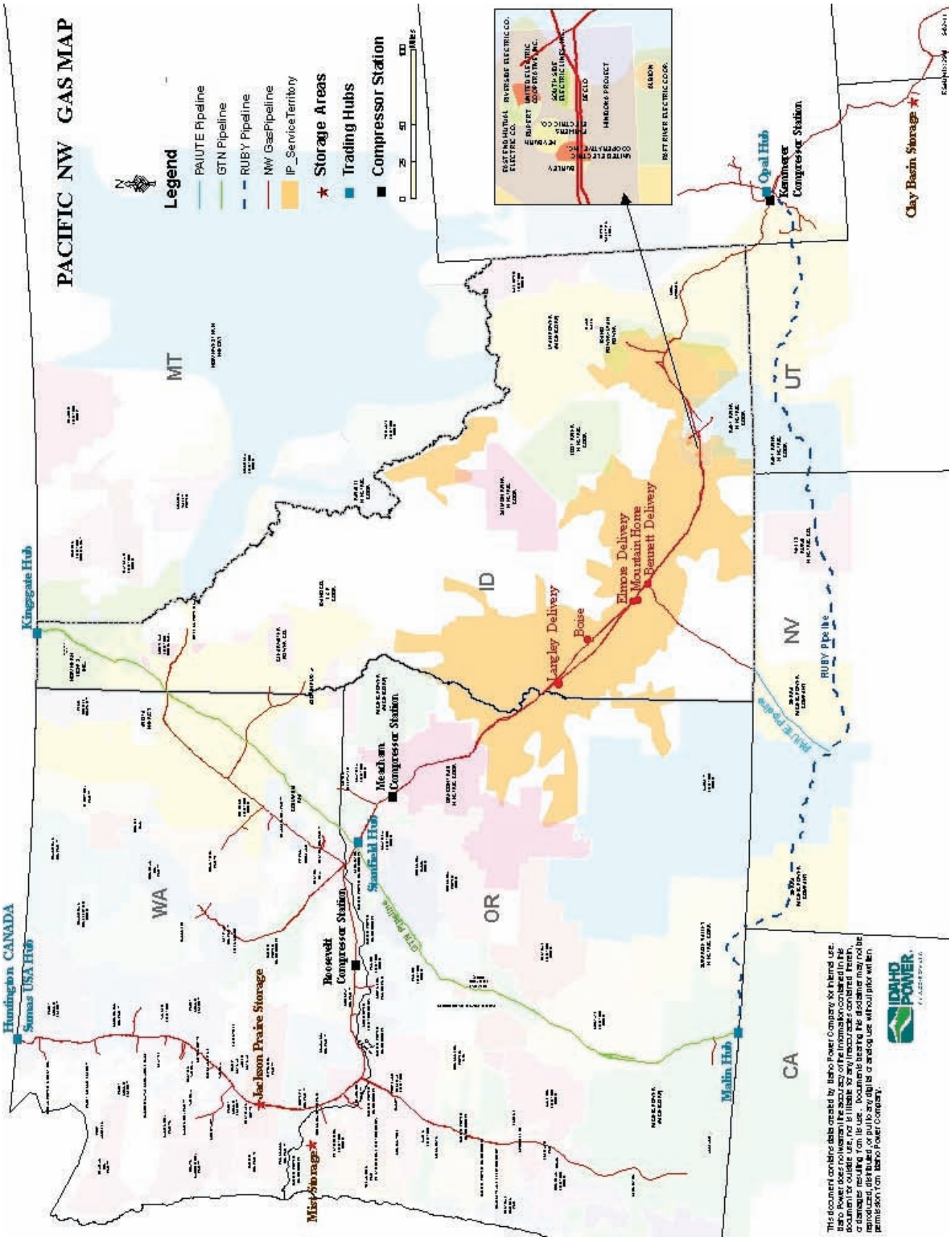


Figure 6.5 Pacific Northwest natural gas transportation paths

Resource Cost Analysis

The costs of a variety of supply-side and demand-side resources were analyzed for the 2011 IRP. Cost inputs and operating data used to develop the resource cost analysis were derived from various sources, including, but not limited to, the NPCC, the US Department of Energy (DOE), independent consultants, and regional energy project developers. Resource costs are presented as follows:

- Levelized fixed cost-per-kW of installed (nameplate) capacity per month
- Total levelized cost-per-MWh of expected plant output or energy saved, given assumed capacity factors and other operating assumptions

The levelized costs for the various supply-side alternatives include capital costs, O&M costs, fuel costs, and other applicable adders and credits. The cost estimates used to determine capital cost of the supply-side resources include engineering development costs, generating and ancillary equipment purchase costs, installation, applicable balance of plant construction, and the costs for a generic transmission interconnection to Idaho Power's network system. More detailed interconnection and transmission system upgrade costs were estimated by Idaho Power's transmission planning group and were included in the total portfolio cost. The capital costs also includes 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, annual incentive, and annual participant costs. The demand-side resource costs do not reflect the financial impact to Idaho Power as a result of these load reduction programs.

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

Emissions Adders for Fossil Fuel-Based Resources

All resource alternatives have potential environmental and other social costs that extend beyond just the capital and operating costs included in the cost of electricity. Fossil fuel-based generating resources are particularly sensitive to some of the environmental and social costs. It is likely that further emissions regulations will be implemented during the period covered in the 2011 IRP.

In the analysis, Idaho Power incorporated estimates for the future cost of certain emissions into the overall cost of the various fossil fuel-based resources. Within the resource cost analysis ranking, the levelized costs for the various fossil fuel-based resources include emissions adders for CO_2, NO_x, Hg, and SO_2. The additional costs are assumed to begin in 2015. Table 6.4 provides the emissions intensity rates assumed in the analysis and the emissions adder costs shown in Table 6.5 were used to calculate the total emissions costs of the various fossil fuel-based resources that were analyzed. Additional information regarding the cost of carbon emissions is provided in the next section.

In addition to including the emission adders in the levelized resource cost analysis, Idaho Power estimates the regulatory environmental compliance costs the company expects for CO_2, NO_x, Hg, and SO_2 emissions for each portfolio in the first 10-year and second 10-year planning periods. The expected case regulatory environmental compliance costs for each planning period is shown in *Appendix C–Technical Appendix.* A sensitivity analysis (low-case and high-case) for these compliance costs can also be found in *Appendix C–Technical Appendix.*

Table 6.4 Emissions intensity rates (lbs/MWh)

Adder	CO_2	NO_x	Hg	SO_2
Pulverized Coal	1,901	3.38	0.000050	8.5339
IGCC	2,279	0.21	0.000006	0.1490
IGCC with Carbon Sequestration	420	0.43	0.000006	0.1833
Distributed Generation Natural Gas	1,115	1.07	N/A	0.0096
SCCT	1,413	1.36	N/A	0.0122
CCCT	809	0.08	N/A	0.0070

Table 6.5 Emissions adder cost assumptions

Adder	Emission Adder Cost	First Year Applied	Annual Escalation
GHG	$20 per ton	2015	5.0%
NO_x	$2,600 per ton[1]	2015	2.5%
Hg	$1,443 per ounce[1]	2015	2.5%
SO_2	$1.75 per ton	2011	2.5%

[1] 2011 dollars

Cost of Carbon Emissions

Although Idaho Power believes a cap-and-trade system is more likely than a carbon tax to be implemented in the future, regulatory requirements dictate the analysis be performed using a carbon adder or tax, which Idaho Power has done for the 2011 IRP. The purpose of a carbon adder is to account for all of the costs in the price of energy produced by carbon-emitting resources.

Four carbon-adder scenarios were analyzed as part of the 2011 IRP: 1) the expected case starting at $20 per ton in 2015 and escalating at 5 percent annually, 2) the high case starting at $25 per ton in 2015 and escalating at 7.5 percent annually, 3) the low case starting at $15 per ton and escalating at 2.5 percent annually, and 4) the zero-cost case where there is no future cost associated with carbon emissions. The carbon adder assumptions used in the 2011 IRP are shown in Figure 6.6. A discussion of the analysis results of the cost of carbon emissions is contained in Chapter 9.

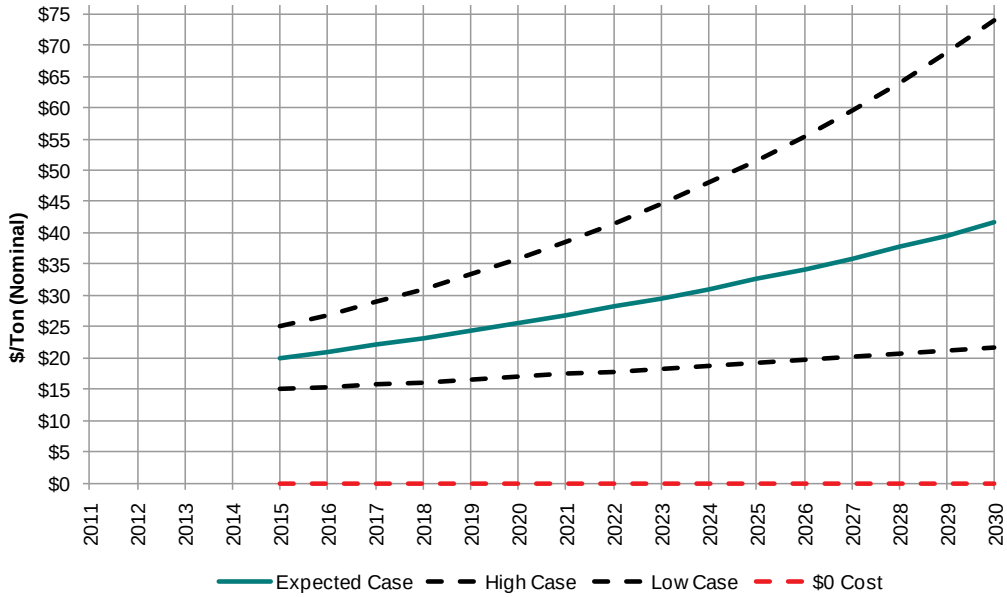


Figure 6.6 Carbon-adder assumptions

Production Tax Credits for Renewable Generating Resources

Various federal tax incentives for renewable resources were extended and/or renewed within the *Emergency Economic Stabilization Act of 2008*. This legislation requires most projects be on line by December 31, 2016, to be eligible for the federal production tax credits (PTC) identified in Section 45 of the *Internal Revenue Code*. The credit is earned on power produced by the project during the first 10 years of operation. The credit, adjusted annually for inflation, is currently valued at $21 per MWh.

Renewable Energy Credits

While the state of Idaho does not have an RPS requirement, Idaho Power believes a federal RES requiring Idaho Power to retire RECs for compliance will be passed by Congress in the near future. Idaho Power believes it is prudent to continue acquiring RECs associated with renewable resources to minimize the impact when a federal RES is implemented.

For the 2011 IRP, the portfolios being analyzed are designed to substantially comply with the *Renewable Electricity Promotion Act of 2010* (S. 3813) introduced in Congress in September 2010 by Senator Jeff Bingaman (D–New Mexico). Under the proposed bill, an initial renewable requirement of 3 percent would begin in 2012 and would increase to 15 percent by 2021.

Three different scenarios for the future value of RECs were analyzed as part of the 2011 IRP: 1) the expected-case scenario where RECs are valued at $7 in 2013 and escalated at 3 percent annually, 2) a high-case scenario where RECs are valued at $21 in 2013 and escalated at 3 percent annually, and 3) a low-case scenario where RECs have no value beginning in 2013. The three REC price assumptions used in the 2011 IRP are presented in Figure 6.7. A discussion of the analysis of the value of RECs in each of the portfolios analyzed in the 2011 IRP is presented in Chapter 9.

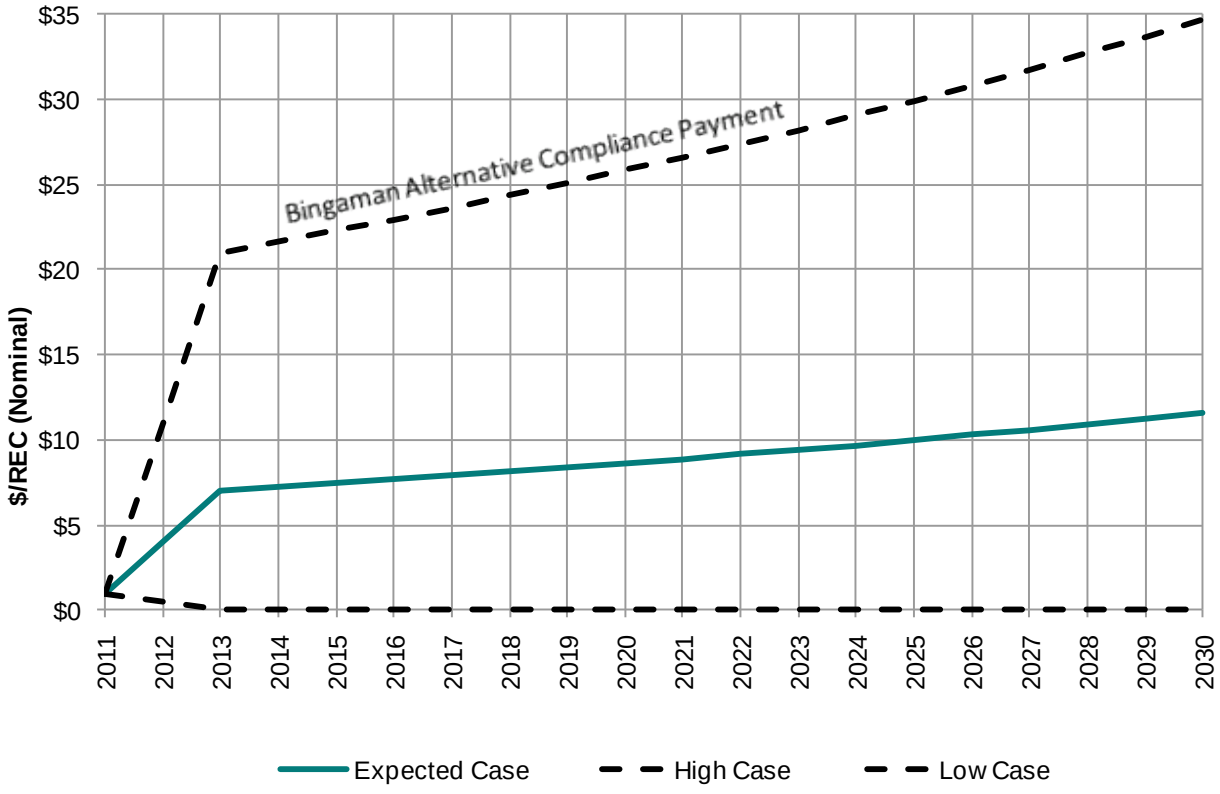


Figure 6.7 REC price assumptions

Levelized Capacity (Fixed) Cost

The annual fixed revenue requirements in nominal dollars for each resource were summed and levelized over a 30-year operating life and are presented as dollars-per-kW of plant nameplate capacity per month. Included in these costs were the cost of capital and fixed O&M estimates. Figure 6.8 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 distributed generation and natural gas peaking resources are the lowest capacity cost alternatives. Distributed generation and gas peaking resources have high operating costs, but the operating costs are not as important when the resource is used only a limited number of hours-per-year to meet peak-hour demand.

Levelized Cost of Production

Certain resource alternatives carry low fixed costs and high variable operating costs, while other alternatives require significantly higher capital investment and fixed operating costs but have low variable operating costs. The levelized cost of production measurement represents the estimated annual cost-per-MWh in nominal dollars for a resource based on an expected level of energy output (capacity factor) over a 30-year operating life.

The nominal, levelized cost of production assuming the expected capacity factors for each resource-type is shown in Figure 6.9. Included in these costs are the cost of capital, non-fuel O&M, fuel, and emissions adders; however, no value for RECs was assumed in this analysis. Resources, such as DSM measures, geothermal, wind, and certain types of thermal generation, appear to be the lowest cost for meeting baseload requirements.

When evaluating a levelized cost for a project and comparing it to the levelized cost of another project, it is important to use consistent assumptions for the computation of each number. The levelized cost of production metric represents the annual cost of production over the life of a resource converted into an equivalent annual annuity. This is similar to the calculation used to determine a car payment; only, in this case, the car payment would also include the cost of gasoline to operate the car and the cost of maintaining the car over its useful life.

An important input into the levelized cost of production calculation for a generation resource is the assumed level of annual capacity utilization over the life of the resource, referred to as capacity factor. A capacity factor of 50 percent would suggest that 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 will be less because the plant would generate more MWh over which to spread the fixed costs. Conversely, lower capacity factor assumptions reduce the MWh and the levelized cost would be higher.

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

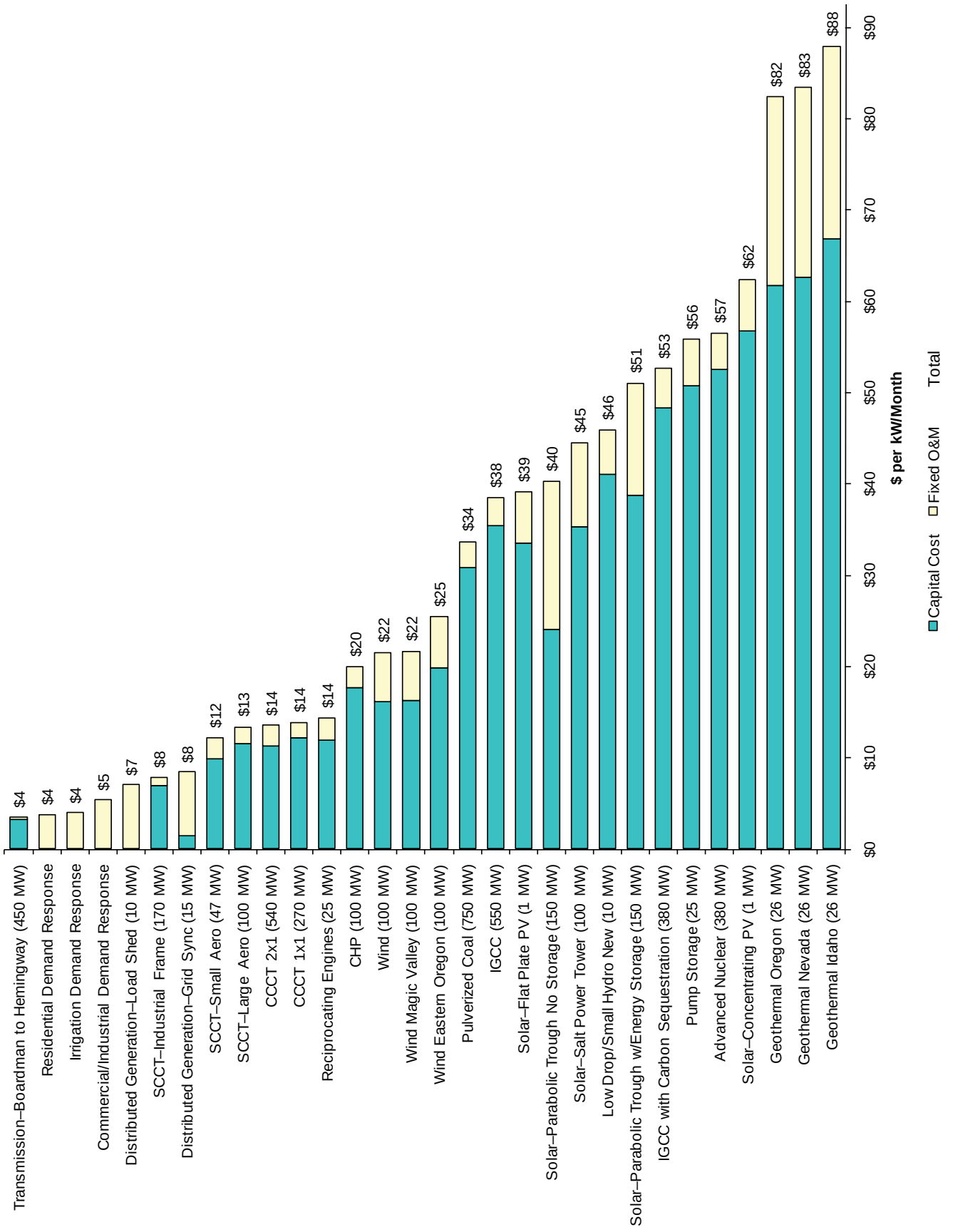


Figure 6.8 30-year levelized capacity (fixed) costs

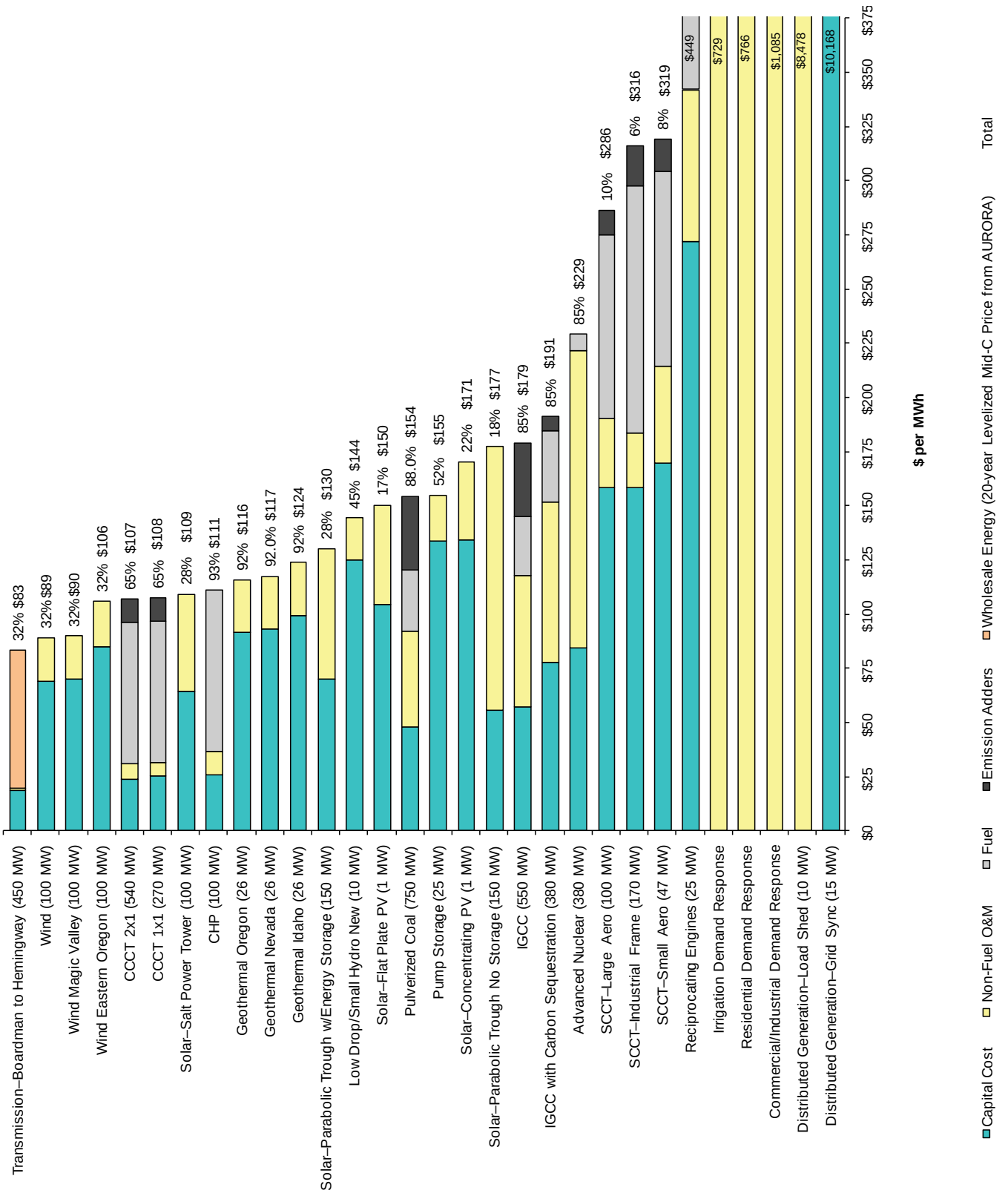


Figure 6.9 30-year levelized cost of production (at stated capacity factors)

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7. TRANSMISSION PLANNING

Past and Present Transmission



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

High-voltage transmission lines have been vital to the development of energy resources to serve Idaho Power customers. Transmission lines have facilitated the development of southern Idaho's network of hydroelectric projects that have served the electric customers of southern Idaho and eastern Oregon. Regional transmission lines that stretch from the Pacific Northwest to the Hells Canyon Complex and on to the Treasure Valley were central to the development of the Hells Canyon Complex 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, which supply approximately 40 percent of the energy consumed by Idaho Power customers. Finally, transmission lines allow Idaho Power to economically balance the variability of its hydroelectric resources with access to wholesale energy markets.

The 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 this, Idaho Power purchases energy from the Mid-Columbia energy trading market to meet peak summer load and sells excess energy to Pacific Northwest utilities during the winter and spring. This practice benefits the environment and Idaho Power's customers because 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, and revenue from others' use of the transmission system is credited to customers in general rates.

Transmission Planning Process

In recent years, FERC has mandated several aspects of the transmission planning process. One regulation requires Idaho Power to participate in transmission planning on a local, sub-regional, and regional basis, as described in Attachment K of the Idaho Power OATT and summarized in the following sections.

Highlights

- Regional transmission interconnections improve reliability by providing the flexibility to move electricity between balancing authorities.
- Restrictions on the Brownlee East Total and Idaho–Northwest transmission paths limit the import of Hells Canyon Complex generation and off-system purchases from the Pacific Northwest.
- The 500-kV Boardman to Hemingway project, expected to be in service in 2016, will significantly increase the capacities of the Brownlee East Total and Idaho–Northwest paths.

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. These 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 full development of the area limited by the land-use plan and other resources of the local area. The plans identify the approximate year the project will be placed in service. Local area plans have been created for four load centers in southern Idaho, 1) eastern Idaho, 2) Magic Valley, 3) Wood River Valley, and 4) Treasure Valley. Development of a fifth plan for the western Treasure Valley and eastern Oregon is in progress.

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 transmission upgrades identified in the Local Area Transmission Advisory Process, the forecasted network customer load (e.g., BPA customers in eastern Oregon and southern Idaho), Idaho Power's retail customer load, and point-to-point transmission customer requirements. By identifying potential resource areas and load-center growth, the required transmission capacity expansions are identified to safely and reliably provide service to customers. The LTP is shared with the sub-regional transmission planning process.

Sub-Regional Transmission Planning

Idaho Power is active in sub-regional transmission planning through the NTTG. NTTG was formed in early 2007 with an overall goal of improving the operation and expansion of the high-voltage transmission system that delivers power to consumers in seven western states. In addition to Idaho Power, other members include Deseret Power Electric Cooperative, NorthWestern Energy, PGE, PacifiCorp (Rocky Mountain Power and Pacific Power), and the Utah Associated Municipal Power Systems (UAMPS). NTTG also relies on a biennial process to develop the sub-regional transmission plan and incorporates the member's biennial local transmission plans. A public stakeholder process evaluates transmission needs as determined by state-mandated IRPs and load forecasts, proposed resource development and generation interconnection queues, and forecast uses of the transmission system by wholesale transmission customers.

Regional Transmission Planning

WECC's Transmission Expansion Planning Policy Committee (TEPPC) serves as the regional transmission planning facilitator in the western United States. Specifically, TEPPC has three distinct functions, 1) oversee data management for the western interconnection, 2) provide policy and management of the planning process, and 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 a regional level, these functions serve to fulfill the requirement to coordinate planning between transmission owners/operators and sub-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. These activities include

regional 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 spans southern Idaho from eastern Oregon 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 earlier in this chapter. Idaho Power's transmission system and paths are shown in Figure 7.1.

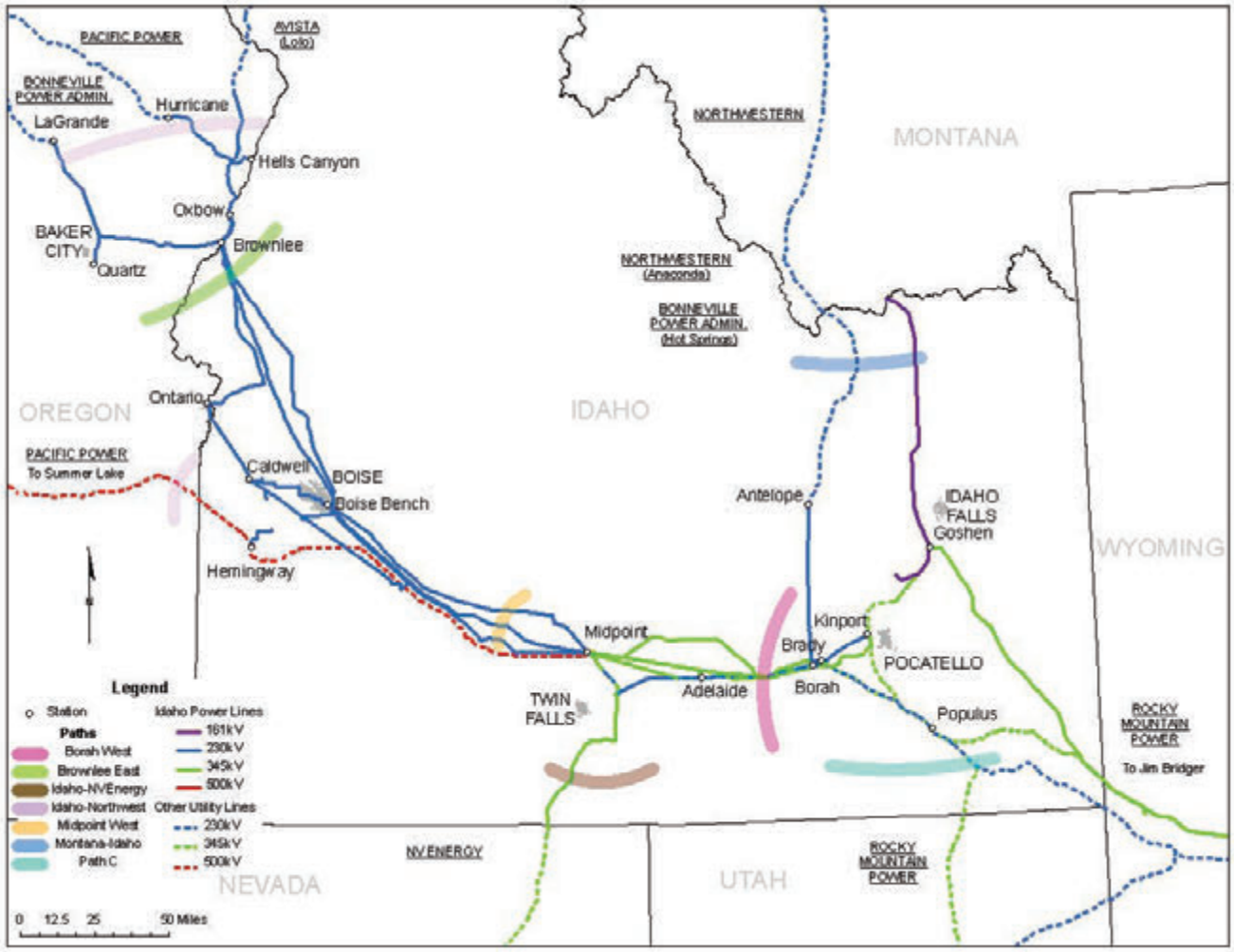


Figure 7.1 Idaho Power transmission system map

The transmission paths identified on the map are described in the following sections, along with descriptions of 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 Hells Canyon Complex and the Pacific Northwest, and the 115-kV interconnection at Harney substation near Burns, Oregon. The Idaho–Northwest path is most likely to be capacity-limited during summer months in low-to-normal water years due to transmission-wheeling obligations for BPA's eastern Oregon and south Idaho loads and energy

imports from the Pacific Northwest to serve Idaho Power's retail load. If new resources, including market purchases, are located west of the path, additional transmission capacity will be required to deliver the energy to eastern Oregon and southern Idaho.

Brownlee East Path

The Brownlee East transmission path is on the east side of the Idaho–Northwest Interconnection shown in Figure 7.1. Brownlee East is comprised of the 230-kV and 138-kV lines east of the Hells Canyon Complex, 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 is located between Brownlee and the Treasure Valley.

The Brownlee East transmission path has different capacity limitations than the Northwest path. The Brownlee East path is most likely to face capacity limitations in the summer during normal-to-high water years. The capacity limitations result from a combination of Hells Canyon Complex hydroelectric generation flowing east into the Treasure Valley, concurrent with transmission-wheeling obligations for BPA's eastern Oregon and southern Idaho loads 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 Hells Canyon Complex, 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 Jefferson–Dillon 161-kV transmission lines. The Idaho–Montana path is also capacity-limited during the summer months as Idaho Power 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 share of energy from the Jim Bridger plant flows over this path, as well as east-side hydroelectric and energy imports from Montana, Wyoming, and Utah. 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 moves east-to-west across the system. Additional transmission capacity will likely be required if new resources, including market purchases, are located east of the path to deliver the energy to the Treasure Valley load center.

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. Capacity on the Midpoint West path is fully subscribed with east-side Idaho Power 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 path to deliver the energy to the Treasure Valley load center.

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 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 Valmy generation plant.

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 operator and owner of all of the transmission lines; however, several of the lines terminate at Idaho Power-owned substations. The path effectively feeds into the Borah West path when power is moving from east-to-west and, consequently, the import capability of Path C is limited by Borah West path capacity limitations.

Table 7.1 Available transmission import capacity

Transmission Path	Total Transmission Capacity*		Available Transmission Capacity (MW)
	Import Direction	Capacity (MW)	
Idaho–Northwest	West-to-East	1,200	0
Idaho–Nevada	South-to-North	262	0
Idaho–Montana	North-to-South	166	0
Brownlee East	West-to-East	1,915	0
Midpoint West	East-to-West	1,027	0
Borah West	East-to-West	2,557	0
Idaho–Utah	South-to-North	1,250	198**

*Total transmission capacity and available transmission capacity as of May 1, 2011.
**Idaho Power estimated value, actual available transmission capacity managed by PacifiCorp.

Transmission Assumptions in the IRP Portfolios

Idaho Power makes resource location assumptions in order to determine the transmission requirements as part of the IRP development process. Regardless of the location, supply-side resources included in the resource stack require local transmission improvements for integration into Idaho Power's system. Additional transmission improvement requirements are dependent on the location and size of the resource. The transmission assumptions and transmission upgrade requirements are summarized in Table 7.2.



The Hemingway substation in southern Idaho is a major hub for power running through Idaho Power's transmission system.

Table 7.2 Transmission assumptions

Resource Type	Geographic Area	Resource levels (per portfolio)	Additional Transmission Requirements
Gas Turbines*	Elmore County	0 MW–150 MW	No upgrades required
		150 MW–325 MW	New 230-kV line into Treasure Valley
		>325 MW	Additional 230-kV line into Treasure Valley
Solar*	Elmore County	0 MW–150 MW	No upgrades required
		150 MW–325 MW	New 230-kV line into Treasure Valley
		>325 MW	Additional 230-kV line into Treasure Valley
CHP	Treasure Valley	0 MW–100 MW	No upgrades required
	Magic Valley	100 MW–200 MW	No upgrades required
Geothermal	Northern Nevada	0 MW–26 MW	No upgrades required
	Cassia County	26 MW–52 MW	No upgrades required
Pumped Storage	Anderson Ranch Reservoir	0 MW–80 MW	No upgrades required
		80 MW–240 MW	New 230-kV line into Treasure Valley

* Because gas and solar resources are assumed to be in the same geographic area, the resource levels and corresponding transmission requirements are cumulative.

The assumptions about the geographic area where particular supply-side resources develop determine the transmission upgrades required. For example, the location of a pumped storage resource listed in Table 7.2 will require a new 230-kV transmission line if sized greater than 80 MW, where other resources of that size may not require such improvements when located in another geographic area. An additional analysis of the transmission requirements was undertaken when these supply-side resources were arranged into portfolios. A transmission plan that provided the required transmission capacity from the new resources to the growing Treasure Valley load center was developed for each portfolio. This analysis of the first 10-year portfolios resulted in each portfolio requiring at least one new 230-kV transmission line into the Treasure Valley.

8. Planning Criteria and Portfolio Selection

Many utilities plan to median, or expected, conditions and then include a reserve margin to cover the 50 percent of the time when conditions are less favorable than median. Idaho Power discussed planning criteria with IPUC and OPUC staff members and the public as part of the 2002 IRP. Out of these discussions came the company's practice of using more stringent planning criteria than median conditions. The planning criteria and planning scenarios are discussed in the following section.



Idaho Power relies on a collaborative process to develop the IRP.

Planning Scenarios and Criteria

The timing and necessity of future generation resources are based on a 20-year forecast of surpluses and deficits for monthly average load and peak-hour load. The 20-year forecast is further divided into two, 10-year periods that coincide with the near-term action plan and the long-term action plan.

The planning criteria for monthly average load planning are 70th percentile water and 70th percentile average load conditions. For peak-hour load conditions, the planning criteria used are 90th percentile water and 95th percentile peak-hour load. The peak-hour analysis is coupled with Idaho Power's ability to import additional energy on its transmission system. Peak-hour load planning criteria are more stringent than average-load planning criteria because Idaho Power's ability to import additional energy is typically limited during peak load periods. The median forecast is no longer used for resource planning but it is used to set retail rates and avoided-cost rates during regulatory proceedings.

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 capacity margin in excess of load while using median load and water conditions. Both approaches are designed to result in a system having generating capacity in reserve for meeting day-to-day operating reserve requirements.

To identify the need and timing of future resources, Idaho Power prepares a load and resource balance, which accounts for generation from all the company's existing resources and planned purchases. The updated load and resource balance showing Idaho Power's existing and committed resources for

Highlights

- Idaho Power uses 70th percentile average load and 70th percentile water conditions for energy planning.
- For peak-hour capacity planning, Idaho Power uses 90th percentile water conditions and 95th percentile peak-hour loads.
- Growth in summertime peak-hour demand continues to drive Idaho Power's needs for additional resources.

average energy and peak-hour load is shown in *Appendix C–Technical Appendix.*

Average Monthly Energy Planning

Average energy surpluses and deficits are determined using 70th percentile water and 70th percentile average load conditions, coupled with Idaho Power's ability to import energy from firm market purchases using reserved network capacity. Figure 8.1 shows the monthly average energy surpluses and deficits with existing and committed resources. The energy positions shown in Figure 8.1 also include the forecast impact of existing DSM programs, the current level of PURPA development, existing PPAs, firm Pacific Northwest import capability, and the expected generation from all Idaho Power-owned resources, including Langley Gulch and the Shoshone Falls upgrade once they are available. Figure 8.1 illustrates that, starting in July 2018, monthly average energy deficit positions grow steadily in magnitude and number of months affected. By July 2030, these energy deficits exceed 600 aMW.

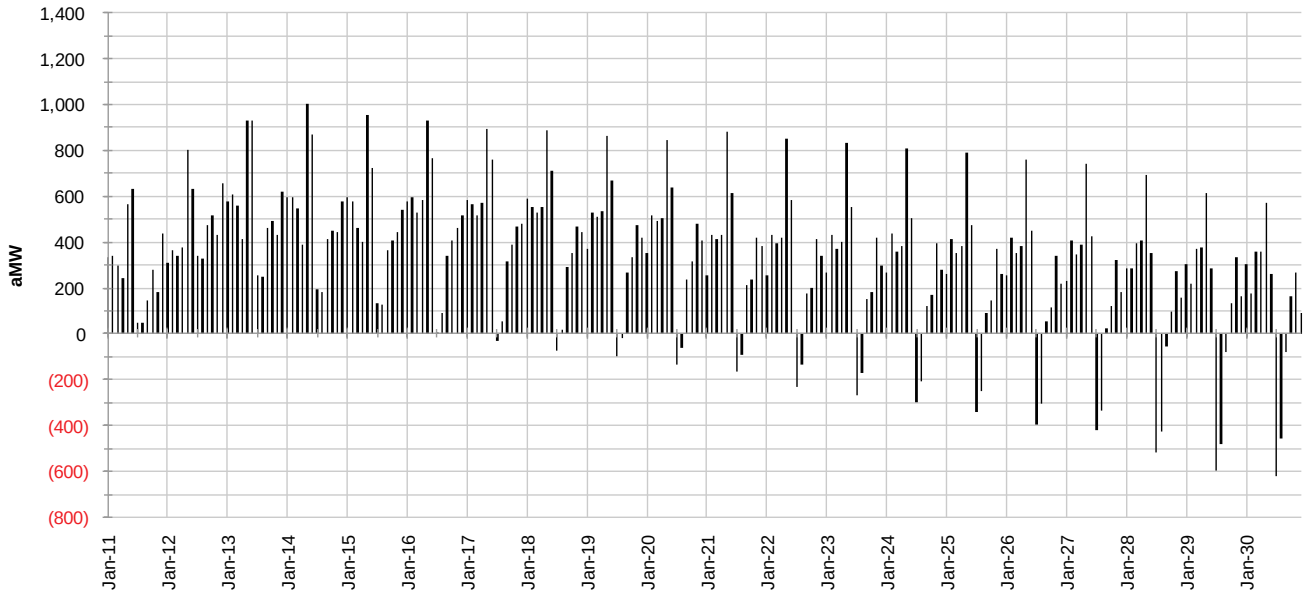


Figure 8.1 Monthly average energy surpluses and deficits with existing and committed resources and existing DSM (70th percentile water and 70th percentile load)

Idaho Power is committed to implementing all cost-effective energy efficiency programs in the IRP prior to evaluating supply-side resource options. Figure 8.2 shows the monthly average energy surplus and deficit data from Figure 8.1 with the addition of all new cost-effective energy efficiency. With the new energy efficiency programs accounted for, monthly average energy deficits in 2030 are reduced to approximately 550 aMW.

Energy deficits are eliminated by designing portfolios containing new resources that are analyzed in the IRP. However, Idaho Power's resource needs have historically been driven by the need for additional summertime peak-hour capacity rather than additional energy, as this is the case in the 2011 IRP.

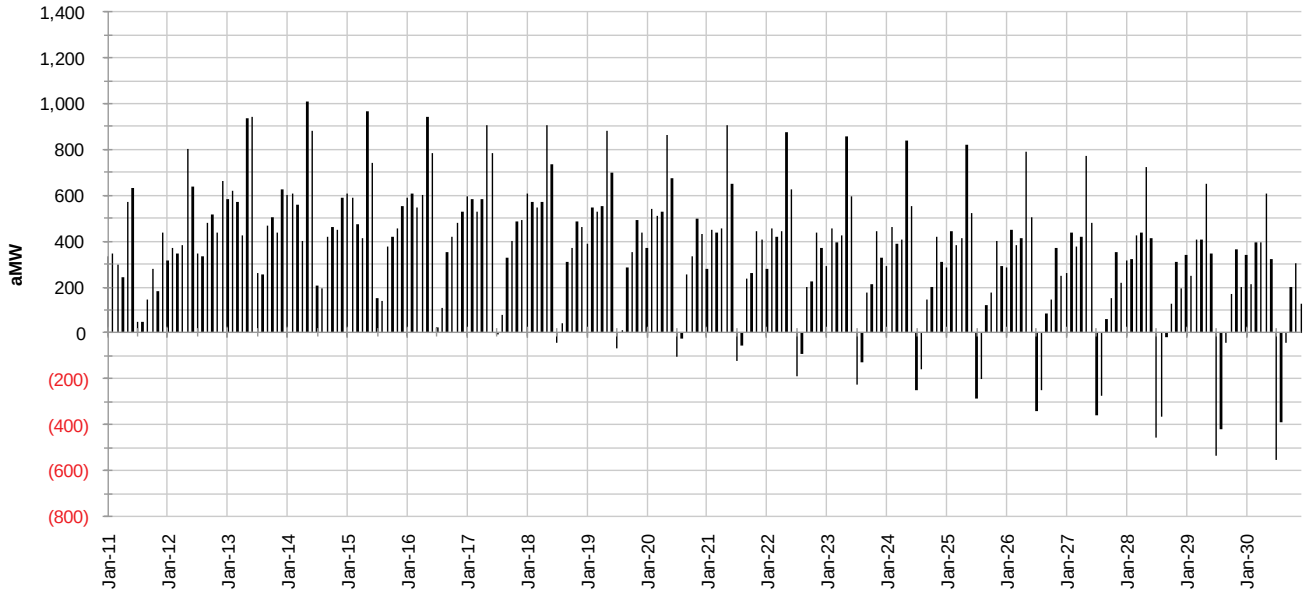


Figure 8.2 Monthly average energy surpluses and deficits with new DSM (70th percentile water and 70th percentile load)

Peak-Hour Planning

Peak-hour load deficits are determined using 90th percentile water and 95th percentile peak-hour load conditions. In addition to these criteria, 70th percentile average load conditions are assumed, but the hydrologic and peak-hour load criteria are the major factors in determining peak-hour load deficits. Peak-hour load planning criteria are more stringent than average-energy criteria because Idaho Power's ability to import additional energy is typically limited during peak-hour load periods.

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

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

Figure 8.3 shows the monthly peak-hour deficits with existing and committed resources. The capacity positions shown in Figure 8.3 also include the forecast impact of existing DSM programs, the current level of PURPA development, existing PPAs, firm Pacific Northwest import capability, and the expected generation from all Idaho Power-owned resources, including Langley Gulch and the Shoshone Falls upgrade once they are available.

A deficit of approximately 100 MW in September 2011 highlights the need for the Langley Gulch CCCT plant as demand response programs are not available in the month of September. Idaho Power is actively managing this near-term deficit in accordance with its *Energy Risk Management Policy and*

Standards. Starting in July 2015, monthly peak-hour deficit positions grow steadily in magnitude and number of months affected. By July 2030, these capacity deficits are approximately 1,300 MW.

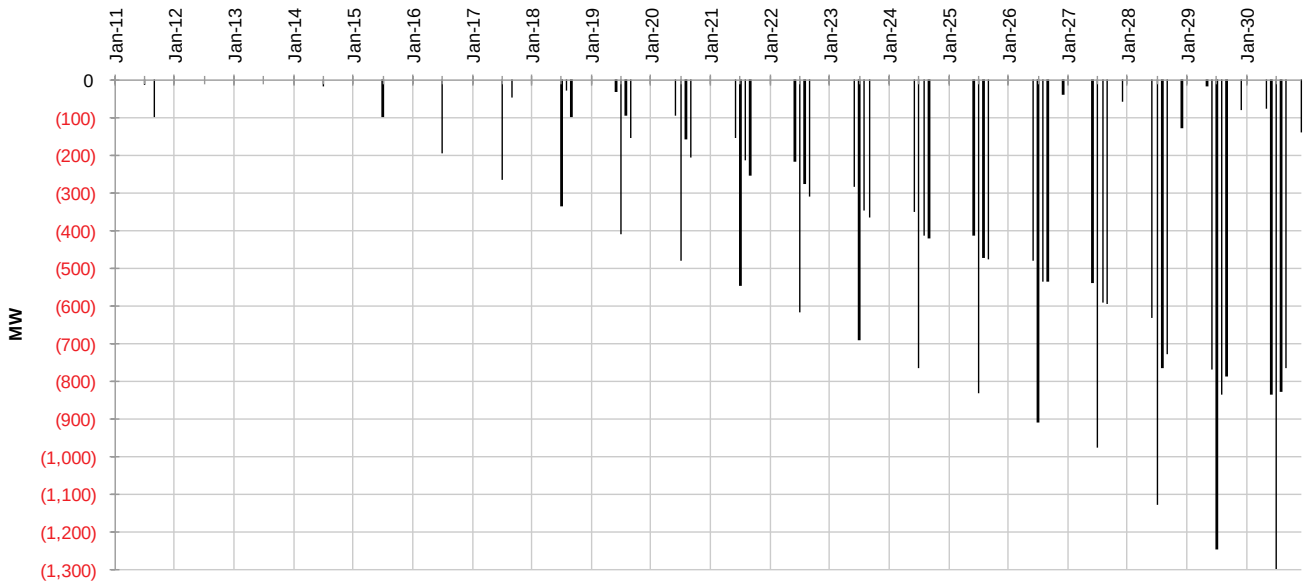


Figure 8.3 Monthly peak-hour deficits with existing and committed resources and existing DSM (90th percentile water and 95th percentile load)

As discussed in Chapter 4, the evaluation of demand response programs was switched from an "all cost-effective DSM" approach to a "needs-based" approach in the 2011 IRP. The new method was designed to identify annual levels of demand response needed to delay the addition of new supply-side peaking resources until the capacity of a SCCT would be greater than the seasonal limitations on demand response programs. Figure 8.4 shows the monthly peak-hour deficit data from Figure 8.3 with the addition of all new DSM under this methodology. With the new DSM accounted for, monthly peak-hour deficits in 2030 are reduced to approximately 1,230 MW.

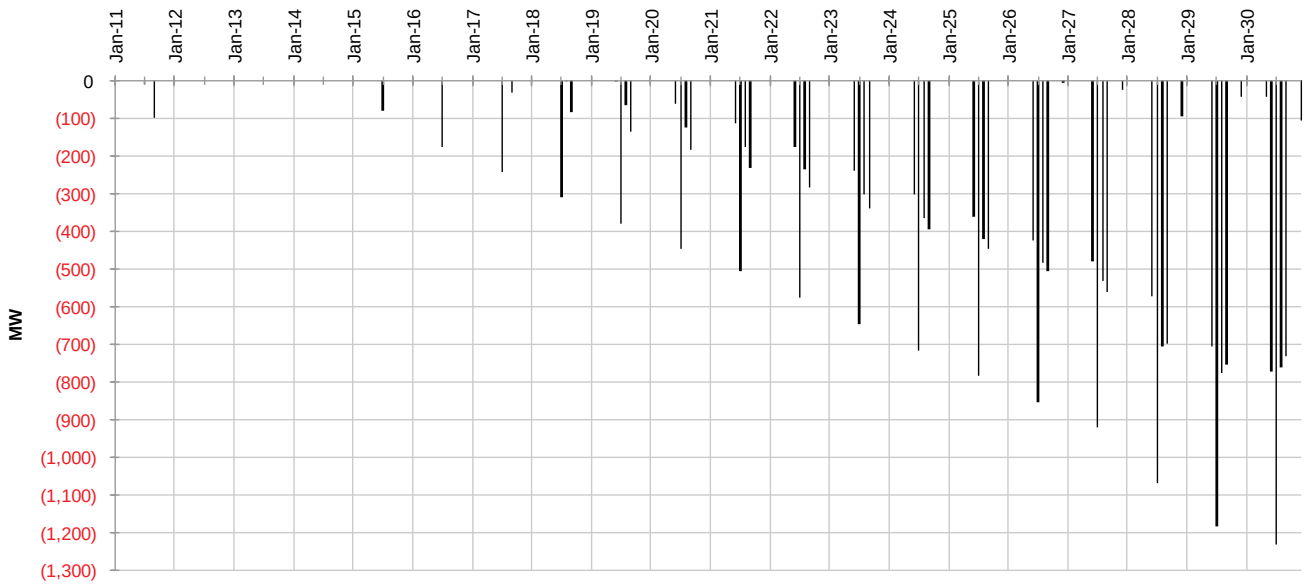


Figure 8.4 Monthly peak-hour deficits with new DSM (90th percentile water and 95th percentile load)

Capacity and energy deficits are eliminated by designing portfolios containing new resources that are analyzed in the IRP. Because Idaho Power's resource needs are driven by the need for additional

summertime peak-hour capacity rather than additional energy, the deficits identified in Figure 8.4 were used to design the portfolios analyzed in the 2011 IRP. In addition to eliminating the peak-hour deficits identified in Figure 8.4, the initial resource portfolios described in the next section also eliminated the energy deficits identified in Figure 8.2.

Portfolio Design and Selection

The 2011 IRP portfolio development strategy divides the study period into two, 10-year periods, 2011–2020 and 2021–2030. Resource portfolios in each 10-year period are designed to satisfy the energy and peak-hour deficits shown in the load and resource balance.

Idaho Power also believes a federal RES will be enacted in the near future, and each portfolio is designed to substantially comply with the RES provisions contained in the *Renewable Electricity Promotion Act of 2010* (S. 3813) introduced in Congress in September 2010, by Senator Jeff Bingaman (D–New Mexico). Under the proposed bill, an initial renewable requirement of 3 percent would begin in 2012 and would increase to 15 percent by 2021.

First 10 Years (2011–2020)

The first 10-year planning period has significant committed resources, including the Langley Gulch CCCT and the Shoshone Falls upgrade. These committed resources are treated as existing resources for the purpose of analyzing each portfolio of new resources. The capital cost of these committed resources is not included in the comparison between portfolios.

For the first 10-year period, the 2011 IRP analyzed nine different resource portfolios. The new resources shown are designed to reduce previously discussed deficits and to meet proposed RES requirements. A summary of the resource portfolios analyzed for the first 10 years of the planning horizon is shown in Figure 8.5, and a description of each portfolio follows.

1-1 Sun & Steam		1-2 Solar		1-3 B2H		1-4 SCCT		1-5 CCCT	
2011		2011		2011		2011		2011	
2012	Solar PV-1	2012		2012		2012		2012	
2013	Solar PV-5	2013		2013		2013		2013	
2014	CHP-75	2014	Solar PV-5	2014		2014		2014	
2015	Solar PV-30	2015	Solar PT-100	2015	Eastside Purchase	2015	SCCT Frame	2015	CCCT
2016	CHP-100	2016	Solar PT-100	2016	B2H-450	2016		2016	
2017	Geothermal-52	2017	Solar PT-125	2017		2017	SCCT Frame	2017	
2018	Solar PT-125	2018	Solar PV-50	2018		2018		2018	
2019	Solar PV-30	2019	Solar PT-100	2019		2019	SCCT S Aero-94	2019	SCCT Frame
2020	Solar PT-75	2020	Solar PV-50	2020		2020		2020	
MW	**493**	**MW**	**530**	**MW**	**450**	**MW**	**434**	**MW**	**470**

1-6 CHP		1-7 Balanced		1-8 Pumped Storage		1-9 Distributed Gen	
2011		2011		2011		2011	
2012		2012		2012		2012	Dist Gen-10
2013		2013		2013		2013	
2014		2014		2014		2014	
2015	CHP-100	2015	CHP-100	2015	Pump St-80	2015	SCCT Frame
2016	SCCT Frame	2016	SCCT Frame	2016	SCCT Frame	2016	
2017		2017	Solar PV-10	2017		2017	SCCT Frame
2018	CHP-50	2018	Solar PT-100	2018	Pump St-80	2018	
2019	CHP-50	2019	Geothermal-26	2019	SCCT S Aero-47	2019	SCCT S Aero-94
2020	SCCT S Aero-94	2020	SCCT S Aero-47	2020	Pump St-80	2020	
MW	**464**	**MW**	**453**	**MW**	**457**	**MW**	**444**

Figure 8.5 Initial resource portfolios (2011–2020)

- **1-1 Sun and Steam**—This resource portfolio was designed by IRPAC members as a result of a portfolio design workshop held by Idaho Power. The portfolio consists of a mixture of solar PV and

power tower resources with geothermal and CHP. The purpose of this portfolio is to evaluate the cost of an all-renewable portfolio. The total nameplate capacity of this portfolio is 493 MW.

- **1-2 Solar—**This resource portfolio includes a mixture of solar PV and power tower resources and is designed to test the performance of a portfolio consisting entirely of solar resources. The total nameplate capacity of this portfolio is 530 MW.
- **1-3 Boardman to Hemingway—**This resource portfolio includes the Boardman to Hemingway transmission line project is anticipated to be available in 2016. A more expensive market purchase on the east side of Idaho Power's system was needed to meet a peak-hour deficit in the summer of 2015 prior to the Boardman to Hemingway line becoming available. The total nameplate capacity of this portfolio is 450 MW.
- **1-4 SCCT**—This resource portfolio includes three SCCT's—two industrial-frame units and two small aeroderivative units (47 MW each). The purpose of this portfolio is to compare the cost of market purchases on the Boardman to Hemingway line against building gas-peaking capacity near load. The total nameplate capacity of this portfolio is 434 MW.
- **1-5 CCCT—**This resource portfolio includes one CCCT and one SCCT. Like portfolio 1-4, the purpose of this portfolio is to compare the cost of market purchases on the Boardman to Hemingway line against building baseload gas capacity near load. The total nameplate capacity of this portfolio is 470 MW.
- **1-6 CHP—**This resource portfolio includes a mixture of CHP resources with two SCCTs. The purpose of this portfolio is to compare the cost of CHP resources to the cost of CCCT and SCCT technologies. The total nameplate capacity of this portfolio is 464 MW.
- **1-7 Balanced**—This resource portfolio includes a mixture of CHP, SCCTs, geothermal, and solar resources. The purpose of this portfolio is to evaluate the cost of a balanced and diversified portfolio. The total nameplate capacity of this portfolio is 453 MW.
- **1-8 Pumped Storage—**This resource portfolio includes a mixture of pumped storage resources and SCCTs. The purpose of this portfolio is to compare the cost of pumped storage to other resource alternatives. The total nameplate capacity of this portfolio is 457 MW.
- **1-9 Distributed Generation—**This resource portfolio is identical to portfolio 1-4 SCCT with the exception that it includes a 10-MW distributed generation resource. The purpose of this portfolio is to evaluate the cost and value of the proposed distributed generation program. Additional details on the distributed generation program can be found in Chapter 5. The total nameplate capacity of this portfolio is 444 MW.

Second 10 Years (2021–2030)

For the second 10-year period, the 2011 IRP analyzed 10 different resource portfolios. The second 10-year planning period is more of an academic exercise than the first 10-year period, where resources are identified that will require a financial commitment. The new resources shown are designed to reduce previously discussed deficits and to meet proposed RES requirements. A summary of the resource portfolios analyzed for the second 10 years of the planning horizon is shown in Figure 8.6, and a description of each portfolio follows.

2-1 Nuclear		2-2 IGCC		2-3 SCCT/Wind		2-4 CCCT/Wind		2-5 Hydro/CHP	
2021	Solar PT-100	2021	Geothermal-52	2021	SCCT S Aero-141	2021	CCCT	2021	Hydro Sm-60
2022	Pump St-50	2022	SCCT Frame	2022	Wind-100	2022	Wind-150	2022	CHP-75
2023	Solar PT-100	2023		2023	SCCT S Aero-141	2023		2023	Pump St-80
2024	Nuclear	2024	CHP-50	2024	Wind-100	2024		2024	CHP-100
2025		2025	Solar PT-75	2025	SCCT S Aero-94	2025		2025	Hydro-40
2026		2026	IGCC w/CS	2026	Wind-100	2026	CCCT	2026	Pump St-80
2027		2027		2027	SCCT S Aero-141	2027		2027	Hydro Sm-100
2028	Nuclear	2028	Solar PT-75	2028	SCCT S Aero-141	2028	Wind-150	2028	SCCT S Aero-141
2029	Pump St-50	2029		2029	SCCT S Aero-94	2029	SCCT Frame	2029	Hydro Sm-80
2030		2030		2030		2030		2030	Hydro Sm-60
MW	**800**	**MW**	**802**	**MW**	**1,052**	**MW**	**1,070**	**MW**	**816**

2-6 Balanced 1		2-7 Balanced 2		2-8 PNW Transmission		2-9 E/S Transmission		2-10 Renewable	
2021	Geothermal-52	2021	Geothermal-52	2021	Geothermal-52	2021	Geothermal-52	2021	CHP-75
2022	SCCT Frame	2022	CHP-75	2022	PNW Purchase	2022	E/S Purchase	2022	Pump St-80
2023		2023	SCCT Frame	2023		2023		2023	Solar PT-150
2024	Solar PT-50	2024		2024		2024		2024	
2025	CCCT	2025	Geothermal-52	2025		2025		2025	CHP-75
2026		2026	CHP-75	2026		2026		2026	Solar PT-150
2027		2027	Hydro Sm-60	2027	Solar PV-20	2027	Solar PV-20	2027	Solar PV-150
2028	Hydro Sm-60	2028	CCCT	2028	Geothermal-52	2028	Geothermal-52	2028	Geothermal-52
2029	SCCT Frame	2029		2029	SCCT Frame	2029	SCCT Frame	2029	Hydro Sm-100
2030		2030		2030		2030		2030	Solar PV-200
MW	**802**	**MW**	**784**	**MW**	**794**	**MW**	**794**	**MW**	**1,032**

Figure 8.6 Initial resource portfolios (2021–2030)

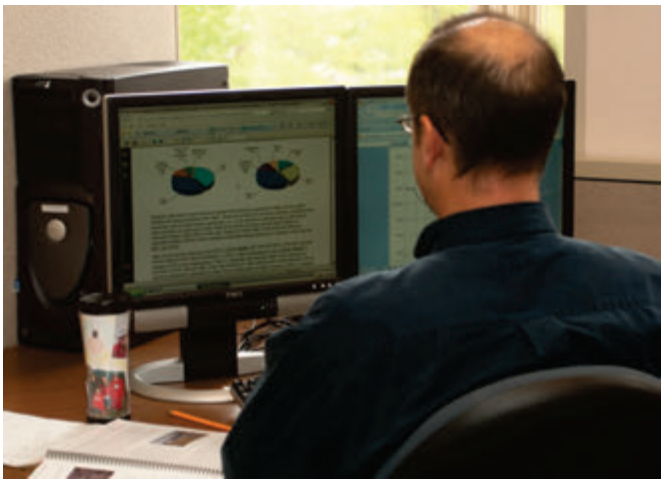
- **2-1 Nuclear—**This resource portfolio includes a mixture of pumped storage and solar resources combined with 500 MW of nuclear resources. The purpose of this portfolio is to evaluate the cost of the advanced nuclear technology against other resource alternatives. The total nameplate capacity of this portfolio is 800 MW.
- **2-2 IGCC**—This resource portfolio includes a mixture of geothermal, solar, CHP, and SCCT resources combined with a 380-MW IGCC resource. The purpose of this portfolio is to evaluate the cost of the IGCC technology against other resource alternatives. The total nameplate capacity of this portfolio is 802 MW.
- **2-3 SCCT/Wind—**This resource portfolio includes a combination of wind and SCCT resources. The purpose of this portfolio is to evaluate the cost of a portfolio that contains wind resources that supply energy and RECs and gas peaking units that provide capacity. The total nameplate capacity of this portfolio is 1,052 MW.
- **2-4 CCCT/Wind**—This resource portfolio includes a combination of wind and CCCT resources. The purpose of this portfolio is to evaluate the cost of a portfolio that contains wind resources that supply energy and RECs and gas baseload resources that provide capacity and energy. The total nameplate capacity of this portfolio is 1,070 MW.
- **2-5 Hydro/CHP—**This resource portfolio includes a combination of small hydroelectric, pumped storage, CHP and SCCT resources. The purpose of this portfolio is to evaluate the cost of a portfolio that contains hydroelectric and CHP resources. The total nameplate capacity of this portfolio is 816 MW.
- **2-6 Balanced 1—**This resource portfolio includes a mixture of geothermal, solar, small hydroelectric, and SCCT resources. The purpose of this portfolio is to evaluate the cost of a balanced and diversified portfolio. The total nameplate capacity of this portfolio is 802 MW.

- **2-7 Balanced 2—**This resource portfolio includes a mixture of geothermal, CHP, small hydroelectric, and SCCT resources. The purpose of this portfolio is to evaluate the cost of a balanced and diversified portfolio. The total nameplate capacity of this portfolio is 784 MW.
- **2-8 PNW Transmission—**This resource portfolio includes a mixture of geothermal, solar, and an SCCT resource combined with an additional 500 MW of transmission capacity to the Pacific Northwest. The purpose of this portfolio is to evaluate the cost of a portfolio that substantially relies on increased market purchases from the Pacific Northwest. The total nameplate capacity of this portfolio is 794 MW.
- **2-9 Eastside Transmission—**This resource portfolio includes a mixture of geothermal, solar, and an SCCT resource combined with an additional 500 MW of transmission capacity across southern Idaho and into Wyoming. The purpose of this portfolio is to evaluate the cost of a portfolio that substantially relies on market purchases from the east side of Idaho Power's system. The total nameplate capacity of this portfolio is 794 MW.
- **2-10 Renewable—**This resource portfolio was designed by IRPAC members as a result of a portfolio design workshop held by Idaho Power. The portfolio consists of a mixture of solar PV and power tower resources, geothermal, CHP, small hydroelectric, and pumped-storage resources. The purpose of this portfolio is to evaluate the cost of an all-renewable portfolio. The total nameplate capacity of this portfolio is 1,032 MW.

Details on how the portfolios were modeled and the assumptions used in the analysis are provided in Chapter 9. Chapter 9 also presents the risk analysis and the process that lead to the selection of a preferred and alternate portfolio for each 10-year period.

9. MODELING ANALYSIS AND RESULTS

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.



Computer modeling is an essential part of preparing the IRP.

The AURORA software applies economic principles and dispatch simulation 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 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 detail 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.

Economic Evaluation Components and Assumptions

The total cost of each portfolio analyzed for the IRP is determined by four components: 1) variable operating costs (determined with AURORA), 2) the capital cost of new resources in each portfolio,

Highlights

- Idaho Power uses the AURORA Electric Market Model as the primary tool for determining future resource build out of operations and portfolio cost impacts for the 20-year IRP planning period.
- The 2011 IRP incorporates anticipated federal RES legislation and plans for the resources necessary to comply with the legislation.
- Quantitative risk factors analyzed in the 2011 IRP include the cost of carbon emissions, natural gas prices, capital cost, load growth, DSM program performance, REC prices, electric market prices, and third-party transmission subscription.

3) the cost of transmission upgrades necessary for each portfolio, and 4) the value of RECs generated by renewable resources in each portfolio. In addition, numerous financial assumptions are necessary to calculate the total portfolio cost. The financial assumptions used in the 2011 IRP are shown in Table 9.1.

Table 9.1 Financial assumptions

Plant Operating (Book) Life	30 Years
Discount rate (weighted average cost of capital)	7.00%
Composite tax rate	39.10%
Deferred rate	35.00%
General O&M escalation rate	3.00%
Emissions adder escalation rate	2.50%
Carbon adder escalation rate	5.00%
Annual property tax escalation rate (% of investment)	0.29%
Property tax escalation rate	3.00%
Annual insurance premium (% of investment)	0.31%
Insurance escalation rate	2.00%
AFUDC rate (annual)	7.00%
Production tax credit escalation rate	3.00%

AURORA Modeling

Idaho Power uses the AURORA model to evaluate the variable cost of production for existing and committed resources along with the new resources proposed in the portfolios. Operational constraints are approximated along with energy purchases and sales in the regional market. While more extreme planning criteria are used to determine the average energy and peak-hour capacity of existing resources in the load and resource balance, median or 50th percentile conditions are used in AURORA for modeling load and hydroelectric generation. The following sections describe additional variable operating costs also included in the analysis.

Carbon Cost

The potential cost of carbon emissions is accounted for in the IRP by applying a carbon adder or tax. The carbon adder is applied to all carbon-emitting resources within the WECC starting in 2015. Including the carbon adder cost for all carbon-emitting resources in the AURORA model results in market prices that reflect the anticipated future cost of carbon emissions. Therefore, the cost of carbon emissions is captured for specific resources and in the price of market purchases and sales.

The carbon adder increases the dispatch cost of each carbon-emitting resource in AURORA, which affects how the model economically dispatches resources. Once a unit is dispatched, the carbon adder can also affect how much generation is produced from each unit. Past experience shows the carbon adder has to be very large to completely curtail units; however, smaller carbon adders reduce generation compared to a similar unit with no carbon adder. Additional details on the carbon adder and the values used for the high, expected, low and no carbon scenarios can be found in Chapter 6.

Transmission Modeling

The need for additional power from new resources or market purchases will require additional transmission. Idaho Power faces severe transmission capacity limitations when evaluating additional supply-side resources. These transmission limitations were a major factor in evaluating supply-side resources, such as Bennett Mountain, Danskin, the Elkhorn Valley Wind Project, and Langley Gulch in previous IRPs.

The 2011 IRP uses different transmission assumptions for each of the 10-year periods. For the first 10-year period, transmission capacity is increased only to the extent necessary to deliver the energy from the new resources to the Treasure Valley in southwest Idaho. Idaho Power has adopted a conservative approach for the first 10 years and includes additional transmission capacity for market purchases only when market-need is specifically identified in a resource portfolio.

For the second 10-year period, transmission capacity identified in the preferred portfolio from the first 10-year period is included, plus any additional transmission necessary for each resource portfolio in the second 10-year period.

Natural Gas Transportation Cost

For the 2011 IRP analysis, the cost of gas transportation for existing resources, including the Langley Gulch project, is based on the cost of existing pipeline capacity. Because existing pipeline capacity is close to being fully utilized, the transportation cost for new gas resources reflects the cost of adding additional pipeline capacity for delivery to Idaho Power's service area.

The increased cost for new pipeline capacity is approximately twice the current tariff rate. For the IRP, the additional cost for new pipeline capacity was added to the cost of each new gas resource outside the AURORA model. Additional details on transportation costs can be found in *Appendix C–Technical Appendix.* The natural gas price forecast described in Chapter 6 is based on a Sumas hub price and does not include any transportation cost.

Capital Cost

Idaho Power uses an internal financial analysis model to evaluate the capital cost of new resources and to estimate the associated revenue requirements. Estimated construction costs are escalated at the base inflation rate of 3 percent per year and included in the model.

Estimated capital costs are translated into an annual revenue requirement that corresponds to the size and timing of the investment required for each resource. The annual revenue requirement for each resource portfolio is then discounted and summed. The annual revenue requirement analysis has the benefit of matching the annual revenue requirements with the corresponding annual energy benefits. The annual revenue requirement analysis eliminates the need to estimate resource values beyond the study period because resource capital costs and resource benefits are matched annually within the study period.

Transmission Cost

For the IRP, the total estimated transmission cost of each resource portfolio is used to determine the annual transmission revenue requirement, and the NPV of the cost is included in the portfolio evaluation. A more detailed presentation of the transmission assumptions for each portfolio can be found in *Appendix C–Technical Appendix.*

The degree of Idaho Power's investment participation differs between the portfolios, and the costs are included according to the transmission subscription in each resource portfolio. Each transmission subscription represents an Idaho Power equity investment in the project. Each equity investment translates into a revenue requirement, and the revenue requirements for the transmission investments are estimated and included in the portfolio total cost comparisons. Idaho Power's investment defines the revenue requirement, and the NPV of the revenue requirement is included as part of the expected-case cost of each resource portfolio. The NPV of any possible transmission capacity sales to third parties are included in the risk analysis as project benefits.

Two categories of transmission are accounted for in the IRP. The first is the transmission that integrates resources and allows energy to flow from a generation resource to Idaho Power's load centers.

An example of this type of transmission are the transmission lines that deliver generation from the Hells Canyon Complex to the load center in the Treasure Valley.

Interstate transmission is the second transmission type and is generally higher voltage and covers greater distances. Interstate transmission is planned on a regional basis to meet the needs of electric utilities and the needs of third parties requesting transmission service. Very little interstate transmission has been constructed in the last 30 years. Examples of interstate transmission include the proposed Gateway West and Boardman to Hemingway projects.

In the first 10-year portfolios (2011–2020), only portfolio 1-3 Boardman to Hemingway included a proposed interstate transmission project. This was the Boardman to Hemingway project with an on-line date of 2016 and Idaho Power's share of the line at 450 MW. For the second 10-year period (2021–2030), all the portfolios assume that the preferred portfolio 1-3 Boardman to Hemingway is built, and only portfolios 2-8 Pacific Northwest Transmission and 2-9 Eastside Transmission included additional interstate transmission projects. In portfolio 2-8 Pacific Northwest Transmission, Idaho Power adds 500 MW of additional capacity between Idaho and the Pacific Northwest in 2022. In portfolio 2-9 Eastside Transmission, the Gateway West project is built in 2022, allowing Idaho Power to have an additional 500 MW of transmission capacity for market purchases from the east side of Idaho Power's service area.

Renewable Energy Certificates

For the 2011 IRP analysis, each portfolio is designed to substantially comply with the *Renewable Electricity Promotion Act of 2010* (S. 3813) introduced in Congress in September 2010, by Senator Jeff Bingaman (D–New Mexico). Under the proposed bill, an initial renewable requirement of 3 percent would begin in 2012 and would increase to 15 percent by 2021.

Because it is impossible to exactly match the number of RECs Idaho Power would need to meet this requirement with the amount of RECs created by individual resources, the value of additional RECs and the cost of purchasing RECs if short is captured in the total cost of each portfolio. With the exception of portfolio 2-4 CCCT & Wind, all the portfolios analyzed had a net benefit from the value of surplus RECs. This value is shown as a negative cost in Tables 9.2 and 9.3. The forward price curve for RECs used in the analysis is presented in Chapter 6.

Expected-Case Portfolio Analysis Results

The NPV total portfolio cost is calculated by summing the variable operating costs calculated in AURORA, the capital and transmission costs, and the value of RECs from each portfolio. The expected-case NPV total portfolio cost of each of the portfolios analyzed for the first 10-year period are shown in Table 9.2.

Under expected case conditions, for the first 10-year period, portfolio 1-3 Boardman to Hemingway is the lowest cost portfolio at $3.18 billion, while portfolio 1-4 SCCT is the second lowest at $3.22 billion. These results are similar to the results of the 2009 IRP analysis where the Boardman to Hemingway project was evaluated against a portfolio of SCCT resources that could be built close to load centers.

Table 9.2 Expected case total portfolio cost (2011–2020)

	NPV Portfolio Costs (2011 dollars, 000's)				
Base Case	**Variable (AURORA)**	**Capital**	**Transmission**	**RECs**	**Total**
1-1 Sun & Steam	$3,041,735	$552,164	$17,925	($24,396)	**$3,587,428**
1-2 Solar	$2,924,308	$683,497	$20,865	($32,033)	**$3,596,637**
1-3 Boardman to Hemingway	$3,088,318	$0*	$98,929	($9,940)	**$3,177,308**
1-4 SCCT	$3,099,029	$108,835	$22,748	($9,940)	**$3,220,672**
1-5 CCCT	$3,115,384	$188,415	$19,546	($9,940)	**$3,313,406**
1-6 CHP	$3,162,397	$190,436	$15,798	($9,940)	**$3,358,691**
1-7 Balanced	$3,085,533	$293,344	$16,349	($15,384)	**$3,379,843**
1-8 Pumped Storage	$3,093,051	$416,887	$23,099	($15,206)	**$3,517,831**
1-9 Distributed Generation	$3,099,323	$114,153	$22,748	($9,940)	**$3,226,284**

*Portfolio 1-3 Boardman to Hemingway capital cost is included in the transmission column.

Table 9.3 shows the NPV total cost of each portfolio analyzed for the second 10-year period. Under expected-case conditions, the NPV cost of portfolios 2-8 Pacific Northwest Transmission and 2-9 Eastside Transmission are close at $3.30 billion and $3.32 billion respectively. Portfolio 2-6 Balanced 1 is the next lowest-cost portfolio at $3.50 billion.

Table 9.3 Expected case total portfolio cost (2021-2030)

	NPV Portfolio Costs (2011 dollars, 000's)				
Base Case	**Variable (AURORA)**	**Capital**	**Transmission**	**RECs**	**Total**
2-1 Nuclear	$2,548,176	$1,806,082	$25,300	($713)	$4,378,845
2-2 IGCC	$2,665,714	$958,555	$59,523	($2,908)	$3,680,885
2-3 SCCT & Wind	$3,079,453	$515,846	$27,147	($2,545)	$3,619,901
2-4 CCCT & Wind	$3,095,043	$498,966	$26,688	$246	$3,620,943
2-5 Hydro & CHP	$3,014,673	$880,443	$27,622	($6,669)	$3,916,069
2-6 Balanced 1	$2,937,689	$555,581	$10,646	($2,646)	$3,501,270
2-7 Balanced 2	$2,952,566	$668,771	$10,849	($8,840)	$3,623,346
2-8 Pacific Northwest Transmission*	$2,933,037	$335,516	$29,278	($1,773)	$3,296,059
2-9 Eastside Transmission*	$2,929,353	$335,516	$53,373	($1,773)	$3,316,469
2-10 Renewable	$2,910,691	$1,112,624	$10,504	($11,537)	$4,022,282

*2-8 Pacific Northwest Transmission and 2-9 Eastside Transmission capital costs are included in the transmission column.

Portfolio Carbon Emissions

Figure 9.1 shows the average CO_2 intensity for each portfolio analyzed for the first 10-year period. The average intensity for each portfolio includes emissions from new resources in addition to emissions from Idaho Power's existing and committed resources. The intensity rates range from approximately 775 lbs-per-MWh to 805 lbs-per-MWh and are all well below Idaho Power's 2005 intensity rate of 1,194 lbs-per-MWh.

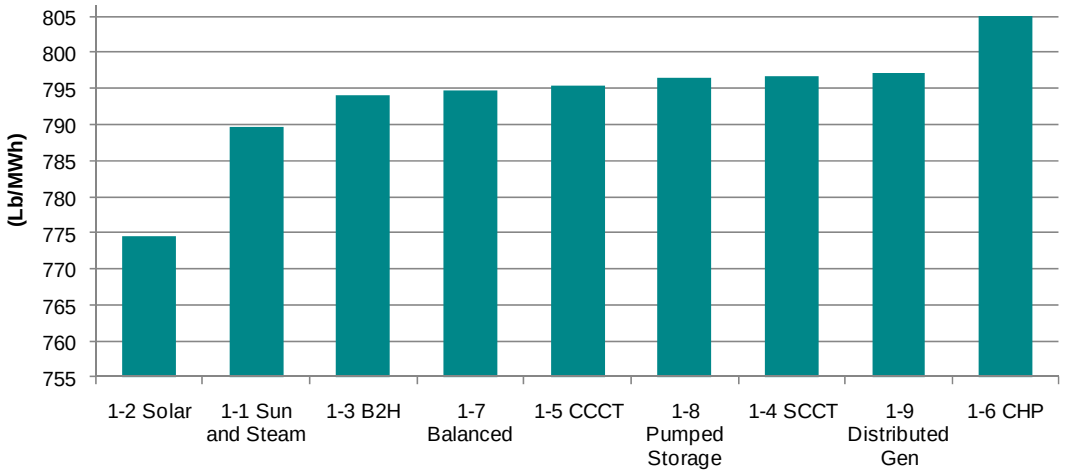


Figure 9.1 Average CO_2 intensity by portfolio (2011–2020)

Figure 9.2 shows similar information for the portfolios analyzed for the second 10-year period, which assumes portfolio 1-3 Boardman to Hemingway is built. The intensity rates range from approximately 660 lbs-per-MWh to 745 lbs-per-MWh, which shows a further reduction from the portfolios analyzed in the first 10-year period.

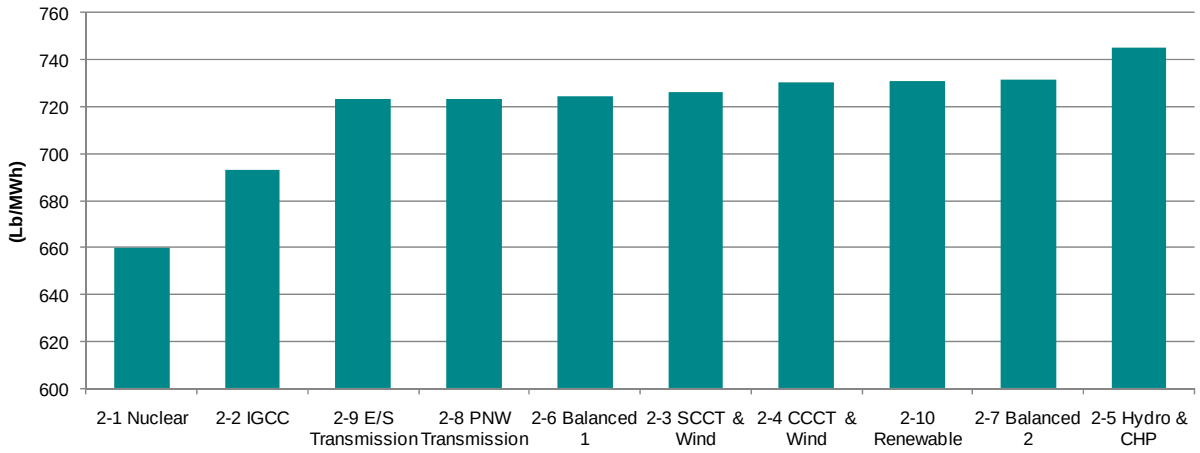


Figure 9.2 Average CO_2 intensity by portfolio (2021–2030)

The lower emissions intensity rates presented in Figures 9.1 and 9.2 are the result of the carbon adder used in the IRP analysis in addition to the reduced operation of Idaho Power's coal resources at times when market prices are lower than the dispatch cost of the coal resources. These results also indicate a majority of the risk associated with the future regulation of carbon is related to Idaho Power's existing resources.

Risk Analysis and Results

Idaho Power evaluated all the resource portfolios identified in the 2011 IRP for both qualitative and quantitative risks. Risk analysis identifies resource portfolios that perform well in a variety of possible future scenarios and to reduce total risk.

One of the major risks is load-growth uncertainty associated with the present economic conditions. Economic growth has slowed considerably in Idaho Power's service area, and there has been extensive speculation regarding the duration of the economic downturn. A quick return to the economic growth rates of the past 20 years will require additional generation resources to meet load.

The other factor affecting load growth is the effectiveness of Idaho Power's DSM programs. Idaho Power projects continued success with DSM programs, but the success is dependent on overall economic conditions as well as program funding and consumer preferences. A lower realization factor for DSM programs will increase load and require additional generation resources.

Electric vehicles are another factor having the potential to increase load. Study reports completed by the Electric Power Research Institute (EPRI) and Oak Ridge National Laboratory were used to estimate load impacts associated with electric-vehicle charging. The impact on the load forecast is assumed to be relatively small—about 9 aMW in 2020, reaching 43 aMW at the end of the forecast period in 2030. Further discussion on electric vehicles is contained in *Appendix A–Sales and Load Forecast.*

Many of the other risk factors are regulatory in nature. Idaho Power faces regulatory uncertainty associated with carbon regulation and a federal RES. Idaho Power is planning for a resource future that restricts the quantity of carbon that can be released into the earth's atmosphere. The proposed carbon legislation is anticipated to restrict the quantity of carbon emissions and increase the price of RECs. Limited or ineffective carbon legislation could lead Idaho Power and other utilities to continue to generate from traditional, fossil-fuel plants.

Natural gas prices are primarily affected by supply and demand; however, economic growth, load growth, carbon legislation, and transmission availability will also influence prices. Presently, natural gas prices are relatively low. However, Idaho Power analyzed the portfolio costs under a scenario where natural gas is considerably more expensive.

Qualitative Risk Analysis

Qualitative analysis preferences are chosen through judgment and do not lend themselves to the deterministic quantitative metrics. Idaho Power discussed the qualitative factors in public forums, including the IRPAC meetings, as well as in regulatory workshops and proceedings. Some of the qualitative risks, such as planning for new large loads, may be considered policy issues and are discussed in Chapter 1. The qualitative risk of schedule delays and siting issues associated with the Boardman to Hemingway transmission project are addressed by identifying both a preferred and alternate resource portfolios. Many of the qualitative risks, such as carbon policy, resource technology, and market price risk, are covered in the quantitative analysis through variations in carbon emissions prices, capital cost, and natural gas prices. In general, Idaho Power addresses the qualitative risks through policy discussions with the IRPAC and regulatory agencies or by associating the risk with proxy variables in the quantitative analysis.

Quantitative Risk Analysis

For the 2011 IRP, Idaho Power analyzed high, low, and expected cases for the following risk factors: 1) carbon, 2) natural gas prices, 3) capital cost, 4) DSM variability, 5) load variability, and 6) REC prices. In addition to the high, low, and expected cases for carbon, a no-carbon cost case was also analyzed.

The results of the quantitative risk analysis show a change from the expected cost of each portfolio for each risk factor analyzed. The results of the quantitative risk analyses are presented in terms of NPV total portfolio cost resulting in a side-by-side comparison of the range of potential costs for each risk factor.

Carbon Risk (2011–2020)

Four carbon adder scenarios, an expected case and three alternate cases, were analyzed as part of the 2011 IRP. A description of the four cases is contained in Chapter 6. With respect to the cost of carbon, the nine portfolios perform relatively similarly for the three alternate levels of carbon cost considered.

As expected—given their renewable focus, the 1-1 Sun and Steam and 1-2 Solar portfolios are not as adversely affected by high carbon costs (costs estimated to increase slightly less than costs for other portfolios), nor are they benefitted as much by lower or zero carbon costs. However, the modest differences between portfolios in comparing the estimated cost effects associated with the levels of carbon cost suggest that much of the cost of carbon is driven by the operation of Idaho Power's existing and committed resources. Thus, based on the varying levels of carbon cost risk considered, none of the portfolios are likely to lead to a catastrophic financial outcome occurring as a result of carbon costs deviating from expected costs.

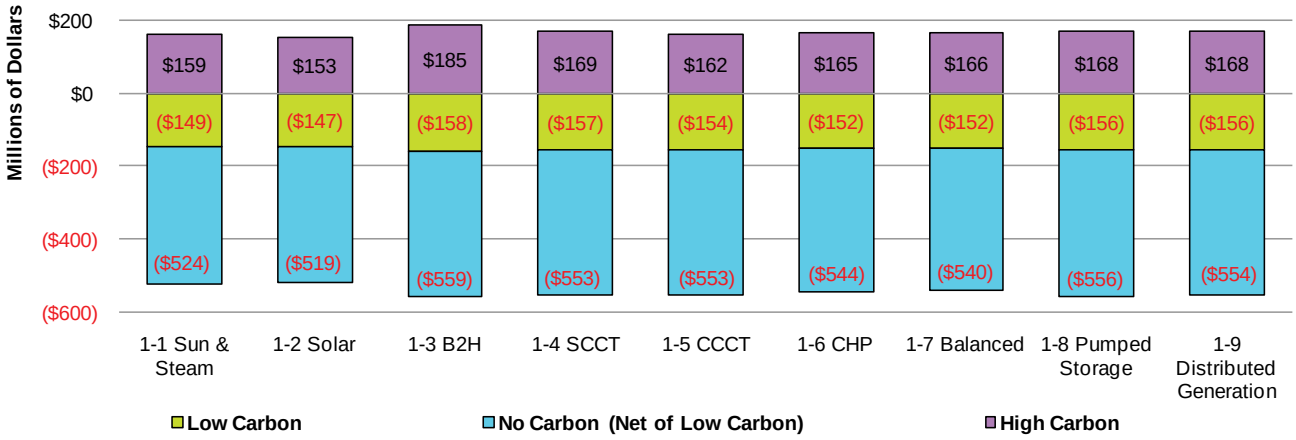


Figure 9.3 Carbon risk analysis results (2011–2020)

Natural Gas Price Risk (2011–2020)

Three natural gas price scenarios were analyzed for the 2011 IRP—high, expected, and low. Additional details of the natural gas price scenarios are presented in Chapter 6, and the results are presented in Figure 9.4. As expected, portfolios having SCCT, CCCT, or CHP resources show a greater range of risk associated with natural gas prices. The portfolios having elevated risk related with higher-than-expected natural gas prices include 1-1 Sun and Steam, 1-6 CHP, and 1-7 Balanced. Conversely, these portfolios are likely to experience greater cost decreases in the event of lower-than-expected natural gas prices. The risk analysis also indicates that the 1-5 CCCT portfolio is projected to benefit disproportionately from lower-than-expected natural gas prices, because the CCCT is economically dispatched more frequently under the low natural gas price scenario.

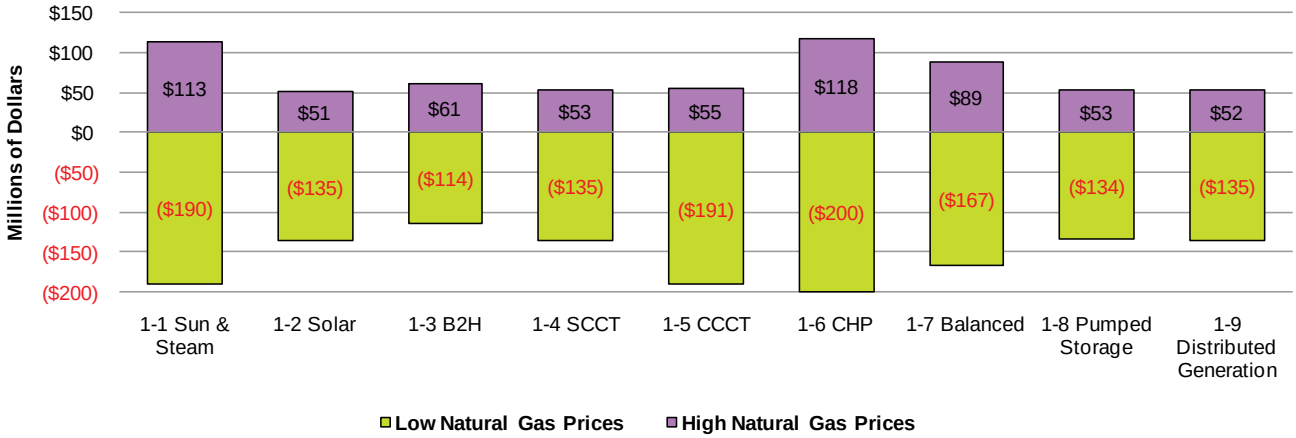


Figure 9.4 Natural gas price risk analysis results (2011–2020)

Capital Cost Risk (2011–2020)

For the 2011 IRP, Idaho Power introduced asymmetry into the estimates of capital cost risk. The introduction of this bias is consistent with comments received from the IRPAC suggesting that development costs for particular resources do not have equal increase/decrease potential. Figure 9.5 illustrates the assumed range in capital costs for considered generating resources, where the horizontal dash for each resource is the expected-case cost in dollars per kW, and the vertical bar reflects the potential capital cost risk for each resource relative to its expected-case cost. Figure 9.5 includes resources used in portfolios for both the first and second 10-year periods of the analysis.

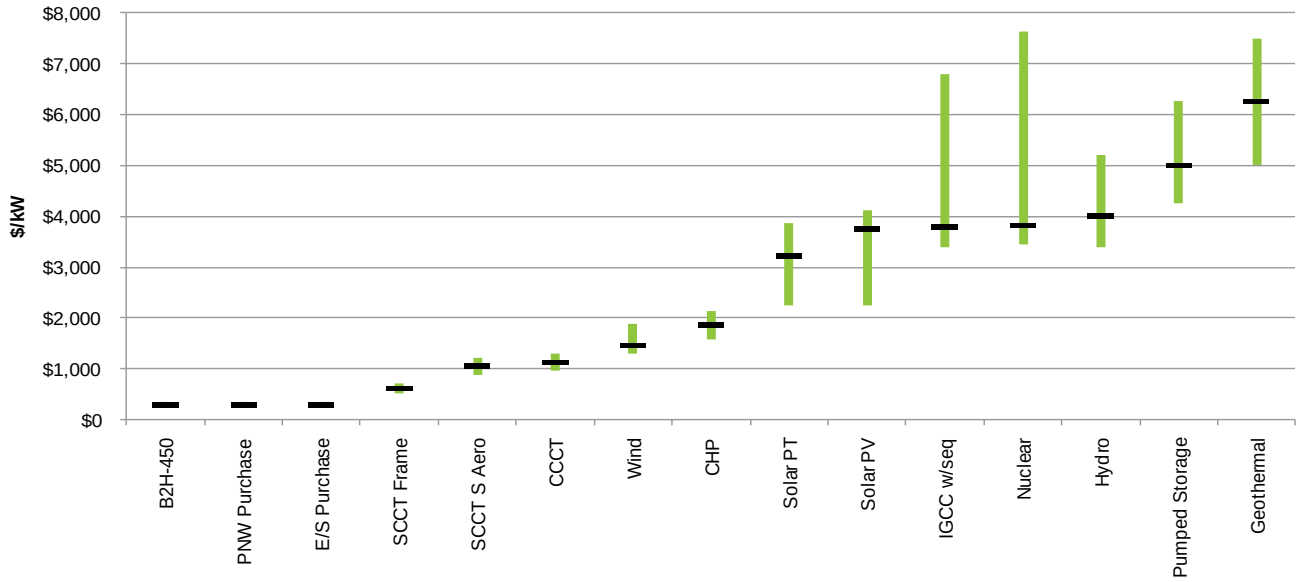


Figure 9.5 Capital cost risk analysis

The results of the capital cost risk analysis demonstrate that resource portfolios comprised of high-capital-cost resources have the greatest potential for deviating from expected-case portfolio cost estimates. The asymmetry in the capital-cost risk is particularly evident for portfolio 1-1 Sun and Steam, 1-2 Solar, and 1-8 Pumped Storage. Solar resources (thermal and PV) are expected to have a greater potential for capital cost decrease versus cost increase; consequently, the two, solar-based portfolios are likely to have the greatest cost-reduction potential. Solar-powered resources are also estimated to have substantial potential for increased capital costs. Consequently, the potential cost increase for portfolios containing solar resources either matches or exceeds that of other portfolios. The results of the capital-cost risk analysis are presented in Figure 9.6.

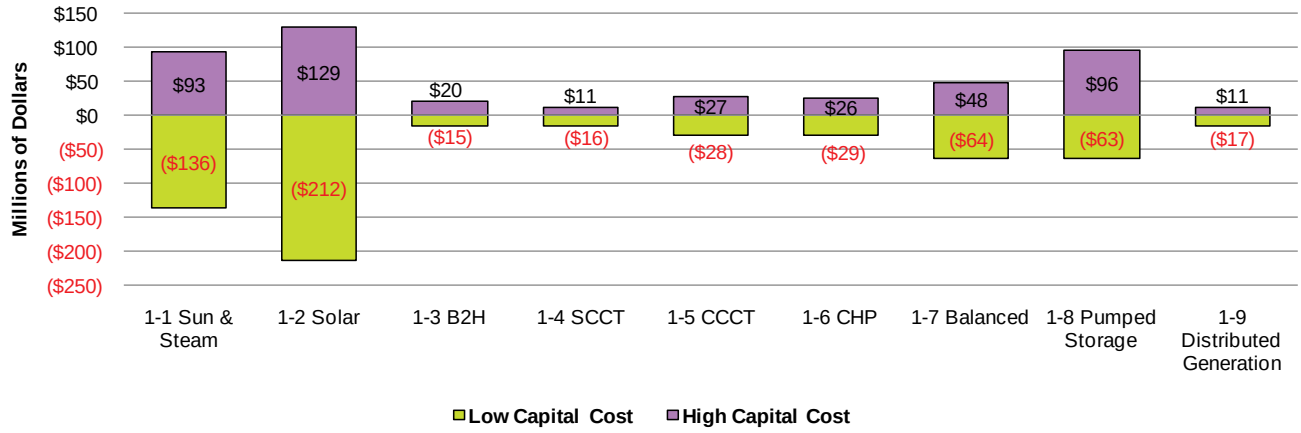


Figure 9.6 Capital-cost risk analysis results (2011–2020)

Risk Due to DSM Variability (2011–2020)

The 2011 IRP risk analysis also evaluated the costs associated with higher-than-expected and lower-than-expected levels of DSM. For the high-DSM case, DSM levels resulting in load being 8 percent lower than expected are reached by the mid-2020s. For the low-DSM case, lower than expected DSM levels resulting in load being 4 percent higher-than-expected are reached by the mid-2020s. The DSM risk scenarios analyzed are shown in Figure 9.7.

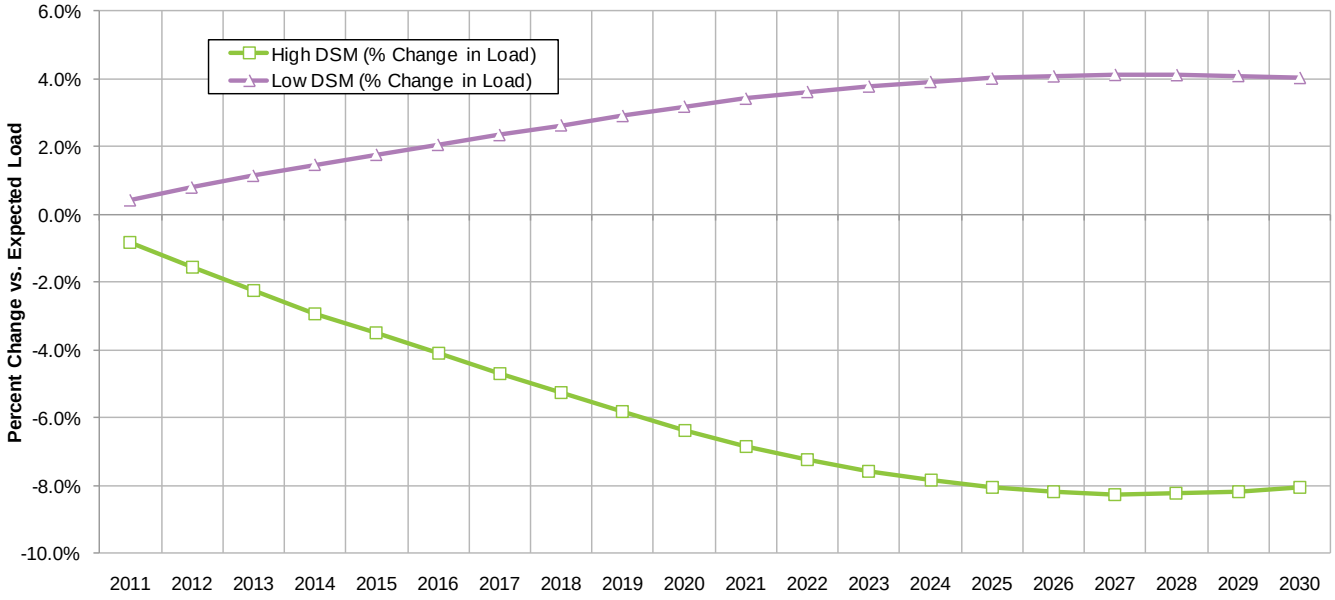


Figure 9.7 DSM variability risk analysis

Figure 9.8 indicates that deviations of DSM program performance from the expected-case forecast have a relatively small impact on total portfolio costs, and the estimated impacts are relatively uniform across portfolios.



Figure 9.8 DSM variability risk analysis results (2011–2020)

Risk Due to Load Variability (2011–2020)

For the 2011 IRP, high- and low-load risk scenarios were derived to analyze the impact of deviations in the IRP load forecast. Figure 9.9 shows the range in load analyzed as a percentage of the expected-case load forecast. For the high-case, loads are approximately 10 percent higher than the expected-case forecast by the end of the planning period in 2030. For the low-case, loads are nearly 10 percent lower than the expected-case forecast in 2030.

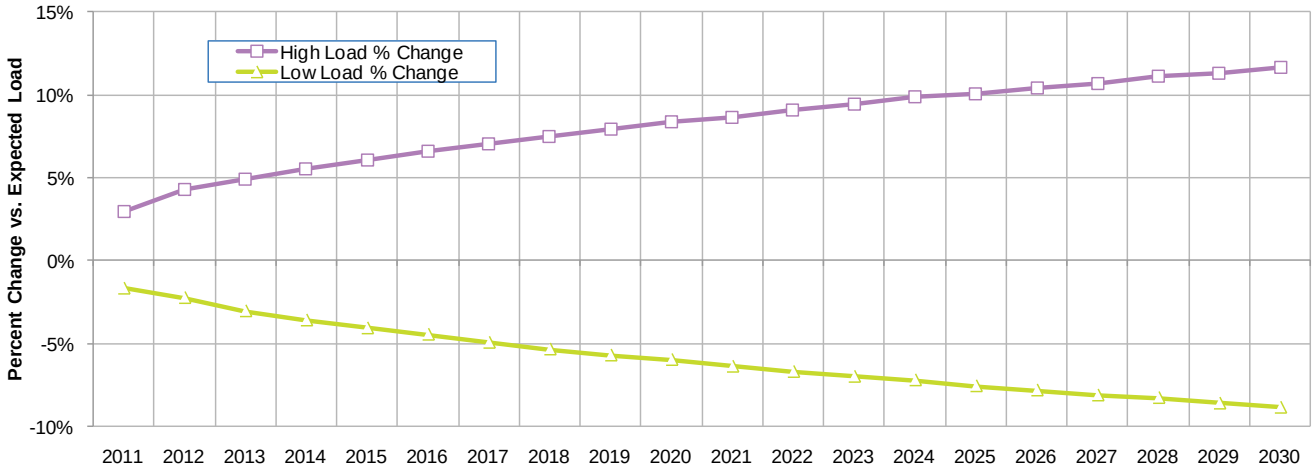


Figure 9.9 Load variability risk analysis

Figure 9.10 indicates that load deviations from the expected-case forecast have the potential to significantly impact portfolio costs. However, the estimated impacts are fairly uniform across portfolios, suggesting equal exposure with respect to load risk for the portfolios. Furthermore, the analysis accounts only for power supply costs and does not include revenues associated with retail sales being higher or lower than expected.

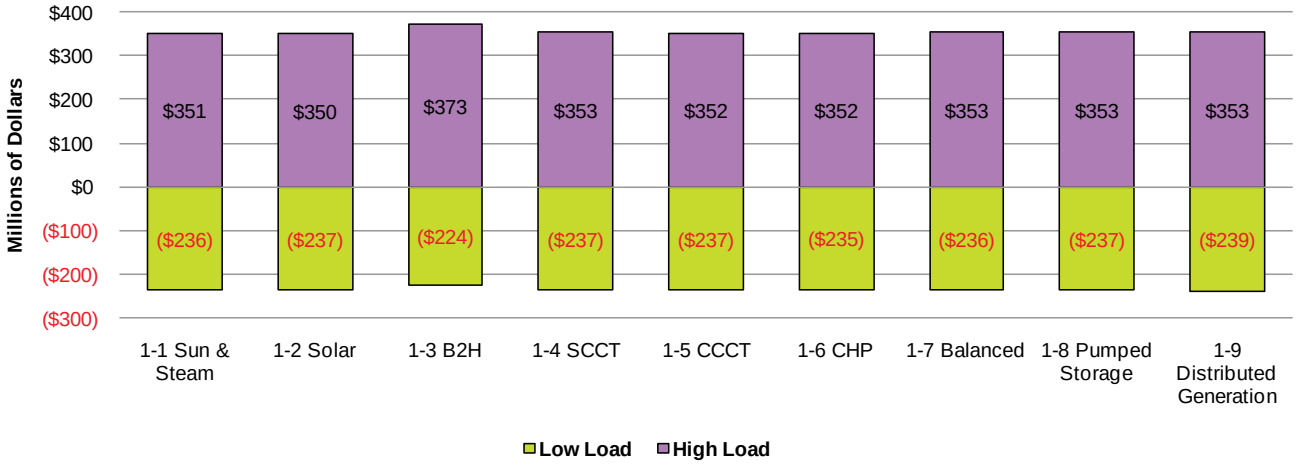


Figure 9.10 Load risk analysis results (2011–2020)

REC Price Risk (2011–2020)

In addition to an expected case for REC prices, high- and low-price scenarios were also analyzed. Additional details on the REC price scenarios is presented in Chapter 6. The results of the analysis indicate none of the portfolios are exposed to severe risk potential with respect to REC price. This is expected because each portfolio was designed to have approximately the number of RECs needed to be compliant with a federal RES.

Because a majority of the portfolios have surplus RECs, high REC prices result in lower portfolio costs relative to the expected REC price case. Similarly, RECs having little or no value leads to higher portfolio costs. The small differences between portfolios follow expected trends. For example, portfolios that generate more RECs (1-1 Sun and Steam and 1-2 Solar) will see a greater cost decrease as a consequence of high REC prices. Conversely, the cost of these portfolios increases more under the low REC price scenario.



Figure 9.11 REC price risk analysis results (2011–2020)

Quantitative Risk Analysis Summary (2011–2020)

Several conclusions can be drawn from the quantitative risk analysis performed for the first 10-year period. Those conclusions include the following:

- Portfolios with solar resources (1-1 Sun and Steam and 1-2 Solar) could have substantially lower-than-expected capital costs, and therefore lower total portfolio costs. However, this lower cost potential is insufficient to overcome the disparity between the expected costs of these portfolios and the expected cost of portfolio 1-3 Boardman to Hemingway.
- The portfolios are designed for REC compliance, and, consequently, carry minimal exposure to REC price risk.
- Portfolio 1-3 Boardman to Hemingway has minimal potential for cost increases or decreases associated with capital costs deviating from expected costs.
- A substantial portion of the carbon cost risk is driven by Idaho Power's existing and committed resources.

The following sections present a similar analysis for the second 10 year period (2021–2030).

Carbon Risk (2021–2030)

Portfolio 2-1 Nuclear, with no incremental carbon-producing resources, has the least potential for cost deviations as a result of the high, low, and no carbon cost scenarios. However, the differences between this portfolio and the other portfolios, with respect to the cost of carbon, are relatively modest. Again, this suggests that carbon risk is primarily due to Idaho Power's existing and committed resources. Figure 9.12 shows the results of the carbon risk analysis for the second 10-year period.

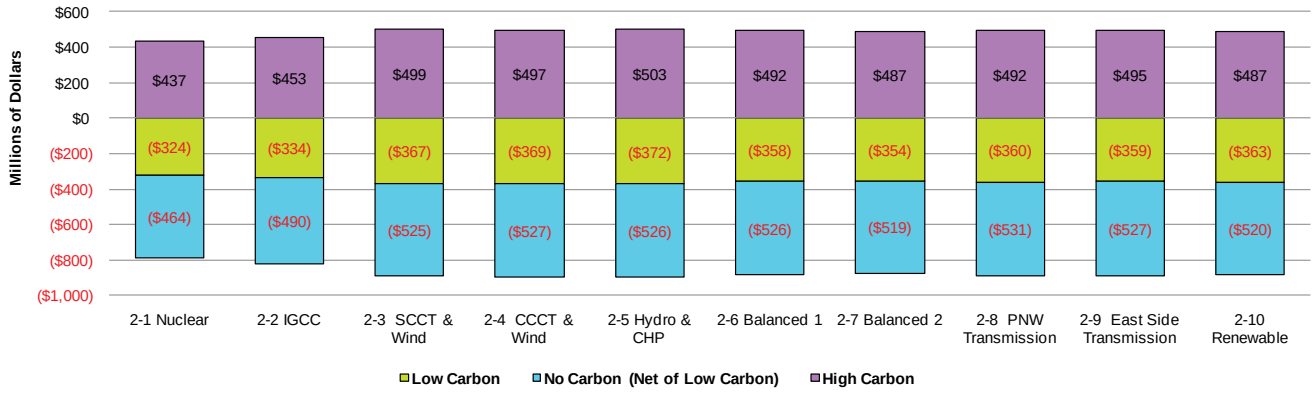
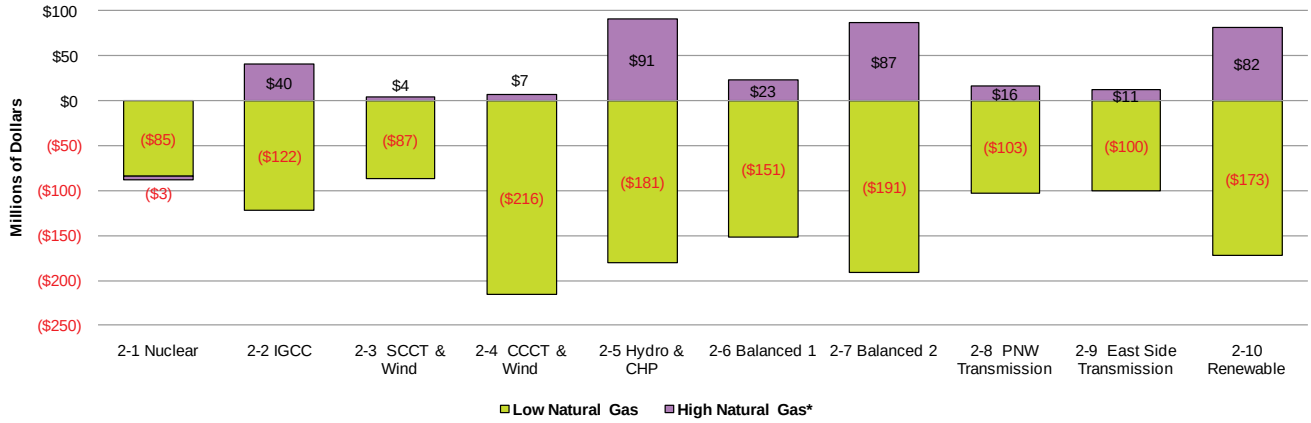


Figure 9.12 Carbon risk analysis results (2021–2030)

Natural Gas Price Risk (2021–2030)

Lower-than-expected natural gas prices lead to portfolio costs that are lower than those occurring under expected natural gas price conditions. The portfolio cost reductions are greatest for the portfolios containing new gas resources. Under higher-than-expected natural gas prices, portfolio 2-5 Hydro and CHP and portfolio 2-7 Balanced 2 have the highest risk under a high-gas-price scenario. These portfolios contain CHP resources, which are typically operated at high-capacity factors to meet the needs of the steam host. Portfolio 2-6 Balanced 1 has a modest potential for cost deviations occurring in response to different-than-expected natural gas prices. Figure 9.13 shows the results of the natural gas price risk analysis for the second 10-year period.



*In portfolio 2-1 Nuclear, high natural gas prices results in a reduced portfolio cost of ($3).

Figure 9.13 Natural Gas price risk analysis results (2021–2030)

Capital Cost Risk (2021–2030)

Figure 9.14 shows the range of costs for portfolios due to capital cost risk. The results of the analysis shows that nuclear generating facilities have considerably greater potential for capital-cost increases versus their potential for cost decrease. This is evident in the potential cost increase of portfolio 2-1 Nuclear, which could have an NPV cost of $1.3 million more than expected under the high capital-cost scenario. Portfolio 2-2 IGCC also has a substantially greater risk for cost increases relative to other portfolios. Portfolio 2-6 Balanced 1 is among the group of portfolios having the lowest exposure to capital cost risk.

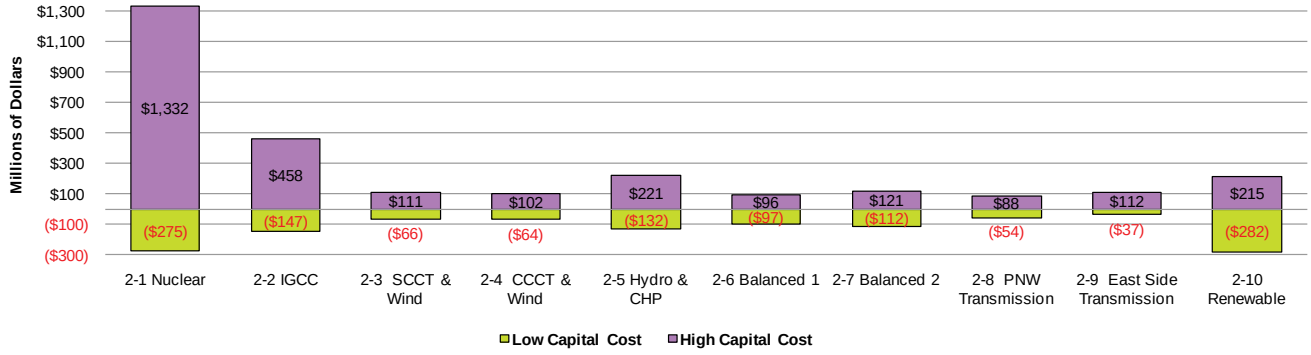


Figure 9.14 Capital cost risk analysis results (2021–2030)

Risk Due to DSM Variability (2021–2030)

The 10 resource portfolios considered for the second 10 years contain the same energy efficiency and demand response programs. The potential for portfolio costs to deviate as a result of different-than-expected DSM program performance is very similar between the portfolios.

Thus, the DSM risk is not a characteristic that can be used to discriminate between the different resource portfolios.



Figure 9.15 DSM risk analysis results (2021–2030)

Risk Due to Load Variability (2021–2030)

Different-than-expected load conditions also increase or decrease costs similarly between the portfolios considered for the second 10 years. This suggests that the portfolios have equal exposure to load variability risk.

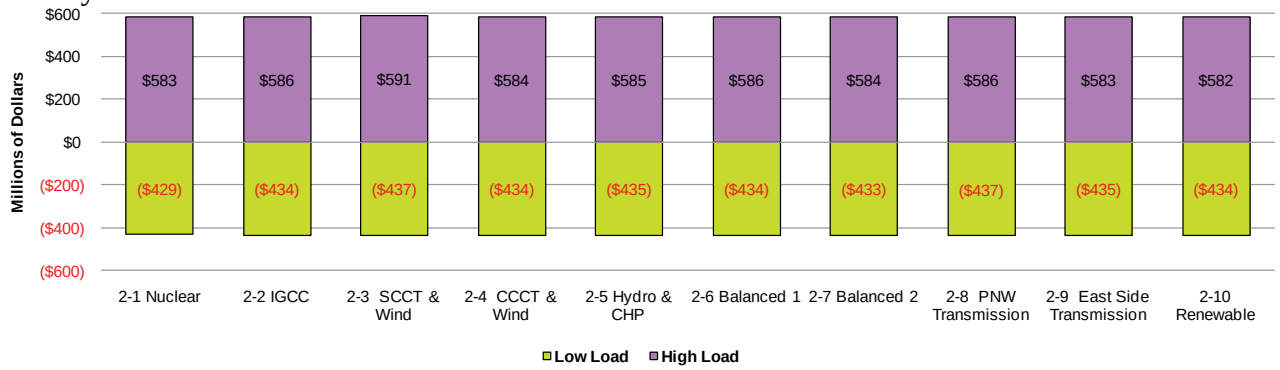
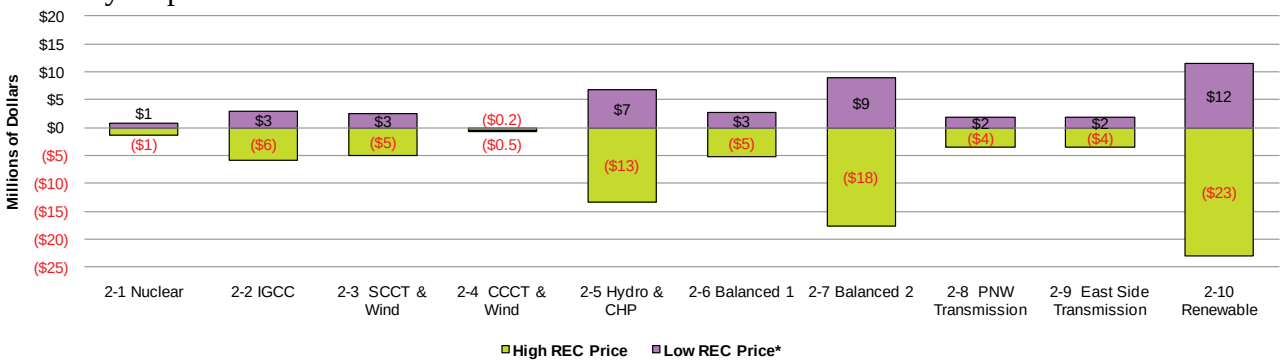


Figure 9.16 Load variability risk analysis results (2021–2030)

REC Price Risk (2021–2030)

As seen in the analysis for the first 10-year period, REC prices have a minimal impact on total portfolio costs. Portfolio 2-10 Renewable produces the greatest amount of surplus RECs and, consequently, has the highest potential for a cost decrease as a result of higher-than-expected REC prices. Conversely, this portfolio has the greatest risk for increased costs due to lower-than-expected REC prices. However, the potential cost changes due to the high- and low-REC price scenarios are similar between portfolios and relatively small compared to other risk factors. This suggests the portfolios are similarly exposed to REC price risk, which is minimal. Figure 9.17 shows the results of the REC price risk analysis for the second 10-year period.



*In portfolio 2-4 CCCT & Wind, a low REC price results in a reduced portfolio cost of ($.02).

Figure 9.17 REC price risk analysis results (2021–2030)

Quantitative Risk Analysis Summary (2021–2030)

Under higher-than-expected capital costs, portfolios 2-1 Nuclear and 2-2 IGCC have the greatest exposure to higher costs relative to the other portfolios. With this exception, the differences between the portfolios with respect to the risk factors considered are generally modest, suggesting that the portfolios contain a similar amount of risk exposure. Other conclusions from the 2021–2030 risk analysis include the following:

- All portfolios are designed to be compliant with a federal RES and, consequently, carry minimal exposure to REC price risk.
- A substantial portion of the carbon cost risk is driven by Idaho Power's existing and committed resources. However, there is some incremental carbon risk associated with all the portfolios except portfolio 2-1 Nuclear. This incremental exposure is evidenced by the greater potential for cost increase/decrease of the other portfolios relative the nuclear portfolio.
- Portfolio 2-10 Renewable has the greatest potential for total cost decrease occurring as a result of lower-than-expected capital costs, reflecting the expectation that solar-powered resources have a greater potential for capital cost decreases than increases.
- The 2-6 Balanced 1, 2-8 PNW Transmission, and 2-9 Eastside Transmission portfolios are among the group of portfolios having the lowest exposure to capital cost risk.

Stochastic Analysis

Stochastic analysis is a statistical technique often used in resource planning. The OPUC recognized the benefits of stochastic analysis and included stochastic analysis as part of its Resource Planning Guidelines (Oregon Docket UM 1056, Order 07-047, February 9, 2007, Appendix A, page 4, Guideline 4 b). The entire Oregon order listing the resource planning guidelines is included in *Appendix C–Technical Appendix*. Idaho Power has used a probabilistic analysis to model loss of load in the 2011 IRP as well as in previous resource plans. Idaho Power applied a stochastic analysis to the natural gas price forecast in the 2009 IRP, and the 2011 IRP is Idaho Power's first application of a stochastic analysis to the expected cost of the various resource portfolios.

Idaho Power modeled the combined effects of the risk variables on the resource portfolio costs for each of the 10-year periods. The results of the stochastic analysis were then used as the determining factor in identifying the preferred and alternate portfolios.

To complete the stochastic analysis, Idaho Power identified six risk variables, calculated the incremental resource portfolio cost at the extremes of the range for each risk variable, divided the cost range for each risk variable into five sections, and randomly sampled from the five sections to calculate a distribution of resource portfolio costs. The key points for the analysis of the first 10-year period include the following:

- Nine resource portfolios
- Six risk variables
- Five quintile segments for the range of each risk variable
- 100,000 random samples
- One distribution of costs for each resource portfolio

Risk Variables

Idaho Power identified six risk variables that are included in the stochastic analysis, 1) natural gas price, 2) REC price, 3) carbon cost, 4) load variation, 5) DSM variation, and 6) capital cost. Idaho Power and the IRPAC identified a range for each of the six variables, and Idaho Power applied the range to each risk variable and calculated the range of portfolio costs for the risk variable using the AURORA model. For example, in the year 2020 natural gas prices were expected to be within the approximate range of $6.50 to $10.50 per MMBtu. Idaho Power then used AURORA and the identified range to calculate the cost of each resource portfolio at the two natural gas price extremes. For portfolio 1-3 Boardman to Hemingway the values are—base cost: $86 million; high natural gas price: $96 million; and low natural gas price: $108 million.

Portfolio 1-3 Boardman to Hemingway shows an interesting result. Of the three possibilities analyzed, the base cost with intermediate natural gas prices had the lowest overall cost. Under high gas prices, Idaho Power paid more for energy, and the costs increase; under low gas costs, off-system energy sales were not as profitable for Idaho Power and its customers.

In the case of natural gas prices, the range used in the stochastic analysis was from the low value of $86 million to the high value of $108 million, or a range of $22 million. Similarly, a range was calculated for each of the six risk variables for all nine resource portfolios in the first 10 years. The low value for most of the risk variables in most of the resource portfolios was lower than the base portfolio cost.

After determining the high and low values for each risk variable, the portfolio cost range was divided into five equal segments. For the Boardman to Hemingway portfolio example, the range from $86 million to $108 million was divided into five segments with each segment equal to $4.4 million. Similarly, the range was divided into five equal segments for each of the six risk variables. The entire process was repeated for each of the nine resource portfolios. Five possible states for each of the six risk variables create over 15,000 possible combinations.

Stochastic Modeling

The objective of the stochastic modeling was to estimate the distribution of the incremental portfolio costs. The distribution was calculated by randomly sampling from the range for each risk value, combining the effects of the six risk values, and calculating the resulting resource portfolio cost. The sampling process was repeated 100,000 times for each resource portfolio to estimate the distribution of the resource portfolio costs.

Each risk variable was assumed to be uniformly distributed over the range of values. The uniform distribution means that there is an equal chance of sampling from each of the five segments of the range. For natural gas prices and the 1-3 Boardman to Hemingway portfolio, the uniform distribution means that each $4.4-million segment was equally likely to be sampled. In 100,000 draws, each segment is expected to be sampled 20,000 times.

Three of the six risk variables were considered independent: load variation, DSM variation, and capital cost. For capital costs, independence means that the result of any other risk variable is presumed to have no, or only minor, influence on the capital cost.

The first three risk variables were assumed to show some level of coincidence: natural gas price, REC price, and carbon cost. Specifically, carbon cost was assumed to be the primary risk factor. REC prices were assumed to be 80-percent coincident with carbon cost, and natural gas price was assumed to be 60-percent coincident with carbon cost. The coincidence means that if the sample for carbon cost is from the highest segment in the risk range, there is an 80-percent chance that the sample

of the REC price will also be in the highest segment, with a 60 percent chance that the sample of the natural gas price will also be in the highest segment. Likewise for a sample from any of the other four segments in the carbon cost range. The coincidence was added to the model to reflect the thought that the three variables may be correlated. Even though each of the six risk variables was uniformly distributed, Idaho Power assumed that there is a coincidence factor between three of the six risk variables.

Stochastic Analysis Results and Portfolio Selection (2011–2020)

The results of 100,000 samples for portfolio 1-3 Boardman to Hemingway are shown in the histogram in Figure 9.18.

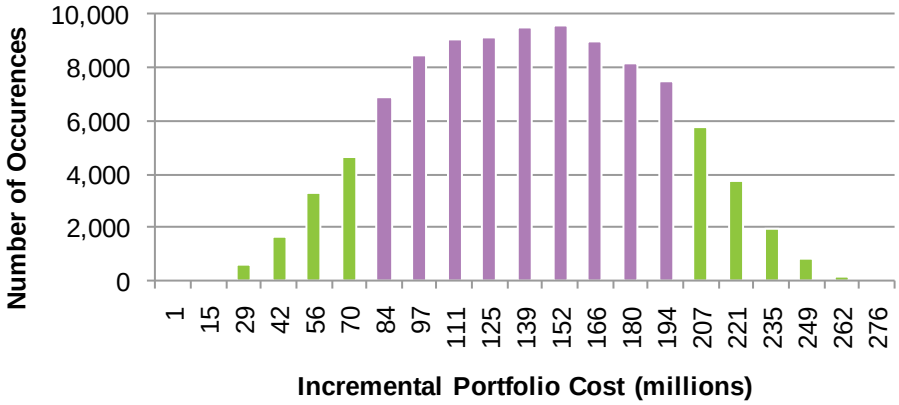


Figure 9.18 Sampling results from portfolio 1-3 Boardman to Hemingway

Based on the sampling of the stochastic analysis, the incremental cost of the Boardman to Hemingway portfolio is expected to range from approximately $1 million to $276 million, with a median value of $133 million. The green bars show the lowest 10 percent and the highest 10 percent of the distribution, and the purple bars represent the middle 80 percent of the distribution. The distribution for portfolio 1-3 Boardman to Hemingway appears to be a normal distribution; however, other resource portfolios had distributions that appear less like a normal distribution. The histogram for portfolio 1-4 SCCT is shown in Figure 9.19. The stochastic cost range for the SCCT portfolio does not appear to be normally distributed; the histogram is roughly flat from an incremental portfolio cost of $100 million up to $200 million and declines on either end. The summary data for all of the resource portfolios, including the distribution charts, is included in *Appendix C–Technical Appendix.*

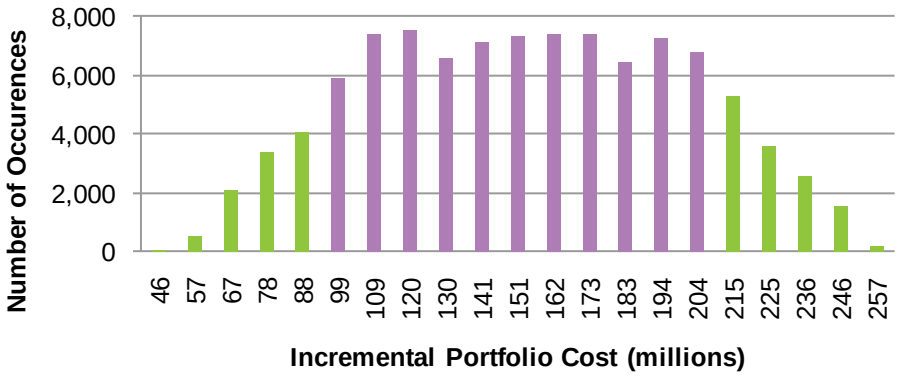


Figure 9.19 Sampling results from portfolio 1-4 SCCT

Table 9.4 compares the nine resource portfolios during the 2011–2020 time period. The table shows the base cost of each resource portfolio, the rank of the base cost in the stochastic analysis, the median of the stochastic analysis, some values defining the range of the stochastic analysis. The base rank is the percentile in the stochastic analysis representing the base cost of the resource portfolio. For example, the

base cost of 1-3 Boardman to Hemingway is approximately $86 million, and $86 million would fall at the 19th percentile in the stochastic distribution—19 percent of the draws have a cost less than the 1-3 Boardman to Hemingway base cost of $86 million, and 81 percent of the draws have a higher cost than the base cost of $86 million.

Table 9.4 Stochastic analysis results (2011–2020)

	Portfolio Cost Calculations (000)				Risk Analysis Range (000)				
	Base	Base Rank	Stochastic Median	Difference	Lower	10th	Median	90th	Upper
1-1 Sun & Steam	$496,198	54%	$488,367	-$7,831	$201,786	$356,662	$488,367	$612,505	$808,750
1-2 Solar	$505,407	58%	$478,897	-$26,510	$162,718	$321,382	$478,897	$628,336	$805,521
1-3 Boardman to Hemingway	$86,079	19%	$133,582	$47,503	$1,143	$67,712	$133,582	$198,852	$276,164
1-4 SCCT	$129,443	36%	$148,643	$19,200	$46,060	$88,149	$148,643	$210,860	$256,889
1-5 CCCT	$222,177	60%	$208,242	-$13,935	$66,345	$138,884	$208,242	$277,954	$368,603
1-6 CHP	$267,462	44%	$277,183	$9,721	$104,783	$195,179	$277,183	$361,535	$486,767
1-7 Balanced	$288,613	44%	$299,237	$10,624	$115,778	$217,378	$299,237	$381,340	$507,002
1-8 Pumped Storage	$426,601	31%	$462,254	$35,653	$287,183	$376,777	$462,254	$550,862	$645,560
1-9 Distributed Generation	$135,055	39%	$151,697	$16,642	$49,879	$91,196	$151,697	$212,500	$259,478

Figure 9.20 shows an overview of the stochastic analysis for all of the resource portfolios for the 2011–2020 time period.

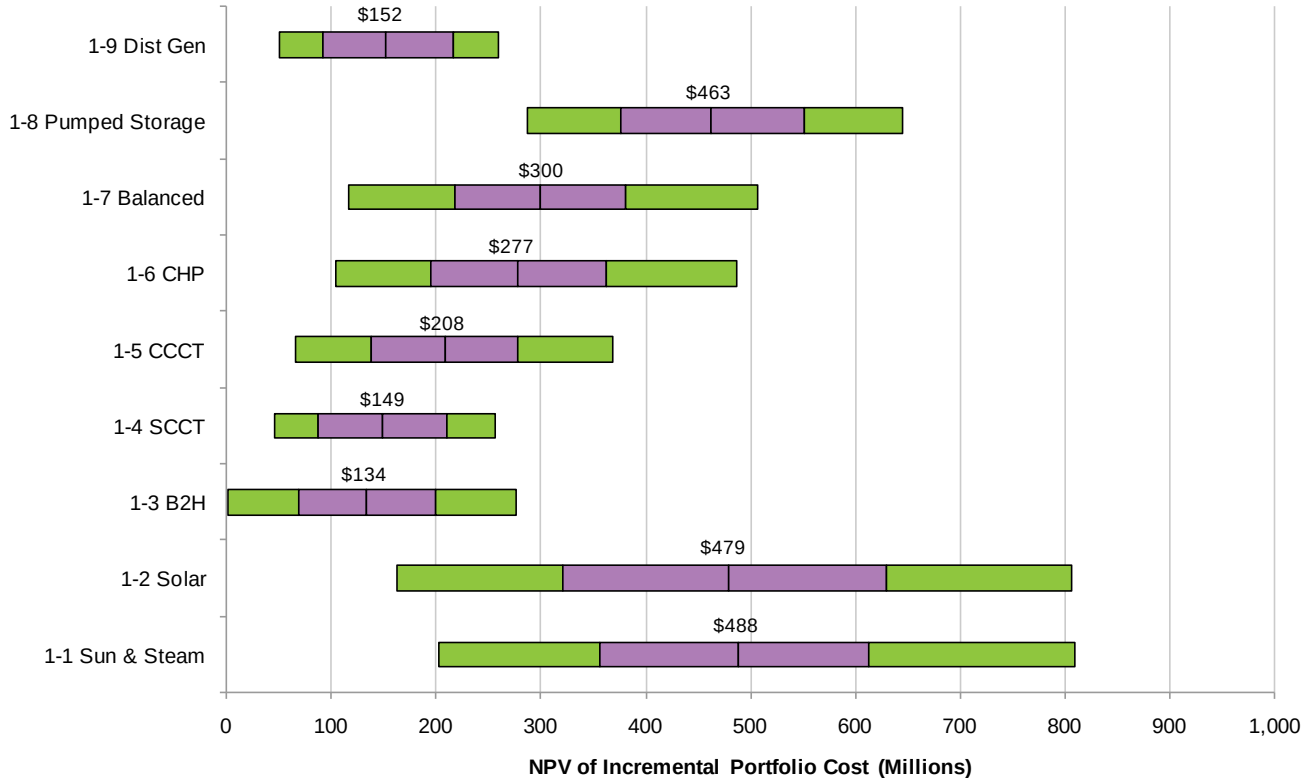


Figure 9.20 Stochastic analysis results (2011–2020)

The length of the bars in Figure 9.20 show the stochastic range of the incremental portfolio costs. The purple portion of the bar represents the middle 80 percent of the distribution, and the green bars at either end represent the 10-percent tails of the distribution similar to the colors in the histogram presented in Figure 9.19. The upper and lower limits, median, 10th, and 90th percentile values represented in Figure 9.20 are also shown in Table 9.4.

The capital cost risk variable seems to have the greatest effect on the stochastic range for a resource portfolio and the stochastic range of a resource portfolio increases as the capital cost of the portfolio cost increases. Portfolio 1-4 SCCT has the lowest capital cost, and 1-1 Sun and Solar and 1-2 Solar have the highest capital cost.

The link between the stochastic range and the capital cost is a direct result of Idaho Power's summer capacity deficit as described in Chapter 8 and Figure 8.1. The effect of the summer capacity deficits is that Idaho Power needs energy during a limited number of summer hours each year to meet customers' peak demand. Limited operation of a generation resource leads to low total operating costs, even if the hourly operating costs are high, because the resource operates only during a limited number of hours each year to meet peak demand.

Limited operation means that variations in the capital costs can overshadow any variations in operating costs when the corresponding capital costs are high, even for resources with extremely low operating costs. An example is a solar PV resource where the operating costs are very low, but the capital costs are high. What the range also indicates is if the capital costs of a resource, such as solar, decline sufficiently, both the overall portfolio cost and the stochastic range will be reduced.

The conclusion of the stochastic analysis indicates that the two resource portfolios with SCCT generation, 1-4 SCCT and 1-9 Distributed Generation have the smallest stochastic price risk range. Portfolio 1-3 Boardman to Hemingway has the lowest expected cost and a slightly larger risk range. Capital costs overshadow the operating costs for the other resource portfolios, especially for the resource portfolios with a large amount of solar generation, 1-1 Sun and Solar and 1-2 Solar. The resource portfolios with the lowest capital cost have the smallest stochastic price range.

The stochastic analysis is a key part of the portfolio selection process used by Idaho Power in the 2011 IRP. Based on the expected low cost, and the limited risk spread, Idaho Power selected two resource portfolios for the first 10 years of the planning period (2011–2020), 1-3 Boardman to Hemingway (preferred) and 1-4 SCCT (alternate).

Stochastic Analysis Results and Portfolio Selection (2021–2030)

Idaho Power followed the same process to analyze the second 10 years of the planning period:

- Ten resource portfolios
- Six risk variables
- Five quintile segments for the range of each risk variable
- 100,000 random samples
- One distribution of costs for each resource portfolio

The 2011 IRP also identifies a preferred portfolio and an alternate portfolio for the 2021–2030 time period. However, the selection of these two portfolios is not as straightforward as the selection for the first 10-year period. The preferred portfolio is 2-6 Balanced 1, which incorporates geothermal, solar, small hydroelectric, and natural gas resources. The alternate portfolio for the second 10-year period is 2-8 Pacific Northwest Transmission which substantially relies on additional market purchases from the Pacific Northwest. An explanation of the rationale for the selection of these portfolios follows.

Figure 9.21 shows the incremental cost distribution for portfolio 2-6 Balanced 1, and Figure 9.22 shows the same information for the 2-8 Pacific Northwest Transmission portfolio.

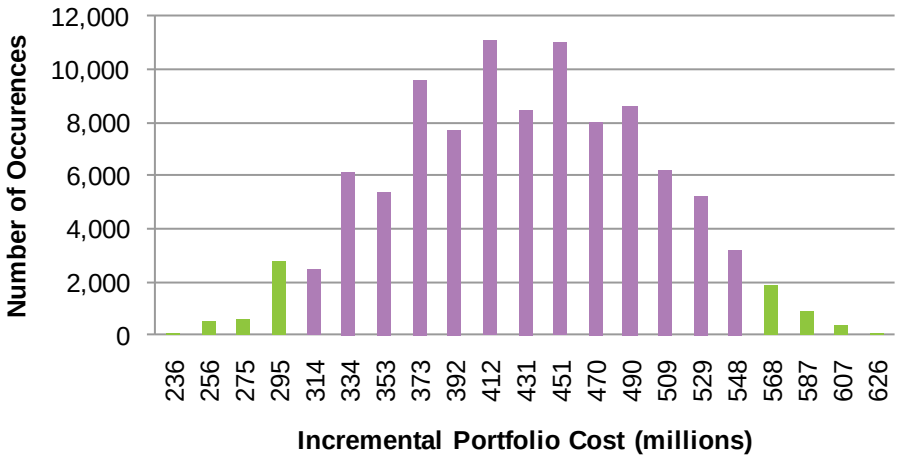


Figure 9.21 Sampling results from portfolio 2-6 Balanced 1

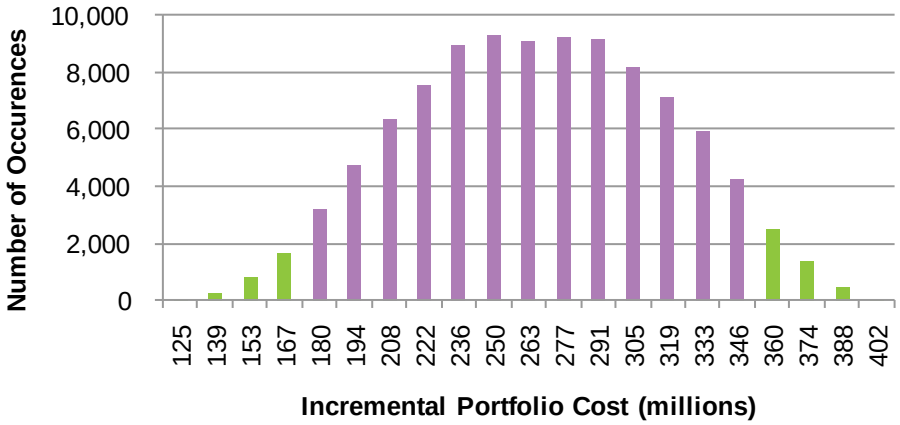


Figure 9.22 Sampling results from portfolio 2-8 Pacific Northwest Transmission

Like the first 10 years of the planning period, the distribution of the results from stochastic analysis of some resource portfolios more closely approximates a normal distribution than for other resource portfolios. Having a normal distribution is an interesting finding, but the normal distribution is not critical to the analysis or to the selection of a preferred portfolio. The main information resulting from the stochastic analysis is the cost range for the resource portfolio.

Table 9.5 shows the cost distribution for all 10 resource portfolios considered in the stochastic analysis of the second 10 years of the planning period, and Figure 9.23 shows the graphical results of the stochastic analysis for all of the resource portfolios for the 2021–2030 time period.

The nuclear resource portfolio has the highest expected cost and the broadest cost range. Like the analysis of the first 10 years, the cost distribution is driven by capital costs, and nuclear generation has a very high capital cost. The preferred and alternate portfolios, 2-6 Balanced 1 and 2-8 Pacific Northwest Transmission, both have relatively low-expected costs and a narrow range of possible costs.

Although the results of the stochastic analysis show portfolios 2-8 Pacific Northwest Transmission and 2-9 Eastside Transmission have a lower expected total portfolio cost, neither was selected as the preferred portfolio. Because of uncertainty regarding the ability to build new long-distance, high-voltage transmission projects in the second 10-year planning period, Idaho Power does not believe either portfolio presents the best option. In addition, the low cost of these portfolios is contingent on long-term, low market prices that are currently the result of a surplus of energy in the Pacific Northwest for portfolio 2-8, and the anticipation of low market prices on the east side of Idaho Power's system due to considerable amounts of wind generation being built in Wyoming.

Table 9.5 Stochastic analysis results (2021–2030)

	Portfolio Cost Calculations (000)				Risk Analysis Range (000)				
	Base	Base Rank	Stochastic Median	Difference	Lower	10th	Median	90th	Upper
2-1 Nuclear	$1,323,279	13%	$1,906,067	$582,788	$937,479	$1,258,961	$1,906,067	$2,558,841	$2,826,562
2-2 IGCC	$625,319	25%	$774,304	$148,985	$355,848	$524,204	$774,304	$1,024,405	$1,200,846
2-3 SCCT & Wind	$564,334	35%	$591,640	$27,306	$460,369	$516,699	$591,640	$667,135	$725,935
2-4 CCCT & Wind	$565,377	78%	$511,684	-$53,693	$332,030	$421,411	$511,684	$599,584	$722,088
2-5 Hydro & CHP	$860,503	44%	$879,828	$19,325	$586,902	$720,494	$879,828	$1,042,838	$1,221,484
2-6 Balanced 1	$445,704	63%	$421,349	-$24,355	$236,458	$326,718	$421,349	$513,673	$626,463
2-7 Balanced 2	$567,780	59%	$546,270	-$21,510	$283,996	$412,351	$546,270	$674,989	$855,880
2-8 Pacific Northwest Transmission	$240,492	53%	$234,915	-$5,577	$104,988	$169,359	$234,915	$300,819	$373,437
2-9 Eastside Transmission	$260,903	50%	$261,081	$178	$125,155	$192,356	$261,081	$328,692	$401,798
2-10 Renewable	$966,716	63%	$904,983	-$61,733	$523,823	$692,378	$904,983	$1,121,324	$1,333,728

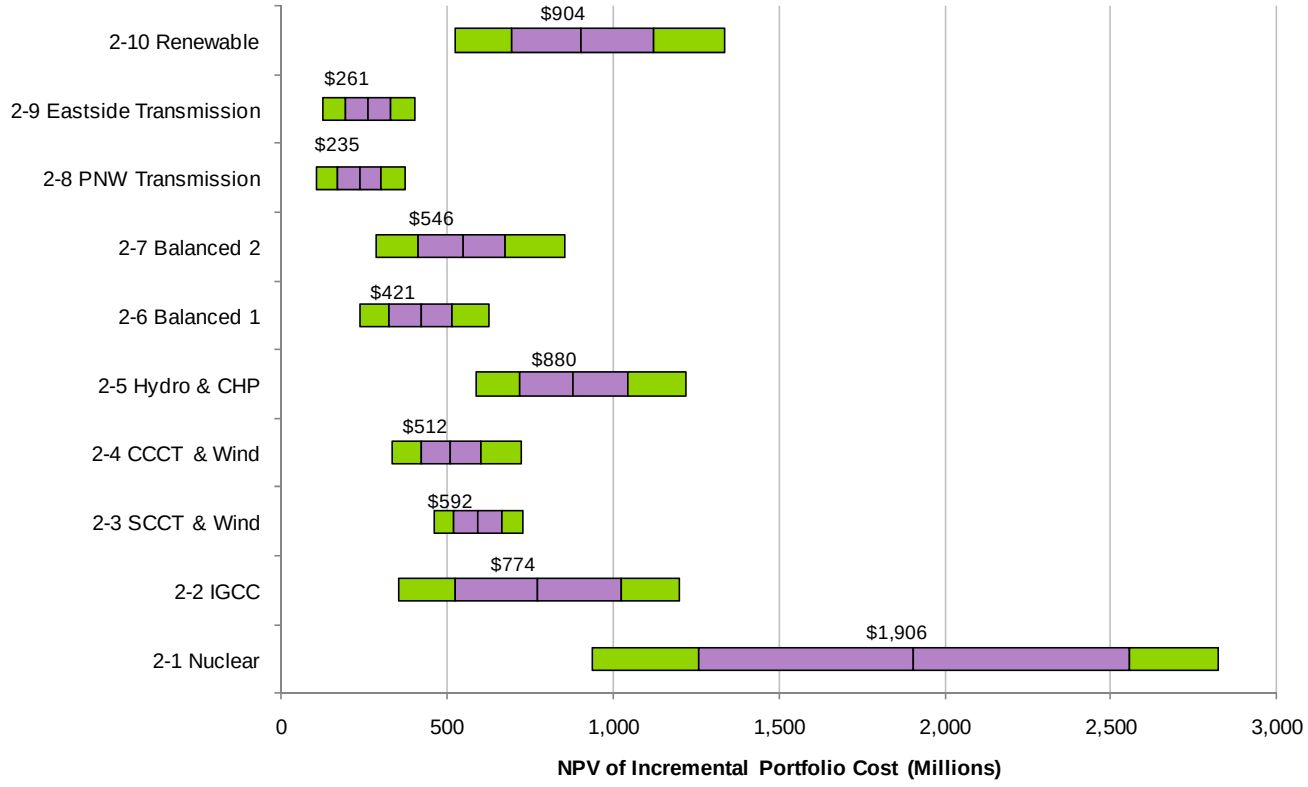


Figure 9.23 Stochastic analysis results (2021–2030)

Although it has a slightly higher expected cost, portfolio 2-6 Balanced 1 was selected as the preferred portfolio because it contains a diversified set of resources that are low risk, it does not rely on substantial technology improvements, and Idaho Power is confident it could be implemented.

Tipping Point Analysis—Market Risk

Idaho Power examined the effect of wholesale market prices on the cost of portfolio 1-3 Boardman to Hemingway relative to the cost of the less-market-dependent 1-4 SCCT portfolio. While the cost of purchased power rises with increased market prices, the revenues associated with surplus power sales

also increase. Therefore, the Boardman to Hemingway portfolio remains the lower-cost portfolio under all elevated market price scenarios, and a tipping point does not exist.

However, further investigation into just the purchased power component of these two portfolios provides some useful information related to market price risk. The NPV total cost of the Boardman to Hemingway portfolio is approximately $43 million less than the cost of the SCCT portfolio. The Boardman to Hemingway portfolio also has an additional 62,000 MWh of market purchases when compared to the SCCT portfolio.

To make up the difference in total portfolio cost, average market prices for the additional 62,000 MWh of purchases in the Boardman to Hemingway portfolio would need to be more than $700 per MWh. While this analysis ignores the benefit of surplus sales at higher market prices, it offers insight on the level market prices would have to rise to in order to make the Boardman to Hemingway portfolio no longer the least-cost option.

Tipping Point Analysis—Boardman to Hemingway

The 2011 IRP analysis assumes Idaho Power has 28-percent equity ownership in the Boardman to Hemingway project. If third-party equity interest in the project is less than expected, the company's share of the capital cost for the project will be higher, and the total cost of portfolio 1-3 Boardman to Hemingway will also be higher. Therefore, a tipping point analysis was performed to determine how great of an ownership share Idaho Power could take in the project in order for the total cost of portfolio 1-3 Boardman to Hemingway to be equivalent to the next best alternative, portfolio 1-4 SCCT.

The results of the analysis indicate Idaho Power's share of the project could go as high as 42 percent before the cost of the two portfolios were equal. This analysis assumes that Idaho Power's use of the Boardman to Hemingway line is the same as it was under the expected 28-percent ownership scenario, and the incremental capital cost associated with a greater equity share is not offset by economic utilization of the additional capacity. Figure 9.24 presents the graphical results of the analysis and additional details of the calculations can be found in *Appendix C–Technical Appendix*.

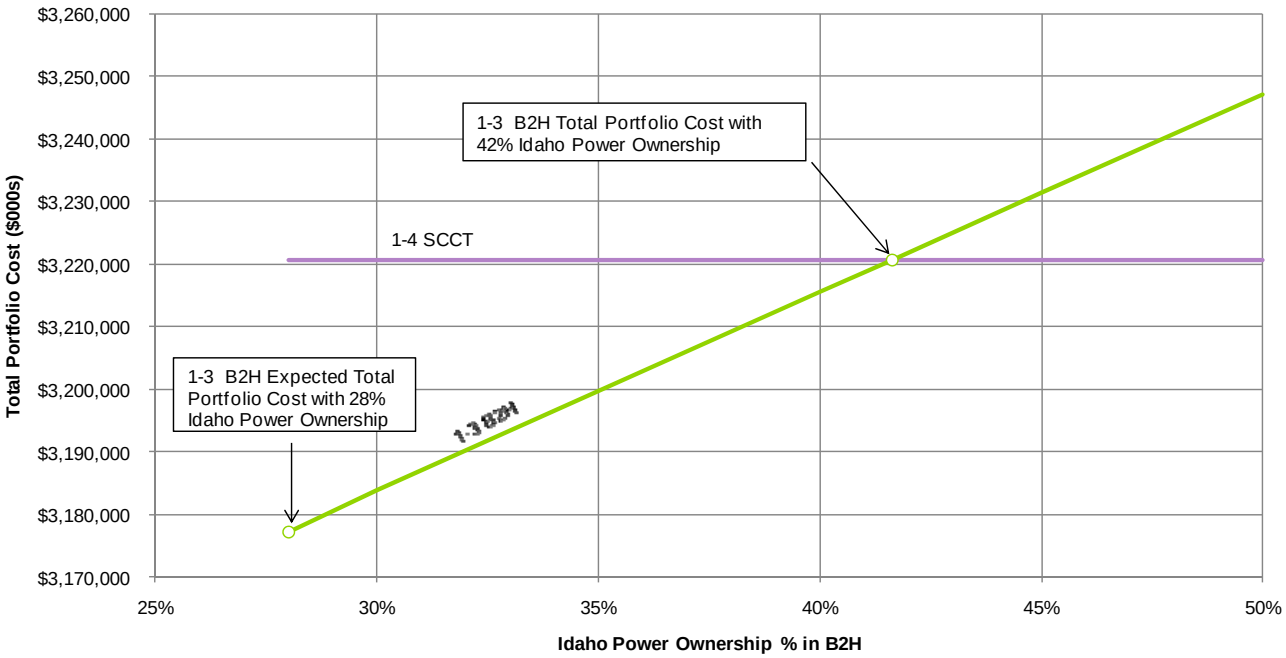


Figure 9.24 Boardman to Hemingway ownership tipping point analysis

Tipping Point Analysis—Cost of Solar Resources versus Market Purchases

Recent trends in the decreasing cost of solar PV technology generated significant interest from members of the IRPAC. If this trend continues, solar PV will become more cost competitive with other available resource options. A tipping point analysis was performed to determine how low the cost of solar PV would have to be in order to be competitive with portfolio 1-3 Boardman to Hemingway, which relies on market purchases.

For the tipping point analysis, Idaho Power investigated the capital cost decrease necessary to make the total cost of portfolio 1-2 Solar equivalent to the total cost of portfolio 1-3 Boardman to Hemingway. Figure 9.25 shows the results of the tipping point analysis. The figure notes that average solar costs (average of solar thermal and PV) are expected to be $3,614 per kW and would need to decrease by 72 percent to $1,012 per kW to match the total cost of portfolio 1-3 Boardman to Hemingway. This analysis assumes that capital cost decreases affecting the solar resources are specific to these resources, and would not place downward pressure on the capital cost of the Boardman to Hemingway transmission project or on wholesale power market prices. If wholesale power market prices rise, a smaller reduction in solar capital costs is necessary for the portfolio costs to be equal. Current federal tax incentives available for solar technologies are included in this analysis.

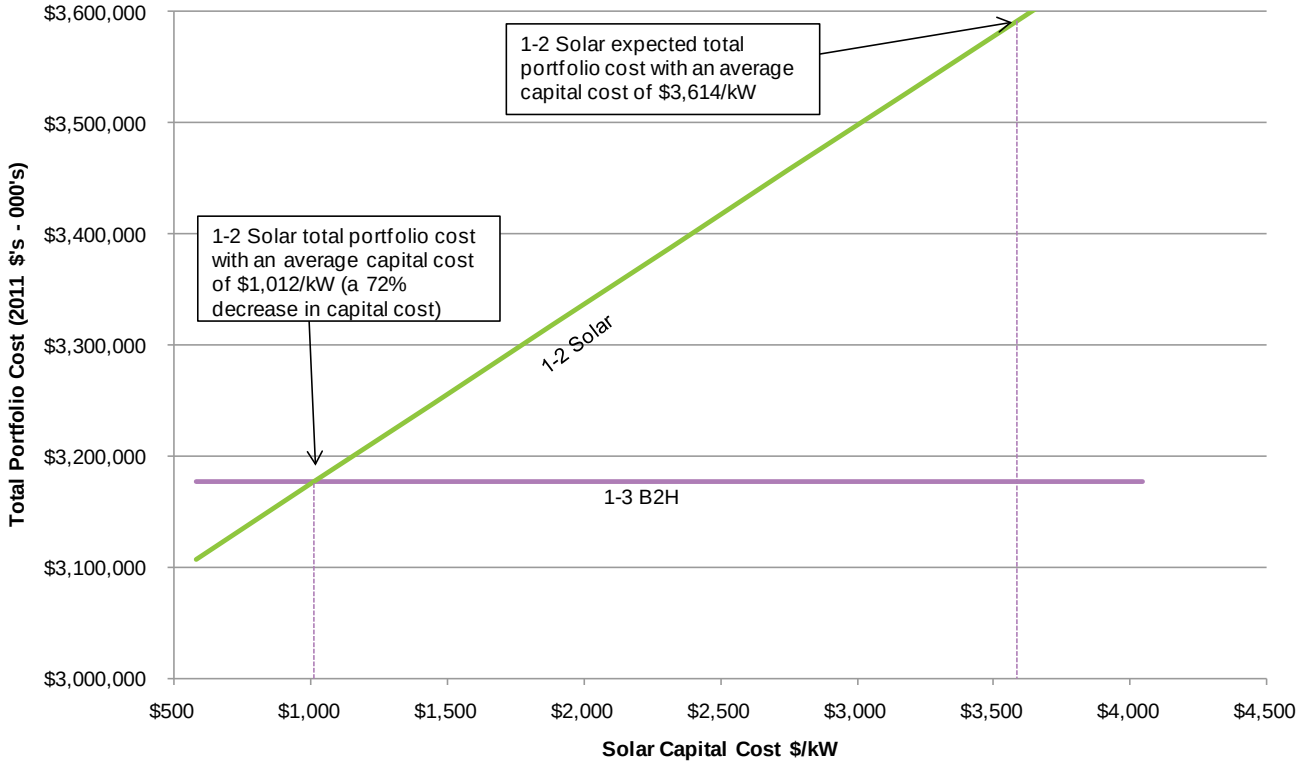


Figure 9.25 Cost of solar tipping point analysis

Capacity Planning Margin

Idaho Power discussed planning criteria assumptions 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 2011 IRP, Idaho Power has calculated the capacity planning margin resulting from the resource development identified in the preferred resource portfolio. When calculating the planning margin, the total resources available to meet demand consist of the additional resources available under the preferred portfolio plus the generation from existing and committed resources assuming expected-case (50th percentile) water and load conditions. The generation from existing resources also includes expected firm purchases from regional markets. The resource total is then compared with expected-case (50th percentile) peak-hour load, with the excess resource capacity designated as planning margin. The calculated planning margin provides an alternative view of the adequacy of the preferred portfolio, which was formulated to meet more stringent load conditions under less favorable water conditions.

Idaho Power maintains 330 MW of transmission import capacity above the forecast peak load to cover the worst single planning contingency. The worst single planning contingency is defined as an unexpected loss equal to Idaho Power's share of two units at the Jim Bridger coal facility. The reserve level of 330 MW translates into a reserve margin of approximately 10 percent and the reserved transmission capacity allows Idaho Power to import energy during an emergency via the NWPP. A 330-MW reserve margin is also roughly equivalent to a Loss of Load Expectation (LOLE) of 1 day in 10 years, a standard industry measurement. Capacity planning margin calculations for July of each year through the planning period are shown in Tables 9.6 and 9.7.

Table 9.6 Capacity planning margin (2011–2020)

Capacity Planning Margin										
Load and Resource Balance	**Jul-11**	**Jul-12**	**Jul-13**	**Jul-14**	**Jul-15**	**Jul-16**	**Jul-17**	**Jul-18**	**Jul-19**	**Jul-20**
Load Forecast (50th%) - Aug 2010 w/No DSM	(3,367)	(3,440)	(3,560)	(3,656)	(3,750)	(3,832)	(3,908)	(3,982)	(4,060)	(4,136)
Existing DSM (Energy Efficiency)	33	48	64	79	93	107	121	135	149	163
Load Forecast (50th% w/EE)	(3,334)	(3,392)	(3,496)	(3,577)	(3,657)	(3,725)	(3,787)	(3,847)	(3,911)	(3,973)
Existing Demand Response	330	310	315	315	321	351	351	351	351	351
Peak-Hour Forecast w/DR	**(3,004)**	**(3,082)**	**(3,181)**	**(3,262)**	**(3,336)**	**(3,374)**	**(3,436)**	**(3,496)**	**(3,560)**	**(3,622)**
Existing Resources										
Coal	963	963	963	963	963	963	963	963	963	963
Gas (Langley Gulch)	0	300	300	300	300	300	300	300	300	300
Hydro (50th%)—HCC	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120
Hydro (50th%)—Other	286	286	286	285	284	283	282	281	281	280
Shoshone Falls Upgrade	0	0	0	0	0	4	4	4	4	4
Sho-Ban Water Lease	47	48	48	48	48	0	0	0	0	0
Total Hydro (50th%)	1,453	1,454	1,454	1,453	1,452	1,407	1,406	1,405	1,405	1,404
CSPP (PURPA)	160	161	166	166	166	166	166	166	166	166
Power Purchase Agreements										
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	0	0	20	20	20	20	20	20	20	20
Clatskanie Exchange - Take	12	12	12	12	12	0	0	0	0	0
Clatskanie Exchange - Return	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (83 MW)	83	83	0	0	0	0	0	0	0	0
Mead Purchase	75	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	185	110	47	47	47	35	35	35	35	35
Firm Pacific NW Import Capability	126	233	229	225	222	218	214	209	205	201
Gas Peakers	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	**3,302**	**3,637**	**3,574**	**3,569**	**3,565**	**3,504**	**3,499**	**3,494**	**3,489**	**3,484**
Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(3)**	**(71)**	**(138)**

2011 IRP DSM	**Jul-11**	**Jul-12**	**Jul-13**	**Jul-14**	**Jul-15**	**Jul-16**	**Jul-17**	**Jul-18**	**Jul-19**	**Jul-20**
Industrial	2	3	5	6	7	8	8	9	10	10
Commercial	0	1	1	2	2	3	3	3	4	4
Residential	1	2	4	6	8	10	12	15	17	20
Total New DSM Peak Reduction	3	6	10	14	17	20	24	27	31	34
Remaining Monthly Surplus/Deficit	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(40)**	**(103)**

2009 IRP Resources	**Jul-11**	**Jul-12**	**Jul-13**	**Jul-14**	**Jul-15**	**Jul-16**	**Jul-17**	**Jul-18**	**Jul-19**	**Jul-20**
2015 Eastside Purchase	0	0	0	0	83	0	0	0	0	0
2016 B2H	0	0	0	0	0	450	450	450	450	450
2021 Geothermal	0	0	0	0	0	0	0	0	0	0
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	83	450	450	450	450	450
Remaining Monthly Surplus/Deficit	302	561	403	321	329	600	537	475	410	347
Planning Margin	10.0%	18.2%	12.7%	9.8%	9.9%	17.8%	15.6%	13.6%	11.5%	9.6%

Table 9.7 Capacity planning margin (2021–2030)

Capacity Planning Margin										
Load and Resource Balance	**Jul-21**	**Jul-22**	**Jul-23**	**Jul-24**	**Jul-25**	**Jul-26**	**Jul-27**	**Jul-28**	**Jul-29**	**Jul-30**
Load Forecast (50th%) - Aug 2010 w/No DSM	(4,211)	(4,289)	(4,370)	(4,448)	(4,524)	(4,605)	(4,680)	(4,773)	(4,858)	(4,918)
Existing DSM (Energy Efficiency)	177	191	205	219	233	247	261	275	289	275
Load Forecast (50th% w/EE)	(4,034)	(4,098)	(4,165)	(4,229)	(4,291)	(4,358)	(4,419)	(4,498)	(4,569)	(4,643)
Existing Demand Response	351	351	351	351	351	351	351	351	351	351
Peak-Hour Forecast w/DR	**(3,683)**	**(3,747)**	**(3,814)**	**(3,878)**	**(3,940)**	**(4,007)**	**(4,068)**	**(4,147)**	**(4,218)**	**(4,292)**
Existing Resources										
Coal	908	908	908	908	908	908	908	908	908	908
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300
Hydro (50th%)—HCC	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120	1,120
Hydro (50th%)—Other	280	280	280	280	280	280	280	280	280	280
Shoshone Falls Upgrade	4	4	4	4	4	4	4	4	4	4
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0
Total Hydro (50th%)	1,404	1,404	1,404	1,404	1,404	1,404	1,404	1,404	1,404	1,404
CSPP (PURPA)	166	166	166	166	166	166	166	101	63	93
Power Purchase Agreements										
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20
Clatskanie Exchange - Take	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange - Return	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (83 MW)	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0
Total Power Purchase Agreements	35	35	35	35	35	35	35	35	35	35
Firm Pacific NW Import Capability	257	254	250	246	243	238	234	231	227	224
Gas Peakers	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	**3,485**	**3,482**	**3,478**	**3,474**	**3,471**	**3,466**	**3,462**	**3,394**	**3,352**	**3,379**
Monthly Surplus/Deficit	**(198)**	**(265)**	**(336)**	**(404)**	**(469)**	**(541)**	**(606)**	**(753)**	**(866)**	**(913)**
2011 IRP DSM	**Jul-21**	**Jul-22**	**Jul-23**	**Jul-24**	**Jul-25**	**Jul-26**	**Jul-27**	**Jul-28**	**Jul-29**	**Jul-30**
Industrial	11	11	12	12	13	13	13	13	13	13
Commercial	5	5	5	6	6	6	6	6	6	6
Residential	22	24	27	30	32	35	38	40	43	45
Total New DSM Peak Reduction	38	41	44	48	51	54	57	59	62	65
Remaining Monthly Surplus/Deficit	**(160)**	**(224)**	**(292)**	**(357)**	**(419)**	**(487)**	**(550)**	**(694)**	**(804)**	**(848)**
2009 IRP Resources	**Jul-21**	**Jul-22**	**Jul-23**	**Jul-24**	**Jul-25**	**Jul-26**	**Jul-27**	**Jul-28**	**Jul-29**	**Jul-30**
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0
2016 B2H	450	450	450	450	450	450	450	450	450	450
2021 Geothermal	52	52	52	52	52	52	52	52	52	52
2022 SCCT Frame	0	170	170	170	170	170	170	170	170	170
2024 Solar Power Tower	0	0	0	44	44	44	44	44	44	44
2025 CCCT	0	0	0	0	300	300	300	300	300	300
2028 Small Hydro	0	0	0	0	0	0	0	52	52	52
2029 SCCT Frame	0	0	0	0	0	0	0	0	170	170
New Resource Subtotal	502	672	672	716	1,016	1,016	1,016	1,068	1,238	1,238
Remaining Monthly Surplus/Deficit	342	448	380	360	598	529	467	374	434	390
Planning Margin	9.3%	11.9%	10.0%	9.3%	15.2%	13.2%	11.5%	9.0%	10.3%	9.1%

Loss of Load Expectation

Idaho Power used a spreadsheet model[3] to calculate the LOLE for the preferred and alternate portfolios identified in the 2011 IRP. The assessment assumes critical water conditions at the existing hydroelectric facilities and the planned additions for the preferred and alternate portfolios. As mentioned in previous chapters, Idaho Power uses a capacity benefit margin (CBM) of 330 MW in transmission planning to provide the necessary reserves for unit contingencies. The CBM capacity is reserved in the transmission system and is sold on a non-firm basis until forced unit outages require use of the transmission capacity. The 2011 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/purchase outage rates (EFORd), and generation and transmission capacities to compute a LOLE for each hour of the 20-year planning period. Demand response programs were modeled as a reduction in the hourly load during the mid-week peak hours rather than as a dispatchable resource due to the limited energy of the demand response programs. The LOLE analysis is performed on a monthly basis to permit capacity de-rates for maintenance or lack of fuel (water).

The typical metric used in the utility industry to assess probability-based resource reliability is a LOLE of 1 day in 10 years. Idaho Power has chosen to calculate 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 0.5–1.0 hours per year. The results of the loss of load probability analysis are shown in Figure 9.26, and additional data can be found in *Appendix C–Technical Appendix*.

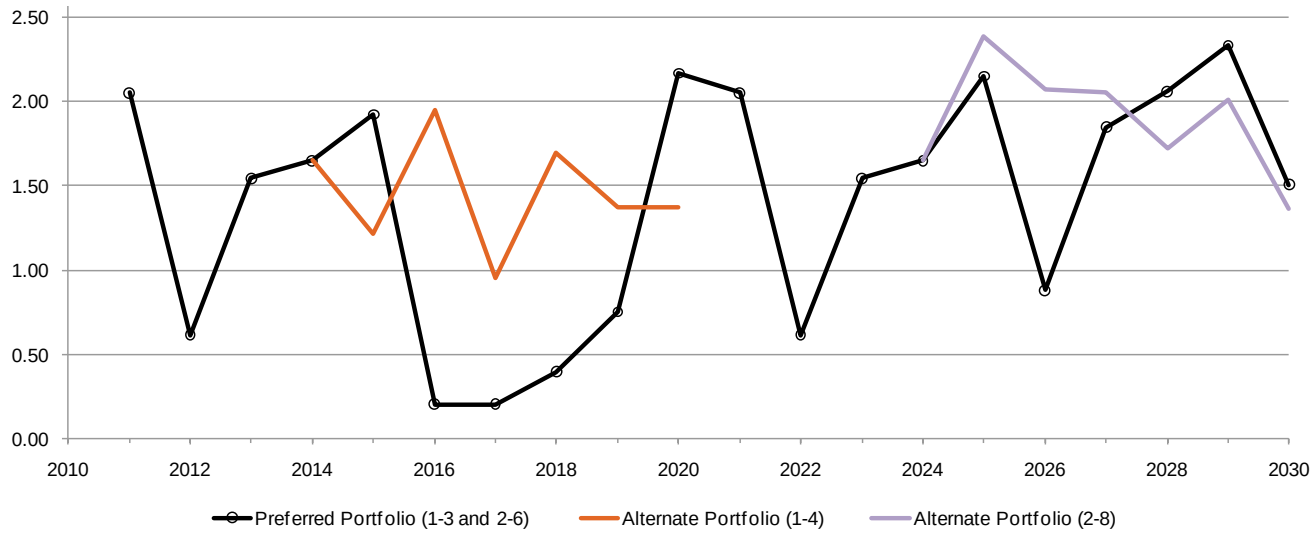


Figure 9.26 Loss of load expectation

In performing the analyses, there were several instances where extending purchases of east-side energy similar to the purchases contemplated in 2010–2012 were necessary to achieve the results shown in Figure 9.26.

[3] Based on Roy Billinton "Power System Reliability Evaluation" Chapter 2&3, Copyright 1970.

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10. ACTION PLANS

Once the final preferred portfolio has been selected, an action plan is necessary to identify the steps that must be taken to implement the plan. Like the portfolio analysis, the action plan is split into two, 10-year periods. The near-term action plan addresses the years 2011–2020, and the long-term action plan covers the years 2021–2030. The two action plans represent the culmination of the IRP process.



Action plans describe how Idaho Power will implement the results of the IRP.

Near-Term Action Plan (2011–2020)

The near-term action plan describes the actions Idaho Power plans to take over the next 10 years to implement the preferred portfolio (2011–2020). No long-lead-time generation resources, such as advanced nuclear or IGCC are considered in the near-term plan. However, Idaho Power intends to continue its efforts to participate in regional utility planning forums and to explore regional alliances as generation resource, energy storage, energy efficiency, and transmission technologies develop.

Table 10.1 presents a list of the resources Idaho Power expects to add to its generation portfolio over the next 10 years for both the preferred portfolio and an alternate portfolio. An alternate portfolio is also identified in the IRP in the event substantial changes impact the assumptions used to select the preferred portfolio.

Table 10.1 Near-term action plan (2011–2020)

Year	Preferred Resource Portfolio 1-3 Boardman to Hemmingway	Alternative Resource Portfolio 1-4 SSCT
2011		
2012		
2013	Solar Demonstration Project (500kW–1 MW)	Solar Demonstration Project (500kW–1 MW)
2014		
2015	Eastside PPA (83 MW)	SCCT (170 MW)
2016	Boardman to Hemingway (450 MW)	
2017		SCCT (170 MW)
2018		
2019		SCCT (94 MW)
2020		

Highlights

- The Boardman to Hemingway transmission line is the primary resource in the near-term action plan, and the long-term action plan includes a diverse set of renewable and gas-fired resources.
- Idaho Power is proposing a solar demonstration project as part of the 2011 IRP.
- IRPAC members and members of the public made significant contributions through the nine public meetings conducted while preparing the 2011 IRP.

Preferred Portfolio Near-Term Action Plan

The Boardman to Hemingway transmission line and associated market purchases is the primary resource addition in the near-term action plan preferred portfolio. The new transmission line was first identified in Idaho Power's 2006 IRP, and the company continues working to acquire the necessary regulatory approvals and permits necessary to begin construction. Construction of the Boardman to Hemingway transmission line is expected to start in early 2014, after completing the permitting, regulatory, and engineering work. If the Boardman to Hemingway project is substantially delayed, Idaho Power will have to consider implementing the alternate portfolio.

The preferred portfolio also includes a market purchase from the east side of Idaho Power's system. The purchase is necessary to cover a summer peak-hour deficit in 2015 that exists before the Boardman to Hemingway line becomes available in 2016. Idaho Power has used the east side for market purchases in the past, but prices have historically been higher than the prices at the Mid-C hub in the Pacific Northwest. A purchase on the east side does not require substantial lead time, and Idaho Power will continue to monitor market prices, load growth, and the status of the Boardman to Hemingway project prior to committing to this purchase.

As part of the 2011 IRP, Idaho Power is proposing to construct a solar demonstration project. Details of this proposal are explained in Chapter 1 and the project could be on line as early as late 2012.

Alternate Portfolio Near-Term Action Plan

The alternate portfolio presents the actions Idaho Power will take if the Boardman to Hemingway transmission line is significantly delayed or canceled. In the alternate resource portfolio, Idaho Power anticipates adding natural gas-fired SCCTs to meet capacity deficits. The company expects to acquire the generation resources identified in the alternate portfolio through a competitive RFP process meeting the requirements of Oregon Order 06-446 issued on August 10, 2006, as well as any revisions to the requirements resulting from Oregon Docket UM 1182.

Although the alternate portfolio identifies the first 170-MW SCCT in 2015, in the event the alternate portfolio is implemented, Idaho Power will continue to evaluate resource needs and may alter the size, timing, and technology of the combustion turbine depending on market conditions at the time an RFP is issued.

Should the permitting, regulatory, engineering work, or construction of the Boardman to Hemingway project be delayed, Idaho Power will face the decision to acquire the first resource identified in the alternate portfolio. To meet the competitive procurement guidelines, Idaho Power would need to initiate the resource procurement process by issuing an RFP as early as 2012. Beginning the procurement process in 2012 is necessary to achieve an on-line date in 2015. The resource procurement process would most likely begin prior to the completion of Idaho Power's 2013 IRP, which is scheduled to be filed in June 2013.

Long-Term Action Plan (2021–2030)

The long-term action plan describes Idaho Power's planned resource acquisitions during the second 10 years of the planning period (2021–2030). The long-term action plan assumes that the near-term action plan is completed with only minor variations. If the Boardman to Hemingway project is significantly delayed or canceled and Idaho Power implements the alternate resource plan in the first 10 years of the planning period, Idaho Power may reconsider its concerns about over-reliance on market purchases and select the alternate resource portfolio relying on a regional transmission project for the second 10 years of the planning period.

It is important to note that the Gateway West project was included in each resource portfolio for only the second 10-year period when current transmission constraints required the addition of new transmission capacity for resources to be added in southern Idaho east of the Treasure Valley load center. The amount of Gateway West capacity is different in each portfolio, depending on other included resources. Although the resources in the preferred portfolio for the second 10-year period were analyzed without the addition of the Gateway West transmission project, Idaho Power plans to continue permitting the Gateway West project because of uncertainty associated with the location of resources planned so far in the future and the long lead time required to permit high-voltage transmission projects.

With the exception of the Gateway West transmission project, both the preferred and alternate resource portfolios for the second 10 years of the planning period include a combination of renewable and natural gas-fired resources. The long-term action plan for both the preferred and alternate portfolios is shown in Table 10.2.

Table 10.2 Long-term action plan (2021–2030)

Year	Preferred Resource Portfolio 2-6 Balanced 1	Alternative Resource Portfolio 2-7 PNW Transmission
2021	Geothermal (52 MW)	Geothermal (52 MW)
2022	SCCT (170 MW)	Pacific NW Purchase (500 MW)
2023		
2024	Solar Power Tower (50 MW)	
2025	CCCT (300 MW)	
2026		
2027		Solar PV (20 MW)
2028	Small Hydro (60 MW)	Geothermal (52 MW)
2029	SCCT (170 MW)	SCCT (170 MW)
2030		

Preferred Portfolio Long-Term Action Plan

The preferred portfolio selected for the second 10 years consists of a diverse mixture of renewable and natural gas resources. With the possible exception of the solar power tower technology, none of the identified resources present a technological challenge. The longest lead-time resource in the preferred portfolio is the CCCT identified to come on line in 2025, which would require approximately four years to design, permit, and construct. Therefore no significant actions are required in the next two years to pursue this portfolio.

After the 2011 IRP, Idaho Power's next IRP will be completed in June 2013. Idaho Power will continue to evaluate "balanced" portfolios, as they have historically performed well in the IRP analysis.

Alternate Portfolio Long-Term Action Plan

The alternate portfolio for the second 10 years presents a dilemma. Although this portfolio performed well, as covered in Chapter 9, concerns regarding an over-reliance on market purchases and the future ability of utilities to permit and construct long-distance, high-voltage transmission raise questions regarding the viability of this portfolio.

Idaho Power will continue to monitor forward market prices and the progress that can be made on the Boardman to Hemingway and Gateway West projects between now and the completion of the 2013 IRP. Based on recent experience, new long-distance, high-voltage transmission projects require a lead time of 8–10 years. If additional transmission capacity to either the Pacific Northwest or to the east side of

Idaho Power's system continues to perform well in the IRP analysis, Idaho Power will need to begin work on permitting and initial designs for new transmission projects shortly after the completion of the 2013 IRP.

Conclusion

Each Idaho Power IRP builds on the foundation of earlier resource plans, and each plan includes incremental changes due to forecasts of future events. The 2011 IRP is no exception.

Idaho Power and other utilities in the West face major regional transmission decisions. No significant interstate transmission has been built in the region for many years. Idaho Power's 2006 IRP was the first of the company's resource plans where Idaho Power made a significant commitment to new interstate transmission projects. Idaho Power continues its commitment to regional transmission with the 2011 IRP.

The Boardman to Hemingway transmission line and associated market purchases is the primary resource addition in the near-term preferred resource portfolio, and Idaho Power is currently acquiring the necessary regulatory approvals and permits to begin construction. As part of acknowledging the 2009 IRP, the OPUC requested Idaho Power treat the Boardman to Hemingway project as an uncommitted resource in the 2011 IRP. And, once again, the Boardman to Hemingway transmission project has outperformed other alternatives.

In the 2011 plan, Idaho Power conducted a thorough analysis of resource alternatives, including generation, transmission, demand-response, and energy efficiency. The only committed resources not yet constructed but included in the 2011 IRP are the Langley Gulch CCCT and an upgrade at the company's Shoshone Falls hydroelectric project. The Boardman to Hemingway transmission project was analyzed using the same methods as other uncommitted resources. After the analysis, the Boardman to Hemingway transmission line is again the preferred resource to meet customer needs in Idaho and Oregon.

Idaho Power strongly supports public involvement in the planning process. Idaho Power thanks the IRPAC members and the public for their contributions to the 2011 IRP. The IRPAC discussed many technical aspects of the 2011 resource plan along with a significant number of political/societal topics at nine meetings conducted during the second half of 2010 and the first half of 2011. Idaho Power's resource planning process is better because of the contributions from the IRPAC members and the public.

Idaho Power prepares an IRP biennially. At the time of the next plan in 2013, Idaho Power will have additional information regarding supply-side resources, demand-side management programs, fuel prices, economic conditions, and load growth. In addition, Idaho Power hopes to have better information regarding potential carbon regulations, the development of a federal RES, and the feasibility of advanced nuclear, IGCC, and other resource options that currently face technological challenges.

One of the key strengths of Idaho Power's planning process is that the IRP is updated every two years. Frequent planning allows Idaho Power, the IRPAC, the IPUC, the OPUC, and concerned customers to revisit the IRP and make periodic adjustments and corrections to reflect changes in technology, economic conditions, and regulatory requirements. During the two years between resource plan filings, the public and regulatory oversight of the activities identified in the near-term action plan allows for discussion and adjustment of the IRP as warranted.

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GLOSSARY OF ABBREVIATIONS

AC–Alternating Current

A/C–Air Conditioning

ACOE–United States Army Corps of Engineers

AFUDC–Allowance for Funds Used During Construction

akW–Average kilowatt

aMW–Average Megawatt

BLM–Bureau of Land Management

BOR–Bureau of Reclamation

BPA–Bonneville Power Administration

CAA–Clean Air Act

CAES–Center for Advanced Energy Studies

CAIR–Clean Air Interstate Rule

CAMP–Comprehensive Aquifer Management Plan

CAP–Community Advisory Process

CBM–Capacity Benefit Margin

CCCT–Combined-Cycle Combustion Turbine

CCR–Coal Combustion Residuals

CCX–Chicago Climate Exchange

CFI–Carbon Financial Instrument

cfs–Cubic-Feet-per-Second

CHP–Combined Heat and Power

Clatskanie PUD–Clatskanie People's Utility District

CPCN–Certificate of Public Convenience and Necessity

CO_2–Carbon Dioxide

CPCN–Certificate of Public Convenience and Necessity

CREP–Conservation Reserve Enhancement Program

DC–Direct Current

DOE–Department of Energy

DRAM–Dynamic Random Access Memory

DSM–Demand-Side Management

EEAG–Energy Efficiency Advisory Group

EIA–Energy Information Administration

EPA–Environmental Protection Agency

EPRI–Electric Power Research Institute

ESA–Endangered Species Act

ESPA–Eastern Snake River Plain Aquifer

F–Fahrenheit

FCA–Fixed-Cost Adjustment

FCP–Formal Consultation Package

FCRPS–Federal Columbia River Power System

FEIS–Final Environmental Impact Statement

FERC–Federal Energy Regulatory Commission

FPA–Federal Power Act

FWS–US Fish and Wildlife Service

GHG–Greenhouse Gas

HAP–Hazardous Air Pollutants

Hg–Mercury

HRSG–Heat Recovery Steam Generator

IDWR–Idaho Department of Water Resources

IGCC–Integrated Gasification Combined Cycle

INL–Idaho National Laboratory

IOER–Idaho Office of Energy Resources

IPUC–Idaho Public Utilities Commission

IRP–Integrated Resource Plan

IRPAC–IRP Advisory Council

kV–Kilovolt

kW–Kilowatt

kWh–Kilowatt Hour

lbs–Pounds

LOLE–Loss of Load Expectation

LTP–Local Transmission Plan

m^2–square meters

mm–Millimeter

MMBtu–Million British Thermal Units

MSA–Metropolitan Statistical Area

MW–Megawatt

MWh–Megawatt Hour

NAAQS–National Ambient Air Quality Standards

NEEA–Northwest Energy Efficiency Alliance

NEO–Northeast Oregon

NEPA–National Environmental Policy Act

NERC–North American Electric Reliability Corporation

NTTG–Northern Tier Transmission Group

NPCC–Northwest Power and Conservation Council

NO_x–Nitrogen Oxide

NPV–Net Present Value

NWPP–Northwest Power Pool

NREL–National Renewable Energy Laboratory

NSR–New Source Review

NYMEX–New York Mercantile Exchange

O&M–Operating and Maintenance

OATT–Open Access Transmission Tariff

ODEQ–Oregon Department of Environmental Quality

ODOE–Oregon Department of Energy

OPUC–Public Utility Commission of Oregon

PCA–Power Cost Adjustment

PCB–Polychlorinated Biphenyls

PM&E–Protection, Mitigation, and Enhancement

PGE–Portland General Electric Company

PPA–Power Purchase Agreement

PRC–Power Resources Cooperative

PTC–Production Tax Credit

PURPA–*Public Utility Regulatory Policies Act of 1978*

PV–Photovoltaic

QF–Qualifying Facility

RCRA–*Resource Conservation and Recovery Act of 1976*

REC–Renewable Energy Certificate

RES–Renewable Electricity Standard

RFP–Request for Proposal

RH BART–Regonal Haze Best Available Retrofit Technology

RPS–Renewable Portfolio Standard

SCCT–Simple-Cycle Combustion Turbine

SCR–Selective Catalytic Reduction

SO_2–Sulfur Dioxide

SRBA–Snake River Basin Adjudication

TASCO–The Amalgamated Sugar Company

TEPPC–Transmission Expansion Planning Policy Committee

UAMPS–Utah Associated Municipal Power Systems

USFS–United States Forest Service

WDEQ–Wyoming Department of Environmental Quality

WECC–Western Electricity Coordinating Council

W–Watt



Appendix A—Sales and Load Forecast

For the 2011 Integrated Resource Plan

June 2011

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INTRODUCTION

Idaho Power has prepared *Appendix A–Sales and Load Forecast* as an appendix to its *2011 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 2011 through 2030.

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

The expected-case load forecast assumes median temperatures and median rainfall. Since actual loads can vary significantly, dependent on weather conditions, two alternative scenarios were considered to address the load variability due to weather. A 70th percentile average load forecast and 90th percentile average load forecast were prepared to illustrate the weather-related uncertainty inherent in forecasting electrical loads. The 70th percentile load forecast assumes monthly loads that can be exceeded in three-out-of-ten years (30 percent of the time). The 90th percentile load forecast assumes monthly loads that can be exceeded in one-out-of-ten years (10 percent of the time).

In the expected-case scenario, Idaho Power's system load is forecast to increase to 2,362 average megawatts (aMW) in the year 2030 from the 2011 forecast load of 1,819 aMW. The expected-case forecast system load growth rate averages 1.4 percent per year over the 20 years of the planning period (2011–2030). In the more critical 70th percentile load forecast, used for resource planning, the system load is forcasted to read 2,414 aMW. Idaho Power system peak load (95th percentile) is forecast to grow to 4,901 megawatts (MW) in the year 2030 from the 2008 actual system summer peak of 3,214 MW. The highest system peak on record was 3,214 MW and occurred on Monday, June 30, 2008, at 3:00 p.m. In the expected-case scenario, Idaho Power system peak increases at an average growth rate of 1.8 percent per year over the 20 years of the planning period (2011–2030). The number of Idaho Power active retail customers increased from the December 2010 level of 490,869 customers to over 653,000 customers at year-end 2030.

This year's economic forecast was based on a forecast of national and regional economic activity developed by Moody's Analytics, Inc., a national econometric consulting firm. Moody's Analytics, Inc., July 2010 macroeconomic forecast strongly influenced *Appendix A–Sales and Load Forecast*. The national, state, metropolitan statistical area (MSA), and county econometric projections are tailored to Idaho Power's service area using an economic database developed by an outside consultant. Specific demographic projections are also developed for the service area from national and local census data. National economic drivers from Moody's Analytics, Inc., were also used in development of *Appendix A–Sales and Load Forecast*.

Economic growth assumptions influence several of the individual class of service growth rates. The number of households in Idaho is projected to grow at an annual average rate of 1.2 percent during

the forecast period. Growth in the number of households within individual counties in Idaho Power's service area differs from statewide household growth patterns. Service area households are derived from county-specific household forecasts. The number of households, incomes, employment projections, economic output, real retail electricity prices, and customer consumption patterns are used to develop load projections.

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

The future load impacts of implemented and committed Idaho Power energy efficiency demand-side management (DSM) programs are considered within *Appendix A–Sales and Load Forecast*. These programs and their expected impacts are addressed in more detail in Idaho Power's *Demand-Side Management 2010 Annual Report*. This report is Appendix B to the 2011 IRP.

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

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

2011 IRP SALES AND LOAD FORECAST

Average Load

The 2011 IRP average system load forecast is lower initially than the 2009 IRP average system load forecast. However, after 2015, the 2011 IRP forecast is higher in all remaining years of the forecast period . The recovery in the national and service-area economy is expected to cause load growth to steadily revive. In addition, the lowered expectations in existing and committed energy efficiency measures, combined with retail electricity prices that incorporate much-reduced impact of carbon on Idaho Power's retail electricity prices, result in an increase of forecast average loads. Significant factors and considerations that influenced the outcome of the 2011 IRP load forecast include the following:

- The retail electricity price forecast used to prepare the *Appendix A–Sales and Load Forecast* in the 2009 IRP reflected the fixed and variable costs of integrating the resources identified by the 2006 IRP preferred portfolio, including the expected cost of carbon emissions. When compared to the electricity price forecast used to prepare the *Appendix A–Sales and Load Forecast*, the 2009 IRP price forecast yielded significantly higher future electricity prices. The price forecast difference is primarily the result of differing carbon cost assumptions between the two forecasts. The 2009 IRP retail electricity price forecast assumed a carbon tax scenario (from the 2006 IRP), and the 2011 IRP electricity price forecast assumed a cap-and-trade carbon scenario (from the 2009 IRP). Under the cap-and-trade carbon scenario, Idaho Power curtailed carbon emissions from coal units to comply with target emissions. The carbon assumptions from the 2006 IRP is the driver for the 2011 IRP's retail electricity price forecasts.
- The sales and load forecast reflects the increased expected demand for energy and peak capacity of Idaho Power's newest special-contract customer, Hoku Materials, located in Pocatello, Idaho. At the time this forecast was completed (August 2010), Hoku Materials planned to begin operation in January 2011 and will reach full capacity by April 2011. The current sales and load forecast assumes that Hoku Materials will consume 74 aMW of energy each year and have a peak demand of 82 MW (each measure excluding line losses) once continuous operation is reached in 2013.
- The load forecast used for the 2011 IRP reflects a recovery in the service area economy following a severe recession in 2008 and 2009, as well as a much smaller impact of carbon regulation on future energy rates charged to Idaho Power retail customers. Both factors resulted in a higher long-term load forecast than was used in the 2009 IRP. The collapse in the housing sector in 2008 and 2009 dramatically slowed the growth in the number of new households and residential customers being added to Idaho Power's service area. In addition, the number of commercial customers being added also slowed dramatically as a result of the economic downturn. However, by 2012, residential and commercial customer growth is expected to recover; and by 2015, customer additions are forecast to approach the growth that occurred prior to the housing bubble (2000–2004).
- In this year's forecast, an additional customer referred to in this document as "Special" was included in the Additional Firm Load category, even though a long-term contract had not yet been fully executed. At the time this forecast was prepared (August 2010), several interested parties had taken significant steps toward the ultimate development and location of their businesses within Idaho Power's service area. It was determined that the real possibility of the new large load was significant enough that it would be imprudent of the company to ignore the possible impact. The anticipated load of the new "Special" contract has been included in this

forecast based on discussions with the interested parties. The existing special contracts and the new "Special" contract together make up the Additional Firm Load category.

- There continues to be significant uncertainty associated with the growth of new industrial and special contract customers and their potential impact on the load forecast. The forecast uncertainty is associated with the increasing number of entities that have contacted Idaho Power and expressed interest in locating their operations within Idaho Power's service area and the unknown magnitude of the energy and peak-demand requirements. The current sales and load forecast reflects only those customers that have a very high probability of relocating to the service area or have made financial commitments and whose facilities are actually being constructed at this time. Therefore, the large numbers of businesses that have contacted Idaho Power and shown interest, but have not made commitments, are not included in the current sales and load forecast.
- In another improvement to this year's forecast, Idaho Power used Itron's residential Statistically Adjusted End-Use (SAE) model to prepare the long-term residential sales forecast. Recently, many utilities have adopted Itron's SAE modeling approach to include greater end-use information into the forecast process.
- Existing energy efficiency program performance is estimated and included in the sales and load forecast base, lowering the energy and peak demand forecast. However, the impact of demand response programs is accounted for in the IRP load and resource balance. The amount of committed and implemented DSM programs for each month of the planning period is shown in the IRP load and resource balance in *Appendix C–Technical Appendix*.
- A somewhat higher irrigation sales forecast is expected, compared to earlier forecasts (prior to the 2009 IRP) due to a substantial increase in weather-adjusted irrigation sales in 2007 and 2008 (6% in 2007 and 8% in 2008). Higher farm commodity prices appear to be the primary reason behind the irrigation sales increase. Farmers appear to have taken advantage of the commodities market by planting all available acreage. In addition, the conversion of hand line to electrically operated pivot irrigation systems may explain a part of the increased energy consumption. In recent years, the increased labor costs associated with moving hand lines and increased concerns for water conservation has triggered the substitution of labor with electrically operated pivots.

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:

- This year's peak forecast also reflects the increased expected peak demand of an additional "Special" contract customer. The anticipated peak load of the new contract has been included in this year's forecast based on discussions with the interested parties.
- The 2011 IRP peak-demand forecast was adjusted downward to reflect the estimated impact of energy efficiency DSM programs selected for implementation since 2001. Energy efficiency programs are incorporated into the peak-demand forecast as the programs are committed and implemented.
- The 2011 IRP peak demand forecast model does not consider or adjust for the impact of demand response programs. The demand response programs are accounted for in the IRP load and resource balance as a reduction in peak demand.

- The peak model allows peaks to be calculated at the 50th, 90th, and 95th percentiles of peak day temperatures for each month of the year.
- Recent historical peak data is added to the peak model regressions. The July 2002, July 2003, June 2005, and July 2005 peak day temperatures were near the 100th percentile, and their addition to the regression models impacted forecast results. In addition, new system peaks were reached in July 2007 and again in June 2008 and were incorporated into the peak forecast model regressions.
- Idaho Power continues to use a median peak day temperature driver in lieu of an average peak day temperature driver. The median peak day temperature has a 50-percent probability of being exceeded. Peak day temperatures are not normally distributed and can be skewed by one or more extreme observations; therefore, the median temperature better reflects expected temperatures. The weighted average peak day temperature drivers are calculated over the 1980–2009 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 individual sales category. Independent sales forecasts are prepared for each of the major customer classes: residential, commercial, irrigation, and industrial. Individual energy and peak-demand forecasts are developed for special contract customers, including Micron Technology, Inc., (Micron Technology), Simplot Fertilizer Company (Simplot Fertilizer), Idaho National Laboratory (INL), Hoku Materials, one additional high-probability special contract customer (referred to as "Special"), and Raft River Rural Electric Cooperative, Inc. (Raft River)—the electric distribution utility serving Idaho Power's former customers in Nevada. These six, special contract customers are combined into a single forecast category labeled Additional Firm Load. In the 2009 IRP sales and load forecast, the "Special" contract load was combined with the industrial sector (Schedule 19) load forecast. Given the magnitude of their expected future load, the "Special" contract has now been combined with the other larger special contract customers that have monthly metered demands greater than 20,000 kilowatts (kW). Lastly, the contract off-system category represents long-term contracts to supply firm energy and demand to off-system customers. At this time, there are no long-term contracts. The assumptions for each of the individual categories are described in greater detail in the respective sections.

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

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

The peak-load forecast was prepared in conjunction with the 2011 sales forecast. Idaho Power has two distinct peak periods: 1) a winter peak, resulting from space heating demand that normally occurs in December, January, or February; and 2) a larger, summer-peak that normally occurs in late June or July. The summer peak generally occurs when extensive air conditioning usage coincides with significant irrigation demand.

Peak loads are forecast using 12 regression equations and are a function of average peak day temperatures, 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, Simplot Fertilizer, Hoku Materials, Idaho Power's newest "Special" contract customer, and Raft River are forecast based on historical analysis and contractual considerations.

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

Fuel Prices

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

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

Short-term and long-term nominal electricity price increases are generated internally from Idaho Power financial models. The 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 (2011–2030)
(average annual percent change)

	Nominal	Real*
Electricity–2011 IRP–Carbon	2.6%	0.9%
Electricity–2009 IRP–Carbon	5.1%	3.2%
Natural Gas	2.5%	0.8%

*adjusted for inflation

Figure 1 illustrates the average electricity price paid by Idaho Power's residential customers over the historical period 1970–2010 and over the forecast period 2011–2030. Both nominal and real prices are shown. In the 2011 IRP carbon scenario, nominal electricity prices are expected to slowly climb to nearly 13 cents per kilowatt-hour (kWh) by the end of the forecast period in 2030. Real electricity prices (inflation adjusted) in the carbon scenario are expected to increase over the forecast period at an average rate of 0.9 percent each year. In the 2009 IRP electricity price carbon scenario, nominal electricity prices were assumed to climb to nearly 22 cents per kWh by 2030, and real electricity prices (inflation adjusted) were expected to increase over the forecast period at an average rate of 3.2 percent each year. The impact of the much higher electricity price forecast on the 2009 IRP load forecast was significant and served to slow the growth in electricity sales, especially in the last 10 years of the forecast period.

The electricity price forecast used to prepare the sales and load forecast in the 2009 IRP reflected the fixed and variable costs of integrating the resources identified by the 2006 IRP preferred portfolio, including the expected costs of carbon emissions. When compared to the electricity price forecast used to prepare the 2011 IRP sales and load forecast, the 2009 IRP price forecast yielded significantly higher future prices. The price forecast difference is primarily the result of differing carbon cost assumptions between the two forecasts. The 2009 IRP retail electricity price forecast assumed a carbon tax scenario (from the 2006 IRP), and the 2011 IRP electricity price forecast assumed a cap-and-trade carbon scenario (from the 2009 IRP). Under the cap-and-trade carbon scenario, Idaho Power curtailed carbon emissions from coal units to comply with target emissions.

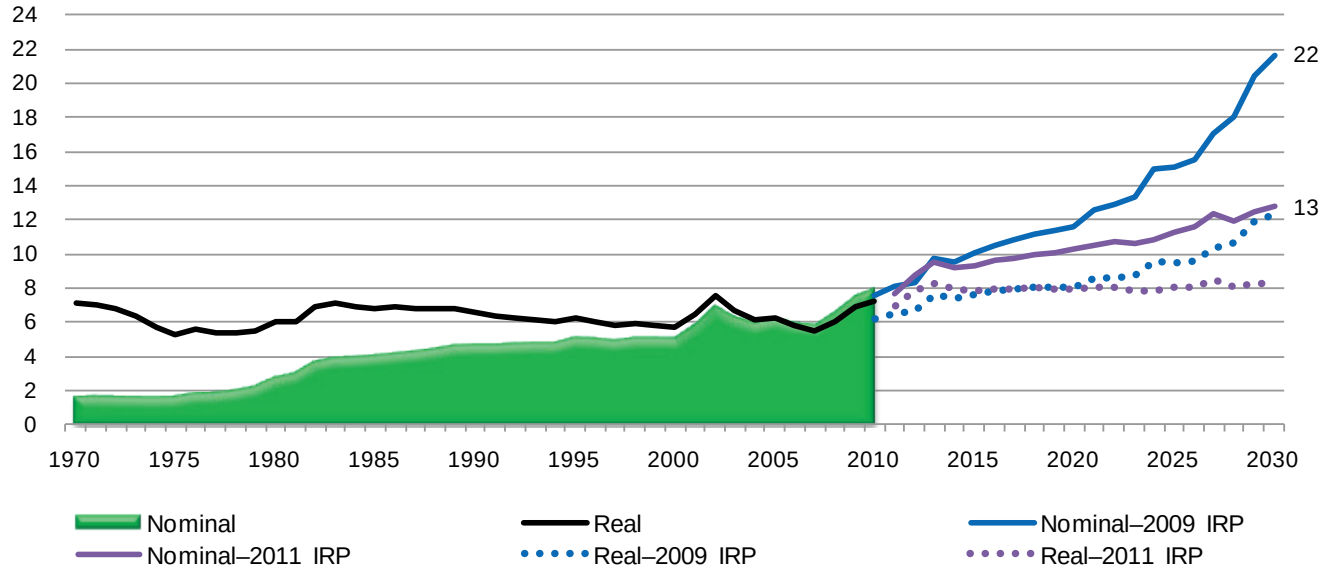

Figure 1. Forecasted electricity prices
(cents per kWh)

Electricity prices for Idaho Power customers moved significantly higher 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. Over the 1990–2000 period, electricity prices rose only 8 percent overall, an annual average compound growth rate of 0.8 percent each year.

Figure 2 illustrates the average natural gas price paid by Intermountain Gas Company's residential customers over the historical period 1970–2009, and forecast prices from 2010–2030. 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 again moving sharply upward in 2004, 2005, and 2006. Natural gas prices moved downward in 2010, reflecting the collapse in natural gas prices that began in 2009. After bottoming in 2010, nominal natural gas prices are expected to rise in 2011, plateau through 2014, and then slowly rise throughout the remainder of the forecast period. Natural gas prices at the end of the forecast period are expected to be about 40 percent higher than 2009, growing at an average rate of 2.5 percent per year over the forecast period (2011–2030). Real natural gas prices (adjusted for inflation) are expected to increase over the same period at an average rate of 0.8 percent each year.

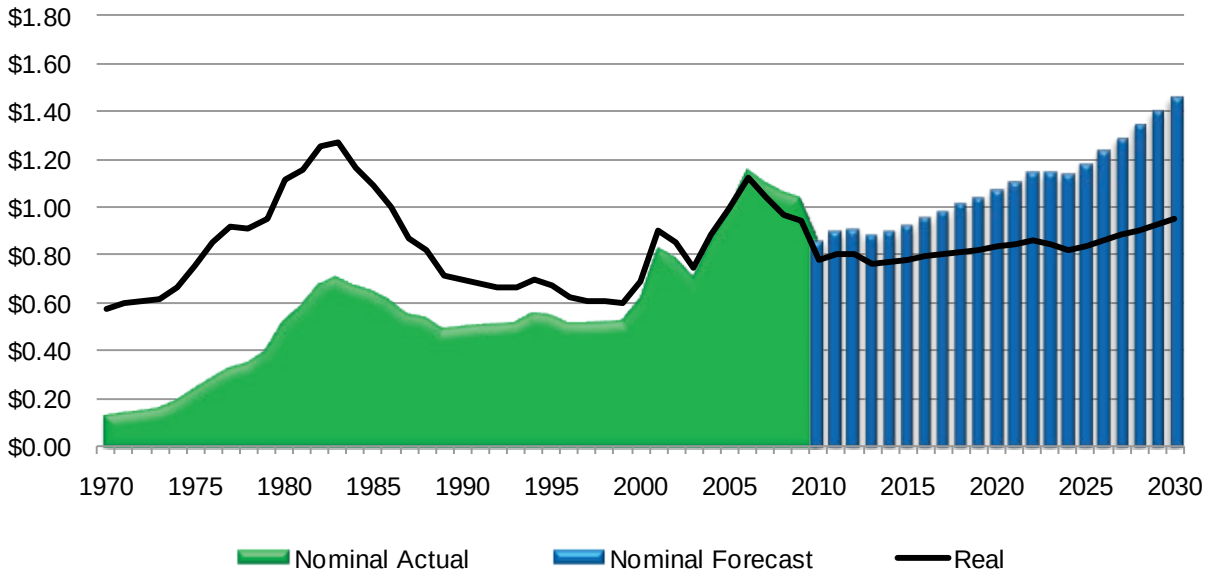

Figure 2. Forecasted residential natural gas prices
(dollars per therm)

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 2011 IRP price forecast, the long-term growth rates of electricity and natural gas prices are nearly identical.

Electric Vehicles

With the anticipated introduction of electric vehicles in December 2010 from General Motors and Nissan, Idaho Power includes a forecast of the potential load impact associated with customer needs for battery recharging. Without the benefit of actual consumer adoption data and clarity on charging infrastructure composition, the forecast methodology relies on previous modeling efforts from EPRI[1] and Oak Ridge National Laboratory[2] drawing on their forecasts of the electric-vehicle market share and charging usage and loads. The assumptions of these and other early forecasts were made without benefit of empirical vehicle performance attributes, such as vehicle battery capacity, pricing, actual consumer adoption behavior, and other salient marketing variables. Since these variables represent primary economic determinants of electric-vehicle adoption, the early forecasts are subject to potentially high degrees of revision. Other determinant variables, such as gasoline price, exhibit high degrees of volatility that add to the wide range of potential adoption outcomes.

The Oak Ridge study assumed a 25 percent electric-vehicle share of new vehicle registrations by 2020 and thereafter held constant. The EPRI study relied on year 2050 share scenarios that ranged from 20 percent to 80 percent. Their medium range forecast for 2020 was approximately 35 percent. After evaluating historical rates of adoption of new transportation technology, particularly those associated with fuel-efficient diesel engine adoption in Europe, the Idaho Power model was based on a

[1] Environmental Assessment of Plug-In Hybrid Electric Vehicles, July, 2007.

[2] Potential Impacts of Plug-in Hybrid Electric Vehicles on Regional Power Generation, January, 2008.

40-percent share by 2050 with annual adoption growth rate associated with diesel-technology adoption. The resulting Idaho Power forecast share of electric vehicles of new, light-duty vehicles registered in Idaho Power's service area is approximately 12 percent in 2020 and 26 percent in 2030. These rates were applied to a forecast of new, light-duty vehicle registrations for Idaho Power's service area using base-case assumptions from Moody's Analytics, Inc.

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

Figure 3 illustrates the increase in loads expected from the roll-out of electric vehicles over 2010–2030. The impact on the load forecast is assumed to be relatively small—about 9 aMW in 2020, reaching 43 aMW at the end of the forecast period in 2030. The load impacts were allocated to the residential and commercial sales forecasts using an 80/20 split, the residential sector representing the greatest impact.



Figure 3. Electric vehicles
(aMW)

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, Inc., 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 that 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 over the 1980–2009 time period (the most recent 30 years) was 1,036. The 70th percentile HDD is 1,074 and would be exceeded in three-out-of-ten years. The 90th percentile HDD is 1,291 and would be exceeded in one-out-of-ten 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 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 that 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 2011 IRP. Three average load scenarios were prepared based on a statistical analysis of the historical monthly weather variables listed. The probability associated with each individual 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. The probability associated with each individual 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 average load and peak demand to be considered. In other Idaho Power planning, such as the preparation of the financial forecast or the operating plan, the expected-case (50th percentile) average load forecast and the 90th percentile peak-demand forecast are typically used.

Load Forecasts Based on Economic Uncertainty

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

Two additional load forecasts for the Idaho Power service area were prepared. The forecasts provide a range of possible load growths for the 2011–2030 planning period due to variable economic and demographic conditions. The high economic growth and low economic growth scenarios were prepared based on statistical analysis to empirically reflect 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 (1985–2009).

The estimated probabilities for the three different load scenarios are reported in Table 2. The probability estimates are calculated using the annual growth rates in weather-adjusted system sales (excluding Astaris) observed between 1985 and 2009. The standard deviation observed during the historical time period is used to estimate the dispersion around the expected-case scenario. The probability estimates assume that the expected forecast is the median growth path, i.e., there is a 50-percent probability that the actual growth rate will be less than the expected-case growth rate, and a 50-percent chance that the actual growth rate will be greater than the expected-case growth rate. In addition, the probability estimates assume that the variation in growth rates will be equivalent to the variation in growth rates observed over the past 25 years (1985–2009). The high- and low-case load forecasts also reflect the consideration and integration of existing energy efficiency DSM program effects as a reduction to the average load forecasts.

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

System load includes the sum of residential, commercial, industrial, irrigation, special contracts (including Astaris, historically), and Raft River. Idaho Power system load projections are reported in Table 4 and pictured in Figure 4. The expected-case system load forecast growth rate averages 1.4 percent per year over the 20 years of the planning period. The low scenario projects that system load will increase at an average rate of 1.0 percent per year throughout the forecast period. The high scenario projects load growth of 1.8 percent per year. Idaho Power has experienced both the high- and low-growth rates in the past. These scenario forecasts provide a range of projected growth rates that cover approximately 80 percent of the probable outcomes as measured by Idaho Power's historical experience.

Table 4. System load growth
(aMW)

					Annual Growth Rate
Growth	**2011**	**2015**	**2020**	**2030**	**2011–2030**
Low	1,793	1,894	1,970	2,158	1.0%
Expected	1,819	1,970	2,090	2,362	1.4%
High	1,878	2,094	2,271	2,642	1.8%

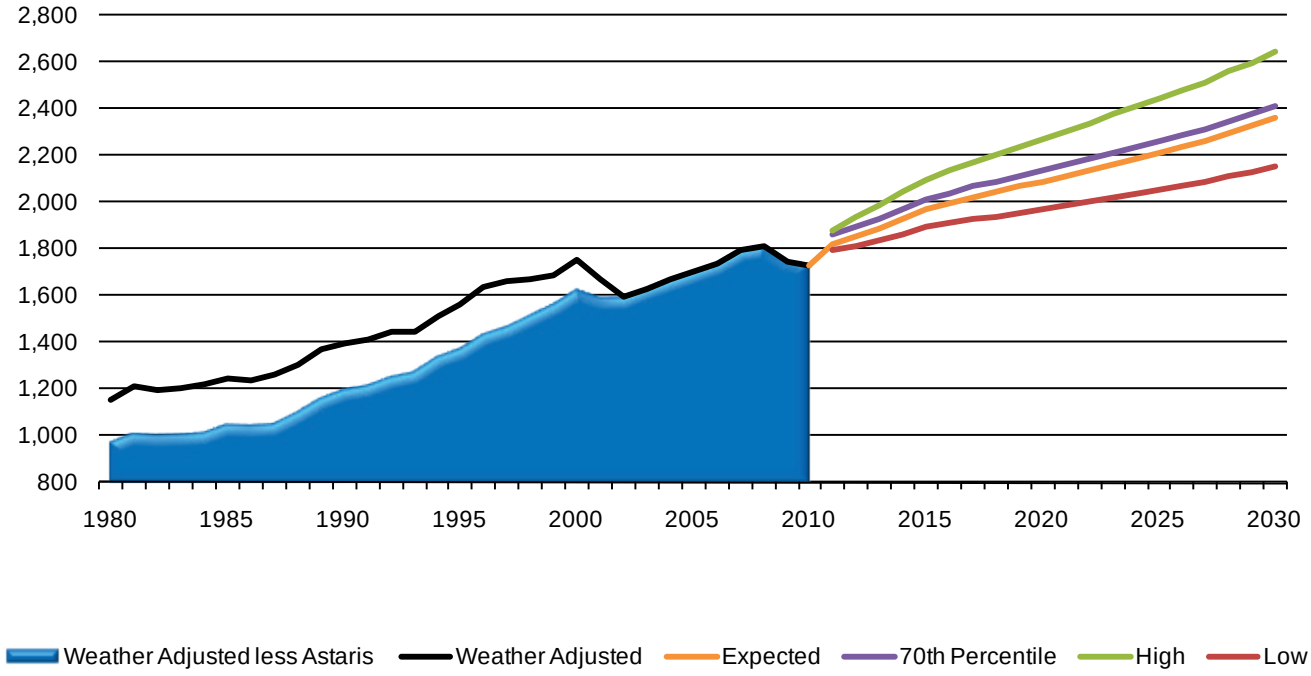

Figure 4. Forecasted system load
(aMW)

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RESIDENTIAL

The expected-case residential load is forecast to increase from 595 aMW in 2011 to 786 aMW in 2030, an average annual compound growth rate of 1.5 percent. In the 70th percentile scenario, residential load is forecast to increase from 611 aMW in 2011 to 810 aMW in 2030, matching the expected-case residential growth rate. The residential load forecasts are reported in Table 5 and shown graphically in Figure 5.

Table 5. Residential load growth
(aMW)

Growth	2011	2015	2020	2030	Annual Growth Rate 2011–2030
90th Percentile	646	681	744	860	1.5%
70th Percentile	611	644	702	810	1.5%
Expected Case	595	626	682	786	1.5%

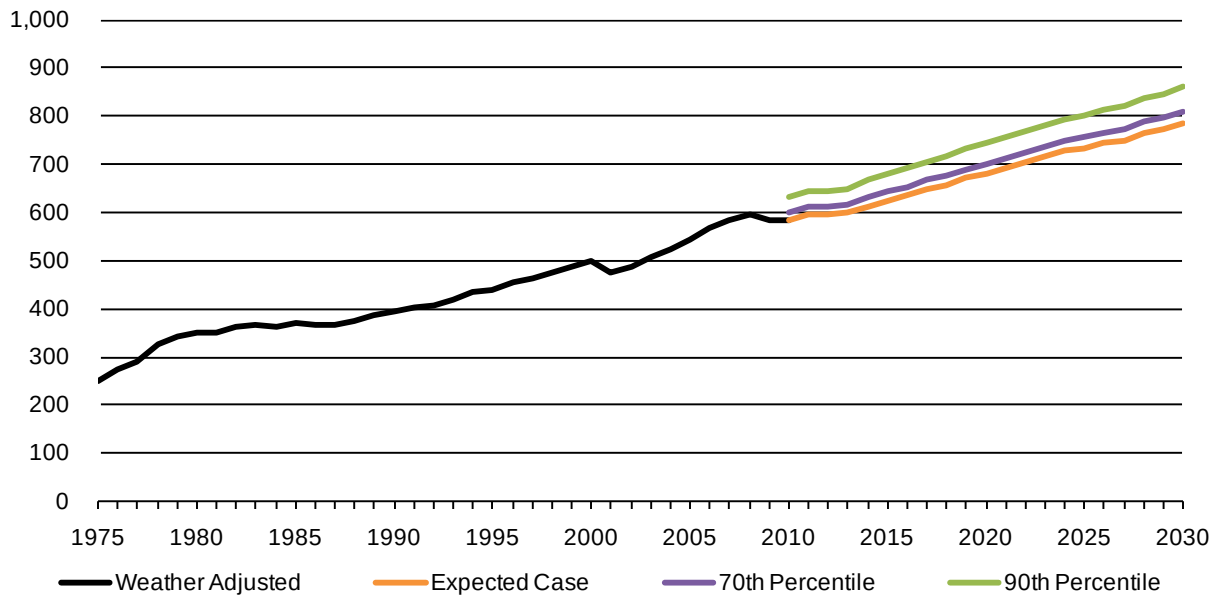

Figure 5. Forecasted residential load
(aMW)

Sales to residential customers made up 33 percent of Idaho Power's system sales in 1980 and 37 percent of system sales in 2010. The residential customer proportion of system sales is forecast to be approximately 36 percent in 2030. There were 408,754 residential customers as of December 2010. The number of residential customers is projected to increase to approximately 536,000 by December 2030. The relative customer proportions of Idaho Power's total electricity sales are shown in Figure 16.

The average sales per residential customer were nearly 13,000 kWh in 1975. Average sales increased to over 14,800 kWh per residential customer in 1979 before declining to 13,150 kWh in 2001. In 2002 and 2003, residential-use-per-customer dropped dramatically—over 500 kWh per customer from 2001—the result of two years of significantly higher electricity prices combined with a weak national and service-area economy. The reduction in electricity prices in June 2003 and a recovery in the service-area economy caused residential-use-per-customer to stabilize and rise through 2007. However, the recession

in 2008 and 2009 combined with conservation programs designed to reduce electricity use served to slow the growth in residential-use-per-customer. The average sales per residential customer are expected to slowly rise to approximately 12,900 kWh per year in 2030. Average annual sales per residential customer are shown in Figure 6.

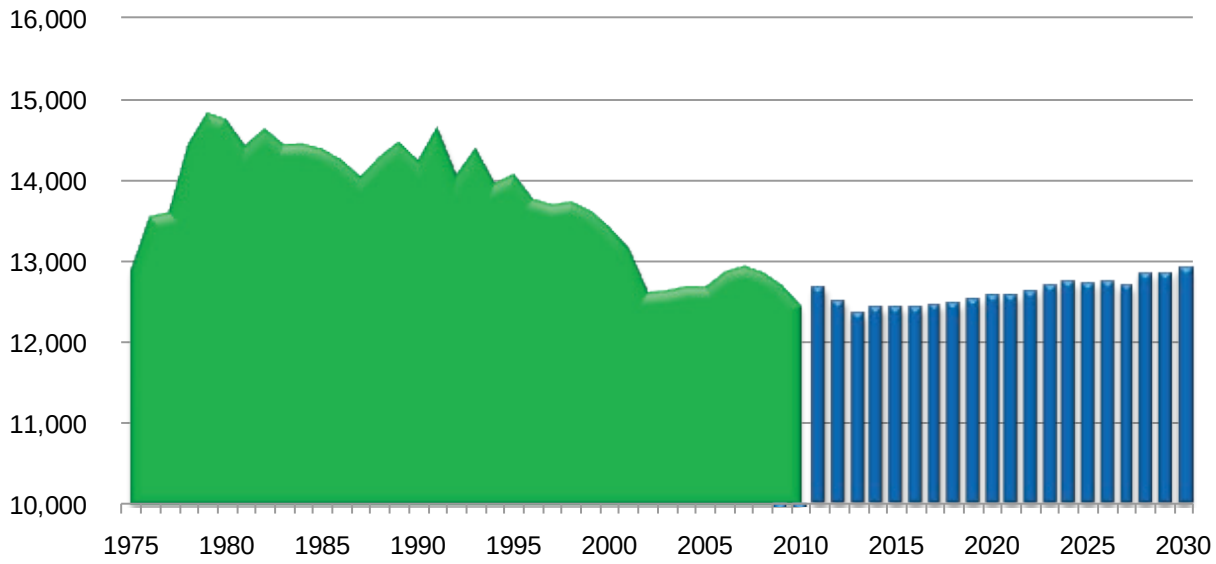

Figure 6. Forecasted residential-use-per-customer
(weather-adjusted kWh)

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, Inc., July 2010 forecast of county housing stock and demographic data. The residential-customer forecast for 2011–2030 shows an average annual growth rate of 1.4 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, Inc., 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 forecasted DSM, by the residential-customer forecast.

COMMERCIAL

The commercial category is primarily made up of Idaho Power's Small General Service and Large General Service customers. Other schedules considered part of the commercial category are Unmetered General Service, Street Lighting Service, Traffic Control Signal Lighting Service, and Dusk-to-Dawn Customer Lighting.

In the expected-case scenario, commercial load is projected to increase from 439 aMW in 2011 to 561 aMW in 2030. The average annual compound-growth rate of commercial load is 1.3 percent during the forecast period. As summarized in Table 6, the commercial load in the 70th percentile scenario is projected to increase from 443 aMW in 2011 to 568 aMW in 2030. The commercial load forecasts are illustrated in Figure 7.

Table 6. Commercial load growth
(aMW)

Growth	2011	2015	2020	2030	Annual Growth Rate 2011–2030
90th Percentile	453	479	504	583	1.3%
70th Percentile	443	468	492	568	1.3%
Expected Case	439	463	486	561	1.3%

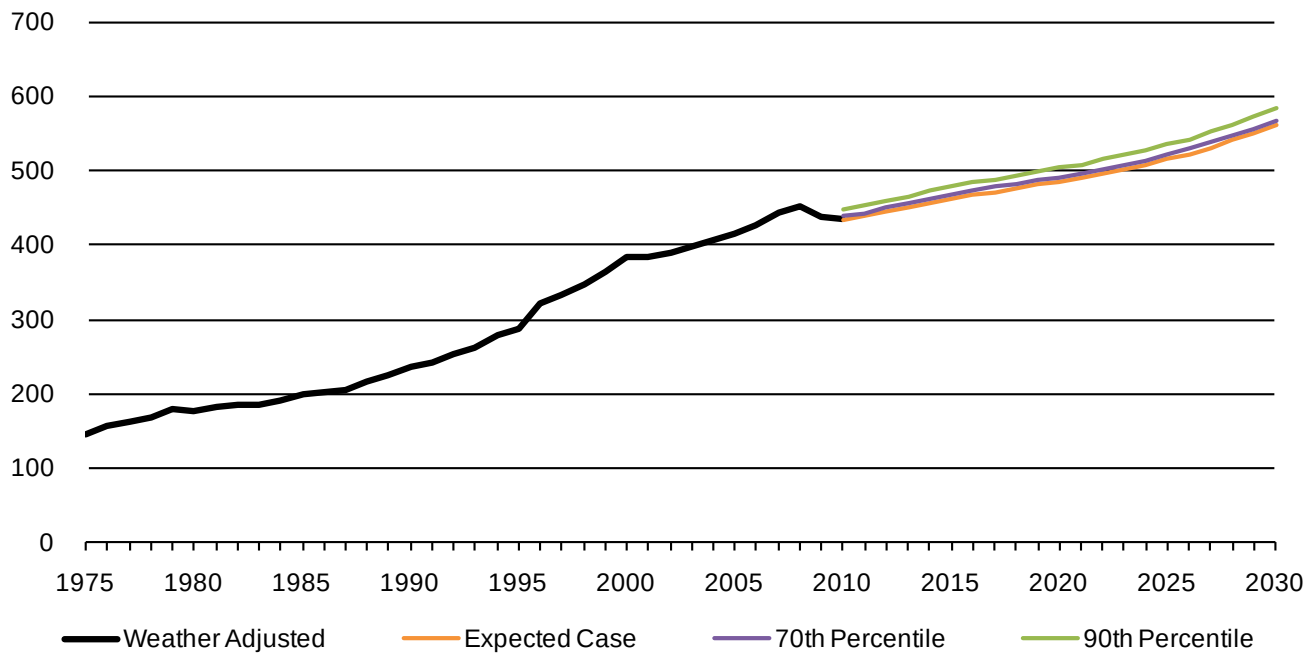

Figure 7. Forecasted commercial load
(aMW)

As of December 2010, Idaho Power had 64,647 commercial customers. The number of commercial customers is expected to increase at an average annual growth rate of 2 percent, reaching 94,600 customers by 2030. Commercial customers consumed nearly 17 percent of Idaho Power system sales in 1980 and nearly 28 percent of system sales in 2010. The commercial customer proportion of system sales is projected to decline to 26 percent of system sales by 2030. The relative customer proportions of Idaho Power's total electricity sales are shown in Figure 16.

The average consumption per commercial customer increased to a record 67,500 kWh in 2001. However, two years of significantly higher electricity prices combined with a weak national and service-area economy caused a setback in the growth of commercial-use-per-customer beginning in 2002. The reduction in electricity prices in June 2003 and a recovery in the service-area economy slowed the rate of decline in commercial-use-per-customer through 2007. However, a severe recession in 2008 and 2009 caused commercial-use-per-customer to drop considerably. After flattening out over the time period 2010–2011, commercial-use-per-customer is projected to continue its downward trend. The primary reasons for the decline are higher retail electricity prices due to generating plant additions and DSM program impacts on energy sales. The average consumption per commercial customer is expected to decrease to approximately 52,400 kWh per customer in 2030. Average annual use per commercial customer is shown in Figure 8.

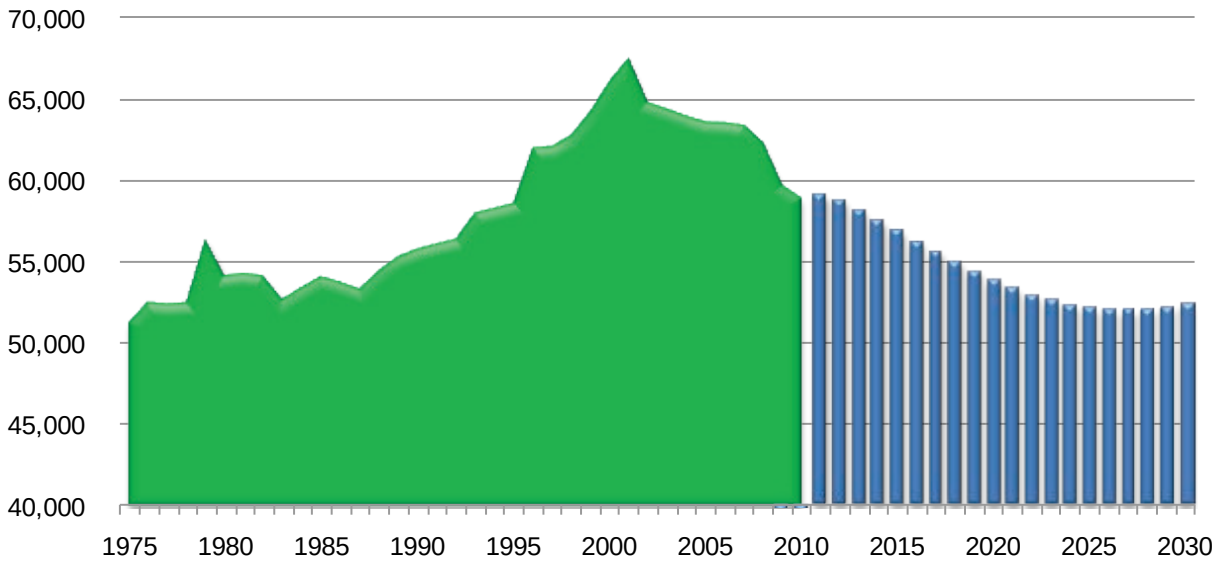

Figure 8. Forecasted commercial-use-per-customer
(weather-adjusted kWh)

The commercial-use-per-customer forecast is based on a forecast of the number of commercial customers and an econometric analysis of commercial sector sales. The number of commercial customers being added each year is a direct function of the number of new residential customers being added. Additionally, the number of residential customers being added is a direct function of the number of new service-area households as derived from Moody's Analytics, Inc., July 2010 economic forecast of county housing stock and demographic data. The commercial-customer forecast for 2011–2030 shows an average annual growth rate of 2 percent.

The commercial-sales forecast equation considers several factors affecting electricity sales to the commercial sector. Commercial sales are a function of HDD (wintertime), CDD (summertime), the number of service area households and service area employment as derived from Moody's Analytics, Inc., forecasts, and the real price of electricity. The commercial-use-per-customer forecast is arrived at by dividing the commercial sales forecast, which considers the impacts of forecasted DSM, by the commercial-customer forecast.

IRRIGATION

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

Throughout the forecasted period, the expected-case irrigation load is forecast to slowly rise from 197 aMW in 2011 to 207 aMW in 2030, an average annual compound growth rate of 0.3 percent. The expected-case, 70th percentile, and 90th percentile scenarios forecast slow growth in irrigation load over the 2011–2030 time period. In the 70th percentile scenario, irrigation load is projected to be 213 aMW in 2011 and 223 aMW in 2030. The individual irrigation load forecasts are reported in Table 7 and shown in Figure 9. The figure illustrates the poorer economic conditions and the dramatic reduction in land being put into production that was experienced by the agricultural economy in the mid-1980s.

Table 7. Irrigation load growth
(aMW)

Growth	2011	2015	2020	2030	Annual Growth Rate 2011–2030
90th Percentile	232	234	237	242	0.2%
70th Percentile	213	215	217	223	0.2%
Expected Case	197	199	202	207	0.3%

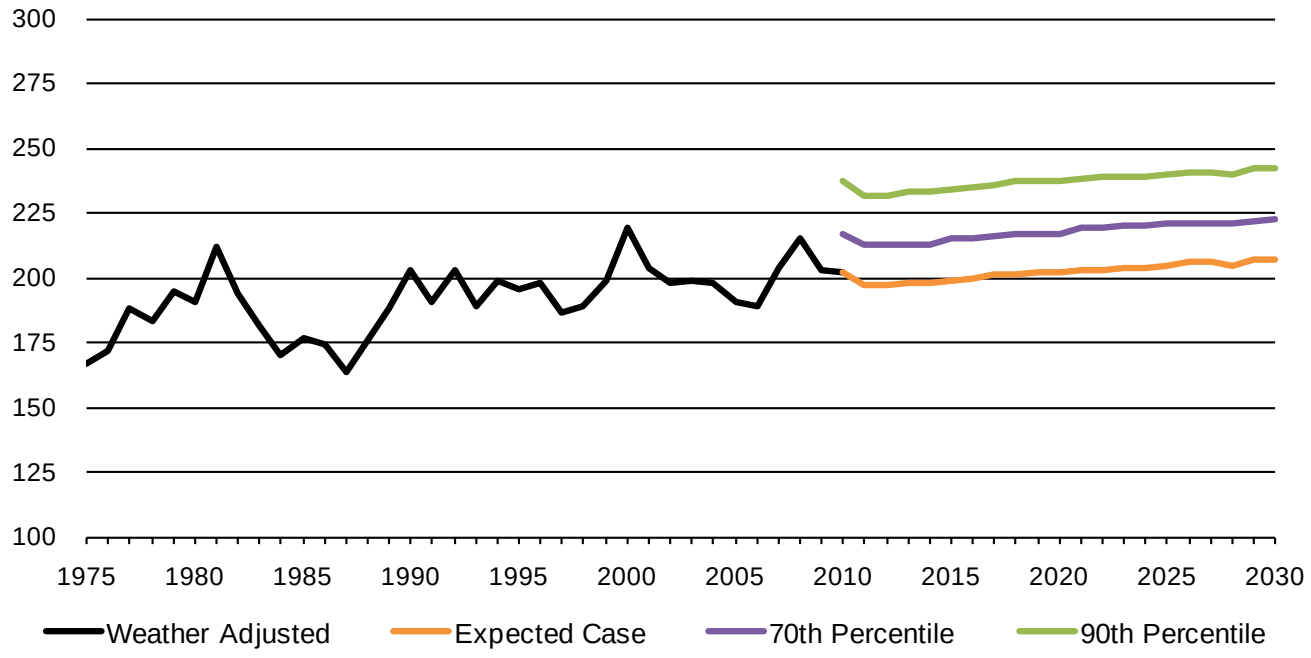

Figure 9. Forecasted irrigation load
(aMW)

It is important to understand the annual average-load figures reported in Table 7 and graphed in Figure 9 are calculated using the 8,760 hours of a typical year. In the highly seasonal irrigation sector, over 97 percent of the annual energy is billed during the six months from May through October, and nearly half

of the annual energy is billed in just two months, July and August. During the summer, hourly irrigation loads can exceed 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 30 percent of the energy consumed during the July calendar-month for general business sales. Note that it is the monthly forecast load figures that are being evaluated for resource planning purposes, not the annual average loads.

The 2011 irrigation sales forecast model considers several factors affecting electricity sales to the irrigation class, including temperature, precipitation, spring rainfall, *Moody's Gross Produce: Farms, for Idaho*, and the real price of electricity. Considerations were made for the unusually low electricity consumption in the 2001 crop year due to the voluntary load-reduction program.

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

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

Irrigation sales represented about 18 percent of weather-normalized Idaho Power system sales in 1980. Irrigation sales reached a maximum proportion of 20 percent of Idaho Power system sales in 1977. In 2010, the irrigation proportion of system sales was 13 percent due to the much higher relative growth in other customer classes. By 2030, irrigation customers are projected to consume less than 10 percent of Idaho Power system sales. The irrigation customer load proportion is shown in Figure 16.

In 1980, Idaho Power had about 10,850 active irrigation accounts. By 2010, the number of active irrigation accounts had increased to 17,846 and is projected to be about 23,500 irrigation accounts at the end of the planning period in 2030.

Since 1988, Idaho Power has experienced some growth in the number of irrigation customers, but very little, if any, growth in total electricity sales (weather-adjusted) to this sector. The number of customers has increased because customers are converting previously furrow-irrigated land to sprinkler-irrigated land. However, the conversion rate is low, and the kWh use-per-customer for these customers is substantially less than the average existing Idaho Power irrigation customer. This is due to the fact that water for furrow irrigation is gravity-drawn from canals and not pumped from deep, groundwater wells. In 2007 and 2008, irrigation sales (weather-adjusted) increased by 8 percent and 6 percent, respectively, over each prior year. The increase can be explained, in part, by the gradual increase in the planting of more water-intensive crops, such as alfalfa and corn, to meet the higher demand for feed associated with the growing dairy industry in Idaho. Also, 2008 saw unprecedented crop prices for almost all crops, causing customers to irrigate all of the acreage that was available in 2008.

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

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 made up of Idaho Power's Large Power Service (Schedule 19) customers with monthly metered demands between 1,000 kW and 20,000 kW. In 1975, Idaho Power had about 70 industrial customers, which represented about 10 percent of Idaho Power's system sales. By December 2010, the number of industrial customers had risen to 121, representing approximately 16 percent of system sales. Special contracts are addressed in the Additional Firm Load section of this document.

In the expected-case forecast, industrial load grows from 262 aMW in 2011 to 359 aMW in 2030, an average annual growth rate of 1.7 percent (Table 8). As a general rule, industrial loads are not weather sensitive, and the forecasts in the 70th and 90th percentile scenarios are identical to the expected-case industrial load scenario. The industrial load forecast is pictured in Figure 10.

Table 8. Industrial load growth
(aMW)

Growth	2011	2015	2020	2030	Annual Growth Rate 2011–2030
Expected Case	262	283	302	359	1.7%

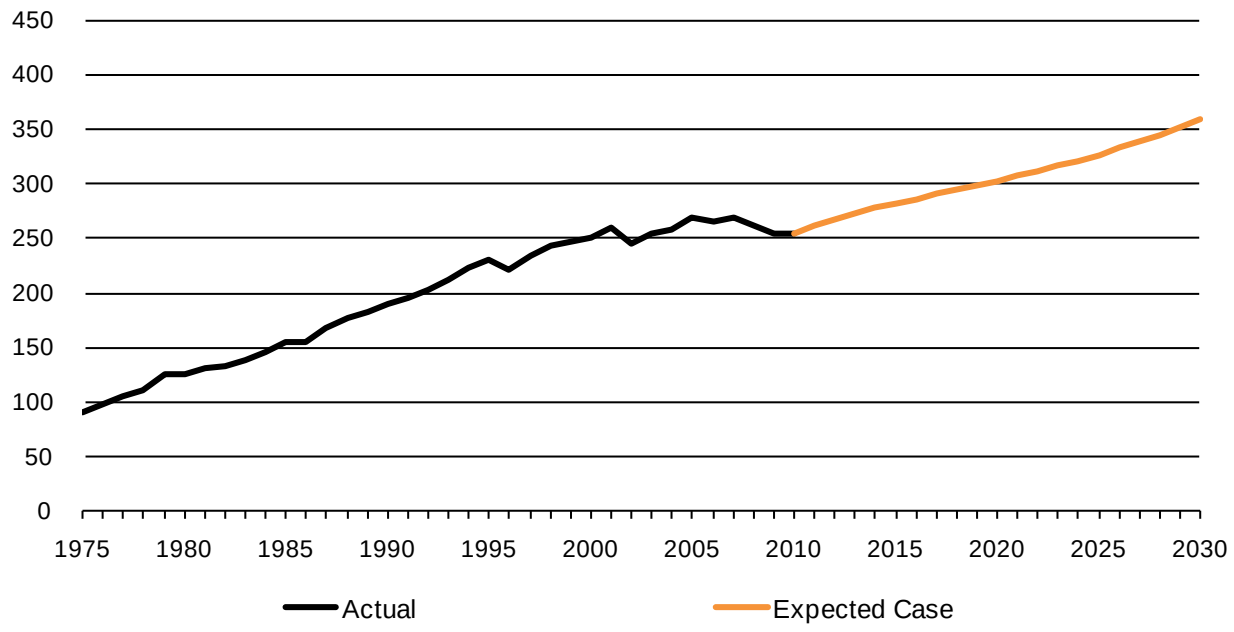

Figure 10. Forecasted industrial load
(aMW)

The industrial energy forecast is based on the most recent (July 2010) national, state, MSA, and county economic forecasts from Moody's Analytics, Inc., and the resulting derived economic forecast for Idaho Power's service area.

Since rate tariff definitions do not correspond with economic activity types, Idaho Power's Schedule 19 customers were categorized, and their historical electricity sales were summarized by economic activity. This is also true for the large commercial loads, so Schedule 9 Primary and Transmission customers' energy sales were also included for forecasting purposes and later recombined

with the commercial sector sales forecast. The appropriate employment series (or population time series) were matched to each economic sector or industry group. Regression models were developed for 17 industry groups to determine the relationship between historical electricity sales and historical employment, population, and/or other relevant explanatory variables. The estimated coefficients from the industry group regression models were then applied to the appropriate employment, population, and other relevant drivers, which resulted in the escalation of electricity sales to the various industry groups over time.

Figure 11 illustrates the 2010 industrial electricity consumption by industry group. By far the largest share of electricity was consumed by the Food and Kindred Products sector (46 percent); followed by Electronic/Electrical Equipment and Industrial/Commercial Machinery (7 percent); Educational Services, Wholesale and Retail Trade, and Health Services (each representing 6 percent); and Other Manufacturing (5 percent). As Figure 11 shows, several other industry groups make up the remaining share of the 2010 industrial electricity consumption.

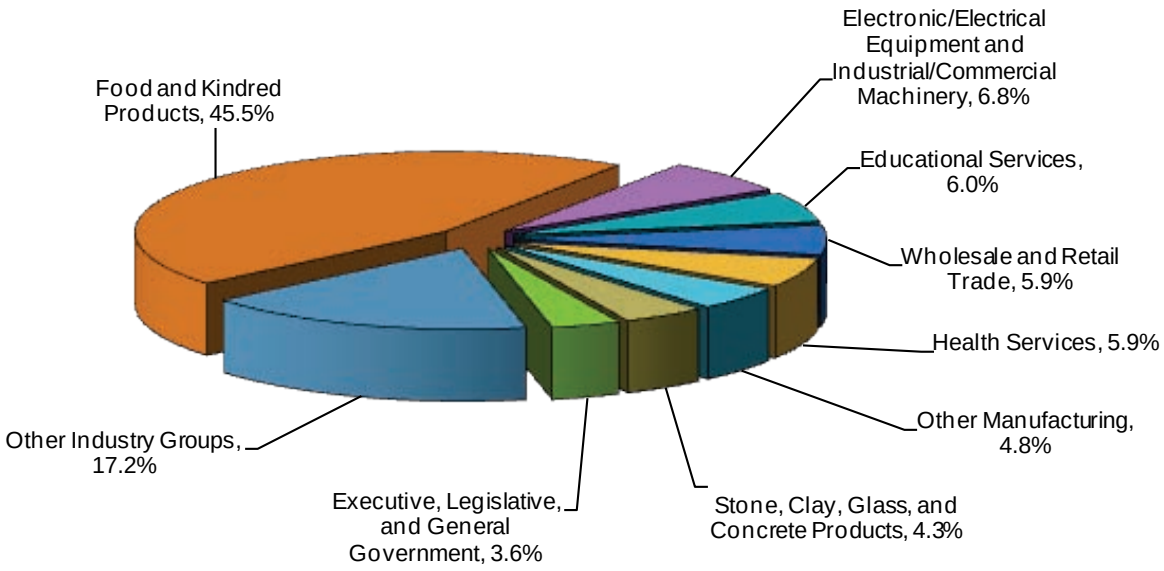

Figure 11. Industrial electricity consumption by industry group
(based on 2010 figures)

ADDITIONAL FIRM LOAD

The additional firm load category consists of Idaho Power's largest customers. Idaho Power's tariff requires the company serve requests for electric service greater than 20 MW under a "special contract" schedule negotiated between Idaho Power and each of these individual large-power customers. The contract and tariff schedule are then approved by the appropriate commission. A special contract allows for customer-specific, cost-of-service analysis and consideration of unique operating characteristics to be accounted for in the agreement. A special contract also allows Idaho Power to provide requested service consistent with system capability and reliability. Idaho Power currently has four special contract customers recognized as firm load customers. These special contract customers are Micron Technology, Simplot Fertilizer, INL, and Hoku Materials. In addition, the company has a term sales contract with Raft River. Raft River is not required to meet the 20-MW electric service minimum.

It is difficult to predict when a new special contract customer will begin taking service from Idaho Power. However, because of the magnitude of their load and subsequent impact on system resources, it is important to anticipate such load if a customer of that size is considered eminent. In this year's forecast, the company has included the anticipated load of an additional special contract customer referred to as "Special" in the additional firm load category, even though a long-term special contract had not yet been fully executed. At the time this forecast was prepared (August 2010), several interested parties had taken significant steps toward the ultimate development and location of their businesses within Idaho Power's service area. It was determined that the real possibility of the new large load was significant enough that it would be imprudent of the company to ignore the possible impact. The anticipated load of the new "Special" contract has been included in this forecast based on discussions with the interested parties. The existing special contract customers and the new "Special" contract together make up the additional firm load category.

In the expected-case forecast, additional firm load is expected to increase from 165 aMW in 2011 to 243 aMW in 2030, an average growth rate of 2 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 12.

Table 9. Additional firm load growth
(aMW)

Growth	2011	2015	2020	2030	Annual Growth Rate 2011–2030
Expected Case	165	229	236	243	2%

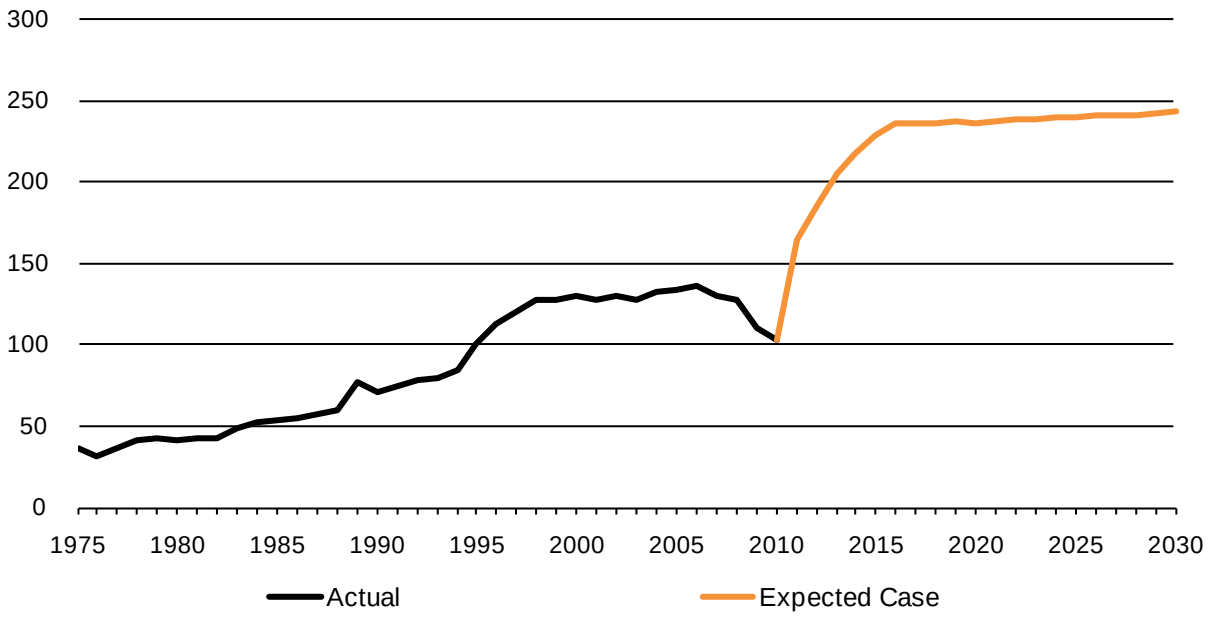

Figure 12. Forecasted additional firm load
(aMW)

Micron Technology

Micron Technology is currently Idaho Power's largest individual customer and employs approximately 5,000 workers in the Boise MSA. Electricity sales to Micron Technology moved considerably downward in 2009 and 2010 as Micron phased out its 200-millimeter (mm) dynamic random access memory (DRAM) operations at its Boise facility. The company continues to operate its 300-mm research and development fabrication facility in Boise and perform a variety of other activities, including product design and support, quality assurance, systems integration and related manufacturing, corporate, and general services. Once establishing a new floor for energy consumption at the facility at about a quarter less energy use than in recent years, 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 United States. The future electricity usage at the plant is expected to grow at a slow pace throughout the planning period (2011–2030). The primary driver of long-term electricity sales growth at Simplot Fertilizer is Moody's Analytics, Inc., forecast of gross product in the pesticide, fertilizer, and other agricultural chemical manufacturing for the Pocatello MSA.

Idaho National Laboratory

The US Department of Energy (DOE) provided an energy-consumption and peak-demand forecast through 2030 for the INL. The forecast calls for loads to increase considerably through 2014, remain flat for six years, and then slowly decline throughout the remainder of the forecast period. As of October 1994, the INL nuclear reactor no longer generates electricity, consequently, the amount of electricity provided by Idaho Power increased considerably.

Hoku Materials

The sales and load forecast reflects the increased expected demand for energy and peak capacity of Idaho Power's newest special contract customer, Hoku Materials, located in Pocatello, Idaho. At the time this forecast was completed (August 2010), Hoku Materials was planning to begin operation in January 2011 and reach full capacity by April 2011. The current sales and load forecast assumes that Hoku Materials will consume 74 aMW of energy each year and have a peak demand of 82 MW (each measure excluding line losses), once continuous operation is reached in 2013.

"Special" Contract

In this year's forecast, an additional customer referred to in this document as "Special" was included in the additional firm load category, even though a long-term contract had not yet been fully executed. At the time this forecast was prepared (August 2010), several interested parties had taken significant steps toward the ultimate development and location of their businesses within Idaho Power's service area. It was determined that the real possibility of the new large load was significant enough that it would be imprudent of the company to ignore the possible impact. The anticipated load of the new "Special" contract has been included in this forecast based on discussions with the interested parties. The existing special contracts and the new "Special" contract together make up the additional firm load category.

Raft River Rural Electric Cooperative

A term sales contract with Raft River was established as a full-requirements contract after being approved by the Federal Energy Regulatory Commission (FERC) and the Public Utility Commission of Nevada. Raft River is the electric distribution utility serving Idaho Power's former customers in Nevada. In April 2001, Idaho Power sold the transmission facilities and rights-of-way that serve about 1,250 customers in northern Nevada and 90 customers in southern Owyhee County to Raft River. Raft River is located entirely within Idaho Power's load control area.

The contract with Raft River expired on September 30, 2010. However, Raft River renewed the agreement for an additional one-year term, which would extend service until September 30, 2011. The load forecasts in the 2011 IRP assume that Idaho Power will continue to provide service to the Raft River area through September 30, 2011.

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COMPANY SYSTEM PEAK

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

The all-time system summer peak demand was 3,214 MW, recorded on Monday, June 30, 2008, at 3:00 p.m. The previous year's summer peak demand was 3,193 MW and occurred on Friday, July 13, 2007, at 4:00 p.m. The summer system peak load growth accelerated over the 10 years ending in 2008 as a record number of residential and commercial customers were added to the system and air conditioning became standard in nearly all new residential homes and new commercial buildings.

In the 90th percentile forecast, total system summer peak load is expected to increase from 3,494 MW in 2011 to 4,870 MW in the year 2030, an average growth rate of 1.8 percent per year over the planning period (Table 10). In the 95th percentile forecast, total system summer peak load is expected to increase from 3,515 MW in 2010 to 4,901 MW in the year 2030. The three scenarios of projected system summer peak load are illustrated in Figure 13. 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	2011	2015	2020	2030	Annual Growth Rate 2011–2030
95th Percentile	3,515	3,854	4,190	4,901	1.8%
90th Percentile	3,494	3,831	4,164	4,870	1.8%
50th Percentile	3,334	3,657	3,973	4,643	1.8%

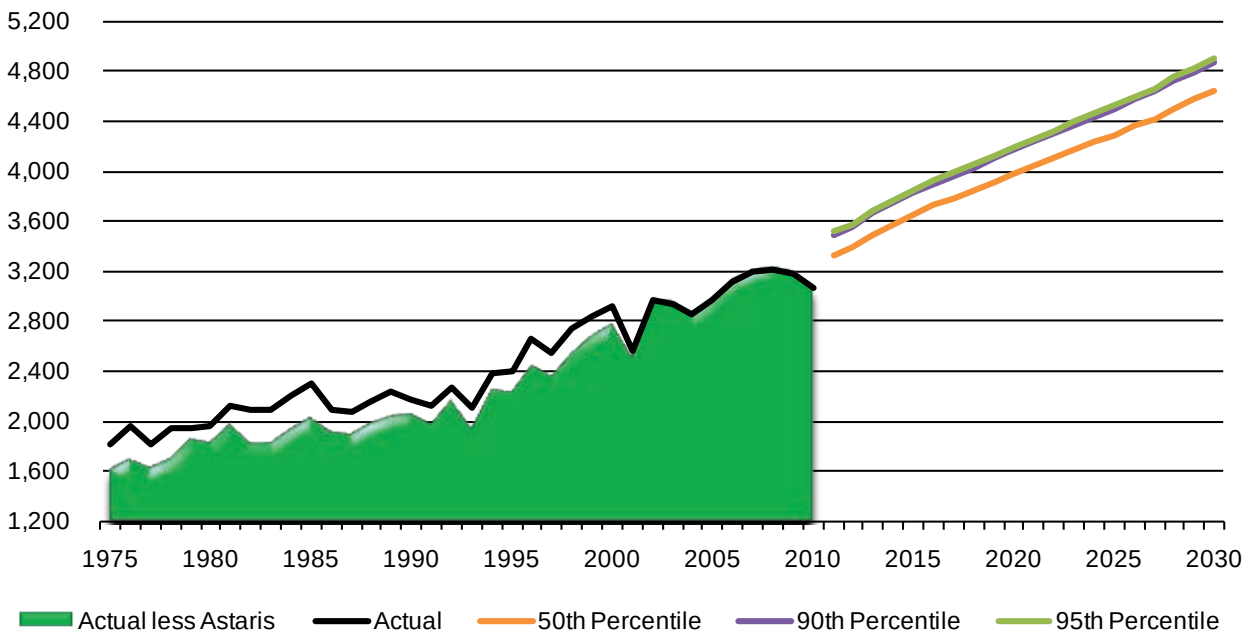

Figure 13. Forecasted system summer peak
(MW)

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 14, historical system winter peak load is much more variable than

summer system peak load. This is because the variability of peak day temperatures in winter months is far greater than the variability of peak day temperatures in summer months. The wider spread of the winter peak forecast lines in Figure 14 illustrates the higher variability associated with winter peak-day temperatures.

In the 90th percentile forecast, total system winter peak load is expected to increase from 2,693 MW in 2011 to 3,336 MW in 2030, an average growth rate of 1.1 percent per year over the planning period (Table 11). In the 95th percentile forecast, total system winter peak load is expected to increase from 2,815 MW in 2011 to 3,509 MW in 2030, an average growth rate of 1.2 percent per year over the planning period (Table 11). The three scenarios of projected system winter peak load are illustrated in Figure 14.

Table 11. System winter peak load growth
(MW)

Growth	2011	2015	2020	2030	Annual Growth Rate 2011–2030
95th Percentile	2,815	2,948	3,121	3,509	1.2%
90th Percentile	2,693	2,815	2,976	3,336	1.1%
50th Percentile	2,384	2,478	2,604	2,896	1.0%

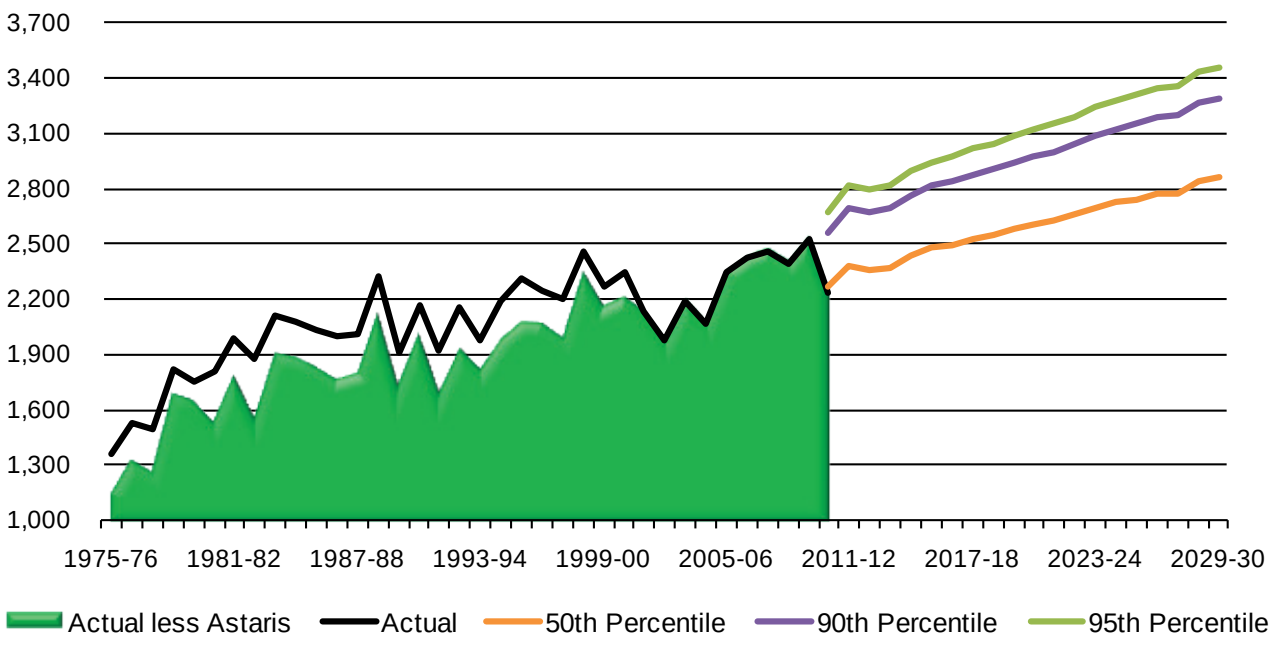

Figure 14. Forecasted system winter peak
(MW)

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 Raft River. System load excludes all long-term, firm, off-system contracts.

The expected-case system load forecast is based on the most recent Moody's Analytics, Inc., economic forecast for the nation and the service area and represents Idaho Power's most probable load growth during the planning period. The expected-case forecast system load growth rate averages 1.4 percent per year over the 2011–2030 time period. Company system load projections are reported in Table 12 and shown in Figure 15.

In the expected-case forecast, company system load is expected to increase from 1,819 aMW in 2011 to 2,362 aMW in 2030. In the 70th percentile forecast, company system load is expected to increase from 1,860 aMW in 2011 to 2,414 aMW by 2030, an average growth rate of 1.4 percent per year over the planning period (Table 12).

Table 12. System load growth
(aMW)

Growth	2011	2015	2020	2030	Annual Growth Rate 2011–2030
90th Percentile	1,931	2,088	2,218	2,508	1.4%
70th Percentile	1,860	2,013	2,136	2,414	1.4%
Expected Case	1,819	1,970	2,090	2,362	1.4%

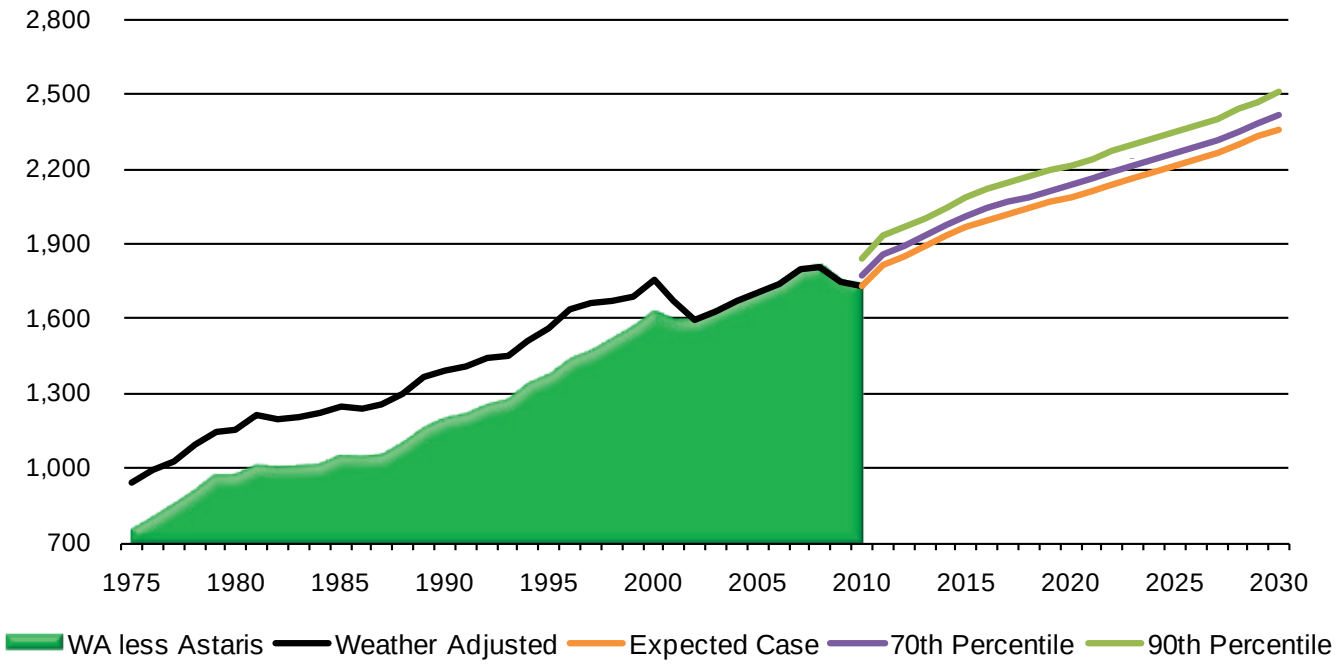

Figure 15. Forecasted system load
(aMW)

The Astaris elemental phosphorous plant (previously FMC) was located at the western edge of Pocatello, Idaho. Although no longer a customer of Idaho Power, Astaris has been Idaho Power's largest

individual customer and, in some past years, averaged nearly 200 aMW each month. In April 2002, the special contract between Astaris and Idaho Power was terminated. Without the dampening effects of Astaris on historical system load growth, the system load excluding Astaris more accurately portrays the underlying general business growth trend within the service area.

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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TOTAL COMPANY LOAD

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

The composition of total company electricity sales by year is shown in Figure 16. Residential sales are forecast to be over 32 percent higher in 2030, gaining nearly 1.7 million MWh over 2011. Commercial sales are expected to be nearly 28 percent higher or nearly 1.1 million MWh above 2011 followed by industrial (37 percent higher or nearly 0.8 million additional MWh) and irrigation (only 5 percent higher in 2030 than 2011). Electricity sales to Astaris ended in April 2002.

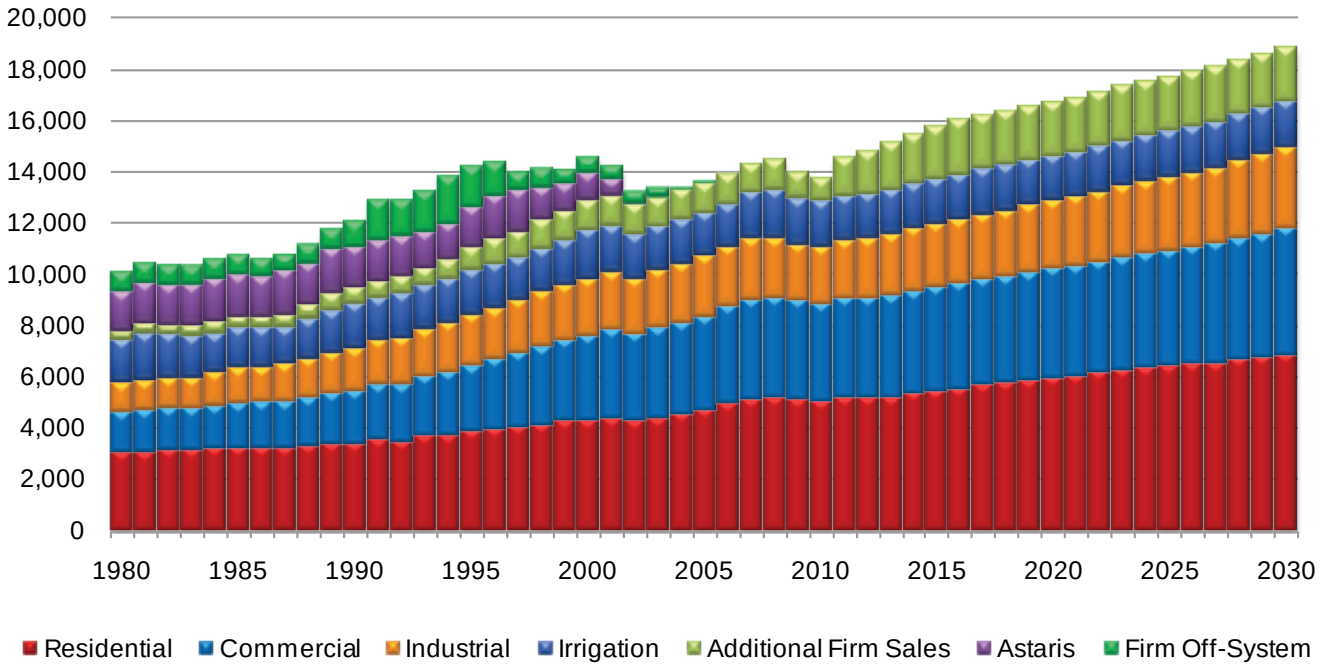

Figure 16. Composition of total company electricity sales
(thousands of MWh)

The additional firm load category (which represents sales to Micron Technology, Simplot Fertilizer, INL, Hoku Materials, Idaho Power's newest "Special" contract customer, and Raft River) is forecast to grow by 47 percent over the 2011–2030 time period, largely due to the addition of Hoku Materials and Idaho Power's newest "Special" contract customer as special contract customers.

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DEMAND-SIDE MANAGEMENT

DSM consists of energy efficiency programs that reduce customer energy use year-round and demand response programs that are targeted at reducing load during specific periods of high demand. The impact of energy efficiency programs are considered in the 2011 IRP *Appendix A–Sales and Load Forecast*; however, demand response programs are accounted for in the 2011 IRP load and resource balance and not in the load forecast. The sales and load forecast, adjusted for existing and committed energy efficiency programs, serves as the basis for establishing the baseline forecast for surpluses and deficits which were used to develop portfolios for the 2011 IRP.

Energy Efficiency Programs

The 2011 IRP *Appendix A–Sales and Load Forecast* follows the methodology established in an Itron white paper[3], "Incorporating DSM into the Load Forecast". The authors discussed methods for adjusting load forecasts to account for DSM programs. According to Itron, there are several potential econometric frameworks that can be applied to account for DSM in the forecast period. The methods are designed to adjust the load forecast by accounting for the amount and continuing momentum of the historic DSM contained in the load forecast model.

The "DSM trend" method was chosen as the preferred method to incorporate DSM into the load forecasts for the commercial, industrial, and irrigation sectors. The alternative methods make explicit efforts to adjust DSM out of the history and out of the forecast. The DSM trend takes a different approach by recognizing that historical DSM and DSM trends are embedded in the actual sales data. Forecasting models built on these data implicitly assume that the levels and trends for DSM savings in the history continue into the forecast at approximately the same rate. As a result, the forecast needs to be adjusted only if DSM impacts are expected to be greater or less than the historical trends.

In the final step of the DSM trend method, the forecast is adjusted if the cumulative impacts of past and future programs are expected to accelerate or decelerate relative to the DSM trend line. In this method, the forecast is adjusted up or down by the difference between the DSM trend line and the cumulative impact of past and future programs.

If the total cumulative impact of past and future programs is expected to fall short of the historical trend, then the energy forecast should be adjusted upward by the amount of the deceleration below the DSM trend line.

In another improvement to this year's forecast, Idaho Power used Itron's residential SAE model to prepare the long-term residential sales forecast. Recently, many utilities have adopted Itron's SAE modeling approach to include greater end-use information into the forecast process. When applying the SAE framework, DSM activity is naturally incorporated in the efficiency assumptions and the calibration to historic sales data. Efficiency assumptions incorporate national-level DSM impacts. Calibration incorporates specific utility DSM impacts. Therefore, additional adjustments to the residential energy forecast for existing DSM programs were not made.

When using an econometric or SAE model, historical DSM investments influence the historical sales data, the forecast model parameters, and the resulting sales projections. As DSM investment increases,

[3] 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).

forecasters need to adjust their sales forecasts to account for this acceleration relative to the historic DSM implicitly included in an unadjusted forecast.

The forecast resulting from the adjusted history is designed to reflect sales without the impact of energy efficiency programs. The results from the regression models are subsequently adjusted downward to account for future energy efficiency program performance.

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

Because the sales and load forecast is prepared before new energy efficiency programs are determined, new energy efficiency programs are not included in the forecast. The impact of the new programs is accounted for in the IRP load and resource balance prior to determining the need for additional supply-side resources. The forecast performance of both existing and new energy efficiency and demand response programs is shown in the load and resource balance in *Appendix C–Technical Appendix*. In the next planning cycle, the impact of new committed programs will be considered when updating the individual class-level sales forecasts.

Demand Response Programs

Prior to the 2009 IRP, demand response program performance was accounted for in the sales and load forecast. Beginning with the 2009 IRP, demand response programs are accounted for in the load and resource balance. Demand response program data, including operational targets for demand reduction, program expenses, and cost-effective summaries are detailed in *Appendix C–Technical Appendix*.

Demand response programs are treated as supply-side resources in the 2011 IRP and are not incorporated into the sales and load forecast. In the load and resource balance, the forecast of existing demand response programs is subtracted from the peak-hour load forecast prior to accounting for existing supply-side resources. Likewise, the performance of new demand response programs is accounted for prior to determining the need for additional supply-side resources. Because energy efficiency programs also result in a reduction to peak demand, there is a component of peak-hour load reduction due to energy efficiency programs that is integrated into the sales and load forecast. This provides a consistent treatment of both types of programs as energy efficiency programs are considered in the sales and load forecast, while all demand response programs are included in the load and resource balance.

A thorough description of each of the energy efficiency and demand response programs is included in *Appendix B–Demand Side Management 2010 Annual Report*.

Appendix A1. Historical and Projected Sales and Load

Residential Load

Historical Residential Sales and Load, 1970–2010
(weather-adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	132,135		9,944	1,314		151
1971	138,071	4.5%	10,392	1,435	9.2%	165
1972	145,208	5.2%	10,838	1,574	9.7%	182
1973	152,957	5.3%	11,501	1,759	11.8%	202
1974	160,151	4.7%	12,099	1,938	10.1%	224
1975	167,622	4.7%	12,871	2,158	11.3%	249
1976	175,720	4.8%	13,544	2,380	10.3%	273
1977	184,561	5.0%	13,594	2,509	5.4%	288
1978	194,650	5.5%	14,427	2,808	11.9%	325
1979	202,982	4.3%	14,821	3,008	7.1%	343
1980	209,629	3.3%	14,741	3,090	2.7%	352
1981	213,579	1.9%	14,416	3,079	-0.4%	352
1982	216,696	1.5%	14,627	3,170	2.9%	362
1983	219,849	1.5%	14,430	3,172	0.1%	366
1984	222,695	1.3%	14,438	3,215	1.4%	364
1985	225,185	1.1%	14,375	3,237	0.7%	371
1986	227,081	0.8%	14,244	3,234	-0.1%	368
1987	228,868	0.8%	14,037	3,213	-0.7%	365
1988	230,771	0.8%	14,282	3,296	2.6%	376
1989	233,370	1.1%	14,463	3,375	2.4%	386
1990	238,117	2.0%	14,236	3,390	0.4%	393
1991	243,207	2.1%	14,654	3,564	5.1%	404
1992	249,767	2.7%	14,062	3,512	-1.5%	405
1993	258,271	3.4%	14,392	3,717	5.8%	419
1994	267,854	3.7%	13,957	3,738	0.6%	433
1995	277,131	3.5%	14,067	3,898	4.3%	440
1996	286,227	3.3%	13,759	3,938	1.0%	456
1997	294,674	3.0%	13,692	4,035	2.4%	464
1998	303,300	2.9%	13,727	4,164	3.2%	475
1999	312,901	3.2%	13,616	4,260	2.3%	488
2000	322,402	3.0%	13,409	4,323	1.5%	500
2001	331,009	2.7%	13,156	4,355	0.7%	476
2002	339,764	2.6%	12,616	4,286	-1.6%	487
2003	349,219	2.8%	12,639	4,414	3.0%	507
2004	360,462	3.2%	12,689	4,574	3.6%	525
2005	373,602	3.6%	12,687	4,740	3.6%	543
2006	387,707	3.8%	12,872	4,991	5.3%	568
2007	397,286	2.5%	12,940	5,141	3.0%	585
2008	402,520	1.3%	12,858	5,176	0.7%	594
2009	405,144	0.7%	12,696	5,144	-0.6%	585
2010	407,551	0.6%	12,441	5,070	-1.4%	582

Residential Load

Projected Residential Sales and Load, 2011–2030

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2011	411,162	0.9%	12,677	5,212	2.8%	595
2012	415,787	1.1%	12,514	5,203	-0.2%	594
2013	423,098	1.8%	12,350	5,225	0.4%	598
2014	432,043	2.1%	12,425	5,368	2.7%	614
2015	440,364	1.9%	12,441	5,478	2.1%	626
2016	447,754	1.7%	12,425	5,563	1.6%	636
2017	454,724	1.6%	12,468	5,669	1.9%	648
2018	461,592	1.5%	12,473	5,757	1.6%	658
2019	468,394	1.5%	12,530	5,869	1.9%	671
2020	475,070	1.4%	12,568	5,971	1.7%	682
2021	481,514	1.4%	12,578	6,056	1.4%	692
2022	487,734	1.3%	12,627	6,159	1.7%	704
2023	493,690	1.2%	12,703	6,271	1.8%	717
2024	499,477	1.2%	12,737	6,362	1.4%	727
2025	505,167	1.1%	12,722	6,427	1.0%	734
2026	510,811	1.1%	12,745	6,510	1.3%	743
2027	516,404	1.1%	12,691	6,554	0.7%	749
2028	521,918	1.1%	12,851	6,707	2.3%	766
2029	527,380	1.0%	12,849	6,776	1.0%	774
2030	532,835	1.0%	12,908	6,878	1.5%	786

Commercial Load

Historical Commercial Sales and Load, 1970–2010
(weather-adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	21,375		42,773	914		105
1971	22,077	3.3%	45,388	1,002	9.6%	115
1972	22,585	2.3%	46,142	1,042	4.0%	120
1973	23,286	3.1%	48,144	1,121	7.6%	128
1974	24,096	3.5%	49,027	1,181	5.4%	136
1975	25,045	3.9%	51,218	1,283	8.6%	147
1976	26,034	3.9%	52,512	1,367	6.6%	157
1977	27,112	4.1%	52,414	1,421	3.9%	162
1978	27,831	2.7%	52,474	1,460	2.8%	169
1979	28,087	0.9%	56,389	1,584	8.4%	180
1980	28,797	2.5%	54,141	1,559	-1.6%	178
1981	29,567	2.7%	54,282	1,605	2.9%	184
1982	30,167	2.0%	54,126	1,633	1.7%	186
1983	30,776	2.0%	52,684	1,621	-0.7%	186
1984	31,554	2.5%	53,410	1,685	3.9%	191
1985	32,417	2.7%	54,076	1,753	4.0%	201
1986	33,208	2.4%	53,747	1,785	1.8%	203
1987	33,975	2.3%	53,312	1,811	1.5%	206
1988	34,723	2.2%	54,432	1,890	4.4%	216
1989	35,638	2.6%	55,285	1,970	4.2%	226
1990	36,785	3.2%	55,761	2,051	4.1%	236
1991	37,922	3.1%	56,076	2,127	3.7%	243
1992	39,022	2.9%	56,359	2,199	3.4%	253
1993	40,047	2.6%	57,970	2,321	5.6%	263
1994	41,629	4.0%	58,246	2,425	4.4%	280
1995	43,165	3.7%	58,555	2,528	4.2%	287
1996	44,995	4.2%	61,960	2,788	10.3%	322
1997	46,819	4.1%	62,038	2,905	4.2%	333
1998	48,404	3.4%	62,713	3,036	4.5%	347
1999	49,430	2.1%	64,186	3,173	4.5%	363
2000	50,117	1.4%	66,043	3,310	4.3%	383
2001	51,501	2.8%	67,454	3,474	5.0%	384
2002	52,915	2.7%	64,719	3,425	-1.4%	390
2003	54,194	2.4%	64,320	3,486	1.8%	399
2004	55,577	2.6%	63,898	3,551	1.9%	407
2005	57,145	2.8%	63,527	3,630	2.2%	415
2006	59,050	3.3%	63,487	3,749	3.3%	427
2007	61,640	4.4%	63,330	3,904	4.1%	445
2008	63,492	3.0%	62,249	3,952	1.2%	451
2009	64,151	1.0%	59,635	3,826	-3.2%	437
2010	64,421	0.4%	58,851	3,791	-0.9%	434

Commercial Load

Projected Commercial Sales and Load, 2011–2030

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2011	64,995	0.9%	59,059	3,839	1.2%	439
2012	66,265	2.0%	58,734	3,892	1.4%	445
2013	67,892	2.5%	58,122	3,946	1.4%	451
2014	69,600	2.5%	57,471	4,000	1.4%	457
2015	71,252	2.4%	56,873	4,052	1.3%	463
2016	72,840	2.2%	56,204	4,094	1.0%	468
2017	74,398	2.1%	55,579	4,135	1.0%	472
2018	75,950	2.1%	54,977	4,176	1.0%	477
2019	77,497	2.0%	54,399	4,216	1.0%	482
2020	79,031	2.0%	53,841	4,255	0.9%	486
2021	80,551	1.9%	53,342	4,297	1.0%	491
2022	82,058	1.9%	52,929	4,343	1.1%	496
2023	83,549	1.8%	52,592	4,394	1.2%	502
2024	85,030	1.8%	52,307	4,448	1.2%	508
2025	86,505	1.7%	52,116	4,508	1.4%	515
2026	87,976	1.7%	52,022	4,577	1.5%	523
2027	89,445	1.7%	51,979	4,649	1.6%	531
2028	90,906	1.6%	52,057	4,732	1.8%	541
2029	92,365	1.6%	52,166	4,818	1.8%	550
2030	93,823	1.6%	52,363	4,913	2.0%	561

Irrigation Load

Historical Irrigation Sales and Load,1970–2010

(weather-adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	7,319		126,039	922		105
1971	7,518	2.7%	136,020	1,023	10.9%	117
1972	7,815	4.0%	131,163	1,025	0.2%	117
1973	8,341	6.7%	140,226	1,170	14.1%	134
1974	8,971	7.6%	147,179	1,320	12.9%	151
1975	9,480	5.7%	154,226	1,462	10.7%	167
1976	9,936	4.8%	152,340	1,514	3.5%	172
1977	10,238	3.0%	160,870	1,647	8.8%	188
1978	10,476	2.3%	152,800	1,601	-2.8%	183
1979	10,711	2.2%	159,986	1,714	7.1%	195
1980	10,854	1.3%	154,900	1,681	-1.9%	191
1981	11,248	3.6%	165,138	1,857	10.5%	212
1982	11,312	0.6%	150,370	1,701	-8.4%	194
1983	11,133	-1.6%	143,424	1,597	-6.1%	182
1984	11,375	2.2%	131,427	1,495	-6.4%	170
1985	11,576	1.8%	133,730	1,548	3.6%	177
1986	11,308	-2.3%	134,686	1,523	-1.6%	174
1987	11,254	-0.5%	127,375	1,433	-5.9%	164
1988	11,378	1.1%	136,257	1,550	8.2%	176
1989	11,957	5.1%	137,704	1,647	6.2%	188
1990	12,340	3.2%	144,106	1,778	8.0%	203
1991	12,484	1.2%	133,777	1,670	-6.1%	191
1992	12,809	2.6%	139,469	1,786	7.0%	203
1993	13,078	2.1%	126,585	1,655	-7.3%	189
1994	13,559	3.7%	128,848	1,747	5.5%	199
1995	13,679	0.9%	125,761	1,720	-1.5%	196
1996	14,074	2.9%	123,537	1,739	1.1%	198
1997	14,383	2.2%	114,002	1,640	-5.7%	187
1998	14,695	2.2%	112,933	1,660	1.2%	189
1999	14,912	1.5%	117,103	1,746	5.2%	199
2000	15,253	2.3%	125,903	1,920	10.0%	219
2001	15,522	1.8%	115,103	1,787	-7.0%	204
2002	15,840	2.0%	109,768	1,739	-2.7%	198
2003	16,020	1.1%	108,979	1,746	0.4%	199
2004	16,297	1.7%	106,547	1,736	-0.5%	198
2005	16,936	3.9%	98,843	1,674	-3.6%	191
2006	17,062	0.7%	96,848	1,652	-1.3%	189
2007	17,001	-0.4%	104,905	1,783	7.9%	204
2008	17,428	2.5%	108,350	1,888	5.9%	215
2009	17,708	1.6%	100,186	1,774	-6.0%	203
2010	17,846	0.8%	99,148	1,769	-0.3%	202

Irrigation Load

Projected Irrigation Sales and Load, 2011–2030

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2011	18,264	2.3%	94,526	1,726	-2.4%	197
2012	18,541	1.5%	93,518	1,734	0.4%	197
2013	18,821	1.5%	91,968	1,731	-0.2%	198
2014	19,101	1.5%	90,686	1,732	0.1%	198
2015	19,379	1.5%	90,049	1,745	0.7%	199
2016	19,655	1.4%	89,212	1,753	0.5%	200
2017	19,932	1.4%	88,237	1,759	0.3%	201
2018	20,212	1.4%	87,324	1,765	0.4%	201
2019	20,487	1.4%	86,337	1,769	0.2%	202
2020	20,767	1.4%	85,426	1,774	0.3%	202
2021	21,045	1.3%	84,531	1,779	0.3%	203
2022	21,323	1.3%	83,591	1,782	0.2%	203
2023	21,601	1.3%	82,745	1,787	0.3%	204
2024	21,878	1.3%	81,991	1,794	0.4%	204
2025	22,157	1.3%	81,160	1,798	0.2%	205
2026	22,437	1.3%	80,269	1,801	0.2%	206
2027	22,712	1.2%	79,463	1,805	0.2%	206
2028	22,988	1.2%	78,494	1,804	0.0%	205
2029	23,268	1.2%	77,943	1,814	0.5%	207
2030	23,547	1.2%	77,079	1,815	0.1%	207

Industrial Load

Historical Industrial Sales and Load, 1970–2010

(weather-adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	49		9,173,784	445		52
1971	50	3.3%	10,474,941	525	17.9%	60
1972	56	12.1%	10,944,714	615	17.2%	71
1973	63	12.3%	10,889,056	687	11.7%	79
1974	65	2.2%	11,464,249	739	7.6%	84
1975	71	10.5%	11,014,121	785	6.1%	91
1976	73	3.0%	11,681,540	858	9.3%	99
1977	85	15.1%	10,988,826	929	8.3%	106
1978	99	17.6%	9,786,753	972	4.7%	111
1979	109	9.6%	9,989,158	1,087	11.8%	126
1980	112	2.7%	9,894,706	1,106	1.7%	125
1981	118	5.7%	9,718,723	1,148	3.9%	132
1982	122	3.5%	9,504,283	1,162	1.2%	133
1983	122	-0.3%	9,797,522	1,194	2.7%	138
1984	124	1.5%	10,369,789	1,282	7.4%	147
1985	125	1.2%	10,844,888	1,357	5.9%	155
1986	129	2.7%	10,550,145	1,357	-0.1%	155
1987	134	4.1%	11,006,455	1,474	8.7%	169
1988	133	-1.0%	11,660,183	1,546	4.9%	177
1989	132	-0.6%	12,091,482	1,594	3.1%	183
1990	132	0.2%	12,584,200	1,662	4.3%	191
1991	135	2.5%	12,699,665	1,719	3.4%	196
1992	140	3.4%	12,650,945	1,770	3.0%	203
1993	141	0.5%	13,179,585	1,854	4.7%	212
1994	143	1.7%	13,616,608	1,948	5.1%	223
1995	120	-15.9%	16,793,437	2,021	3.7%	230
1996	103	-14.4%	18,774,093	1,934	-4.3%	221
1997	106	2.7%	19,309,504	2,042	5.6%	235
1998	111	4.6%	19,378,734	2,145	5.0%	244
1999	108	-2.3%	19,985,029	2,160	0.7%	247
2000	107	-0.8%	20,433,299	2,191	1.5%	250
2001	111	3.5%	20,618,361	2,289	4.4%	260
2002	111	-0.1%	19,441,876	2,156	-5.8%	246
2003	112	1.0%	19,950,866	2,234	3.6%	255
2004	117	4.3%	19,417,310	2,269	1.5%	259
2005	126	7.9%	18,645,220	2,351	3.6%	270
2006	127	1.0%	18,255,385	2,325	-1.1%	265
2007	123	-3.6%	19,275,551	2,366	1.8%	270
2008	119	-3.1%	19,412,391	2,308	-2.4%	261
2009	124	4.0%	17,987,570	2,224	-3.6%	254
2010	121	-2.0%	18,310,726	2,220	-0.2%	254

Industrial Load

Projected Industrial Sales and Load, 2011–2030

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2011	121	-0.2%	18,958,898	2,294	3.3%	262
2012	125	3.3%	18,768,661	2,346	2.3%	268
2013	125	0.0%	19,133,471	2,392	1.9%	273
2014	126	0.8%	19,320,558	2,434	1.8%	278
2015	128	1.6%	19,318,966	2,473	1.6%	283
2016	131	2.3%	19,155,425	2,509	1.5%	286
2017	134	2.3%	18,997,015	2,546	1.4%	291
2018	134	0.0%	19,256,620	2,580	1.4%	295
2019	136	1.5%	19,239,155	2,617	1.4%	299
2020	139	2.2%	19,087,337	2,653	1.4%	302
2021	140	0.7%	19,218,638	2,691	1.4%	308
2022	142	1.4%	19,241,280	2,732	1.5%	312
2023	142	0.0%	19,514,996	2,771	1.4%	317
2024	145	2.1%	19,391,910	2,812	1.5%	321
2025	147	1.4%	19,454,919	2,860	1.7%	327
2026	148	0.7%	19,673,262	2,912	1.8%	333
2027	149	0.7%	19,892,894	2,964	1.8%	339
2028	152	2.0%	19,876,216	3,021	1.9%	344
2029	155	2.0%	19,862,920	3,079	1.9%	352
2030	156	0.6%	20,124,445	3,139	2.0%	359

Additional Firm Sales and Load*

Historical Additional Firm Sales and Load, 1970–2010

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	319		36
1971	295	-7.5%	34
1972	284	-3.7%	32
1973	291	2.2%	33
1974	282	-2.9%	32
1975	314	11.1%	36
1976	277	-11.8%	31
1977	311	12.4%	36
1978	357	14.9%	41
1979	373	4.3%	43
1980	360	-3.4%	41
1981	377	4.7%	43
1982	367	-2.5%	42
1983	425	15.8%	49
1984	466	9.6%	53
1985	471	1.1%	54
1986	483	2.5%	55
1987	503	4.2%	57
1988	531	5.6%	60
1989	671	26.5%	77
1990	625	-6.8%	71
1991	661	5.7%	75
1992	681	3.0%	78
1993	689	1.2%	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	1,119	-2.1%	128
2002	1,139	1.8%	130
2003	1,120	-1.6%	128
2004	1,157	3.3%	132
2005	1,176	1.6%	134
2006	1,189	1.2%	136
2007	1,142	-4.0%	130
2008	1,114	-2.4%	127
2009	965	-13.4%	110
2010	907	-6.1%	103

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

Additional Firm Sales and Load*

Projected Additional Firm Sales and Load, 2011–2030

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2011	1,449	59.9%	165
2012	1,627	12.3%	185
2013	1,799	10.6%	205
2014	1,902	5.7%	217
2015	2,002	5.3%	229
2016	2,071	3.4%	236
2017	2,065	-0.3%	236
2018	2,070	0.2%	236
2019	2,075	0.2%	237
2020	2,073	-0.1%	236
2021	2,075	0.1%	237
2022	2,082	0.3%	238
2023	2,089	0.4%	238
2024	2,096	0.3%	239
2025	2,101	0.2%	240
2026	2,112	0.5%	241
2027	2,113	0.0%	241
2028	2,119	0.3%	241
2029	2,119	0.0%	242
2030	2,125	0.3%	243

*Includes Micron Technology, Simplot Fertilizer, INL, Hoku Materials, "Special", and Raft River Rural Electric Cooperative, Inc.

Company System Load (excluding Astaris)

Historical Company System Sales and Load, 1970–2010
(weather-adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	3,915		494
1971	4,279	9.3%	539
1972	4,540	6.1%	573
1973	5,027	10.7%	634
1974	5,461	8.6%	690
1975	6,001	9.9%	758
1976	6,395	6.6%	806
1977	6,817	6.6%	858
1978	7,199	5.6%	912
1979	7,766	7.9%	976
1980	7,796	0.4%	977
1981	8,066	3.5%	1,015
1982	8,033	-0.4%	1,009
1983	8,009	-0.3%	1,012
1984	8,144	1.7%	1,018
1985	8,367	2.7%	1,053
1986	8,382	0.2%	1,050
1987	8,434	0.6%	1,056
1988	8,813	4.5%	1,104
1989	9,257	5.0%	1,164
1990	9,507	2.7%	1,201
1991	9,740	2.5%	1,218
1992	9,949	2.1%	1,254
1993	10,237	2.9%	1,275
1994	10,599	3.5%	1,340
1995	11,045	4.2%	1,375
1996	11,387	3.1%	1,437
1997	11,669	2.5%	1,469
1998	12,116	3.8%	1,517
1999	12,461	2.8%	1,564
2000	12,888	3.4%	1,627
2001	13,022	1.0%	1,592
2002	12,745	-2.1%	1,593
2003	13,000	2.0%	1,633
2004	13,287	2.2%	1,668
2005	13,571	2.1%	1,703
2006	13,906	2.5%	1,738
2007	14,336	3.1%	1,795
2008	14,439	0.7%	1,810
2009	13,933	-3.5%	1,746
2010	13,758	-1.3%	1,732

Company System Load (including Astaris)

Historical Company System Sales and Load, 1970–2010 Astaris Sales and Load (1970–2002)
(weather-adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)	Astaris Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	5,572		693	1,657		189
1971	5,787	3.9%	720	1,508	-9.0%	172
1972	6,359	9.9%	791	1,819	20.6%	207
1973	6,672	4.9%	831	1,645	-9.6%	188
1974	7,105	6.5%	887	1,643	-0.1%	188
1975	7,558	6.4%	945	1,557	-5.3%	178
1976	7,970	5.5%	995	1,575	1.2%	179
1977	8,234	3.3%	1,028	1,418	-10.0%	162
1978	8,741	6.2%	1,097	1,542	8.8%	176
1979	9,160	4.8%	1,143	1,395	-9.6%	159
1980	9,309	1.6%	1,157	1,513	8.5%	172
1981	9,700	4.2%	1,211	1,634	8.0%	186
1982	9,587	-1.2%	1,195	1,554	-4.9%	177
1983	9,619	0.3%	1,205	1,610	3.6%	184
1984	9,845	2.4%	1,221	1,701	5.7%	194
1985	9,980	1.4%	1,247	1,614	-5.1%	184
1986	9,935	-0.5%	1,236	1,554	-3.7%	177
1987	10,126	1.9%	1,259	1,692	8.9%	193
1988	10,448	3.2%	1,300	1,635	-3.4%	186
1989	10,961	4.9%	1,368	1,703	4.2%	194
1990	11,111	1.4%	1,394	1,604	-5.8%	183
1991	11,349	2.1%	1,411	1,609	0.3%	184
1992	11,519	1.5%	1,442	1,570	-2.4%	179
1993	11,674	1.3%	1,448	1,437	-8.4%	164
1994	12,019	3.0%	1,510	1,420	-1.2%	162
1995	12,612	4.9%	1,563	1,567	10.4%	179
1996	13,076	3.7%	1,639	1,689	7.8%	192
1997	13,297	1.7%	1,664	1,628	-3.6%	186
1998	13,389	0.7%	1,670	1,273	-21.8%	145
1999	13,512	0.9%	1,690	1,051	-17.4%	120
2000	13,942	3.2%	1,753	1,054	0.3%	120
2001	13,681	-1.9%	1,671	658	-37.5%	75
2002	12,757	-6.8%	1,594	11	-98.3%	1
2003	13,000	1.9%	1,633	0	-100.0%	0
2004	13,287	2.2%	1,668	0	0.0%	0
2005	13,571	2.1%	1,703	0	0.0%	0
2006	13,906	2.5%	1,738	0	0.0%	0
2007	14,336	3.1%	1,795	0	0.0%	0
2008	14,439	0.7%	1,810	0	0.0%	0
2009	13,933	-3.5%	1,746	0	0.0%	0
2010	13,758	-1.3%	1,732	0	0.0%	0

Company System Load

Projected Company System Sales and Load, 2011–2030

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2011	14,521	5.5%	1,819
2012	14,803	1.9%	1,852
2013	15,093	2.0%	1,890
2014	15,437	2.3%	1,932
2015	15,751	2.0%	1,970
2016	15,991	1.5%	1,998
2017	16,174	1.1%	2,023
2018	16,348	1.1%	2,045
2019	16,545	1.2%	2,070
2020	16,726	1.1%	2,090
2021	16,898	1.0%	2,114
2022	17,098	1.2%	2,139
2023	17,313	1.3%	2,166
2024	17,511	1.1%	2,189
2025	17,694	1.0%	2,214
2026	17,912	1.2%	2,241
2027	18,084	1.0%	2,263
2028	18,385	1.7%	2,298
2029	18,606	1.2%	2,329
2030	18,870	1.4%	2,362

Contract Off-System Load

Historical Contract Off-System Sales and Load, 1970–2010

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	386		44
1971	439	13.6%	50
1972	448	2.0%	51
1973	489	9.3%	56
1974	501	2.3%	57
1975	568	13.5%	65
1976	613	7.9%	70
1977	659	7.5%	75
1978	684	3.7%	78
1979	759	11.1%	87
1980	762	0.3%	87
1981	752	-1.2%	86
1982	736	-2.2%	84
1983	710	-3.5%	81
1984	747	5.2%	85
1985	779	4.3%	89
1986	670	-13.9%	77
1987	644	-4.0%	73
1988	675	4.9%	77
1989	740	9.7%	84
1990	968	30.8%	111
1991	1,537	58.8%	175
1992	1,348	-12.3%	154
1993	1,557	15.5%	178
1994	1,811	16.3%	207
1995	1,583	-12.6%	181
1996	1,285	-18.8%	146
1997	674	-47.5%	77
1998	716	6.2%	82
1999	568	-20.6%	65
2000	587	3.3%	67
2001	538	-8.4%	61
2002	454	-15.7%	52
2003	346	-23.6%	40
2004	19	-94.4%	2
2005	10	-47.0%	1
2006	0	-100.0%	0
2007	0	0.0%	0
2008	0	0.0%	0
2009	0	0.0%	0
2010	0	0.0%	0

Projected Contract Off-System Sales and Load, 2011–2030

2011–2030	0	0.0%	0

Total Company Load

Historical Total Company Sales and Load, 1970–2010
(weather-adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	5,958		738
1971	6,226	4.5%	772
1972	6,807	9.3%	844
1973	7,162	5.2%	889
1974	7,605	6.2%	946
1975	8,126	6.8%	1,012
1976	8,583	5.6%	1,067
1977	8,894	3.6%	1,106
1978	9,425	6.0%	1,178
1979	9,920	5.2%	1,233
1980	10,071	1.5%	1,247
1981	10,453	3.8%	1,300
1982	10,323	-1.2%	1,282
1983	10,329	0.1%	1,289
1984	10,592	2.5%	1,309
1985	10,759	1.6%	1,339
1986	10,605	-1.4%	1,315
1987	10,770	1.5%	1,335
1988	11,123	3.3%	1,379
1989	11,701	5.2%	1,455
1990	12,079	3.2%	1,508
1991	12,886	6.7%	1,592
1992	12,867	-0.1%	1,601
1993	13,231	2.8%	1,632
1994	13,830	4.5%	1,724
1995	14,195	2.6%	1,750
1996	14,361	1.2%	1,790
1997	13,971	-2.7%	1,744
1998	14,105	1.0%	1,754
1999	14,081	-0.2%	1,757
2000	14,529	3.2%	1,822
2001	14,219	-2.1%	1,735
2002	13,210	-7.1%	1,648
2003	13,347	1.0%	1,674
2004	13,306	-0.3%	1,670
2005	13,581	2.1%	1,704
2006	13,906	2.4%	1,738
2007	14,336	3.1%	1,795
2008	14,439	0.7%	1,810
2009	13,933	-3.5%	1,746
2010	13,758	-1.3%	1,732

Total Company Load

Projected Total Company Sales and Load, 2011–2030

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2011	14,521	5.5%	1,819
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2024	17,511	1.1%	2,189
2025	17,694	1.0%	2,214
2026	17,912	1.2%	2,241
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2028	18,385	1.7%	2,298
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2030	18,870	1.4%	2,362







Appendix B—Demand-Side Management 2010 Annual Report

For the 2011 Integrated Resource Plan

June 2011

IDAHO POWER®
An IDACORP Company

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GLOSSARY OF ACRONYMS

aMW—Average Megawatt

A/C—Air Conditioning

ACB, Inc—Advertising Checking Bureau, Inc.

AMI—Advanced Metering Infrastructure

ARRA—American Reinvestment and Recovery Act

B/C—Benefit Cost

BCA—Building Contractors Association

BCASEI—Building Contractors Association of South East Idaho

BCASWI—Building Contractors Association of Southwestern Idaho, Inc.

BOP—Builder Option Package

BOMA—Building Owners and Managers Association International

BPA—Bonneville Power Administration

CAES—Center for Advanced Energy Studies

CAP—Community Action Partnership

CAPAI—Community Action Partnership Association of Idaho, Inc.

CAIS—Certified Agricultural Irrigation Specialist

CD—Compact Disc

CEE—Consortium for Energy Efficiency, Inc.

CEERI—CAES Energy Efficiency Resource Initiative

CEI—Continuous Energy Improvement

CEL—Cost-Effective Limit

CFL—Compact Fluorescent Lamp/Light

CHQ—Corporate Headquarters (Idaho Power)

CID—Certified Irrigation Designer

CIS—Customer Information System

CLRIS—Customer and Load Research Information System

COP—Coefficient of Performance

CRM—Customer Relationship Management

CSI—Crime Scene Investigation

CSR—Customer Service Representative

DEER—Database for Energy Efficiency Resources

DHP—Ductless Heat Pump

DOE—Department of Energy

DSM—Demand-Side Management

DSR—Demand-Side Resource

EA4—Energy Audit 4

ECM—Electronically Commutated Motor

EEAG—Energy Efficiency Advisory Group

EECBG—Energy Efficiency Conservation Block Grant

EISA—*Energy Independence and Security Act of 2007*

ESI—Energy Scene Investigation

ETO—Energy Trust of Oregon

EPA—Environmental Protection Agency

FCA—Fixed-Cost Adjustment

GMPG—Green Motors Practice Group

GPM—Gallons per Minute

H&CE—Heating & Cooling Efficiency Program

hp—Horsepower

HPS—Home Performance Specialist

HSPF—Heating Seasonal Performance Factor

HVAC—Heating, Ventilation, and Air Conditioning

ICL—Idaho Conservation League

IDL—Integrated Design Lab in Boise

IECC—International Energy Conservation Code

INL—Idaho National Laboratory

IOER—Idaho Office of Energy Resources

IPUC—Idaho Public Utilities Commission

IRP—Integrated Resource Plan

IRPAC—Integrated Resource Plan Advisory Council

IRS—Internal Revenue Service

iSTEM–Idaho Science, Technology, Engineering and Mathematics

IT—Information Technology

kW—Kilowatt

kWh—Kilowatt-hour

LCD—Liquid Crystal Display

LED—Light-Emitting Diode

LEEF—Local Energy Efficiency Funds

LIHEAP—Low Income Home Energy Assistance Program

MOU—Memorandum of Understanding

MHAFB—Mountain Home Air Force Base

MPER—Market Progress Evaluation Report

MW—Megawatt

MWh—Megawatt-hour

NAHB—National Association of Home Builders

NEEM—Northwest Energy Efficient Manufactured Housing Program

NEEA—Northwest Energy Efficiency Alliance

NEMA—National Electrical Manufacturers Association

NPCC—Northwest Power and Conservation Council

NW EM Demo—Northwest Energy Management Demonstration Project

NWES—Northwest ENERGY STAR®

OPUC—Public Utility Commission of Oregon

OSV—On-Site Verification

PCA—Power Cost Adjustment

PCT—Participant Cost Test

PECI—Portland Energy Conservation, Inc.

PLC—Power-Line Carrier

PLMA—Peak Load Management Alliance

PTCS—Performance Tested Comfort System

QA—Quality Assurance

RAD—Responsible Appliance Disposal

RAP—Resource Action Programs

RFP—Request for Proposal

RIM—Ratepayer Impact Measure Test

RS&E—Runyon, Saltzman & Einhorn

RTF—Regional Technical Forum

RTUG—Commercial Rooftop Unit Work Group

Rider—Idaho Energy Efficiency Rider and Oregon Energy Efficiency Rider

SCCT—Simple-Cycle Combustion Turbine

SCO—State-Certifying Organization

SEE—Students for Energy Efficiency

SEEARP—State Energy Efficient Appliance Rebate Program

SIC—Standard Industrial Classification Codes

SIR—Savings-to-Investment Ratio

SO_2—Sulfur Dioxide

SRA—Snake River Alliance

SRVBCA—Snake River Valley Building Contractors Association

TLS—Transport Layer Security

TOU—Time-of-Use

TRC—Total Resource Cost

UC—Utility Cost

USA—Utility Service Agreement

W—Watt

WAQC—Weatherization Assistance for Qualified Customers

EXECUTIVE SUMMARY

In 2010, Idaho Power achieved a year of increased energy savings, reduced demand, increased evaluation and research, and enhanced energy efficiency education and customer outreach. Demand-side management (DSM) activities focused on evaluation, savings, program participation, customer satisfaction, and energy efficiency awareness. Through program expansion and improvements, the company's DSM portfolio of programs and energy savings opportunities have increased.

Idaho Power's overall annual energy savings from energy efficiency activities increased in 2010. Energy savings for 2009 were 143,146 megawatt hours (MWh), including the Northwest Energy Efficiency Alliance (NEEA) savings. In 2010, these savings increased over 31 percent to 187,626 MWh. From Idaho Power's energy efficiency programs alone, the savings increased 30 percent, from 132,443 MWh in 2009 to 172,292 MWh in 2010. This is enough energy to supply over 13,500 average homes in Idaho Power's service area. Since 2002, Idaho Power's DSM efforts have accumulated energy savings and demand response reduction greater than any other time in the company's history. Demand reduction for Idaho Power's demand response programs increased from 218 megawatts (MW) in 2009 to 336 MW in 2010. This is more than twice as large as the capacity of Idaho Power's Bennett Mountain peaker plant located near Mountain Home, Idaho. Total expenditures on DSM-related activities increased from almost $35 million in 2009 to $46 million in 2010.

Idaho Power's focus on program evaluation and research in 2010 resulted in process evaluations completed on five commercial, industrial, and irrigation programs and on four residential programs. Two different independent third-party contractors conducted these evaluations. The company also contracted with a third-party consultant to conduct a residential home energy use survey. Idaho Power continued to participate with other research and evaluation organizations, such as NEEA, the Regional Technical Forum (RTF), and the Idaho Integrated Design Lab (IDL in Boise). Also in 2010, Idaho Power developed a new integrated database with a unified table structure to store DSM program data and more effectively track program performance.

The percentage of customers who have a positive perception of Idaho Power's energy efficiency efforts continued to increase, indicated by the results of Idaho Power's 2010 quarterly customer relationship survey. Results showed steady improvement over recent years. Customers' positive perception of Idaho Power's energy efficiency efforts increased from 39 percent in early 2003 to 57 percent in late 2010. Idaho Power continued to expand its customer satisfaction measurement activities, which enabled Idaho Power to identify actionable areas for improvement.

Pursuit of cost-effective energy efficiency is a primary objective for Idaho Power. Energy efficiency and demand response provides economic and operational benefits to the company and its customers. Enhancement of information and programs helps ensure customers have opportunities to learn about their energy use and participate in programs. To optimize the acquisition of cost-effective DSM, Idaho Power has advanced a progressive regulatory model and expanded its educational initiatives. Additionally, Idaho Power played a key role in the launching of the Center for Advanced Energy Studies (CAES) Energy Efficiency Research Initiative (CEERI).

The *Demand Side Management 2010 Annual Report* provides a review of the company's DSM activities and finances throughout 2010, outlines Idaho Power's plans for DSM activities, and satisfies the reporting requirements set out in the Idaho Public Utilities Commission's (IPUC) Order Nos. 29026 and 29419.

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INTRODUCTION

Idaho Power's *Demand Side Management* (DSM) *2010 Annual Report* provides a review of the financial and operational performance of Idaho Power's DSM activities and initiatives for the 2010 calendar year. The company provides a wide range of opportunities for all customer classes to participate in programs, to be informed about energy use, and to reduce their energy consumption.

Idaho Power's two main objectives for DSM programs are to achieve all prudent, cost-effective energy efficiency resources to meet its electrical system's energy and demand needs and to provide customers with programs and information to help them manage their energy usage. The company achieves these objectives through the development, implementation, and prudent management of programs that provide energy and demand savings, and through outreach and education. When possible, Idaho Power implements identical programs in its Idaho and Oregon service areas.

Customer participation in Idaho Power's energy efficiency and demand response programs continues to increase, as do energy savings and demand reduction. The energy savings exclusively from Idaho Power's energy efficiency programs in 2010 was 172,292 megawatt-hour (MWh), a 30 percent increase over the 132,443 MWh energy savings in 2009. Demand reduction for the demand response programs also substantially increased in 2010. Combined, the Irrigation Peak Rewards, FlexPeak Management, and A/C Cool Credit programs resulted in an estimated summer peak reduction of 336 megawatt (MW), which is a 54 percent increase from the reduction achieved in 2009.

In a continuing effort to fulfill the objectives of the Memorandum of Understanding (MOU) which was signed by Idaho Power, Idaho Public Utilities Commission (IPUC) staff, and Idaho's other investor-owned utilities on January 25, 2010, Idaho Power has made several additions to this year's report. Included this year is a new appendix attached to this document, titled Appendix 5. This appendix shows program savings and costs separated into Idaho Power's Idaho and Oregon jurisdictions and by funding source. The other addition is the *2010 DSM Detailed Expenses by Program* table that reports expenses by funding source and cost category. This table is included in *Supplement 1: Cost Effectiveness*. Supplement 1 shows all of the standard cost-effectiveness tests for its programs, including the calculation of the Ratepayer Impact Measure (RIM) Test for each program. The company also continued to enhance its third-party evaluation activities. In 2010, all Idaho Power energy efficiency programs are shown to be cost-effective, and all of its demand response programs are cost-effective from both a long-term perspective and for 2010 under a one-year perspective.

Demand-Side Management Programs

The programs within Idaho Power's energy efficiency and demand response portfolio are offered to four major customer sectors: residential, commercial, industrial, and irrigation. The commercial and industrial energy efficiency programs are made available to customers in either sector. The sector is generally referred to as the commercial/industrial sector in this report.

Idaho Power categorized its DSM activities in four categories: demand response, energy efficiency, market transformation, and other programs and activities. The other programs and activities are generally to provide customer outreach and education concerning the efficient use of electricity. All of these activities are coordinated to forward Idaho Power's enhanced commitment to energy efficiency, demand response, and customer satisfaction.

Figures 1–3 show the historic energy savings, demand reduction, and DSM expenses.

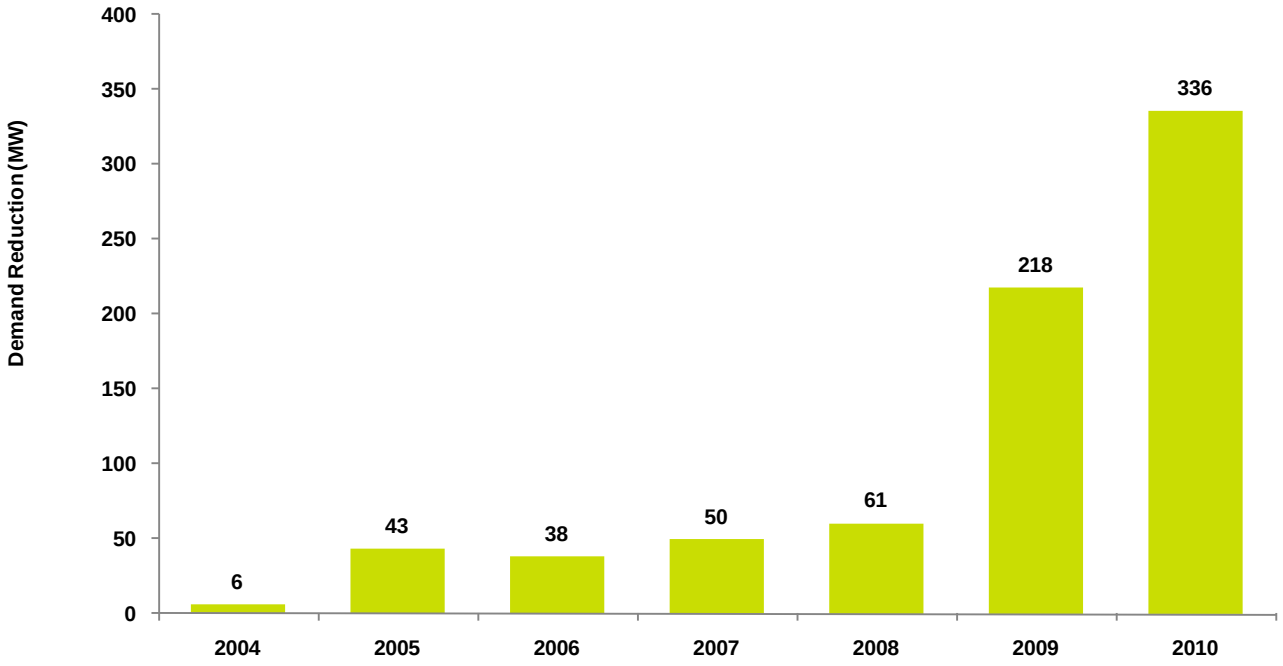

Figure 1. Annual demand response reduction 2004–2010 (MW)

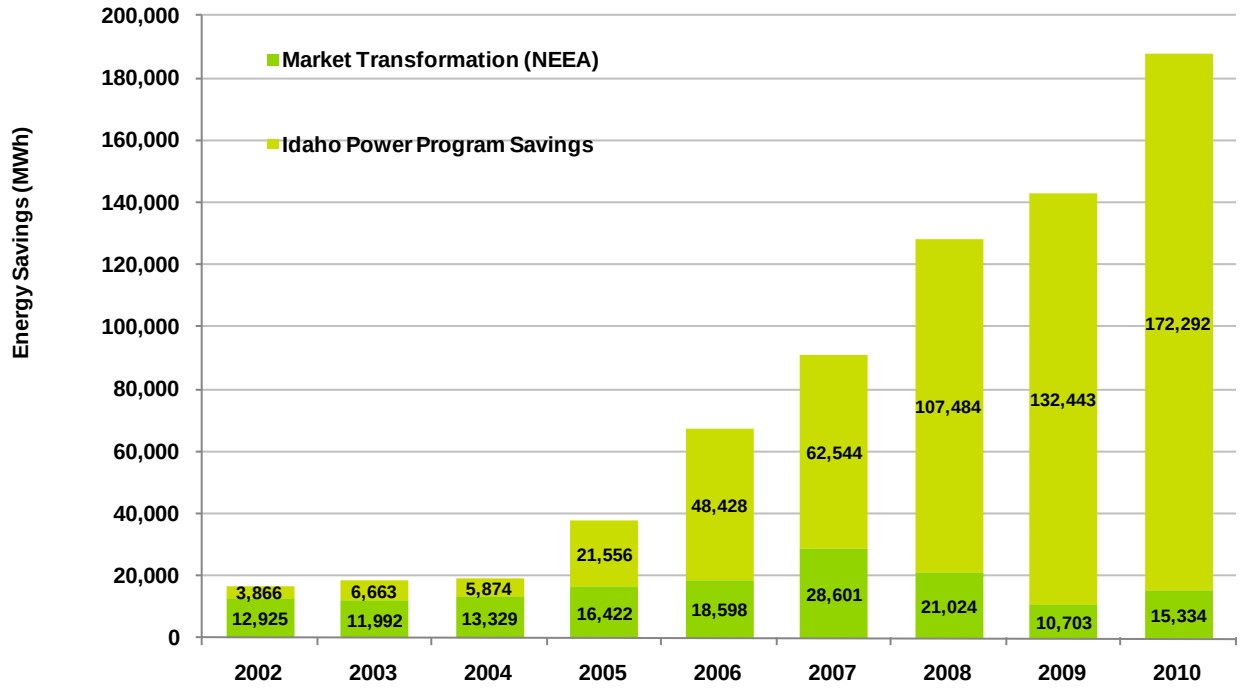

Figure 2. Annual energy savings 2002–2010 (MWh)



Figure 3. DSM expense history 2002–2010 (millions of dollars)

Demand Response Programs

Demand response programs are considered a resource to reduce Idaho Power's demand for electricity at specific times of the day and year when electricity is normally in short supply. The new, all-time winter system peak of 2,528 MW was set on Thursday, December 10, 2009, at 8:00 a.m. The summer peak in 2010 was 2,930 MW set on Monday, June 28, 2010 at 7:00 p.m., below the Idaho Power's all-time system peak of 3,214 MW on Monday, June 30, 2008, at 3:00 p.m. Idaho Power estimates that if it did not have demand response programs, the summer system peak would have been approximately 3,087 MW on July 16, 2010 at 7:00 p.m.

In 2010, Idaho Power's Energy Efficiency and Demand Response personnel worked closely with representatives from other departments within the company on two distinct yet related projects. The first was to optimize the dispatch of the demand response programs on a day-to-day basis to achieve the greatest possible demand reduction over the longest time period while still having all programs dispatched at the time of the system peak. For this goal, representatives from the Energy Efficiency, Power Supply, Compliance, System Dispatch, Regulatory Affairs, Transmission Planning, and Generation Dispatch departments met weekly to determine a potential dispatch schedule for the following week. This team considered the upcoming load forecast, weather forecast, generation availability, and the magnitude of the forecast system peak in order to set a dispatch schedule. The actual decision to dispatch was made on a day-ahead basis by Power Supply Operations.

The second major demand response project for the company in 2010 was to work with members of Load Forecasting, Power Supply Planning, Load Research, Regulatory Affairs, and Energy Efficiency Programs to determine the optimum amount of demand response the company can and should plan for in the long-term Integrated Resource Plan (IRP) process. This research and analysis led to the filing of case number IPC-E-10-46 in Idaho and Advice number 11-1 in Oregon. Both of these regulatory filings

proposed that the company make substantial changes to the method by which the Irrigation Peak Reward participants are paid for their demand reduction.

The measure of demand response program performance is the number of MW of reduced electrical demand that the company needs to serve during system peak periods. In 2010, Idaho Power again offered three demand response programs. The A/C Cool Credit program was offered to residential customers and the FlexPeak Management program was offered to commercial/industrial customers. The Irrigation Peak Rewards program was available for irrigation customers. The Irrigation Peak Rewards program was modified in 2010 to add the ability to dispatch the program on Saturdays and to add the potential for the company to use the program starting at 1:00 p.m. instead of 2:00 p.m. The program season was also extended from ending on July 31 to ending on August 15.

Energy Efficiency Programs

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

Market Transformation

Market transformation is a method of achieving energy savings through engaging and influencing large national and regional companies and organizations. These organizations are in a position to affect the design of energy usage in products, services, and practices that affect electricity consumption. Idaho Power achieves market transformation savings primarily through its participation in Northwest Energy Efficiency Alliance (NEEA). Idaho Power also supports market transformation accomplished by appliance or building code modifications or enforcement.

Other Programs and Activities

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

Table 1 provides a list of the DSM programs and their respective sectors, operational category, the state in which each was available in 2010, and energy savings.

Table 1. 2010 DSM, sectors, programs, operational type, and energy savings

Program by Sector	Operational Type	State	Savings
Residential			
A/C Cool Credit	Demand Response	ID/OR	39.0 MW
Ductless Heat Pump Pilot	Energy Efficiency	ID/OR	364 MWh
Energy Efficient Lighting	Energy Efficiency	ID/OR	28,083 MWh
Energy House Calls	Energy Efficiency	ID/OR	1,199 MWh
ENERGY STAR® Homes Northwest	Energy Efficiency	ID/OR	883 MWh
Heating & Cooling Efficiency Program	Energy Efficiency	ID/OR	1,104 MWh
Home Improvement Program	Energy Efficiency	ID	3,986 MWh
Home Products Program	Energy Efficiency	ID/OR	1,444 MWh
Oregon Residential Weatherization	Energy Efficiency	OR	<1 MWh
Rebate Advantage	Energy Efficiency	ID/OR	165 MWh
Residential Energy Efficiency Education Initiative	Other Programs and Activities	ID/OR	n/a
See ya later, refrigerator®	Energy Efficiency	ID/OR	1,568 MWh
Weatherization Assistance for Qualified Customers	Energy Efficiency	ID/OR	3,742 MWh
Weatherization Solutions for Eligible Customers	Energy Efficiency	ID	313 MWh
Commercial/Industrial			
Building Efficiency	Energy Efficiency	ID/OR	10,820 MWh
Commercial Education Initiative	Other Programs and Activities	ID/OR	n/a
Easy Upgrades	Energy Efficiency	ID/OR	35,824 MWh
FlexPeak Management	Demand Response	ID/OR	47.5 MW
Holiday Lighting Program	Energy Efficiency	ID/OR	249 MWh
Oregon Commercial Audits	Energy Efficiency	OR	n/a
Custom Efficiency	Energy Efficiency	ID/OR	71,580 MWh
Irrigation			
Irrigation Efficiency Rewards	Energy Efficiency	ID/OR	10,968 MWh
Irrigation Peak Rewards	Demand Response	ID/OR	249.7 MW
All Sectors			
Northwest Energy Efficiency Alliance	Market Transformation	ID/OR	15,334 MWh

Program Performance

In 2010, energy savings increased as compared to 2009 for residential, commercial, and industrial by 65 percent, 13 percent, and 38 percent, respectively. There was a 17 percent reduction in the savings from the irrigation sector. The residential sector savings increased to 42,851 MWh; the commercial sector savings increased to 46,893 MWh; the industrial sector increased to 71,580 MWh; and the irrigation sector decreased to 10,968 MWh. The reduction in savings in the irrigation sector was primarily the result of program maturity and new program requirements that began in 2010. Additional energy savings continue to be realized through market transformation partnership activities with NEEA.

Customer participation increased in most of the existing programs during the year. The number of projects completed under the Easy Upgrades program increased from 1,224 projects in 2009 to 1,535 projects in 2010, a 25 percent increase. Participation in the Home Improvement Program increased by almost 200 percent, from 1,188 homes in 2009 to 3,537 in 2010. As a result of the continuation of the depressed housing market in 2010, the number of homes given incentives in the Rebate Advantage program decreased. Surprisingly, the ENERGY STAR® Homes Northwest program

participation increased by almost 33 percent by providing incentives for 630 homes in 2010 as compared to 474 homes in 2009.

A few individual programs were big contributors to overall energy savings. The Custom Efficiency program accounted for 42 percent of Idaho Power's energy savings from programs, resulting in an estimated 71,580 MWh of savings. The Easy Upgrades program in the commercial sector provided 21 percent, or 35,824 MWh, of estimated energy savings. In the residential sector, the Energy Efficient Lighting program saved 28,083 MWh, accounting for 16 percent of overall energy savings by giving incentives to over one million bulbs in 2010.

Table 2 shows the 2010 annual energy savings, percent of energy usage, number of customers, and average megawatt (aMW) savings associated with each of the DSM program categories. The table also provides a comparison of the 2010 contribution of each sector in terms of energy usage and its respective size in number of customers. Unless otherwise noted, all energy savings presented in this report are measured or estimated at the customers' meter, excluding line losses.

Table 2. 2010 Program Sector Summary and Energy Use

	Energy Efficiency Program Impacts[a]				Idaho Power System Sales		
	Direct Expenses	Energy Savings (MWh)	Average Energy (aMW)	Peak Load Reduction (MW)[b]	Sector Total (MWh)	Percentage of Energy Usage	Number of Customers
Residential	$ 8,093,078	42,851	4.9		4,983,423	36.70%	408,754
Commercial	5,535,273	46,893	5.4	8.7	3,763,495	27.71%	64,647
Industrial	8,778,125	71,580	8.2	9.5	3,126,504	23.02%	121
Irrigation	2,200,814	10,968	1.3	3.3	1,706,632	12.57%	18,547
Market Transformation	2,391,217	15,334	1.8	n/a	n/a	n/a	n/a
Total	**$26,998,507**	**187,626**	**21.0**	**21.5**	**13,580,054**	**100.0%**	**492,069**

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

2010 Activities

In 2010, Idaho Power continued to expand its DSM programs in order to increase participation and energy savings. Many of the activities in 2010 also revolved around evaluation and research. The company was also engaged in enhanced regulatory reporting and filings.

Idaho Power's residential end-use survey or *Home Energy Survey* was completed in 2010. The survey was the latest in a series of periodic end-use studies conducted by Idaho Power, with the last survey completed in 2004. The primary objective of the 2010 study was to profile residential customers to better understand their housing and end-use characteristics that included home demographics, fuel source, home heating and cooling, and appliance and consumer electronics saturation. A copy of this report is included in *Supplement 2: Evaluation*.

In 2010, Idaho Power designed and developed a new comprehensive database that will more effectively store savings results, measure information, and allow for more efficient incentive processing for customers. The database was developed with a unified table structure across all energy efficiency programs on a SQL Server database platform that is easily scalable for future program additions and changes. The database structure allows for the integration of DSM program data with Idaho Power's customer information system (CIS) along with financial databases for tracking and processing customer incentive payments. Because of the unified and consistent table structure, the database is well positioned

for the future transition to the new CIS and customer relationship management (CRM) tool that will be implemented through the federal Smart Grid Investment Grant program. While the database table structure is consistent across programs, each program has the ability to track custom fields that are unique to their program. The database application was tested in late 2010 and completed for all but two programs by the beginning of 2011. The final programs will be integrated into the system in early 2011.

Idaho Power collaborated with the City of Boise to serve as the implementer for the Boise City Home Audit Project. Additionally, the company continued participation with NEEA's Ductless Heat Pump (DHP) Pilot. Idaho Power also modified the Irrigation Peak Rewards program.

During 2010, Idaho Power began its contractual participation in, and funding of, NEEA under the 2010 to 2014 agreement. NEEA's efforts in the northwest impact Idaho Power's customers by encouraging regional market transformation. Idaho Power representatives participated on several NEEA committees and events. Idaho Power also continued to help fund and participate in the Regional Technical Forum (RTF) and uses the results from the RTF's research in program development and cost-effectiveness analysis.

On March 16, 2010, Idaho Power filed case number IPC-E-10-09, which was a request for the IPUC to designate Idaho Power's expenditure of $50,701,740 in Idaho Rider funds in 2008 and 2009 as prudently incurred expenses. This prudency filing was the first designed to comply with the agreed-upon principles set forth in the MOU for Prudency Determination of DSM Expenditures. On November 16, 2010, in Order No. 32113, the IPUC found that the company acted prudently in the administration of its Rider-funded DSM programs and expenses.

Energy Efficiency Advisory Group

Formed in 2002, the Energy Efficiency Advisory Group (EEAG) provides input on formulating and implementing energy efficiency and demand reduction programs funded by the Rider. Currently, the EEAG consists of 14 members from across Idaho Power's service area and the Pacific Northwest. Members represent a cross-section of customers, including individuals 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.

In 2010, the EEAG met three times, February 18, May 26, and October 26. During the meetings, Idaho Power requested recommendations and discussion on new program proposals, marketing methods, and specific measure details; provided a status of the Rider funding and expenses; updated ongoing programs and projects; and supplied general information on DSM issues. Idaho Power relies on input from the EEAG to provide a customer and public interest review of energy efficiency and demand response programs and expenses. The minutes from the 2010 EEAG meetings are included in *Supplement 2: Evaluation*.

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

Smart Meter Project

Idaho Power continued with the current Smart Meter Project by installing Advanced Meter Infrastructure (AMI). The Smart Meter Project will enhance Idaho Power's energy efficiency efforts in several ways. Hourly data is being collected by these meters and can be viewed by customers via the Internet. This will enable customers to be more informed and more wisely manage their use of electricity. Customer hourly energy data and monthly demand data will eventually help to evaluate energy efficiency and demand response programs. Idaho Power will continue to expand its use of the power-line communications technology to dispatch demand response programs.

As of February 2011, Idaho Power had installed 283,500 residential smart meters and 47,756 commercial Smart Meters, totaling 331,256 meters as part of the company's three-year AMI deployment. While 2009 saw meters installed primarily in the Treasure Valley area, 2010 continued to deploy meters into Canyon County as well as the Payette and Ontario, Oregon areas served by the company. By year-end, installations were completed in the Mountain Home area. Work commenced in the Pocatello area in January 2011 and will continue until the end of May. From June to December 2011, the Twin Falls and Hailey areas will be outfitted with AMI technology. To date, 83 of the expected 134 substations installations are completed. Overall, the project is on schedule.

Regulatory Initiatives

Idaho Power believes there are three essential components of an effective regulatory model for DSM: 1) the timely recovery of DSM program costs, 2) the removal of financial disincentives, and 3) the availability of financial incentives in order for the company to have the opportunity to earn on the energy efficiency investments like other investments in which the company is engaged. Since 2002, Idaho Power has recovered its DSM program costs through the Rider with the intended result of providing more timely recovery of DSM costs. Coupled with cost recovery is a need for clear and achievable guidelines for prudency. To address the removal of financial disincentives, Idaho Power is testing the effects of a fixed-cost adjustment (FCA) mechanism in a five-year pilot initiative. The FCA pilot just completed year four.

To introduce an option to provide financial incentives for DSM, in October the company filed case number IPC-E-10-27 with the IPUC. Part of the filing establishes the company's proposal to move incentive payments for one DSM program to a regulatory asset account in order to begin earning its authorized rate of return on the DSM investment. This would allow some energy efficiency investments to be treated similar to supply-side investments and not treated as inferior investments. In that same filing, the company proposed moving the recovery of incentive payments of demand response programs out of the Rider and into the Power Cost Adjustment (PCA) mechanism. This move would treat the cost recovery of demand response payments similar to other supply-side resource expenses, such as fuel purchase power and surplus sales.

DSM Expenditures

Funding for DSM programs in 2010 came from several sources. The Rider funds are collected directly from customers on their monthly bills. The Idaho Rider is currently 4.75 percent of base rate revenues. On March 5, 2010, Idaho Power filed with the Public Utilities Commission of Oregon (OPUC) to increase the Oregon Rider from 1.5 percent to 3.0 percent and to eliminate the monthly caps on the residential and irrigation bills. This was approved on June 1, 2010. Energy efficiency and demand response-related expenses not funded through the Rider, including costs for administration and

overhead, are included as part of Idaho Power's ongoing operation and maintenance costs. Total DSM expenses funded from all sources were $45.8 million in 2010.

Table 3 provides a summary of the 2010 expenses and energy savings by each funding category.

Table 3. 2010 funding source and energy impact

Funding Source	Expenses	MWh Savings
Idaho Rider	$ 42,479,692	174,779
Oregon Rider	1,704,367	9,105
Idaho Power Base Rates	1,648,792	3,742
Total	**$ 45,832,851**	**187,626**

Table 4 and Figure 4 show Idaho Power's Rider expenses separated by expense category. The expenses in the Materials category are primarily A/C Cool Credit switches. Other Expenses includes marketing ($514 thousand), program evaluation ($293 thousand), and program training ($190 thousand). Purchased services includes payments made to NEEA and contract payments made to third-party contractors who help administer Idaho Power's programs, such as M2M for the Irrigation Peak Rewards program and JACO for the See ya later, refrigerator program.

Table 4. 2010 Idaho and Oregon Rider expenditures by category

	Total	% of Total
Incentive Expense	$32,048,751	73%
Labor/Administration	2,828,287	6%
Materials	345,066	1%
Other Expense	1,040,237	2%
Purchased Services	7,921,718	18%
Total 2010 Rider Expenditures, by Category	**$44,184,058**	**100%**

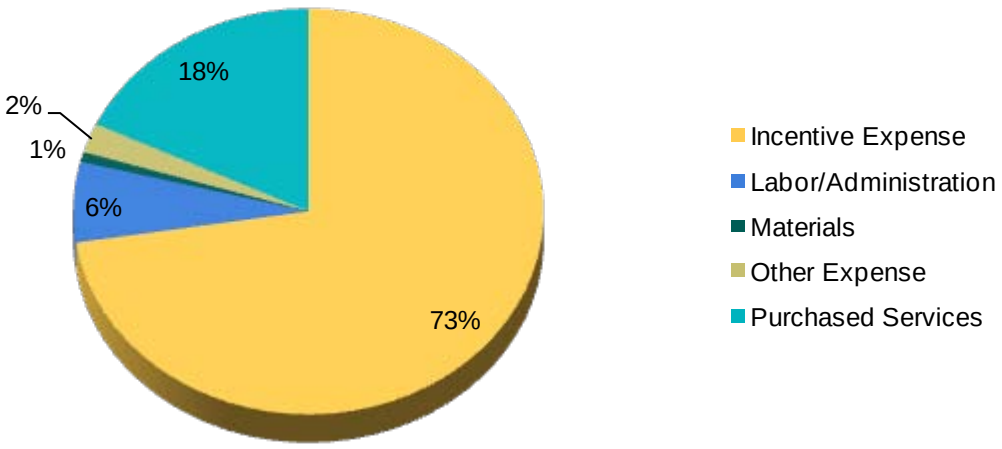

Figure 4. 2010 Oregon and Idaho Rider expenditures by category

Figure 5 shows Idaho Power Rider incentives expenses separated by type of program and by type of sector, either Demand Response (DR) or Energy Efficiency (EE).

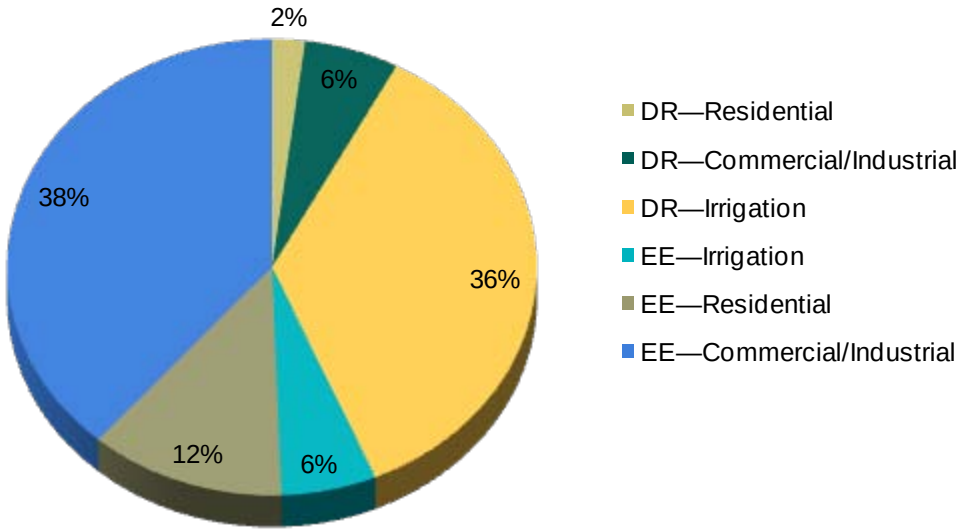

Figure 5. 2010 Idaho and Oregon Rider incentives by sector

Future Plans

Many of Idaho Power's DSM programs are selected for implementation through its biennial IRP. The IRP is a public document that details Idaho Power's strategy for economically maintaining the adequacy of its power system into the future. The IRP process balances cost, risk, and environmental concerns in developing a preferred portfolio of future resources that meet the specific energy needs of Idaho Power and its customers. In 2011, Idaho Power plans to continue to increase participation, energy savings, and demand reduction from existing energy efficiency and demand response programs. Additionally, the company will add measures as identified in the 2011 IRP to its existing programs and continue to expand its efforts in energy efficiency education. Idaho Power also plans to expand the FlexPeak Management program as defined in its contract with EnerNOC, Inc., the third-party demand response aggregator who administers this program.

Marketing

DSM marketing plans are developed annually. These plans focus on distinct customer segments, including residential, commercial/industrial, and irrigation. Each segment's marketing plan includes the goals, strategy, tactics, previous marketing results/research, and budgets for each individual program within that segment. The plan is reviewed at the six-month mark to ensure tactics are being implemented and to update information as necessary. A variety of sources help inform marketing decisions. These include primary research, secondary research, historical performance, and third-party segmentation software.

As part of the company's awarded Smart Grid Investment Grant, work will continue on the CRM tool in 2011. This new marketing tool will track customer interactions and centralize customer marketing data, providing in-depth information about Idaho Power customers. This new technology will allow the

Customer Relations and Energy Efficiency department to better interact with customers, meet their needs, and accelerate energy efficiency and demand response program participation. Resource efficiencies in regard to the CRM tool will be gained in part by replacing current manual marketing processes with automated processes and workflows.

Program Evaluation

Program evaluation is an important facet of Idaho Power's DSM operational activities. Idaho Power relies on evaluation by third-party contractors, internal analyses, and regional studies to ensure the ongoing cost-effectiveness of programs through validation of energy savings and demand reduction. The results of Idaho Power's evaluation efforts are used to enhance or initiate program changes. Throughout 2010, Idaho Power revised its comprehensive evaluation plan for energy efficiency and demand response programs. The current evaluation plan is included in *Supplement 2: Evaluation*. Although the evaluation plan is expected to be used for scheduling evaluations, the timing of specific program evaluations will be based on considerations of program evaluation needs, and other relevant regional studies.

In 2010, the company completed process evaluations on all of its commercial, industrial, and irrigation programs. It also completed process evaluations on four of its residential energy efficiency programs. Although Requests for Proposals (RFP) were issued in April 2010, the studies were completed in late 2010, and the final reports were received in early 2011. All of these studies were conducted under contract with third-party independent evaluation firms. The company is in the process of reviewing the recommendations and constructing implementation plans to incorporate the results of these evaluations into the program processes. Copies of these evaluations are included in *Supplement 2: Evaluation*.

Customer Satisfaction

Since 1995, Idaho Power has employed an independent third-party research vendor to conduct customer relationship surveys. The intent of these surveys is to measure the overall customer relationship and satisfaction with Idaho Power. As such, consistency in survey format is an important aspect of being able to trend results over a period of time. Occasionally, when there are changes in Idaho Power operations that may significantly affect a customer's relationship with the company, slight changes or additions have been allowed to the survey instrument to accommodate new relationship attributes. Because of Idaho Power's increased activity with energy efficiency programs in 2003 and the impact those programs may have on a customer's satisfaction with the company, Idaho Power added two questions related to awareness of Idaho Power's energy efficiency efforts to the overall survey instrument. In 2010, again because of increased activity and interest in Idaho Power's energy efficiency programs, the company added three additional questions to the survey to measure customers' participation in, and satisfaction with, Idaho Power's energy efficiency programs. However, it is important to reiterate that the intent of this survey is not to measure all aspects of any or all energy efficiency programs offered by Idaho Power. The survey measures satisfaction of a number of different aspects of the customer's relationship with Idaho Power, including energy efficiency, at a very high level.

The 2010 results of Idaho Power's quarterly customer relationship survey showed steady improvement over recent years. The percentage of customers who have a positive perception of Idaho Power's energy efficiency efforts continued to grow, with a 46 percent increase in positive customer perception from 2003 to 2010. Customers' positive perception of Idaho Power's energy efficiency efforts increased from 39 percent in early 2003 to 57 percent in late 2010. Idaho Power continues to expand its customer satisfaction measurement activities, which enable Idaho Power to identify actionable areas for

improvement. Figure 6 depicts quarterly growth in the number of customers who indicated Idaho Power met or exceeded their needs concerning energy efficiency efforts encouraged by Idaho Power.

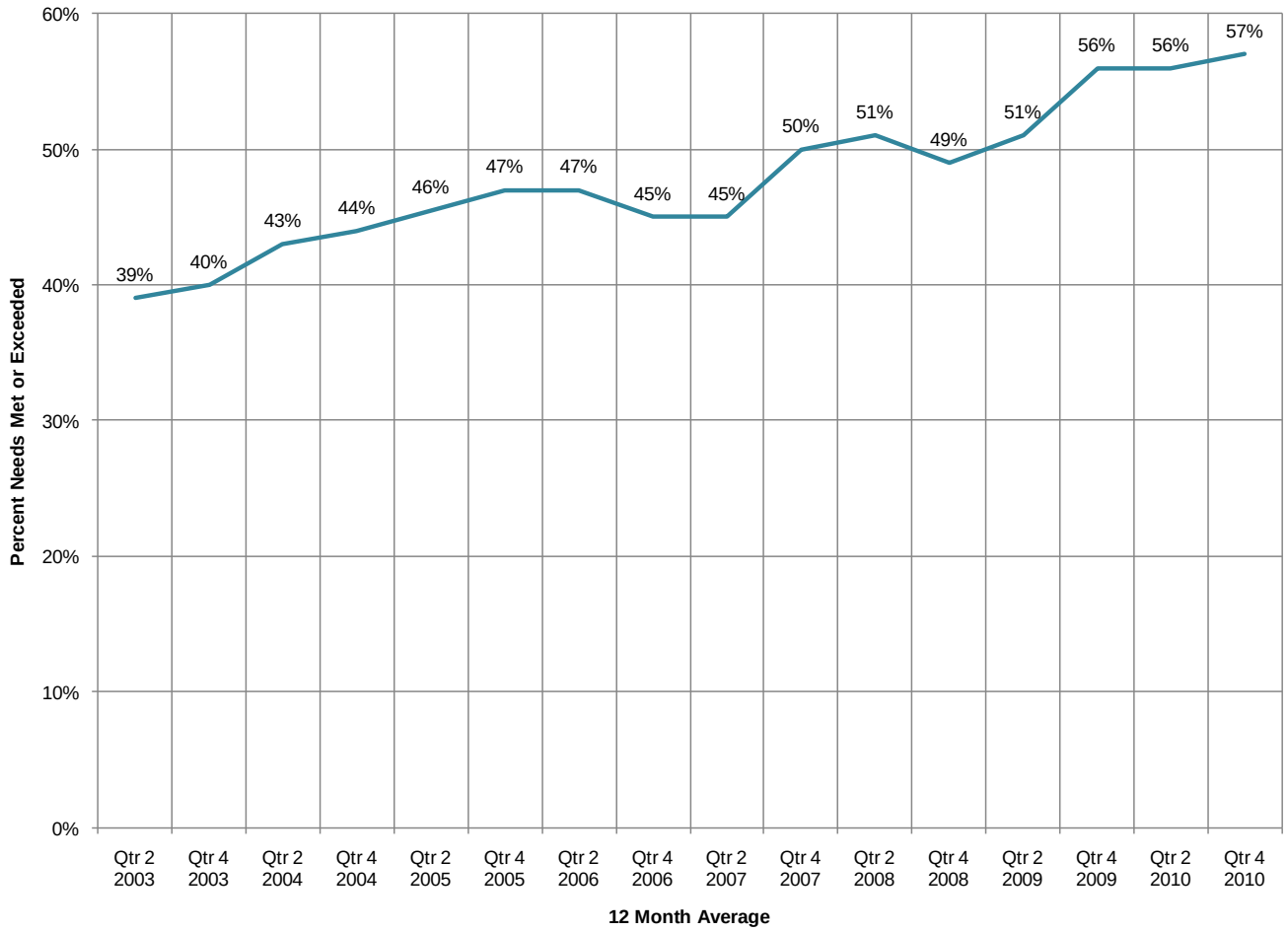

Figure 6. Percent of customers whose needs are met or exceeded by Idaho Power's energy efficiency efforts

In 2010, Idaho Power added three new questions to the general relationship survey related to energy efficiency programs: 1) Have you participated in any of Idaho Power's energy efficiency programs? 2) Which energy efficiency program did you participate in? 3) Overall, how satisfied are you with the energy efficiency program? Overall, 33 percent of the survey respondents across all sectors indicated they have participated in at least one Idaho Power energy efficiency program. Of survey respondents who have participated in at least one Idaho Power energy efficiency program, 95 percent are "very" or "somewhat" satisfied with the program.

Several surveys measured customer satisfaction with individual programs in 2010. The surveys also provide guidance for program modification, marketing, and evaluation. Survey results are presented in the following program descriptions in this report: DHP Pilot, Heating & Cooling Efficiency (H&CE) Program, Easy Savings Program, Residential Energy Efficiency Education Initiative, Weatherization Solutions for Eligible Customers, Easy Upgrades, and FlexPeak Management.

Idaho Power programs have ongoing customer satisfaction measurements as a follow-up to the application process. For example, Easy Upgrades provides an ongoing, Web-based customer survey for its participants. Results of these surveys indicate general satisfaction and help guide program

improvement and marketing efforts. After each session of the Energy Efficiency and Green Living Series, Idaho Power requests attendees fill out a customer feedback form rating the program. The H&CE Program provides an opportunity for customer and contractor feedback through surveys.

Cost-Effectiveness

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

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

Idaho Power's goal is for all mature programs to have benefit/cost (B/C) ratios greater than 1.0 for the total resource cost (TRC) test, utility cost (UC) test, and participant cost test (PCT) at the program level and the measure level. Only the program level tests are used in cases where there is significant interaction between measures. This year, Idaho Power has calculated the RIM test for each program, and the results of these calculations are included in *Supplement 1: Cost-Effectiveness*. Idaho Power may launch a pilot program to evaluate estimates or assumptions in the cost-effectiveness analysis. Following implementation of a program, cost-effectiveness analyses are reviewed annually, including actual program information, such as actual program expenses, savings, or participation levels. If measures or programs are determined to not be cost effective after implementation, the program or measures are reexamined and modified based on input from the EEAG. In 2010, all of Idaho Power's energy efficiency programs are shown to be cost-effective from the TRC, UC, and PCT perspectives. All three of the company's demand response programs are cost-effective from both a long-term perspective as well as for 2010 under a one-year perspective.

Appendix 4 contains the UC and TRC B/C ratios using actual cost information over the life of each program through 2010. 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. A complete description of Idaho Power's methodology, input assumptions, sources, and results is presented in *Supplement 1: Cost-Effectiveness*.

DSM Annual Report Structure

The structure of Idaho Power's *Demand-Side Management 2010 Annual Report* remained for the most part unchanged from the 2009 report, aligning with the reporting requirements included in the MOU with the IPUC staff.

This main *Demand-Side Management 2010 Annual Report* document remains similar to previous years, organized primarily by customer sector categorized by residential, commercial/industrial, and irrigation. The sector descriptions are followed by information regarding programs in that sector. Each program description includes a chart containing 2010 and 2009 program metrics in tabular format, followed by a general description, 2010 activities, cost-effectiveness, customer satisfaction/evaluation, and 2011 plans. Each program section contains detailed information in relation to program changes and the reasoning behind those changes, including details 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. The appendices following the written sections contain tabular information on the 2010 expenses and savings and supply historic information for all energy efficiency programs and demand response activities at Idaho Power.

Historically, Idaho Power divided its service area into five regions; 1) Canyon, consisting primarily of Canyon and Gem counties; 2) Western, consisting of the company's Oregon jurisdiction and Adams 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 three, historical regions are referred to throughout this report.

Appendices 1–4 remain generally unchanged in form and contain financial, energy and demand savings, and levelized costs and program life B/C ratios from the UC and the TRC perspectives. In the main report, Appendix 5 has been added. It contains detailed financial and energy savings information separated by Idaho Power's two jurisdictions, Idaho and Oregon.

Also included this year are two supplements and an attached compact disc (CD). *Supplement 1: Cost-Effectiveness* contains detailed cost effectiveness information by program and energy-savings measure 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, RIM, and PCT perspectives. The RIM test is a new addition this year. The RIM test measures the impact to customer bills or rates due to changes in utility revenues and operating costs caused by an energy efficiency program. Idaho Power used the formula for the RIM test as provided in the *California Standard Practice Manual, Economic Analysis of Demand-Side Programs and Projects, October 2001*. *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) provided by NEEA is attached to Supplement 2.

RESIDENTIAL SECTOR OVERVIEW

Description

The Idaho Power service area covers a population of a little more than one million people. At the end of 2010, Idaho Power was serving 408,754 residential customers in its Idaho and Oregon service areas. During 2010, Idaho Power added 2,123 residential customers, making it the third consecutive year of relatively modest growth of residential customers within the company's service area. These additional residential customers represented a slightly lower amount than the 2,258 residential customers added in 2009. A continued sluggish regional economy and few housing starts were the main drivers of this trend. In 2010, the residential segment represented 39 percent of Idaho Power's total electricity usage and contributed 45 percent of total revenue for the company.

Milder temperatures, a sluggish economy, energy efficiency activities, customer education, and successful dispatching of company-sponsored DSM programs led to a system peak of only 2,930 MW on June 28, 2010, at 7:00 p.m. For the second consecutive year, Idaho Power did not set a new summer system peak record. The record summer peak of 3,214 MW was established on June 30, 2008, at 3:00 p.m. Idaho Power continued its education and promotion of energy efficiency programs and information to all residential customers by participating in local and regional events as well as conducting target visits with trade allies, contractors, and vendors during the year. These tasks and activities contributed to increased program participation and improvement in customer satisfaction results.

Annual program savings in the residential sector of 42,850,839 kWh were recorded as part of 2010 program offerings to customers, with more than a 16-million kWh increase over 2009 program performance of 25,979,920 kWh. While several programs experienced increased savings in 2010, the increase in annual savings was driven mostly by growth in customer participation of both the Energy Efficient Lighting and Home Improvement Programs. The Energy Efficient Lighting program provided 1,190,139 discounted bulbs to customers through retailers during 2010, resulting in 28,082,738 kWh in annual savings, which more than doubled the sales of 549,846 bulbs in 2009. Participation in the Home Improvement Program, which offers incentives for increasing attic insulation, grew from 1,661 homes to 3,537 homes in 2010, resulting in 3,986,199 kWh of annual savings. Table 5 provides a summary of 2010 residential program performance for both energy efficiency programs and the one residential demand response program.

Programs

Table 5. 2010 Residential Program Summary

Program	Participants		Total Costs Utility	Total Costs Resource	Savings Annual Energy (kWh)	Savings Peak Demand (MW)
Demand Response						
A/C Cool Credit	30,803	homes	$ 2,002,546	$ 2,002,546	n/a	39.0
Total			**$ 2,002,546**	**$ 2,002,546**		**39.0**
Energy Efficiency						
Ductless Heat Pump Pilot	104	homes	$ 189,231	$ 439,559	364,000	
Energy Efficient Lighting	1,190,139	bulbs	2,501,278	3,976,476	28,082,738	
Energy House Calls	1,602	homes	762,330	762,330	1,198,655	
ENERGY STAR® Homes Northwest	630	homes	375,605	579,495	883,260	
Heating & Cooling Efficiency Program	217	homes	327,669	1,073,604	1,104,497	
Home Improvement Program	3,537	homes	944,716	2,112,737	3,986,199	
Home Products Program	16,322	appliances/fixtures	832,161	1,025,151	1,443,580	
Oregon Residential Weatherization	1	home	6,050	6,275	320	
Rebate Advantage	35	homes	39,402	66,142	164,894	
See ya later, refrigerator®	3,152	refrigerators/freezers	565,079	565,079	1,567,736	
Weatherization Assistance for Qualified Customers	400	homes/non-profits	1,321,132	2,927,898	3,741,652	
Weatherization Solutions for Eligible Customers	47	homes	228,425	228,425	313,309	
Total			**$ 8,093,078**	**$ 13,763,171**	**42,850,839**	

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

Programs available to residential customers include one demand response program, 12 energy efficiency programs, and an energy efficiency educational initiative. The demand response program A/C Cool Credit had more than 34,600 customers enrolled as of the end of 2010. The residential efficiency programs include Energy House Calls, Rebate Advantage, ENERGY STAR® Homes Northwest, Oregon Residential Weatherization, Home Products, Energy Efficient Lighting, See ya later, refrigerator®, Weatherization Assistance for Qualified Customers (WAQC), H&CE Program, DHP Pilot, Home Improvement, and Weatherization Solutions for Eligible Customers.

The Boise City Home Audit Project was initiated in 2010. Idaho Power partnered with the City of Boise, which received funding initiated by the American Reinvestment and Recovery Act (ARRA), to serve as the program implementer for the city. The combination of financial support through the act and Idaho Power Rider funds allows the program to be fuel neutral and target 600–700 homes within the city limits of Boise. The program is scheduled to be completed by spring 2012 and includes a blower-door test, customer education, installation of compact fluorescent light (CFL) bulbs, low-flow showerhead, and other energy efficiency measures for qualified customers.

Idaho Power continued to increase its participation in the number of retail and community outreach events during 2010. Many of these events were partnerships with community retailers, including Home Depot, Lowe's, Costco, and Fred Meyer. The company also participated in home and garden shows, several Parade of Homes events across Idaho Power's service area, the Idaho Green Expo, a library education series, and other community events across the company's service area.

Presentations to community groups and businesses were another emphasis during the year, with nearly 400 presentations conducted in 2010. For example, Idaho Power customer representatives made

approximately 130 presentations to civic and community groups, including chambers of commerce, school boards, service organizations, and businesses. The presentations took place during such times as staff meetings, business lunches, and Rotary luncheons; other examples of presentations are provided in the Residential Energy Efficiency Education Incentive section of this *Demand-Side Management 2010 Annual Report*. These partnerships and outreach activities created specific opportunities for the company to share the importance of energy efficiency and give customers information and options about participating in programs.

Idaho Power conducts the Burke Customer Relationship survey each year. Fifty-four percent of residential survey respondents in 2010 indicated Idaho Power is meeting or exceeding their needs with information on how to save energy or reduce their bill. Fifty-three percent of residential respondents indicated Idaho Power is meeting or exceeding their needs by encouraging energy efficiency with its customers. Overall, 37 percent of Idaho Power residential customers surveyed in 2010 indicated Idaho Power is meeting or exceeding their needs in offering energy efficiency programs; while 26 percent of the residential survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of residential survey respondents who have participated in at least one Idaho Power energy efficiency program, 85 percent are “very” or “somewhat” satisfied with the program.

A/C Cool Credit

	2010	2009
Participation and Savings		
Participants (participants)[a]	30,803	30,391
Energy Savings (kWh)	n/a	n/a
Demand Reduction (MW)[a]	39.0	38.5
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$1,854,979	$3,305,814
Oregon Energy Efficiency Rider	$74,071	$144,622
Idaho Power Funds	$73,496	$1,552
Total Program Costs—All Sources	$2,002,546	$3,451,988
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	n/a	n/a
Total Resource Benefit/Cost Ratio	n/a	n/a
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	1.11	
Total Resource Benefit/Cost Ratio	1.11	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2003	

[a] Program participation and demand reduction reflect enrollment as of July 31st. Year-end enrollment in the program was 34,640 homes, with 6,095 new participants joining the program.

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 on and off via a direct-load control device installed on the A/C unit. Participants receive a monthly monetary incentive for participating in the program during the summer season. This program enables Idaho Power to reduce system peaking requirements during times when summer peak load is high.

Individual radio-controlled or power-line carrier (PLC) switches are installed on customers' A/C units. These switches allow Idaho Power to cycle customers' A/Cs during a cycling event. As Idaho Power's Smart Meter project expands across its service area, more new switches will be PLC switches that will allow broader participation. Under this program, Idaho Power may cycle participants' A/Cs for up to 40 hours each month in the months of June, July, and August. In return, participants receive a $7 per-month credit on their Idaho Power bill during July, August, and September.

2010 Activities

The program expanded its presence on the Mountain Home Air Force Base (MHAFB) housing from 522 to 803 total participants. There were three cycling events in 2010, one in each of the summer months. The three events in 2010 were on June 29 from 4:00 p.m. to 7:00 p.m., July 16 from 4:00 p.m. to 7:00 p.m., and August 5 from 4:28 p.m. to 7:00 p.m. Due to mild temperatures, all events were cycled at 50 percent.

Cycling event hours continued to be in three-hour periods, pinpointing the peak time with less potential impact on participants. Summer 2010 temperatures were mild. This resulted in fewer high-demand days, so there was less need for cycling to reduce demand. Generally, the need for cycling starts near the end of June when temperatures rise. With high temperatures milder in 2010, there was less need for A/C. Lower average temperatures also improve a home's ability to cool naturally overnight and retain less heat the following day.

Marketing approaches during 2010 covered a range of methods, including bill stuffers, direct mail, follow-up letters, and newspaper advertisements. One successful marketing piece was a letter accompanied by a dual-purpose piece: a magnet to record important phone numbers mounted to a cardstock reusable bookmark. This piece was sent out in three waves, with the results ranging from 1 percent to over 2.5 percent sign-up rates. All three waves had about the same response rate range. Idaho Power employees continued visiting large businesses, providing program information, and speaking at luncheon presentations.

The Smart Meter installations brought two new opportunities to market the A/C Cool Credit program. The first was to advertise the program on the back of the door hanger left at the customer's home when a Smart Meter was installed. This generated sign ups and added to the general awareness of the program. The second opportunity provided new areas for switch installation as the Smart Meter area expanded into areas previously unavailable due to no, or limited, paging reception for the radio-controlled switches.

A cause-related marketing approach, consisting of partnering with both the Idaho Foodbank and Southeast Oregon Regional Food Bank, was repeated in 2010. It provided customers an additional opportunity to sign up for the program. During a "limited time offer," a $20 contribution went to the food bank in the participant's location for enrolling in the A/C Cool Credit program. The winter promotion, from October 2009–February 2010, resulted in a total of $22,220, equal to 66,660 meals, for the Idaho Foodbank, and $1,080, equal to 5,400 pounds of food, for the Southeast Oregon Regional Food Bank. This marketing approach yielded 1,165 new A/C Cool Credit sign-ups in 2010.

The call center customer service representative (CSR) pilot continued into 2010. CSRs received training in signing up new A/C Cool Credit participants at the point of contact when an Idaho Power customer initiates or transfers his/her account by phone. This resulted in 86 sign ups in 2010.

Outreach to Heating, Ventilation, and A/C (HVAC) companies continued as-needed to provide their employees with training on the A/C Cool Credit switch. Increasing the HVAC technician's knowledge of switch boxes contributes to positive customer relations between the customer and the technician servicing the A/C Cool Credit program participant's A/C unit.

In 2010, the two paging providers discontinued their service to the Twin Falls and Pocatello areas. A search was conducted for alternative paging providers but none were available for that area. Alternative methods of communicating with the switches were researched. An adequate solution was not available. This resulted in the inability to cycle the participants in those two areas during summer 2010. In response, marketing to these areas and installation of new switches was halted.

At the May 26, 2010, EEAG meeting, Idaho Power explained some of the paging issues experienced by customers in the Twin Falls and Pocatello areas. Idaho Power asked EEAG members for feedback and suggestions on how to proceed with this issue. EEAG members supported crediting those affected customers on their bill with the use of non-Rider funds. The participants in these areas were paid an incentive dispite the lack of Smart Meter communication. The company determined that it was less

expensive to pay an incentive than to again recruit A/C Cool program participants. The Smart Meter deployment expanded into these affected areas in late 2010, and the company began to replace paging switches with smart grid-compatible switches. Switches started being changed out in late 2010 with plans to continue into early spring, with the new switches being operational before the start of cycling season 2011.

Idaho Power initiated a process improvement in 2010, by changing the method of transferring data to contractor, Honeywell, Inc., Utilities Solutions. In the past, each e-mail containing customer information had to be manually encrypted when sent. This required Honeywell, Inc., to log into a special system to access the information each time they received an encrypted e-mail. The process kept the customer data secure, but resulted in additional time and work for both parties. Idaho Power's Information Technology (IT) department determined that Transport Layer Security (TLS) was an equally secure method of transferring data between the two parties and did not require manually encoding and decoding. Once approved and in place, the new process allowed quicker transfer of data, which results in responding to customer requests in a timelier manner.

Cost-Effectiveness

Although the B/C analysis for the A/C Cool Credit program is based on a 20-year model that uses financial and DSM alternative costs assumptions from the 2009 IRP, the company also tracks cost-effectiveness on an annual basis. As published in the 2009 IRP, for peaking alternatives, such as demand response programs, a 170-MW simple-cycle combustion turbine (SCCT) is used as an avoided resource cost. Idaho Power's A/C Cool Credit cost-effectiveness model is updated annually with actual benefits and costs. The benefits are based on peak reduction and shifted energy use. In 2010, the A/C Cool Credit model update included the expense of paying incentives to the Twin Falls and Pocatello participants for which no demand reduction was realized. This additional expense had no effect on the 20-year cost-effectiveness and no material effect on the 2010 annual cost-effectiveness. From a long-term perspective, the A/C Cool Credit program had a TRC ratio of 1.11 and from a one-year prospective a TRC ratio of 1.23. See *Supplement 1: Cost-Effectiveness* for details on the cost-effectiveness assumptions and data.

Customer Satisfaction and Evaluations

In 2010, 2,837 accounts ended participation in the A/C Cool Credit program. Of those, 2,807, or 98.9 percent, ended participation at approximately the same time as their Utility Service Agreement (USA) expired. The USA is the customer's agreement with Idaho Power for electrical service. It begins when they sign up for service, and ends when they end service.

Approximately 30 accounts, or 1 percent, stopped participating in the program for reasons other than the canceling of electric service. This was determined by an analysis of the end-dates for contract riders, which are the agreements to participate in the A/C Cool Credit program, and end-dates for USAs.

In early 2010, Idaho Power contracted with Paragon Consulting Services and received a detailed plan to evaluate the impacts of the 2010 A/C Cool Credit program. Idaho Power is using this evaluation plan as a basis for conducting a comprehensive impact evaluation in 2011.

2011 Strategies

In February 2011, Idaho Power issued an RFP to evaluate the impacts of the A/C Cool Credit program, including electrical demand reduction and energy impacts, effects of various curtailment strategies on

indoor air temperature of participants, strategies to balance load reduction with customer comfort, estimation of available load reduction as a non-spinning reserve resource, and identification of parameters to predict potential load reduction. Idaho Power plans to select a contractor in March 2011. Customer recruitment and data collection equipment installation will conclude in May before the curtailment season begins. Analysis of the data will begin in September with the final report delivered in December 2011.

The 2011 program target is to reach 40,000 total participants. Once the target is achieved, the company will continue A/C Cool Credit marketing and promotion to determine if saturation has been achieved or if it is possible to increase participation. As Smart Meters are installed in those areas where the paging signal is unavailable, the A/C Cool Credit program will be able to expand.

The remaining 1,565 paging switches will be changed out in the Twin Falls and Pocatello areas in early 2011, so all replacements for these areas will be completed before the start of cycling season 2011. The majority of Smart Meter substations in these areas will be completed and operational before June 1, 2011, with a few exceptions. Once the substation is active, communication to the new switches will be available. The substations not commissioned before the start of cycling season will either be brought online shortly thereafter, or serve very few A/C Cool Credit participants. The result is that Idaho Power can cycle most of the switches/participants in the Twin Falls and Pocatello areas.

Ductless Heat Pump Pilot

	2010	2009
Participation and Savings		
Participants (homes)	104	96
Energy Savings (kWh)	364,000	409,180
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$181,969	$192,264
Oregon Energy Efficiency Rider	$7,262	$9,740
Idaho Power Funds	$0	$0
Total Program Costs—All Sources	$189,231	$202,004
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.044	$.031
Total Resource Benefit/Cost Ratio	$0.103	$.086
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	3.47	
Total Resource Benefit/Cost Ratio	1.38	
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 during 2009. The company extended the project as an Idaho Power DHP pilot through 2010. A main goal of the Northwest DHP pilot project was to promote the DHP technology as an energy-saving alternative for customers who primarily heat their homes with electric heating. Idaho Power offered customers a $1,000 incentive to participate.

The program targets homes heated with electric zonal systems. Typically, these homes do not have air ducting, 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 baseboard, ceiling, and wall-mounted systems. Homes heated with natural gas forced-air systems or electric forced-air systems do not qualify. Qualifications include having one indoor unit installed in the main living area of the home. Since this is where most occupants spend the majority of their time, and DHP systems can serve up to 1,000 square feet, this is the most efficient application of the technology.

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

Though the official pilot recruitment period concluded at the end of 2009, field monitoring on selected homes throughout the Pacific Northwest, billing data analysis, and other evaluations will continue through 2011.

2010 Activities

Idaho Power targeted 100 participants for NEEA's Northwest DHP Pilot. As participation levels neared the 100-application limit in 2009, the company announced to contractors that Idaho Power would extend the pilot and accept additional applications throughout 2010. Completed projects in 2010 exceeded 2009 by eight projects, or 8 percent.

Along with other utilities in the region, Idaho Power decided to continue the pilot to maintain the valuable momentum created in the marketplace among contractors and customers. Idaho Power promoted the pilot to customers through an article in its monthly residential customer newsletter, *Customer Connection*, and by sending direct mail letters to 28,492 targeted customers based on several factors, including energy usage during specific months and geographical region. The company also marketed the pilot to contractors by visiting with them and informing them of the pilot.

In November, Idaho Power held a one-day training session for contractors interested in the DHP Pilot. The Northwest DHP Pilot sponsored the event. The session covered product training and information on how to become a participating contractor. There were 31 attendees representing 21 HVAC companies.

In the fourth quarter, Idaho Power, through its new database, improved the method to process DHP incentive applications. Using the Customer and Load Research Information System (CLRIS), an existing software platform, a database was developed enabling all of the application data to be entered and stored for analysis. The database also initiated the incentive payment process. It has enabled the elimination of multiple files previously used to store data.

Cost-Effectiveness

The Northwest DHP Pilot finished its second year in 2010. Complete details about the regional effort can be found at the project website at www.nwductless.com. Data collection will be completed for the 13 chosen sites in Idaho Power's service area during 2011, and the post-installation billing data will be compiled and analyzed by a regional contractor.

The RTF has released provisional annual savings, based on a one indoor-unit installation with at least one ton of heating capacity or greater and employ an inverted driven compressor. The savings per unit is estimated at 3,500 annual kWh until the pilot analysis is completed. The RTF deemed one savings metric regardless of prior cooling, whether the DHP is displacing electric-resistance heat or zonal heat, or in what climate zone the unit is located. Participant costs in 2009 were determined by taking the median price as reported on Idaho Power's applications. These participant prices were used because the units purchased in Idaho Power's service area were approximately $900 less than the provisionally deemed regional costs. In 2010 the RTF updated the participant costs to $3,400. This level of expense confirmed what Idaho Power's data indicated; consequently, the provisionally deemed cost was used for all cost-effective analysis in 2010. For more detailed information about the cost-effectiveness savings, calculations, and assumptions, see the *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

As part of the regional pilot, a NEEA contractor conducted quality assurance (QA) on-site verifications (OSV). The regional pilot targeted 10 percent of completed installations. In 2010, 13 DHP Pilot projects in Idaho Power's service area were inspected by NEEA's contractor to ensure projects complied with program requirements. The QAs proved beneficial for customers, contractors, and Idaho Power. For example, customers were shown how to operate their systems correctly, the contractors were able to

review the installation requirements of the DHPs, and Idaho Power was able to observe the installation process.

Idaho Power mailed a 12-question satisfaction survey to 52 participants in 2010, and 41 surveys were returned, resulting in a 79 percent response rate. Most respondents heard about the DHP Pilot from their heating and cooling contractor or a letter from Idaho Power. Sixty-eight percent of the respondents were aware that Idaho Power offered an incentive for the purchase of a DHP prior to their purchasing one. Seventy-three percent of the respondents indicated that the Idaho Power incentive influenced their purchasing decision "a lot." The most common reason cited for installing a DHP was "no ducting available for other heating sources." Ninety-eight percent of the respondents were "very satisfied" with the DHP Pilot, and 100 percent said they "definitely would" recommend the program to a friend or relative. Approximately 93 percent of homeowners rated their contractor as "very knowledgeable," while 7 percent of the contractors were rated as "somewhat knowledgeable." Results of the survey are in *Supplement 2: Evaluation*.

The surveys have played an important role in evaluating the types of marketing tactics being used. The results indicate most customers are learning about the incentive program prior to purchasing a ductless heat pump. This result substantiates the need to market the program. Of equal importance is that there is not one source but multiple sources needed to reach the customers. This supports the overall strategy of trying new ways to generate market awareness. It is also apparent that, without the incentive, these systems might not be installed at the current rate. The survey results also indicate the performance of the overall program is valued by the customer. This supports the value in providing further enhancements to make the program even more seamless. In addition, that the majority of the customers indicate they would recommend the incentive to others makes customers a valuable marketing voice.

Idaho Power is continuing its participation in the Northwest DHP Pilot and evaluation. This extensive evaluation effort is designed to provide a technical evaluation of DHP technology as a retrofit opportunity, measure achievable energy savings, assess market response, and provide a process evaluation of the pilot program.

In 2010, NEEA made available an MPER update for the DHP Pilot. The following are highlights included in the report. Fifty-nine utilities participated and installed 3,899 units, exceeding the pilot's installation goal of 2,500 units as of December 31, 2009. Participants reported high levels of satisfaction concerning understanding incentive information, finding a contractor, locating program information, and receiving their incentive checks in a reasonable time. Of the participants, 66 percent said they would not or might not have purchased a DHP without the incentive. Pilot participants were interviewed for the report. Nearly 99 percent of them indicated they have the displaced electric heating equipment in place but use their DHP as the primary heating source. Of the 20 percent of participants who were planning to purchase some type of A/C equipment, none of them continued with that plan after they installed their DHP. Most participants reported receiving non-energy benefits with the DHPs, such as increased comfort, air filtration, and simple equipment control. The adaptation to large-scale integration projects remain limited due to the concern of DHPs' performance in severe climate conditions. A copy of the report is in *Supplement 2: Evaluation*.

2011 Strategies

Idaho Power will continue offering incentives to customers, in 2011. Idaho Power will increase participation in local manufacturer-training events held by local wholesalers. These training events enable Idaho Power to reach and align with contractors not yet familiar with this pilot.

For contractors to be eligible to participate in the DHP Pilot, they must receive mandatory DHP factory-product training for each of the brands they sell and attend a mandatory Idaho Power orientation. Product training is attainable via local HVAC wholesalers, manufacturer representatives, or Idaho Power-sponsored events. The Idaho Power orientation describes specific product features and installation methods required for incentive application approval. The company orientation further describes required installation features, such as a DHP with an inverter-driven compressor, inverter-driven or variable-speed blower, and R410A refrigerant. Rigid line set covers are also required. The orientation also describes the requirements to qualify the home, install the DHP in the main living area, submit all paperwork, and teach the homeowner how to use the DHP. Contractors are alerted that their first installation will be inspected.

Changes to the pilot in 2011, include modifying the incentive value from $1000 to $750 for installations completed after January 31, 2011. Idaho Power redistributed the funds to increase the incentive amount for electric-furnace to air-source heat pump incentive option in the H&CE Program. Idaho Power will work closely with participating contractors to help them understand and apply the incentive process with their clients. DHPs remain an emerging technology in the Idaho Power service area.

New marketing methods will be used in 2011 to reach the target audience. Methods include participating in residential coupon mailer packets reaching all of the Idaho Power service area, posting articles about DHPs on social media sites that Idaho Power participates in, and advertising the pilot in newspapers that service specific areas not generally serviced with natural gas. The traditional ongoing methods, such as bill inserts and direct mail, will also continue in 2011.

Satisfaction surveys will be mailed to all 2011 incentive recipients. The response data will be compiled and analyzed to help improve all facets of the pilot. The final pilot evaluation report is expected to be available in 2012. The regional DHP Pilot team will provide limited QA inspections for the region in 2011. Idaho Power will investigate augmenting the regional QA inspection with its own QA inspections.

Energy Efficient Lighting

	2010	2009
Participation and Savings		
Participants (bulbs)	1,190,139	549,846
Energy Savings (kWh)	28,082,738	13,410,748
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$2,442,931	$1,190,065
Oregon Energy Efficiency Rider	$58,347	$17,300
Idaho Power Funds	$0	$1
Total Program Costs—All Sources	$2,501,278	$1,207,366
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.020	$0.020
Total Resource Benefit/Cost Ratio	$0.031	$0.024
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	4.54	
Total Resource Benefit/Cost Ratio	3.49	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2002	

Description

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

The Energy Efficient Lighting program achieves residential energy savings by replacing less-efficient lighting with more-efficient technology. According to research performed by NEEA, the average older home has 38 light bulbs. New homes have an average of 77 light bulbs. Changing these bulbs represents a low-cost, easy way for all customers to achieve energy savings.

2010 Activities

There was record participation in 2010 in the Energy Efficient Lighting program, with incentives provided on over one million bulbs. This represents approximately three bulbs per residential account.

Two promotions, one for spiral bulbs and the other for specialty bulbs, such as globes, three-way, and reflector bulbs, were held during 2010. Idaho Power continued to run an independent retailer promotion focusing on spiral bulbs priced at about 99 cents per bulb. Fluid Market Strategies (Fluid) managed this promotion.

In August, the program achieved a contract sales threshold that lowered the administrative fee paid to Fluid by $0.48 per bulb, resulting in significant cost-savings for the rest of the promotion year. Savings are estimated at $133,005.

Idaho Power participated in the Bonneville Power Administration (BPA) Change a Light promotion focused on specialty bulbs. Portland Energy Conservation, Inc. (PECI), managed this promotion from January to March 2010. BPA awarded the promotion contract to Fluid, beginning April 1, 2010. Fluid administered the promotion for the remainder of 2010 under a new name, Simple Steps, Smart Savings™.

Both PECI and Fluid provided enhanced field support as part of their promotions. Contractor staff from these two organizations visited stores on a regular schedule to check pricing, stock, and signage. The result was better visibility of Idaho Power's promotions.

Additional 2010 program activities included direct distribution, in-store events, and an on-air radio interview. Idaho Power has a small direct distribution program, whereby bulbs are given directly to customers at approved venues. The idea is that, if given a free bulb, customers might try CFLs for the first time or be encouraged to replace additional lamps. Guidelines for approved venues and direct distribution have been developed to ensure customer fairness. Eight considerations are used to evaluate the appropriateness of distributing CFL bulbs to customers and include identifying venues that have an energy efficiency tie, a residential focus, and allow for an Idaho Power presence.

During 2010, Idaho Power participated in five in-store events with large and small national retailers designed to communicate directly to customers at the point of sale. Idaho Power had light displays at the entrances of stores, and Idaho Power staff was available to answer questions about CFLs.

Idaho Power participated on The HomeFix Show with Joe Prin on 670 KBOI AM. The show reaches an audience estimated at 19,320 listeners. Program staff from Idaho Power spent an hour on air answering phone-in questions about lighting. This is an effective, low-cost marketing and education opportunity.

Cost-Effectiveness

In 2010, the RTF updated savings assumptions for CFLs to differentiate the savings between the typical twist bulbs and the various specialty bulb types. The RTF determined that specialty CFL use differed from standard CFL use. While standard twist-CFLs have a storage rate of 36 percent, the RTF voted to reduce the storage rate for specialty bulbs to 20 percent to account for higher costs, smaller package size, and reduced socket saturation. Take-back for specialty bulbs was reduced from 5 percent to 0 percent. While the annual savings for retail spiral bulbs remained at 24 kWh after accounting for storage and take-back, annual savings for specialty-bulbs range from 12.9 kWh to 38 kWh, depending on their application. For detailed cost-effectiveness assumptions, metrics, and sources, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

In 2010, NEEA released the 2009–2010 *Residential Lighting Market Research Study* prepared by the energy consulting, testing, and certification company KEMA. The study concluded that sales of ENERGY STAR CFLs declined in the Northwest between 2008 and 2009 and identified several potential factors for this, including the economy and a "leveling off" of the market. Sales of utility discounted CFLs declined less significantly than non-utility discounted CFLs. In the NEEA study, the 2010 sales in the Northwest were expected to be higher than 2009. The study also concluded consumer satisfaction with CFLs remains fairly high. A copy of this report is included in NEEA Market Effects Evaluations in *Supplement 2: Evaluation*.

2011 Strategies

No major changes are anticipated for the Energy Efficient Lighting program in 2011. Idaho Power plans to continue in-store promotions for buy downs and markdowns of bulbs. The spiral bulb promotion with Fluid has been extended through December 2011. Since Fluid is the contractor for both promotions, the Change a Light contract extension was negotiated to leverage the cost-savings associated with the regional promotion. The administrative fee for this Idaho Power-only promotion will be at the same rate as the BPA specialty promotion.

The specialty bulb promotion with BPA will go through September 2011 and may be extended beyond. Idaho Power will continue to distribute limited quantities of bulbs directly to customers at approved public energy efficiency events and continue to participate in in-store educational events. The company will monitor the market and emerging technologies.

Idaho Power is monitoring industry trends and federal regulations to determine impacts to utility lighting programs, such as impacts on market transformation, cost-effectiveness, and value of utility programs. Specifically, Idaho Power is monitoring implementation of the *Energy Independence and Security Act of 2007* (EISA) and the new lighting technologies, such as light-emitting diode (LED) and new energy-efficient EISA-compliant incandescent bulbs.

EISA requires, by 2012–2014, specific light bulbs use 30 percent less energy than today's incandescent bulbs. For traditional A-lamp, the standards will apply to 100-watt (W) bulbs in January 2012 and end with 40-W bulbs in January 2014. By 2020, a Tier 2 would become effective requiring bulbs to be at least 70 percent more efficient, effectively equal to today's CFLs.

The EISA, CFLs will be one of the options for customers. The market is unlikely to change immediately for several reasons. First, the efficiency standards are phased in over several years starting in 2012. The 75-W bulbs must meet the standards by 2013 and 60-W bulbs by 2014. Second, many specialty bulbs, such as reflectors, globes, and three-way bulbs are exempt from the law. Third, an incandescent bulb or other bulb technology that is 30 percent more efficient could satisfy the law; however, CFLs are 75 percent more efficient. In 2010, manufacturers introduced a halogen bulb that meets the requirements but offers only the minimum energy savings required under the law.

LED light bulbs are on display at many major retailers. In 2010, ENERGY STAR released criteria for LED replacement bulbs. As of January 2011, there were approximately 40 products on this list; 87 percent are reflectors. Market prices for LED products are significantly higher than CFLs and EISA-compliant halogens. Idaho Power will continue to evaluate the price, availability, savings, and cost effectiveness to see if a cost-effective program could be offered. Idaho Power will continue to monitor trends and developments in LED technologies.

Energy House Calls

	2010	2009
Participation and Savings		
Participants (bulbs)	1,602	1,266
Energy Savings (kWh)	1,198,655	928,875
Demand Reduction (MW)		n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$724,895	$479,174
Oregon Energy Efficiency Rider	$37,435	$90,420
Idaho Power Funds	$0	$0
Total Program Costs—All Sources	$762,330	$569,594
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.054	$0.052
Total Resource Benefit/Cost Ratio	$0.054	$0.052
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	3.06	
Total Resource Benefit/Cost Ratio	3.06	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2002	

Description

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

Services and products offered through the Energy House Calls program include duct testing and sealing according to Performance Tested Comfort System (PTCS) standards set by the RTF and adopted by the BPA; installing five CFL bulbs; providing two furnace filters, along with replacement instructions; testing water heater temperature for proper setting; and distributing energy efficiency educational materials for manufactured home occupants. The value of the service is not charged to the customer. The value of a typical cost range of the average service call would be $325 to $550, depending on the complexity of the repair. Idaho Power provides the customer with the sub-contractor contact information. Customers access the service by directly calling one of the recognized, certified sub-contractors specially trained to provide these services in their region.

Program delivery is under contract with Ecos IQ, Inc., a company with experience managing and supplying duct-sealing service programs. Ecos IQ, Inc., coordinates the sub-contractors performing local weatherization and energy efficiency services, processes sub-contractor paperwork, invoices Idaho Power, and pays sub-contractors for work performed.

2010 Activities

Idaho Power renegotiated the contract with Ecos IQ, Inc., for continuing delivery of the Energy House Calls program during 2010. Energy House Calls serviced approximately 1,600 manufactured homes during 2010, resulting in over 1,000,000 kWh savings. Eighty percent of the homes serviced were located in the Treasure Valley. Twenty percent were outside the Treasure Valley, consisting of 13 percent in Southern Idaho and 7 percent in Eastern Idaho. QA was conducted on 5 percent of the homes serviced in the program.

In 2010, lower participation was expected in areas outside the Treasure Valley, based on the assumption those areas were saturated. However, Idaho Power continued to market to all locations within the company's service area. Throughout the year, it became evident that there is still potential in areas outside of the Treasure Valley.

Marketing campaigns included a bill stuffer sent to all Idaho Power residential customers, a radio spot on the The HomeFix Show with Joe Prin on 670 KBOI, a new program brochure to be used by Idaho Power representatives in the field and at Idaho Power-sponsored events, and a redesign of the direct-mail letter, including a Spanish version. The direct-mail letters were sent to specific customers four times during 2010. These additional marketing efforts created increased participation above expectations. The bill insert was sent in August; the radio spot occurred in March; the brochure was completed in June; the direct-mail letter was revised in March; and direct mailings were sent in January, April, May, and July.

Cost-Effectiveness

Savings for Energy House Calls are primarily based on the savings of the duct-sealing of an electrically heated home. The savings are specific to the different climate zones within the company's service area. Different savings are also used based on differing types of heating and cooling equipment in the homes where the measures are installed. Additional savings are gained from the up-to-five CFL bulbs directly installed in the homes at the time that the duct-sealing is done.

The RTF reviewed the savings assumptions for duct sealing in manufactured homes in 2010; however, the regional utilities are still reporting the 2007 RTF deemed savings to BPA through its Planning, Tracking, and Reporting website. To align with the savings reported by the region to BPA, the 2007 RTF deemed savings have been applied to all Idaho Power homes serviced in 2010. The updated RTF savings assumptions will be applied to the program in 2011. The revised savings have been reviewed, and the program remains cost-effective. For more detailed information about the cost-effectiveness savings and assumptions, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

To monitor QA in 2010, third-party audits, with a survey question, were conducted in 5 percent of the homes served. Of the 78 homes inspected, 76 homes of those customers expressed that the Energy House Call was a positive experience. Twenty-three of the 78 homes received a "fail," requiring the sub-contractor to return to the home to remedy the situation.

Based on the review of the "failed" homes by an Ecos IQ, Inc., representative, 23 homes out of 78 was not an acceptable failure rate. Twenty-one of the 23 failed homes were the result of a single sub-contractor. An Ecos IQ, Inc., representative raised the concern to the contractor after each series of QAs throughout the year. Since the last of the QAs conducted were at the end of 2010, it was apparent

the issues had not been resolved. Ecos IQ, Inc., took corrective action against the sub-contractor after the final results were received.

The remedy to these issues—after the first QA inspections completed in February 2010—was to halt the use of the worker who had the majority of the problems until he received intensive training from a master trainer and met the master trainer's criteria post-training. The sub-contractor's performance seemed to improve during the second round of QA inspections in June, but worsened during the December inspections, which was followed by termination of the contractor from the program.

In 2010, Idaho Power contracted with Global Energy Partners, LLC, to provide a process evaluation of the Energy House Calls program. This evaluation included a program data review, program logic model, internal customer survey evaluation, industry best-practices comparison, conclusions, and recommendations. The final report was received in February 2011 and indicated that the program "is successful despite a declining base of eligible participants," and "is surpassing its participation goals." The report also noted that the program "is well designed," and "has an invested project specialist." The program "incorporates several best practices," and "has an actionable marketing plan." Additionally, "the majority of participants recommend the program to others." The main recommendation for improvement was to develop a more accurate estimate of the eligible market for this program. Idaho Power intends to incorporate this recommendation using the recently completed residential end-use survey results. The results of the evaluation are in *Supplement 2: Evaluation*.

The company is currently analyzing other recommendations made by the consultants for possible future implementation. Program changes made in 2011 will be highlighted in next year's *Demand-Side Management 2011 Annual Report*.

2011 Strategies

Plans for the upcoming year include continuing the direct-mail campaign to all of the Idaho Power service area to improve participation. Because of the rapid turnover of customers in manufactured homes, Idaho Power will update the mailing list currently used for the direct-mail letters. The list is generated from homes designated as being manufactured or mobile identified from the Idaho Power's CIS. That list is analyzed for homes that appear to use electric heat, based on kWh usage during certain months of the year. The company will also continue to explore low-cost methods of marketing this program to all residential customers believed to have electrically heated manufactured homes. This form of marketing may yield additional word-of-mouth promotion to new, potential program participants.

In June 2011, the contract with Ecos IQ, Inc., expires. Idaho Power may not renew the contract because it may be possible that the program could be fully administered internally after that date. The logistics of such a decision will be evaluated in advance of the contract expiration.

ENERGY STAR® Homes Northwest

	2010	2009
Participation and Savings		
Participants (homes)	630	474
Energy Savings (kWh)	883,260	705,784
Demand Reduction (MW)		1.1
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$369,344	$348,829
Oregon Energy Efficiency Rider	$6,093	$5,928
Idaho Power Funds	$168	$866
Total Program Costs—All Sources	$375,605	$355,623
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.033	$0.039
Total Resource Benefit/Cost Ratio	$0.051	$0.055
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	2.68	
Total Resource Benefit/Cost Ratio	2.05	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2003	

Description

ENERGY STAR® Homes Northwest is a regionally coordinated initiative supported by a partnership between Idaho Power and NEEA to improve energy-efficient construction practices for new, single-family homes. This program targets the lost opportunity savings and summer-demand reduction that result from energy-efficient new construction codes and building practices. Idaho Power accomplishes this by increasing the efficiency of the residential building envelope and air-delivery system.

The ENERGY STAR Homes Northwest residential construction program builds homes that are at least 15 percent more energy efficient than those built to standard Idaho code. The program specifications for ENERGY STAR Homes Northwest are verified by independent, third-party home performance specialists (HPS) and are certified by Advanced Energy, an organization that conducts the certification inspections for Idaho and the US Environmental Protection Agency (EPA). The homes are more efficient, comfortable, and durable than standard homes constructed according to local building codes.

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

In 2010, builders involved in ENERGY STAR Homes Northwest receive a $400 incentive per home built to the Northwest Builder Option Package (BOP) standards, for both gas- and electric-heated homes in Idaho Power's service area. Builders who enter their homes in a Parade of Homes received the

standard $400 incentive plus an additional $600 incentive to encourage builders to construct ENERGY STAR homes and enter those homes in future Parade of Homes events.

The Idaho Power program collaborates with many local entities for program management, such as ENERGY STAR Homes Northwest and builders. A large part of the program's role in 2010 was conducting education and training activities for residential new construction industry partners.

2010 Activities

Although the 2010 housing market was still in a downturn throughout the Idaho Power service area, 630 ENERGY STAR homes were certified. This is the highest number of homes ever certified in the Idaho Power service area in a single year. Idaho Power believes the increase in certifications during 2010 is due to builders' understanding of the value in building to ENERGY STAR standards.

Idaho Power implemented a process improvement in 2010 by moving from paper to paperless certification and incentive processing. HPS electronically entered all field certification data on the Northwest ENERGY STAR (NWES) database. The Idaho Power program specialist then pulled data from the database to process incentives. This new process allowed builders to receive their ENERGY STAR certifications and their Idaho Power incentives more quickly. It alleviated misplaced paperwork and increased HPS accountability regarding placing certification information into the database in a timely manner.

Idaho Power conducted numerous ENERGY STAR promotional activities during 2010. The company presented energy efficiency awards at the Building Contractors Association of Southwest Idaho , Inc., (BCASWI) Parade of Homes awards banquet and at the Snake River Valley Building Contractors Association (SRVBCA) Parade of Home awards banquet.

The company maintained a presence in the building industry by supporting the Building Contractors Associations (BCA), throughout Idaho Power's service area. Specifically, the company participated in the BCASWI Builder's Expo, the SRVBCA Builder's Expo, the Magic Valley Builders Association Parade of Homes, the BCASWI Parade of Homes, SRVBCA Parade of Homes, Building Contractors Association of South East Idaho (BCASEI) Parade of Homes, and the Idaho BCA Convention.

Media campaigns were used as a method to heighten awareness of the ENERGY STAR Homes Northwest program. The program specialist was a guest on The HomeFix Show with Joe Prin on 670 KBOI AM, discussing the benefits and values of the ENERGY STAR Homes Northwest program for both builders and potential homeowners.

Other marketing projects involved adding a message about this program to residential customers' electric bills. These bill messages encouraged Idaho Power customers to visit ENERGY STAR qualified homes in their local Parade of Homes events. A program bill stuffer sent information to all residential customers in the Idaho Power service area.

Idaho Power was a sponsor of the 2010 St. Jude Dream Home in conjunction with NWES. This ENERGY STAR qualified home was also certified as a National Association of Home Builders (NAHB) green home and was the first certified and tested net-zero-energy home in Idaho. Idaho Power and NWES produced a media campaign consisting of radio and newspaper advertising promoting ENERGY STAR Homes and the St. Jude Dream Home. *A Healthy Homes Guide,* a booklet—targeting consumers—containing tips and information on healthy, energy-efficient homes, was produced and distributed throughout the valley as a part of this campaign. In addition, a bill insert promoting

ENERGY STAR Homes and the St. Jude Home was sent out during the campaign. The media campaign culminated in June with the St. Jude Dream Home raffle, with proceeds benefiting the St. Jude Children's Hospital.

In October 2010, the St. Jude Dream Home 2011 kickoff and groundbreaking took place. The Dream Home will be a ENERGY STAR qualified home. This 2011 home will also be raffled off to benefit the St. Jude Children's Hospital. Idaho Power will again collaborate on a smaller scale with Northwest ENERGY STAR to support the St. Jude Dream Home project.

Idaho Power also sponsored Realtor and builder trainings. Two trainings were held in the Boise area during 2010 to train both builders and HPS on the new 2011 ENERGY STAR specifications. Northwest ENERGY STAR and Energy Inspectors delivered these trainings respectively. Northwest ENERGY STAR trainers in the Boise area delivered two additional ENERGY STAR Homes Realtor trainings. One class toured and received training in the "net-zero" St. Jude Dream Home. Fifty area Realtors attended both sessions combined. Informal conversation with participants indicated positive feedback regarding the training.

Cost-Effectiveness

Cost-effectiveness analysis assumptions for the 2010 ENERGY STAR Homes Northwest program remain the same as 2009. There were no changes in building codes and standards or program specifications that impacted the program. In summer 2010, the RTF released updated savings for this program accounting for the new 2011 higher baseline of building standards for ENERGY STAR homes. These new savings estimates will be incorporated in the 2011 program analysis. Savings for the 2010 analysis were estimated to be 1,400 annual kWh for a typical home built to ENERGY STAR home standards based on a 2008 analysis provided by Ecotope, Inc,. The report was provided in the *Demand-Side Management 2009 Annual Report Supplement 2: Evaluation*. For more detailed information about the cost-effectiveness savings, calculations, and assumptions, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

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

Ten percent of homes certified in the ENERGY STAR Homes Northwest program are reviewed for QA purposes.

The State-Certifying Organization (SCO) performs QA. Energy Inspectors was the SCO for the State of Idaho from May 2009 to December 31, 2010. Energy Inspectors is not renewing their contract for 2011. The Washington State University Energy Extension Program has been contracted by NEEA to assume QA and technical assistance duties within the State of Idaho. QA results from 2010 are in *Supplement 2: Evaluation.*

2011 Strategies

The ENERGY STAR Homes Northwest program will be undergoing some changes for 2011. Due to the 2009 International Energy Conservation Code (IECC) implementation on January 1, 2011, and adoption by the State of Idaho, gas-heated homes are no longer cost effective. As a result, Idaho Power will no

longer be paying incentives on gas-heated homes. The program will be transitioning to an electrically heated homes program, effective January 1, 2011. Builders involved in ENERGY STAR Homes Northwest will receive a $1,000 incentive per home built to the Northwest BOP, electric-only standards in Idaho Power's service area. Builders showcasing their electric-only home in a BCA Parade of Homes event will receive the standard $1,000 incentive plus an additional $500 parade marketing incentive. During the October 26, 2010, EEAG meeting, incentive payments on all electric homes and the new code specifications on other utilities was discussed.

Idaho Power plans to continue marketing efforts to help sell ENERGY STAR homes, including educating consumers, Realtors, and appraisers about the benefits and features of ENERGY STAR homes. Results will be influenced by the housing market's potential improvements. The company is planning a media campaign in conjunction with Northwest ENERGY STAR in late spring/early summer 2011 throughout the Idaho Power service area. This campaign will promote the 2011 St. Jude Dream Home, ENERGY STAR Homes Northwest, and the program builders. This campaign will include sending a bill stuffer in June to all residential customers.

Heating & Cooling Efficiency Program

	2010	2009
Participation and Savings		
Participants (homes)	217	349
Energy Savings (kWh)	1,104,497	1,274,829
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$314,963	$458,216
Oregon Energy Efficiency Rider	$12,706	$20,032
Idaho Power Funds	$0	$125
Total Program Costs—All Sources	$327,669	$478,373
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.025	$0.034
Total Resource Benefit/Cost Ratio	$0.083	$0.054
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	2.50	
Total Resource Benefit/Cost Ratio	1.22	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2007	

Description

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

The objective of the H&CE Program is to acquire kWh savings and provide customers an energy efficient alternative to other forms of electric space heating. Incentives are provided to residential customers and HVAC contractors who install eligible equipment and services. The eligible measures in 2010 included air-source heat pumps, open-loop water-source heat pumps, and evaporative coolers.

Participating HVAC companies are required to perform all installations and services, with the exception of evaporative coolers, which can be self-installed. The program continued through 2010 with the same portfolio of incentives.

2010 Activities

The H&CE Program's list of measures and incentives during 2010 included the following:

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

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

efficiency 8.5 HSPF. Homes with oil or propane heating systems must be located in areas where natural gas is not available.

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

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

- The customer incentive for replacing an existing electric, oil, or propane heating system with a new open-loop water-source heat pump is $1,000 for minimum efficiency 3.5 COP. Homes with oil or propane heating systems must be located in areas where natural gas is not available.

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

- The evaporative cooler customer incentive is $150.

To build and maintain relationships with participating contractors, the program specialist visited several participating contractor shops throughout the year to promote the program, check for program understanding, and offer support. The program performed 19 random OSV, 8.6 percent of the total applicants, to verify the information submitted on the paperwork matched what was actually installed at customers' sites. Overall, OSV results were favorable with respect to the contractors; however, a few contractors had not installed the required sensor to lock-out strip heat above a certain outdoor temperature. The program continues to work with contractors to help them understand why this requirement is necessary.

The federal tax credits, available to qualifying homeowners who install energy-efficient products as outlined in Section 25C of the Internal Revenue Service (IRS), continued through 2010. It included a credit of up to $1,500 toward the installation of high-efficiency residential heating and cooling systems. Feedback from contractors to Idaho Power indicated that the tax credit influenced the ratio of applications received by Idaho Power relative to the HSPF rating of the equipment being installed. The federal tax credit program required a minimum HSPF of 8.5. Approximately 95 percent of the applications received by Idaho Power in 2010 for air source heat pumps were for the 8.5 HSPF rating. The balance of applications was for the 8.2 HSPF rating.

The program was promoted at various home and garden trade shows and at other community events, such as the Idaho Green Expo and St. Luke's Women's Show. These opportunities provided direct access to customers, creating the opportunity to raise awareness of Idaho Power's energy efficiency incentives.

A new, color brochure was developed, printed, and distributed. It is tailored to the residential homeowner. The brochures were given to contractors as selling tools when they meet with their residential clients. Idaho Power also provides the brochures to interested customers at trade shows and events. The flier addressed the need for a marketing resource describing the availability of the incentives, provided guidance on heat pumps, and described important purchase considerations.

Idaho Power held training sessions for contractors in February, March, June, and September that provided general instruction on heat pumps and program guidelines. Approximately 25 people attended the sessions. These training sessions remain an important part of the program for two reasons. First, trainings create opportunities to invite additional contractors into the program. Second, trainings support the existing participating contractors with an increased ability to leverage the incentive program to residential clients.

Idaho Power improved the method to process heat pump incentive applications. Using CLRIS, a database was developed that allowed for all of the application data to be entered and stored for analysis and for immediate initiation of the incentive payment process. The process improvement enabled the program specialist to eliminate multiple files previously used to store, manage, and evaluate data.

Idaho Power uses a third-party contractor to process the incentive applications and provide trade-ally support. In March 2010, Honeywell, Inc., was selected as the new contractor. This change was made to decrease costs, shorten turnaround time for processing incentive applications, and improve the contractor and customer satisfaction. The contractors received increased local support because the Honeywell, Inc., representative could visit contractors at their businesses as needed.

In addition, Honeywell, Inc., provides a variety of timely contractor services, such as picking up incentive applications, returning calls quickly, and responding to questions in a thorough and customer-oriented fashion. Honeywell, Inc., has a local presence, so Idaho Power uses them to help troubleshoot customer/contractor issues via the representative for Honeywell, Inc., resulting in quicker resolution and increased contractor and customer satisfaction. Idaho Power developed a portal that Honeywell, Inc., uses as a program database to process incentive applications. This allows Idaho Power to maintain the database within the company's system that is secure and yet accessible to the third-party contractor.

Cost-Effectiveness

In August 2010, the RTF reviewed savings and costs for air-source heat pumps along with proper sizing and installation saving specific to the Northwest. Idaho Power adopted the updated savings and calculated savings for all air-source heat pump conversions with an HSPF rating of 8.5 using the 2010 deemed-savings. These savings are specific to climate zone and the presence or absence of central A/C prior to conversion. The updated RTF analysis replaced prior year's savings that were based on an independent third-party analysis conducted for Idaho Power by Ecotope, Inc., in 2009.

Savings estimates for the conversion from electric forced-air furnaces or upgrades from older air-source heat pumps to open-loop water-source heat pumps were not analyzed by the RTF. The savings for these measures are unchanged from the 2009 report. While savings for air-source heat pump upgrades were also analyzed and released by the RTF in 2010, the savings were not adopted because the analyzed baseline efficiency was an HSPF of 8.5, which is not aligned with the 2010 program design. In 2010, the H&CE Program gave incentives for heat pump upgrades at two tiers of efficiency: tier 1 for air-source heat pumps with an efficiency of at least 8.2 HSPF and tier 2 for heat pumps greater than or equal to an HSPF of 8.5. Savings for open-loop water-source heat pumps and air-source heat pump upgrades are documented in the 2009 Ecotope, Inc., *Heat Pump Sizing Specifications and Heat Pump Measures Savings Estimates* that was provided in the *Demand-Side Management 2009 Annual Report Supplement 2: Evaluation*. For more detailed information about the cost effectiveness savings, calculations, and assumptions, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

Customer satisfaction surveys were mailed to 127 participants in the H&CE Program in 2010. Surveys containing responses to 14 questions were returned from 66 participants who received incentives for new heat pumps, resulting in a 52 percent response rate. Respondents were asked to rate the amount of influence the Idaho Power incentive had in their purchasing decision. Sixty-eight percent said it had "some" influence, while 13 percent said it had "a lot" of influence. The remaining 19 percent said it had influenced their decision "not at all." The participants were asked if they were aware of the incentive program prior to the purchase of their heat pump. Seventy percent said they were aware of the incentive, while 30 percent said they were not aware of the incentive program. When the participants were asked to rate their contractor's knowledge of the incentive program, 73 percent said their contractor was "very knowledgeable." Another 15 percent said their contractor was "somewhat knowledgeable." The balance of respondents rated their response as "neutral," or "not very knowledgeable," or "not knowledgeable at all," with percentages of 5 percent, 5 percent, and 3 percent respectively. The majority of respondents, 77 percent, indicated that they heard about the H&CE Program from their heating and cooling contractor. Seventy-seven percent of the respondents indicated they are "very satisfied" with the H&CE Program, and 83 percent said they "definitely would" recommend the program to a friend or relative.

The survey results indicate the incentive program continues to have substantial influence in customers' decision process about purchasing a new heat pump. This is further supported in that the majority claimed being aware of the incentive program prior to the purchase. The current marketing efforts, therefore, will be continued, and new tactics will be added. In addition, the incentive process will be further streamlined to continue the favorable opinion the customers conveyed regarding installing contractors. The contractors' success with the program relies on their ability to understand it, thereby encouraging more of their customers to participate in it. The survey responses also indicate the majority of market awareness is being generated by the efforts of the contractors. This would indicate that other marketing efforts through Idaho Power will further the message while reducing the program dependency on the contractors' efforts.

Surveys containing eight questions were also sent to the nine incentive recipients for new evaporative coolers. Five surveys, a 55 percent response rate, were received from these recipients. When they were asked if they were aware of the incentive prior to their purchase, 60 percent said they were, and 40 percent said they were not. When asked to rate how much influence the incentive had in the purchasing decision, 60 percent said the incentive had "a lot" of influence, while 40 percent said it had influenced the decision "not at all." Sixty percent of the respondents indicated they heard about the H&CE Program from a retail store.

For ongoing QA, Honeywell, Inc., is the third-party contractor responsible for performing OSVs. Honeywell, Inc., inspected approximately 22 percent of the projects completed in 2010 for the H&CE Program. Honeywell, Inc., performed OSVs on 48 installations. Of these 48 installations, 77 percent, or 37 installations, were either compliant or were brought into compliance. Contractors for the remaining 11 projects that had difficulty passing the OSV did not receive an incentive payment.

In 2010, Idaho Power contracted with Global Energy Partners, LLC, to provide a process evaluation of the H&CE Program. This evaluation included a program data review, program logic model, internal customer survey evaluation, industry best-practices comparison, conclusions, and recommendations. The final report was received in February 2011 and noted that this program is "successful" and "well designed." The program "is meeting its goals," "incorporates several best practices," and "has an actionable marketing plan and satisfied participants." Recommendations for program

improvement centered on enhancing relationships with HVAC contractors, especially those who have not yet participated in this program. The results of the evaluation are in *Supplement 2: Evaluation*.

The company is currently analyzing other recommendations made by the consultants for possible future implementation. Program changes made in 2011 will be highlighted in the *Demand-Side Management 2011 Annual Report*.

2011 Strategies

New program marketing tactics will be used in 2011 to reach the target audience. Tactics include direct mail to target customers, participating with companies distributing coupon packets from local businesses to the Idaho Power service area, posting articles about the heat pump incentives on social media sites that Idaho Power participates in, and advertising in newspapers in specific areas not generally serviced with natural gas. The ongoing method of using bill inserts will continue in 2011.

Idaho Power and the program specialist will work closely with the participating contractors to help them maximize their ability to market the program incentives with their clients. The development of a premium group of participating contractors is a vital component to the success of the program. The program specialist and residential customer representatives will visit these contractors and prospective contractors throughout 2011.

Satisfaction surveys will be mailed to all 2011 incentive recipients. The response data will be compiled and analyzed to help improve all facets of the program.

Enhancements are being made to the incentives available for air-source heat pumps. The first change will help reduce complexity in the program. Currently there are incentives for two efficiency levels, heat pumps with minimum HSPF of 8.2 or 8.5. Only 4.8 percent of the incentives paid in 2010 were for heat pumps with the minimum 8.2 HSPF. The 95.2 percent balance of paid incentives were for heat pumps with a minimum 8.5 HSPF. In response to this trend and due to the measure's non-cost-effectiveness, the 8.2 HSPF option is being eliminated in first quarter 2011. This includes all the types of program equipment being replaced, such as old air-source heat pumps, electric furnaces, oil furnaces, and oil/propane furnaces. It also includes new heat pumps being installed in new home construction. The second modification will be to increase the incentive for changing electric furnaces to air-source heat pumps. This incentive will increase from $400 to $1000. In 2010, about 35 percent of the air-source heat pump incentives paid were for the replacement of electric furnaces. The goal is to increase participation by 30 percent in this particular category.

Idaho Power will hold several training sessions for contractors. General instruction on heat pumps as well as program guidelines will be provided. These training sessions remain an important component of the program. Sessions create opportunities to invite additional contractors into the program while fortifying the abilities of the existing participating contractors to promote the incentive program to residential clients.

Continuous process improvement during 2011 will focus on maximizing the productivity of Idaho Power staff and participating contractors involved with the program, and enable more time to be placed on tasks that add direct value to the program. The goal is to identify opportunities for complexity-reduction related to tasks performed by Idaho Power and participating contractors. Initial areas of focus will be on program information and distribution through the H&CE Program website pages. The navigation and display of content will be reviewed and improved to simplify access and

comprehension. This is necessary due to the amount of technical information and forms contained in this program.

Home Improvement Program

	2010	2009
Participation and Savings		
Participants (homes)	3,537	1,188
Energy Savings (kWh)	3,986,199	1,338,876
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$944,716	$321,140
Oregon Energy Efficiency Rider	$0	$0
Idaho Power Funds	$0	$0
Total Program Costs—All Sources	$944,716	$321,140
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.016	$0.019
Total Resource Benefit/Cost Ratio	$0.035	$0.032
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	8.66	
Total Resource Benefit/Cost Ratio	4.39	
Program Characteristics		
Program Jurisdiction	Idaho	
Program Inception	2008	

Description

The Home Improvement Program offers incentives to homeowners for installing attic insulation that reduces energy-use throughout the year while impacting summer peak demand by reducing A/C use. The program pays an incentive of 15 cents per-square-foot to Idaho residential customers in the Idaho Power service area for additional attic insulation professionally installed after June 1, 2009. Any insulation contractor can provide this service and there is no preferred-contractor list associated with this program. New insulation must increase the R-value by R-10 or greater.

A large majority of Idaho Power's residential customers qualify for the program, though specific program qualifications are required to receive the incentive. Only existing, single-family homes qualify for an incentive. This includes duplexes and townhomes with the attic area over conditioned space. Homes must have central A/C or be electrically heated. Only attic insulation installed over conditioned space qualifies for an incentive. An insulation contractor must professionally install the insulation. Incentives are paid on added attic insulation up to an R-50.

2010 Activities

In May 2010, a process improvement was implemented when Idaho Power outsourced the program incentive processing to Advertising Checking Bureau (ACB), Inc., a third-party incentive-processing company. ACB, Inc., receives, enters, and processes all incentive applications for the Home Improvement Program. The change resulted in improved incentive processing and payment time.

Various marketing techniques were employed in 2010. A targeted direct-mail campaign began in May 2010 and ran through July 2010. The direct-mail letter was sent to targeted customers using the

PRIZM marketing segmentation software. Response to this direct-mail piece was very positive with large numbers of incentive applications coming in during those months. Between May 2010 and July, 640 insulation incentive payments were received and paid.

A Val-Pak Advertisement, in conjunction with the See ya later, refrigerator® program, was sent out in August, September, and October to select zip codes in the Treasure Valley and Eastern Idaho. Phone-call volume increased substantially within days of each of the three mailings.

A bill insert went out in July, followed by a dual-program bill insert in conjunction with the See ya later, refrigerator program in November. Both bill inserts resulted in an increased volume of calls regarding program details and provided opportunities for customer education.

The Home Improvement Program paid 3,537 incentives during 2010, the first full year of the program's implementation.

Cost-Effectiveness

Savings estimates for the Home Improvement Program attic-insulation measure were based on a simulation modeling and analysis performed by Ecotope Inc. Their modeling simulated homes with and without the duct work in the attic area of the home and focused on cooling energy savings benefits from increased attic insulation. A 2,200 square-foot house was used as the prototype similar to ENERGY STAR homes. For more detailed information about the cost-effectiveness savings, calculations, and assumptions, see *Supplement 1: Cost-Effectiveness*.

During 2010, the RTF reviewed and deemed weatherization measures including attic insulation from a heating perspective by climate zone. Because this analysis did not include the impacts of central A/C, Idaho Power was unable to adopt these savings estimates for 2010 savings. As of February 2011, the RTF decided to review these measures again and make corrections in 2011. Idaho Power expects the savings from cooling will be included in the new deemed savings. The overall cost-effectiveness of the program measure can then be assessed by the presence of central A/C, electric heat, or both.

Customer Satisfaction and Evaluations

Third-party contractors reviewed 7 percent of all insulation jobs completed in the Home Improvement Program for QA purposes. Of the QA completed in 2010, two installations were considered inadequate. These issues were addressed with the insulation installers and corrected.

In 2010, the Home Improvement Program was included in the residential process evaluation. Idaho Power contracted with Global Energy Partners, LLC, to provide a process evaluation of the Home Improvement Program. This evaluation included a program-data review, program-logic model, internal customer survey evaluation, industry best-practices comparison, conclusions, and recommendations. The final report was received in February 2011 and showed that the program has "surpassed its participation goal," is "cost effective," has a "very low cost per kWh saved," and "is very affordable for customers." Recommendations for program improvement included the need to obtain more primary data from customers to determine customer/contractor satisfaction, barriers to participation, and customer receptiveness to offering additional measures. The results of the evaluation are in *Supplement 2: Evaluation*.

The company is currently analyzing other recommendations made by the consultants for possible future implementation. This program is scheduled to be included in an impact evaluation in 2011.

2011 Strategies

Plans for the upcoming year include a targeted direct-mailing campaign in May and June. An informational bill stuffer is being planned for June or July 2011. Due to the success of the Val-Pak mailing, similar mailings are being planned throughout the year with additional zip codes receiving the mailer. A marketing campaign consisting of newspaper advertisements and radio spots is planned for fall 2011.

In addition to the questions on the customer's program *Qualification Application*, a marketing question, "How did you hear about the program?" was added in 2011.

Analysis is currently underway to look at adding new measures to the Home Improvement Program in 2011. Measures being considered and analyzed are wall/floor insulation, windows, duct sealing, and air infiltration. These measures were discussed in the October 26, 2010, EEAG meeting.

Home Products Program

	2010	2009
Participation and Savings		
Participants (appliances/fixtures)	16,322	9,499
Energy Savings (kWh)	1,443,580	1,638,038
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$813,171	$498,980
Oregon Energy Efficiency Rider	$18,990	$12,283
Idaho Power Funds	$0	$50
Total Program Costs—All Sources	$832,161	$511,313
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.057	$0.031
Total Resource Benefit/Cost Ratio	$0.070	$0.051
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	2.45	
Total Resource Benefit/Cost Ratio	1.67	
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, lighting, or other products. ENERGY STAR is a government-backed program that designates products as energy efficient. Appliances and products with ENERGY STAR must meet higher, stricter efficiency criteria than federal standards.

With the addition of ENERGY STAR qualified freezers in July 2010, current offerings and related incentives include clothes washers ($50), refrigerators ($30), freezers ($20), light fixtures (up to $15 per fixture), ceiling fans with light kits, or ceiling fan light-kit attachments (up to $20 per fixture). Program participation is a simple process for customers. The customer completes the brief incentive application, submits it with a copy of the sales receipt, and, if the purchase qualifies, receives an incentive check by mail.

The Home Products Program has two additional product offerings providing the retailer/manufacturer the incentive as opposed to the consumer. This can translate into lower retail prices on the most efficient units, such as those in the showerhead promotion. These products are select energy-efficient electronics and low-flow showerheads.

Incentive payments to retailers and manufacturers, rather than the end consumer, were intended to drive the manufacture, distribution, and promotion of more energy-efficient consumer electronics at the retail level. This mid/upstream incentive model is potentially powerful in changing those markets with a high volume of sales and small per-product incentive dollars.

2010 Activities

Marketing of the Home Products Program to customers occurs primarily through retail outlets. Idaho Power provided information to store managers and employees through training sessions at store staff meetings and through periodic visits by Idaho Power representatives. Collateral materials, such as program brochures with application forms, were distributed to nearly 100 retail stores as needed. In addition, program modifications were delivered via letters sent directly to store managers.

In May 2010, Idaho Power began outsourcing the processing of applications for the Home Products Program to a third-party vendor, ACB, Inc. Through an RFP process, a vendor was chosen and ACB, Inc., began receiving applications. The capability of this vendor allows customers to complete an online application, print the confirmation page, and mail it with a copy of the sales receipt.

Idaho Power promoted the program directly to residential customers via retail store salespeople, Idaho Power field staff, bill stuffers, community promotions, an updated Idaho Power program website, an hour-long interview on The HomeFix Show with Joe Prin on 670 KBOI, and other outreach activities. During 2010, bill stuffers detailing the program were mailed to all residential customers, one during the summer (July), and one during the holiday season (November).

With the addition of freezers and the new processing vendor, the program brochure was redesigned and distributed to retailers in July 2010. The brochure also serves as the application. The customer fills out the self-mailer application, includes the sales receipt in the built-in pouch, seals the application with the self-adhesive flap, and places a stamp on the application.

The brochure redesign allowed Idaho Power the opportunity to add an option for customers who wish to donate their entire incentive to Project Share, an energy assistance program in which Idaho Power partners with the Salvation Army to help those in need. From July through December, Home Products Program participants donated $170 to this cause. A Project Share donation thank you card was created for the Home Products Program and sent to customers who chose to donate.

In addition, hang-tags were produced and distributed to lighting showrooms and retailers who sell qualifying fixtures. Static clings—small, sticky decals—are also distributed to retailers for placement on qualifying clothes washers and refrigerators. The prominent focus for using hang tags and clings was to highlight the respective incentive amounts.

The Consumer Electronics Initiative, in partnership with NEEA, continued in 2010. The initiative provides an incentive to retailers who sell flat-screen televisions, monitors, and desktop computers that are 30 percent more energy efficient than the minimum ENERGY STAR standard (ENERGY STAR +30 percent). Computer monitors and desktop computers were added in 2010. NEEA managed all aspects of the program, while, in 2010 and beyond, the funding for the initiative is taken from NEEA partners' general funding. Only the retailers who signed contracts with NEEA are involved, though nearly all retail stores in Idaho Power's service area will have had the opportunity to participate. Idaho Power assisted in marketing the initiative through a bill insert during the holiday season (December) highlighting the new "Energy Forward" energy-efficient electronics marketing campaign.

The Home Products Program exceeded the targets for 2010. Idaho Power paid 16,322 incentives during 2010. Incentives were issued for approximately 8,885 clothes washers; 6,025 refrigerators; 223 freezers; 676 light fixtures; 36 ceiling fans; and three light kits.

In June 2010, Idaho Power began a retailer-based promotion for low-flow showerheads. Fluid Market Strategies (Fluid), as part of the BPA's regional Simple Steps, Smart Savings™ program, administers the program. The industry standard for showerheads is 2.5 gallons per minute (GPM). Showerheads in the Simple Steps, Smart Savings promotion use 2.0 GPM or less, resulting in less hot water per shower and less electricity used to make hot water. The promotion is similar to the lighting promotions with incentives paid to manufacturers, resulting in lower retail prices for the more efficient units.

The showerhead promotion began in June 2010. Marketing for this program includes point-of-purchase signs, Idaho Power Web content, and the BPA-sponsored website for the regional promotion. Fluid staff conducts retailer training, visits store site to check retail signs, and monitors sales. In 2010, there were 474 promotional showerheads sold in the Idaho portion of Idaho Power's service area, resulting in $3,318 in incentives and $199 in administrative costs. The break-out of showerheads sold included 198 of the 1.5 GPM showerheads and 276 of the 2.0 GPM showerheads. Savings realized included 20,935 kWh for the 1.5 GPM showerheads and 18,432 kWh for the 2.0 GPM showerheads.

Cost-Effectiveness

Two new measures were added to the Home Products Program in 2010, ENERGY STAR freezers and low-flow showerheads. Savings and cost assumptions for freezers were based on deemed data from the RTF. The RTF savings methodology was also used for low-flow showerheads. After the original RTF savings were released in May 2010, Idaho Power adjusted the savings downward based on the electric hot water heater saturation in the Idaho Power service area. This adjustment was based on information from Idaho Power's *2004 Home Energy Survey*. The electric hot water heater saturation percentage has since been updated with the *2010 Home Energy Survey* results, and the low-flow showerheads still remain cost-effective.

Clothes washers and refrigerator savings and cost assumptions were also updated by the RTF in 2010. In summer 2010, the RTF approved changing the methodology and new baselines for calculating the saving for ENERGY STAR. In 2009, Idaho Power based annual savings of 215.19 kWh and 96.51 kWh for clothes washer and refrigerator respectively from the Nexant, *Demand Side Management Potential Study (2009)*. As a result of the RTF update, the annual energy savings for clothes washers was reduced to 121 kWh, while refrigerator savings was reduced to 44 kWh. These reductions in savings attributed to the program's overall reduction in annual savings between 2009 and 2010, despite the increase in participation.

While the measures reviewed by the RTF still remain cost-effective, it was discovered that the Idaho Power incentives for refrigerators and freezers are higher than the RTF's updated participant cost assumptions. Idaho Power plans to review these costs and incentive levels in 2011 and adjust the program accordingly.

The RTF also updated savings and cost assumptions of for ENERGY STAR lights and fixtures in 2010. These assumptions include LED down-light fixtures, which were unavailable prior to 2010. Of the 676 light fixtures processed in 2010, the 15 LED fixtures were shown to be not cost-effective. In addition to the LED light fixtures, the three ceiling fan light kits that received incentives in 2010 were also shown to be not cost-effective. There is little information on ceiling fan light kits, and the savings and cost assumptions are based on Idaho Power staff research and assumptions. Since the Home Products Program gives incentives to all ENERGY STAR products, the ceiling fan light kits and LED fixtures have remained in the program for consistency purposes and customer satisfaction; however, Idaho Power will determine if the measure will be removed or modified from the program's offerings when the other measures within Home Products Program are reviewed in 2011.

For more detailed information about the cost-effectiveness of these measures, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

Retail salespeople assisted in promoting the program to Idaho Power's and the retailers' mutual customers. Information gathered from a question on the incentive application form indicated salespeople are a proven, effective avenue for marketing the program. In fact, 55 percent of the responses indicated salespeople were how they learned about the incentive program. This is followed by 20 percent learned from in-store materials (brochures), 11 percent from one of two bill inserts sent to all residential customers, 3 percent from the newspaper, 2 percent from the Idaho Power website, 8 percent from other means, and 1 percent from radio.

The *Demand-Side Management 2009 Annual Report* indicated that a process evaluation would be completed for the Home Products Program in 2010. Home Products Program was a relatively new program offering in 2010, and many process changes were implemented; therefore, it was decided to conduct a process evaluation on other residential programs in 2010. The descriptions and copies of the process evaluations conducted in 2010 are included in *Supplement 2: Evaluation*.

2011 Strategies

Based on 2010 successes, the marketing strategy for 2011 will remain similar with only minimal adjustments and updates as needed. The Home Products Program will cross-promote with other Idaho Power programs as opportunities arise and develop promotional materials. Idaho Power will continually review potential products for addition to the program during 2011 and beyond.

Participation for 2011 may not have the same spike as 2010; however, participation is expected to remain constant, or decrease slightly from 2010 numbers. The company speculates much of the increase in applications in 2010 was due not only to greater customer awareness of the program, but also due to the Idaho State Energy Efficient Appliance Rebate Program (SEEARP) available to Idaho residential customers beginning in March 2010. This state-run program offered incentives on many of the same products as Idaho Power, but at an even higher incentive. Therefore, Idaho Power customers could apply and receive both incentives, spurring purchases of these appliances during the time the SEEARP was in effect. Funds supporting the SEEARP program were exhausted in 2010 and are no longer available in 2011.

The Consumer Electronics Initiative partnership with NEEA will continue in 2011. Idaho Power will seek opportunities to promote this initiative, when applicable.

Idaho Power will continue to participate in the regional showerhead promotion, Simple Steps, Smart Savings. The BPA promotion will run through September 2011, with a likely extension through the remainder of 2011.

Oregon Residential Weatherization

	2010	2009
Participation and Savings		
Participants (homes)	1	1
Energy Savings (kWh)	320	2,907
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$0	$0
Oregon Energy Efficiency Rider	$4,575	$6,359
Idaho Power Funds	$1,475	$1,285
Total Program Costs—All Sources	$6,050	$7,644
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.011	$0.203
Total Resource Benefit/Cost Ratio	$0.062	$0.223
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	2.28	
Total Resource Benefit/Cost Ratio	1.17	
Program Characteristics		
Program Jurisdiction	Oregon	
Program Inception	1980	

Description

Idaho Power offers free energy audits for electrically heated customer homes within the Oregon service area. This is a statutory program offered under Oregon Rate Schedule No. 78. On a customer's request, an Idaho Power representative visits the home to analyze it for energy efficiency. An estimate of costs and savings for specific measures is given to the customer. Idaho Power offers financial assistance for a portion of the costs for weatherization measures, either as a cash incentive or with a 6.5 percent interest loan.

2010 Activities

During the month of June, Idaho Power sent every Oregon residential customer an informational brochure about energy audits and home weatherization financing. A total of 15 Oregon customers responded. Each of the 15 customers returned a card from the brochure indicating interest in a home energy audit, weatherization loan, or incentive payment. Twelve audits and responses to customer inquiries to the program were completed.

Idaho Power issued one rebate totaling $46.81 for 320 kWh savings. The rebate and related savings was for ceiling insulation. There were no loans made through this program during 2010. Two customer responses were directed to Cascade Natural Gas because their heating source was gas. No customers canceled their request.

Cost-Effectiveness

The Oregon Residential Weatherization program is a statutory program as provided for in Oregon Rate Tariff No. 78. The cost-effectiveness of this program is defined within this tariff. Page 4 of Tariff No. 78 lists the measures that are determined to be cost effective and the required measure life cycles for specific measures. This tariff also includes the cost-effective limit (CEL) for measure lives of 7, 15, 25, and 30 years. In 2010, the only project competed under the Oregon Residential Weatherization program was a ceiling insulation measure. The CEL for insulation is $1.34 per annual kWh saved, and the actual levelized cost of energy savings for the one 2010 project is just over 1 cent from the UC perspective and 6 cents from the TRC perspective, resulting in this program being considered cost effective.

2011 Strategies

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

Rebate Advantage

	2010	2009
Participation and Savings		
Participants (homes)	35	57
Energy Savings (kWh)	164,894	247,348
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$34,283	$43,954
Oregon Energy Efficiency Rider	$5,119	$5,571
Idaho Power Funds	$0	$0
Total Program Costs—All Sources	$39,402	$49,525
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.018	$0.015
Total Resource Benefit/Cost Ratio	$0.031	$0.029
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	8.61	
Total Resource Benefit/Cost Ratio	3.57	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2003	

Description

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

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 Housing Program (NEEM) establishes quality-control and energy-efficiency specifications for qualified homes. NEEM is a consortium of manufacturers and state energy offices in the Northwest. In addition to specifications and quality, NEEM tracks the production and on-site performance of ENERGY STAR qualified manufactured homes.

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

2010 Activities

During 2010, Idaho Power paid 35 incentives on new manufactured homes, which accounted for approximately 165,000 kWh savings. The depressed housing economy in 2010 had a dramatic effect on all types of housing and contributed to a lower number of incentives than expected. At least nine of the previously participating dealerships closed between 2009 and 2010, which had a negative impact on the

program. Communications with other Northwest utilities conducting similar programs indicated they also saw a sharp decrease in participation.

The marketing strategy during 2010 was more customer-focused than in the past, as opposed to strictly using dealerships to promote the program. An Internet-based Google AdWords campaign was created mid-July, whereby specific keyword searches prompt potential program participants to click on an advertising link that guides them to the Idaho Power website where they learn more about energy efficiency programs. From July through December, the campaign received 302 clicks with 285,160 impressions.

Idaho Power continued to support dealerships in 2010 by providing them with Rebate Advantage brochures, applications, and call-out cards as needed. Customer representatives visited these dealerships to distribute material, promote the program, and answer salespersons' questions. In April, a letter was sent to all dealerships promoting the program, the benefits of ENERGY STAR qualified homes, and the qualifications to participate. This letter was intended as more of a reminder piece and to generate inquiries they may have since all of the dealerships are aware of the program and many of them participated in 2010.

Cost-Effectiveness

ENERGY STAR manufactured home ratings are used to determine the energy savings of this program. These savings are specific to the heating and cooling zones in Idaho Power's service area where the home will be placed. In addition to varying by climate zone, savings vary depending on whether the customer purchases a home with or without central A/C or if a heat pump or forced-air furnace is chosen. For detailed lists of savings by climate zone and housing options, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

Idaho Power did not conduct any surveys or research on this program in 2010. A program impact evaluation of the Rebate Advantage program is planned in 2011. A process evaluation of the Rebate Advantage program was scheduled for 2010; however, due to the economic downturn and decreased participation in this program, evaluation funds were reallocated to Energy House Calls.

2011 Strategies

Idaho Power plans to continue the Rebate Advantage program in 2011, explore new marketing methods, and promote the program using internal resources and externally at the dealership level. Customer representatives will enhance relationships with dealerships by visiting each dealership quarterly, offering program support, answering questions, and distributing materials. The involvement of local Idaho Power personnel interacting with the local dealers reemphasizes the importance of promoting the benefits of ENERGY STAR qualified homes and products.

The company will continue to explore additional marketing strategies aimed directly at the end consumer. These will include continuing, and revising as needed, the Google AdWords campaign; sending a bill insert to all residential customers, which may be shared with the ENERGY STAR Homes Northwest program; and revisiting the direct-mail letter finalized in 2010. The letter will be sent to select Idaho Power customers using Claritas PRIZM segmentation methodology matched with company customer information.

See ya later, refrigerator®

	2010	2009
Participation and Savings		
Participants (refrigerators/freezers)	3,152	1,661
Energy Savings (kWh)	1,567,736	1,132,802
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$548,872	$297,587
Oregon Energy Efficiency Rider	$16,207	$7,815
Idaho Power Funds	$0	$0
Total Program Costs—All Sources	$565,079	$305,402
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.054	$0.041
Total Resource Benefit/Cost Ratio	$0.054	$0.041
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	1.88	
Total Resource Benefit/Cost Ratio	1.88	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2009	

Description

The See ya later, refrigerator® program provides incentives to customers for recycling refrigerators and freezers. The program acquires energy savings through the removal of refrigerators and stand-alone freezers from residential homes throughout Idaho Power's service area, focusing on secondary and spare units commonly found in basements and garages. Customers receive a $30 incentive check mailed after removal of the unit. Although all qualified units are collected, the program is targeting older, extra units for maximum savings.

Idaho Power contracts with JACO to provide most services for this program. Idaho Power provides participant confirmation, supplemental marketing, and internal program administration. Marketing includes newspaper ads, bill inserts, *Customer Connection* articles, website content, and promotion at events.

JACO provides customer service, unit pickup, unit recycling, reporting, marketing assistance, and incentive payments. Customers call the JACO customer service center regarding program questions and scheduling unit collections.

JACO crews pick up units at customers' homes. While still at the customers' homes, JACO cuts the cord, and the door seals so the refrigerator can no longer be used. JACO then transports and ships the units to the final recycler. JACO issues the incentive payments to customers and tracks the unit information at the account level. JACO contracts with Runyon, Saltzman & Einhorn (RS&E), a marketing firm, to provide marketing support. RS&E has experience marketing utility refrigerator recycling programs nationwide and brings expertise and proprietary market research to Idaho Power's program.

The See ya later, refrigerator name is trademarked by PacifiCorp. Through its JACO contract, Idaho Power has been granted the rights to use this trademark. In 2010, PacifiCorp issued brand guidelines specifying the capitalization, comma use, and trademark symbol for the name.

2010 Activities

During 2010, the program recycled 664 freezers and 2,488 refrigerators for an associated annual savings of 368,520 kWh and 1,199,216 kWh, respectively.

In 2010, Idaho Power made several program improvements and worked with JACO to refine program delivery. Early in 2010, Idaho Power and JACO refined the customer verification process to ensure timely evaluation of participant eligibility. This program requires some sharing of customer data with JACO. Customers enroll in the program directly with JACO. Idaho Power receives participant data daily, reviews the information, approves or denies the participant, and transfers completed files back to JACO. Several process improvements were made to this data transfer procedure. Idaho Power developed an archive system to store transferred files and refined a mechanism to search records. Programming adjustments were made by JACO to ensure data accuracy.

A second program improvement to increase customer satisfaction was the addition of an option for participants to donate their incentive to Project Share. Project Share is an energy assistance program in partnership with the Salvation Army. Project Share helps customers in need pay for energy services including fuels, bills, and furnace repairs. Upon enrollment in See ya later, refrigerator, participants are given the option to receive their $30 incentive or to donate it to Project Share. Research on similar donation mechanisms show 2 percent of people choose this option[1]. The option was launched in April 2010. Since the option became available, 2.5 percent of participants have donated their incentive, raising $2,010 for Project Share.

The See ya later, refrigerator program also qualified Idaho Power for the US EPA Responsible Appliance Disposal (RAD) program. RAD is a voluntary partnership program that began in October 2006 to help protect the ozone layer and reduce emissions of greenhouse gases. Idaho Power joined as a RAD program partner in August 2010. The program is free of charge. Companies, such as utilities, involved in appliance recycling agree to report on units collected and materials recycled. JACO completes this report for Idaho Power at no charge. The benefits of the program include use of EPA RAD logo on marketing materials and opportunities for public recognition by EPA, which can serve as an additional free or low-cost marketing opportunity.

Cost-Effectiveness

In early 2010, a regional review of refrigerator/freezer recycling programs was undertaken by the RTF. The results were approved in June. The previous savings assumption based on the average life was 682-kWh annual savings with a remaining measure life of eight years for either refrigerators or freezers. The updated savings split out the impacts between freezers and refrigerators and resulted in a differential remaining measure life. These changes were based on data collected from regional utility programs. Refrigerators were deemed to have an average remaining life of nine years with an annual average savings of 482 kWh, and freezers were assigned a shorter remaining life of six years with higher savings

[1] Source: http://www.taxadmin.org/fta/rate/checkoff.html

at 555 kWh of annual savings. Both program measures remained cost effective in 2010. For details, see *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

JACO tracks unit statistics for each unit collected, including information on how the customer heard about the program and when the customer enrolled. Unit statistics about the unit collected include the age of the unit, the location it is housed, and other data, which help to refine Idaho Power's assumptions regarding cost-effectiveness.

Results of the 2010 unit data showed that 21 percent of units the program picked up were stand-alone freezers, and 79 percent of the units were refrigerators. Forty-eight percent of the units were secondary, 33 percent primary, and 19 percent were unknown. The average vintage of units collected was 1983, with 63 percent of the units manufactured between 1965 and 1990, generally the least-efficient years of manufacture.

The program reclaims or recycles up to 95 percent of the components of each unit collected. In 2010, this translated into over 425,489 pounds of material. Reclaimed materials may include oils or refrigerants that can be distilled and then reused.

JACO and Idaho Power also track data related to the marketing effectiveness of the program. Results of customer tracking information indicate 45 percent of customers report learning of the program through bill inserts, which ran in March, July, and October. Twenty percent of customers report learning of the program through a friend or neighbor. Other word-of-mouth activities, such as events and utility personnel, account for an additional 2 percent of signups. Although appliance retailers also refer customers to the program, Idaho Power does not pursue this marketing channel because a retailer selling a new unit will usually pick up and recycle the old one. Newspaper advertisements comprise seven percent of enrollments. Eighty-one percent of customers enrolling in the program use the toll-free telephone number. Nineteen percent use the online enrollment form.

Idaho Power uses the customer information that JACO and the company collect to target future marketing efforts and increase effectiveness of marketing while reducing the cost. Figure 7 indicates information sources and percentage of responses regarding the 3,152 customers reporting hearing about the program through particular sources. The category "Other" includes sources, such as community events, electric utility offices, marketing services, repeat customers, truck ads, Web Internet searches, and unknown sources.

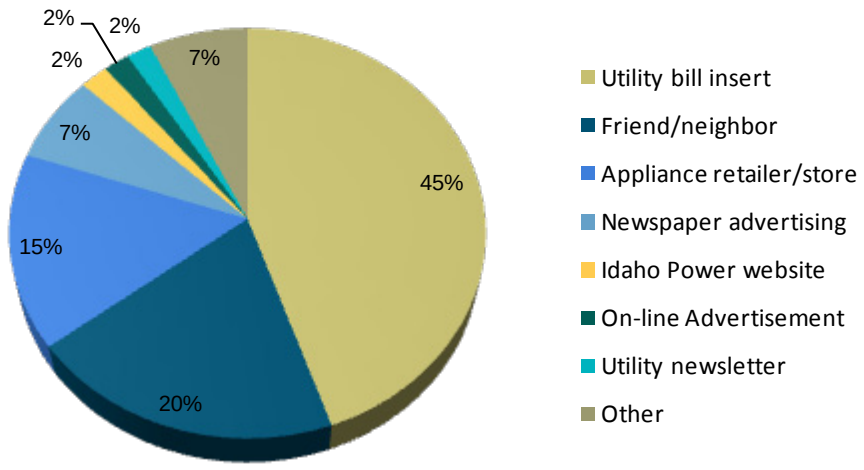

Figure 7. How customers heard about See ya later, refrigerator®

2011 Strategies

Idaho Power plans to continue implementing the program and managing the contract with JACO. The media plan for 2011 includes newspaper ads, bill inserts, Valpak ads, and customer newsletters, pending available space. Keyword pay-per-click ads will be on Google all year. Idaho Power through RS&E will also run Yahoo behavioral target online ads. The company will continue promotion at energy efficiency and community outreach events and on the Idaho Power website.

A process evaluation of the See ya later, refrigerator program is scheduled for 2011.

Weatherization Assistance for Qualified Customers

	2010	2009
Participation and Savings		
Participants (homes/non-profits)	400	437
Energy Savings (kWh)	3,741,652	4,678,815
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	$1,321,132	$1,294,862
Total Program Costs—All Sources	$1,321,132	$1,294,862
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.027	$0.021
Total Resource Benefit/Cost Ratio	$0.035	$0.035
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	4.68	
Total Resource Benefit/Cost Ratio	3.22	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	1989	

Description

The WAQC program provides funding to install cost-effective weatherization measures in qualified owner-occupied and rental homes that are electrically heated. In 2010, 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 nonprofit organizations who serve special needs populations. In compliance with IPUC Order No. 29505, Idaho Power funds the Community Action Partnership (CAP) agencies to administer the WAQC program in its service area.

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

Energy-saving home measures provided by this program include upgrades to windows, doors, wall insulation, ceiling insulation, floor insulation, infiltration, ducts, water heaters, pipes, furnace tune-ups, furnace modification, furnace replacement, and CFLs. Consistent with the State of Idaho Weatherization Assistance Program, WAQC offers several measures that have costs but do not save energy or 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 home or compromise a household's existing indoor air quality. Other non-energy savings measures are allowed under this program to help facilitate the effective performance of those measures yielding energy savings.

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

For more details on the WAQC program, view the most recent regulatory report, *Weatherization Assistance for Qualified Customers 2009 Annual Report*, April 1, 2010, located in *Supplement 2: Evaluation.*

2010 Activities

During 2010, CAP agencies weatherized 373 electrically heated homes in Idaho and 27 in Oregon, totaling 400 weatherized homes. Annual energy savings were 3,452 MWh for Idaho and 289 MWh for Oregon. There were no buildings housing nonprofit organizations that serve special needs populations weatherized in 2010. The dollar allotment for this fund will carry over and be available for use in 2011.

Cost-Effectiveness

The cost-effectiveness for the WAQC program is determined using an energy savings audit program known as Energy Audit 4 (EA4). The EA4 audit program is used by state weatherization programs and is approved for use by the DOE. During an initial audit of a potential home, the auditor begins the use of an EA4. The EA4 compares efficiency of measures prior to weatherization to the efficiency after the proposed improvement. The output of the EA4 savings-to-investment ratio (SIR) is analogous to a B/C ratio. If the EA4 computes a SIR of 1.0 or higher, where the energy-savings benefits of the measures outweigh the cost of the project, the CAP agency is authorized to complete that energy-saving measure(s). In addition to the individual measure SIR, the entire home weatherization job is required to show a SIR of 1.0 or higher. In some cases, the SIR accounts for measures that provide no actual savings, but are provided for either the health or safety of the customer or are required to make the other measures with savings more effective. Cost-effectiveness details are located in *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

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

Idaho Power personnel reviews weatherized homes with special needs customers as needed or requested by customers. Annually, Idaho Power participates in the audits of 5 percent of the homes weatherized under the WAQC program. Additionally, the DOE audits the state agencies each year. The DOE audits include field work as well as paperwork and billing audits.

2011 Strategies

Idaho Power will continue program funding and participate in the review of WAQC. The company is involved 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.

Weatherization Solutions for Eligible Customers

	2010	2009
Participation and Savings		
Participants (homes)	47	41
Energy Savings (kWh)	313,309	211,720
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$216,202	$160,459
Oregon Energy Efficiency Rider	$2,306	$0
Idaho Power Funds	$9,917	$2,536
Total Program Costs—All Sources	$228,425	$162,995
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.056	$0.059
Total Resource Benefit/Cost Ratio	$0.056	$0.059
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	1.98	
Total Resource Benefit/Cost Ratio	1.98	
Program Characteristics		
Program Jurisdiction	Idaho[a]	
Program Inception	2008	

[a] Oregon Rider balance of $2,306 will be re-classed to the Idaho Rider in 2011.

Description

Weatherization Solutions for Eligible Customers is an energy efficiency program designed to serve Idaho Power residential customers who are slightly above poverty level and, therefore, do not financially qualify for the company's larger weatherization program, WAQC. The program measures and implementation process mirrors WAQC. The installation of energy efficiency measures and repairs are allowed as long as the improvements have a SIR of 1.0 or higher or that ensure the savings due to interaction between measures. The amount spent on each home is limited to an annual average per home. Homes considered for this program will be electrically heated and either owned or rented. If rented, the landlord's permission is needed, backed with an agreement of not increasing the unit's rent for a minimum of two years.

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

2010 Activities

Home Energy Management, LLC, is the contractor who administers the program throughout Idaho Power's southern region. The total budget for this area was $200,000, which includes a 10 percent administrative fee for Home Energy Management, LLC. Qualifying guidelines for the year were between 175 percent and 250 percent of the federal poverty level.

By year end, Home Energy Management, LLC, weatherized 40 electrically heated homes of eligible Idaho Power customers, at no cost to the customer. Energy savings achieved was 259,100 kWh/year, with an average home savings of 6,477 kWh/year. Total costs were $182,478, with an average job production cost of $4,147. Twenty manufactured homes, 17 single-family homes, two duplexes, and one multi family unit were weatherized in 2010. Thirty-six of the 40 weatherized homes in the Southern region were owner occupied, and four were renter occupied.

In October 2010, Energy Zone, LLC, started weatherizing homes for this program in Idaho Power's Canyon region. By year-end, Energy Zone, LLC, weatherized seven homes saving 54,209 kWh per year, or 7,744 average kWh per home. Energy Zone, LLC, averaged $4,494 per home production costs. Total spending was $34,607, which included administrative fees for the contractor. Of the seven homes weatherized, three were single-family homes and four were manufactured homes. Six of the homes were owner occupied, and one was renter occupied.

Marketing of the program was done several ways without additional costs to the program. The contractors advertised the program in their regions by creating program fliers that were distributed by contractor employees throughout mobile home parks and at specific property management Realtor offices. Fliers were also left with previous customers who spread information about the program to families and friends who might qualify. Word-of-mouth continued to be an effective marketing tool for the program in 2010.

Cost-Effectiveness

Like the WAQC program, Weatherization Solutions for Eligible Customers program uses the energy audit software program, EA4. During an initial audit of a potential home, the auditor completes an energy-savings audit using the EA4. The EA4 audit program is used by state weatherization programs and approved for use by the DOE. If the EA4 computes a SIR of 1.0 or higher, Home Energy Management, LLC, and Energy Zone, LLC, are authorized to complete that energy-saving measure. In addition to the individual measure SIR, the entire home weatherization job project is required to show a SIR of 1.0 or higher. Idaho Power customer representatives in the Southern and Canyon region verify installed measures in homes of participating customers using actual job sheets submitted by Home Energy Management, LLC, and Energy Zone, LCC. In addition to the job screening done by the agency, Idaho Power also assesses cost-effectiveness, looking at the UC test of each measure that is allowed as part of the contract with Home Energy Management, LLC, that currently includes windows, doors, insulation, venting, infiltration, ducts, health and safety measures, water heater, pipes, furnace repair, furnace replacement, and CFL installation. The cost-effectiveness testing by measure is consistent with standard methods used in other programs. Actual savings and cost measure submitted by CAP agencies is used in place of deemed measure values to asses cost-effectiveness. The actual average annual savings estimates are considered more accurate than a deemed number because of the number of inputs that are applied from the EA4 data analysis. The final savings numbers per measure and a complete list of cost-effectiveness assumptions can be reviewed in *Supplement 1: Cost-Effectiveness*.

Table 6. 2010 Weatherization Solutions for Eligible Customers: individual measure breakdown

Measure	Instances installed	kWh Savings	Cost of measures
Windows	19	49,343	$ 27,399
Doors	19	27,514	14,936
Wall Insulation	4	13,317	4,774
Ceiling Insulation	27	48,565	23,863
Floor Insulation	33	62,075	45,887
Venting	23		2,981
Infiltration	27	39,965	14,455
Ducts	26	28,152	7,774
Health and Safety	29		10,326
Water heater	14	2,825	1,345
Pipes	36	1,822	3,605
Furnace repair	8		1,829
Furnace replacement	6	32,808	24,984
CFL install	44	6,923	972
Audit invest	46		12,221
Total		**313,309**	**$ 197,351**

Customer Satisfaction and Evaluations

Of the 47 participants, all customers provided written positive feedback about the work done in their home. Each customer filled out a Customer Response/Job Completion Form provided to them at the final visit and completion of weatherization services at their home. Most customers made positive comments about how professional the weatherization crew was during the weatherization of their home. Many customers thanked Idaho Power for the program and reported learning more about using energy wisely.

2011 Strategies

The program will continue to be offered to Idaho Power customers in the Southern and Canyon regions in 2011. Home Energy Management, LLC, is under contract to weatherize 28 homes in Idaho Power's Southern region, and Energy Zone, LLC, is under contract to weatherize 56 homes in Idaho Power's Canyon region. Idaho Power will begin efforts to expand the program into the Eastern region.

The annual average cost of $6,500 per home will be used in 2011 in order to ensure a whole-house approach. All measures will meet the minimum savings-to-investment threshold when applied through the state-approved energy audit.

Eligible customers will include Idaho Power customers who heat their homes electrically and earn an income between 175 percent and 250 percent of the federal poverty level. Customers either purchasing or renting their homes may be eligible. Idaho Power plans to save an average of 9,000 kWh per weatherized home per year for a total energy savings of 756,000 kWh annually.

As in 2010, identification of potential participants will be made through several means. Energy Assistance/LIHEAP applicants at CAP agencies who do not meet income qualifications are sent denial letters. Program contractors will use this list of denied customers at CAP agencies to market the Weatherization Solutions for Eligible Customers program. Contractors will distribute fliers explaining

the program and qualifying guidelines to customers heating their homes with electricity provided by Idaho Power in both regions.

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COMMERCIAL/INDUSTRIAL SECTOR OVERVIEW

Description

Idaho Power's commercial and industrial sector consists of over 64,000 customers. In 2010, the commercial sector's number of new customers increased by 298, an increase of 0.5 percent. The energy usage of the commercial customers varies from a few kWh each month to several hundred thousand kWh per month. Commercial customers represent approximately 28 percent of billed sales.

Industrial customers and the special contract sector are Idaho Power's largest individual energy consumers. There are approximately 121 industrial customers. These customers can use millions of kWh per month and account for about 23 percent of Idaho Power's system sales.

Energy efficiency annual energy savings increased by 27 percent to 118,473,001 kWh in 2010 when compared to 2009 program results. Custom Efficiency represented the highest change in magnitude of savings by increasing program 2010 annual savings by 19,744,463 kWh over 2009 annual savings, with 91 additional projects over 2009. Building Efficiency saw the highest percentage increase amongst commercial and industrial programs, with annual savings increasing by 43 percent over 2009 annual savings. Table 7 is a summary of savings and expenses from the four commercial and industrial energy efficiency programs and one demand response program.

Programs

Table 7. 2010 Commercial/Industrial program summary

Program	Participants		Total Costs		Savings	
			Utility	Resource	Annual Energy (kWh)	Peak Demand (MW)
Demand Response						
FlexPeak Management	60	sites	$ 1,902,680	$1,902,680	n/a	47.5
Total			**$ 1,902,680**	**$1,902,680**		**47.5**
Energy Efficiency						
Building Efficiency	70	projects	$ 1,509,682	$ 3,312,963	10,819,598	0.9
Easy Upgrades	1,535	projects	3,974,410	7,655,397	35,824,463	7.8
Holiday Lighting	25	projects	46,132	65,308	248,865	0.0
Custom Efficiency	233	projects	8,778,125	17,172,176	71,580,075	9.5
Total			**$14,308,349**	**$28,205,844**	**118,473,001**	**18.2**

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

Three major programs targeting different energy efficiency projects are available to commercial/industrial customers in the company's Idaho and Oregon service areas. Easy Upgrades offers a menu of retrofit measures with prescriptive incentive amounts for lighting, HVAC, motors, building shell, plug loads, and grocery refrigeration. These energy-saving measures give customers the option of personally choosing the best selections for incorporating energy efficiency into their business. The Building Efficiency program is available for new construction projects and large remodels. These projects typically capture lost opportunity savings. This program continues to be successful, incorporating qualified energy savings improvements for lighting, cooling, building shell, and energy-control options. Participants in the Building Efficiency and Easy Upgrades programs can receive incentives of up to $100,000 per site per year for any approved, completed projects. The Custom

Efficiency program offers financial incentives for large commercial and industrial energy users undertaking projects that are more complex to improve the efficiency of their electrical systems or processes. Incentive levels are 70 percent of the project cost or 12 cents per kWh for first-year savings, whichever is less.

The Holiday Lighting program encourages commercial customers to purchase more-efficient LED holiday lights. This program is offered to both Idaho and Oregon Customers. In 2010, the Holiday Lighting program was evaluated from several perspectives, including customer participation, access to LEDs in the market place, and cost-effectiveness. Based on the outcome of the research, the Holiday Lighting program will not be offered in 2011.

Idaho Power continues to offer the Oregon Commercial Audits program to medium and small commercial customers.

FlexPeak Management is a demand response program offered to Idaho and Oregon commercial and industrial customers. Idaho Power contracted with EnerNOC, Inc., a third-party aggregator, to reduce peak demand at critical times. EnerNOC, in turn, contracts directly with Idaho Power's commercial and industrial customers to achieve demand reduction. In May 2010, Idaho Power received the Demand Response Program Achievement Award from the Peak Load Management Alliance (PLMA) for its FlexPeak Management demand response program. PLMA is a non-profit group of organizations with a business interest in electrical load that is dedicated to creating a community of expertise on demand response and its role in creating efficient electricity markets.

The Green Rewind measure is available to Idaho Power's agricultural, commercial, and industrial customers. The sectors' combined 56 Green Rewind motors achieved a total savings of 243,091 kWh in 2010, with 20 commercial/industrial sector motors contributing 55,126 kWh and 36 irrigation sector motors contributing 187,965 kWh.

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

Motor service centers are paid $2.00 per horsepower (hp) for each National Electrical Manufacturers Association (NEMA) Standard hp rated motor between 15 and 5,000 hp that receives a verified Green Rewind. The GMPG requires all service centers to sign and adhere to the GMPG Annual Member Commitment Quality Assurance agreement. The GMPG follows up with quality check and QA.

Idaho Power continues to use the IDL in Boise to advance energy efficiency practices relating to building retrofits, remodels, and new construction. Additionally, the IDL in Boise continues to provide clients with current and accurate information regarding energy efficiency technologies and best practices through monthly newsletters, blog updates, and by hosting and facilitating constituent meetings.

In 2010, Idaho Power contracted with the IDL in Boise to perform the following tasks:

- Develop climate design resources specific to Idaho that can be used to facilitate passive strategies in new commercial and industrial construction projects.

- Conduct research and write a white paper describing a strategy for developing an energy efficiency labeling program for all commercial, industrial, and retail buildings in Idaho.
- Conduct 17 education sessions for architects, engineers, and other design and construction professions on energy efficiency topics.
- Facilitate the Idaho Building Simulation Users' Group to improve the energy efficiency-related skills of design and engineering professionals.
- Conduct research for developing a high-performance speaker's bureau.
- Complete post-occupancy evaluations on three facilities that have incorporated energy efficiency measures.
- Create a demonstration and training area for electrical contractors to learn the necessary skills to successfully install and commission daylight harvesting lighting control systems.
- Research common plug load use profiles in office buildings to identify strategies to reduce plug loads.
- Provide building efficiency consultations, design analyses, and plan reviews to Idaho Power customers.

A considerable amount of time was spent in 2010 reviewing the measure offerings and incentive levels in Easy Upgrades, Building Efficiency, and Custom Efficiency. Several measure changes were made to Building Efficiency due to the state adoption of the 2009 IECC. Both measure offerings and incentive levels within Building Efficiency were changed to address the new code. With a large percentage of lighting projects completed in both Easy Upgrades and Custom Efficiency, lighting was a focus in 2010. Based on that review, several changes will be implemented in 2011 to both programs' lighting offerings. The changes are designed to make the programs more consistent in their application and review process and with the program terms and conditions. Additionally, an increased focus was placed on pre- and post-project inspections on lighting projects.

Other 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. In the 2010 surveys, 55 percent of Idaho Power's large commercial and industrial customers surveyed in 2010 for the Burke Customer Relationship survey indicated Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Forty-five percent of survey respondents indicated Idaho Power was meeting or exceeding their needs with information on how to save energy or reduce their bill. Sixty-eight percent of respondents indicated Idaho Power was meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 74 percent of the large commercial and industrial survey respondents indicated they have participated in at least one Idaho Power energy efficiency program. Of 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 that 35 percent of these customers said Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Forty-nine percent of survey respondents indicated Idaho Power was meeting or exceeding their needs with information on how to save energy or reduce their bill. Fifty-five percent of respondents

indicated Idaho Power was meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 16 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, 87 percent are "very" or "somewhat" satisfied with the program.

In 2011, Idaho Power will focus on successfully integrating all of the new program changes across the sector programs. That focus will include identifying process improvements, supplying energy efficiency specific education to Idaho Power trade allies, contractors, and customers, and completing more pre- and post-project inspections. Additionally, the programs will analyze recommendations from the process evaluations conducted on the commercial and industrial programs in 2010.

Effective July 14, 2012, there will be new Standards for General Service Fluorescent Lamps. Idaho Power is reviewing the new requirements and will consider them when deciding what changes to make for the lighting measures and respective incentives for the 2012 commercial/industrial lighting measures.

Building Efficiency

	2010	2009
Participation and Savings		
Participants (projects)	70	72
Energy Savings (kWh)	10,819,598	6,146,139
Demand Reduction (MW)	0.9	1.3
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$1,466,179	$$1,300,466
Oregon Energy Efficiency Rider	$43,422	$26,323
Idaho Power Funds	$81	$339
Total Program Costs—All Sources	$1,509,682	$1,327,128
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.016	$0.024
Total Resource Benefit/Cost Ratio	$0.035	$0.043
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	4.62	
Total Resource Benefit/Cost Ratio	2.69	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2004	

Description

The Building Efficiency program enables customers in Idaho Power's service area to apply energy-efficient design features and technologies that would otherwise be lost opportunities for savings to their projects. The program offers a menu of measures and incentives for lighting, cooling, building shell, and control-efficiency options. Customers involved in the construction of new buildings or construction projects with significant additions, remodels, or expansions can receive incentives up to $100,000. Commercial and industrial customers taking service under, or who will take service under, Schedule 7 (Small General Service), Schedule 9 (Large General Service), Schedule 19 (Large Power Service), or special-contract customers are eligible to participate. Program marketing is targeted at architects, engineers, and other local design professionals.

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

2010 Activities

The Building Efficiency program completed 68 Idaho and two Oregon projects in 2010, resulting in 10,552,135 kWh in energy savings in Idaho and 267,493 kWh in energy savings in Oregon. The increase in energy savings is attributed to an increase in the number of projects incorporating energy management control systems for lighting and HVAC.

New construction and major renovation project design and construction life is much longer than small retrofits and requires consistency in program measures and operation. To reduce confusion for customers with long construction projects, the Building Efficiency program did not change in 2010, maintaining a consistent and clear program for customers.

Fourteen measures are offered through this program and include reduced-power-density lighting, daylight photo controls, occupancy sensors, high-efficiency exit signs, premium efficiency HVAC units, additional unit efficiency bonus, efficient complex cooling systems, air-side economizers, reflective roof treatment, high-performance windows, window shading, energy management control system, demand-control ventilation, and variable-speed drives.

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. Seventeen technical training lunches were completed in 2010, with 338 attendees, including architects, engineers, interior designers, and project managers. Topics included Integrated Design Principals, Commissioning, Benchmarking + Measurement and Verification, Daylight in Buildings: Getting the Details Right, Demand Control Ventilation, Daylight Sensing Electric Lighting Controls, High Performance Classrooms, The Role of Life Cycle Cost Assessment in Idaho, and Hybrid Cooling and Performance Modeling.

In 2010, Idaho Power evaluated program changes and modifications to be implemented beginning 2011. The 2009 IECC was implemented in the State of Idaho effective January 1, 2011. The impact of IECC 2009 on program measure savings and incentives were researched and reviewed. The existing measures were evaluated along with the current participation levels for each measure. Customer and customer representative feedback indicated the need to simplify incentive payment calculations. The 2011 Building Efficiency program has been modified to reflect the impact of these recommendations and implementation of IECC 2009.

Cost-Effectiveness

To calculate energy savings, the Building Efficiency program measures the incremental efficiency of each measure over a code or standard-practice installation baseline. Savings are calculated through two main methods. When available, savings are calculated using actual measurement parameters for both the measure at code and at efficiency.

The other method for calculating savings in the program is based on industry-standard assumptions when precise measurements are not available. 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 regional and national sources including the RTF, the Database for Energy Efficiency Resources (DEER), and the Consortium for Energy Efficiency, Inc. (CEE) 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 (kW) reduction as the unit being used. Complete measure level details for cost-effectiveness can be found in *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

In 2010, Idaho Power contracted with The Cadmus Group, Inc., to provide a process evaluation of the Building Efficiency program. This evaluation included a program data review, program logic model, internal customer survey evaluation, industry best practices comparison, and conclusions and recommendations. The final report was received in February 2011 and noted that Idaho Power, as a primary sponsor of the IDL in Boise, provided free technical assistance and training to local architects and designers through the Building Efficiency program. The report also noted that this program increased in participation by 20 percent in the last year. Recommendations for program improvement included the need to update program collateral materials and conduct additional market research with program participants and non-participants. Idaho Power is currently analyzing all recommendations. The complete report is provided in *Supplement 2: Evaluation.*

The company also contracted with The Cadmus Group, Inc., to conduct a *Market Characterization Study* for this program. Among other things, this study includes a scenario that applies a comparison of current and forecasted market penetration to the cost-effective potential estimated in the *Demand Side Management Potential Study, August 14, 2009* report by Nexant. The gap analysis indicates the Building Efficiency program is currently exceeding the savings potential estimates, especially in the HVAC sector. The analysis also shows current program costs per MWh are approximately one-half of the costs estimated in the potential study. The complete report is provided in *Supplement 2: Evaluation*.

The IDL in Boise also performed additional post occupancy evaluations of the program in 2010. The post-occupancy evaluation specifically focused on opportunities for pre- and post-intervention studies and on identifying opportunities for education and further research. The final report is scheduled for delivery in March 2011, and Idaho Power will consider all viable recommendations identified in the report.

2011 Strategies

In 2011, Idaho Power will implement program changes and modifications to align with IECC 2009 as the base line for energy-savings calculations. The 2011 program will have simplified incentive calculations and increased energy efficiencies for qualification. A briefing on the modifications was presented at the October 26, 2010, EEAG meeting, and questions were addressed.

Final reports from The Cadmus Group, Inc.'s, 2010 process evaluations were received in February 2011. All viable process recommendations will be considered and prioritized for implementation in 2011. Process changes implemented in 2011 will be highlighted in the *Demand-Side Management 2011 Annual Report*.

The Building Efficiency program will continue to sponsor technical training through the IDL in Boise. Technical trainings will expand to include two to four education sessions based on energy efficiency education needs of design professionals in the Pocatello, Twin Falls, and Sun Valley markets.

Custom Efficiency

	2010	2009
Participation and Savings		
Participants (projects)	223[a]	132
Energy Savings (kWh)	71,580,075	51,835,612
Demand Reduction (MW)	9.5	6.7
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$8,046,168	$5,816,305
Oregon Energy Efficiency Rider	$717,132	$236,910
Idaho Power Funds	$14,825	$8,252
Total Program Costs—All Sources	$8,778,125	$6,061,467
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.014	$0.013
Total Resource Benefit/Cost Ratio	$0.027	$0.024
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	7.85	
Total Resource Benefit/Cost Ratio	3.29	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2003	

[a] Does not include Green Motor Rewinds

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-efficient projects. Incentives reduce customers' payback periods for projects that might not be completed otherwise. Program offerings include training and education on energy efficiency, energy auditing services for project identification and evaluation, and financial incentives for project implementation.

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

Project implementation begins after Idaho Power reviews and approves an application, followed by the finalization of the terms and conditions of the applicant's and Idaho Power's obligations. In some cases, large, complex projects may take as long as two years to complete. Oftentimes, Idaho Power conducts follow-up or post-inspection validation via third-party engineering firms. Incentive levels for the Custom Efficiency program stayed at 70 percent of the project cost, or 12 cents per kWh first-year savings, whichever is less.

2010 Activities

A total of 223 projects were completed in 2010 by 152 companies, including 19 Oregon projects from 12 different companies. Program energy savings increased in 2010 by 38 percent over the prior year, from 51,836 MWh to 71,525 MWh. Completed projects increased by 74 percent in 2010. The increase in program participation and energy savings was a direct result of increased participation of lighting and fan projects. As stated in the sector overview, Green Rewind is available to Idaho Power's Custom Efficiency customers. This measure maintains the motor's original efficiency and ensures an efficient use of electricity to run the motor. There were 20 Green Rewind motors in the commercial/industrial sector in 2010, contributing 55,126 kWh in savings.

Key components in facilitating customer implementation of energy efficiency projects are facility energy auditing, customer technical training, and education services. Because the link between energy audits and completion of projects is historically significant, Idaho Power continued expanding the number of contractors available for customer scoping audits from six companies in 2009 to eight companies in 2010. Selection of engineering firms is based on the firm's expertise in all major equipment areas and their ability to provide resources for customers throughout Idaho Power's service area.

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. A total of 10 technical training classes were completed in 2010. Topics included compressed air, chilled water systems, pumping systems, variable frequency drives, and refrigeration. The level of attendance at these classes remains high with a total of 234 customers attending the workshops.

The Custom Efficiency program has achieved a high service area penetration rate. Through 2010, approximately 73 percent of the large power service customers submitted an application for a project. Idaho Power engineers met with another 18 percent of the customers to discuss energy efficiency programs and opportunities within customer facilities. In summary, 91 percent of large power service customers submitted projects to, or met, with Idaho Power.

Table 8 shows the Custom Efficiency program's annual energy savings by end use, number of projects, and kWh saved.

Table 8. Custom Efficiency annual energy savings by measure

Program Summary By Measure	Number of projects	kWh saved
Lighting	159	33,234,770
Fan	28	13,614,289
Compressed Air	5	6,738,503
Pump	3	2,567,460
Refrigeration	14	10,387,189
Other	21	4,982,738
Total	**223**	**71,524,949**[a]

[a] Does not include Green Motor Rewinds

Cost-Effectiveness

All projects submitted through the Custom Efficiency program must meet cost-effectiveness requirements, which include TRC, UC, and PCT tests from a project perspective. The program requires

all costs related to the energy efficiency implementation and energy-savings calculations are gathered and submitted with the program application. Payback is calculated with and without incentives, along with the estimated dollar savings for installing energy efficiency measures. As the projects 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 utilized via a Scoping Audit, Detailed Audit, or engineering measurement and verification services available under the Custom Efficiency program. Details for cost-effectiveness are in *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

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

On many projects, and especially larger and more complex projects, Idaho Power or a third-party consultant conducts on-site power monitoring and data collection before and after project implementation. The measurement and verification process ensures achievement of projected energy savings. Verifying applicants' information confirms that demand reduction and energy savings are obtained and 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 verification of energy savings, costs, estimates of measure life, and any final recommendations to ensure the persistence of savings.

In 2010, Idaho Power contracted with The Cadmus Group, Inc., to provide a process evaluation of the Custom Efficiency program. This evaluation included a program data review, program logic model, internal customer survey evaluation, industry best practices comparison, conclusions, and recommendations. The final report was received in February 2011 and stated that "overall, the program is operating smoothly from design to implementation," and "in many ways, the Custom Efficiency program exemplifies a quality efficiency program compared to similar efforts across the country." Recommendations for program improvement included the completion of the program manual including pre- and post-inspection protocols and standards and the need to conduct additional market research with program and trade ally participants. Idaho Power is currently analyzing all recommendations. Any program changes made in 2011 will be highlighted in the *Demand-Side Management 2011 Annual Report*. The complete report is provided in *Supplement 2: Evaluation*.

The company also contracted with The Cadmus Group, Inc., to conduct a *Market Characterization Study* for this program. Among other things, this study includes a scenario that applies a comparison of current and forecasted market penetration to the cost-effective potential estimated in the *Demand Side Management Potential Study, August 14, 2009* report by Nexant. The gap analysis shows that the Custom Efficiency program is currently meeting the forecasted achievable potential savings and the costs per MWh are similar to the forecast in the potential study. The complete report is provided in *Supplement 2: Evaluation*.

Because the customers who participate in the Custom Efficiency program are some of Idaho Power's largest customers, program managers or major customer representatives solicit customer satisfaction feedback for the Custom Efficiency program. This is authenticated in customers' willingness to

participate in the Custom Efficiency program posting the customer's *Success Stories* on the Idaho Power website. At the end of 2010, 14 additional *Success Stories* describing 2010 projects were posted on the company's website. An example of a success story posted in 2010 refers to a project Roaring Springs completed early in the year. Idaho Power provided Roaring Springs a $75,665 incentive for energy efficiency upgrades that reduce Roaring Springs costs and is expected to save about $65,000 in electric bills per year, according to the owner. The estimated total savings of the project was 822,825 kWh per year. The owner said, "I can't thank these guys at Idaho Power enough. They really went above and beyond." Copies of the 2010 *Success Stories* are provided in *Summary 2: Evaluation.*

2011 Strategies

In 2011, Idaho Power plans to continue expanding the Custom Efficiency program through a number of activities. These activities will include direct marketing of the Custom Efficiency program by Idaho Power major customer representatives to inform the customers of the Idaho Power energy efficiency programs available and ways the customer can reduce energy costs. In addition, Idaho Power will continue to provide site visits and energy audits for project identification; technical training for customers; funding for detailed energy audits for larger, complex projects; and delivery of NEEA-sponsored energy improvement practices to customers.

Final reports from The Cadmus Group, Inc.'s, 2010 process evaluations were received in February 2011. All viable process recommendations will be considered and prioritized for implementation in 2011. Process changes implemented in 2011 will be highlighted in the *Demand-Side Management 2011 Annual Report*. The company plans on conducting an impact evaluation in 2011.

Both the Custom Efficiency and Easy Upgrades programs offer lighting incentives to commercial and industrial customers. Having lighting programs with different characteristics can cause confusion among field staff, contractors, and customers. In 2011, Idaho Power will continue to make program changes to lighting projects within both Custom Efficiency and Easy Upgrades. The objectives will be to develop a single lighting calculator, standardize terms and conditions, and follow a similar project verification protocol between programs. Better alignment of the incentives between the two programs will lessen program confusion and potentially increase participant satisfaction.

Easy Upgrades

	2010	2009
Participation and Savings		
Participants (projects)	1,535	1,224
Energy Savings (kWh)	35,824,463	35,171,627
Demand Reduction (MW)	7.8	6.1
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$3,862,653	$3,213,388
Oregon Energy Efficiency Rider	$111,757	$108,533
Idaho Power Funds	$0	$3,584
Total Program Costs—All Sources	$3,974,410	$3,325,505
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.013	$0.011
Total Resource Benefit/Cost Ratio	$0.024	$0.032
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	7.93	
Total Resource Benefit/Cost Ratio	2.94	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2006	

Description

The Easy Upgrades program encourages commercial and industrial customers in Idaho and Oregon to implement energy efficiency retrofits by offering incentives up to $100,000 per-site, per-year. Eligible measures cover a variety of energy-saving opportunities in lighting, HVAC, motors, building shell, plug loads, and grocery refrigeration. Although Easy Upgrades is designed to be "easy" for Idaho Power customers, it is one of the company's largest and most complex programs, containing 143 separate measures. A complete listing of the measures offered through the Easy Upgrades program is included in *Supplement 1: Cost-Effectiveness*.

Idaho Power commercial or industrial customers taking service under Rate Schedule 7 (Small General Service), Rate Schedule 9 (Large General Service), Rate Schedule 19 (Large Power Service), and special-contract customers are eligible. Potential participants first assess their energy-saving opportunities by talking with their equipment supplier, contractor, or Idaho Power customer representatives. For projects with expected incentive payments of more than $1,000, applicants must submit a preliminary application prior to initiating the project. In that case, the customer or contractor completes the preliminary application form and submits it with relevant worksheet(s) describing the location and planned scope of their project. On Idaho Power's review and acceptance, the preliminary application allows a customer to collect an incentive if the project is completed within 90 days. For smaller projects with expected incentive payments of less than $1,000, customers may elect to skip the preliminary application and just submit their final application for payment. These projects must have been completed no more than six months prior to submitting their application for payment. Under the Easy Upgrades program, incentive payments may be made to the customer's contractor; however, the customer must specifically assign the payment to the contractor in the application process.

2010 Activities

To Idaho Power's trade allies, contractors, and customers who participated in Easy Upgrades, 2010 appeared to be a relatively normal year. From Idaho Power's perspective, 2010 was a year that presented many challenges and opportunities. Challenges were created as the program continued to experience strong growth in the number of projects being submitted. Opportunities were created when Idaho Power expanded the responsibility of day-to-day program operations to multiple internal program specialists. Having multiple program specialists involved benefited the program by streamlining processes, enhancing employee development, leveraging staff experience, and creating more consistent program management across Idaho Power's commercial and industrial energy efficiency programs. To ensure projects met the terms and conditions of the program, more pre-project and post-project inspections were conducted by Idaho Power. In July, a new program specialist was selected to lead Easy Upgrades. Idaho Power hired a contract employee to conduct pre- and post-project inspections. Due to the increase in program participation, employee resources almost doubled from 2009.

As existing program specialists and energy efficiency engineers became involved in day-to-day operations, process improvements such as streamlining application processing became an initial focus. The incentive check letter mailed to customers on completed projects was automated, saving valuable staff time. Additionally, data-entry processes were automated, making them more efficient and improving accuracy.

In 2010, Idaho Power focused on data-gathering and analysis. In preparation for the 2011 program-change rollout, Idaho Power contracted with Evergreen Consulting to advise Idaho Power on lighting options within Easy Upgrades. Evergreen Consulting is a regionally and nationally recognized energy efficiency consulting group that specializes in energy-efficient lighting program implementation. This work included redesigning the lighting tool customers and trade allies use in calculating and submitting incentives for lighting projects.

Idaho Power worked with the company's customer representatives and external trade allies to obtain feedback on the 2010 program changes being considered for implementation in 2011.

In addition to developing a new lighting tool, other changes to the program for 2011 included updating the program terms and conditions, revising incentive levels on some measures, and adding new lighting measure to encourage customers to install technologies that are more efficient.

Easy Upgrades conducted four workshops in December targeting to trade allies and large commercial customers to review the 2011 proposed program changes. These workshops were held across Idaho Power's service area. Workshop topics included new program terms and conditions, application processing, and a demonstration of the new lighting tool. In addition to program-specific material, a 90-minute lighting technology training session was given. Trade allies appreciated receiving the information in advance of the 2011 program rollout. The lighting tool demonstration and the lighting training were two highlights of the workshop. Trade allies provided feedback that they would like to see more lighting training in classes.

Four *Business-Specific Energy Savings Tips* brochures were developed for grocery stores, health care facilities, restaurants, and hotels. These tip sheets provide information and ideas on how to save energy, serving as a resource for specific businesses. Additionally, Idaho Power customer representatives use the brochures when meeting with these businesses.

Presentations were made to various business and professional groups. Idaho Power participates in the local Building Owners and Managers Association International (BOMA) chapter. The Easy Upgrades program was promoted at other events, including sponsoring the 2010 Idaho Better Bricks awards and the Idaho Smart Growth awards.

Cost-Effectiveness

In 2010, Idaho Power did not make changes to the measures offered under the Easy Upgrades program. For most of the measures, deemed savings and cost from the Nexant *Demand Side Management Potential Study (2009)* were used for the cost-effectiveness analysis. For the balance of the measures, engineering estimates were used to calculate expected savings results. In preparation for the program modifications for 2011, a cost-effectiveness review or analysis was conducted on all current measures.

For 2011, several measures that were determined to be not cost-effective were either removed from the program or modified. The Nexant *Demand Side Management Potential Study (2009)* identified six measures that may not be cost effective. These measures were the window shading, flat-panel liquid crystal display (LCD), occupancy sensor controls for office equipment, high-efficiency coin-operated washers without electric water, air-cooled multiplex systems, and evaporative-cooled multiplex systems. After further internal review in consultation with the EEAG, these measures were removed from the program's offerings for 2011. As for 2010, only three out of the six measures were used by the customers and comprise 0.2 percent of the measures receiving incentives. The four lighting measures determined not cost effective in 2009 as well as the other lighting measures were updated for 2011 with the new lighting tool. Additionally, a new custom line item is now included within the lighting tool to accept combinations not captured by the prescriptive approach. This new custom option allows the customer to enter specific information, such as wattages of existing and proposed fixtures, hours of operations, and costs for a proposed a lighting project. The determination of cost-effectiveness of these measures is based on these entries.

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

Customer Satisfaction and Evaluations

As part of the ongoing evaluation process, surveys were sent to 382 program participants in mid-October, and 113 responded to the survey, resulting in a 30 percent response rate. The purpose of the survey was to collect customer feedback on the program and on the products they installed as well as the contractor used for their project. Over 61 percent of the 113 survey respondents said they learned about the program "from a contractor, supplier, or vendor." Another 17 percent of these customers indicated they learned about the program "from an Idaho Power employee."

When asked a series of questions about their experience with Idaho Power and the Easy Upgrades program, 60 percent "strongly agreed" that Idaho Power staff provided accurate and helpful information. Sixty-six percent "strongly agreed" that Idaho Power staff was helpful; 53 percent "strongly agreed" that the Easy Upgrades incentive application forms were easy to follow; and 63 percent "strongly agreed" that their application was processed in a timely manner.

Ninety-one percent of the respondents indicated they are "very satisfied" with the energy efficiency equipment they installed under the Easy Upgrades program.

Only 17 percent of the respondents indicated their project would not have changed at all if they had not participated in the Easy Upgrades program. Of those who said their project would have changed if they

had not participated in the Easy Upgrades program, 40 percent said they would have "kept using existing equipment," 27 percent would have "canceled the project altogether;" 21 percent said they would have had to "postpone the project for more than 1 year;" and 16 percent said they would have "repaired existing equipment." Sixty-six percent of the respondents said they could not have paid the full cost of the project without the Easy Upgrades incentive. When asked a series of questions about what influenced their decision about whether or not to do the project, 76 percent said the Easy Upgrades incentive was "very influential;" and 54 percent said the amount of energy-savings potential was "very influential."

Respondents were asked a series of questions about the contractor they used for the Easy Upgrades project. The majority of respondents ranked their contractor "excellent" on quality of work, courteousness and professionalism, knowledge of equipment and knowledge of the Easy Upgrades program, completing work in a timely manner, and explaining efficiency aspects of new equipment. Fifty-five percent said they used the contractor because they had "used them for other projects;" and 86 percent said they "definitely would" recommend the contractor to a business associate.

Ninety percent of respondents said they were "very likely" to participate in the Easy Upgrades program again and were "very likely" to recommend the Easy Upgrades program to a business associate.

Copies of these surveys and survey results can be found in *Supplement 2: Evaluation*.

Results of the customer satisfaction survey were reviewed by the program specialist as part of the process of identifying changes to the program for 2011. The specialist wanted to know if there were any issues with the program to address in the 2011 program changes; there were none. The specialist presented a few key survey results at Trade Ally Workshops held throughout the Idaho Power service area early in December 2010. These results included the following:

- The important role the trade allies serve for promoting the Easy Upgrades program to their customers
- The significant function the Idaho Power incentive played in helping customers implement their retrofit projects
- The customers' needs for the contractors to provide more information on energy efficiency measures and how to best use their energy efficiency equipment

The Easy Upgrades program specialist will continue to monitor customer satisfaction with the program throughout 2011.

Idaho Power contracted with The Cadmus Group, Inc., to provide a process evaluation of the Easy Upgrades program. This evaluation included a program data review, program logic model, internal-customer survey evaluation, industry best practices comparison, conclusions, and recommendations. The final report was received in February 2011 and indicated that this program had high appeal to Idaho Power customers and has grown rapidly. Recommendations for program improvement included the need to conduct additional market research with program and trade ally participants, update program marketing and outreach materials, and improve program data tracking and QA efforts. Idaho Power is currently analyzing all recommendations. Program changes made in 2011 will be highlighted in the *Demand-Side Management 2011 Annual Report*. The complete report is provided in *Supplement 2: Evaluation*.

The company also contracted with The Cadmus Group, Inc., to conduct a *Market Characterization Study* for this program. Among other things, this study includes a scenario that applies a comparison of current and forecasted market penetration to the cost-effective potential estimated in the *Demand Side Management Potential Study, August 14, 2009* report by Nexant. The gap analysis indicates current savings from the Easy Upgrades program are outpacing the forecasted achievable potential and this program has significant potential for growth. The study also predicts this gap to narrow in 2014 and recommends more aggressive marketing activities may be required in the future. The complete report is provided in *Supplement 2: Evaluation*.

2011 Strategies

Several program changes will be implemented in 2011. Program participants will be required to sign a MOU to be eligible to participate in Easy Upgrades. The MOU addresses the terms and conditions participants are required to follow. More detailed project information will be required on applications. The additional information will assist in verifying the scope of each project.

Measure changes for 2011 will include the following.

Lighting

Several administrative and program requirements for lighting projects will be implemented in 2011. Changes will include a new lighting tool. Submission of the new lighting tool will be required for project applications. Manufacturer cut-sheets on equipment being installed will also be required at the time new projects are submitted. A "custom" option for non-standard lighting applications will be included in the lighting tool. For example, cost-effective outdoor lighting measures will be eligible for program incentives under the new non-standard option. Based on cost-effective analysis, several incentive levels will be modified. Additionally, more pre- and post-installation site verifications will be performed. The program will develop a detailed inspection process for lighting projects.

Building Shell

Premium windows are redefined as those with a Solar Heat Gain Coefficient of 0.30 or less and a U-factor of 0.30 or less. Window-shade film was removed based on cost-effective analysis. Insulated and high-speed automatic door measures were removed from Easy Upgrades and moved to the Custom Efficiency program.

Grocery Refrigeration

The incentives for anti-sweat heat controls, Electronically Commutated Motor (ECM) case fan motors, and LED display case lighting were increased. Air-cooled multiplex and evaporative-cooled multiplex systems were removed based on cost-effective analysis.

Plug Load

Flat panel LCD displays, office equipment occupancy sensors, and coin-operated washing machines (without electric hot water) were removed based on cost-effective analysis.

Final reports from The Cadmus Group, Inc.'s, 2010 process evaluations were received in February, 2011. All viable process recommendations will be considered and prioritized for implementation in 2011. Process changes implemented in 2011 will be highlighted in the *Demand-Side Management 2011 Annual Report*.

Plans include the provision of educational topics at trade ally workshops. Topics will be focus on maximizing energy-savings opportunities and increasing customer satisfaction.

Effective July 14, 2012, there will be new Standards for General Service Fluorescent Lamps. Idaho Power is aware of these new requirements and will work with regional market players to develop strategies in deciding what changes to make for the lighting measures and respective incentives for the 2012 Easy Upgrades program.

FlexPeak Management

	2010	2009
Participation and Savings		
Participants (sites)	60	33
Energy Savings (kWh)	n/a	n/a
Demand Reduction (MW)	47.5	19.3
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$1,807,527	$528,681
Oregon Energy Efficiency Rider	$95,153	$0
Idaho Power Funds	$0	$0
Total Program Costs—All Sources	$1,902,680	$528,681
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	n/a	n/a
Total Resource Benefit/Cost Ratio	n/a	n/a
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	1.14	
Total Resource Benefit/Cost Ratio	1.14	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2009	

Description

FlexPeak Management is a voluntary demand response program targeting Idaho Power's industrial and large commercial customers that are capable of reducing their electrical energy loads for short periods during summer peak days. The program became available to the company's Idaho customers in May 2009 and to the company's Oregon customers in May 2010. The program objective is to reduce the demand on Idaho Power's system during peak times through customers' voluntary electrical use reduction. The program is active June 1 to August 31, between the hours of 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.

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.

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 without negative 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, EnerNOC commits a demand reduction level in MW to Idaho Power that EnerNOC is obligated to meet in 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.

2010 Activities

On February 26, 2010, as part of Case No. IPC-E-09-02, the company filed with the IPUC a *FlexPeak Management 2009 Preliminary Report* dated February 24, 2010, in accordance with the request in IPUC Order No. 30805 for a preliminary evaluation of the program prior to making a request for prudency of program expenditures. A copy of this report is included in *Supplement 2: Evaluation*.

Also on February 26, 2010, as part of the same case IPC-E-09-02, the company filed a petition requesting the IPUC approve an amendment to the agreement between Idaho Power and EnerNOC. The contract changes accomplished clarification of language regarding accrual of energy payments, adjustment of language regarding baseline calculations, correction of an error in EnerNOC penalty calculations, and addition of a non-solicitation clause.

On June 2, 2010, under Order No. 31098, the IPUC granted the company's Petition for Approval of the Amendment to the Agreement in June 2010.

In March 2010, the company filed an application with the OPUC to approve the FlexPeak Management program in its Oregon service area to be made available to Idaho Power Oregon customers. The OPUC opened docket UM 1473 to evaluate the application, which was approved on June 2, 2010, in Order No. 10-206.

The first week of the program, EnerNOC committed to provide a reduction of 29.96 MW. This weekly commitment, or "nomination," was comprised of 49 facility sites, of which 30 participated in the program in 2009 and 19 added in 2010. The reduction at the end of the season was 30.80 MW, comprised of 64 facility sites. The commitment peaked in July at 34.2 MW.

Idaho Power called four demand response events for the FlexPeak Management program. In each case, EnerNOC successfully exceeded the committed MW reduction. One event occurred in June, two in July, and one in August. The highest hourly reduction achieved was in July, at 47.5 MW, which exceeded the target reduction for the summer of 2010 of 30 MW.

Cost-Effectiveness

Although the B/C analysis for the FlexPeak Management program is based on a 10-year model, the company also tracks cost-effectiveness on an annual basis. Both calculations use financial assumptions and DSM alternative costs from the 2009 IRP. As published in the 2009 IRP, for peaking alternatives, such as demand response programs, a 170-MW SCCT is used as the alternative resource in Idaho Power's cost-effectiveness analysis. This analysis is updated annually with actual benefits and costs. For the FlexPeak Management program, the benefits are based on measured demand reduction at the participants' meter. The costs include the fees paid to EnerNOC and Idaho Power administration for the program. The 2010 cost-effective analysis demonstrated the FlexPeak program has a TRC ratio of 1.14

from a long-term perspective and a TRC ratio of 1.33 for 2010. *Supplement 1: Cost-Effectiveness* contains details on the cost-effectiveness assumptions and data.

Customer Satisfaction and Evaluations

In early 2010, EnerNOC sent an Annual Customer Survey to 27 of the 2009 participants via e-mail. Nine participants responded for a 33 percent response rate. On a scale of 1 to 10, 10 being "very satisfied," the average level of satisfaction with EnerNOC's communication with the participants was 7.1, the average level of satisfaction with how EnerNOC managed the demand response events was 8.3, the average level of satisfaction with the installation and maintenance of equipment installed at participants' facilities was 8.1, and the average level of overall satisfaction with EnerNOC was 7.7. On a scale of 1 to 10, 10 being "extremely likely," when asked how likely they would be to recommend EnerNOC to a colleague or business partner, the average result was 8.0. Of the nine responses, three reported no difference in their opinion of Idaho Power based on their participation in the program, five reported an improved opinion of Idaho Power, and one gave no response.

EnerNOC sent a post-event survey via e-mail after the first event in June 2010 to 125 participants at 53 sites representing all the sites enrolled in the event. Ten participants responded for an 8 percent response rate. Results were positive. 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 9.1. 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 9.1. 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 9.9. 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 9.2. When asked about their overall satisfaction with EnerNOC, on a scale of 1 to 10, 10 being "very satisfied," the average response was 8.9.

Copies of these surveys and survey results can be found in *Supplement 2: Evaluation*.

2011 Strategies

EnerNOC plans to conduct a post-season customer satisfaction survey for the 2010 season first quarter 2011. The results will be made available to Idaho Power. Idaho Power will continue to evaluate the best use of the program to meet the program objectives, maximize the benefit to Idaho Power's system, and refine internal criteria to call demand reduction events.

Holiday Lighting Program

	2010	2009
Participation and Savings		
Participants (projects)	25	32
Energy Savings (kWh)	248,865	142,109
Demand Reduction (MW)	n/a	n/a
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$45,816	$33,673
Oregon Energy Efficiency Rider	$316	$257
Idaho Power Funds	$0	$0
Total Program Costs—All Sources	$46,132	$33,930
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.024	$0.031
Total Resource Benefit/Cost Ratio	$0.034	$0.066
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	3.63	
Total Resource Benefit/Cost Ratio	1.87	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2008	

Description

The Holiday Lighting program offers incentives to commercial customers to replace incandescent lighting with more efficient LED holiday lighting. Customers turn in their strings of holiday lights for recycling at various Pacific Recycling locations and receive a receipt verifying the type and count of lights. The customer initiates the incentive process by submitting an application to Idaho Power, along with their recycling receipt and new bulb purchase receipt.

2010 Activities

A 2010 analysis of the program identified that an increasing ratio of mini-incandescent lights to C7 and C9 lights being turned in for recycling was having a significant impact on program cost-effectiveness. Additionally, several market observations were taken into account. Feedback from participants indicated a preference for LEDs in the future because of the durability and reduced hazard provided by LED technology. The increased availability of LED lighting in wholesale and retail stores, and use of the technology in the marketplace led to the acceptance of the LED technology. These factors combined to indicate that LED usage for holiday displays was becoming the standard choice in the market. Based on those factors, two program decisions were made: 1) beginning in mid-2010, incentives for mini-incandescent lights were not offered; and 2) customers were notified that 2010 would be the last year Idaho Power would offer the program. A bill stuffer went out in October 2010 notifying commercial customers of these program changes.

In 2010, there were 25 participants in the Holiday Lighting program with a total savings of 248,865 kWh/year. This is approximately half the energy savings achieved in 2009.

The largest program participant was the Idaho Botanical Garden, with an estimated annual savings of 46,899 kWh. Their Winter Garden Aglow holiday display recycled over 23,000 incandescent lights, and replaced them with approximately 10,000 LED lights. It is estimated that over 36,500 visitors attended this event.

Although the incentive was available only to commercial customers, the program was useful as a means of introducing Idaho Power customers to the advantages of LED technology and helped make LED lighting the preferred choice when it comes to replacing existing holiday lighting. LED lighting has now become readily available at most stores supplying holiday lighting to both commercial and residential markets.

As LED technology developed, LED replacement bulbs became available. When the Holiday Lighting program originally launched, LED light strings did not have replaceable bulbs. LED replacement bulbs for use in existing C7 and C9 strings were also not widely available at the time of program startup. In the past two years, increasing number of customers wanted to turn in bulbs yet keep their strings of sockets. Idaho Power staff was involved in counting and picking up these bulbs for disposal. This logistical step would have become an increasing concern had the program continued.

Cost-Effectiveness

In the original program design, savings estimates were computed for both commercial grade LED C7/C9 and mini-LED bulbs. Based on a review of manufacturing specifications of the LED C7/C9 bulbs, it was calculated they use 5 W less per bulb over a comparable incandescent C7/C9 bulb. LED mini bulbs were calculated to have 0.41 W of reduction per bulb. With an assumed 12 hours of use daily, seasonal savings per bulb were estimated to be 2.9 kWh for C7/C9 bulbs and 0.24 kWh for mini LEDs.

As part of the 2009 cost-effective analysis conducted in 2010, mini LEDs were found not cost-effective and were discontinued from the program midway through 2010 before the holiday season. The cost of mini LEDs decreased, and the availability of commercial-grade, non-LED mini bulbs declined, indicating a transformed market. This commercial trend or market transformation of mini-LED bulbs was mirrored by the emergence of residential programs through large retailers that provided discounts to customers purchasing LED bulbs and recycling incandescent similar to Holiday Lighting. The Holiday Lighting program was discontinued after the 2010 holiday season. Cost-effective model assumptions and analysis are included in *Supplement 1: Cost-Effectiveness*.

Customer Satisfaction and Evaluations

Overall, customers conveyed their appreciation for the program. Some customers were disappointed that incentives on the mini-incandescent were no longer offered. Customers were informed that a major goal of the program was to achieve market transformation in holiday lighting and with so many displays now being supported by LEDs, it was clear that LEDs have become a viable and acceptable option.

2011 Strategies

The Holiday Lighting incentive will no longer be offered. However, information regarding the use of LED technology for holiday displays will be provided on customers' request.

Oregon Commercial Audits

	2010	2009
Participation and Savings		
Participants (audits)	22	41
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	$5,049	$20,732
Idaho Power Funds	$0	$0
Total Program Costs—All Sources	$5,049	$20,732
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	n/a	n/a
Total Resource Benefit/Cost Ratio	n/a	n/a
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	n/a	
Total Resource Benefit/Cost Ratio	n/a	
Program Characteristics		
Program Jurisdiction	Oregon	
Program Inception	1983	

Description

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

2010 Activities

Idaho Power sent out its annual mailing to approximately 3,400 Oregon commercial customers in October 2010. Customers were notified of the availability of no-cost energy audits and provided the Idaho Power publication *Saving Energy Dollars*. Twenty-two customers requested an audit, with 15 audits completed by Idaho Power and seven completed by a third-party contractor.

EnerTech Services, the third-party energy auditing contractor, delivered Idaho Power energy efficiency program information to customers during the audits they conducted. During the delivery of information, EnerTech Services discussed maintenance and efficiency opportunities that may be available to meet customer needs.

Cost-Effectiveness

As previously stated, the Oregon Commercial Audits program is a statutory program offered under Oregon Rate Schedule No. 82. Since the required parameters of the Commercial Energy Audit Program

are specified in Schedule No. 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

An excellent example of the value of an audit is the identification of actual savings opportunities and incentives in the customer's facility. This was demonstrated during a restaurant audit completed in 2010. This example describes customer engagement in energy efficiency opportunities.

During the walk-through evaluation, the customer representative and the customer discussed potential lighting conversions, refrigeration positioning and temperature control, and window-glazing options. If the customer followed through on the lighting suggestions by upgrading from T-12 lamps with magnetic ballasts to T-8 lamps with electronic ballasts, the conversion would save approximately 30 percent of the energy used for lighting.

After the audit, the customer verbally indicated to the customer representative satisfaction with the discussion regarding potential energy efficiency opportunities at the site. A follow-up call revealed that the customer was interested in using the Idaho Power energy efficiency programs and conducting a lighting retrofit. Program requirements and contact information was provided.

2011 Strategies

In 2011, Idaho Power's audit contractor will continue to introduce participants to energy efficiency through lighting and HVAC system maintenance by suggesting customers seek alternatives that are more efficient as they support and replace their existing equipment. EnerTech Services will continue to help customers identify projects that save energy and help meet the customers' other needs, such as improving space comfort. The audit process will continue to be used as a way to introduce customers to available Idaho Power incentive programs.

IRRIGATION SECTOR OVERVIEW

Description

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

In December 2010, the active and inactive irrigation service locations totaled 18,547 system-wide. This is a reduction of 1.4 percent compared to 2009, due to removal of some irrigation meters that were not used for multiple years. Irrigation customers accounted for 1,706,632 MWh of energy usage in 2010, which was up from 2009 by over 3 percent. This sector represented about 13 percent of Idaho Power's total electricity usage and about 23 percent of peak demand. Energy usage for this sector has not grown significantly in many years; however, there is substantial yearly variation in demand due primarily to the impact of weather on irrigation needs.

Idaho Power currently offers two programs to the irrigation sector: 1) Irrigation Peak Rewards, a demand response program designed to decrease peak demand; and 2) Irrigation Efficiency Rewards, an energy efficiency program designed to encourage replacement or improvement of inefficient systems and components. Idaho Power also pays incentives to customers participating in the Green Rewind, which is a measure that ensures the motor's original efficiency is maintained if it is rewound at an approved service center. Table 9 summarizes the overall expenses and program performance for both the energy efficiency and demand response programs provided to irrigation customers.

The Irrigation Peak Rewards program was able to reduce peak summer demands by almost 250 MW during the program's peak performance event during the summer of 2010, an increase of 90 MW over last summer's program performance. More than 500 additional service point locations were enrolled for the 2010 season.

Irrigation Efficiency Rewards program, which has been in operation since 2003, saw its annual savings drop by 2,189,189 kWh to 10,968,430 kWh of annual savings as compared to 2009 reported savings. The reduction in savings in 2010 was primarily the result of fewer menu projects being submitted in 2010. Generally, there seem to be fewer irrigation systems that need to replace or repair the 11 menu items offered as a result of the program being available or the past four years. In addition, a few applications were not approved in 2010 due to the new rule adopted in 2010 requiring measures to have been installed within a year.

Programs

Table 9. 2010 Irrigation program summary

Program	Participants	Total Costs		Savings	
		Utility	Resource	Annual Energy (kWh)	Peak Demand (MW)
Demand Response					
Irrigation Peak Rewards	2,038 service points	$13,330,826	$13,330,826	n/a	249.7
Total		**$13,330,826**	**$13,330,826**	**n/a**	**249.7**
Energy Efficiency					
Irrigation Efficiency Rewards	753 projects	$2,200,814	$6,968,598	10,968,430[a]	3.3
Total		**$2,200,814**	**$6,968,598**	**10,968,430**	**3.3**

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

Each year, the company conducts a customer relationship survey. Overall, 50 percent of Idaho Power irrigation customer surveyed in 2010 for the Burke Customer Relationship survey indicated Idaho Power was meeting or exceeding their needs in offering energy efficiency programs. Fifty-eight percent of survey respondents indicated Idaho Power is meeting or exceeding their needs with information on how to save energy or reduce their bill. Fifty-six percent of respondents indicated Idaho Power is meeting or exceeding their needs with encouraging energy efficiency with its customers. Overall, 36 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.

Irrigation Efficiency Rewards

	2010	2009
Participation and Savings		
Participants (projects)	753[a]	887
Energy Savings (kWh)	10,936,463	13,157,619
Demand Reduction (MW)	3.3	3.4
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$2,059,676	$2,112,391
Oregon Energy Efficiency Rider	$110,034	$152,134
Idaho Power Funds	$31,104	$29,371
Total Program Costs—All Sources	$2,200,814	$2,293,896
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	$0.030	$0.026
Total Resource Benefit/Cost Ratio	$0.096	$0.077
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	5.22	
Total Resource Benefit/Cost Ratio	1.61	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2003	

[a] Does not include Green Motor Rewinds

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 the customer recover a portion of the costs of installation of a new, more efficient irrigation system and energy efficient improvements to an existing irrigation system.

Two separate options help meet the needs for major or minor changes on new or existing systems. The Custom Incentive Option addresses extensive retrofits of existing systems or new irrigation systems, providing component upgrades and large-scale improvements. For new systems, the incentive is 25 cents per first year kWh saved above standard installation methods, not to exceed 10 percent of total project cost. For existing system upgrades, the incentive is 25 cents per first year 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 pumping hp requirement or hours of operation.

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

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

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

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

Payments are calculated on predetermined average kWh savings per component. Idaho Power reviews and analyzes each proposal for a system or component modification, determining and verifying the energy savings.

The Green Rewind program enables customers to maintain the motor's original efficiency and ensures an efficient use of electricity to run the motor. Motor service centers are paid $2.00 per hp for each NEMA Standard hp-rated motor between 15 and 5,000 hp that receives a verified Green Rewind. The RTF originally approved the Green Motors Practices rewinding as an energy efficiency measure and approved a table of deemed savings in July 2007 for industrial applications. In July 2009, the RTF reviewed and approved savings for motor rewinds for industrial and agricultural applications. The new savings were posted in 2010.

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

2010 Activities

There were no major changes made to the basic structure of the program during 2010. However, a modification regarding the time frame in which irrigation components are eligible for an incentive was made for all menu payments effective January 4, 2010, with approval from the OPUC. Going forward from January 4, 2010, the new eligibility states that customer invoices must be provided to the company no later than one year after the purchase date of the equipment.

Idaho Power agricultural representatives, program specialist, and 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 Irrigation Association.

Idaho Power continued to market the program by varying the location of workshops and offering new presentations to irrigation customers. In 2010, Idaho Power provided six workshops promoting the Irrigation Efficiency Reward program throughout the service area. Approximately 180 customers attended workshops in Blackfoot, Aberdeen, Burley, Twin Falls, Grand View, and Nampa. Idaho Power also accepted invitations to present the program at four workshops sponsored by agricultural groups in Fairfield, Shoshone, Nampa, and Jackpot, Nevada. Exhibitor booths were displayed at regional agricultural trade shows, including the Eastern and Western Idaho Agriculture Expos, the Agri Action Ag show, the Idaho Ag Summit, and the Idaho Irrigation Equipment Association show and conference.

Of the 753 irrigation efficiency projects completed in 2010, the 610 associated with the Menu Incentive Option provided 5,219 MWh of energy savings and 1.02 MW of demand reduction. The Custom Incentive Option had 143 projects, of which 68 were new irrigation systems and 75 were on existing systems. This option provided 5,561 MWh of energy savings and 2.23 MW of demand reduction for the year. Also during 2010, irrigation customers contributed 187,965 kWh of energy savings from 36 motors participating in the Green Motor Rewind measure.

In 2010, Idaho Power reviewed the cost-effectiveness of continuing the Green Motor Rewind initiative for both industrial and agricultural motors. Based on the new RTF-approved energy savings, it was determined that some of the smaller motors did not pass the PCT. For 2011, rewinds on motors less than 25 hp have been removed from the initiative.

Cost-Effectiveness

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

Each application under the Menu Incentive Option received by Idaho Power also undergoes an assessment to ensure savings are achieved. Payments are calculated on predetermined average kWh savings per measure. In some cases, the energy savings estimated in the Menu Incentive Option are adjusted downward to reflect how the components are actually being used.

In 2010, RTF provisionally deemed updated savings and cost assumptions for several irrigation hardware measures. Idaho Power reviewed the savings and costs for measures identified for the western Idaho region. Several RTF measures were either averaged or combined to align with Idaho Power's program offering. Some measures annual gross energy savings increased and improved the measure's cost-effectiveness. For instance, the hub replacement measure was identified as not cost-effective in the 2009 *Supplement 1: Cost-Effectiveness*. RTF increased savings from 40 kWh/year, to 69 kWh/year which improved the measure's TRC from 0.71 to 1.14.

Nearly all the measures remained cost effective, despite the changes made to the measure savings and cost assumption. However, the rebuilt and new wheel line levelers appeared to not be cost effective using the new savings assumptions. The RTF reduced savings from 20 kWh per year to 2 kWh per year. This significant decrease in savings contributed to the TRC dropping from 1.34 in 2009 to 0.27 in 2010. One factor contributing to the measure's non-cost-effectiveness is the participant cost. RTF assumes the cost to be $3.25 per unit. However, according to invoices received by Idaho Power through the program, leveler rebuilding kits cost less than $1.00 while new levelers cost about $12.00. A majority of the levelers that are eligible for incentives through the program are for the rebuilt levelers; however, the cost of the new levelers is driving up the average participant cost. Idaho Power is currently reviewing this measure to determine if the measure is, in fact, cost-effective, or if it will be removed from the menu offerings. A decision will be made by the summer of 2011 when Idaho Power reviews other changes to the program.

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

Customer Satisfaction and Evaluations

On January 5, 2010 an RTF subcommittee, composed of the Energy Trust of Oregon (ETO), the RTF, Rocky Mountain Power, and Idaho Power, presented a methodology for calculating the deemed irrigation hardware measures. The methodology was approved by the RTF. The RTF included a suggestion that utilities should make appropriate adjustments to the inputs for calculating energy savings for unique service area characteristics. The RTF's decision stated that the deemed irrigation measures should be reviewed in 13 months. At the RTF meeting on January 5, 2010, Rocky Mountain Power announced they were conducting an evaluation of savings from its irrigation hardware program and that information will be available from the Idaho market. Idaho Power is waiting for the results of this evaluation before designing additional evaluation. Idaho Power is considering partnering with an Idaho university to further evaluate and test irrigation equipment that will aid in determining individual measure savings.

In 2010, Idaho Power contracted with The Cadmus Group, Inc., to provide a process evaluation of the Irrigation Efficiency Rewards program. This evaluation included a program data review, program logic model, internal customer survey evaluation, industry best practices comparison, conclusions, and recommendations. The final report was received in February 2011 and noted that this is "a robust, ambitious, and leading-edge irrigation program," and that the program has "strong relationships with customers and trade allies, credibility, and high demand." Recommendations for program improvement included the need to conduct additional surveys to provide on-going data regarding program satisfaction, operation, and market trends. It was also recommended that Idaho Power consider expanding outreach and assistance efforts to capitalize on the technical strength of a "well-trained" Idaho Power program staff. Idaho Power is currently analyzing all recommendations. Any program changes made in 2011 will be highlighted in the *Demand-Side Management 2011 Annual Report*. The complete report is provided in *Supplement 2: Evaluation*.

2011 Strategies

Marketing plans for 2011 include conducting three to five customer-based irrigation workshops and three to five training sessions for irrigation dealers and manufacturers. These workshops and training sessions enable discussions between Idaho Power representatives, the company's customers, and irrigation dealers, while continually educating them about the program and ways to participate. Each year, workshops are conducted in different local areas. Subjects and presentations are updated to offer new ideas.

Idaho Power is also reviewing the program with input from customers regarding other energy-saving measures that can be offered in the Menu Incentive Option. It is also planned to further review information provided by the RTF and other research to make improvements to the program.

Final reports from The Cadmus Group's, Inc., 2010 process evaluations were received in February 2011. All viable process recommendations will be considered and prioritized for implementation in 2011. Process changes implemented in 2011 will be highlighted in the *Demand-Side Management 2011 Annual Report*.

Irrigation Peak Rewards

	2010	2009
Participation and Savings		
Participants (service points)	2,038	1,512
Energy Savings (kWh)	n/a	n/a
Demand Reduction (MW)	249.7	160
Program Costs by Funding Source		
Idaho Energy Efficiency Rider	$13,096,946	$9,131,929
Oregon Energy Efficiency Rider	$184,075	$451,673
Idaho Power Funds	$49,805	$71,681
Total Program Costs—All Sources	$13,330,826	$9,655,283
Program Levelized Costs		
Utility Levelized Cost ($/kWh)	n/a	n/a
Total Resource Benefit/Cost Ratio	n/a	n/a
Program Life Benefit/Cost Ratios		
Utility Benefit/Cost Ratio	1.43	
Total Resource Benefit/Cost Ratio	1.37	
Program Characteristics		
Program Jurisdiction	Idaho/Oregon	
Program Inception	2004	

Description

Idaho Power's Irrigation Peak Rewards program is a voluntary program available to all Idaho and Oregon agricultural irrigation customers. The purpose of the program is to produce a decrease in the company's system summer peak by turning off specified irrigation pumps with the use of one or more load control devices during the program season June 15 through August 15.

Idaho Power has operated its Irrigation Peak Rewards program since starting with a pilot program in 2004. Since that time, Idaho Power has made changes to the program many times with the largest change being the dispatch option that was added before the 2009 irrigation season.

In 2010, the program was active from June 15 to August 15. All Idaho Power irrigation customers taking service under Schedule 24 in both Idaho and Oregon were eligible and participants chose between three options: 1) the Electric Timer Option, 2) an Automatic Dispatch Option that allows Idaho Power to remotely turn participants' pumps off, or 3) a Manual Dispatch Option designed for large service locations with 1,000 hp or greater that allows participating customers, after being notified by Idaho Power, to choose which pumps to manually turn off during summer peak hours.

Participants in the Electronic Timer Option can choose to have all irrigation pumps on a single, metered service point turned off one, two, or three times per week. Interruptions occur from 4:00 p.m. to 8:00 p.m., and Idaho Power determines the specific weekday or weekdays to schedule the interruption of all pumps at each service point. Installation fees between $250 and $500 are applied to participating service locations less than 75 hp.

For customers participating in the dispatch options, load control events could occur up to four hours per day, up to 15 hours per week, but no more than 60 hours per season. For 2010, dispatchable load control events could happen between 1:00 p.m. and 8:00 p.m. on weekdays and Saturday. A control device attached to the customer's individual pump electrical panels allows Idaho Power to remotely control the pumps. Installation fees between $500 and $1,000 were applied to participating service points with less than 30 hp.

A customer's incentive appeared as a bill credit that sums the demand credit and energy credit applied to a customer's monthly bills. Credits are prorated for periods when reading/billing cycles do not align with the program season dates from June 15 to August 15. All customer incentives participating in the Electric Timer, Automatic Dispatch, or Manual Dispatch Options are calculated using Idaho Power meter billing data. In addition, manual option customers' incentives are calculated using interval metering data. The demand credit is calculated by multiplying the monthly billing kW by the demand-related incentive amount for the interruption option selected by the customer. The energy credit is calculated by multiplying the monthly billing kWh usage by the energy related incentive amount for the interruption option selected by the customer. Installation fees and opt-out penalties are completed through manual bill adjustments. Incentives determined from interval meter data for service points classified as large service locations are completed through a manual process and customers received the incentives in the form of a check in 2010. Incentives offered are listed in Table 10.

Table 10. Option incentives

Option	Demand Credit ($ per billing kW)		Energy Credit ($ per billing kWh)
Timer Option Incentives			
One day	$3.15		
Two days	$4.65	plus	$0.002
Three days	$4.65	plus	$0.007
Automatic & Manual Dispatch Options Incentives	$4.65	plus	$0.031

Under the rules of the Automatic and Manual Dispatch Options, participants have the ability to opt out of dispatch events five times per service point. Each opt-out incurs a fee of $0.005 per kWh based in the current month's billing kWh, which may be pro-rated to correspond with the dates of program operation and are completed through manual bill adjustments.

2010 Activities

In 2010 most of the challenges surrounding the dispatch devices and communications that occurred in the prior year were resolved, working with Idaho Power's third-party contractor. This resulted in the Irrigation Peak Rewards dispatch load control system working much better. In 2010, the program achieved a maximum peak load reduction of approximately 249.7 MW. This represents a 38 percent increase from 2009. Participation has been very good with this program. Of all eligible irrigation service locations, approximately 11 percent are participating in the program. In 2010, there were 2,038 metered service points enrolled in the program. Of the 2,038 enrolled service points, approximately 14 percent were enrolled in the Electric Timer Option and 86 percent were enrolled in the Automatic and Manual Dispatch Options.

Changes in 2010 included moving the program season from June 1–July 31, to June 15–August 15. Additionally, the days of the week the program can be activated was extended to include Saturdays.

These changes were made to help align the program availability to better match Idaho Power's system peaks.

Idaho Power attempted to distribute the Electric Timer Option participating service points evenly throughout each weekday, based on cumulative demand reduction potential. However, due to service point size variability, enrollment requests by customers, enrollment opt-outs, and other variables, the load reduction could not be exactly balanced. All participants in the Automatic and Manual Dispatch Options were grouped into five regional areas to be dispatched on each scheduled event day. Table 11 shows the MW reduction achieved daily on a week-by-week basis.

Table 11. Total program daily MW reduction without distribution losses using realization rates

	Monday	Tuesday	Wednesday	Thursday	Friday
June 15–18	0.7	0.8	0.9	0.8	0.7
June 21–25	0.7	0.8	0.9	0.8	0.7
June 28–July 2	7.0	192.4[a]	8.9	7.5	7.3
July 5–9	7.0	8.5	8.9	7.5	221.0
July 12–16	7.0	8.5	8.9	7.5	7.3
July 19–23	6.2	7.5	7.8	6.6	6.4
July 26–30	6.2	7.5	7.8	6.6	6.4
August 2–6	3.5	4.2	4.4	143.2	3.6
August 9–13	3.5	4.2	4.4	3.8	3.6

[a] Shaded cells are days when dispatch events occurred.

Idaho Power continued to market the program by varying the location of workshops and offering new presentations to irrigation customers. In 2010, Idaho Power provided six workshops promoting the Irrigation Peak Rewards program throughout the service area. Approximately 180 customers attended workshops in Blackfoot, Aberdeen, Burley, Twin Falls, Grand View, and Nampa. Idaho Power also accepted invitations to present the program at four workshops sponsored by agricultural groups in Fairfield, Shoshone, Nampa, and Jackpot, Nevada. Exhibitor booths were also displayed at regional agricultural trade shows, including the Eastern and Western Idaho Agriculture Expos, the Agri Action Ag show, the Idaho Ag Summit, and the Idaho Irrigation Equipment Association show and conference.

In February 2010, a customer mailing was sent to all eligible Idaho Power irrigation customers with at least one service point over 30 hp. The mailing included a program explanation, a program application, the program's incentive structure, a listing of the customer's eligible service points, and a potential incentive estimate for each program option based on the customer's 2009 usage. A second mailing of the program brochure was sent to all eligible customers with pumps under 30 hp. These customers with less than 30 hp are less likely to participate because of the installation fees resulting in multi-year payback from the incentive. If these customers had a desire to participate, all additional information including application and contract agreement was mailed to them at their request. Additionally, numerous one-on-one conversation with Idaho Power agriculture representatives familiarized customers with the new technology and program details.

Based on the results of the 2009 Irrigation Peak Rewards customer survey, process improvement changes implemented in 2010 included redesigning the program application and rewriting the program brochure to clarify the program information. The 2010 application worksheet was expanded to contain actual incentives received for participating service points with the corresponding previous year's

enrollment option. Customers who participated in 2009 were automatically re-enrolled at their option for the 2010 season.

In addition, Manual Dispatch Option customers received their incentives in the form of a check in 2010. This payment process change limited errors and customer confusion in 2010.

Cost-Effectiveness

Although the B/C analysis for the Irrigation Peak Rewards program is based on a 20-year model, the company also tracks cost-effectiveness on an annual basis. Both calculations use financial and DSM alternative costs assumptions from the IRP. As published in the 2009 IRP, for peaking alternatives, such as demand response programs, a 170 MW SCCT is used as the alternative resource for avoided cost. Idaho Power's cost-effectiveness model representing the program over a 20-year period is updated annually with actual benefits and costs. The benefits are based on peak reduction and shifted energy use. In 2010, the company included an estimate of customer costs in the cost-effective analysis. This change in inputs made the UC and TRC ratios differ. Updating the cost-effectiveness model in 2010 resulted in a UC B/C ratio of 1.43 from the 20-year perspective and 1.14 for 2010. The UC B/C ratio is 1.37 from the 20-year perspective and 1.12 for 2010. For details on the cost-effectiveness assumptions, see *Supplement 1: Cost-Effectiveness.*

Customer Satisfaction and Evaluations

In 2010, Idaho Power conducted a review of the Irrigation Peak Rewards in an effort to ensure the program's design was aligned with the resource needs identified by the IRP. Analysts and engineers from Idaho Power's Customer Relations & Energy Efficiency, Power Supply Planning, and Load Forecasting departments conducted this review. Based on this review, Idaho Power determined there is an optimum amount of demand response that can be effectively used on Idaho Power's system and there is a more economical way of paying for the program.

2011 Strategies

Substantial program changes have been proposed by Idaho Power and were filed with the IPUC on December 10, 2010, under Case No. IPUC IPC-E-10-46 and the OPUC on January 7, 2011, under Advice No. 11-01. These program modifications are a result of Idaho Power's internal review and input from the Idaho Irrigation Pumpers Associations, Integrated Resource Plan Advisory Council (IRPAC), and the EEAG.

Seven program changes are proposed for 2011 implementation:

- Change the incentive structure to a fixed and variable payment that pays customers a portion of their incentive for participating and a portion of their incentive based on how much the company uses the program.
- Include one program event in the fixed portion of the payment.
- Allow the company to pay the variable portion of the incentive through a check at the end of the season.
- Require participants in the Manual Dispatch Option (>1000 hp) to nominate the amount of kW they are enrolling in the program.

- Change the baseline calculation for the Manual Dispatch Option from maximum demand in 24 hours prior to the average demand between 10:00 p.m. and 11:00 a.m. prior to an event.

- Modify the opt-out penalty for the program to $1 per kW per opt-out.

- Add the 8:00 p.m. to 9:00 p.m. hour as an option that customers can sign up for that pays a higher variable incentive.

Marketing plans for 2011 will be to maintain customer participation through what will likely be a transition year from the past incentive structure to the proposed structure if state regulators approve Idaho Power's proposed changes. Idaho Power will continue to educate customers on the program, through workshops and agriculture shows, though may have to limit participation levels to near current levels, based on the overall need for demand response as a resource to meet future loads.

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 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. 2010 was the first year of NEEA's new, five-year plan. Thus, it was a year of realignment and expansion.

NEEA performs several Market Progress Evaluation Reports (MPER) on various energy efficiency efforts each year. In addition to the MPERs, NEEA provides market research reports for energy efficiency initiatives throughout the Pacific Northwest. Each of the reports applicable to Idaho is included in the *NEEA Market Effects Evaluations* in *Supplement 2: Evaluation*.

In 2010, Idaho Power energy efficiency staff attended advisory meetings, served on sub-committees, attended the first-ever conference in Seattle, Washington, and participated in NEEA sponsored studies and research.

NEEA Activities

Commercial and Industrial NEEA Activities in Idaho

NEEA continued to provide support for commercial energy efficient activities in Idaho in 2010. This included partial funding of the IDL in Boise and local BetterBricks® trainings and workshops. Idaho Power's commercial sector programs, Building Efficiency and Easy Upgrades, are designed to leverage NEEA, BetterBricks, and the IDL in Boise activities.

In the industrial sector, NEEA expanded the Continuous Energy Improvement (CEI) efforts to the small-to-medium-sized businesses, defined as less than 250 employees per site. CEI is a multi-year strategic effort designed to improve energy efficiency in the industrial sector. Prior CEI efforts focused on two regional industries considered heavy energy users, 1) the food processing and 2) the pulp and paper industries. Participants achieve cost savings through the adoption of energy-efficient business practices. CEI provides expert support, resources, and services, supplying companies with the training and tools for making energy efficiency a core business value. This effort is supported by providing technical knowledge to organizations and to Idaho Power customers collaborating on energy efficiency implementation.

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. Ten technical training classes were completed in 2010. Topics included compressed air, chilled water systems, pumping systems, variable frequency drives, and refrigeration. The level of attendance at these classes remains high with 234 customers attending the workshops.

A program specialist for the Custom Efficiency program attended two NEAA-sponsored trainings for The Northwest Energy Management Demonstration Pilot Project. The specialist served as a utility support, while gathering information regarding the pending energy-management standard.

The NEEA is partnering with the US DOE to conduct the Northwest Energy Management Demonstration project (NW EM Demo), an energy management pilot for industrial companies. One of Idaho Power's large customers is one of the four companies participating in the pilot. The goal of the project is for participants in the project to help shape the new US energy-management system standard through their experiences and may play a role refining the pending global energy management standard for participating industrial companies. Key findings from the NW EM Demo may help inform the new ISO 50001 International Energy Management Standard for industry, which may impact how companies worldwide manage energy.

Residential NEEA Activities in Idaho

NEEA's Residential Advisory Committee is comprised of representatives from various utilities, the BPA, NEEA staff, and occasional representatives from program partner firms and consultants. The committee meets quarterly to discuss upcoming projects, potential programs, and initiatives.

The residential programs leader usually attends this meeting or sends a residential team member when topics warrant staff participation. These meetings are a useful mechanism for networking with other utility peers, getting updates on regional activities and similar utility program efforts, and providing feedback to NEEA to use in their planning efforts.

NEEA continues to provide support for the ENERGY STAR® Homes Northwest program offered by Idaho Power. NEEA offers technical assistance, funding for certifications, and builder and market support.

In 2009, NEEA launched a Consumer Electronics Initiative. Idaho Power contributed $160,000 to this multi-year effort, which included manufacturer support and consumer marketing for ENERGY STAR televisions that are 30 percent more efficient than baseline ENERGY STAR models. Computer monitors and desktop computers were included in the program in 2010. In 2010 and beyond, the funding for the Initiative is provided by NEEA's multiple Northwest utilities partners' general funding. Eligible models and point-of-purchase marketing collateral were placed in Idaho Power's service area.
NEEA representatives throughout 2010 conducted in-store training of sales staff. Energy savings are being tracked by NEEA, and 2010 data will be available the mid-year 2011.

In 2010, NEEA conducted a series of focus groups around the Northwest, including Boise, to help develop the most effective marketing message. With the results, a new marketing campaign , Energy Forward was developed by NEEA to highlight that the products with the designated Energy Forward are the most advanced energy-saving products available. New point-of-purchase marketing materials were created and placed on qualifying units by NEEA representatives throughout the Northwest. A new website was created to describe the campaign: http://www.energyefficientelectronics.org.

Idaho Power also participated in a NEEA-sponsored DHP study in 2009. The first MPER on the DHP Pilot became available in 2010. Detailed information about this project is provided in the DHP Pilot description in this *Demand-Side Management 2010 Annual Report*.

In December 2010, Idaho Power program specialists, analysts, and leadership attended the Efficiency Connections Northwest conference in Seattle, Washington. This conference was created by the region's utilities and NEEA with the goal to advance energy efficiency awareness and its integration in the Northwest. Topics at the conference included methods to promote energy efficiency, increasing collaboration between utilities, new and emerging technologies, market transformation, and energy codes.

During 2010, the Idaho Power DHP Pilot program specialist participated in the monthly Web-based seminar conferences held by NEEA. The goal of the Web-based seminar was to update the Northwest utilities participating in the DHP incentive program. Topics included year-to-date updates on the number of incentives paid, NEEA marketing strategies for the program, QA evaluations, contractor performance, energy evaluation plans, and general feedback from the utilities.

Other NEEA Activities in Idaho

Each year, NEEA underwrites the Idaho Energy Conference through a contract with the Association of Idaho Cities. In addition, in 2010 NEEA provided $25,000 in support to the IDL in Boise, which provides energy consulting services to commercial customers throughout Idaho Power's service area.

The Residential Energy Efficiency Education Initiative specialist represented Idaho Power on the NEEA Conduit Online Community Steering Team in 2010. Conduit (www.conduitnw.org) will be an online resource to facilitate information sharing, coordination, and collaboration among energy efficiency professionals in the Northwest. Pilot testing is targeted for March 2011. Idaho Power is involved in this testing. Conduit is slated for a general launch in May 2011.

Idaho Power's customer research and analyst leader is an active participant in NEEA's Cost-Effectiveness Advisory Committee. This committee meets three to four times a year to review NEEA cost-effectiveness models, assumptions, and, ultimately, energy-savings estimates. Idaho Power's energy efficiency analyst participates in NEEA's Northwest Research Group. This group meets throughout the year to catalogue and coordinate energy efficiency research projects regionally.

NEEA Funding

In 2010, Idaho Power began the first year of the 2010–2014 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 2010, 100 percent was funded through the Idaho and Oregon Riders.

In 2010, Idaho Power paid $2,391,217 to NEEA. The Idaho jurisdictional share of the payments was $2,271,656, while $119,561 was paid for the Oregon jurisdiction. Other expenses associated with NEEA activities, such as administration and travel, were paid by Idaho Power.

Preliminary estimates reported by NEEA indicate that Idaho Power's share of regional market transformation MWh savings for 2010 is 15,334 MWh, or 1.8 aMW. Idaho Power relies on NEEA to report the energy savings and other benefits of NEEA's regional portfolio of initiatives. For further information about NEEA, visit their website at www.nwalliance.org.

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OTHER PROGRAMS AND ACTIVITIES

Residential Energy Efficiency Education Initiative

Idaho Power recognizes the value of general energy efficiency awareness and education in creating behavior change and customer demand for, and satisfaction with, its programs. The Residential Energy Efficiency Education Initiative's goal is promoting energy efficiency to the residential community sector. This goal is achieved by creating and delivering educational programs that increase Idaho Power's energy efficiency program participation and result in energy efficient and conservation-oriented behaviors and choices.

The Residential Energy Efficiency Education Initiative distributed energy efficiency messages through a variety of communication methods during 2010. Increased customer awareness of energy-saving ideas was accomplished via distribution of approximately 8,750 copies of the 96-page book *30 Simple Things You Can Do To Save Energy*, a joint publishing project between Idaho Power and The Earthworks Group. The book was updated and reprinted. Searchable versions of both the English and Spanish texts were uploaded to Idaho Power's website during 2010. Customers may now also download or request hard copies of the book via the Web.

Through August of 2010, Idaho Power continued to provide weekly energy efficiency messages each Saturday morning on The HomeFix Show with Joe Prin on 670 KBIO AM. Additionally, energy efficiency messages aired on KBSU radio through February and March.

In May, Idaho Power launched a new educational project partnership with the Idaho Commission for Libraries, Avista, and Rocky Mountain Power. The three utilities worked together to make Energy Efficiency Kits available to all Idaho residents through the public library checkout system. Idaho Power customers represent 60 percent of the population served. There were 245 kits sent to 140 public libraries. The kits contain a Kill A Watt™ Meter, instructions, and energy-saving tips. Based on the first two quarterly reports, with 71 percent and 89 percent of jurisdictions reporting respectively, Idaho Power customers represented 80 percent of the total circulation with 546 checkouts. When library staff members were asked to estimate the satisfaction of their customers, the majority of the responses were positive with 18 percent indicating "very satisfied" and 76 percent indicating "satisfied."

In addition to these activities, Idaho Power was one of the sponsors of the third annual Idaho Green Expo in May. As part of Idaho Power's commitment to the Expo, the company distributed 5,000 re-usable shopping bags with the message "Reduce Your Use" to the more than 8,500 people who attended the 2010 Expo. Idaho Power's educational emphasis this year at the Expo was about *ENERGY Tools*, a full-featured suite of energy efficiency tools available on the company's website. Participants who visited the booth had the opportunity to sign up for *Account Manager* and view near-real-time data of the energy use in their homes. This prompted personal discussion about how individual attendees could reduce their consumption and gave Idaho Power employees the opportunity to introduce the myriad of available tools, such as the Energy Library, Energy Calculators, Home Audit, and other customer resources. The message was well-received. Idaho Power staff at the booth interacted with just over 7 percent of all attendees. *Account Manager* sign-ups for the Expo weekend were up 37 percent and 53 percent, respectively, from the two weekends just prior to the Expo. Moreover, the seven-day period beginning May 8 showed a 23 percent increase in signups over the seven-day period beginning May 1. Idaho Power presented three educational workshops at this event 1) Smart Meters = Smarter Idaho, 2) Renewable Energy for Your Home or Business, and 3) Building Your Home Energy Plan. The company also participated on a residential panel that presented

Building a Greener Idaho. Lastly, Idaho Power partnered with GreenWorks Idaho to develop and administer an exit survey. Information collected about Green Expo attendees centered primarily on why they attended the show. There were 318 surveys completed. The Green Expo participant profiles will be used to improve messaging and goals and increase Idaho Power's return-on-investment for future sponsorship of this event. It will also establish a baseline so Idaho Power can begin to track trends among Green Expo attendees and the population they represent over time. Although 36 percent of the respondents reported having participated in an energy efficiency program and/or A/C Cool Credit, this behavior ranked seventh out of the eight sustainable practices surveyed.

In September 2010, Idaho Power participated in the St. Luke's Women's Show for the third consecutive year. The event was important due to the size of the audience and because its demographic component aligned with Idaho Power's residential energy efficiency target audience. However, the nature of the show did not allow for the desired depth of interaction as in past years. In 2010, Idaho Power focused on drawing participants into the booth to complete an in-depth survey, providing Idaho Power with participant profiles and key market data. The company collected 496 completed surveys, exceeding the goal of 400. Idaho Power plans on refining the survey for this event in upcoming years and using it to inform Idaho Power's educational efforts, program marketing activities, and program design.

Key findings were 13 percent of those surveyed stopped at the booth to learn about energy efficiency, 9 percent said they stopped to learn about Idaho Power's programs, and 4 percent said they stopped to ask a question of the Idaho Power employees at the booth.

Respondents were asked if they had installed or replaced various equipment in their homes in the past three years. Forty percent of respondents said they had replaced a clothes washer, 37 percent a refrigerator, and 30 percent a dishwasher. They were also asked a series of demographic questions like whether they pay the electricity bill at home, what role they play in purchasing or upgrade decisions at their home, whether they own or rent their home, and their gender, age, and education levels.

Idaho Power further increased its energy efficiency presence in the community by providing program information at 116 special events. As part of process improvement accomplishments, the Outreach Tracking System was implemented during the second quarter of the year. It captured details of a variety of outreach activities and requests.

Field staff throughout Idaho Power's service area gave dozens of energy efficiency presentations. The Customer Relations and Energy Efficiency department provided 20 presentations on Idaho Power's energy efficiency programs and energy saving ideas to businesses, schools, and community organizations. The Power to Make a Difference program was delivered 98 times in public schools and 10 times for various civic groups.

Seven of these presentations were part of the 2010 Energy Efficiency & Green Living Series. This series was re-designed to improve the return on investment. Fewer topics were presented at more locations. The residential program specialist along with other program specialists presented content. Publicity was conducted primarily via the Internet and posters/fliers distributed at the venues. In addition to the Boise Public Library, sessions were conducted at the Meridian, Eagle, and Ada Community Libraries. In Twin Falls, the College of Southern Idaho's Sustainability Council hosted two sessions at the College of Southern Idaho. This year's topics were titled *Simple Changes Make Cents: Tips, Tricks & Tools to Reduce Electricity Bills*, and *Get Ready, Get Set, Go: Powering Homes with Alternative Energy*.

The seven sessions combined attracted 135 participants. The Residential Energy Efficiency Education Initiative collected participant evaluations at the 2010 Energy Efficiency & Green Living Series. The survey return rate was 69 percent, with 93 participants completing a survey following the presentations.

Overall, 79 percent of attendees "strongly agree" the information presented was useful, and 66 percent "strongly agree" the information presented met their expectations. Fifty-six percent said they "definitely would" and 44 percent said they "probably would" recommend the session to a friend or family member. Sixty percent said they "very likely" would attend future Energy Efficiency and Green Living Series presentations, and 36 percent said they are "somewhat likely" to attend future presentations. When asked what topic they "would attend" the future, 61 percent responded renewable energy; 49 percent responded landscaping for energy efficiency; 44 percent said Idaho Power rebates and incentive programs; 43 percent said energy-efficient window coverings; and 41 percent said energy efficiency for older homes. Comments related to what actions they would take as a result of attending the session included more energy awareness, changing existing light bulbs, making other home improvements, exploring solar energy options, and looking for ways to better educate themselves.

The Residential Energy Efficiency Education Initiative continued to provide energy efficiency tips in response to media inquiries and for various Idaho Power publications, such as the *Green Power Newsletter*, the A*/C Cool Credit Newsletter*, *Customer Connection*, the high bill/tiered rate customer letters, the AMI door hangers, and *News Scans*.

Idaho Power sponsored two general education efforts during the year. The first was the publication of the 2010 Energy Efficiency insert for use in *The Idaho Statesman* in June. The insert presented Idaho Power's Energy Efficiency Programs, introduced the SEE program and the Kill A Watt Meter program, discussed the reasons why energy efficiency is important, and offered energy efficiency tips regarding choosing a contractor and dealing with the summer heat. It also emphasized *ENERGY Tools* and energy use data available through *Account Manager* as a result of the smart meter installations. The second campaign began in late November and early December. It promoted Energy Efficient Gift Giving ideas through various print media and bill inserts to help educate people regarding considerations when purchasing electronics for their homes.

Idaho Power frequently made additional educational presentations about energy efficiency, Idaho Power programs, and energy efficiency tips. The company created an energy efficiency presentation to educate students about the efficient use of energy in their homes. The program targets fourth- to sixth-grade student audiences. During 2010, the Idaho Power community education team presented *The Power to Make a Difference* in 103 classrooms across the service area. Idaho Power is planning to continue making revisions and improvements to the presentation.

Also during 2010, Idaho Power community education conducted 42 presentations and programs regarding energy efficiency to senior centers and civic groups within the company's service area. *The Power to Make a Difference* presentation demonstrated the importance of energy efficiency in the community. The other component of educational outreach was reviewing energy efficiency program options as well as low- and no-cost ways for customers to save energy and money in their homes or businesses.

In 2010, Idaho Power contracted with Global Energy Partners, LLC, to provide a process evaluation of the Residential Energy Efficiency Education Initiative. This evaluation included a program data review, program logic model, internal customer survey evaluation, industry best practices comparison, conclusions, and recommendations. The final report was received in February 2011 and found that the

program "conducted a wide variety of marketing and outreach to residential customers," and "is well received by the customers reached." Recommendations for program improvement included the need for prioritization of desired behavior changes and the need to gather additional data to enhance the measurement of success of activities the program undertakes. The results of the evaluation are in *Supplement 2: Evaluation*.

The company is currently analyzing other recommendations made by the consultants for possible future implementation. Program changes made in 2011 will be highlighted in the *Demand-Side Management 2011 Annual Report*.

During 2011, the initiative's goals are to increase program participation and promote education and energy-saving ideas that result in energy-efficient and conservation-oriented behaviors and choices. Plans for 2011 include working with other Idaho Power program specialists and participating contractors to distribute the book *30 Simple Things You Can Do To Save Energy* to program participants when energy efficiency upgrades are made. Idaho Power will continue the partnership with the Idaho Commission for Libraries, Avista, and PacifiCorp to provide Kill A Watt Meters to libraries throughout Idaho for lending to library patrons and will work with the libraries to establish another distribution channel for *30 Simple Things You Can Do To Save Energy*. Stand-alone energy efficiency education tools, such as newsletter fillers, public service announcements, and one-page discussion starters will be developed and marketed to sustainably-minded businesses and organizations. Contacts will be made with high schools and other educational institutions to see what additional opportunities there may be to provide energy efficiency education and materials for students. The Residential Energy Efficiency Initiative will continue to develop the Outreach Tracking System to improve the quality of data captured and to continue to increase the effectiveness of outreach efforts.

Easy Savings® Program

As a result of IPUC Order No. 30772, Idaho Power committed to fund energy efficiency education for customers receiving energy assistance through the federal LIHEAP. Case No. IPC E-08-10 specified that $125,000 be paid to CAP agencies in the Idaho Power service area on a pro-rated basis. In addition, the target for the educational information is qualified families who heat their homes with electricity provided by Idaho Power. As in 2009, CAPAI, signed a contract with Resource Action Programs (RAP) for provision of the Easy Savings® Program in 2010.

Two main desired outcomes of the Easy Savings Program are to educate recipients about saving energy in their homes to reduce energy usage and to allow hands-on experience installing low-cost measures.

The primary target for the program is households qualifying for energy assistance who do not contain household members who meet criteria for weatherization prioritization. The criteria for a household prioritized for weatherization services include elderly, disabled individuals, and families with children.

The Easy Savings Program provides a kit containing low-cost/no-cost energy-saving items to customers qualifying to receive a LIHEAP benefit on their Idaho Power bill. Kit items include the following:

- CFLs
- 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 and stickers for the laundry and lights
- *Quick Start Guide* to installation (printed in English and Spanish)
- Educational materials and information on Idaho Power energy efficiency programs
- Easy Savings Survey (printed in Spanish and English)

In 2010, payments totaling $125,000 were sent to regional CAP agency executive directors by Idaho Power. The agencies are allowed to keep 10 percent of their portion of the $125,000 to cover expenses for additional time spent on the Easy Savings Program.

Kits were delivered to CAPAI prior to January 2010. Throughout the year, 2,594 kits were distributed to Idaho Power customers approved to receive energy assistance benefits on their Idaho Power bills.

A participant survey inquiring about installation experiences and actions taken to reduce energy use was included in the kits during 2010. Tracking was done via kit/survey numbering system. Returned surveys were used to track educational impact of the program. A drawing from all returned surveys was held and six families won a $100 gift certificate each, provided by CAPAI.

Of the 2,594 surveys distributed, 273 completed surveys were received back from customers describing their experience installing kit items in their homes, resulting in a 10.5 percent response rate. Nine questions referred to the customer taking a suggested action to reduce energy use, and two other questions confirming installation of kit items.

Overall, survey results show that over 64 percent of the customers who received the kits and returned a survey installed five or more kit items. Over 76 percent of the 268 families answering the question "How much have you learned about saving energy and money in your home?" reported "I learned a lot."

Survey results indicated that 256 families reported recycling or unplugging a second or old refrigerator or freezer. Information about how to apply for a rebate from Idaho Power's See ya later, refrigerator® program was included in kit.

Additionally, 258 families reported they lowered, or will lower, their heat during the day and at night. Other energy efficiency actions taken by participants include 247 families who reported installing both CFLs and the 231 families who reported installing the high-efficiency showerhead included in the kit. Most families reported adjusting water, refrigerator, or freezer temperature as suggested by the *Quick Start Guide*. Copies of the survey and survey results can be found in *Supplement 2: Evaluation*.

In November 2010, CAPAI signed an agreement with RAP to provide 2,127 energy kits for the 2011 program. The kits will be delivered to the CAPAI warehouse before January 2011 for distribution to each agency and to qualified Idaho Power customers throughout the year.

In 2011, each agency will retain 30 percent of their portion of the $125,000 to be used to help pay the salary of a certified educator, as agreed upon by Idaho Power and the CAPAI agencies. Educators from each CAP agency will complete the Home Energy Conservation Certification curriculum taught by CAPAI's Energy Programs coordinator prior to distributing kits to customers. The 2011 program allows agencies 30 percent of the total funds as opposed to the 2010 program, which allowed 10 percent.

Educators in regional agencies will distribute kits and conduct seminars for targeted recipients in order to have all kits distributed prior to the upcoming heating season in the fall.

Continuing in 2011, customers will be encouraged to return the surveys included in the kits in order to be entered into a drawing for prizes provided by CAPAI.

Commercial Education Initiative

Idaho Power continued to enhance its Commercial Education Initiative, established in 2008. The main objectives are to inform and educate commercial customers regarding energy efficiency, enhance awareness and increase participation in existing commercial energy efficiency and demand response programs, and enhance customer satisfaction regarding the company's energy efficiency initiatives. To accomplish these objectives, the program specialist works in tandem with Idaho Power customer representatives assigned to commercial market segments to capitalize on their established strategic customer relationships.

The program specialist oversees the distribution of informational materials and works directly with trade allies, who in turn support and promote Idaho Power's energy efficiency programs. Additionally, the program specialist routinely conducts individual site visits in an effort to customize energy efficiency recommendations for individual customers or customer segment. Site visits also serve as field and staff training opportunities for future site visits.

In 2010, Idaho Power implemented the use of the Equipment Efficiency Specification Sheets developed by the company in 2009 for customer use. The information contained on these specification sheets focus on common commercial facility equipment and energy efficiency opportunities.

Idaho Power carried out its plan to capitalize on effective customer projects by creating success stories that highlight customers' energy efficiency projects. Nineteen customer *Success Stories* were added in 2010 to the Custom Efficiency webpage on the Idaho Power website at www.idahopower.com/EnergyEfficiency/Business/Programs/CustomEfficiency/customEfficiency_SuccessStories.cfm and are included in *Supplement 2: Evaluation*.

Also in 2010, Idaho Power developed Energy Efficiency Tip Sheets for use by commercial customers. These tip sheets provide standardized energy efficiency recommendations tailored to specific commercial market segments, which included restaurants, health care facilities, hotels, and grocery stores. Market segments were identified using the North American Industry Classification System's Standard Industrial Classification (SIC) codes for each segment. Informational materials, including the health care, hotel, and grocery tip sheets were given to customers during site visits. The restaurant tip sheet was used in a mass mailing to over 2,100 customer locations. Because of the low return for the cost required to do target mailings, distribution of the other three target pieces will be done through site visits and customer request for information.

By year-end, the Commercial Education Initiative staff performed a total of 96 walkthrough evaluations, contractor visits, and presentations to municipalities and professional groups. Idaho Power provided input and funding for 48 presentations and training sessions, in collaboration with the IDL in Boise.

Another important part of the education initiative is identifying challenges in the delivery of efficiency education messages to commercial customers. A newly emerging challenge has been locating appropriate audiences. As the industry matures, audiences needing energy information are not readily identifiable. The accessibility to receptive audiences has become much more difficult over the past few

years. Two years ago, almost any energy topic presentation appropriately marketed was well attended. In 2010, there were energy efficiency presentations and trainings offered industry-wide with limited new content, provided to audiences knowledgeable about energy efficiency. Often, attendees were energy efficiency authorities or established contractors. In most presentations and trainings in 2010, knowledgeable and experienced attendees outnumbered the audience needing energy efficiency ideas and practices.

A possible solution for locating untapped markets in need of energy efficiency training was identified through interactions with another organization that Idaho Power collaborated with in 2010. Idaho Power conducted a joint presentation/training in McCall in 2010 with the Snake River Alliance (SRA). This well-attended event generated numerous requests for information and services. The SRA targets smaller markets where training and resources are less available. They identified participant fatigue as an issue, which plagues other organizations concerned with efficiency information and training. Because of the event, a potential market emerged; the smaller commercial markets in rural areas. Another use of the smaller market approach in 2010 was an Idaho Power presentation for the Idaho Commission for Libraries, resulting in high attendance and further requests for information and services.

Idaho Power contracted with The Cadmus Group, Inc. to provide a process evaluation of the Commercial Education Initiative. This evaluation included a program data review, program logic model, internal customer survey evaluation, industry best practices comparison, conclusions, and recommendations. The final report was received in February 2011. The report noted that this initiative provides valuable educational and technical services to commercial customers and supports many of the programs in Idaho Power's commercial/industrial portfolio. Recommendations for program improvement included the need to have more clearly defined goals, update marketing materials, enhance program tracking capabilities, and gather customer feedback. Idaho Power is currently analyzing all recommendations. Program changes made in 2011 will be highlighted in the *Demand-Side Management 2011 Annual Report*. The complete report is provided in *Supplement 2: Evaluation*.

In 2011, the Commercial Education Initiative will seek future opportunities to assist small communities interested in learning more about energy efficiency. The initiative will continue to conduct site visits, use the Equipment Efficiency Specification Sheets, distribute target market information tip sheets, and present at professional meetings. Additionally, the initiative will continue to work with education programs. such as Boise State University's Small Business Development Center, supporting their efficiency evaluations for small businesses. Also in 2011, the initiative will provide consultation to energy efficiency education programs at local colleges, including College of Western Idaho and the College of Southern Idaho. A sixth tailored Energy Efficiency Tip Sheet, designed for schools, will be distributed in 2011, along with the other five tailored tip sheets providing standardized and specialized energy efficiency recommendations.

Final reports from The Cadmus Group's, Inc., 2010 process evaluations were received in February 2011. All viable process recommendations will be considered and prioritized for implementation in 2011. Process changes implemented in 2011 will be highlighted in the *Demand-Side Management 2011 Annual Report*.

Local Energy Efficiency Funds

The purpose of LEEF is to provide modest funding for short-term projects and activities that do not fit within other categories of energy efficiency programs, but that still provide energy savings or a defined benefit to the promotion of energy-efficient behaviors or activities.

In 2010, Idaho Power sponsored one LEEF project. A payment of $250 was made to the Idaho Conservation League (ICL) to sponsor 50 percent of the cost of a home audit and weatherization demonstration, in support of ICL's 10/10/10 energy efficiency initiative. The initiative was part of a national effort by conservation organizations to highlight global warming by sponsoring various demonstrations and activities on October 10, 2010. The day's events in Hailey, Idaho, included a public educational forum that Idaho Power personnel participated in and the home-audit demonstration.

Students for Energy Efficiency

Idaho Power created the SEE program in 2009. Idaho students participate in energy assessments of their schools and homes using science and math skills to evaluate and provide recommendations regarding energy improvements and energy efficiency. At numerous presentations, including EEAG, the success of this program has been praised.

There were two primary initiatives in 2010. The first one was a program for high school students. The project is designed as a "learning lab" where students gain a better understanding of energy, how it is measured, and how to use it more efficiently. The second initiative was an elementary program focused on sixth-grade students. Students receive a tool kit and exercises that the sixth graders work on in their classroom, as well as take-home exercises to work on with their families.

During the 2010–2011 school year, over 300 students are participating in the high school program, and over 6,500 students are participating in the elementary program.

The SEE program promotes targeted educational standards that reinforce the Idaho Department of Education Content Standards for Science. The four main topics addressed are: 1) defining energy, 2) identifying how energy is used, 3) describing energy measurement methods, and 4) determining how energy can be used more efficiently.

Schools participating in the SEE program provide benefits to their communities in the form of reduced energy use and reduced operating costs. Evaluations by program participants were conducted following the completion of the students' assessment reports, presentations, and participation.

During the summer of 2010, a review of the program activities for the 2009–2010 school year was conducted with the assistance of the SEE Community Advisory Group, participating teachers and students, Idaho Power's customer research and analysis leader, customer research coordinator, and energy efficiency evaluator. Teacher survey results, as compiled and analyzed by the customer research coordinator, indicate overwhelming approval and continued interest in the program.

The in-school training schedule was adjusted to include two training sessions per school. The first two-hour session introduces the program and the Crime Scene Investigation (CSI)/Energy Scene Investigation (ESI) concept to students; acquaints them with the equipment; and introduces concepts on assessing lighting, building envelope, plug and phantom loads, and energy usage per square foot. A second one-hour session assists students in analyzing and understanding energy assessment data they have collected; using the Easy Upgrades Calculator to determine current energy usage and potential energy and cost savings based on their recommendations; and determining report format and target audiences for presentations.

Presentations promoting the SEE program were made to the Idaho Science, Technology, Engineering and Mathematics (iSTEM) conference, the Idaho Environmental Education Association conference, and the Idaho Science Teachers Association conference.

The development of the SEE program followed the IPUC Order No. 30760, dated March 27, 2009, directing the use of a portion of the proceeds from 2007 sulfur dioxide (SO_2) emissions credits sold by Idaho Power. The order called for delivery of the energy education program for two years and a report summarizing the results. Idaho Power will produce the report following the close of the 2010–2011 school year.

Regional Technical Forum

The BPA and the Northwest Power and Conservation Council (NPCC) established the RTF in 1999. Since 2004, Idaho Power has supported the RTF by providing annual financial support, regularly attending monthly meetings, and participating in various subcommittees.

The forum's purpose is advising BPA, the NPCC, the region's utilities, and organizations, including NEEA and the ETO on technical matters related to energy efficiency and renewable-resources development. Activities include the development of standardized protocols for verifying and evaluating energy savings and tracking conservation and renewable resource goals. Providing feedback and suggestions for improving the effectiveness of regional energy efficiency and renewable resource development programs are additional activities of the RTF. The RTF also recommends a list of eligible conservation measures and the estimated savings associated with those measures. Idaho Power takes the information provided by the RTF into consideration when conducting research and analysis on new and current measures. The RTF meets 10–12 times annually to review and provide comments on analyses and other materials prepared by NPCC and BPA staff and RTF contractors. Idaho Power uses the savings estimate and calculations provided by the RTF when applicable to the Idaho climate zones and load characteristics.

In 2010, Idaho Power staff participated in all of the RTF's meetings and was involved in various subcommittees. Idaho Power has been involved in the ongoing Commercial Rooftop Unit Work Group (RTUG) subcommittee since 2007. Currently, nine sites in Idaho Power's service area have been metered since 2008 and is part of the nation's largest publically available rooftop unit data set. A commercial program specialist actively participates in the RTUG subcommittee meetings. The Idaho Power Irrigation sector specialists contributed to the irrigation measure analysis while on the Irrigation Hardware Subcommittee during 2009 and early 2010. An Idaho Power Custom Efficiency program specialist was solicited for the Grocery Refrigeration Subcommittee in 2010 and will remain on the subcommittee during 2011. Also in 2011, the H&CE Program specialist will participate on the Ground-Source Heat Pump Subcommittee.

Boise City Home Audit Project

The City of Boise received stimulus dollars via the US DOE Energy Efficiency Conservation Block Grant (EECBG). Idaho Power is partnering with the city to create a limited-term, residential energy audit project that will include installation of some low-cost energy-saving measures for 650 homes. The audits will identify larger efficiency needs. Homeowners will be provided information on programs that can assist them with the costs of implementing these additional measures, such as information on the City of Boise's Home Improvement Loan Program.

Idaho Power will design and manage the project, with City approval, and contract with HPS to perform the energy audits and installation of measures.

The energy audit will include a blower door test, a visual inspection of crawl space and attic, and a collection of data regarding the home and its energy use. Potential low-cost energy-saving measures that

could be installed in each home include limited sealing of air leaks, such as mastic around furnace unit; installing CFLs; insulating water pipes that are three feet or less between the water heater and the structure; and installing a low-flow showerhead. The visit will include educating customers on a variety of items, such as how to replace their furnace filter or lower the temperature on their water heater.

Participating customers pay $49 for the audit and installation of measures, with the remaining cost covered by the EECBG funds. This is a great value for the customer. Energy audits of this type normally cost $300 and more, not including the measures, materials, and labor. The cost of the materials potentially installed at each home is approximately $100.

Target audience for this project is Boise City residential customers living in single-family, site-built homes under 3,000 square feet. The homes must be owner-occupied as a year-round residence. It is necessary for the customer to have lived in the home for at least 12 months, allowing retrieval of a full year of historical data prior to installation of any measures related to this project. In addition, it is desirable that the customer plans to stay in the home for the next year or two. This would allow post-installation data collection based on the same family/electric use style. Twenty-five percent of targeted homes must be all electric.

Participants will be selected on a first-come, first-served basis. Applicants received beyond the allotment will be placed on a standby list to be used if an accepted applicant decides not to participate or does not qualify.

In 2010, the project design was complete. An RFP for auditors was sent, applicants reviewed, and three companies selected. The selected auditors and QA company completed contracts. In October 2010, the auditors were trained on the project and process. The project launched mid-November, and marketing letters were sent to a small randomly selected group from a larger target group. The audits and QA of the audits began after that. Reporting to the city is done monthly and quarterly. Audits and QA will continue through approximately May 2011. At that time, the analysis process will begin.

REGULATORY INITIATIVES

Idaho Power believes there are three essential components of an effective regulatory model for DSM: 1) the timely recovery of DSM program costs, 2) the removal of financial disincentives, and 3) the availability of financial incentives.

Since 2002, Idaho Power has recovered its DSM program costs through the Rider with the intended result of providing more timely recovery of DSM costs. To address the removal of financial disincentives, Idaho Power is testing the effects of a FCA mechanism in a five-year pilot initiative. The FCA pilot just completed year four. To introduce an option to provide financial incentives for DSM, the company filed in October Case IPC-E-10-27 to move incentive payments for one DSM program to a regulatory asset account in order to begin earning its authorized rate of return on the DSM investment. This will allow some energy efficiency investments to be treated similar to supply-side investments and not treated as inferior investments. In the same filing, the company also proposed moving the recovery of incentive payments of demand response programs out of the Rider mechanism and into the PCA mechanism. This move would treat the cost recovery of demand response incentive payments similar to other supply-side resource expenses such as fuel, purchase power, and surplus sales. These mechanisms are discussed in more detail below.

Fixed-Cost Adjustment Pilot

Under the FCA, rates are annually adjusted up or down to recover or refund the difference between the fixed costs authorized by the IPUC and the fixed costs Idaho Power actually received the previous year through energy sales. This mechanism removes the financial disincentive that exists when Idaho Power invests in energy efficiency and demand response resources. The FCA Pilot is limited to the residential and small commercial classes in recognition of the fact that, for these customers, a high percentage of fixed costs are recovered through their energy charges.

During the initial three-year period in which the FCA, Schedule 54, was in effect, Idaho Power made strong progress toward improving and enhancing its efforts to promote energy efficiency and DSM activities. The company increased the number of energy efficiency and demand response programs it offers and substantially increased both its investment in DSM activities and the MWh savings obtained through these activities. Results from the first three years of the pilot indicated that the true-up mechanism was working as intended.

On October 1, 2009, the company filed an application with the IPUC to convert the FCA to an ongoing and permanent rate schedule. On April 29, 2010, the IPUC issued Order No. 31063 extending the FCA as a pilot for an additional two years, effective January 1, 2010.

On May 28, 2010, the IPUC issued Order No. 31081 approving the company's request to implement FCA rates for fixed-cost deferrals in 2009. Beginning June 1, 2010, the company implemented an overall rate adjustment of 1.85 percent to residential and small general service customers to collect a combined $6.3 million in under-collected fixed costs. Residential customers experienced a rate increase of 0.1218 cents/kWh, while small general service customers experienced an increase of 0.1535 cents/kWh. The rate adjustments resulted in a collection of an additional $3.6 million over the then current billed amounts and will be in place until May 31, 2011.

Irrigation Peak Rewards Filings in Idaho and Oregon

In 2010, Idaho Power enhanced its traditional annual review of the Irrigation Peak Rewards program by conducting an additional study in conjunction with its 2011 IRP analysis. This study was conducted in an effort to ensure that the program's design is aligned with the resource needs identified by the IRP.

After a thorough review of resource need and demand-reduction potential, the company concluded that its need for demand response extended beyond 8:00 p.m. to at least 9:00 p.m. Further, the company concluded that its annual capacity need during the highest 60 hours of demand was expected to vary by more than 50 percent (167 MW) during the next five years. Based on these findings, the company filed program modifications to its Irrigation Peak Rewards programs in Idaho (Case No. IPC-E-10-46) and Oregon (Advice No. 11-01).

In its filings, Idaho Power first sought to include the 8:00 p.m. to 9:00 p.m. hour as an "Extended Interruption" option on a voluntary basis. Customers willing to accept an extended interruption period would receive a higher incentive payment for event hours. In return, Idaho Power would be able to reduce loads across the entire peak period.

Second, in an effort to better align annual program costs with the annual capacity need, the company proposed to change the incentive structure for the program from a fixed incentive payment methodology to a methodology that combined a fixed and variable incentive payment. Having a portion of the incentive based on the actual utilization of the resource would more closely align the cost of demand response with the variable capacity needed.

Third, to encourage equipment testing and participant familiarity with the program, Idaho Power recommended the program be modified to allow one program test event per program season that is not subject to a variable payment.

Overall, the proposed program modifications are reflective of a collaborative process in which Idaho Power received feedback from numerous stakeholder groups, including the Idaho Irrigation Pumpers Association, the Commission Staff, the EEAG, and the IRPAC. The revised program, as proposed, will more closely align program incentives with the company's need for demand response. The company will continue to monitor the program's performance and report on program results next year through the *Demand-Side Management 2011 Annual Report*.

Demand-Side Resource Business Model Filing

On October 22, 2010, Idaho Power filed Case No. IPC-E-10-27 with the IPUC requesting authorization to implement a demand-side resource (DSR) business model that would 1) move demand response incentive payments into the PCA on a prospective basis beginning June 1, 2011; 2) establish a regulatory asset for Custom Efficiency program incentive costs beginning January 1, 2011; and 3) change the carrying charge on the Idaho Energy Efficiency Rider (Rider) from the customer deposit rate to the company's authorized rate of return. Idaho Power requested an order by March 15, 2011.

Idaho Power stated in the filing that from a regulatory standpoint, successful DSR business activities require clear and achievable guidelines for prudency. There must be a timely recovery of out-of-pocket expenditures that appropriately recognizes the time value of money and does not negatively impact cash flow in a significant way. Economic disincentives to reduce load must be mitigated through better pricing, decoupling, or some other mechanism that does not strand fixed cost recovery. Finally,

the company must have the ability to earn on the energy efficiency investments just like any other business activity in which the company is engaged.

The Rider balance is presently negative by more than $17 million and has been negative since April 2008. The large growing balance reflects success associated with increasing programs, expenditures, and savings in DSR. However, continuing to increase the negative balance is problematic. A Rider account with an extended negative balance breaks the symmetry of the mechanism and negatively impacts the company's cash flow. The company believes there is a more appropriate path that would allocate some of the expenses to more suitable alternatives for recovery.

All costs for the demand response programs are presently recovered through the Rider. Currently, the Idaho Rider charge is 4.75 percent of base rates applied to all customer groups. In this filing, Idaho Power requested authority to remove recovery of customer and demand-aggregator contractor incentive payments for all company demand response programs from the Rider balancing account and transfer these costs to the PCA for 100 percent recovery on a prospective basis. Idaho Power proposed to begin shifting the recovery of the demand response incentive costs to the PCA beginning with the company's forecast of April 2011 through March 2012 power supply costs, currently expected to be approximately $14.6 million. Idaho Power proposes to include these costs in the PCA in a manner consistent with the current PCA methodology. The company would forecast Idaho demand response incentive payments just as it does for its forecast of fuel, purchased power, and surplus sales. This forecasted amount of demand response incentive costs would be included in PCA rates, effective June 1, 2011.

In addition to moving demand response incentive costs to the PCA, Idaho Power proposed to change the method of recovering a portion of the energy efficiency program incentive costs. Currently, all energy efficiency incentive costs are recovered through the Rider balancing accounts. The company proposed to capitalize the direct incentive payments associated with the Custom Efficiency program to enable the company to earn a return on a portion of its DSR activities. The company proposed to start booking incentive payments to a regulatory asset account beginning January 1, 2011. The balance in the account would be included in the company's revenue requirement at the time of a future rate case and would be amortized over four years. The then-current commission authorized rate of return would be applied as a carrying charge during the deferral period and the amortization period. This treatment will keep the selected DSR assets on par with supply-side assets.

Because of the large negative balance existing in the Rider and because it will take almost two years to work this balance down given the prospective nature of the company's previously stated requests, Idaho Power requests that the IPUC authorize the carrying charge on the remaining balance to reflect the company's authorized rate of return (currently 8.18 overall rate of return with a 10.5 return on equity component) instead of the interest rate on customer deposits (currently 1.0 percent). Changing the current carrying charge is particularly important should the IPUC decide against part or all of the company's requests.

If the IPUC implements the company's two proposals, the 2010 negative Rider balance of $17,592,938 is projected to shrink to a negative $3,356,306 in 2011 and, in the middle of 2012, it is expected that this account will approach zero.

On March 3, 2011, Idaho Power filed testimony in support of a settlement Stipulation in this case. Terms of the Stipulation include moving demand response program incentives associated with the A/C Cool Credit program, the Irrigation Peak Rewards program, and the FlexPeak Management program to the PCA on a prospective basis beginning June 1, 2011. A one-year interim per kWh tariff

rate will be implemented for each customer class in order to recover the same amount of revenue from each class as would have been recovered through a DSM Rider charge. The parties agree that incentive payments of the Custom Efficiency program would be capitalized as a regulatory asset beginning January 1, 2011, with a carrying charge equal to the current IPUC authorized rate of return. Once placed in rates, this regulatory asset will be amortized over seven years and will earn the then-current, commission-approved authorized rate of return. The parties also agree that the Idaho Rider carrying charge will remain at the customer deposit rate. The parties signing the Stipulation were Idaho Power, IPUC Staff, the ICL, Northwest Energy Coalition, SRA, and CAPAI. The Idaho Irrigation Pumpers Association, Inc., did not sign the Stipulation, but do not oppose it. The industrial customers of Idaho Power did not sign the Stipulation and are expected to file testimony in opposition to the Stipulation. At this time, the IPUC has not issued a final order in this case.

Energy Efficiency Rider—Prudency

On March 16, 2010, Idaho Power, under Case No., IPC-E-10-09 filed an application to the IPUC for an order designating Idaho Power's expenditure of $50,701,740 in Idaho Rider funds in 2008 and 2009 as prudently incurred expenses. This prudency filing was the first designed to comply with the agreed-upon principles set forth in the MOU for Prudency Determination of DSM Expenditures. The filing included as attachments to the *Demand-Side Management 2009 Annual Report*, along with two new documents, *Supplement 1: Cost-Effectiveness* and *Supplement 2: Evaluation*. On November 16, 2010, in Order No. 32113, the IPUC found that the company acted prudently in the administration of its DSM programs and found its 2008 and 2009 Rider expenditures were approved for ratemaking purposes. On page 9 of the Order, the IPUC states; "The Commission exhorts Idaho Power to continue on this path toward improvement. Idaho Power should seek to employ independent evaluators for all of its DSM programs and take affirmative steps toward achieving measurable improvements in its documentation, verification and record-keeping processes for these programs."

Energy Efficiency Rider—Oregon

On March 5, 2010, Idaho Power filed a request with the OPUC under Tariff Advice 10-03 to increase the Rider from 1.5 percent of base rates to 3.0 percent of base rates and to eliminate the funding caps on residential and irrigation bills. On April 27, this request was approved, effective June 1, 2010.

CONTINUED COMMITMENT

Every year, Idaho Power enhances its commitment to providing DSM programs that offer broader opportunities for Idaho Power's customers to manage their energy and demand use. Idaho Power also continues its effort to make its own facilities more energy efficient and to find ways to promote energy efficiency in its communities and its employees' lives. A review of specific efforts is listed in the following sections.

Continued Expansion and Broad Availability of Efficiency and Demand Response Programs

In 2010, Idaho Power broadened the portfolio of programs offered to customers. Programs continue to add service areas where they are available to customers and continue to add new measures for customer participation. This expansion of programs and offerings helps ensure more customers each year have the opportunity to participate in programs. Some highlights for 2010 are as follows:

- Weatherization Solutions for Eligible Customers program expanded to the Idaho counties of Canyon, Gem, Payette, Boise, Washington, Valley, and Adams.
- Idaho Power partnered with City of Boise to implement the Boise City Home Audit Project to provide reduced priced audits for 600–700 residents.
- Idaho Power was a major sponsor of Idaho's first Net-Zero Energy Home promotion in conjunction with the St. Jude Dream Home campaign.
- In June 2010, as part of the Home Products Program, Idaho Power began a showerhead promotion program for 1.5 GPM and 2.0 GPM units and added freezers to the program's offerings.
- The successful SEE program completed a second year of operation with 300 high school and 6,000 elementary students participating.
- New educational material was developed for several programs including a Healthy Homes Guide and Energy Efficiency Kits available at local libraries.
- More information was available on the Web for customers interested in energy efficiency, including the booklet *30 Simple Things You Can Do To Save Energy* and access to individualized *Energy Tools*.
- Energy Efficiency Tip Sheets were developed for different sectors of commercial customers.
- Custom Efficiency participants' *Success Stories* were posted to the Idaho Power website.

Building-Code Improvement Activity

Idaho Power was supportive of the legislative effort in the Idaho State legislature to enact the 2009 IECC for implementation January 1, 2011.

Pursuit of Appliance Code Standards

In 2010, Idaho Power provided support for efforts for national appliance standards. Letters of support were provided to both Senator Mike Crapo and Senator James Risch pointing to the broad economic, operational, and environmental benefits of energy efficiency to the citizens of Idaho.

Promotion of Energy Efficiency through Electricity Rate Design

Idaho Power continues to support a policy of gradually moving all customers into rates designed to provide cost-based price signals and to encourage the wise and efficient use of energy.

In 2010, Idaho Power took a new look at its policy for how to work with new and expanding large-load customers. A policy was established that provides service consistent with system capability, that offers a suite of flexible services, including seasonal shaping and standby service, that provides some mitigation of rate impacts on existing customers and that considers sustainability, economic development goals, and environmental effects of using the company's resources. As part of this effort, in August, the company filed to change the eligibility cap for Schedule 19 customers from 25 MW to 20 MW. By lowering the size limit, the company can address these service issues to new large loads that may be coming into the service area. In December 2010, under Order No. 32132, the IPUC approved the request.

On March 1, 2010, as per Order 10-064 in General Rate Case UE 213, Idaho Power implemented mandatory time-of-use rates (TOU) for all customers on Schedule 9 Primary and Schedule 9 Transmission. With this rate change, all industrial customers on Schedule 19 and Schedule 9 P and T across the Idaho Power service area are on TOU rates. Idaho Power also implemented a load-factor pricing rate structure for irrigation customers on Schedule 24 in Oregon. These rate change proposals were driven by the explicit Idaho Power objective of providing customers with cost-based price signals, which encourage the wise and efficient use of energy.

Third-Party, Independent Verification

Idaho Power understands that credible and transparent program evaluations are critical to ensuring maximum program performance. Independent, third-party consultants are used to provide impact and process evaluations to verify that program specifications are met, provide viable recommendations for program improvement, and validate energy savings achieved through Idaho Power's programs.

In 2010, process evaluations were completed by third-party consultants on nine programs, including H&CE Program, Energy House Calls, Home Improvement Program, Residential Energy Efficiency Education Initiative, Easy Upgrades, Building Efficiency, Custom Efficiency, Commercial Energy Efficiency Education Initiative, and Irrigation Efficiency Rewards. Copies of these reports can be found in *Supplement 2: Evaluation*.

Idaho Power uses independent, third-party contractors for QA and OSV for several programs. The H&CE Program uses a third-party contractor to perform QA and OSV of approximately 10 percent of completed customer projects. The Energy House Calls program contracts with third-party experts to perform QA analysis on approximately 5 percent of homes serviced by the program. These contractors visit the customer site within approximately one month of the energy house call to verify that the energy efficiency measures were performed to program specifications. And the ENERGY STAR® Homes Northwest program uses contractors for third-party verification, ensuring that each ENERGY STAR

qualified home is built to ENERGY STAR standards. Another third-party contractor provides QA and certifies each qualifying home as an ENERGY STAR home.

Throughout 2010, Idaho Power participated with NEEA to conduct several third-party evaluations. These studies included evaluation of the DHP Pilot, Residential Lighting Market Research, Market for Energy Efficient Electronics, Evaluation of Codes and Standards Market Progress, Northwest ENERGY STAR Homes Northwest, and several market effects evaluations in the residential, commercial, and industrial sectors.

The company also funds and participates in the RTF. The RTF is an advisory committee that was established in 1999 to develop regional standards for verifying and evaluating savings from energy efficiency programs and measures. Idaho Power uses the RTF as a source for information regarding energy efficiency programs and measures and uses the RTF databases to provide deemed savings for a portion of the energy efficiency measures implemented by the company's customers.

Idaho Power's Internal Energy Efficiency Commitment

Idaho Power's continued commitment toward promoting energy efficiency extends beyond encouraging, providing incentives, and educating its customers.

Idaho Power's corporate headquarters (CHQ) participated in strategic elimination of power loads during peak use through the FlexPeak Management program. In August, Idaho Power entered into an agreement with EnerNOC to enroll the CHQ in FlexPeak Management—Idaho Power's commercial/industrial demand response program. EnerNOC enlists and contracts with Idaho Power's commercial and industrial customers to voluntarily reduce their electricity use primarily during times of Idaho Power system peaks. EnerNOC provides participants with auditing assistance, energy monitoring software, demand reduction performance monitoring, coaching, and other related services. The agreement with Idaho Power to enroll the CHQ was executed in early August 2010. Unlike other program participants, Idaho Power does not receive any financial incentives to participate. By the end of August, the company received usage data through EnerNOC's energy monitoring software and performed CHQ site-testing to establish the amount of load available for reduction. The amount of reduction EnerNOC commits to achieve on Idaho Power's behalf will be based on the demand reduction available at the CHQ each week during the active program season beginning in June 2011. EnerNOC is obligated to achieve the reduction they nominate, or commit to, each week if Idaho Power calls an event. EnerNOC works closely with its program participants to estimate their reduction potential accurately. Idaho Power now has a facility reduction plan in place that could be executed at any time to reduce electricity use if necessary.

During 2010, the company continued with the multi-year remodel and retrofit of the CHQ, completing the second floor of the building. The project included installing T-5 lighting that uses 60 percent less energy than old lighting packages. Natural light supplemented the T-5 lighting, accomplished through light harvesting near the exterior walls. Additionally, use of shorter 53-inch cubical partitions allowed more daylight while reducing lighting costs. Further retrofits included occupancy and vacancy sensors in all enclosed office and meeting spaces, low-flow toilets and automatic sink faucets in the restrooms, and window blinds that are 60 percent opaque with a horizontal range of motion that never needs closed. Other projects included the ongoing Payette Operations Center upgrades from T-12 to T-8 high-bay fluorescent lighting in the garage and materials area. The Canyon Operations Center lighting retrofit from T-12 to T-8 throughout the facility was completed in 2010. Twin Falls Operations Center's garage and materials areas received upgrades, from T-12 fixtures to high-bay fluorescent T-8 fixtures.

Numerous energy efficiency projects are budgeted for 2011. The remodel of the CHQ will continue with a focus on the first floor. A completion of the lighting retrofit at the Payette Operations Center is planned. Though it will take several years to complete lighting retrofits in the company's sub-stations across the service area, planning is underway in 2011. The company is engineering a new energy-efficient chilled water system for the CHQ with implementation planned during 2012 through 2013.

CAES Energy Efficiency Research Initiative

The Center for Advanced Energy Studies (CAES) is a public–private technical and policy research partnership based in Idaho Falls, and comprised of Boise State University, Idaho State University, University of Idaho, the DOE, and Idaho National Laboratory (INL). The State of Idaho launched the newest activity under the CAES umbrella on October 27, 2010 when Idaho Governor C.L. "Butch" Otter announced the formation of the CAES Energy Efficiency Research Initiative (CEERI).

Idaho Power was involved in the initial discussion and planning for CEERI, and joined Governor Otter and other representatives of participating entities in signing a proclamation in support of the initiative's formation. Signatories included Boise State University, University of Idaho, Boise Metro Chamber of Commerce, National Resources Defense Council, Idaho Office of Energy Resources (IOER), Idaho Innovation Council, Micron Technology, and other Idaho-based companies.

The initiative's initial focus is in four main areas: 1) public outreach and education, 2) workforce development, 3) college-level curriculum, and 4) research/technical development. Idaho Power's involvement in CEERI enables the company to positively influence energy-efficiency education and research. The company will also benefit from educational opportunities for Idaho Power customers and employees and from the development of a workforce with relevant skills.

Sustainable Operations/Sustainability

In 2010, Idaho Power began an internal sustainability effort with a mission to promote and support exceptional financial, environmental, and social stewardship across Idaho Power business practices. A Sustainability Council was formed with members representing major company departments with the expressed vision to make sustainability a corporate value. A sustainability charter containing an operational definition, mission, vision, and objectives was drafted for review and endorsement by executive council. The objectives for 2011 include development of a sustainability plan. This plan included internal and external reporting, and determination of baseline operating parameters for several Idaho Power facilities, including energy use.

Green Team

During spring 2010, Idaho Power employees started an internal Green Team. The mission of the Green Team was to champion sustainable activities by Idaho Power and its employees that promoted energy efficiency, environmental and community stewardship, and the wise use of resources. Some of the projects worked on during 2010 included a company-wide recycling initiative, the Refugee Community Garden Project, a no-idling campaign, and a monthly Green Bag educational seminar effort.

APPENDICES

This report includes five appendices. Appendix 1 contains financial information for 2010, showing the beginning balance, ending balance, and the expenditures for the Idaho and Oregon Riders, BPA funding, and NEEA payments and credits. Appendix 2 also contains financial information showing expenses by funding source for each of Idaho Power's energy efficiency 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 2010. Appendix 4 shows similar data as Appendix 3, but also includes data for past years' program performance, B/C ratios from the utility perspective, and from the TRC perspectives for active programs. An addition to this year's report is Appendix 5. This new appendix shows program savings and costs separated into Idaho Power's Idaho and Oregon jurisdictions and by funding source.

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. A new table, *2010 DSM Detailed Expenses by Program*, 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 various 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 included with each supplement.

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Appendix 1. Idaho Rider, Oregon Rider, and NEEA funding balances

Idaho Energy Efficiency Rider	
2010 Beginning Balance	$ (9,718,518)
2010 Funding plus Accrued Interest	34,605,272
Total 2010 Funds	24,886,751
2010 Expenses	(42,479,692)
2010 Year-End Balance	$ (17,592,938)
Oregon Energy Efficiency Rider	
2010 Beginning Balance	$ (866,772)
2010 Funding plus Accrued Interest	697,464
Total 2010 Funds	(169,308)
2010 Expenses	(1,704,367)
2010 Year-End Balance	$ (1,873,675)
NEEA Payments and Escrow Credit Funds Balance	
2010 Idaho Power Contractual Obligation[a]	$ 2,391,217
2010 Year-End Balance	$ 2,391,217

[a] Idaho Power shall prepay estimated expenses quarterly, where the amount shall be amortized over the respective quarter. Funding of NEEA, approved by IPUC Order 31080, dated 5/12/10. Reconciliation between the estimated expenditures and the actual expenditures for the quarter will be completed 30 days after the quarter end or by March 1st for year-end. A true-up of the variance will be included in the next quarter's invoice, not to exceed 125% of its five-year total direct funding contribution.

Appendix 2. 2010 DSM expenses by funding source (dollars)

Sector/Program	Idaho Rider	Oregon Rider	Idaho Power	Total Program
Energy Efficiency/Demand Response				
Residential				
A/C Cool Credit	$ 1,854,979	$ 74,071	$ 73,496	**$ 2,002,546**
Ductless Heat Pump Pilot	181,969	7,262	0	**189,231**
Energy Efficient Lighting	2,442,931	58,347	0	**2,501,278**
Energy House Calls	724,895	37,435	0	**762,330**
ENERGY STAR® Homes	369,344	6,093	168	**375,605**
Heating & Cooling Efficiency Program	314,963	12,706	0	**327,669**
Home Improvement Program	944,716	0	0	**944,716**
Home Products Program	813,171	18,990	0	**832,161**
Oregon Residential Weatherization	0	4,575	1,475	**6,050**
Rebate Advantage	34,283	5,119	0	**39,402**
See ya later, refrigerator®	548,872	16,207	0	**565,079**
Weatherization Assistance for Qualified Customers	0	0	1,321,132	**1,321,132**
Weatherization Solutions for Eligible Customers[a]	216,202	2,306	9,917	**228,425**
Commercial/Industrial				
Building Efficiency	1,466,179	43,422	81	**1,509,682**
Easy Upgrades	3,862,653	111,757	0	**3,974,410**
FlexPeak Management	1,807,527	95,153	0	**1,902,680**
Holiday Lighting	45,816	316	0	**46,132**
Oregon Commercial Audits	0	5,049	0	**5,049**
Custom Efficiency	8,046,168	717,132	14,825	**8,778,125**
Irrigation				
Irrigation Efficiency Rewards	2,059,676	110,034	31,104	**2,200,814**
Irrigation Peak Rewards	13,096,946	184,075	49,805	**13,330,826**
Energy Efficiency Total	**$ 38,831,290**	**$ 1,510,049**	**$ 1,502,003**	**$ 41,843,342**
Market Transformation				
NEEA[b]	2,271,656	119,561	0	**2,391,217**
Market Transformation Total	**$ 2,271,656**	**$ 119,561**	**$ 0**	**$ 2,391,217**
Other Programs and Activities				
Residential				
Residential Energy Efficiency Education Initiative	211,695	10,397	0	**222,092**
Commercial				
Commercial Education Initiative	65,327	3,438	0	**68,765**
Other				
Energy Efficiency Direct Program Overhead	100,087	7,831	9,956	**117,874**
Local Energy Efficiency Funds	238	13	0	**251**
Other Programs and Activities Total	**$ 377,347**	**$ 21,679**	**$ 9,956**	**$ 408,982**
Indirect Program Expenses				
Residential Overhead	132,082	6,941	0	**139,023**
Commercial/Industrial/Irrigation Overhead	143,140	7,543	0	**150,683**
Energy Efficiency Accounting and Analysis	698,907	37,068	136,833	**872,808**
Energy Efficiency Advisory Group	2,651	112	0	**2,763**
Special Accounting Entries	22,619	1,414	0	**24,033**
Indirect Program Expenses Total	**$ 999,399**	**$ 53,078**	**$ 136,833**	**$ 1,189,175**
Totals	**$ 42,479,692**	**$ 1,704,367**	**$ 1,648,792**	**$ 45,832,851**

[a] Oregon Rider balance of $2,306 will be reclassed to the Idaho Rider in 2011.

[b] NEEA funding addressed in IPUC per Order No. 31080, dated 5/12/10. 2011 annual expense expected at $3.3 m (see footnote, Appendix 1 for additional information).

Appendix 3. 2010 DSM program activity

Program	Participants		Total Costs: Utility[b]	Total Costs: Resource[c]	Savings: Annual Energy (kWh)	Savings: Peak Demand[d] (MW)	Measure Life	Nominal Levelized Costs[a]: Utility ($/kWh)	Nominal Levelized Costs[a]: Total Resource ($/kWh)
Demand Response									
A/C Cool Credit	30,803	homes	$ 2,002,546	$ 2,002,546	n/a	39.0	n/a	n/a	n/a
Irrigation Peak Rewards	2,038	service points	13,330,826	13,514,246	n/a	249.7	n/a	n/a	n/a
FlexPeak Management	60	sites	1,902,680	1,902,680	n/a	47.5	n/a	n/a	n/a
Total			**$ 17,236,052**	**$17,419,472**	**n/a**	**336.2**			
Energy Efficiency									
Residential									
Ductless Heat Pump Pilot	104	homes	$ 189,231	$ 439,559	364,000		20	$ 0.044	$ 0.103
Energy Efficient Lighting	1,190,139	bulbs	2,501,278	3,976,476	28,082,738		5	0.020	0.031
Energy House Calls	1,602	homes	762,330	762,330	1,198,655		20	0.054	0.054
ENERGY STAR® Homes Northwest	630	homes	375,605	579,495	883,260		25	0.033	0.051
Heating & Cooling Efficiency Program	217	homes	327,669	1,073,604	1,104,497		20	0.025	0.083
Home Improvement Program	3,537	homes	944,716	2,112,737	3,986,199		45	0.016	0.035
Home Products Program	16,322	appliances/fixtures	832,161	1,025,151	1,443,580		15	0.057	0.070
Oregon Residential Weatherization	1	home	6,050	6,275	320		30	0.011	0.062
Rebate Advantage	35	homes	39,402	66,142	164,894		25	0.018	0.031
See ya later, refrigerator®	3,152	refrigerators/freezers	565,079	565,079	1,567,736		8	0.054	0.054
Weatherization Assistance for Qualified Customers	400	homes/non-profits	1,321,132	2,927,898	3,741,652		25	0.027	0.035
Weatherization Solutions for Eligible Customers	47	homes	228,425	228,425	313,309		25	0.056	0.056
Sector Total			**$ 8,093,078**	**$13,763,171**	**42,850,839**		**12**	**$ 0.021**	**$ 0.036**
Commercial									
Building Efficiency	70	projects	1,509,682	3,312,963	10,819,598	0.9	12	0.016	0.035
Easy Upgrades	1,535	projects	3,974,410	7,655,397	35,824,463	7.8	12	0.013	0.024
Holiday Lighting	25	projects	46,132	65,308	248,865	0.0	10	0.024	0.034
Oregon Commercial Audits	22	audits	5,049	5,049	n/a		n/a	n/a	n/a
Sector Total			**$ 5,535,273**	**$11,038,718**	**46,892,926**	**8.7**	**12**	**$ 0.013**	**$ 0.027**
Industrial									
Custom Efficiency[1]	223	projects	8,778,125	17,172,176	71,580,075	9.5	12	0.014	0.027
Sector Total			**$ 8,778,125**	**$17,172,176**	**71,580,075**	**9.5**	**12**	**$ 0.014**	**$ 0.027**

Appendix 3. 2010 DSM program activity (continued)

Program	Participants	Total Costs: Utility[b]	Total Costs: Resource[c]	Savings: Annual Energy (kWh)	Savings: Peak Demand[d] (MW)	Measure Life	Nominal Levelized Costs[a]: Utility ($/kWh)	Nominal Levelized Costs[a]: Total Resource ($/kWh)
Irrigation								
Irrigation Efficiency Rewards[2]	753 projects	2,200,814	6,968,598	10,968,430	3.3	8	0.030	0.096
Sector Total		**$ 2,200,814**	**$ 6,968,598**	**10,968,430**	**3.3**	**8**	**$ 0.030**	**$ 0.096**
Market Transformation								
Northwest Energy Efficiency Alliance[3]		$ 2,391,217	$ 2,391,217	15,334,073				
Other Programs and Activities								
Residential								
Residential Energy Efficiency Education Initiative		$ 222,092	$ 222,092					
Commercial								
Commercial Education Initiative		68,765	68,765					
Other								
Energy Efficiency Direct Program Overhead		117,874	117,874				n/a	n/a
Local Energy Efficiency Funds	1 project	251	251					
Total Program Direct Expense		**$ 44,643,541**	**$69,162,332**	**187,626,344**	**357.7**			
Indirect Program Expense		1,189,310						
Total DSM Expense		**$ 45,832,851**						

[a] Levelized Costs are based on financial inputs from Idaho Power's 2009 IRP, and calculations include line loss adjusted energy savings.

[b] The Total Utility Cost is all cost incurred by Idaho Power to implement and manage a DSM program.

[c] The Total Resource Cost is the total expenditures for a DSM program from the point of view of Idaho Power and its customers.

[d] Summer Peak Demand is reported where program MW reduction is documented. Demand response program reductions are reported with 13% peak loss assumptions Demand Response reduction is non-coincident.

[1] Custom Efficiency savings includes 20 Green Motors Rewsindparticipants totaling 55,126 kWh of annual savings not counted in project totals.

[2] Irrigation Efficiency includes 36 Green Motors participants totaling 187,965 kWh of annual savings not counted in project totals.

[3] Savings are preliminary estimates provided by NEEA.

Appendix 4. DSM expense and performance 2002–2010

Program/Year	Participants	Total Costs		Savings and Demand Reduction				Levilized Costs [a]		Program Life Benefit/Cost Ratios[b]	
		Utility[c]	Resource[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											
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					
Total		**$13,402,500**	**$13,402,500**							**1.11**	**1.11**
FlexPeak Management											
2009	33	528,681	528,681			19.3					
2010	60	1,902,680	1,902,680			47.5					
Total		**$ 2,431,361**	**$ 2,431,361**							**1.14**	**1.14**
Irrigation Peak Rewards											
2004	58	344,714	344,714			5.6					
2005	894	1,468,282	1,468,282			40.3					
2006	906	1,324,418	1,324,418			31.8					
2007	947	1,615,881	1,615,881			37.4					
2008	897	1,431,840	1,431,840			35.1					
2009	1,512	9,655,283	9,655,283			160.2					
2010	2,038	13,330,826	13,514,246			249.7					
Total		**$29,171,244**	**$29,354,664**							**1.43**	**1.37**
Residential Efficiency											
Ductless Heat Pump Pilot											
2009	96	$ 202,004	$ 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		
Total	**200**	**$ 391,235**	**$ 891,164**	**773,180**			**20**	**$ 0.043**	**$ 0.098**	**3.47**	**1.38**

Appendix 4. DSM expense and performance 2002–2010 (continued)

Program/Year	Participants	Total Costs: Utility[c]	Total Costs: Resource[d]	Savings and Demand Reduction: Annual Energy (kWh)	Savings and Demand Reduction: Average Energy[e] (aMW)	Peak Demand[f] (MW)	Measure Life (Years)	Levilized Costs[a]: Total Utility ($/kWh)	Levilized Costs[a]: Total Resource ($/kWh)	Program Life Benefit/Cost Ratios[b]: Utility	Program Life Benefit/Cost Ratios[b]: Total Resource
Residential Efficiency											
Energy Efficient 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	11,619	243,033	310,643	3,299,654	0.38		7	0.012	0.015		
2003	12,663	314,641	464,059	3,596,150	0.41		7	0.014	0.021		
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		
Total	**2,642,513**	**$ 6,214,162**	**$ 8,082,552**	**77,943,613**			**5**	**$ 0.018**	**$ 0.023**	**4.54**	**3.49**
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	67,616	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		
Total	**8,522**	**$ 3,784,096**	**$ 3,515,340**	**9,215,987**			**20**	**$ 0.035**	**$ 0.032**	**3.06**	**3.06**
ENERGY STAR® Homes Northwest											
2003		13,597	13,597								
2004	44	140,165	335,437	101,200	0.01	0.1	25	0.103	0.246		
2005	200	253,105	315,311	415,600	0.05	0.4	25	0.045	0.056		
2006	439	469,609	602,651	912,242	0.10	0.9	25	0.038	0.049		

Appendix 4. DSM expense and performance 2002–2010 (continued)

Program/Year	Participants	Total Costs		Savings and Demand Reduction				Levilized Costs[a]		Program Life Benefit/Cost Ratios[b]	
		Utility[c]	Resource[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 STAR® Homes Northwest											
2007	303	$ 475,044	$ 400,637	629,634	0.07	0.6	25	$ 0.056	$ 0.047		
2008	254	302,061	375,007	468,958	0.05	0.6	25	0.048	0.059		
2009	474	355,623	498,622	705,784	0.08	1.1	25	0.039	0.055		
2010	630	375,605	579,495	883,260	0.10		25	0.033	0.051		
Total	**2,344**	**$ 2,384,809**	**$ 3,120,758**	**4,116,678**			**25**	**$ 0.045**	**$ 0.059**	**2.68**	**2.05**
Heating & Cooling Efficiency Program											
2006		17,444	17,444								
2007	4	488,211	494,989	1,595	0.00		18	27.344	27.710		
2008	359	473,551	599,771	561,441	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	0.10		20	0.025	0.083		
Total	**929**	**$ 1,785,249**	**$ 2,950,479**	**2,942,362**			**20**	**$ 0.056**	**$ 0.092**	**2.50**	**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		
Total	**1,470**	**$ 444,594**	**$ 708,014**	**1,656,690**			**45**	**$ 0.018**	**$ 0.028**	**8.66**	**4.39**
Home Products Program											
2007		9,275	9,275								
2008	3,034	250,860	468,056	541,615			15	0.044	0.082		
2009	9,499	511,313	844,811	1,638,038			15	0.031	0.051		
2010	16,322	832,161	1,025,151	1,443,580			15	0.057	0.070		
Total	**28,855**	**$ 1,603,609**	**$ 2,347,293**	**3,623,233**			**15**	**$ 0.044**	**$ 0.064**	**2.45**	**1.67**
Oregon Residential Weatherization											
2002	24	-662	23,971	4,580	0.00		25	0.010	0.389		
2003		-943									
2004	4	1,057	1,057								

Appendix 4. DSM expense and performance 2002–2010 (continued)

Program/Year	Participants	Total Costs: Utility[c]	Total Costs: Resource[d]	Savings and Demand Reduction: Annual Energy (kWh)	Savings and Demand Reduction: Average Energy[e] (aMW)	Peak Demand[f] (MW)	Measure Life (Years)	Levilized Costs[a]: Total Utility ($/kWh)	Levilized Costs[a]: Total Resource ($/kWh)	Program Life Benefit/Cost Ratios[b]: Utility	Program Life Benefit/Cost Ratios[b]: Total Resource
Residential Efficiency											
Oregon Residential Weatherization											
2005	4	$ 612	$ 3,608	7,927	0.00		25	$ 0.006	$ 0.034		
2006		4,126	4,126								[3]
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	7,644	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		
Total	**38**	**$ 29,083**	**$ 81,789**	**47,901**			**30**	**$ 0.044**	**$ 0.124**	**2.28**	**1.17** [4]
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		
Total	**700**	**$ 408,088**	**$ 1,011,955**	**2,470,593**			**25**	**$ 0.013**	**$ 0.032**	**8.61**	**3.57**
See ya later, refrigerator®											
2009	1,661	305,402	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		
Total	**4,813**	**$ 870,481**	**$ 870,480**	**2,700,538**			**8**	**$ 0.049**	**$ 0.049**	**1.88**	**1.88**
Weatherization Solutions for Eligible Customers											
2008	16	52,807	48,162	71,680	0.01		25	0.055	0.050		
2009	41	162,995	162,995	211,720	0.02		25	0.059	0.059		
2010	47	228,425	288,425	313,309	0.04		25	0.056	0.056		
Total	**104**	**$ 444,227**	**$ 439,582**	**596,708**			**25**	**$ 0.058**	**$ 0.057**	**1.98**	**1.98**

Appendix 4. DSM expense and performance 2002–2010 (continued)

Program/Year	Participants	Total Costs: Utility[c]	Total Costs: Resource[d]	Savings and Demand Reduction: Annual Energy (kWh)	Savings and Demand Reduction: Average Energy[e] (aMW)	Peak Demand[f] (MW)	Measure Life (Years)	Levilized Costs[a]: Total Utility ($/kWh)	Levilized Costs[a]: Total Resource ($/kWh)	Program Life Benefit/Cost Ratios[b]: Utility	Program Life Benefit/Cost Ratios[b]: Total Resource
Residential Efficiency											
Window A/C Trade Up Pilot											
2003	99	$ 6,687	$ 10,492	14,454	0.00		12	$ 0.051	$ 0.079		
Total	**99**	**$ 6,687**	**$ 10,492**	**14,454**			**12**	**$ 0.005**	**$ 0.082**		
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	1,207,705	2,814,471	3,452,025	0.39		25	0.027	0.035		
Total	**3,420**	**$ 8,956,705**	**$14,258,403**	**22,785,189**			**25**	**$ 0.030**	**$ 0.048**	**5.24**	**3.59**
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											
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	113,427	113,427	289,627	0.03		25	0.030	0.025		
Total	**167**	**$213,321**	**$ 336,712**	**524,612**			**25**	**$ 0.031**	**$ 0.050**	**4.12**	**3.00**
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		

Appendix 4. DSM expense and performance 2002–2010 (continued)

Program/Year	Participants	Total Costs: Utility[c]	Total Costs: Resource[d]	Savings and Demand Reduction: Annual Energy (kWh)	Savings and Demand Reduction: Average Energy[e] (aMW)	Peak Demand[f] (MW)	Measure Life (Years)	Levilized Costs[a]: Total Utility ($/kWh)	Levilized Costs[a]: Total Resource ($/kWh)	Program Life Benefit/Cost Ratios[b]: Utility	Program Life Benefit/Cost Ratios[b]: Total Resource
Residential—Weatherization Assistance for Qualified Customers (WAQC)											
WAQC—BPA Supplemental											
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**	**$ 0.038**		
Commercial											
Air Care Plus Pilot											
2003	4	$ 5,764	$ 9,061	33,976	0.00		10	$ 0.021	$ 0.033		
2004		344	$344								
Total	**4**	**$ 6,108**	**$ 9,405**	**33,976**			**10**	**$ 0.023**	**$ 0.035**		
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	130,591	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	1,327,128	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		
Total	**276**	**$ 5,157,747**	**$ 8,197,104**	**27,579,888**			**12**	**$ 0.021**	**$ 0.034**	**4.62**	**2.69**
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		
Total	**3,529**	**$7,061,079**	**$22,086,718**	**66,283,658**			**12**	**$ 0.012**	**$ 0.038**	**7.93**	**2.94**
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		
Total	**46**	**$ 62,712**	**$ 145,982**	**650,066**			**10**	**$ 0.020**	**$ 0.047**	**3.63**	**1.87**

Appendix 4. DSM expense and performance 2002–2010 (continued)

Program/Year	Participants	Total Costs		Savings and Demand Reduction				Levilized Costs[a]		Program Life Benefit/Cost Ratios[b]	
		Utility[c]	Resource[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 Audits											
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								
Total	**128**	**$ 38,470**	**$ 42,470**								
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**	**$ 89,858**	**223,368**			**12**	**$ 0.012**	**$ 0.046**		
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		
Total	**570**	**$24,914,034**	**$59,407,144**	**225,703,208**			**12**	**$ 0.013**	**$ 0.030**	**7.85**	**3.29**
Irrigation											
Irrigation Efficiency											
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		

Appendix 4. DSM expense and performance 2002–2010 (continued)

Program/Year	Participants	Total Costs		Savings and Demand Reduction				Levilized Costs[a]		Program Life Benefit/Cost Ratios[b]	
		Utility[c]	Resource[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											
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		
Total	**4,049**	**$11,692,468**	**$37,821,084**	**67,015,012**			**8**	**$ 0.026**	**$ 0.085**	**5.22**	**1.61**
Other Programs											
Building Operator Training											
2003	71	$ 48,853	$ 48,853	1,825,000	0.21		5	$ 0.006	$ 0.006		
2004	26	43,969	43,969	650,000	0.07		5	0.014	0.014		
2005	7	1,750	4,480	434,167	0.05		5	0.001	0.002		
Total	**104**	**$ 94,572**	**$ 97,302**	**2,909,167**			**5**	**$ 0.007**	**$ 0.007**		
Commercial Education Initiative											
2005		3,497	3,497								
2006		4,663	4,663								
2007		26,823	26,823								
2008		72,738	72,738								
2009		120,584	120,584								
2010		68,765	68,765								
Total		**$ 297,070**	**$ 297,070**								
Distribution Efficiency											
2005		21,552	43,969								
2006		24,306	24,306								
2007		8,987	8,987								

Appendix 4. DSM expense and performance 2002–2010 (continued)

Program/Year	Participants	Total Costs		Savings and Demand Reduction				Levilized Costs[a]		Program Life Benefit/Cost Ratios[b]	
		Utility[c]	Resource[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											
Distribution Efficiency											
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								
Total		**$ 509,651**	**$ 509,651**								
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 Energy Efficiency 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								
Total		**$ 630,887**	**$ 630,887**								
Solar 4R Schools											
2009		42,522	45,522								
Total		**$ 42,522**	**$ 45,522**								

Appendix 4. DSM expense and performance 2002–2010 (continued)

Program/Year	Participants	Total Costs: Utility[c]	Total Costs: Resource[d]	Savings and Demand Reduction: Annual Energy (kWh)	Savings and Demand Reduction: Average Energy[e] (aMW)	Peak Demand[f] (MW)	Measure Life (Years)	Levilized Costs[a]: Total Utility ($/kWh)	Levilized Costs[a]: Total Resource ($/kWh)	Program Life Benefit/Cost Ratios[b]: Utility	Program Life Benefit/Cost Ratios[b]: Total Resource
Other Programs											
Local Energy Efficiency Funds											
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	$0.047		
2010	1	251	251		0.00			n/a	n/a		
Total	**543**	**$ 83,259**	**$ 130,909**	**232,298**			**10**	**$0.046**	**$0.072**	**n/a**	**n/a**
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	21,024,729	2.40						[8]
2009		968,263	968,263	10,702,998	1.22						[8]
2010		2,391,217	2,391,217	15,334,073	1.75						[9]
Total		**$10,438,170**	**$ 10,438,170**	**148,929,041**							
Consumer Electronic Initiative											
2009		160,762	160,762								
Total		**$ 160,762**	**$ 160,762**								
Annual Totals											
2002		**$ 1,932,520**	**$ 2,366,591**	**16,791,100**	**1.92**	**0.0**					
2003		**2,566,229**	**3,125,573**	**18,654,343**	**2.13**	**0.0**					
2004		**3,827,212**	**4,860,912**	**19,202,780**	**2.19**	**6.6**					
2005		**6,523,349**	**10,383,578**	**37,978,035**	**4.34**	**44.3**					

Appendix 4. DSM expense and performance 2002–2010 (continued)

Program/Year	Participants	Total Costs		Savings and Demand Reduction				Levilized Costs[a]		Program Life Benefit/Cost Ratios[b]	
		Utility[c]	Resource[d]	Annual Energy *(kWh)*	Average Energy[e] *(aMW)*	Peak Demand[f] (MW)	Measure Life (Years)	Total Utility ($/kWh)	Total Resource ($/kWh)	Utility	Total Resource
Annual Totals											
2006		**$ 11,174,181**	**$ 20,950,111**	**67,026,303**	**7.65**	**44.4**					
2007		**14,896,816**	**26,182,014**	**91,145,357**	**10.40**	**58.5**					
2008		**20,213,215**	**44,771,182**	**128,508,579**	**14.61**	**74.9**					
2009		**33,821,062**	**53,090,852**	**143,146,364**	**16.15**	**236.6**					
2010		**44,643,541**	**69,162,333**	**187,626,344**	**21.23**	**357.7**					
Total Direct Program		**$139,598,124**	**$ 234,893,146**	**710,079,205**							
Indirect Program Expense											
DSM Overhead and Other Indirect											
2002		$ 128,855									
2003		-41,543									
2004		142,334									
2005		177,624									
2006		309,832									
2007		765,561									
2008		980,305									
2009		1,025,704									
2010		1,189,175									
Total		**$ 4,677,850**									
Total Expense											
2002		**$ 2,061,375**									
2003		**2,524,686**									
2004		**3,969,549**									
2005		**6,700,973**									
2006		**11,484,013**									
2007		**15,662,377**									
2008		**21,193,520**									
2009		**34,846,766**									
2010		**45,832,851**									
Total 2002–2010		**$63,596,492**									

End notes:

[a] Levelized Costs are based on financial inputs from IPC's 2009 IRP, and calculations include line loss adjusted energy savings.

[b] Program life B/C ratios are provided for active programs only.

[c] The Total Utility Cost is all cost incurred by IPC to implement and manage a DSM program.

[d] The Total Resource Cost is the total expenditures for a DSM program from the point of view of IPC and its customers as a whole.

[e] Average Demand = Annual Energy/8,760 annual hours.

[f] Peak Demand is reported for programs that directly reduce load or measure demand reductions during summer peak season. Peak demand reduction for demand response programs is reported at the generation level assuming 13% peak line losses and is non-coincident.

[1] Peak MW achieved based on mid-week load reduction schedule.

[2] Utility cost reflects collected funds on previous bad loan write-offs.

[3] Utility cost reflects only audit and administration costs; there was no further activity in 2006.

[4] Levelized cost calculation includes bad loan write-off expense and funds collected from previously written off loans.

[5] Beginning in 2005, BPA funds were no longer applied to CAP agency payments.

[6] Oregon statutory program. The company does not monitor customer implementation of audit recommendations and thus does not estimate savings for this program. Audit expense not involving outside contractor services are booked to general customer service.

[7] Measure life is weighted life (based on energy savings) of custom option (15 years) and menu options (5 years).

[8] Savings were adjusted by NEEA in 2010.

[9] Savings are preliminary estimates provided by NEEA.

Appendix 5. 2010 DSM program activity by state jurisdiction

Program	Idaho Participants	Idaho Utility Costs	Idaho Demand Reduction/ Annual Energy Savings	Oregon Participants	Oregon Utility Costs	Oregon Demand Reduction/ Annual Energy Savings
Demand Response			**(MW)**			**(MW)**
A/C Cool Credit	30,482 homes	$ 1,928,447	38.6	321 homes	$ 74,099	0.4
Irrigation Peak Rewards	2,005 service points	13,144,261	245.5	33 service points	186,565	4.2
FlexPeak Management	56 sites	1,807,527	36.1	4 sites	95,153	11.4
Total		**$16,880,235**	**320.2**		**$ 355,817**	**16.0**
Energy Efficiency			**(kWh)**			**(kWh)**
Residential						
Ductless Heat Pump Pilot	101 homes	$ 181,969	353,500	3 homes	$ 7,262	10,500
Energy Efficient Lighting	1,171,010 bulbs	2,442,931	27,618,937	19,129 bulbs	58,347	463,800
Energy House Calls	1,525 homes	724,895	1,157,871	77 homes	37,435	40,784
ENERGY STAR® Homes Northwest	630 homes	369,504	883,260	0 homes	6,101	0
Heating & Cooling Efficiency Program	212 homes	314,963	1,081,875	5 homes	12,706	22,622
Home Improvement Program	3,537 homes	944,716	3,986,199	0 homes	0	0
Home Products Program	16,061 appliances/fixtures	813,171	1,418,905	261 appliances/fixtures	18,990	24,675
Oregon Residential Weatherization	0 home	0	0	1 home	6,050	320
Rebate Advantage	30 homes	34,283	145,578	5 homes	5,119	19,316
See ya later, refrigerator®	3,070 refrigerators/freezers	548,872	1,527,190	82 refrigerators/freezers	16,207	40,546
Weatherization Assistance for Qualified Customers	373 homes/non-profits	1,205,446	3,452,025	27 homes/non-profits	115,686	289,627
Weatherization Solutions for Eligible Customers	47 homes	226,119	313,309	0 homes	2,306	0
Total		**$ 7,806,869**	**41,938,649**		**$ 286,209**	**912,190**
Commercial						
Building Efficiency	6 projects	1,466,256	10,552,135	2 projects	43,426	267,463
Easy Upgrades	1,487 projects	3,862,653	35,200,511	48 projects	111,757	623,952
Holiday Lighting	25 projects	45,816	248,865	0 projects	316	0
Oregon Commercial Audits	0 audits	0	0	22 audits	5,049	0
Total		**$ 5,374,725**	**46,001,511**		**$ 160,548**	**891,415**
Industrial						
Custom Efficiency	204 projects	8,060,252	65,148,471	19 projects	717,873	6,431,604
Total		**$ 8,060,252**	**65,148,471**		**$ 717,873**	**6,431,604**

Appendix 5. 2010 DSM program activity by state jurisdiction (continued)

Program	Idaho Participants	Idaho Utility Costs	Idaho Demand Reduction/ Annual Energy Savings (kWh)	Oregon Participants	Oregon Utility Costs	Oregon Demand Reduction/ Annual Energy Savings (kWh)
Energy Efficiency			**(kWh)**			**(kWh)**
Irrigation						
Irrigation Efficiency Rewards	728 projects	$ 2,089,225	10,575,018	25 projects	$ 111,589	393,412
Total		**$ 2,089,225**	**10,575,018**		**$ 111,589**	**393,412**
Market Transformation						
Northwest Energy Efficiency Alliance [1]		$ 2,271,656	14,567,370		$ 119,561	766,704
Other Programs and Activities						
Residential						
Residential Energy Efficiency Education Initiative		211,695			$ 10,397	
Commercial						
Commercial Education Initiative		65,327			3,438	
Other						
Energy Efficiency Direct Program Overhead		109,545			8,329	
Local Energy Efficiency Funds	1 project	238		0 projects	13	
Total Direct Program Expense		**$42,869,767**			**$ 1,773,774**	
Indirect Program Expense		1,129,390			59,920	
Total Annual Savings			**178,231,019**			**9,395,325**
Total DSM Expense		**$43,999,157**			**$ 1,833,694**	

[1] Savings are preliminary estimates provided by NEEA. Oregon is credited with 5% of annual NEEA savings.



Appendix C—Technical Appendix

For the 2011 Integrated Resource Plan

June 2011

IDAHO POWER®
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INTRODUCTION

Appendix C—Technical Appendix contains supporting data and explanatory materials used to develop Idaho Power's *2011 Integrated Resource Plan* (IRP).

The main document, the IRP, contains a full narrative of Idaho Power's resource planning process. Additional information regarding the 2011 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 2010 Annual Report*. The IRP, including the three appendices, was filed with the Idaho and Oregon public utility commissions in June 2011.

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
208-388-2483

IRP ADVISORY COUNCIL ROSTER

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 2011 IRP, Idaho Power hosted a field trip covering wind, hydro, and natural gas resources, two portfolio-design workshops, and nine monthly IRPAC meetings. The IRPAC meetings served as an open forum for discussions related to the development of the IRP 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.....John Gardner
Heinz Frozen Foods .....Steve Munn
INL.....Tom Moriarty
Micron.....Michael Bick
Simplot.....Don Sturtevant

Public Interest Representatives

Boise Metro Chamber of Commerce .....Bill Connors
Idaho Conservation League .....Ben Otto
Idaho Department of Commerce.....Lane Packwood
Idaho Office of Energy Resources .....John Chatburn
Idaho State House of Representatives.....Representative Elaine Smith
Idaho State Senate.....Senator Russ Fulcher
Northwest Power and Conservation Council.....Jim Yost/Shirley Lindstrom
Oil/Gas Industry Advisor.....David Hawk
Snake River Alliance .....Ken Miller
Water Issues Advisor .....Vince Alberdi

Regulatory Commission Representatives

Idaho Public Utilities Commission .....Rick Sterling
Public Utility Commission of Oregon .....Erik Colville

SALES AND LOAD FORECAST DATA

Average Annual Forecast Growth Rates

	2011–2016	2011–2021	2011–2030
Sales			
Residential Sales	1.31%	1.51%	1.47%
Commercial Sales	1.30%	1.13%	1.31%
Irrigation Sales	0.31%	0.30%	0.26%
Industrial Sales	1.81%	1.61%	1.66%
Additional Firm Sales	7.40%	3.65%	2.03%
System Sales	1.95%	1.53%	1.39%
Total Sales	1.95%	1.53%	1.39%
Loads			
Residential Load	1.35%	1.52%	1.48%
Commercial Load	1.29%	1.13%	1.30%
Irrigation Load	0.26%	0.30%	0.26%
Industrial Load	1.74%	1.60%	1.66%
Additional Firm Sales	7.40%	3.65%	2.03%
System Load Losses	1.47%	1.33%	1.32%
System Load	1.89%	1.51%	1.38%
Total Load	1.89%	1.51%	1.38%
Peaks			
System Peak	2.23%	1.93%	1.76%
Total Peak	2.23%	1.93%	1.76%
Winter Peak	1.09%	1.10%	1.13%
Summer Peak	2.23%	1.93%	1.76%
Customers			
Residential Customers	1.72%	1.59%	1.37%
Commercial Customers	2.31%	2.17%	1.95%
Irrigation Customers	1.48%	1.43%	1.35%
Industrial Customers	1.60%	1.47%	1.35%

Expected-Case Load Forecast

Monthly Summary[1]	1/2011	2/2011	3/2011	4/2011	5/2011	6/2011	7/2011	8/2011	9/2011	10/2011	11/2011	12/2011
Average Load (aMW)–50th Percentile												
Residential	810	684	575	490	450	490	636	614	494	479	596	819
Commercial	474	432	405	387	398	430	503	487	433	400	418	493
Irrigation	2	1	1	59	286	524	611	501	314	50	1	1
Industrial	261	261	253	244	250	271	269	270	266	268	265	271
Additional Firm	136	155	172	181	176	153	146	154	170	175	180	185
Loss	165	148	133	128	150	184	217	201	163	129	138	171
System Load	1,848	1,682	1,540	1,489	1,709	2,054	2,381	2,228	1,839	1,501	1,598	1,941
Light Load	1,702	1,553	1,416	1,355	1,535	1,846	2,154	1,976	1,674	1,358	1,468	1,804
Heavy Load	1,974	1,778	1,629	1,588	1,858	2,205	2,577	2,409	1,972	1,613	1,703	2,048
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	1,848	1,682	1,540	1,489	1,709	2,054	2,381	2,228	1,839	1,501	1,598	1,941
Peak Load (MW)–90th Percentile												
System Peak (1 Hour)	2,499	2,394	2,090	1,888	2,833	3,325	3,494	3,171	3,004	2,053	2,169	2,693
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,499	2,394	2,090	1,888	2,833	3,325	3,494	3,171	3,004	2,053	2,169	2,693
	1/2012	**2/2012**	**3/2012**	**4/2012**	**5/2012**	**6/2012**	**7/2012**	**8/2012**	**9/2012**	**10/2012**	**11/2012**	**12/2012**
Average Load (aMW)–50th Percentile												
Residential	806	679	571	487	448	491	640	618	495	478	594	819
Commercial	480	437	410	392	404	438	512	494	440	405	423	500
Irrigation	1	1	1	59	287	527	614	504	315	50	0	1
Industrial	266	257	259	250	256	277	275	276	272	275	271	276
Additional Firm	199	195	194	189	185	162	154	163	182	193	200	206
Loss	169	149	135	129	151	186	219	204	164	130	140	173
System Load	1,921	1,719	1,569	1,506	1,731	2,082	2,414	2,259	1,868	1,531	1,629	1,975
Light Load	1,769	1,587	1,443	1,370	1,555	1,871	2,184	2,004	1,700	1,386	1,497	1,836
Heavy Load	2,052	1,816	1,659	1,615	1,869	2,236	2,612	2,443	2,015	1,636	1,736	2,094
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	1,921	1,719	1,569	1,506	1,731	2,082	2,414	2,259	1,868	1,531	1,629	1,975
Peak Load (MW)–90th Percentile												
System Peak (1 Hour)	2,497	2,387	2,086	1,867	2,876	3,377	3,555	3,205	3,056	2,084	2,183	2,676
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,497	2,387	2,086	1,867	2,876	3,377	3,555	3,205	3,056	2,084	2,183	2,676

[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 2011 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]	1/2013	2/2013	3/2013	4/2013	5/2013	6/2013	7/2013	8/2013	9/2013	10/2013	11/2013	12/2013
Average Load (aMW)–50th Percentile												
Residential	807	679	571	486	448	495	648	626	500	480	596	833
Commercial	485	441	415	397	410	445	520	502	446	411	429	507
Irrigation	1	1	0	59	286	526	613	503	315	50	0	1
Industrial	271	271	264	255	261	283	281	282	277	280	276	280
Additional Firm	213	211	207	202	198	193	202	200	201	206	213	219
Loss	170	151	136	130	153	189	224	207	167	132	141	176
System Load	1,948	1,753	1,593	1,529	1,756	2,130	2,487	2,319	1,906	1,559	1,656	2,016
Light Load	1,794	1,619	1,465	1,391	1,578	1,915	2,250	2,058	1,734	1,411	1,522	1,875
Heavy Load	2,069	1,854	1,693	1,630	1,897	2,303	2,674	2,508	2,056	1,666	1,765	2,138
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	1,948	1,753	1,593	1,529	1,756	2,130	2,487	2,319	1,906	1,559	1,656	2,016
Peak Load (MW)–90th Percentile												
System Peak (1 Hour)	2,506	2,395	2,101	1,866	2,924	3,478	3,662	3,298	3,130	2,113	2,202	2,690
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,506	2,395	2,101	1,866	2,924	3,478	3,662	3,298	3,130	2,113	2,202	2,690
	1/2014	**2/2014**	**3/2014**	**4/2014**	**5/2014**	**6/2014**	**7/2014**	**8/2014**	**9/2014**	**10/2014**	**11/2014**	**12/2014**
Average Load (aMW)–50th Percentile												
Residential	827	693	583	497	460	510	671	648	516	493	612	851
Commercial	491	445	420	402	416	452	528	510	453	416	434	514
Irrigation	1	1	1	59	287	526	613	503	315	50	0	1
Industrial	276	276	269	259	266	288	286	287	282	285	281	285
Additional Firm	224	223	219	214	209	204	214	211	213	218	225	231
Loss	174	154	138	133	155	192	228	211	170	135	144	180
System Load	1,993	1,792	1,629	1,563	1,793	2,173	2,540	2,370	1,949	1,597	1,697	2,061
Light Load	1,836	1,655	1,499	1,422	1,610	1,953	2,298	2,103	1,774	1,446	1,559	1,916
Heavy Load	2,117	1,895	1,732	1,666	1,936	2,349	2,731	2,581	2,090	1,707	1,818	2,175
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	1,993	1,792	1,629	1,563	1,793	2,173	2,540	2,370	1,949	1,597	1,697	2,061
Peak Load (MW)–90th Percentile												
System Peak (1 Hour)	2,566	2,439	2,146	1,915	2,980	3,556	3,747	3,383	3,197	2,152	2,252	2,766
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,566	2,439	2,146	1,915	2,980	3,556	3,747	3,383	3,197	2,152	2,252	2,766
Monthly Summary	**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	841	704	592	505	468	522	690	667	529	503	623	865
Commercial	497	449	424	406	421	459	537	517	460	422	439	520
Irrigation	2	1	1	59	289	530	617	507	317	50	1	1
Industrial	280	280	273	263	270	293	290	291	287	290	286	289
Additional Firm	236	234	230	225	221	216	225	223	224	229	237	243
Loss	176	156	141	135	158	195	232	215	173	137	147	182
System Load	2,032	1,824	1,661	1,594	1,827	2,215	2,591	2,420	1,990	1,632	1,732	2,100
Light Load	1,871	1,685	1,528	1,450	1,641	1,991	2,344	2,147	1,811	1,477	1,591	1,952
Heavy Load	2,158	1,929	1,766	1,699	1,987	2,379	2,786	2,635	2,134	1,744	1,856	2,216
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,032	1,824	1,661	1,594	1,827	2,215	2,591	2,420	1,990	1,632	1,732	2,100
Peak Load (MW)–90th Percentile												
System Peak (1 Hour)	2,606	2,470	2,180	1,945	3,035	3,629	3,831	3,459	3,260	2,188	2,290	2,815
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,606	2,470	2,180	1,945	3,035	3,629	3,831	3,459	3,260	2,188	2,290	2,815

[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 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2016	2/2016	3/2016	4/2016	5/2016	6/2016	7/2016	8/2016	9/2016	10/2016	11/2016	12/2016
Average Load (aMW)–50th Percentile												
Residential	851	711	598	510	474	532	706	683	540	511	632	880
Commercial	501	453	428	410	426	465	544	523	466	426	443	525
Irrigation	2	2	1	60	290	532	620	509	319	51	1	1
Industrial	284	274	277	267	274	297	295	295	291	295	290	293
Additional Firm	248	244	241	235	230	224	232	229	229	233	240	245
Loss	179	157	142	136	160	198	235	218	175	139	149	185
System Load	2,065	1,840	1,687	1,618	1,854	2,248	2,631	2,458	2,020	1,654	1,754	2,128
Light Load	1,901	1,699	1,552	1,472	1,665	2,021	2,380	2,180	1,838	1,497	1,612	1,979
Heavy Load	2,205	1,944	1,785	1,725	2,016	2,414	2,847	2,658	2,165	1,778	1,869	2,246
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,065	1,840	1,687	1,618	1,854	2,248	2,631	2,458	2,020	1,654	1,754	2,128
Peak Load (MW)–90th Percentile												
System Peak (1 Hour)	2,636	2,497	2,205	1,962	3,084	3,693	3,902	3,519	3,314	2,211	2,312	2,843
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,636	2,497	2,205	1,962	3,084	3,693	3,902	3,519	3,314	2,211	2,312	2,843
	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	865	720	606	517	482	544	725	701	553	521	643	893
Commercial	505	455	432	413	431	471	550	529	471	430	447	530
Irrigation	2	2	1	60	291	533	621	510	320	51	1	1
Industrial	288	288	281	271	279	302	299	300	295	299	294	297
Additional Firm	248	246	241	235	230	223	232	229	229	233	240	244
Loss	181	160	144	138	161	200	238	221	178	141	151	187
System Load	2,089	1,869	1,704	1,634	1,873	2,274	2,666	2,491	2,046	1,675	1,775	2,153
Light Load	1,924	1,726	1,568	1,487	1,682	2,044	2,412	2,210	1,861	1,516	1,631	2,002
Heavy Load	2,231	1,977	1,803	1,752	2,023	2,442	2,885	2,694	2,193	1,800	1,891	2,283
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,089	1,869	1,704	1,634	1,873	2,274	2,666	2,491	2,046	1,675	1,775	2,153
Peak Load (MW)–90th Percentile												
System Peak (1 Hour)	2,662	2,510	2,223	1,978	3,124	3,751	3,967	3,579	3,365	2,232	2,335	2,879
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,662	2,510	2,223	1,978	3,124	3,751	3,967	3,579	3,365	2,232	2,335	2,879
	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	876	727	613	522	488	554	741	718	564	529	652	908
Commercial	509	457	435	417	435	477	557	536	476	434	451	535
Irrigation	2	2	1	60	292	535	624	512	321	51	1	1
Industrial	292	291	284	275	282	306	303	304	299	303	298	301
Additional Firm	249	246	241	235	230	224	233	229	230	234	240	245
Loss	183	161	145	139	163	203	242	224	180	143	152	190
System Load	2,110	1,885	1,720	1,649	1,891	2,299	2,700	2,523	2,070	1,693	1,795	2,180
Light Load	1,943	1,741	1,582	1,500	1,699	2,066	2,442	2,238	1,884	1,533	1,648	2,027
Heavy Load	2,241	1,993	1,819	1,768	2,042	2,469	2,921	2,729	2,233	1,809	1,912	2,312
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,110	1,885	1,720	1,649	1,891	2,299	2,700	2,523	2,070	1,693	1,795	2,180
Peak Load (MW)–90th Percentile												
System Peak (1 Hour)	2,678	2,521	2,236	1,984	3,163	3,806	4,031	3,634	3,414	2,251	2,354	2,906
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,678	2,521	2,236	1,984	3,163	3,806	4,031	3,634	3,414	2,251	2,354	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 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2019	2/2019	3/2019	4/2019	5/2019	6/2019	7/2019	8/2019	9/2019	10/2019	11/2019	12/2019
Average Load (aMW)–50th Percentile												
Residential	890	737	621	530	496	567	761	738	578	539	663	924
Commercial	513	460	439	420	440	482	564	542	482	438	455	540
Irrigation	2	2	1	60	292	536	625	513	321	51	1	1
Industrial	295	295	288	279	287	310	308	308	304	308	303	305
Additional Firm	249	247	242	236	231	224	233	230	230	234	241	245
Loss	185	163	147	140	165	205	245	228	183	145	154	192
System Load	2,134	1,903	1,738	1,665	1,911	2,326	2,736	2,558	2,097	1,715	1,817	2,208
Light Load	1,966	1,758	1,599	1,515	1,716	2,090	2,475	2,269	1,909	1,552	1,669	2,053
Heavy Load	2,267	2,013	1,847	1,775	2,064	2,514	2,942	2,766	2,263	1,832	1,935	2,341
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,134	1,903	1,738	1,665	1,911	2,326	2,736	2,558	2,097	1,715	1,817	2,208
Peak Load (MW)–90th Percentile												
System Peak (1 Hour)	2,704	2,538	2,255	2,000	3,203	3,865	4,098	3,695	3,464	2,273	2,378	2,943
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,704	2,538	2,255	2,000	3,203	3,865	4,098	3,695	3,464	2,273	2,378	2,943
	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	902	746	629	536	504	579	780	756	591	549	674	937
Commercial	516	464	442	424	445	488	570	547	487	442	459	545
Irrigation	2	2	1	60	293	538	627	515	322	51	1	1
Industrial	299	289	292	283	291	315	312	312	308	312	307	309
Additional Firm	248	243	241	235	230	224	233	230	230	234	240	245
Loss	187	163	148	142	166	207	248	231	185	146	156	194
System Load	2,155	1,907	1,753	1,680	1,929	2,351	2,771	2,591	2,123	1,734	1,836	2,231
Light Load	1,985	1,761	1,613	1,528	1,733	2,113	2,506	2,299	1,932	1,569	1,687	2,075
Heavy Load	2,290	2,015	1,864	1,790	2,097	2,525	2,979	2,822	2,276	1,852	1,967	2,355
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,155	1,907	1,753	1,680	1,929	2,351	2,771	2,591	2,123	1,734	1,836	2,231
Peak Load (MW)–90th Percentile												
System Peak (1 Hour)	2,726	2,549	2,271	2,013	3,242	3,922	4,164	3,753	3,514	2,293	2,400	2,976
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,726	2,549	2,271	2,013	3,242	3,922	4,164	3,753	3,514	2,293	2,400	2,976
	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	912	752	634	541	510	589	797	773	602	557	682	951
Commercial	520	465	446	427	449	494	577	554	493	446	463	550
Irrigation	2	2	1	61	294	540	628	516	323	51	1	1
Industrial	303	303	296	287	295	319	316	317	312	316	311	313
Additional Firm	249	246	242	236	231	225	234	230	230	234	241	245
Loss	189	165	150	143	168	210	251	234	187	148	158	197
System Load	2,176	1,934	1,769	1,694	1,947	2,376	2,804	2,624	2,148	1,753	1,856	2,258
Light Load	2,004	1,786	1,627	1,541	1,749	2,136	2,537	2,328	1,955	1,586	1,705	2,099
Heavy Load	2,324	2,045	1,871	1,806	2,117	2,552	3,015	2,857	2,303	1,884	1,977	2,383
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,176	1,934	1,769	1,694	1,947	2,376	2,804	2,624	2,148	1,753	1,856	2,258
Peak Load (MW)–90th Percentile												
System Peak (1 Hour)	2,743	2,563	2,285	2,021	3,282	3,978	4,229	3,809	3,564	2,312	2,418	3,004
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,743	2,563	2,285	2,021	3,282	3,978	4,229	3,809	3,564	2,312	2,418	3,004

[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 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2022	2/2022	3/2022	4/2022	5/2022	6/2022	7/2022	8/2022	9/2022	10/2022	11/2022	12/2022
Average Load (aMW)–50th Percentile												
Residential	925	760	641	547	517	601	817	792	615	566	693	967
Commercial	525	469	450	431	455	501	585	561	499	451	467	556
Irrigation	2	2	1	61	295	541	630	517	324	51	1	1
Industrial	308	308	301	291	299	324	321	322	317	321	316	317
Additional Firm	249	247	242	237	232	225	235	231	231	235	241	246
Loss	191	167	151	145	170	212	255	237	190	150	160	200
System Load	2,201	1,953	1,787	1,711	1,967	2,404	2,842	2,660	2,176	1,775	1,878	2,287
Light Load	2,027	1,804	1,644	1,557	1,767	2,161	2,571	2,360	1,980	1,606	1,725	2,126
Heavy Load	2,350	2,065	1,890	1,824	2,139	2,582	3,075	2,876	2,333	1,907	2,001	2,413
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,201	1,953	1,787	1,711	1,967	2,404	2,842	2,660	2,176	1,775	1,878	2,287
Peak Load (MW)–90th Percentile												
System Peak (1 Hour)	2,768	2,580	2,304	2,037	3,323	4,038	4,296	3,871	3,617	2,334	2,443	3,042
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,768	2,580	2,304	2,037	3,323	4,038	4,296	3,871	3,617	2,334	2,443	3,042
	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	939	770	650	554	525	614	838	813	629	576	704	981
Commercial	530	473	454	436	460	508	593	568	506	456	472	562
Irrigation	2	2	1	61	295	542	631	519	325	52	1	1
Industrial	313	312	305	295	304	329	326	326	322	326	321	322
Additional Firm	250	248	243	238	233	226	235	232	232	236	242	247
Loss	194	169	153	146	172	215	259	241	192	152	162	202
System Load	2,227	1,973	1,807	1,730	1,989	2,434	2,881	2,698	2,206	1,798	1,902	2,315
Light Load	2,051	1,822	1,662	1,574	1,786	2,188	2,607	2,394	2,007	1,627	1,747	2,153
Heavy Load	2,379	2,087	1,911	1,854	2,148	2,614	3,118	2,918	2,365	1,932	2,026	2,455
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,227	1,973	1,807	1,730	1,989	2,434	2,881	2,698	2,206	1,798	1,902	2,315
Peak Load (MW)–90th Percentile												
System Peak (1 Hour)	2,800	2,601	2,326	2,060	3,365	4,100	4,367	3,938	3,671	2,358	2,471	3,089
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,800	2,601	2,326	2,060	3,365	4,100	4,367	3,938	3,671	2,358	2,471	3,089
	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	949	776	655	559	531	624	856	831	641	585	713	992
Commercial	535	478	459	441	466	515	601	576	514	462	477	568
Irrigation	2	2	1	61	296	544	634	520	326	52	1	1
Industrial	317	306	310	299	308	334	331	331	326	331	325	327
Additional Firm	250	246	243	238	233	227	236	232	232	236	242	247
Loss	196	170	155	148	173	218	262	244	195	154	164	204
System Load	2,250	1,978	1,824	1,746	2,008	2,462	2,919	2,734	2,234	1,819	1,923	2,340
Light Load	2,072	1,827	1,677	1,588	1,804	2,213	2,641	2,426	2,033	1,646	1,767	2,176
Heavy Load	2,390	2,090	1,938	1,861	2,169	2,661	3,138	2,957	2,410	1,944	2,049	2,481
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,250	1,978	1,824	1,746	2,008	2,462	2,919	2,734	2,234	1,819	1,923	2,340
Peak Load (MW)–90th Percentile												
System Peak (1 Hour)	2,822	2,614	2,343	2,073	3,407	4,160	4,435	3,999	3,725	2,380	2,493	3,124
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,822	2,614	2,343	2,073	3,407	4,160	4,435	3,999	3,725	2,380	2,493	3,124

[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 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2025	2/2025	3/2025	4/2025	5/2025	6/2025	7/2025	8/2025	9/2025	10/2025	11/2025	12/2025
Average Load (aMW)–50th Percentile												
Residential	956	780	658	562	535	633	871	846	650	591	720	1,002
Commercial	541	482	465	446	473	524	610	584	522	468	483	576
Irrigation	2	2	1	61	297	545	635	522	327	52	1	1
Industrial	323	323	315	305	313	339	336	337	332	336	331	333
Additional Firm	251	249	244	239	234	228	237	233	234	237	243	248
Loss	198	172	156	149	175	220	265	247	198	156	166	207
System Load	2,271	2,007	1,840	1,762	2,028	2,489	2,954	2,769	2,262	1,840	1,944	2,367
Light Load	2,092	1,854	1,693	1,603	1,822	2,237	2,673	2,457	2,058	1,665	1,786	2,201
Heavy Load	2,413	2,122	1,956	1,878	2,190	2,690	3,176	3,015	2,425	1,966	2,083	2,498
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,271	2,007	1,840	1,762	2,028	2,489	2,954	2,769	2,262	1,840	1,944	2,367
Peak Load (MW)–90th Percentile												
System Peak (1 Hour)	2,837	2,628	2,356	2,079	3,448	4,218	4,501	4,056	3,779	2,401	2,512	3,150
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,837	2,628	2,356	2,079	3,448	4,218	4,501	4,056	3,779	2,401	2,512	3,150
	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	965	785	663	566	541	643	888	863	662	599	728	1,011
Commercial	548	488	471	453	480	533	620	594	531	475	490	584
Irrigation	2	2	1	61	298	546	636	523	327	52	1	1
Industrial	329	329	321	310	319	345	342	343	338	342	337	339
Additional Firm	253	250	246	240	235	229	238	235	235	238	245	249
Loss	200	174	158	151	177	223	269	251	200	158	168	209
System Load	2,297	2,028	1,860	1,781	2,050	2,519	2,994	2,808	2,293	1,864	1,968	2,393
Light Load	2,116	1,873	1,711	1,620	1,841	2,264	2,709	2,491	2,087	1,687	1,808	2,225
Heavy Load	2,441	2,144	1,977	1,898	2,229	2,705	3,219	3,057	2,458	1,992	2,109	2,526
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,297	2,028	1,860	1,781	2,050	2,519	2,994	2,808	2,293	1,864	1,968	2,393
Peak Load (MW)–90th Percentile												
System Peak (1 Hour)	2,861	2,645	2,375	2,093	3,491	4,280	4,571	4,119	3,836	2,426	2,536	3,183
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,861	2,645	2,375	2,093	3,491	4,280	4,571	4,119	3,836	2,426	2,536	3,183
	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	968	786	664	566	543	649	901	875	669	603	732	1,026
Commercial	556	494	478	460	488	543	631	604	541	483	497	593
Irrigation	2	2	1	61	298	547	638	524	328	52	1	1
Industrial	336	335	327	316	324	351	348	349	344	348	343	346
Additional Firm	252	250	246	240	236	229	239	235	235	239	245	249
Loss	202	175	159	152	179	225	272	254	203	160	170	212
System Load	2,316	2,042	1,875	1,796	2,068	2,545	3,028	2,841	2,320	1,884	1,987	2,427
Light Load	2,133	1,886	1,725	1,634	1,858	2,287	2,739	2,520	2,111	1,705	1,825	2,257
Heavy Load	2,473	2,159	1,983	1,914	2,248	2,733	3,255	3,093	2,487	2,025	2,117	2,561
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,316	2,042	1,875	1,796	2,068	2,545	3,028	2,841	2,320	1,884	1,987	2,427
Peak Load (MW)–90th Percentile												
System Peak (1 Hour)	2,865	2,650	2,382	2,088	3,532	4,336	4,635	4,169	3,890	2,446	2,549	3,197
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,865	2,650	2,382	2,088	3,532	4,336	4,635	4,169	3,890	2,446	2,549	3,197

[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 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2028	2/2028	3/2028	4/2028	5/2028	6/2028	7/2028	8/2028	9/2028	10/2028	11/2028	12/2028
Average Load (aMW)–50th Percentile												
Residential	988	799	676	577	554	667	928	902	688	617	747	1,041
Commercial	564	503	486	467	497	554	643	615	552	492	506	602
Irrigation	2	2	1	61	298	547	637	524	328	52	1	1
Industrial	343	331	333	322	330	357	354	356	350	354	349	352
Additional Firm	252	248	246	241	236	230	239	236	236	239	245	249
Loss	205	177	162	154	181	229	277	259	207	163	173	216
System Load	2,354	2,060	1,904	1,823	2,097	2,583	3,079	2,891	2,360	1,917	2,021	2,462
Light Load	2,168	1,902	1,751	1,658	1,884	2,322	2,786	2,565	2,148	1,735	1,856	2,289
Heavy Load	2,514	2,176	2,013	1,954	2,265	2,774	3,331	3,127	2,530	2,060	2,153	2,610
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,354	2,060	1,904	1,823	2,097	2,583	3,079	2,891	2,360	1,917	2,021	2,462
Peak Load (MW)–90th Percentile												
System Peak (1 Hour)	2,919	2,675	2,420	2,131	3,582	4,409	4,718	4,253	3,952	2,480	2,593	3,267
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,919	2,675	2,420	2,131	3,582	4,409	4,718	4,253	3,952	2,480	2,593	3,267
	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	995	803	679	579	559	676	944	918	698	623	754	1,053
Commercial	573	510	494	476	506	565	655	627	563	502	514	613
Irrigation	2	2	1	62	300	550	641	526	330	52	1	1
Industrial	350	350	340	328	336	364	361	362	357	360	356	359
Additional Firm	252	250	246	241	237	230	240	237	236	239	245	249
Loss	208	180	163	156	184	232	281	263	210	165	175	219
System Load	2,379	2,094	1,923	1,842	2,121	2,617	3,122	2,933	2,394	1,942	2,045	2,495
Light Load	2,191	1,934	1,769	1,676	1,905	2,352	2,824	2,602	2,179	1,758	1,879	2,320
Heavy Load	2,528	2,214	2,034	1,975	2,291	2,810	3,378	3,172	2,583	2,075	2,179	2,645
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,379	2,094	1,923	1,842	2,121	2,617	3,122	2,933	2,394	1,942	2,045	2,495
Peak Load (MW)–90th Percentile												
System Peak (1 Hour)	2,936	2,702	2,435	2,138	3,628	4,472	4,792	4,315	4,010	2,505	2,614	3,293
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,936	2,702	2,435	2,138	3,628	4,472	4,792	4,315	4,010	2,505	2,614	3,293
	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	1,006	810	685	585	566	688	965	939	712	632	764	1,069
Commercial	583	518	503	485	516	577	669	640	576	512	524	624
Irrigation	2	2	1	62	300	550	641	527	330	52	1	1
Industrial	357	357	347	335	342	370	368	369	364	367	362	367
Additional Firm	252	250	246	242	238	231	241	238	237	240	246	250
Loss	211	182	166	158	186	235	285	267	213	168	178	222
System Load	2,412	2,120	1,948	1,866	2,147	2,653	3,169	2,979	2,432	1,972	2,075	2,534
Light Load	2,221	1,958	1,792	1,698	1,929	2,384	2,867	2,643	2,213	1,785	1,906	2,356
Heavy Load	2,562	2,242	2,071	1,989	2,319	2,867	3,407	3,222	2,624	2,107	2,210	2,686
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,412	2,120	1,948	1,866	2,147	2,653	3,169	2,979	2,432	1,972	2,075	2,534
Peak Load (MW)–90th Percentile												
System Peak (1 Hour)	2,968	2,726	2,460	2,159	3,676	4,539	4,870	4,386	4,071	2,536	2,646	3,336
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,968	2,726	2,460	2,159	3,676	4,539	4,870	4,386	4,071	2,536	2,646	3,336

[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 2011 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

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Billed Sales (MWh)–50th Percentile										
Residential	5,212,406	5,203,339	5,225,209	5,368,280	5,478,414	5,563,357	5,669,304	5,757,369	5,869,128	5,970,745
Commercial	3,838,581	3,892,057	3,946,012	3,999,968	4,052,337	4,093,919	4,134,970	4,175,514	4,215,706	4,255,106
Irrigation	1,726,426	1,733,923	1,730,933	1,732,192	1,745,054	1,753,457	1,758,741	1,765,002	1,768,786	1,774,046
Industrial	2,294,027	2,346,083	2,391,684	2,434,390	2,472,828	2,509,361	2,545,600	2,580,387	2,616,525	2,653,140
Additional Firm	1,449,272	1,627,180	1,798,947	1,901,753	2,002,406	2,070,809	2,065,176	2,069,629	2,074,558	2,073,248
System Sales	14,520,712	14,802,582	15,092,784	15,436,583	15,751,039	15,990,903	16,173,791	16,347,900	16,544,703	16,726,284
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0
Total Sales	14,520,712	14,802,582	15,092,784	15,436,583	15,751,039	15,990,903	16,173,791	16,347,900	16,544,703	16,726,284
Generation Month Sales (MWh)–50th Percentile										
Residential	5,211,472	5,220,832	5,234,696	5,375,496	5,483,894	5,587,315	5,674,976	5,764,646	5,875,700	5,994,114
Commercial	3,842,581	3,906,684	3,949,996	4,003,861	4,055,659	4,108,526	4,138,224	4,178,743	4,218,887	4,269,976
Irrigation	1,726,429	1,733,968	1,730,933	1,732,196	1,745,056	1,753,504	1,758,743	1,765,003	1,768,788	1,774,094
Industrial	2,299,135	2,350,458	2,395,812	2,438,153	2,476,427	2,512,935	2,549,050	2,583,953	2,620,131	2,656,639
Additional Firm	1,449,272	1,627,180	1,798,947	1,901,753	2,002,406	2,070,809	2,065,176	2,069,629	2,074,558	2,073,248
System Sales	14,528,890	14,839,122	15,110,383	15,451,458	15,763,442	16,033,088	16,186,169	16,361,973	16,558,065	16,768,071
Firm Off-System Sales	0	0	0	0	0	0	0	0	0	0
Total Sales	14,528,890	14,839,122	15,110,383	15,451,458	15,763,442	16,033,088	16,186,169	16,361,973	16,558,065	16,768,071
Loss	1,409,072	1,428,282	1,444,136	1,471,939	1,496,894	1,519,773	1,535,352	1,552,758	1,572,301	1,593,865
Required Generation	15,937,962	16,267,403	16,554,519	16,923,397	17,260,337	17,552,861	17,721,520	17,914,731	18,130,365	18,361,936
Average Load (aMW)–50th Percentile										
Residential	595	594	598	614	626	636	648	658	671	682
Commercial	439	445	451	457	463	468	472	477	482	486
Irrigation	197	197	198	198	199	200	201	201	202	202
Industrial	262	268	273	278	283	286	291	295	299	302
Additional Firm	165	185	205	217	229	236	236	236	237	236
Loss	161	163	165	168	171	173	175	177	179	181
System Load	1,819	1,852	1,890	1,932	1,970	1,998	2,023	2,045	2,070	2,090
Light Load	1,655	1,685	1,719	1,758	1,793	1,818	1,840	1,860	1,883	1,902
Heavy Load	1,948	1,984	2,023	2,069	2,110	2,140	2,167	2,190	2,216	2,238
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0
Total Load	1,819	1,852	1,890	1,932	1,970	1,998	2,023	2,045	2,070	2,090
Peak Load (MW)–90th Percentile										
System Peak (1 Hour)	3,494	3,555	3,662	3,747	3,831	3,902	3,967	4,031	4,098	4,164
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0
Total Peak Load	3,494	3,555	3,662	3,747	3,831	3,902	3,967	4,031	4,098	4,164

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Billed Sales (MWh)–50th Percentile										
Residential	6,056,407	6,158,656	6,271,445	6,361,683	6,426,776	6,510,492	6,553,819	6,707,410	6,776,381	6,877,650
Commercial	4,296,755	4,343,256	4,394,013	4,447,644	4,508,307	4,576,705	4,649,243	4,732,314	4,818,303	4,912,860
Irrigation	1,778,962	1,782,409	1,787,374	1,793,802	1,798,253	1,800,997	1,804,775	1,804,427	1,813,588	1,814,979
Industrial	2,690,609	2,732,262	2,771,129	2,811,827	2,859,873	2,911,643	2,964,041	3,021,185	3,078,753	3,139,413
Additional Firm	2,074,887	2,081,619	2,088,963	2,096,186	2,101,203	2,111,939	2,112,515	2,119,494	2,118,995	2,125,092
System Sales	16,897,620	17,098,202	17,312,925	17,511,142	17,694,413	17,911,776	18,084,393	18,384,830	18,606,020	18,869,995
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0
Total Sales	16,897,620	17,098,202	17,312,925	17,511,142	17,694,413	17,911,776	18,084,393	18,384,830	18,606,020	18,869,995
Generation Month Sales (MWh)–50th Percentile										
Residential	6,062,999	6,165,952	6,277,197	6,384,350	6,432,065	6,513,037	6,563,818	6,730,858	6,782,814	6,885,381
Commercial	4,299,700	4,346,120	4,396,725	4,462,767	4,511,182	4,579,493	4,652,274	4,748,002	4,821,327	4,915,869
Irrigation	1,778,963	1,782,411	1,787,376	1,793,851	1,798,254	1,800,998	1,804,775	1,804,477	1,813,589	1,814,980
Industrial	2,694,287	2,735,521	2,774,365	2,815,511	2,863,696	2,915,340	2,967,964	3,024,964	3,082,617	3,143,429
Additional Firm	2,074,887	2,081,619	2,088,963	2,096,186	2,101,203	2,111,939	2,112,515	2,119,494	2,118,995	2,125,092
System Sales	16,910,836	17,111,622	17,324,626	17,552,664	17,706,401	17,920,807	18,101,346	18,427,795	18,619,341	18,884,751
Firm Off-System Sales	0	0	0	0	0	0	0	0	0	0
Total Sales	16,910,836	17,111,622	17,324,626	17,552,664	17,706,401	17,920,807	18,101,346	18,427,795	18,619,341	18,884,751
Loss	1,607,831	1,627,748	1,649,127	1,672,210	1,687,095	1,708,185	1,726,396	1,760,025	1,779,484	1,806,546
Required Generation	18,518,667	18,739,370	18,973,754	19,224,874	19,393,496	19,628,991	19,827,743	20,187,820	20,398,825	20,691,297
Average Load (aMW)–50th Percentile										
Residential	692	704	717	727	734	743	749	766	774	786
Commercial	491	496	502	508	515	523	531	541	550	561
Irrigation	203	203	204	204	205	206	206	205	207	207
Industrial	308	312	317	321	327	333	339	344	352	359
Additional Firm	237	238	238	239	240	241	241	241	242	243
Loss	184	186	188	190	193	195	197	200	203	206
System Load	2,114	2,139	2,166	2,189	2,214	2,241	2,263	2,298	2,329	2,362
Light Load	1,923	1,946	1,970	1,991	2,014	2,038	2,059	2,091	2,118	2,149
Heavy Load	2,264	2,291	2,320	2,343	2,371	2,400	2,424	2,462	2,494	2,529
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0
Total Load	2,114	2,139	2,166	2,189	2,214	2,241	2,263	2,298	2,329	2,362
Peak Load (MW)–90th Percentile										
System Peak (1 Hour)	4,229	4,296	4,367	4,435	4,501	4,571	4,635	4,718	4,792	4,870
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0
Total Peak Load	4,229	4,296	4,367	4,435	4,501	4,571	4,635	4,718	4,792	4,870

70th Percentile Load Forecast

Monthly Summary[1]	1/2011	2/2011	3/2011	4/2011	5/2011	6/2011	7/2011	8/2011	9/2011	10/2011	11/2011	12/2011
Average Load (aMW)–70th Percentile												
Residential	835	713	593	499	465	512	656	625	502	490	611	837
Commercial	482	440	408	391	403	436	509	490	435	403	421	498
Irrigation	2	1	1	75	339	572	633	517	336	57	1	1
Industrial	261	261	253	244	250	271	269	270	266	268	265	271
Additional Firm	136	155	172	181	176	153	146	154	170	175	180	185
Loss	169	152	136	131	158	193	222	205	166	131	140	174
System Load	1,885	1,722	1,563	1,521	1,790	2,137	2,434	2,262	1,876	1,525	1,619	1,965
Light Load	1,736	1,590	1,438	1,384	1,608	1,921	2,202	2,007	1,707	1,380	1,487	1,827
Heavy Load	2,013	1,821	1,653	1,621	1,947	2,295	2,634	2,446	2,011	1,639	1,724	2,074
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	1,885	1,722	1,563	1,521	1,790	2,137	2,434	2,262	1,876	1,525	1,619	1,965
Peak Load (MW)–95th Percentile												
System Peak (1 Hour)	2,553	2,440	2,147	1,901	2,863	3,377	3,515	3,185	3,019	2,068	2,231	2,815
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,553	2,440	2,147	1,901	2,863	3,377	3,515	3,185	3,019	2,068	2,231	2,815
	1/2012	**2/2012**	**3/2012**	**4/2012**	**5/2012**	**6/2012**	**7/2012**	**8/2012**	**9/2012**	**10/2012**	**11/2012**	**12/2012**
Average Load (aMW)–70th Percentile												
Residential	832	708	589	496	463	513	660	629	504	489	610	837
Commercial	488	445	413	396	409	444	518	498	442	409	427	505
Irrigation	1	1	1	75	340	574	636	520	338	57	0	1
Industrial	266	257	259	250	256	277	275	276	272	275	271	276
Additional Firm	199	195	194	189	185	162	154	163	182	193	200	206
Loss	172	153	137	132	159	194	225	207	168	133	142	176
System Load	1,959	1,760	1,592	1,538	1,812	2,165	2,468	2,293	1,905	1,556	1,650	2,000
Light Load	1,804	1,625	1,465	1,399	1,628	1,946	2,232	2,035	1,733	1,408	1,515	1,860
Heavy Load	2,092	1,859	1,684	1,649	1,958	2,325	2,670	2,480	2,055	1,663	1,757	2,121
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	1,959	1,760	1,592	1,538	1,812	2,165	2,468	2,293	1,905	1,556	1,650	2,000
Peak Load (MW)–95th Percentile												
System Peak (1 Hour)	2,551	2,433	2,143	1,880	2,906	3,430	3,577	3,219	3,071	2,099	2,245	2,800
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,551	2,433	2,143	1,880	2,906	3,430	3,577	3,219	3,071	2,099	2,245	2,800

[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 2011 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]	1/2013	2/2013	3/2013	4/2013	5/2013	6/2013	7/2013	8/2013	9/2013	10/2013	11/2013	12/2013
Average Load (aMW)–70th Percentile												
Residential	833	708	589	495	464	517	668	637	508	491	612	851
Commercial	494	449	418	400	415	451	526	506	449	414	432	512
Irrigation	1	1	1	75	339	574	635	519	337	57	0	1
Industrial	271	271	264	255	261	283	281	282	277	280	276	280
Additional Firm	213	211	207	202	198	193	202	200	201	206	213	219
Loss	174	155	138	133	161	197	229	211	170	135	143	179
System Load	1,986	1,795	1,617	1,561	1,838	2,214	2,541	2,354	1,943	1,584	1,677	2,042
Light Load	1,829	1,658	1,487	1,420	1,652	1,990	2,299	2,088	1,768	1,433	1,541	1,899
Heavy Load	2,110	1,898	1,718	1,664	1,986	2,394	2,732	2,546	2,096	1,692	1,787	2,165
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	1,986	1,795	1,617	1,561	1,838	2,214	2,541	2,354	1,943	1,584	1,677	2,042
Peak Load (MW)–95th Percentile												
System Peak (1 Hour)	2,561	2,441	2,157	1,879	2,955	3,533	3,684	3,312	3,146	2,127	2,264	2,817
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,561	2,441	2,157	1,879	2,955	3,533	3,684	3,312	3,146	2,127	2,264	2,817
	1/2014	**2/2014**	**3/2014**	**4/2014**	**5/2014**	**6/2014**	**7/2014**	**8/2014**	**9/2014**	**10/2014**	**11/2014**	**12/2014**
Average Load (aMW)–70th Percentile												
Residential	853	723	602	506	475	533	692	660	525	505	627	870
Commercial	500	453	423	405	421	458	535	514	456	420	438	519
Irrigation	1	1	1	75	340	574	635	519	337	57	0	1
Industrial	276	276	269	259	266	288	286	287	282	285	281	285
Additional Firm	224	223	219	214	209	204	214	211	213	218	225	231
Loss	177	158	141	136	163	201	233	215	174	137	146	182
System Load	2,032	1,834	1,654	1,596	1,875	2,258	2,594	2,406	1,986	1,622	1,718	2,087
Light Load	1,872	1,694	1,521	1,452	1,685	2,030	2,347	2,134	1,807	1,468	1,578	1,941
Heavy Load	2,159	1,940	1,758	1,701	2,026	2,441	2,789	2,619	2,129	1,734	1,841	2,203
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,032	1,834	1,654	1,596	1,875	2,258	2,594	2,406	1,986	1,622	1,718	2,087
Peak Load (MW)–95th Percentile												
System Peak (1 Hour)	2,620	2,485	2,203	1,928	3,011	3,611	3,770	3,398	3,213	2,167	2,314	2,895
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,620	2,485	2,203	1,928	3,011	3,611	3,770	3,398	3,213	2,167	2,314	2,895
	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	868	735	611	514	484	546	711	679	538	515	639	885
Commercial	506	458	428	410	427	466	543	521	463	425	443	525
Irrigation	2	1	1	76	342	577	639	523	340	58	1	1
Industrial	280	280	273	263	270	293	290	291	287	290	286	289
Additional Firm	236	234	230	225	221	216	225	223	224	229	237	243
Loss	180	161	143	138	166	204	237	219	177	140	149	185
System Load	2,072	1,868	1,686	1,627	1,910	2,301	2,646	2,455	2,028	1,657	1,754	2,127
Light Load	1,908	1,725	1,551	1,480	1,716	2,068	2,394	2,179	1,845	1,500	1,611	1,978
Heavy Load	2,201	1,975	1,792	1,734	2,077	2,471	2,845	2,674	2,174	1,771	1,879	2,244
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,072	1,868	1,686	1,627	1,910	2,301	2,646	2,455	2,028	1,657	1,754	2,127
Peak Load (MW)–95th Percentile												
System Peak (1 Hour)	2,661	2,517	2,236	1,958	3,067	3,685	3,854	3,474	3,277	2,203	2,352	2,948
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,661	2,517	2,236	1,958	3,067	3,685	3,854	3,474	3,277	2,203	2,352	2,948

[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 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2016	2/2016	3/2016	4/2016	5/2016	6/2016	7/2016	8/2016	9/2016	10/2016	11/2016	12/2016
Average Load (aMW)–70th Percentile												
Residential	879	742	617	520	490	556	728	695	549	523	648	899
Commercial	510	461	432	414	432	472	550	527	468	429	447	530
Irrigation	2	2	1	76	343	580	642	525	341	58	1	1
Industrial	284	274	277	267	274	297	295	295	291	295	290	293
Additional Firm	248	244	241	235	230	224	232	229	229	233	240	245
Loss	183	162	145	140	168	206	241	222	179	142	151	188
System Load	2,106	1,885	1,713	1,652	1,938	2,334	2,687	2,493	2,057	1,681	1,777	2,156
Light Load	1,939	1,741	1,576	1,503	1,741	2,098	2,431	2,212	1,872	1,521	1,632	2,005
Heavy Load	2,249	1,991	1,812	1,760	2,107	2,507	2,907	2,697	2,205	1,806	1,893	2,275
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,106	1,885	1,713	1,652	1,938	2,334	2,687	2,493	2,057	1,681	1,777	2,156
Peak Load (MW)–95th Percentile												
System Peak (1 Hour)	2,691	2,543	2,261	1,975	3,116	3,750	3,925	3,535	3,331	2,226	2,374	2,978
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,691	2,543	2,261	1,975	3,116	3,750	3,925	3,535	3,331	2,226	2,374	2,978
	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	893	752	626	527	499	569	747	714	562	534	660	914
Commercial	515	464	436	417	437	478	557	534	474	434	451	535
Irrigation	2	2	1	76	344	581	643	526	342	58	1	1
Industrial	288	288	281	271	279	302	299	300	295	299	294	297
Additional Firm	248	246	241	235	230	223	232	229	229	233	240	244
Loss	185	164	147	141	170	209	244	225	182	144	153	190
System Load	2,131	1,915	1,731	1,668	1,957	2,361	2,723	2,527	2,083	1,701	1,798	2,182
Light Load	1,963	1,769	1,592	1,517	1,758	2,122	2,463	2,242	1,896	1,540	1,652	2,029
Heavy Load	2,276	2,025	1,831	1,788	2,114	2,536	2,946	2,733	2,233	1,828	1,916	2,313
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,131	1,915	1,731	1,668	1,957	2,361	2,723	2,527	2,083	1,701	1,798	2,182
Peak Load (MW)–95th Percentile												
System Peak (1 Hour)	2,716	2,556	2,280	1,991	3,156	3,809	3,991	3,595	3,382	2,247	2,397	3,017
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,716	2,556	2,280	1,991	3,156	3,809	3,991	3,595	3,382	2,247	2,397	3,017
	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	905	760	633	532	505	579	764	731	573	542	669	929
Commercial	519	467	439	421	442	484	564	540	479	438	455	540
Irrigation	2	2	1	77	345	583	646	528	343	59	1	1
Industrial	292	291	284	275	282	306	303	304	299	303	298	301
Additional Firm	249	246	241	235	230	224	233	229	230	234	240	245
Loss	187	166	148	142	171	211	247	228	184	145	155	193
System Load	2,153	1,932	1,747	1,683	1,976	2,387	2,757	2,560	2,108	1,720	1,818	2,209
Light Load	1,983	1,784	1,607	1,531	1,775	2,145	2,494	2,271	1,919	1,557	1,670	2,054
Heavy Load	2,287	2,042	1,847	1,804	2,134	2,563	2,983	2,768	2,274	1,838	1,937	2,342
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,153	1,932	1,747	1,683	1,976	2,387	2,757	2,560	2,108	1,720	1,818	2,209
Peak Load (MW)–95th Percentile												
System Peak (1 Hour)	2,733	2,567	2,293	1,997	3,195	3,865	4,056	3,650	3,431	2,266	2,416	3,046
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,733	2,567	2,293	1,997	3,195	3,865	4,056	3,650	3,431	2,266	2,416	3,046

[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 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2019	2/2019	3/2019	4/2019	5/2019	6/2019	7/2019	8/2019	9/2019	10/2019	11/2019	12/2019
Average Load (aMW)–70th Percentile												
Residential	919	771	642	540	514	592	785	751	587	553	681	945
Commercial	523	469	443	424	447	490	571	546	485	442	459	546
Irrigation	2	2	1	77	345	584	647	529	344	59	1	1
Industrial	295	295	288	279	287	310	308	308	304	308	303	305
Additional Firm	249	247	242	236	231	224	233	230	230	234	241	245
Loss	189	167	150	144	173	214	251	231	186	147	157	195
System Load	2,178	1,951	1,765	1,700	1,996	2,415	2,794	2,595	2,136	1,742	1,841	2,237
Light Load	2,006	1,802	1,624	1,546	1,793	2,170	2,528	2,302	1,943	1,577	1,691	2,081
Heavy Load	2,314	2,063	1,877	1,812	2,156	2,610	3,004	2,806	2,304	1,861	1,961	2,372
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,178	1,951	1,765	1,700	1,996	2,415	2,794	2,595	2,136	1,742	1,841	2,237
Peak Load (MW)–95th Percentile												
System Peak (1 Hour)	2,759	2,584	2,312	2,013	3,236	3,924	4,123	3,711	3,482	2,288	2,440	3,086
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,759	2,584	2,312	2,013	3,236	3,924	4,123	3,711	3,482	2,288	2,440	3,086
	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	933	780	650	546	522	605	804	770	600	562	692	959
Commercial	527	473	446	428	451	495	578	552	490	446	463	550
Irrigation	2	2	1	77	346	586	649	531	345	59	1	1
Industrial	299	289	292	283	291	315	312	312	308	312	307	309
Additional Firm	248	243	241	235	230	224	233	230	230	234	240	245
Loss	191	168	151	145	175	216	254	234	189	149	158	197
System Load	2,200	1,956	1,781	1,714	2,015	2,441	2,829	2,629	2,161	1,761	1,861	2,261
Light Load	2,026	1,806	1,639	1,560	1,810	2,194	2,560	2,332	1,967	1,594	1,709	2,103
Heavy Load	2,338	2,066	1,894	1,827	2,191	2,621	3,042	2,863	2,317	1,882	1,994	2,386
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,200	1,956	1,781	1,714	2,015	2,441	2,829	2,629	2,161	1,761	1,861	2,261
Peak Load (MW)–95th Percentile												
System Peak (1 Hour)	2,781	2,595	2,328	2,026	3,276	3,983	4,190	3,770	3,532	2,307	2,462	3,121
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,781	2,595	2,328	2,026	3,276	3,983	4,190	3,770	3,532	2,307	2,462	3,121
	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	943	787	656	551	528	615	822	787	612	570	701	973
Commercial	531	475	450	431	456	502	585	558	496	450	467	556
Irrigation	2	2	1	77	347	587	650	532	346	59	1	1
Industrial	303	303	296	287	295	319	316	317	312	316	311	313
Additional Firm	249	246	242	236	231	225	234	230	230	234	241	245
Loss	193	170	152	146	176	219	257	238	191	151	160	200
System Load	2,222	1,984	1,797	1,729	2,033	2,467	2,864	2,662	2,187	1,781	1,881	2,288
Light Load	2,046	1,832	1,653	1,573	1,827	2,217	2,591	2,361	1,990	1,612	1,727	2,128
Heavy Load	2,373	2,098	1,901	1,843	2,211	2,649	3,079	2,898	2,344	1,914	2,003	2,415
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,222	1,984	1,797	1,729	2,033	2,467	2,864	2,662	2,187	1,781	1,881	2,288
Peak Load (MW)–95th Percentile												
System Peak (1 Hour)	2,797	2,609	2,341	2,033	3,316	4,040	4,254	3,826	3,582	2,327	2,481	3,152
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,797	2,609	2,341	2,033	3,316	4,040	4,254	3,826	3,582	2,327	2,481	3,152

[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 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2022	2/2022	3/2022	4/2022	5/2022	6/2022	7/2022	8/2022	9/2022	10/2022	11/2022	12/2022
Average Load (aMW)–70th Percentile												
Residential	956	796	663	558	536	628	842	806	625	580	712	989
Commercial	536	479	454	436	462	508	592	565	502	455	471	561
Irrigation	2	2	1	77	348	588	652	533	346	59	1	1
Industrial	308	308	301	291	299	324	321	322	317	321	316	317
Additional Firm	249	247	242	237	232	225	235	231	231	235	241	246
Loss	196	172	154	148	178	221	261	241	194	153	162	203
System Load	2,248	2,004	1,816	1,747	2,054	2,495	2,902	2,698	2,215	1,803	1,904	2,318
Light Load	2,070	1,851	1,671	1,589	1,845	2,243	2,625	2,394	2,016	1,632	1,749	2,155
Heavy Load	2,400	2,119	1,921	1,862	2,234	2,680	3,140	2,918	2,375	1,938	2,028	2,446
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,248	2,004	1,816	1,747	2,054	2,495	2,902	2,698	2,215	1,803	1,904	2,318
Peak Load (MW)–95th Percentile												
System Peak (1 Hour)	2,823	2,626	2,360	2,049	3,357	4,100	4,323	3,889	3,635	2,349	2,505	3,193
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,823	2,626	2,360	2,049	3,357	4,100	4,323	3,889	3,635	2,349	2,505	3,193
	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	971	806	672	565	544	641	863	827	639	591	723	1,004
Commercial	541	483	459	440	467	516	600	573	509	460	476	567
Irrigation	2	2	1	77	348	590	653	535	347	59	1	1
Industrial	313	312	305	295	304	329	326	326	322	326	321	322
Additional Firm	250	248	243	238	233	226	235	232	232	236	242	247
Loss	198	174	156	150	180	224	265	245	196	155	165	205
System Load	2,275	2,025	1,836	1,765	2,076	2,526	2,942	2,737	2,246	1,827	1,928	2,347
Light Load	2,095	1,871	1,689	1,606	1,865	2,270	2,662	2,428	2,043	1,653	1,771	2,182
Heavy Load	2,430	2,142	1,942	1,893	2,243	2,712	3,184	2,960	2,407	1,963	2,054	2,489
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,275	2,025	1,836	1,765	2,076	2,526	2,942	2,737	2,246	1,827	1,928	2,347
Peak Load (MW)–95th Percentile												
System Peak (1 Hour)	2,855	2,647	2,383	2,072	3,400	4,163	4,393	3,956	3,690	2,373	2,533	3,243
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,855	2,647	2,383	2,072	3,400	4,163	4,393	3,956	3,690	2,373	2,533	3,243
	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	982	814	678	570	551	653	882	845	651	599	733	1,015
Commercial	546	489	464	445	473	523	609	581	517	466	482	574
Irrigation	2	2	1	78	349	592	656	536	348	59	1	1
Industrial	317	306	310	299	308	334	331	331	326	331	325	327
Additional Firm	250	246	243	238	233	227	236	232	232	236	242	247
Loss	200	175	158	151	182	227	268	248	199	157	167	208
System Load	2,299	2,031	1,854	1,782	2,097	2,554	2,981	2,774	2,274	1,848	1,950	2,373
Light Load	2,117	1,876	1,705	1,621	1,884	2,296	2,696	2,461	2,069	1,673	1,791	2,206
Heavy Load	2,442	2,146	1,971	1,899	2,265	2,761	3,205	3,000	2,453	1,975	2,077	2,516
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,299	2,031	1,854	1,782	2,097	2,554	2,981	2,774	2,274	1,848	1,950	2,373
Peak Load (MW)–95th Percentile												
System Peak (1 Hour)	2,877	2,660	2,400	2,086	3,442	4,224	4,462	4,017	3,745	2,394	2,555	3,280
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,877	2,660	2,400	2,086	3,442	4,224	4,462	4,017	3,745	2,394	2,555	3,280

[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 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2025	2/2025	3/2025	4/2025	5/2025	6/2025	7/2025	8/2025	9/2025	10/2025	11/2025	12/2025
Average Load (aMW)–70th Percentile												
Residential	989	818	682	573	555	662	897	860	661	606	739	1,026
Commercial	553	493	470	451	480	532	618	589	525	472	488	582
Irrigation	2	2	1	78	350	593	657	538	349	60	1	1
Industrial	323	323	315	305	313	339	336	337	332	336	331	333
Additional Firm	251	249	244	239	234	228	237	233	234	237	243	248
Loss	202	177	159	153	184	229	271	251	202	159	168	210
System Load	2,321	2,061	1,871	1,798	2,117	2,582	3,017	2,809	2,302	1,869	1,971	2,401
Light Load	2,138	1,904	1,721	1,636	1,901	2,321	2,729	2,492	2,095	1,692	1,810	2,232
Heavy Load	2,466	2,180	1,989	1,917	2,286	2,791	3,244	3,058	2,468	1,998	2,112	2,533
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,321	2,061	1,871	1,798	2,117	2,582	3,017	2,809	2,302	1,869	1,971	2,401
Peak Load (MW)–95th Percentile												
System Peak (1 Hour)	2,892	2,674	2,413	2,092	3,483	4,283	4,528	4,075	3,799	2,415	2,574	3,309
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,892	2,674	2,413	2,092	3,483	4,283	4,528	4,075	3,799	2,415	2,574	3,309
	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	999	824	687	578	561	672	915	878	673	614	748	1,035
Commercial	560	499	476	457	488	541	628	599	534	480	495	590
Irrigation	2	2	1	78	351	594	658	539	350	60	1	1
Industrial	329	329	321	310	319	345	342	343	338	342	337	339
Additional Firm	253	250	246	240	235	229	238	235	235	238	245	249
Loss	205	179	161	154	186	232	275	255	204	161	171	213
System Load	2,348	2,083	1,892	1,818	2,139	2,613	3,057	2,848	2,334	1,894	1,996	2,427
Light Load	2,163	1,924	1,740	1,654	1,922	2,349	2,766	2,526	2,123	1,714	1,833	2,257
Heavy Load	2,495	2,203	2,011	1,937	2,326	2,806	3,287	3,101	2,502	2,024	2,138	2,561
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,348	2,083	1,892	1,818	2,139	2,613	3,057	2,848	2,334	1,894	1,996	2,427
Peak Load (MW)–95th Percentile												
System Peak (1 Hour)	2,916	2,691	2,431	2,106	3,527	4,346	4,599	4,137	3,856	2,440	2,598	3,345
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,916	2,691	2,431	2,106	3,527	4,346	4,599	4,137	3,856	2,440	2,598	3,345
	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	1,003	825	688	578	564	679	928	890	680	618	752	1,051
Commercial	568	505	483	464	496	551	639	609	544	488	502	599
Irrigation	2	2	1	78	351	595	660	540	350	60	1	1
Industrial	336	335	327	316	324	351	348	349	344	348	343	346
Additional Firm	252	250	246	240	236	229	239	235	235	239	245	249
Loss	207	180	162	156	188	234	278	258	207	163	172	216
System Load	2,367	2,098	1,907	1,833	2,158	2,640	3,092	2,881	2,360	1,914	2,015	2,461
Light Load	2,180	1,938	1,754	1,667	1,938	2,372	2,797	2,556	2,148	1,733	1,851	2,289
Heavy Load	2,528	2,219	2,017	1,953	2,346	2,835	3,324	3,137	2,530	2,058	2,146	2,598
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,367	2,098	1,907	1,833	2,158	2,640	3,092	2,881	2,360	1,914	2,015	2,461
Peak Load (MW)–95th Percentile												
System Peak (1 Hour)	2,920	2,696	2,438	2,101	3,568	4,403	4,664	4,188	3,910	2,460	2,611	3,361
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,920	2,696	2,438	2,101	3,568	4,403	4,664	4,188	3,910	2,460	2,611	3,361

[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 2011 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

Monthly Summary[1]	1/2028	2/2028	3/2028	4/2028	5/2028	6/2028	7/2028	8/2028	9/2028	10/2028	11/2028	12/2028
Average Load (aMW)–70th Percentile												
Residential	1,023	840	700	589	575	697	956	918	699	633	768	1,066
Commercial	576	514	491	472	504	562	651	621	555	497	511	609
Irrigation	2	2	1	78	351	595	659	540	350	60	1	1
Industrial	343	331	333	322	330	357	354	356	350	354	349	352
Additional Firm	252	248	246	241	236	230	239	236	236	239	245	249
Loss	210	183	165	158	190	238	283	263	211	166	176	219
System Load	2,407	2,117	1,936	1,860	2,188	2,679	3,144	2,932	2,401	1,948	2,049	2,497
Light Load	2,217	1,955	1,781	1,692	1,965	2,408	2,844	2,601	2,185	1,763	1,882	2,322
Heavy Load	2,570	2,237	2,048	1,994	2,363	2,877	3,401	3,171	2,574	2,093	2,183	2,647
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,407	2,117	1,936	1,860	2,188	2,679	3,144	2,932	2,401	1,948	2,049	2,497
Peak Load (MW)–95th Percentile												
System Peak (1 Hour)	2,974	2,721	2,476	2,144	3,618	4,476	4,747	4,273	3,972	2,494	2,655	3,434
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,974	2,721	2,476	2,144	3,618	4,476	4,747	4,273	3,972	2,494	2,655	3,434
	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	1,031	844	704	592	580	707	972	934	710	639	775	1,079
Commercial	586	521	499	481	514	574	664	633	567	506	519	619
Irrigation	2	2	1	78	353	598	663	542	352	60	1	1
Industrial	350	350	340	328	336	364	361	362	357	360	356	359
Additional Firm	252	250	246	241	237	230	240	237	236	239	245	249
Loss	213	185	167	160	193	241	287	267	214	168	178	222
System Load	2,433	2,152	1,957	1,880	2,212	2,713	3,187	2,974	2,435	1,973	2,074	2,530
Light Load	2,241	1,987	1,800	1,710	1,987	2,439	2,883	2,639	2,216	1,786	1,905	2,353
Heavy Load	2,585	2,275	2,070	2,016	2,389	2,914	3,449	3,217	2,627	2,109	2,210	2,683
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,433	2,152	1,957	1,880	2,212	2,713	3,187	2,974	2,435	1,973	2,074	2,530
Peak Load (MW)–95th Percentile												
System Peak (1 Hour)	2,991	2,748	2,491	2,151	3,665	4,541	4,822	4,335	4,031	2,520	2,677	3,463
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	2,991	2,748	2,491	2,151	3,665	4,541	4,822	4,335	4,031	2,520	2,677	3,463
	1/2030	**2/2030**	**3/2030**	**4/2030**	**5/2030**	**6/2030**	**7/2030**	**8/2030**	**9/2030**	**10/2030**	**11/2030**	**12/2030**
Average Load (aMW)–70th Percentile												
Residential	1,043	852	710	597	587	719	994	955	724	649	786	1,095
Commercial	596	530	508	490	524	586	677	646	580	517	529	631
Irrigation	2	2	1	78	353	598	663	543	352	60	1	1
Industrial	357	357	347	335	342	370	368	369	364	367	362	367
Additional Firm	252	250	246	242	238	231	241	238	237	240	246	250
Loss	216	188	169	162	195	245	292	271	217	171	181	226
System Load	2,466	2,179	1,982	1,904	2,239	2,750	3,235	3,021	2,474	2,004	2,104	2,570
Light Load	2,271	2,012	1,823	1,733	2,011	2,472	2,927	2,680	2,251	1,813	1,933	2,389
Heavy Load	2,620	2,304	2,107	2,030	2,418	2,972	3,478	3,267	2,668	2,141	2,242	2,725
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	2,466	2,179	1,982	1,904	2,239	2,750	3,235	3,021	2,474	2,004	2,104	2,570
Peak Load (MW)–95th Percentile												
System Peak (1 Hour)	3,023	2,772	2,516	2,172	3,713	4,609	4,900	4,406	4,092	2,550	2,708	3,509
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0	0	0
Total Peak Load	3,023	2,772	2,516	2,172	3,713	4,609	4,900	4,406	4,092	2,550	2,708	3,509

[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 2011 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

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Billed Sales (MWh)–70th Percentile										
Residential	5,357,421	5,350,025	5,374,565	5,521,030	5,634,806	5,723,417	5,833,019	5,924,726	6,040,115	6,145,352
Commercial	3,880,072	3,934,333	3,989,337	4,044,412	4,097,916	4,140,627	4,182,801	4,224,463	4,265,773	4,306,283
Irrigation	1,861,930	1,869,427	1,866,437	1,867,696	1,880,558	1,888,961	1,894,245	1,900,506	1,904,290	1,909,550
Industrial	2,294,027	2,346,083	2,391,684	2,434,390	2,472,828	2,509,361	2,545,600	2,580,387	2,616,525	2,653,140
Additional Firm	1,449,272	1,627,180	1,798,947	1,901,753	2,002,406	2,070,809	2,065,176	2,069,629	2,074,558	2,073,248
System Sales	14,842,722	15,127,047	15,420,970	15,769,281	16,088,513	16,333,175	16,520,841	16,699,711	16,901,261	17,087,573
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0
Total Sales	14,842,722	15,127,047	15,420,970	15,769,281	16,088,513	16,333,175	16,520,841	16,699,711	16,901,261	17,087,573
Generation Month Sales (MWh)–70th Percentile										
Residential	5,356,552	5,368,321	5,384,199	5,528,413	5,640,457	5,748,305	5,838,861	5,932,173	6,046,857	6,169,719
Commercial	3,884,105	3,949,205	3,993,381	4,048,367	4,101,300	4,155,506	4,186,117	4,227,754	4,269,015	4,321,445
Irrigation	1,861,934	1,869,472	1,866,438	1,867,700	1,880,561	1,889,009	1,894,248	1,900,508	1,904,292	1,909,598
Industrial	2,299,135	2,350,458	2,395,812	2,438,153	2,476,427	2,512,935	2,549,050	2,583,953	2,620,131	2,656,639
Additional Firm	1,449,272	1,627,180	1,798,947	1,901,753	2,002,406	2,070,809	2,065,176	2,069,629	2,074,558	2,073,248
System Sales	14,850,998	15,164,636	15,438,777	15,784,386	16,101,150	16,376,563	16,533,451	16,714,015	16,914,853	17,130,649
Firm Off-System Sales	0	0	0	0	0	0	0	0	0	0
Total Sales	14,850,998	15,164,636	15,438,777	15,784,386	16,101,150	16,376,563	16,533,451	16,714,015	16,914,853	17,130,649
Loss	1,444,182	1,463,763	1,479,931	1,508,228	1,533,705	1,557,212	1,573,206	1,591,131	1,611,191	1,633,386
Required Generation	16,295,180	16,628,399	16,918,708	17,292,614	17,634,855	17,933,775	18,106,657	18,305,146	18,526,044	18,764,035
Average Load (aMW)–70th Percentile										
Residential	611	611	615	631	644	654	667	677	690	702
Commercial	443	450	456	462	468	473	478	483	487	492
Irrigation	213	213	213	213	215	215	216	217	217	217
Industrial	262	268	273	278	283	286	291	295	299	302
Additional Firm	165	185	205	217	229	236	236	236	237	236
Loss	165	167	169	172	175	177	180	182	184	186
System Load	1,860	1,893	1,931	1,974	2,013	2,042	2,067	2,090	2,115	2,136
Light Load	1,692	1,722	1,757	1,796	1,831	1,857	1,880	1,901	1,924	1,943
Heavy Load	1,992	2,028	2,068	2,114	2,156	2,186	2,214	2,238	2,264	2,287
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0
Total Load	1,860	1,893	1,931	1,974	2,013	2,042	2,067	2,090	2,115	2,136
Peak Load (MW)–95th Percentile										
System Peak (1 Hour)	3,515	3,577	3,684	3,770	3,854	3,925	3,991	4,056	4,123	4,190
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0
Total Peak Load	3,515	3,577	3,684	3,770	3,854	3,925	3,991	4,056	4,123	4,190

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Billed Sales (MWh)–70th Percentile										
Residential	6,234,625	6,340,476	6,456,861	6,550,687	6,619,355	6,706,622	6,753,472	6,910,560	6,983,002	7,087,720
Commercial	4,349,042	4,396,651	4,448,515	4,503,254	4,565,023	4,634,525	4,708,162	4,792,331	4,879,416	4,975,065
Irrigation	1,914,466	1,917,913	1,922,878	1,929,306	1,933,757	1,936,501	1,940,279	1,939,931	1,949,092	1,950,483
Industrial	2,690,609	2,732,262	2,771,129	2,811,827	2,859,873	2,911,643	2,964,041	3,021,185	3,078,753	3,139,413
Additional Firm	2,074,887	2,081,619	2,088,963	2,096,186	2,101,203	2,111,939	2,112,515	2,119,494	2,118,995	2,125,092
System Sales	17,263,629	17,468,921	17,688,347	17,891,260	18,079,212	18,301,230	18,478,470	18,783,502	19,009,257	19,277,774
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0
Total Sales	17,263,629	17,468,921	17,688,347	17,891,260	18,079,212	18,301,230	18,478,470	18,783,502	19,009,257	19,277,774
Generation Month Sales (MWh)–70th Percentile										
Residential	6,241,386	6,347,940	6,462,780	6,574,419	6,624,811	6,709,331	6,763,635	6,935,136	6,989,597	7,095,612
Commercial	4,352,048	4,399,576	4,451,288	4,518,688	4,567,958	4,637,373	4,711,254	4,808,349	4,882,499	4,978,134
Irrigation	1,914,468	1,917,915	1,922,881	1,929,355	1,933,758	1,936,503	1,940,279	1,939,982	1,949,093	1,950,485
Industrial	2,694,287	2,735,521	2,774,365	2,815,511	2,863,696	2,915,340	2,967,964	3,024,964	3,082,617	3,143,429
Additional Firm	2,074,887	2,081,619	2,088,963	2,096,186	2,101,203	2,111,939	2,112,515	2,119,494	2,118,995	2,125,092
System Sales	17,277,075	17,482,570	17,700,277	17,934,159	18,091,427	18,310,486	18,495,648	18,827,925	19,022,801	19,292,751
Firm Off-System Sales	0	0	0	0	0	0	0	0	0	0
Total Sales	17,277,075	17,482,570	17,700,277	17,934,159	18,091,427	18,310,486	18,495,648	18,827,925	19,022,801	19,292,751
Loss	1,647,751	1,668,181	1,690,073	1,713,793	1,729,063	1,750,660	1,769,375	1,803,639	1,823,461	1,851,018
Required Generation	18,924,826	19,150,752	19,390,350	19,647,952	19,820,490	20,061,146	20,265,023	20,631,564	20,846,262	21,143,769
Average Load (aMW)–70th Percentile										
Residential	712	725	738	748	756	766	772	790	798	810
Commercial	497	502	508	514	521	529	538	547	557	568
Irrigation	219	219	220	220	221	221	221	221	222	223
Industrial	308	312	317	321	327	333	339	344	352	359
Additional Firm	237	238	238	239	240	241	241	241	242	243
Loss	188	190	193	195	197	200	202	205	208	211
System Load	2,160	2,186	2,214	2,237	2,263	2,290	2,313	2,349	2,380	2,414
Light Load	1,965	1,989	2,014	2,035	2,058	2,083	2,104	2,137	2,165	2,196
Heavy Load	2,314	2,341	2,371	2,395	2,423	2,452	2,478	2,516	2,548	2,584
Firm Off-System Load	0	0	0	0	0	0	0	0	0	0
Total Load	2,160	2,186	2,214	2,237	2,263	2,290	2,313	2,349	2,380	2,414
Peak Load (MW)–95th Percentile										
System Peak (1 Hour)	4,254	4,323	4,393	4,462	4,528	4,599	4,664	4,747	4,822	4,900
Firm Off-System Peak	0	0	0	0	0	0	0	0	0	0
Total Peak Load	4,254	4,323	4,393	4,462	4,528	4,599	4,664	4,747	4,822	4,900

LOAD AND RESOURCE BALANCE DATA

Monthly Average Energy Load and Resource Balance

	1/2011	2/2011	3/2011	4/2011	5/2011	6/2011	7/2011	8/2011	9/2011	10/2011	11/2011	12/2011
Forecast DSM	14	13	13	14	16	17	17	17	15	14	13	13
Load Forecast (70th% w/DSM)	(1,885)	(1,722)	(1,563)	(1,521)	(1,790)	(2,137)	(2,434)	(2,262)	(1,876)	(1,525)	(1,619)	(1,965)
Existing Resources												
Coal	933	933	863	669	646	914	932	932	932	931	932	932
Gas (Langley Gulch)	0	0	0	0	0	0	0	0	0	0	0	0
Hydro (70th%)—HCC	571	700	590	668	823	714	499	364	410	435	364	473
Hydro (70th%)—Other	217	253	245	240	334	346	278	235	229	224	198	211
Shoshone Falls Upgrade	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	71	0	0	0	0	0
Total Hydro (70th%)	787	953	836	908	1,156	1,060	849	599	639	658	562	684
CSPP (PURPA)	93	97	129	151	185	193	207	210	211	187	163	168
PPAs												
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	48	45	48	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	42	42	0	0	0	0
Total PPAs	49	49	31	34	50	106	144	140	43	26	25	58
Firm Pacific NW Import Capability	133	32	0	0	320	254	126	186	197	0	115	325
Gas Peakers	224	0	0	0	0	240	224	242	0	0	0	233
Existing Resource Subtotal	2,219	2,065	1,859	1,762	2,357	2,767	2,482	2,309	2,021	1,802	1,798	2,400
Monthly Surplus/Deficit	334	343	296	241	566	630	47	47	146	277	179	435
2011 IRP DSM												
Industrial	2	2	2	2	2	2	2	2	2	2	2	2
Commercial	1	1	1	1	1	1	0	1	1	1	1	1
Residential	0	0	0	0	0	1	1	1	0	0	0	0
Total New DSM (aMW)	3	3	3	3	3	3	3	3	3	3	3	3
Monthly Surplus/Deficit	336	345	299	244	569	634	51	50	148	279	182	437
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	0	0	0	0	0	0	0	0	0	0	0	0
2021 Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	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	336	345	299	244	569	634	51	50	148	279	182	437

Monthly Average Energy Load and Resource Balance (continued)

	1/2012	2/2012	3/2012	4/2012	5/2012	6/2012	7/2012	8/2012	9/2012	10/2012	11/2012	12/2012
Forecast DSM	27	26	26	28	31	34	34	33	30	27	27	27
Load Forecast (70th% w/DSM)	(1,959)	(1,760)	(1,592)	(1,538)	(1,812)	(2,165)	(2,468)	(2,293)	(1,905)	(1,556)	(1,650)	(2,000)
Existing Resources												
Coal	932	932	886	776	735	851	931	931	931	930	931	931
Gas (Langley Gulch)	0	0	0	0	0	0	251	251	251	251	251	251
Hydro (70th%)—HCC	571	698	590	666	823	713	499	363	410	433	364	471
Hydro (70th%)—Other	216	252	246	240	333	346	278	235	229	223	198	211
Shoshone Falls Upgrade	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	71	0	0	0	0	0
Total Hydro (70th%)	787	950	835	906	1,156	1,059	848	598	639	656	562	682
CSPP (PURPA)	155	162	179	199	228	229	217	210	211	187	163	170
PPAs												
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	0	0	0	0	0	0	0	0	0	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	45	48	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	49	49	31	34	50	58	102	98	43	46	45	78
Firm Pacific NW Import Capability	122	30	0	0	444	360	233	294	304	0	129	322
Gas Peakers	224	0	0	0	0	240	224	242	0	0	0	224
Existing Resource Subtotal	2,269	2,124	1,932	1,915	2,612	2,798	2,806	2,624	2,378	2,070	2,082	2,657
Monthly Surplus/Deficit	310	364	339	377	799	633	338	331	474	514	433	657
2011 IRP DSM												
Industrial	3	3	3	3	3	3	3	3	3	3	3	3
Commercial	1	1	1	1	1	1	1	1	1	1	1	1
Residential	1	1	1	1	1	2	2	2	1	1	1	1
Total New DSM (aMW)	5	5	5	5	5	6	6	7	5	5	5	5
Monthly Surplus/Deficit	315	369	344	382	804	640	345	337	479	519	438	662
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	0	0	0	0	0	0	0	0	0	0	0	0
2021 Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	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	315	369	344	382	804	640	345	337	479	519	438	662

Monthly Average Energy Load and Resource Balance (continued)

	1/2013	2/2013	3/2013	4/2013	5/2013	6/2013	7/2013	8/2013	9/2013	10/2013	11/2013	12/2013
Forecast DSM	39	39	39	41	46	49	50	48	44	40	39	40
Load Forecast (70th% w/DSM)	(1,986)	(1,795)	(1,617)	(1,561)	(1,838)	(2,214)	(2,541)	(2,354)	(1,943)	(1,584)	(1,677)	(2,042)
Existing Resources												
Coal	931	931	852	558	612	931	931	931	931	930	931	931
Gas (Langley Gulch)	251	251	251	251	251	251	251	251	251	251	251	251
Hydro (70th%)—HCC	572	695	589	666	823	713	499	363	411	431	364	471
Hydro (70th%)—Other	216	252	244	239	332	345	278	235	229	223	198	211
Shoshone Falls Upgrade	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	72	0	0	0	0	0
Total Hydro (70th%)	787	947	834	905	1,155	1,058	848	597	639	654	562	681
CSPP (PURPA)	161	169	189	209	238	239	225	218	219	196	173	178
PPAs												
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	69	69	51	54	70	78	77	70	63	46	45	78
Firm Pacific NW Import Capability	131	37	0	0	443	357	229	291	302	0	148	319
Gas Peakers	233	0	0	0	0	231	233	242	0	0	0	224
Existing Resource Subtotal	2,564	2,404	2,177	1,977	2,769	3,146	2,794	2,600	2,405	2,078	2,110	2,662
Monthly Surplus/Deficit	577	609	561	416	930	932	253	246	462	494	433	620
2011 IRP DSM												
Industrial	5	5	5	5	5	5	5	5	5	5	5	5
Commercial	1	1	1	1	1	1	1	1	1	1	1	1
Residential	1	1	1	1	1	4	4	4	1	1	1	1
Total New DSM (aMW)	8	8	8	8	8	10	10	10	8	8	8	8
Monthly Surplus/Deficit	585	617	569	424	938	942	264	257	470	502	440	628
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	0	0	0	0	0	0	0	0	0	0	0	0
2021 Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	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	585	617	569	424	938	942	264	257	470	502	440	628

Monthly Average Energy Load and Resource Balance (continued)

	1/2014	2/2014	3/2014	4/2014	5/2014	6/2014	7/2014	8/2014	9/2014	10/2014	11/2014	12/2014
Forecast DSM	52	52	52	54	60	65	65	63	57	53	52	52
Load Forecast (70th% w/DSM)	(2,032)	(1,835)	(1,654)	(1,596)	(1,875)	(2,258)	(2,594)	(2,406)	(1,986)	(1,623)	(1,718)	(2,087)
Existing Resources												
Coal	931	931	880	584	722	921	931	931	931	930	931	931
Gas (Langley Gulch)	251	251	251	251	251	251	251	251	251	251	251	251
Hydro (70th%)—HCC	574	682	587	663	823	710	497	362	405	428	365	467
Hydro (70th%)—Other	214	246	241	226	331	345	277	234	228	222	197	209
Shoshone Falls Upgrade	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	72	0	0	0	0	0
Total Hydro (70th%)	787	928	828	889	1,154	1,055	845	595	632	650	561	676
CSPP (PURPA)	164	172	189	209	238	239	225	218	219	196	173	178
PPAs												
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	69	69	51	54	70	78	77	70	63	46	45	78
Firm Pacific NW Import Capability	190	81	0	0	441	353	225	288	301	0	198	318
Gas Peakers	233	0	0	0	0	231	233	233	0	0	0	233
Existing Resource Subtotal	2,625	2,432	2,200	1,987	2,875	3,128	2,787	2,585	2,397	2,073	2,159	2,664
Monthly Surplus/Deficit	593	598	546	391	1,000	870	193	180	411	450	441	577
2011 IRP DSM												
Industrial	6	6	6	6	6	6	6	6	6	6	6	6
Commercial	2	2	2	2	2	2	2	2	2	2	2	2
Residential	2	2	2	2	2	6	6	6	2	2	2	2
Total New DSM (aMW)	10	10	10	10	10	14	14	14	10	10	10	10
Monthly Surplus/Deficit	603	608	556	401	1,010	884	207	194	421	460	451	587
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	0	0	0	0	0	0	0	0	0	0	0	0
2021 Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	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	603	608	556	401	1,010	884	207	194	421	460	451	587

Monthly Average Energy Load and Resource Balance (continued)

	1/2015	2/2015	3/2015	4/2015	5/2015	6/2015	7/2015	8/2015	9/2015	10/2015	11/2015	12/2015
Forecast DSM	64	64	64	66	74	79	79	77	70	65	64	64
Load Forecast (70th% w/DSM)	(2,072)	(1,868)	(1,686)	(1,627)	(1,910)	(2,301)	(2,646)	(2,456)	(2,028)	(1,657)	(1,754)	(2,127)
Existing Resources												
Coal	931	931	834	634	715	814	931	931	931	930	931	931
Gas (Langley Gulch)	251	251	251	251	251	251	251	251	251	251	251	251
Hydro (70th%)—HCC	576	671	586	659	822	708	495	360	406	421	364	464
Hydro (70th%)—Other	212	236	237	223	331	344	276	233	227	221	195	207
Shoshone Falls Upgrade	0	0	0	0	0	0	0	0	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	72	0	0	0	0	0
Total Hydro (70th%)	787	907	823	882	1,153	1,052	843	592	632	642	560	682
CSPP (PURPA)	164	172	189	209	238	239	225	218	219	196	173	178
PPAs												
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	69	69	51	54	70	78	77	70	63	46	45	78
Firm Pacific NW Import Capability	231	113	0	0	440	350	222	286	299	0	237	316
Gas Peakers	233	0	0	0	0	240	233	233	0	0	0	233
Existing Resource Subtotal	2,666	2,443	2,149	2,030	2,865	3,025	2,782	2,581	2,395	2,065	2,197	2,669
Monthly Surplus/Deficit	594	575	463	403	955	724	135	125	367	408	442	542
2011 IRP DSM												
Industrial	7	7	7	7	7	7	7	7	7	7	7	7
Commercial	2	2	2	2	2	2	2	2	2	2	2	2
Residential	3	3	3	3	3	8	8	8	3	3	3	3
Total New DSM (aMW)	12	12	12	12	12	17	17	17	12	12	12	12
Monthly Surplus/Deficit	606	587	475	415	967	741	152	142	379	420	454	554
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	45	48	0	0	0	0
2016 Boardman to Hemingway	0	0	0	0	0	0	0	0	0	0	0	0
2021 Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	45	48	0	0	0	0
Monthly Surplus/Deficit	606	587	475	415	967	741	197	190	379	420	454	554

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 DSM	77	76	76	79	88	93	93	91	83	78	76	76
Load Forecast (70th% w/DSM)	(2,106)	(1,885)	(1,713)	(1,652)	(1,938)	(2,334)	(2,687)	(2,493)	(2,057)	(1,681)	(1,777)	(2,156)
Existing Resources												
Coal	931	931	898	823	715	888	937	937	937	936	937	937
Gas (Langley Gulch)	251	251	251	251	251	251	251	251	251	251	251	251
Hydro (70th%)—HCC	578	668	585	656	821	705	494	358	410	420	365	468
Hydro (70th%)—Other	210	255	240	232	330	343	275	232	227	221	195	205
Shoshone Falls Upgrade	7	34	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	794	957	840	888	1,166	1,067	771	590	636	641	560	684
CSPP (PURPA)	164	172	189	209	238	239	225	218	219	196	173	178
PPAs												
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	64	63	64	65	60	67	67	63	59	65	62	74
Firm Pacific NW Import Capability	254	105	0	0	437	346	218	283	297	0	258	314
Gas Peakers	224	0	0	0	0	240	224	242	0	0	0	233
Existing Resource Subtotal	2,682	2,479	2,243	2,237	2,866	3,099	2,693	2,584	2,399	2,089	2,241	2,671
Monthly Surplus/Deficit	576	594	530	585	929	764	6	90	342	408	464	515
2011 IRP DSM												
Industrial	8	7	7	7	8	8	8	8	7	7	7	7
Commercial	3	3	3	3	3	3	3	3	3	3	3	3
Residential	3	3	3	3	3	10	10	10	3	3	3	3
Total New DSM (aMW)	14	14	14	14	14	20	20	20	14	14	14	14
Monthly Surplus/Deficit	590	608	544	599	942	785	26	111	355	422	478	529
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	0	0	0	0	0	287	232	196	123	110	128	123
2021 Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	287	232	196	123	110	128	123
Monthly Surplus/Deficit	590	608	544	599	942	1,071	258	307	478	531	606	652

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 DSM	88	88	88	92	101	107	108	105	96	90	88	89
Load Forecast (70th% w/DSM)	(2,131)	(1,915)	(1,731)	(1,668)	(1,957)	(2,361)	(2,723)	(2,527)	(2,083)	(1,701)	(1,798)	(2,182)
Existing Resources												
Coal	937	937	904	840	705	916	943	943	943	942	943	943
Gas (Langley Gulch)	251	251	251	251	251	251	251	251	251	251	251	251
Hydro (70th%)—HCC	580	660	583	651	817	702	492	356	404	415	364	465
Hydro (70th%)—Other	208	246	237	220	329	342	274	227	226	220	194	204
Shoshone Falls Upgrade	7	35	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	794	941	835	871	1,162	1,063	768	584	630	635	558	681
CSPP (PURPA)	164	172	189	209	238	239	225	218	219	196	173	178
PPAs												
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	64	63	64	65	60	67	67	63	59	65	62	74
Firm Pacific NW Import Capability	280	117	0	0	435	343	214	281	295	0	281	311
Gas Peakers	224	0	0	0	0	240	224	242	0	0	0	224
Existing Resource Subtotal	2,714	2,482	2,244	2,237	2,850	3,120	2,692	2,582	2,397	2,088	2,268	2,661
Monthly Surplus/Deficit	583	566	514	569	892	758	(30)	54	313	387	470	479
2011 IRP DSM												
Industrial	8	8	8	8	8	8	8	8	8	8	8	8
Commercial	3	3	3	3	3	3	3	3	3	3	3	3
Residential	4	4	4	4	4	12	12	12	4	4	4	4
Total New DSM (aMW)	16	16	16	16	16	24	24	24	16	16	16	16
Monthly Surplus/Deficit	598	582	529	584	908	782	(7)	78	329	403	485	495
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	95	8	46	136	247	290	235	192	135	114	128	152
2021 Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	95	8	46	136	247	290	235	192	135	114	128	152
Monthly Surplus/Deficit	693	590	575	720	1,154	1,072	228	270	464	517	613	646

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 DSM	100	100	100	104	114	121	122	119	109	101	100	101
Load Forecast (70th% w/DSM)	(2,153)	(1,932)	(1,747)	(1,683)	(1,976)	(2,387)	(2,757)	(2,560)	(2,108)	(1,720)	(1,818)	(2,209)
Existing Resources												
Coal	943	947	943	841	726	900	944	944	944	943	944	944
Gas (Langley Gulch)	251	251	251	251	251	251	251	251	251	251	251	251
Hydro (70th%)—HCC	582	649	580	649	813	700	490	355	411	399	364	461
Hydro (70th%)—Other	206	240	235	218	328	341	273	226	221	219	193	203
Shoshone Falls Upgrade	7	35	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	794	925	830	867	1,156	1,060	766	582	632	618	557	675
CSPP (PURPA)	164	172	189	209	238	239	225	218	219	196	173	178
PPAs												
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	64	63	64	65	60	67	67	63	59	65	62	74
Firm Pacific NW Import Capability	296	128	0	0	433	339	209	278	293	0	300	309
Gas Peakers	233	0	0	0	0	240	224	242	0	0	0	224
Existing Resource Subtotal	2,745	2,486	2,278	2,234	2,864	3,096	2,686	2,577	2,398	2,073	2,287	2,654
Monthly Surplus/Deficit	592	554	531	551	888	709	(71)	17	289	353	469	445
2011 IRP DSM												
Industrial	9	9	9	9	9	9	9	9	9	9	9	9
Commercial	4	4	4	4	4	3	3	4	4	4	4	4
Residential	5	5	5	5	5	15	15	15	5	5	5	5
Total New DSM (aMW)	17	17	17	17	17	27	27	27	17	17	17	17
Monthly Surplus/Deficit	609	572	549	569	906	736	(44)	45	307	370	486	463
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	89	7	41	89	230	275	262	211	127	108	171	158
2021 Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	89	7	41	89	230	275	262	211	127	108	171	158
Monthly Surplus/Deficit	699	578	590	658	1,135	1,011	218	256	434	478	657	621

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 DSM	112	112	112	116	127	135	136	133	123	114	112	113
Load Forecast (70th% w/DSM)	(2,178)	(1,951)	(1,765)	(1,700)	(1,996)	(2,415)	(2,794)	(2,595)	(2,136)	(1,742)	(1,841)	(2,237)
Existing Resources												
Coal	944	944	944	843	728	901	950	950	950	949	950	950
Gas (Langley Gulch)	251	251	251	251	251	251	251	251	251	251	251	251
Hydro (70th%)—HCC	583	638	579	646	810	697	489	354	411	394	364	459
Hydro (70th%)—Other	205	228	232	217	328	340	273	225	220	218	192	202
Shoshone Falls Upgrade	7	35	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	794	902	827	864	1,153	1,056	764	580	632	612	556	673
CSPP (PURPA)	164	172	189	209	238	239	225	218	219	196	173	178
PPAs												
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	64	63	64	65	60	67	67	63	59	65	62	74
Firm Pacific NW Import Capability	100	145	0	0	432	335	205	275	291	0	324	307
Gas Peakers	233	0	0	0	0	231	233	242	0	0	0	224
Existing Resource Subtotal	2,550	2,478	2,276	2,231	2,860	3,081	2,695	2,578	2,402	2,073	2,316	2,656
Monthly Surplus/Deficit	372	526	511	532	864	666	(99)	(17)	266	331	475	418
2011 IRP DSM												
Industrial	9	9	9	9	9	10	10	10	9	9	9	9
Commercial	4	4	4	4	4	4	4	4	4	4	4	4
Residential	6	6	6	6	6	17	17	17	6	6	6	6
Total New DSM (aMW)	19	19	19	19	19	31	31	31	19	19	19	19
Monthly Surplus/Deficit	391	546	530	551	884	697	(68)	14	285	351	495	438
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	88	8	28	40	214	291	280	151	119	118	154	149
2021 Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	88	8	28	40	214	291	280	151	119	118	154	149
Monthly Surplus/Deficit	479	553	558	591	1,097	988	212	165	404	469	649	587

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 DSM	125	124	125	128	141	149	150	147	134	126	125	125
Load Forecast (70th% w/DSM)	(2,200)	(1,956)	(1,781)	(1,714)	(2,015)	(2,441)	(2,830)	(2,629)	(2,161)	(1,761)	(1,861)	(2,261)
Existing Resources												
Coal	944	946	944	838	730	896	954	955	949	956	951	959
Gas (Langley Gulch)	251	251	251	251	251	251	251	251	251	251	251	251
Hydro (70th%)—HCC	584	630	579	645	808	696	489	353	411	391	365	457
Hydro (70th%)—Other	204	221	230	213	327	340	272	225	220	218	191	201
Shoshone Falls Upgrade	7	34	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	794	885	824	858	1,150	1,054	763	578	631	609	556	670
CSPP (PURPA)	164	172	189	209	238	239	225	218	219	196	173	178
PPAs												
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	64	63	64	65	60	67	67	63	59	65	62	74
Firm Pacific NW Import Capability	100	157	0	0	430	333	201	272	289	0	346	305
Gas Peakers	233	0	0	0	0	240	233	233	0	0	0	233
Existing Resource Subtotal	2,550	2,474	2,273	2,221	2,858	3,081	2,694	2,570	2,397	2,077	2,338	2,669
Monthly Surplus/Deficit	349	519	491	507	843	640	(136)	(59)	236	316	478	408
2011 IRP DSM												
Industrial	10	10	10	10	10	10	10	10	10	10	10	10
Commercial	5	5	5	5	5	4	4	4	5	5	5	5
Residential	7	7	7	7	7	20	20	19	7	7	7	7
Total New DSM (aMW)	21	21	21	21	21	34	34	34	21	21	21	21
Monthly Surplus/Deficit	371	540	512	528	865	674	(101)	(25)	257	337	499	429
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	97	12	32	95	230	282	280	171	136	138	146	132
2021 Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	97	12	32	95	230	282	280	171	136	138	146	132
Monthly Surplus/Deficit	468	551	544	623	1,094	956	179	146	393	475	645	562

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 DSM	136	134	135	139	154	162	163	159	146	137	135	135
Load Forecast (70th% w/DSM)	(2,222)	(1,984)	(1,797)	(1,729)	(2,033)	(2,467)	(2,864)	(2,662)	(2,187)	(1,781)	(1,881)	(2,288)
Existing Resources												
Coal	889	881	889	788	728	841	899	900	893	901	895	904
Gas (Langley Gulch)	251	251	251	251	251	251	251	251	251	251	251	251
Hydro (70th%)—HCC	585	622	578	637	807	695	488	352	411	390	364	457
Hydro (70th%)—Other	203	219	227	213	327	339	272	224	219	217	191	201
Shoshone Falls Upgrade	7	35	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	794	876	820	850	1,149	1,053	762	577	630	607	555	669
CSPP (PURPA)	164	172	189	209	238	239	225	218	219	196	173	178
PPAs												
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	64	63	64	65	60	67	67	63	59	65	62	74
Firm Pacific NW Import Capability	90	170	0	0	489	389	257	328	347	0	365	364
Gas Peakers	224	0	0	0	0	240	242	233	0	0	0	233
Existing Resource Subtotal	2,476	2,413	2,213	2,163	2,914	3,080	2,702	2,569	2,399	2,020	2,301	2,672
Monthly Surplus/Deficit	254	429	416	434	881	613	(162)	(92)	212	239	420	383
2011 IRP DSM												
Industrial	11	10	10	10	11	11	11	11	11	11	11	11
Commercial	5	5	5	5	5	5	5	5	5	5	5	5
Residential	8	8	8	8	7	22	22	22	8	8	8	8
Total New DSM (aMW)	23	23	23	23	23	38	38	38	23	23	23	23
Monthly Surplus/Deficit	277	452	439	457	904	651	(124)	(55)	235	262	443	406
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	97	12	32	95	230	282	280	171	136	138	146	132
2021 Geothermal	52	52	52	52	52	52	52	52	52	52	52	52
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	149	64	84	147	282	334	332	223	188	190	198	184
Monthly Surplus/Deficit	426	515	523	604	1,186	985	208	169	423	452	642	591

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 DSM	146	144	144	149	165	173	174	170	157	147	145	144
Load Forecast (70th% w/DSM)	(2,248)	(2,004)	(1,816)	(1,747)	(2,054)	(2,495)	(2,902)	(2,698)	(2,215)	(1,803)	(1,904)	(2,318)
Existing Resources												
Coal	887	891	887	791	724	844	889	889	889	887	889	889
Gas (Langley Gulch)	251	251	251	251	251	251	251	251	251	251	251	251
Hydro (70th%)—HCC	585	620	577	636	806	694	487	352	410	389	365	455
Hydro (70th%)—Other	202	218	224	212	327	339	272	224	219	217	190	200
Shoshone Falls Upgrade	7	35	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	794	873	816	848	1,147	1,051	761	577	630	606	555	667
CSPP (PURPA)	164	172	189	209	238	239	225	218	219	196	173	178
PPAs												
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	64	63	64	65	60	67	67	63	59	65	62	74
Firm Pacific NW Import Capability	116	187	0	0	487	386	254	326	346	0	389	361
Gas Peakers	224	0	0	0	0	240	224	242	0	0	0	242
Existing Resource Subtotal	2,500	2,438	2,208	2,164	2,907	3,079	2,671	2,565	2,393	2,005	2,318	2,661
Monthly Surplus/Deficit	252	434	392	418	853	584	(231)	(133)	177	202	415	343
2011 IRP DSM												
Industrial	11	11	11	11	11	11	11	11	11	11	11	11
Commercial	5	5	5	5	5	5	5	5	5	5	5	5
Residential	8	8	8	8	8	25	24	25	8	8	8	8
Total New DSM (aMW)	25	25	25	25	25	41	41	41	25	25	25	25
Monthly Surplus/Deficit	277	458	417	443	878	625	(190)	(92)	202	227	439	368
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	97	12	32	95	230	282	280	171	136	138	146	132
2021 Geothermal	52	52	52	52	52	52	52	52	52	52	52	52
2022 SCCT Frame	0	0	0	0	0	98	92	99	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	149	64	84	147	282	432	424	322	188	190	198	184
Monthly Surplus/Deficit	426	522	501	590	1,159	1,057	233	230	390	417	638	552

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 DSM	153	152	153	159	173	183	184	180	166	156	153	154
Load Forecast (70th% w/DSM)	(2,275)	(2,025)	(1,837)	(1,765)	(2,076)	(2,526)	(2,943)	(2,737)	(2,246)	(1,827)	(1,928)	(2,347)
Existing Resources												
Coal	889	889	889	793	726	845	895	895	895	893	895	895
Gas (Langley Gulch)	251	251	251	251	251	251	251	251	251	251	251	251
Hydro (70th%)—HCC	585	619	577	636	806	693	487	352	410	388	365	454
Hydro (70th%)—Other	202	217	222	212	327	339	271	224	219	217	190	200
Shoshone Falls Upgrade	7	35	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	794	872	814	848	1,147	1,051	761	577	629	605	556	666
CSPP (PURPA)	164	172	189	209	238	239	225	218	219	196	173	178
PPAs												
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	64	63	64	65	60	67	67	63	59	65	62	74
Firm Pacific NW Import Capability	148	208	0	0	485	382	250	323	344	0	410	359
Gas Peakers	233	0	0	0	0	240	224	242	0	0	0	224
Existing Resource Subtotal	2,543	2,455	2,208	2,166	2,906	3,076	2,672	2,568	2,397	2,010	2,346	2,646
Monthly Surplus/Deficit	267	430	371	400	830	551	(270)	(169)	151	184	418	299
2011 IRP DSM												
Industrial	11	11	11	11	12	12	12	12	11	11	11	12
Commercial	6	6	6	6	6	5	5	5	6	6	6	6
Residential	9	9	9	9	9	27	27	27	9	9	9	9
Total New DSM (aMW)	26	27	27	26	26	45	44	45	26	26	26	26
Monthly Surplus/Deficit	294	456	398	427	856	595	(226)	(125)	177	210	444	326
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	97	12	32	95	230	282	280	171	136	138	146	132
2021 Geothermal	52	52	52	52	52	52	52	52	52	52	52	52
2022 SCCT Frame	0	0	0	0	0	98	92	99	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	149	64	84	147	282	432	424	322	188	190	198	184
Monthly Surplus/Deficit	443	520	481	574	1,138	1,027	198	197	365	400	643	510

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 DSM	161	160	161	165	181	192	193	188	174	162	161	162
Load Forecast (70th% w/DSM)	(2,299)	(2,031)	(1,854)	(1,782)	(2,097)	(2,554)	(2,981)	(2,774)	(2,274)	(1,848)	(1,950)	(2,373)
Existing Resources												
Coal	889	889	889	788	728	841	899	900	893	901	895	904
Gas (Langley Gulch)	251	251	251	251	251	251	251	251	251	251	251	251
Hydro (70th%)—HCC	585	619	577	636	806	693	487	352	410	388	365	454
Hydro (70th%)—Other	202	217	222	212	327	339	271	224	219	217	190	200
Shoshone Falls Upgrade	7	34	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	794	871	814	848	1,147	1,051	761	577	629	605	556	666
CSPP (PURPA)	164	172	189	209	238	239	225	218	219	196	173	178
PPAs												
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	64	63	64	65	60	67	67	63	59	65	62	74
Firm Pacific NW Import Capability	170	222	5	2	484	378	246	320	342	0	407	357
Gas Peakers	233	0	0	0	0	231	233	242	0	0	0	224
Existing Resource Subtotal	2,565	2,468	2,213	2,163	2,907	3,058	2,681	2,570	2,393	2,018	2,343	2,653
Monthly Surplus/Deficit	266	437	359	381	810	504	(299)	(204)	119	170	394	281
2011 IRP DSM												
Industrial	12	12	12	12	12	12	12	12	12	12	12	12
Commercial	6	6	6	6	6	6	6	6	6	6	6	6
Residential	10	10	10	10	10	30	30	30	10	10	10	10
Total New DSM (aMW)	28	28	28	28	28	47	48	48	28	28	28	28
Monthly Surplus/Deficit	294	465	387	409	838	552	(252)	(156)	147	198	422	309
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	97	12	32	95	230	282	280	171	136	138	146	132
2021 Geothermal	52	52	52	52	52	52	52	52	52	52	52	52
2022 SCCT Frame	0	0	0	0	0	98	92	99	0	0	0	0
2024 Solar Power Tower	3	7	10	13	17	20	29	25	20	13	6	1
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	152	71	94	160	299	452	453	347	208	203	205	186
Monthly Surplus/Deficit	446	535	481	569	1,138	1,003	201	190	355	400	626	494

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 DSM	167	166	167	172	187	199	200	195	180	168	168	167
Load Forecast (70th% w/DSM)	(2,321)	(2,061)	(1,871)	(1,798)	(2,117)	(2,582)	(3,017)	(2,809)	(2,302)	(1,870)	(1,971)	(2,401)
Existing Resources												
Coal	889	881	889	788	728	841	899	900	893	901	895	904
Gas (Langley Gulch)	251	251	251	251	251	251	251	251	251	251	251	251
Hydro (70th%)—HCC	585	619	577	636	806	693	487	352	410	388	365	454
Hydro (70th%)—Other	202	217	222	212	327	339	271	224	219	217	190	200
Shoshone Falls Upgrade	7	35	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	794	872	814	848	1,147	1,051	761	577	629	605	556	666
CSPP (PURPA)	164	172	189	209	238	239	225	218	219	196	173	178
PPAs												
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	64	63	64	65	60	67	67	63	59	65	62	74
Firm Pacific NW Import Capability	185	235	18	18	482	375	243	318	340	0	405	355
Gas Peakers	233	0	0	0	0	231	233	233	0	0	0	233
Existing Resource Subtotal	2,580	2,474	2,226	2,179	2,905	3,055	2,678	2,559	2,391	2,018	2,341	2,660
Monthly Surplus/Deficit	258	413	355	381	788	473	(339)	(250)	89	148	371	260
2011 IRP DSM												
Industrial	12	12	12	12	12	13	13	13	12	12	12	12
Commercial	6	6	6	6	6	6	6	6	6	6	6	6
Residential	11	11	11	11	11	32	32	32	11	11	11	11
Total New DSM (aMW)	29	29	29	29	29	51	51	51	29	29	29	29
Monthly Surplus/Deficit	288	442	384	411	818	524	(288)	(199)	118	178	400	289
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	97	12	32	95	230	282	280	171	136	138	146	132
2021 Geothermal	52	52	52	52	52	52	52	52	52	52	52	52
2022 SCCT Frame	0	0	0	0	0	98	92	99	0	0	0	0
2024 Solar Power Tower	3	7	10	13	17	20	29	25	20	13	6	1
2025 CCCT	0	0	0	0	0	251	251	251	251	251	251	251
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	152	71	94	160	299	703	704	598	459	454	456	437
Monthly Surplus/Deficit	440	513	478	570	1,117	1,227	416	398	577	632	856	726

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 DSM	172	170	172	177	194	204	206	201	184	173	173	172
Load Forecast (70th% w/DSM)	(2,348)	(2,083)	(1,892)	(1,818)	(2,139)	(2,613)	(3,057)	(2,848)	(2,334)	(1,894)	(1,996)	(2,427)
Existing Resources												
Coal	887	891	887	791	724	844	889	889	889	887	889	889
Gas (Langley Gulch)	251	251	251	251	251	251	251	251	251	251	251	251
Hydro (70th%)—HCC	585	619	577	636	806	693	487	352	410	388	365	454
Hydro (70th%)—Other	202	217	222	212	327	339	271	224	219	217	190	200
Shoshone Falls Upgrade	7	35	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	794	872	814	848	1,147	1,051	761	577	629	605	556	666
CSPP (PURPA)	164	172	189	209	238	239	225	218	219	196	173	178
PPAs												
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	64	63	64	65	60	67	67	63	59	65	62	74
Firm Pacific NW Import Capability	209	252	36	38	480	371	238	315	339	4	404	353
Gas Peakers	233	0	0	0	0	240	233	233	0	0	0	233
Existing Resource Subtotal	2,602	2,502	2,242	2,202	2,900	3,064	2,663	2,545	2,386	2,008	2,334	2,643
Monthly Surplus/Deficit	254	418	350	385	760	451	(394)	(303)	52	114	338	216
2011 IRP DSM												
Industrial	12	12	12	12	13	13	13	13	12	12	13	12
Commercial	6	6	6	6	6	6	6	6	6	6	6	6
Residential	12	12	12	12	12	35	35	35	12	12	12	12
Total New DSM (aMW)	31	31	31	31	31	54	54	54	31	31	31	31
Monthly Surplus/Deficit	285	449	381	415	791	504	(340)	(250)	83	145	369	247
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	97	12	32	95	230	282	280	171	136	138	146	132
2021 Geothermal	52	52	52	52	52	52	52	52	52	52	52	52
2022 SCCT Frame	0	0	0	0	0	98	92	99	0	0	0	0
2024 Solar Power Tower	3	7	10	13	17	20	29	25	20	13	6	1
2025 CCCT	251	251	251	251	251	251	251	251	251	251	251	251
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	403	322	345	411	550	703	704	598	459	454	456	437
Monthly Surplus/Deficit	688	771	726	826	1,341	1,207	364	348	542	599	825	684

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 DSM	176	174	174	180	198	209	210	205	189	178	175	175
Load Forecast (70th% w/DSM)	(2,367)	(2,098)	(1,907)	(1,833)	(2,158)	(2,640)	(3,092)	(2,881)	(2,360)	(1,914)	(2,015)	(2,461)
Existing Resources												
Coal	889	889	889	793	726	845	895	895	895	893	895	895
Gas (Langley Gulch)	251	251	251	251	251	251	251	251	251	251	251	251
Hydro (70th%)—HCC	585	619	577	636	806	693	487	352	410	388	365	454
Hydro (70th%)—Other	202	217	222	212	327	339	271	224	219	217	190	200
Shoshone Falls Upgrade	7	35	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	794	872	814	848	1,147	1,051	761	577	629	605	556	666
CSPP (PURPA)	164	172	189	209	238	239	225	218	219	196	173	178
PPAs												
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	64	63	64	65	60	67	67	63	59	65	62	74
Firm Pacific NW Import Capability	213	257	43	53	478	368	234	313	335	24	401	349
Gas Peakers	224	0	0	0	0	240	242	233	0	0	0	233
Existing Resource Subtotal	2,599	2,504	2,251	2,219	2,899	3,062	2,674	2,549	2,388	2,034	2,337	2,645
Monthly Surplus/Deficit	231	406	344	386	741	423	(417)	(333)	27	120	322	184
2011 IRP DSM												
Industrial	13	13	13	13	13	13	13	13	13	13	13	13
Commercial	6	7	7	7	6	6	6	6	7	7	7	7
Residential	13	13	13	13	13	38	38	38	13	13	13	13
Total New DSM (aMW)	32	32	32	32	32	57	57	57	32	32	32	32
Monthly Surplus/Deficit	263	438	376	418	773	479	(361)	(276)	59	152	354	216
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	97	12	32	95	230	282	280	171	136	138	146	132
2021 Geothermal	52	52	52	52	52	52	52	52	52	52	52	52
2022 SCCT Frame	0	0	0	0	0	98	92	99	0	0	0	0
2024 Solar Power Tower	3	7	10	13	17	20	29	25	20	13	6	1
2025 CCCT	251	251	251	251	251	251	251	251	251	251	251	251
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	403	322	345	411	550	703	704	598	459	454	456	437
Monthly Surplus/Deficit	666	759	721	829	1,323	1,182	343	322	518	606	810	652

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 DSM	178	176	176	183	200	212	213	208	191	180	177	178
Load Forecast (70th% w/DSM)	(2,407)	(2,117)	(1,936)	(1,860)	(2,188)	(2,679)	(3,144)	(2,932)	(2,401)	(1,948)	(2,049)	(2,497)
Existing Resources												
Coal	889	889	889	788	728	841	899	900	893	901	895	904
Gas (Langley Gulch)	251	251	251	251	251	251	251	251	251	251	251	251
Hydro (70th%)—HCC	585	619	577	636	806	693	487	352	410	388	365	454
Hydro (70th%)—Other	202	217	222	212	327	339	271	224	219	217	190	200
Shoshone Falls Upgrade	7	34	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	794	871	814	848	1,147	1,051	761	577	629	605	556	666
CSPP (PURPA)	203	263	231	233	218	219	196	167	184	164	160	189
PPAs												
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	64	63	64	65	60	67	67	63	59	65	62	74
Firm Pacific NW Import Capability	267	68	81	80	477	364	231	310	333	58	399	348
Gas Peakers	224	0	0	0	0	240	224	242	0	0	0	224
Existing Resource Subtotal	2,691	2,405	2,331	2,265	2,880	3,034	2,628	2,509	2,348	2,044	2,323	2,656
Monthly Surplus/Deficit	284	288	394	405	693	355	(515)	(423)	(53)	96	274	159
2011 IRP DSM												
Industrial	13	13	13	13	13	13	13	13	13	13	13	13
Commercial	7	7	7	7	7	6	6	6	7	7	7	7
Residential	14	14	14	14	14	40	40	40	14	14	14	14
Total New DSM (aMW)	33	33	33	33	33	60	59	60	33	33	33	33
Monthly Surplus/Deficit	317	321	428	438	726	415	(456)	(364)	(20)	129	307	192
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	97	12	32	95	230	282	280	171	136	138	146	132
2021 Geothermal	52	52	52	52	52	52	52	52	52	52	52	52
2022 SCCT Frame	0	0	0	0	0	98	92	99	0	0	0	0
2024 Solar Power Tower	3	7	10	13	17	20	29	25	20	13	6	1
2025 CCCT	251	251	251	251	251	251	251	251	251	251	251	251
2028 Small Hydro	0	0	0	8	40	47	52	48	37	12	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	403	322	345	419	590	750	756	646	496	466	456	437
Monthly Surplus/Deficit	720	643	772	857	1,316	1,164	299	282	476	595	763	629

Monthly Average Energy Load and Resource Balance (continued)

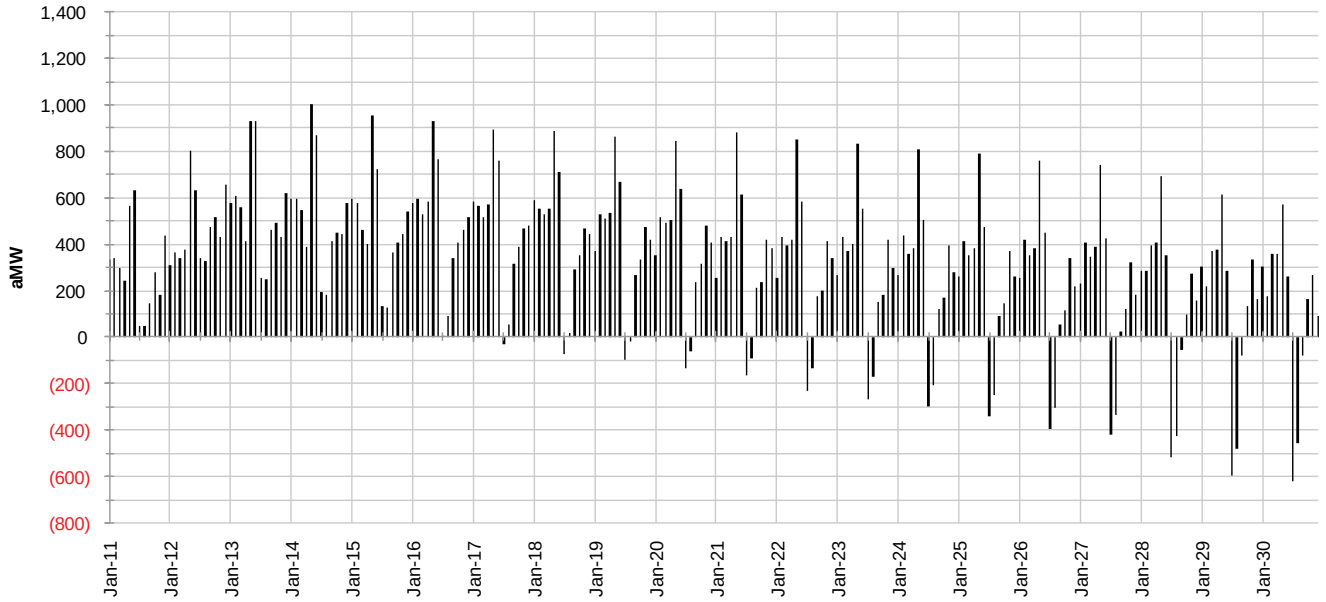
	1/2029	2/2029	3/2029	4/2029	5/2029	6/2029	7/2029	8/2029	9/2029	10/2029	11/2029	12/2029
Forecast DSM	179	177	178	185	201	213	214	209	194	180	179	180
Load Forecast (70th% w/DSM)	(2,433)	(2,152)	(1,957)	(1,880)	(2,212)	(2,713)	(3,187)	(2,974)	(2,435)	(1,973)	(2,074)	(2,530)
Existing Resources												
Coal	889	881	889	788	728	841	899	900	893	901	895	904
Gas (Langley Gulch)	251	251	251	251	251	251	251	251	251	251	251	251
Hydro (70th%)—HCC	585	619	577	636	806	693	487	352	410	388	365	454
Hydro (70th%)—Other	202	217	222	212	327	339	271	224	219	217	190	200
Shoshone Falls Upgrade	7	35	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	794	872	814	848	1,147	1,051	761	577	629	605	556	666
CSPP (PURPA)	225	241	212	203	167	184	164	155	196	203	246	231
PPAs												
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	64	63	64	65	60	67	67	63	59	65	62	74
Firm Pacific NW Import Capability	284	59	97	100	476	362	227	308	331	84	397	346
Gas Peakers	233	0	0	0	0	240	224	242	0	0	0	224
Existing Resource Subtotal	2,740	2,368	2,328	2,255	2,829	2,996	2,592	2,495	2,358	2,108	2,406	2,696
Monthly Surplus/Deficit	307	216	371	375	617	283	(595)	(480)	(77)	135	332	166
2011 IRP DSM												
Industrial	13	13	13	13	13	13	13	13	13	13	13	13
Commercial	7	7	7	7	7	6	6	6	7	7	7	7
Residential	15	15	15	15	15	43	43	43	15	15	15	15
Total New DSM (aMW)	34	34	34	34	34	62	62	62	34	34	34	34
Monthly Surplus/Deficit	341	250	405	409	651	345	(533)	(417)	(43)	169	366	200
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	97	12	32	95	230	282	280	171	136	138	146	132
2021 Geothermal	52	52	52	52	52	52	52	52	52	52	52	52
2022 SCCT Frame	0	0	0	0	0	98	92	99	0	0	0	0
2024 Solar Power Tower	3	7	10	13	17	20	29	25	20	13	6	1
2025 CCCT	251	251	251	251	251	251	251	251	251	251	251	251
2028 Small Hydro	0	0	0	8	40	47	52	48	37	12	0	0
2029 SCCT Frame	0	0	0	0	0	98	92	99	0	0	0	0
New Resource Subtotal	403	322	345	419	590	848	847	744	496	466	456	437
Monthly Surplus/Deficit	744	571	750	828	1,240	1,193	314	327	453	635	822	636

Monthly Average Energy Load and Resource Balance (continued)

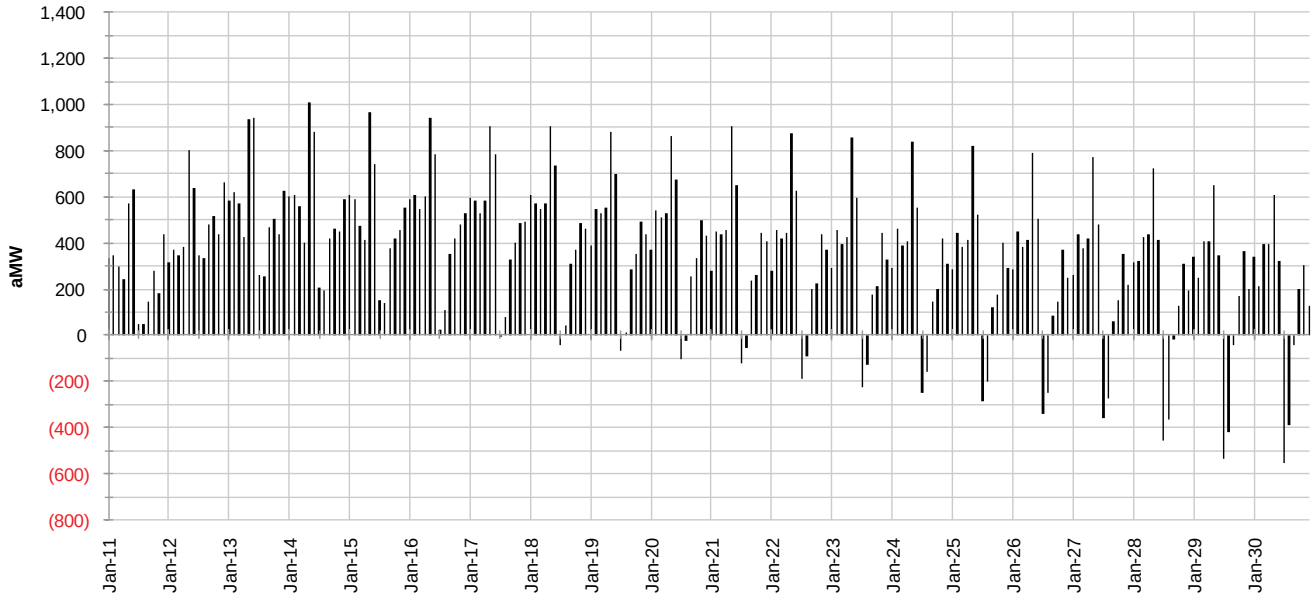
	1/2030	2/2030	3/2030	4/2030	5/2030	6/2030	7/2030	8/2030	9/2030	10/2030	11/2030	12/2030
Forecast DSM	179	177	179	184	201	213	214	209	194	180	179	180
Load Forecast (70th% w/DSM)	(2,466)	(2,179)	(1,982)	(1,904)	(2,239)	(2,750)	(3,235)	(3,021)	(2,474)	(2,004)	(2,104)	(2,570)
Existing Resources												
Coal	887	891	887	791	724	844	889	889	889	887	889	889
Gas (Langley Gulch)	251	251	251	251	251	251	251	251	251	251	251	251
Hydro (70th%)—HCC	585	619	577	636	806	693	487	352	410	388	365	454
Hydro (70th%)—Other	202	217	222	212	327	339	271	224	219	217	190	200
Shoshone Falls Upgrade	7	35	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (70th%)	794	872	814	848	1,147	1,051	761	577	629	605	556	666
CSPP (PURPA)	196	185	178	170	155	196	203	238	239	225	225	212
PPAs												
Elkhorn Valley Wind	34	33	34	35	30	37	37	33	29	35	32	44
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	64	63	64	65	60	67	67	63	59	65	62	74
Firm Pacific NW Import Capability	344	94	147	138	475	359	224	306	330	134	388	344
Gas Peakers	233	0	0	0	0	240	224	242	0	0	0	224
Existing Resource Subtotal	2,769	2,357	2,342	2,263	2,812	3,008	2,618	2,564	2,396	2,167	2,371	2,660
Monthly Surplus/Deficit	303	178	359	358	573	258	(617)	(457)	(77)	164	267	90
2011 IRP DSM												
Industrial	13	13	13	13	13	13	13	13	13	13	13	13
Commercial	7	7	7	7	7	6	6	6	7	7	7	7
Residential	15	16	15	16	15	45	45	45	15	16	15	15
Total New DSM (aMW)	35	35	35	35	35	65	65	65	35	35	35	35
Monthly Surplus/Deficit	338	213	394	393	608	323	(552)	(392)	(42)	199	302	125
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	97	12	32	95	230	282	280	171	136	138	146	132
2021 Geothermal	52	52	52	52	52	52	52	52	52	52	52	52
2022 SCCT Frame	0	0	0	0	0	98	92	99	0	0	0	0
2024 Solar Power Tower	3	7	10	13	17	20	29	25	20	13	6	1
2025 CCCT	251	251	251	251	251	251	251	251	251	251	251	251
2028 Small Hydro	0	0	0	8	40	47	52	48	37	12	0	0
2029 SCCT Frame	0	0	0	0	0	98	92	99	0	0	0	0
New Resource Subtotal	403	322	345	419	590	848	847	744	496	466	456	437
Monthly Surplus/Deficit	741	534	739	812	1,198	1,170	295	353	453	664	757	562

Monthly Average Energy Surplus/Deficit Charts

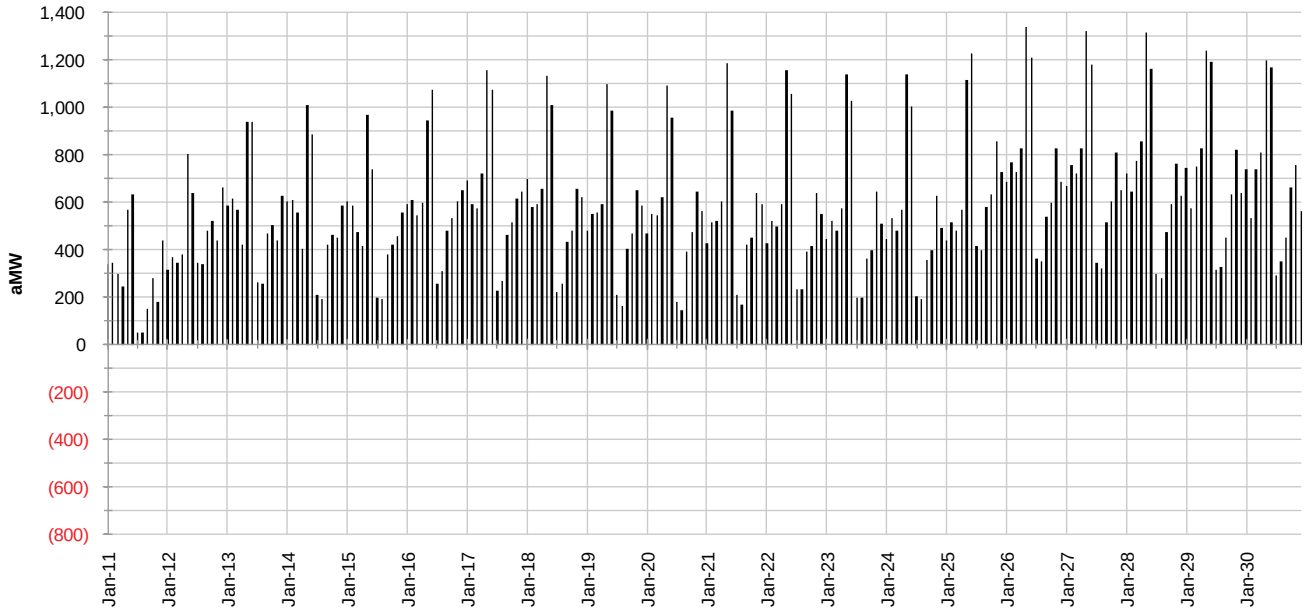
Average energy monthly surpluses and deficits with existing DSM and resources



Average energy monthly surpluses and deficits with existing resources and new DSM



Average energy monthly surpluses and deficits with existing resources, new DSM, and IRP resources



Peak-Hour Load and Resource Balance

	1/2011	2/2011	3/2011	4/2011	5/2011	6/2011	7/2011	8/2011	9/2011	10/2011	11/2011	12/2011
Load Forecast (95th% w/EE)	(2,553)	(2,440)	(2,147)	(1,901)	(2,863)	(3,377)	(3,515)	(3,185)	(3,019)	(2,068)	(2,231)	(2,815)
Existing Demand Response	0	0	0	0	0	330	330	255	0	0	0	0
Peak-Hour Forecast w/DR	(2,553)	(2,440)	(2,147)	(1,901)	(2,863)	(3,047)	(3,185)	(2,930)	(3,019)	(2,068)	(2,231)	(2,815)
Existing Resources												
Coal	963	963	963	963	963	963	963	963	963	963	963	963
Gas (Langley Gulch)	0	0	0	0	0	0	0	0	0	0	0	0
Hydro (90th%)—HCC	1,100	1,000	1,070	1,120	1,150	1,030	1,020	990	980	880	910	1,030
Hydro (90th%)—Other	200	202	192	193	299	307	263	216	210	209	191	200
Shoshone Falls Upgrade	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	47	0	0	0	0	0
Total Hydro (90th%)	1,300	1,202	1,262	1,313	1,449	1,337	1,330	1,206	1,190	1,089	1,101	1,230
CSPP (PURPA)	47	48	54	81	129	143	160	152	136	97	67	63
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
Clatskanie Exchange–Take	4	4	4	6	6	7	6	4	3	1	2	3
Clatskanie Exchange– Return	0	0	(10)	(15)	0	0	0	0	0	(10)	(15)	0
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	83	83	83	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	75	75	0	0	0	0
Total PPAs	19	19	9	6	21	105	179	177	18	6	2	18
Firm Pacific NW Import Capability	180	35	0	0	320	254	126	186	197	0	115	325
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	2,924	2,683	2,705	2,779	3,298	3,219	3,173	3,100	2,919	2,571	2,665	3,015
Monthly Surplus/Deficit	0	0	0	0	0	0	(12)	0	(100)	0	0	0
2011 IRP DSM												
Industrial	2	2	2	2	2	2	2	2	2	2	2	2
Commercial	1	1	1	1	1	1	0	1	1	1	1	1
Residential	0	0	0	0	0	1	1	1	0	0	0	0
Total New DSM Peak Reduction	3	3	3	3	3	3	3	3	3	3	3	3
Remaining Monthly Surplus/Deficit	0	0	0	0	0	0	(8)	0	(98)	0	0	0
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	0	0	0	0	0	0	0	0	0	0	0	0
2021 Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	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	(8)	0	(98)	0	0	0
Remaining Monthly Surplus/Deficit	373	246	561	880	437	175	(8)	174	(98)	506	436	203

Peak-Hour Load and Resource Balance (continued)

	1/2012	2/2012	3/2012	4/2012	5/2012	6/2012	7/2012	8/2012	9/2012	10/2012	11/2012	12/2012
Load Forecast (95th% w/EE)	(2,551)	(2,433)	(2,143)	(1,880)	(2,906)	(3,430)	(3,577)	(3,220)	(3,071)	(2,099)	(2,245)	(2,800)
Existing Demand Response	0	0	0	0	0	310	310	243	0	0	0	0
Peak-Hour Forecast w/DR	(2,551)	(2,433)	(2,143)	(1,880)	(2,906)	(3,120)	(3,267)	(2,977)	(3,071)	(2,099)	(2,245)	(2,800)
Existing Resources												
Coal	963	963	963	963	963	963	963	963	963	963	963	963
Gas (Langley Gulch)	0	0	0	0	0	0	300	300	300	300	300	300
Hydro (90th%)—HCC	1,100	1,000	1,070	1,120	1,150	1,030	1,020	990	980	880	910	1,030
Hydro (90th%)—Other	199	201	192	192	299	307	262	216	209	209	191	200
Shoshone Falls Upgrade	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	48	0	0	0	0	0
Total Hydro (90th%)	1,299	1,201	1,262	1,312	1,449	1,337	1,330	1,206	1,189	1,089	1,101	1,230
CSPP (PURPA)	59	61	65	92	141	150	161	152	136	98	68	64
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	0	0	0	0	0	0	0	0	0	20	20	20
Clatskanie Exchange–Take	4	4	4	6	6	7	6	4	3	1	2	3
Clatskanie Exchange– Return	0	0	(10)	(15)	0	0	0	0	0	(10)	(15)	0
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	83	83	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	19	19	9	6	21	22	104	102	18	26	22	38
Firm Pacific NW Import Capability	122	30	0	0	444	360	233	294	304	0	129	322
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	2,878	2,690	2,715	2,789	3,433	3,248	3,507	3,433	3,326	2,892	2,999	3,333
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
2011 IRP DSM												
Industrial	3	3	3	3	3	3	3	3	3	3	3	3
Commercial	1	1	1	1	1	1	1	1	1	1	1	1
Residential	1	1	1	1	1	2	2	2	1	1	1	1
Total New DSM Peak Reduction	5	5	5	5	5	6	6	7	5	5	5	5
Remaining Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	0	0	0	0	0	0	0	0	0	0	0	0
2021 Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	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	332	262	577	914	532	134	247	463	259	798	759	538

Peak-Hour Load and Resource Balance (continued)

	1/2013	2/2013	3/2013	4/2013	5/2013	6/2013	7/2013	8/2013	9/2013	10/2013	11/2013	12/2013
Load Forecast (95th% w/EE)	(2,561)	(2,441)	(2,157)	(1,879)	(2,955)	(3,533)	(3,684)	(3,312)	(3,146)	(2,127)	(2,264)	(2,817)
Existing Demand Response	0	0	0	0	0	315	315	248	0	0	0	0
Peak-Hour Forecast w/DR	(2,561)	(2,441)	(2,157)	(1,879)	(2,955)	(3,218)	(3,370)	(3,065)	(3,146)	(2,127)	(2,264)	(2,817)
Existing Resources												
Coal	963	963	963	963	963	963	963	963	963	963	963	963
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	1,100	1,000	1,070	1,120	1,150	1,030	1,020	990	980	880	910	1,030
Hydro (90th%)—Other	199	201	192	192	298	307	262	216	209	209	191	199
Shoshone Falls Upgrade	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	48	0	0	0	0	0
Total Hydro (90th%)	1,299	1,201	1,262	1,312	1,448	1,337	1,330	1,206	1,189	1,089	1,101	1,229
CSPP (PURPA)	63	65	69	96	145	154	166	157	140	101	72	67
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
Clatskanie Exchange–Take	4	4	4	6	6	7	6	4	3	1	2	3
Clatskanie Exchange– Return	0	0	(10)	(15)	0	0	0	0	0	(10)	(15)	0
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	39	39	29	26	41	42	41	39	38	26	22	38
Firm Pacific NW Import Capability	131	51	0	0	383	357	229	291	302	0	148	319
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,210	3,035	3,040	3,113	3,696	3,569	3,444	3,371	3,348	2,895	3,022	3,332
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
2011 IRP DSM												
Industrial	5	5	5	5	5	5	5	5	5	5	5	5
Commercial	1	1	1	1	1	1	1	1	1	1	1	1
Residential	1	1	1	1	1	4	4	4	1	1	1	1
Total New DSM Peak Reduction	8	8	8	8	8	10	10	10	8	8	8	8
Remaining Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	0	0	0	0	0	0	0	0	0	0	0	0
2021 Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	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	658	601	890	1,242	750	361	85	317	209	775	765	523

Peak-Hour Load and Resource Balance (continued)

	1/2014	2/2014	3/2014	4/2014	5/2014	6/2014	7/2014	8/2014	9/2014	10/2014	11/2014	12/2014
Load Forecast (95th% w/EE)	(2,620)	(2,485)	(2,203)	(1,928)	(3,011)	(3,611)	(3,770)	(3,398)	(3,213)	(2,167)	(2,314)	(2,895)
Existing Demand Response	0	0	0	0	0	315	315	248	0	0	0	0
Peak-Hour Forecast w/DR	(2,620)	(2,485)	(2,203)	(1,928)	(3,011)	(3,296)	(3,455)	(3,150)	(3,213)	(2,167)	(2,314)	(2,895)
Existing Resources												
Coal	963	963	963	963	963	963	963	963	963	963	963	963
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	1,100	1,000	1,070	1,120	1,150	1,030	1,020	990	980	880	910	1,030
Hydro (90th%)—Other	197	198	191	191	297	305	261	214	208	207	190	197
Shoshone Falls Upgrade	0	0	0	0	0	0	0	0	0	0	0	0
Sho-Ban Water Lease	0	0	0	0	0	0	48	0	0	0	0	0
Total Hydro (90th%)	1,297	1,198	1,261	1,311	1,447	1,335	1,329	1,204	1,188	1,087	1,100	1,227
CSPP (PURPA)	63	66	69	96	145	154	166	157	140	101	72	67
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
Clatskanie Exchange–Take	4	4	4	6	6	7	6	4	3	1	2	3
Clatskanie Exchange– Return	0	0	(10)	(15)	0	0	0	0	0	(10)	(15)	0
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	39	39	29	26	41	42	41	39	38	26	22	38
Firm Pacific NW Import Capability	190	86	0	12	439	353	225	288	301	0	198	318
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,268	3,068	3,039	3,124	3,751	3,563	3,440	3,367	3,346	2,894	3,071	3,329
Monthly Surplus/Deficit	0	0	0	0	0	0	(15)	0	0	0	0	0
2011 IRP DSM												
Industrial	6	6	6	6	6	6	6	6	6	6	6	6
Commercial	2	2	2	2	2	2	2	2	2	2	2	2
Residential	2	2	2	2	2	6	6	6	2	2	2	2
Total New DSM Peak Reduction	10	10	10	10	10	14	14	14	10	10	10	10
Remaining Monthly Surplus/Deficit	0	0	0	0	0	0	(1)	0	0	0	0	0
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	0	0	0	0	0	0	0	0	0	0	0	0
2021 Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	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	(1)	0	0	0	0	0
Remaining Monthly Surplus/Deficit	658	593	846	1,206	750	281	(1)	231	143	737	767	444

Peak-Hour Load and Resource Balance (continued)

	1/2015	2/2015	3/2015	4/2015	5/2015	6/2015	7/2015	8/2015	9/2015	10/2015	11/2015	12/2015
Load Forecast (95th% w/EE)	(2,661)	(2,517)	(2,236)	(1,958)	(3,067)	(3,685)	(3,854)	(3,474)	(3,277)	(2,203)	(2,353)	(2,948)
Existing Demand Response	0	0	0	0	0	321	321	252	0	0	0	0
Peak-Hour Forecast w/DR	(2,661)	(2,517)	(2,236)	(1,958)	(3,067)	(3,364)	(3,533)	(3,222)	(3,277)	(2,203)	(2,353)	(2,948)
Existing Resources												
Coal	963	963	963	963	963	963	963	963	963	963	963	963
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	1,100	1,000	1,070	1,120	1,150	1,030	1,020	990	980	880	910	1,030
Hydro (90th%)—Other	195	196	190	190	296	304	260	213	207	206	189	195
Shoshone Falls Upgrade	0	0	0	0	0	0	0	0	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	48	0	0	0	0	0
Total Hydro (90th%)	1,295	1,196	1,260	1,310	1,446	1,334	1,328	1,203	1,187	1,086	1,099	1,237
CSPP (PURPA)	63	66	69	96	145	154	166	157	140	101	72	67
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
Clatskanie Exchange–Take	4	4	4	6	6	7	6	4	3	1	2	3
Clatskanie Exchange– Return	0	0	(10)	(15)	0	0	0	0	0	(10)	(15)	0
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	39	39	29	26	41	42	41	39	38	26	22	38
Firm Pacific NW Import Capability	231	114	0	38	440	350	222	286	299	14	237	316
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,307	3,094	3,037	3,149	3,751	3,559	3,436	3,364	3,342	2,906	3,109	3,337
Monthly Surplus/Deficit	0	0	0	0	0	0	(97)	0	0	0	0	0
2011 IRP DSM												
Industrial	7	7	7	7	7	7	7	7	7	7	7	7
Commercial	2	2	2	2	2	2	2	2	2	2	2	2
Residential	3	3	3	3	3	8	8	8	3	3	3	3
Total New DSM Peak Reduction	12	12	12	12	12	17	17	17	12	12	12	12
Remaining Monthly Surplus/Deficit	0	0	0	0	0	0	(80)	0	0	0	0	0
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	83	0	0	0	0	0
2016 Boardman to Hemingway	0	0	0	0	0	0	0	0	0	0	0	0
2021 Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	0	83	0	0	0	0	0
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	658	590	813	1,203	696	212	3	159	78	715	768	401

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/EE)	(2,691)	(2,543)	(2,261)	(1,975)	(3,116)	(3,750)	(3,925)	(3,535)	(3,331)	(2,226)	(2,374)	(2,978)
Existing Demand Response	0	0	0	0	0	351	351	273	0	0	0	0
Peak-Hour Forecast w/DR	(2,691)	(2,543)	(2,261)	(1,975)	(3,116)	(3,399)	(3,574)	(3,262)	(3,331)	(2,226)	(2,374)	(2,978)
Existing Resources												
Coal	963	963	963	963	963	963	963	963	963	963	963	963
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	1,100	1,000	1,070	1,120	1,150	1,030	1,020	990	980	880	910	1,030
Hydro (90th%)—Other	193	195	189	189	295	303	260	211	207	206	188	194
Shoshone Falls Upgrade	7	34	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,300	1,229	1,275	1,309	1,460	1,352	1,282	1,202	1,187	1,086	1,098	1,236
CSPP (PURPA)	63	66	69	96	145	154	166	157	140	101	72	67
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	35	35	35	35	35	35	35	35	35	35	35	35
Firm Pacific NW Import Capability	37	139	0	57	437	346	218	283	297	49	258	314
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,114	3,148	3,058	3,176	3,756	3,566	3,379	3,355	3,338	2,951	3,142	3,331
Monthly Surplus/Deficit	0	0	0	0	0	0	(196)	0	0	0	0	0
2011 IRP DSM												
Industrial	8	7	7	7	8	8	8	8	7	7	7	7
Commercial	3	3	3	3	3	3	3	3	3	3	3	3
Residential	3	3	3	3	3	10	10	10	3	3	3	3
Total New DSM Peak Reduction	14	14	14	14	14	20	20	20	14	14	14	14
Remaining Monthly Surplus/Deficit	0	0	0	0	0	0	(175)	0	0	0	0	0
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	0	0	0	0	0	450	450	450	450	450	450	450
2021 Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	0	0	0	0	0	450	450	450	450	450	450	450
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	437	619	810	1,215	654	637	275	563	470	1,188	1,232	817

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/EE)	(2,717)	(2,556)	(2,280)	(1,991)	(3,156)	(3,809)	(3,991)	(3,595)	(3,382)	(2,247)	(2,397)	(3,017)
Existing Demand Response	0	0	0	0	0	351	351	273	0	0	0	0
Peak-Hour Forecast w/DR	(2,717)	(2,556)	(2,280)	(1,991)	(3,156)	(3,458)	(3,641)	(3,322)	(3,382)	(2,247)	(2,397)	(3,017)
Existing Resources												
Coal	963	963	963	963	963	963	963	963	963	963	963	963
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	1,100	1,000	1,070	1,120	1,150	1,030	1,020	990	980	880	910	1,030
Hydro (90th%)—Other	192	193	188	188	291	299	259	210	206	205	187	192
Shoshone Falls Upgrade	7	35	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,299	1,228	1,274	1,308	1,456	1,348	1,281	1,201	1,186	1,085	1,097	1,234
CSPP (PURPA)	63	66	69	96	145	154	166	157	140	101	72	67
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	35	35	35	35	35	35	35	35	35	35	35	35
Firm Pacific NW Import Capability	36	157	14	85	435	343	214	281	295	71	281	311
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,112	3,165	3,071	3,203	3,750	3,559	3,374	3,352	3,335	2,971	3,164	3,326
Monthly Surplus/Deficit	0	0	0	0	0	0	(267)	0	(47)	0	0	0
2011 IRP DSM												
Industrial	8	8	8	8	8	8	8	8	8	8	8	8
Commercial	3	3	3	3	3	3	3	3	3	3	3	3
Residential	4	4	4	4	4	12	12	12	4	4	4	4
Total New DSM Peak Reduction	16	16	16	16	16	24	24	24	16	16	16	16
Remaining Monthly Surplus/Deficit	0	0	0	0	0	0	(243)	0	(32)	0	0	0
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	450	450	450	450	450	450	450	450	450	450	450	450
2021 Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	450	450	450	450	450	450	450	450	450	450	450	450
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	861	1,074	1,257	1,678	1,059	575	207	504	418	1,190	1,232	774

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/EE)	(2,733)	(2,567)	(2,293)	(1,997)	(3,195)	(3,865)	(4,056)	(3,650)	(3,431)	(2,266)	(2,416)	(3,046)
Existing Demand Response	0	0	0	0	0	351	351	273	0	0	0	0
Peak-Hour Forecast w/DR	(2,733)	(2,567)	(2,293)	(1,997)	(3,195)	(3,514)	(3,705)	(3,377)	(3,431)	(2,266)	(2,416)	(3,046)
Existing Resources												
Coal	963	963	963	963	963	963	963	963	963	963	963	963
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	1,100	1,000	1,070	1,120	1,150	1,030	1,020	990	980	880	910	1,030
Hydro (90th%)—Other	191	191	187	187	286	295	258	209	205	204	186	190
Shoshone Falls Upgrade	7	35	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,298	1,226	1,272	1,307	1,451	1,343	1,280	1,200	1,185	1,084	1,096	1,232
CSPP (PURPA)	63	66	69	96	145	154	166	157	140	101	72	67
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	35	35	35	35	35	35	35	35	35	35	35	35
Firm Pacific NW Import Capability	41	175	30	101	433	339	209	278	293	81	300	309
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,116	3,181	3,085	3,218	3,743	3,550	3,368	3,348	3,331	2,980	3,182	3,322
Monthly Surplus/Deficit	0	0	0	0	0	0	(337)	(29)	(100)	0	0	0
2011 IRP DSM												
Industrial	9	9	9	9	9	9	9	9	9	9	9	9
Commercial	4	4	4	4	4	3	3	4	4	4	4	4
Residential	5	5	5	5	5	15	15	15	5	5	5	5
Total New DSM Peak Reduction	17	17	17	17	17	27	27	27	17	17	17	17
Remaining Monthly Surplus/Deficit	0	0	0	0	0	0	(310)	(2)	(82)	0	0	0
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	450	450	450	450	450	450	450	450	450	450	450	450
2021 Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	450	450	450	450	450	450	450	450	450	450	450	450
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	851	1,082	1,260	1,688	1,015	513	140	448	368	1,182	1,233	743

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/EE)	(2,759)	(2,584)	(2,312)	(2,013)	(3,236)	(3,924)	(4,123)	(3,711)	(3,482)	(2,288)	(2,440)	(3,086)
Existing Demand Response	0	0	0	0	0	351	351	273	0	0	0	0
Peak-Hour Forecast w/DR	(2,759)	(2,584)	(2,312)	(2,013)	(3,236)	(3,574)	(3,772)	(3,438)	(3,482)	(2,288)	(2,440)	(3,086)
Existing Resources												
Coal	963	963	963	963	963	963	963	963	963	963	963	963
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	1,100	1,000	1,070	1,120	1,150	1,030	1,020	990	980	880	910	1,030
Hydro (90th%)—Other	190	190	185	186	283	291	257	208	204	203	186	189
Shoshone Falls Upgrade	7	35	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,297	1,225	1,271	1,306	1,448	1,339	1,279	1,199	1,184	1,083	1,096	1,230
CSPP (PURPA)	63	66	69	96	145	154	166	157	140	101	72	67
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	35	35	35	35	35	35	35	35	35	35	35	35
Firm Pacific NW Import Capability	59	195	60	109	432	335	205	275	291	104	117	307
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,133	3,200	3,114	3,225	3,738	3,542	3,363	3,344	3,329	3,002	2,998	3,318
Monthly Surplus/Deficit	0	0	0	0	0	(31)	(409)	(94)	(153)	0	0	0
2011 IRP DSM												
Industrial	9	9	9	9	9	10	10	10	9	9	9	9
Commercial	4	4	4	4	4	4	4	4	4	4	4	4
Residential	6	6	6	6	6	17	17	17	6	6	6	6
Total New DSM Peak Reduction	19	19	19	19	19	31	31	31	19	19	19	19
Remaining Monthly Surplus/Deficit	0	0	0	0	0	(1)	(378)	(63)	(134)	0	0	0
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	450	450	450	450	450	450	450	450	450	450	450	450
2021 Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	450	450	450	450	450	450	450	450	450	450	450	450
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	843	1,086	1,272	1,681	972	449	72	387	316	1,184	1,027	702

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/EE)	(2,781)	(2,595)	(2,328)	(2,026)	(3,276)	(3,983)	(4,190)	(3,770)	(3,532)	(2,307)	(2,462)	(3,121)
Existing Demand Response	0	0	0	0	0	351	351	273	0	0	0	0
Peak-Hour Forecast w/DR	(2,781)	(2,595)	(2,328)	(2,026)	(3,276)	(3,632)	(3,839)	(3,498)	(3,532)	(2,307)	(2,462)	(3,121)
Existing Resources												
Coal	963	963	963	963	963	963	963	963	963	963	963	963
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	1,100	1,000	1,070	1,120	1,150	1,030	1,020	990	980	880	910	1,030
Hydro (90th%)—Other	190	189	185	185	280	288	256	207	204	203	185	188
Shoshone Falls Upgrade	7	34	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,297	1,223	1,270	1,305	1,445	1,336	1,278	1,198	1,184	1,083	1,095	1,230
CSPP (PURPA)	63	66	69	96	145	154	166	157	140	101	72	67
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	35	35	35	35	35	35	35	35	35	35	35	35
Firm Pacific NW Import Capability	81	198	77	124	430	333	201	272	289	125	106	305
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,155	3,201	3,131	3,239	3,734	3,538	3,358	3,341	3,326	3,023	2,986	3,316
Monthly Surplus/Deficit	0	0	0	0	0	(94)	(480)	(157)	(205)	0	0	0
2011 IRP DSM												
Industrial	10	10	10	10	10	10	10	10	10	10	10	10
Commercial	5	5	5	5	5	4	4	4	5	5	5	5
Residential	7	7	7	7	7	20	20	19	7	7	7	7
Total New DSM Peak Reduction	21	21	21	21	21	34	34	34	21	21	21	21
Remaining Monthly Surplus/Deficit	0	0	0	0	0	(60)	(446)	(123)	(184)	0	0	0
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	450	450	450	450	450	450	450	450	450	450	450	450
2021 Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	450	450	450	450	450	450	450	450	450	450	450	450
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	845	1,077	1,274	1,685	929	390	4	327	266	1,187	996	666

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/EE)	(2,797)	(2,609)	(2,341)	(2,034)	(3,316)	(4,040)	(4,254)	(3,826)	(3,582)	(2,327)	(2,481)	(3,152)
Existing Demand Response	0	0	0	0	0	351	351	273	0	0	0	0
Peak-Hour Forecast w/DR	(2,797)	(2,609)	(2,341)	(2,034)	(3,316)	(3,689)	(3,904)	(3,554)	(3,582)	(2,327)	(2,481)	(3,152)
Existing Resources												
Coal	908	908	908	908	908	908	908	908	908	908	908	908
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	1,100	1,000	1,070	1,120	1,150	1,030	1,020	990	980	880	910	1,030
Hydro (90th%)—Other	189	189	184	185	278	286	256	207	203	202	184	188
Shoshone Falls Upgrade	7	35	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,296	1,224	1,270	1,305	1,443	1,335	1,278	1,198	1,184	1,082	1,094	1,229
CSPP (PURPA)	63	66	69	96	145	154	166	157	140	101	72	67
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	35	35	35	35	35	35	35	35	35	35	35	35
Firm Pacific NW Import Capability	138	20	144	200	489	389	257	328	347	0	95	364
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,156	2,969	3,142	3,260	3,736	3,537	3,359	3,341	3,329	2,843	2,920	3,319
Monthly Surplus/Deficit	0	0	0	0	0	(152)	(545)	(212)	(254)	0	0	0
2011 IRP DSM												
Industrial	11	10	10	10	11	11	11	11	11	11	11	11
Commercial	5	5	5	5	5	5	5	5	5	5	5	5
Residential	8	8	8	8	7	22	22	22	8	8	8	8
Total New DSM Peak Reduction	23	23	23	23	23	38	38	38	23	23	23	23
Remaining Monthly Surplus/Deficit	0	0	0	0	0	(114)	(507)	(175)	(230)	0	0	0
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	450	450	450	450	450	450	450	450	450	450	450	450
2021 Geothermal	52	52	52	52	52	52	52	52	52	52	52	52
2022 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	502	502	502	502	502	502	502	502	502	502	502	502
Monthly Surplus/Deficit	0	0	0	0	0	0	(5)	0	0	0	0	0
Remaining Monthly Surplus/Deficit	884	885	1,326	1,752	946	388	(5)	327	272	1,041	964	692

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/EE)	(2,823)	(2,626)	(2,360)	(2,050)	(3,357)	(4,100)	(4,323)	(3,889)	(3,635)	(2,349)	(2,505)	(3,193)
Existing Demand Response	0	0	0	0	0	351	351	273	0	0	0	0
Peak-Hour Forecast w/DR	(2,823)	(2,626)	(2,360)	(2,050)	(3,357)	(3,749)	(3,972)	(3,616)	(3,635)	(2,349)	(2,505)	(3,193)
Existing Resources												
Coal	908	908	908	908	908	908	908	908	908	908	908	908
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	1,100	1,000	1,070	1,120	1,150	1,030	1,020	990	980	880	910	1,030
Hydro (90th%)—Other	189	188	184	185	277	285	256	207	203	202	184	187
Shoshone Falls Upgrade	7	35	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,296	1,224	1,270	1,305	1,442	1,333	1,278	1,198	1,183	1,082	1,094	1,229
CSPP (PURPA)	63	66	69	96	145	154	166	157	140	101	72	67
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	35	35	35	35	35	35	35	35	35	35	35	35
Firm Pacific NW Import Capability	166	41	164	0	487	386	254	326	346	0	119	361
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,184	2,989	3,162	3,060	3,733	3,532	3,356	3,339	3,328	2,842	2,943	3,316
Monthly Surplus/Deficit	0	0	0	0	0	(217)	(616)	(277)	(307)	0	0	0
2011 IRP DSM												
Industrial	11	11	11	11	11	11	11	11	11	11	11	11
Commercial	5	5	5	5	5	5	5	5	5	5	5	5
Residential	8	8	8	8	8	25	24	25	8	8	8	8
Total New DSM Peak Reduction	25	25	25	25	25	41	41	41	25	25	25	25
Remaining Monthly Surplus/Deficit	0	0	0	0	0	(176)	(575)	(235)	(283)	0	0	0
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	450	450	450	450	450	450	450	450	450	450	450	450
2021 Geothermal	52	52	52	52	52	52	52	52	52	52	52	52
2022 SCCT Frame	0	0	0	0	0	170	170	170	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	502	502	502	502	502	672	672	672	502	502	502	502
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	888	891	1,329	1,537	902	496	97	437	219	1,020	965	650

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/EE)	(2,855)	(2,647)	(2,383)	(2,072)	(3,400)	(4,163)	(4,394)	(3,956)	(3,690)	(2,373)	(2,533)	(3,243)
Existing Demand Response	0	0	0	0	0	351	351	273	0	0	0	0
Peak-Hour Forecast w/DR	(2,855)	(2,647)	(2,383)	(2,072)	(3,400)	(3,812)	(4,043)	(3,683)	(3,690)	(2,373)	(2,533)	(3,243)
Existing Resources												
Coal	908	908	908	908	908	908	908	908	908	908	908	908
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	1,100	1,000	1,070	1,120	1,150	1,030	1,020	990	980	880	910	1,030
Hydro (90th%)—Other	189	188	184	185	277	284	256	207	203	202	184	187
Shoshone Falls Upgrade	7	35	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,296	1,224	1,270	1,305	1,442	1,333	1,278	1,198	1,183	1,082	1,094	1,229
CSPP (PURPA)	63	66	69	96	145	154	166	157	140	101	72	67
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	35	35	35	35	35	35	35	35	35	35	35	35
Firm Pacific NW Import Capability	195	64	185	0	485	382	250	323	344	0	147	359
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,213	3,012	3,183	3,060	3,730	3,528	3,352	3,336	3,326	2,842	2,971	3,314
Monthly Surplus/Deficit	0	0	0	0	0	(284)	(691)	(347)	(365)	0	0	0
2011 IRP DSM												
Industrial	11	11	11	11	12	12	12	12	11	11	11	12
Commercial	6	6	6	6	6	5	5	5	6	6	6	6
Residential	9	9	9	9	9	27	27	27	9	9	9	9
Total New DSM Peak Reduction	26	27	27	26	26	45	44	45	26	26	26	26
Remaining Monthly Surplus/Deficit	0	0	0	0	0	(240)	(647)	(302)	(338)	0	0	0
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	450	450	450	450	450	450	450	450	450	450	450	450
2021 Geothermal	52	52	52	52	52	52	52	52	52	52	52	52
2022 SCCT Frame	0	0	0	0	0	170	170	170	0	0	0	0
2024 Solar Power Tower	0	0	0	0	0	0	0	0	0	0	0	0
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	502	502	502	502	502	672	672	672	502	502	502	502
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	886	894	1,329	1,516	859	432	25	370	164	998	967	600

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/EE)	(2,877)	(2,660)	(2,400)	(2,086)	(3,442)	(4,224)	(4,462)	(4,017)	(3,745)	(2,394)	(2,555)	(3,280)
Existing Demand Response	0	0	0	0	0	351	351	273	0	0	0	0
Peak-Hour Forecast w/DR	(2,877)	(2,660)	(2,400)	(2,086)	(3,442)	(3,873)	(4,111)	(3,745)	(3,745)	(2,394)	(2,555)	(3,280)
Existing Resources												
Coal	908	908	908	908	908	908	908	908	908	908	908	908
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	1,100	1,000	1,070	1,120	1,150	1,030	1,020	990	980	880	910	1,030
Hydro (90th%)—Other	189	188	184	185	277	284	256	207	203	202	184	187
Shoshone Falls Upgrade	7	34	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,296	1,222	1,270	1,305	1,442	1,333	1,278	1,198	1,183	1,082	1,094	1,229
CSPP (PURPA)	63	66	69	96	145	154	166	157	140	101	72	67
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	35	35	35	35	35	35	35	35	35	35	35	35
Firm Pacific NW Import Capability	207	68	(0)	0	484	378	246	320	342	8	169	357
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,225	3,015	2,997	3,060	3,729	3,524	3,348	3,333	3,324	2,850	2,993	3,312
Monthly Surplus/Deficit	0	0	0	0	0	(349)	(764)	(412)	(421)	0	0	0
2011 IRP DSM												
Industrial	12	12	12	12	12	12	12	12	12	12	12	12
Commercial	6	6	6	6	6	6	6	6	6	6	6	6
Residential	10	10	10	10	10	30	30	30	10	10	10	10
Total New DSM Peak Reduction	28	28	28	28	28	47	48	48	28	28	28	28
Remaining Monthly Surplus/Deficit	0	0	0	0	0	(302)	(716)	(364)	(393)	0	0	0
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	450	450	450	450	450	450	450	450	450	450	450	450
2021 Geothermal	52	52	52	52	52	52	52	52	52	52	52	52
2022 SCCT Frame	0	0	0	0	0	170	170	170	0	0	0	0
2024 Solar Power Tower	8	15	20	25	31	36	44	41	36	25	15	4
2025 CCCT	0	0	0	0	0	0	0	0	0	0	0	0
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	510	517	522	527	533	708	716	713	538	527	517	506
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	886	900	1,148	1,529	848	406	0	349	145	1,011	983	566

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/EE)	(2,892)	(2,674)	(2,413)	(2,092)	(3,483)	(4,283)	(4,529)	(4,075)	(3,799)	(2,415)	(2,574)	(3,309)
Existing Demand Response	0	0	0	0	0	351	351	273	0	0	0	0
Peak-Hour Forecast w/DR	(2,892)	(2,674)	(2,413)	(2,092)	(3,483)	(3,932)	(4,178)	(3,802)	(3,799)	(2,415)	(2,574)	(3,309)
Existing Resources												
Coal	908	908	908	908	908	908	908	908	908	908	908	908
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	1,100	1,000	1,070	1,120	1,150	1,030	1,020	990	980	880	910	1,030
Hydro (90th%)—Other	189	188	184	185	277	284	256	207	203	202	184	187
Shoshone Falls Upgrade	7	35	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,296	1,224	1,270	1,305	1,442	1,333	1,278	1,198	1,183	1,082	1,094	1,229
CSPP (PURPA)	63	66	69	96	145	154	166	157	140	101	72	67
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	35	35	35	35	35	35	35	35	35	35	35	35
Firm Pacific NW Import Capability	231	102	(0)	4	482	375	243	318	340	31	188	355
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,249	3,050	2,997	3,064	3,727	3,521	3,345	3,331	3,322	2,873	3,012	3,310
Monthly Surplus/Deficit	0	0	0	0	0	(411)	(833)	(471)	(477)	0	0	0
2011 IRP DSM												
Industrial	12	12	12	12	12	13	13	13	12	12	12	12
Commercial	6	6	6	6	6	6	6	6	6	6	6	6
Residential	11	11	11	11	11	32	32	32	11	11	11	11
Total New DSM Peak Reduction	29	29	29	29	29	51	51	51	29	29	29	29
Remaining Monthly Surplus/Deficit	0	0	0	0	0	(361)	(782)	(420)	(448)	0	0	0
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	450	450	450	450	450	450	450	450	450	450	450	450
2021 Geothermal	52	52	52	52	52	52	52	52	52	52	52	52
2022 SCCT Frame	0	0	0	0	0	170	170	170	0	0	0	0
2024 Solar Power Tower	8	15	20	25	31	36	44	41	36	25	15	4
2025 CCCT	0	0	0	0	0	300	300	300	300	300	300	300
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	510	517	522	527	533	1,008	1,016	1,013	838	827	817	806
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	896	923	1,136	1,528	806	647	234	592	390	1,314	1,285	836

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/EE)	(2,916)	(2,691)	(2,431)	(2,106)	(3,527)	(4,346)	(4,599)	(4,137)	(3,856)	(2,440)	(2,598)	(3,345)
Existing Demand Response	0	0	0	0	0	351	351	273	0	0	0	0
Peak-Hour Forecast w/DR	(2,916)	(2,691)	(2,431)	(2,106)	(3,527)	(3,995)	(4,248)	(3,865)	(3,856)	(2,440)	(2,598)	(3,345)
Existing Resources												
Coal	908	908	908	908	908	908	908	908	908	908	908	908
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	1,100	1,000	1,070	1,120	1,150	1,030	1,020	990	980	880	910	1,030
Hydro (90th%)—Other	189	188	184	185	277	284	256	207	203	202	184	187
Shoshone Falls Upgrade	7	35	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,296	1,224	1,270	1,305	1,442	1,333	1,278	1,198	1,183	1,082	1,094	1,229
CSPP (PURPA)	63	66	69	96	145	154	166	157	140	101	72	67
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	35	35	35	35	35	35	35	35	35	35	35	35
Firm Pacific NW Import Capability	260	125	(0)	24	480	371	238	315	339	57	212	353
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,278	3,073	2,997	3,084	3,725	3,517	3,340	3,328	3,321	2,899	3,036	3,308
Monthly Surplus/Deficit	0	0	0	0	0	(478)	(908)	(537)	(535)	0	0	(37)
2011 IRP DSM												
Industrial	12	12	12	12	13	13	13	13	12	12	13	12
Commercial	6	6	6	6	6	6	6	6	6	6	6	6
Residential	12	12	12	12	12	35	35	35	12	12	12	12
Total New DSM Peak Reduction	31	31	31	31	31	54	54	54	31	31	31	31
Remaining Monthly Surplus/Deficit	0	0	0	0	0	(424)	(855)	(483)	(504)	0	0	(7)
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	450	450	450	450	450	450	450	450	450	450	450	450
2021 Geothermal	52	52	52	52	52	52	52	52	52	52	52	52
2022 SCCT Frame	0	0	0	0	0	170	170	170	0	0	0	0
2024 Solar Power Tower	8	15	20	25	31	36	44	41	36	25	15	4
2025 CCCT	300	300	300	300	300	300	300	300	300	300	300	300
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	810	817	822	827	833	1,008	1,016	1,013	838	827	817	806
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	1,203	1,230	1,419	1,835	1,062	583	162	529	333	1,316	1,286	799

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/EE)	(2,920)	(2,696)	(2,438)	(2,101)	(3,568)	(4,403)	(4,664)	(4,188)	(3,910)	(2,460)	(2,611)	(3,361)
Existing Demand Response	0	0	0	0	0	351	351	273	0	0	0	0
Peak-Hour Forecast w/DR	(2,920)	(2,696)	(2,438)	(2,101)	(3,568)	(4,052)	(4,313)	(3,915)	(3,910)	(2,460)	(2,611)	(3,361)
Existing Resources												
Coal	908	908	908	908	908	908	908	908	908	908	908	908
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	1,100	1,000	1,070	1,120	1,150	1,030	1,020	990	980	880	910	1,030
Hydro (90th%)—Other	189	188	184	185	277	284	256	207	203	202	184	187
Shoshone Falls Upgrade	7	35	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,296	1,224	1,270	1,305	1,442	1,333	1,278	1,198	1,183	1,082	1,094	1,229
CSPP (PURPA)	63	66	69	96	145	154	166	157	140	101	72	67
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	35	35	35	35	35	35	35	35	35	35	35	35
Firm Pacific NW Import Capability	293	141	(0)	40	478	368	234	313	335	91	225	349
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,311	3,089	2,997	3,100	3,723	3,514	3,336	3,326	3,317	2,933	3,049	3,304
Monthly Surplus/Deficit	0	0	0	0	0	(538)	(977)	(589)	(593)	0	0	(57)
2011 IRP DSM												
Industrial	13	13	13	13	13	13	13	13	13	13	13	13
Commercial	6	7	7	7	6	6	6	6	7	7	7	7
Residential	13	13	13	13	13	38	38	38	13	13	13	13
Total New DSM Peak Reduction	32	32	32	32	32	57	57	57	32	32	32	32
Remaining Monthly Surplus/Deficit	0	0	0	0	0	(481)	(921)	(533)	(561)	0	0	(25)
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	450	450	450	450	450	450	450	450	450	450	450	450
2021 Geothermal	52	52	52	52	52	52	52	52	52	52	52	52
2022 SCCT Frame	0	0	0	0	0	170	170	170	0	0	0	0
2024 Solar Power Tower	8	15	20	25	31	36	44	41	36	25	15	4
2025 CCCT	300	300	300	300	300	300	300	300	300	300	300	300
2028 Small Hydro	0	0	0	0	0	0	0	0	0	0	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	810	817	822	827	833	1,008	1,016	1,013	838	827	817	806
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	1,233	1,242	1,414	1,858	1,020	527	96	480	277	1,331	1,287	781

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/EE)	(2,974)	(2,721)	(2,476)	(2,144)	(3,618)	(4,476)	(4,747)	(4,273)	(3,972)	(2,494)	(2,655)	(3,434)
Existing Demand Response	0	0	0	0	0	351	351	273	0	0	0	0
Peak-Hour Forecast w/DR	(2,974)	(2,721)	(2,476)	(2,144)	(3,618)	(4,126)	(4,396)	(4,000)	(3,972)	(2,494)	(2,655)	(3,434)
Existing Resources												
Coal	908	908	908	908	908	908	908	908	908	908	908	908
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	1,100	1,000	1,070	1,120	1,150	1,030	1,020	990	980	880	910	1,030
Hydro (90th%)—Other	189	188	184	185	277	284	256	207	203	202	184	187
Shoshone Falls Upgrade	7	34	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,296	1,222	1,270	1,305	1,442	1,333	1,278	1,198	1,183	1,082	1,094	1,229
CSPP (PURPA)	94	158	150	171	157	139	101	70	68	63	63	69
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	35	35	35	35	35	35	35	35	35	35	35	35
Firm Pacific NW Import Capability	335	159	21	81	477	364	231	310	333	126	269	348
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,383	3,198	3,100	3,215	3,735	3,496	3,268	3,236	3,243	2,930	3,085	3,306
Monthly Surplus/Deficit	0	0	0	0	0	(630)	(1,128)	(764)	(729)	0	0	(129)
2011 IRP DSM												
Industrial	13	13	13	13	13	13	13	13	13	13	13	13
Commercial	7	7	7	7	7	6	6	6	7	7	7	7
Residential	14	14	14	14	14	40	40	40	14	14	14	14
Total New DSM Peak Reduction	33	33	33	33	33	60	59	60	33	33	33	33
Remaining Monthly Surplus/Deficit	0	0	0	0	0	(570)	(1,069)	(704)	(696)	0	0	(96)
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	450	450	450	450	450	450	450	450	450	450	450	450
2021 Geothermal	52	52	52	52	52	52	52	52	52	52	52	52
2022 SCCT Frame	0	0	0	0	0	170	170	170	0	0	0	0
2024 Solar Power Tower	8	15	20	25	31	36	44	41	36	25	15	4
2025 CCCT	300	300	300	300	300	300	300	300	300	300	300	300
2028 Small Hydro	0	0	0	8	40	47	52	48	37	12	0	0
2029 SCCT Frame	0	0	0	0	0	0	0	0	0	0	0	0
New Resource Subtotal	810	817	822	835	872	1,054	1,068	1,060	875	839	817	806
Monthly Surplus/Deficit	0	0	0	0	0	0	(1)	0	0	0	0	0
Remaining Monthly Surplus/Deficit	1,253	1,327	1,479	1,939	1,021	484	(1)	356	178	1,307	1,280	710

Peak-Hour Load and Resource Balance (continued)

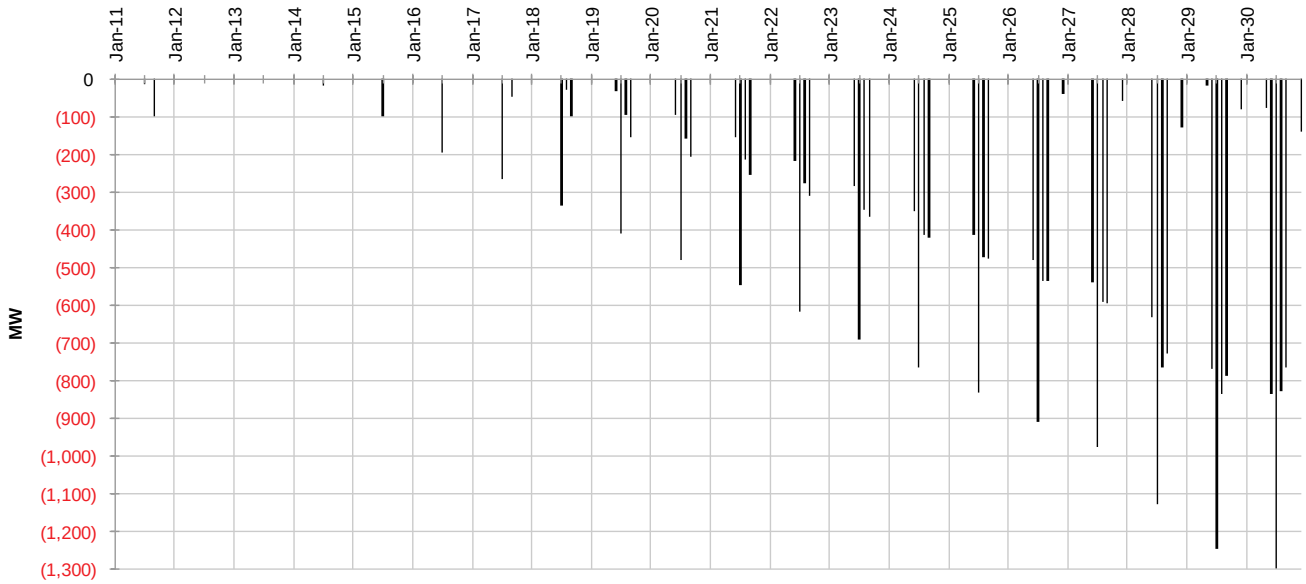
	1/2029	2/2029	3/2029	4/2029	5/2029	6/2029	7/2029	8/2029	9/2029	10/2029	11/2029	12/2029
Load Forecast (95th% w/EE)	(2,991)	(2,748)	(2,492)	(2,151)	(3,665)	(4,541)	(4,822)	(4,335)	(4,031)	(2,520)	(2,677)	(3,463)
Existing Demand Response	0	0	0	0	0	351	351	273	0	0	0	0
Peak-Hour Forecast w/DR	(2,991)	(2,748)	(2,492)	(2,151)	(3,665)	(4,190)	(4,471)	(4,062)	(4,031)	(2,520)	(2,677)	(3,463)
Existing Resources												
Coal	908	908	908	908	908	908	908	908	908	908	908	908
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	1,100	1,000	1,070	1,120	1,150	1,030	1,020	990	980	880	910	1,030
Hydro (90th%)—Other	189	188	184	185	277	284	256	207	203	202	184	187
Shoshone Falls Upgrade	7	35	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,296	1,224	1,270	1,305	1,442	1,333	1,278	1,198	1,183	1,082	1,094	1,229
CSPP (PURPA)	166	171	136	104	70	68	63	61	71	94	149	150
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	35	35	35	35	35	35	35	35	35	35	35	35
Firm Pacific NW Import Capability	350	197	43	103	476	362	227	308	331	142	291	346
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,470	3,251	3,108	3,171	3,647	3,422	3,226	3,226	3,244	2,976	3,193	3,384
Monthly Surplus/Deficit	0	0	0	0	(18)	(768)	(1,245)	(836)	(787)	0	0	(78)
2011 IRP DSM												
Industrial	13	13	13	13	13	13	13	13	13	13	13	13
Commercial	7	7	7	7	7	6	6	6	7	7	7	7
Residential	15	15	15	15	15	43	43	43	15	15	15	15
Total New DSM Peak Reduction	34	34	34	34	34	62	62	62	34	34	34	34
Remaining Monthly Surplus/Deficit	0	0	0	0	0	(705)	(1,183)	(774)	(753)	0	0	(44)
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	450	450	450	450	450	450	450	450	450	450	450	450
2021 Geothermal	52	52	52	52	52	52	52	52	52	52	52	52
2022 SCCT Frame	0	0	0	0	0	170	170	170	0	0	0	0
2024 Solar Power Tower	8	15	20	25	31	36	44	41	36	25	15	4
2025 CCCT	300	300	300	300	300	300	300	300	300	300	300	300
2028 Small Hydro	0	0	0	8	40	47	52	48	37	12	0	0
2029 SCCT Frame	0	0	0	0	0	170	170	170	0	0	0	0
New Resource Subtotal	810	817	822	835	872	1,224	1,238	1,230	875	839	817	806
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	1,324	1,354	1,473	1,888	888	519	55	456	122	1,329	1,367	762

Peak-Hour Load and Resource Balance (continued)

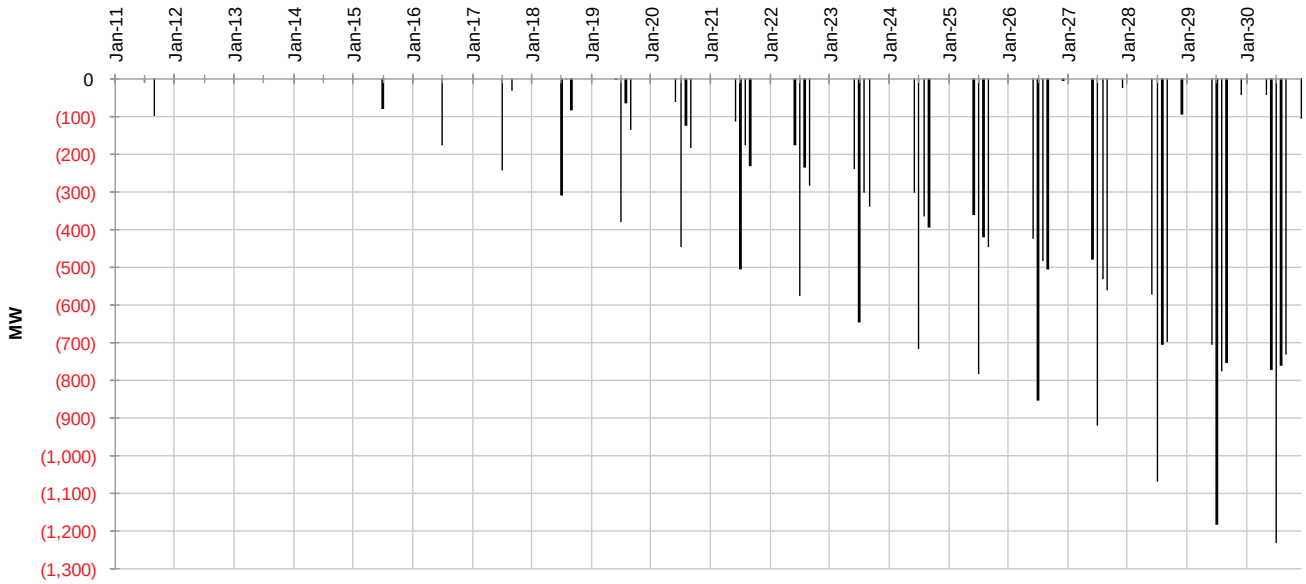
	1/2030	2/2030	3/2030	4/2030	5/2030	6/2030	7/2030	8/2030	9/2030	10/2030	11/2030	12/2030
Load Forecast (95th% w/EE)	(3,023)	(2,772)	(2,516)	(2,172)	(3,713)	(4,609)	(4,901)	(4,406)	(4,092)	(2,550)	(2,708)	(3,509)
Existing Demand Response	0	0	0	0	0	351	351	273	0	0	0	0
Peak-Hour Forecast w/DR	(3,023)	(2,772)	(2,516)	(2,172)	(3,713)	(4,258)	(4,550)	(4,133)	(4,092)	(2,550)	(2,708)	(3,509)
Existing Resources												
Coal	908	908	908	908	908	908	908	908	908	908	908	908
Gas (Langley Gulch)	300	300	300	300	300	300	300	300	300	300	300	300
Hydro (90th%)—HCC	1,100	1,000	1,070	1,120	1,150	1,030	1,020	990	980	880	910	1,030
Hydro (90th%)—Other	189	188	184	185	277	284	256	207	203	202	184	187
Shoshone Falls Upgrade	7	35	16	0	15	19	2	1	0	0	0	12
Sho-Ban Water Lease	0	0	0	0	0	0	0	0	0	0	0	0
Total Hydro (90th%)	1,296	1,224	1,270	1,305	1,442	1,333	1,278	1,198	1,183	1,082	1,094	1,229
CSPP (PURPA)	101	75	67	64	62	70	93	144	154	166	162	136
PPAs												
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5
Raft River Geothermal	10	10	10	10	10	10	10	10	10	10	10	10
Neal Hot Springs Geothermal	20	20	20	20	20	20	20	20	20	20	20	20
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
PPL Montana–Jefferson (83 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Eastside Purchase (50 MW)	0	0	0	0	0	0	0	0	0	0	0	0
Mead Purchase	0	0	0	0	0	0	0	0	0	0	0	0
Total PPAs	35	35	35	35	35	35	35	35	35	35	35	35
Firm Pacific NW Import Capability	370	243	85	143	475	359	224	306	330	184	345	344
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416
Existing Resource Subtotal	3,426	3,201	3,080	3,171	3,637	3,422	3,253	3,307	3,326	3,091	3,259	3,368
Monthly Surplus/Deficit	0	0	0	0	(76)	(837)	(1,296)	(826)	(766)	0	0	(141)
2011 IRP DSM												
Industrial	13	13	13	13	13	13	13	13	13	13	13	13
Commercial	7	7	7	7	7	6	6	6	7	7	7	7
Residential	15	16	15	16	15	45	45	45	15	16	15	15
Total New DSM Peak Reduction	35	35	35	35	35	65	65	65	35	35	35	35
Remaining Monthly Surplus/Deficit	0	0	0	0	(41)	(772)	(1,232)	(761)	(731)	0	0	(106)
2011 IRP Resources												
2015 Eastside Purchase	0	0	0	0	0	0	0	0	0	0	0	0
2016 Boardman to Hemingway	450	450	450	450	450	450	450	450	450	450	450	450
2021 Geothermal	52	52	52	52	52	52	52	52	52	52	52	52
2022 SCCT Frame	0	0	0	0	0	170	170	170	0	0	0	0
2024 Solar Power Tower	8	15	20	25	31	36	44	41	36	25	15	4
2025 CCCT	300	300	300	300	300	300	300	300	300	300	300	300
2028 Small Hydro	0	0	0	8	40	47	52	48	37	12	0	0
2029 SCCT Frame	0	0	0	0	0	170	170	170	0	0	0	0
New Resource Subtotal	810	817	822	835	872	1,224	1,238	1,230	875	839	817	806
Monthly Surplus/Deficit	0	0	0	0	0	0	0	0	0	0	0	0
Remaining Monthly Surplus/Deficit	1,248	1,280	1,421	1,869	831	452	6	469	143	1,414	1,403	700

Peak-Hour Surplus/Deficit Charts

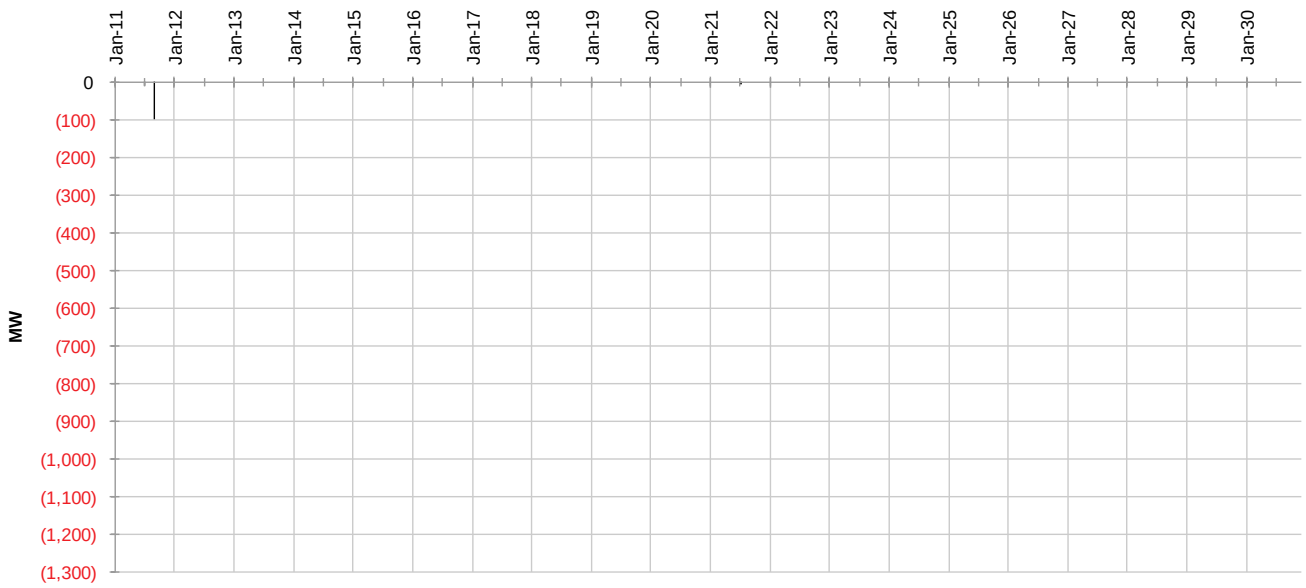
Peak-hour monthly deficits with existing DSM and resources



Peak-hour monthly deficits with existing resources and new DSM



Peak-hour monthly deficits with existing resources, new DSM, and IRP resources



DEMAND-SIDE RESOURCE DATA

Cost Effectiveness

The majority of Idaho Power's energy efficiency programs are preliminarily identified through the integrated resource planning process. Similar to the 2009 IRP, a majority of the anticipated new energy efficiency future commitments for the 2011 IRP come through additional measures added to existing programs and existing program expansion as opposed to new program offerings.

Idaho Power considers cost-effectiveness to be the primary screening tool prior to demand-side management (DSM) program implementation. Idaho Power primarily 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.

Incorporated into the cost-effectiveness analysis are inputs from various sources that represent the most current and reliable information available. For the 2011 IRP, program administration costs were derived from actual 2010 program performance. 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 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 avoided costs.

Idaho Power determines cost-effectiveness on both a program basis and also on a measure-by-measure basis. Demand response program B/C ratios for the residential A/C Cool Credit, Irrigation Peak Rewards, and the commercial and industrial FlexPeak Management program are calculated over a 20-year period which allows for a better comparison with supply-side resource costs. In all cases, whether cost-effectiveness is looked at from the point of view of one measure, as a program, or a 20-year life, for a program to be considered cost-effective the program must have B/C ratios greater than one for both the TRC and UC tests.

The cost-effective analysis methods used at Idaho Power are consistent with published methods and standard practices. Idaho Power relies on the *Electric Power Research Institute End Use Technical Assessment Guide* (TAG) and the *California Standard Practice Manual* for the cost-effectiveness methodology. As defined in the TAG and *California Standard Practice Manual*, the TRC and UC tests are most similar to supply-side cost analysis and provide a useful basis to compare demand-side and supply-side resources.

When developing energy efficiency and demand response resources including program design, Idaho Power uses actual data and experiences from other companies in the region, or throughout the country, to help identify specific program parameters. The regional program review is typically accomplished through discussions with other utilities' program managers and research staff. Other program development resources include; E Source, Edison Electrical Institute (EEI), Consortium for Energy Efficiency (CEE), American Council for an Energy Efficient Economy (ACEEE), Advanced Load Control Alliance (ALCA). For other assumptions, including estimated cost,

savings, Idaho Power relies on sources, such as the NPCC, the RTF, NEEA, the Database for Energy Efficiency Resources (DEER), third-party consultants, and other regional utilities.

Idaho Power may choose to launch a pilot or limited-scale program to evaluate estimates or assumptions in the cost-effectiveness model. Pilot programs are designed to measure actual program experiences, including program expenses, savings, and participation. Following implementation of a program, the cost-effectiveness models are reviewed as data from actual program activity becomes available. The program design may be re-examined after program implementation.

The financial assumptions used in the analysis are consistent with the 2011 IRP, including the discount rate and cost escalation rates. The IRP is also the source of the DSM alternative cost, which is 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 market prices as determined by the AURORAxmp® Electric Market Model. The avoided capacity resource for peak summer hours and for demand response programs is based on a 170 MW natural gas-fired, simple-cycle combustion turbine (SCCT).

Alternate Costs

The prices of avoided energy throughout the 20-year planning period were simulated using the Preferred Portfolio module within the AURORA model. The preferred portfolio module considers the energy capacity and resource costs of the current preferred mix of IRP resources along with regional transmission resources in the Western Electricity Coordinating Council (WECC) region to project forward electric market prices. The forward prices are placed into five homogenous pricing categories that follow the pattern of heavy- and light-load pricing throughout each year of the planning period. The resulting categories are:

- Summer On-Peak (SONP)—Average of Idaho Power variable energy and operating costs of a 170 MW SCCT, which is the marginal resource for peak hour load deficits during summertime heavy load hours
- Summer Mid-Peak (SMP)—Average of heavy load prices from June–August
- Summer Off-Peak (SOFP)—Average of light load prices from June–August
- Non-Summer Mid-Peak (NSMP)—Average of heavy load prices in January–May and September–December
- Non-Summer Off-Peak (NSOFP)—Average of light load prices in January–May and September–December

The SONP is treated differently than the other four pricing periods. During the SONP, additional purchases from the regional power market are not an option due to currently existing transmission constraints. The marginal resource Idaho Power is trying to avoid with DSM efforts for SONP hours is the construction of SCCT. The estimated levelized capacity cost of building a new SCCT is approximately $94 per kW over a 30-year expected plant life. For demand response or direct load

control DSM programs operating during the summer peak, the $94 per kW becomes the cost threshold for program cost-effectiveness.

The avoided capacity value is spread across the annual SONP hours to value the energy efficiency savings occurring during the hours. The total SONP hours vary between 512 to 528 depending on the calendar year. Table DSM-1 lists the financial assumptions used for the cost-effectiveness analysis and new program screening.

Table DSM-2 shows the results of averaging forward energy prices over the 20-year planning period that were used to screen new energy efficiency and demand response programs for cost-effectiveness along with the forecast of operation and maintenance (O&M) costs, including fuel for peak summer hours (SONP). The forward energy prices for measures that have a life longer than 20 years, which is typical for weatherization and building shell measures, are escalated at 3 percent annually as needed.

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 through DSM-7 show the 20-year forecasted impact of energy efficiency by customer class for existing programs, along with the corresponding forecasted UC, and the TRC.

Table DSM-8 outlines the 20-year flow of avoided generation and the benefits attributed to the existing energy efficiency portfolio of programs.

Table DSM-9 summarizes the cost-effectiveness analysis for the existing energy efficiency portfolio of programs through the 20-year IRP planning period.

Table DSM-10 shows the 20-year annual forecasted impact of energy efficiency by customer class for new program measures and existing program expansions.

Table DSM-11 shows the 20-year annual forecast of UC or the costs to administer new program measures and existing program expansions.

Table DSM-12 shows the 20-year flow of resource costs that combines the program participant costs with the costs to administer the program for new program measures and existing program expansions.

Table DSM-13 outlines the 20-year flow of avoided generation and the benefits attributed to new program measures and existing program expansions.

Table DSM-14 summarizes the cost-effectiveness analysis for new program measures and existing program expansions through the 20-year IRP planning period.

Table DSM-15 shows the 20 year annual forecasted operational targets from all existing and new energy efficiency programs.

Tables DSM-16 through DSM-19 show the 20-year flow of demand reduction targets, UC, TRC, and the value of avoided generation for demand response programs, similar to those presented for energy efficiency programs.

Table DSM-20 summarizes the cost-effectiveness for demand response programs and the forecasted impact of the demand response operational targets through the IRP planning horizon.

Table DSM-1. IRP financial assumptions

DSM Analysis Assumptions	
Avoided Capacity Costs	
SCCT	$94/kW
Financial Assumptions	
Weighted average cost of capital (2008 year ending after tax)	7.00%
Financial escalation factor	3.00%
Transmission Losses	
Non-summer secondary losses	10.90%
Summer peak loss	13.00%

Table DSM-2. DSM alternate costs by pricing period

Year	Summer On-Peak* (SONP)	Summer Mid-Peak (SMP)	Summer Off-Peak (SOFP)	Non-Summer Mid-Peak (NSMP)	Non-Summer Off-Peak (NSOFP)
2011	$60.89	$54.42	$36.25	$55.21	$38.22
2012	$69.32	$60.74	$40.77	$61.61	$42.87
2013	$76.15	$65.06	$44.41	$64.89	$45.74
2014	$81.13	$70.10	$48.16	$69.41	$48.81
2015	$102.02	$83.09	$63.18	$82.13	$61.71
2016	$107.46	$87.44	$66.55	$85.69	$64.88
2017	$112.71	$92.77	$71.14	$90.50	$69.13
2018	$117.79	$96.80	$75.64	$95.88	$73.50
2019	$122.76	$102.71	$80.62	$101.44	$78.51
2020	$128.32	$109.45	$86.52	$107.53	$84.34
2021	$134.04	$114.80	$90.59	$113.45	$89.30
2022	$137.67	$119.64	$94.79	$117.74	$92.35
2023	$142.80	$130.75	$102.71	$128.30	$100.59
2024	$148.73	$134.44	$104.67	$133.70	$105.39
2025	$155.25	$143.49	$109.80	$140.64	$109.95
2026	$161.87	$149.37	$113.29	$147.30	$114.66
2027	$168.70	$154.60	$111.26	$153.26	$118.05
2028	$176.12	$160.39	$119.72	$158.69	$124.71
2029	$183.85	$166.21	$125.48	$165.50	$131.51
2030	$191.80	$171.20	$129.24	$170.46	$135.45

* Estimated variable operations and management costs of a 170 MW capacity SCCT.

Table DSM-3. DSM alternate cost summer pricing periods (June 1–August 31)

Hour	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Holiday
1	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
2	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
3	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
4	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
5	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
6	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
7	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
8	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
9	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
10	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
11	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
12	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
13	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
14	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
15	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
16	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
17	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
18	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
19	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
20	SMP	SONP	SONP	SONP	SONP	SONP	SMP	SMP
21	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
22	SMP	SMP	SMP	SMP	SMP	SMP	SMP	SMP
23	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP
24	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP	SOFP

Table DSM-4. DSM alternate cost non-summer pricing periods (September 1–May 31)

Hour	Sunday	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Holiday
1	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
2	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
3	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
4	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
5	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
6	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
7	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
8	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
9	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
10	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
11	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
12	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
13	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
14	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
15	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
16	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
17	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
18	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
19	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
20	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
21	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
22	NSOFP	NSMP	NSMP	NSMP	NSMP	NSMP	NSMP	NSOFP
23	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP
24	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP	NSOFP

Table DSM-5. Cumulative existing energy efficiency portfolio forecast 2011-2030
(aMW w/transmission losses)

Year	Industrial	Irrigation	Commercial	Residential	Total
2011	5	1	6	2	15
2012	10	2	12	5	29
2013	15	3	18	7	43
2014	19	4	24	10	57
2015	23	5	30	11	69
2016	28	6	36	13	82
2017	32	6	42	15	95
2018	37	7	48	16	108
2019	41	8	54	18	121
2020	46	8	60	20	133
2021	50	9	65	22	145
2022	53	9	70	23	155
2023	56	10	74	24	164
2024	59	10	77	25	172
2025	61	11	80	26	178
2026	63	11	83	27	183
2027	64	11	85	27	187
2028	65	11	86	28	190
2029	66	11	86	28	191
2030	66	11	86	28	191

Table DSM-6. Existing energy efficiency portfolio UC 2011-2030

Year	Industrial	Irrigation	Commercial	Residential	Total All Sectors
2011	$5,305,131	$2,066,694	$5,428,863	$6,086,795	$18,887,483
2012	$5,008,928	$1,915,825	$5,709,427	$6,116,523	$18,750,703
2013	$4,690,178	$1,754,044	$5,956,945	$6,071,831	$18,472,998
2014	$4,830,883	$1,580,832	$6,135,653	$6,269,750	$18,817,119
2015	$4,975,810	$1,209,563	$6,319,723	$5,958,083	$18,463,179
2016	$5,125,084	$1,245,849	$6,509,314	$6,154,123	$19,034,371
2017	$5,278,837	$1,283,225	$6,704,594	$6,356,866	$19,623,522
2018	$5,437,202	$1,321,722	$6,905,732	$6,566,552	$20,231,207
2019	$5,600,318	$1,361,373	$7,112,904	$6,763,617	$20,838,212
2020	$5,768,327	$1,402,215	$7,326,291	$6,966,526	$21,463,358
2021	$5,347,239	$1,299,853	$6,791,471	$6,457,969	$19,896,533
2022	$4,895,695	$1,190,088	$6,217,969	$5,912,630	$18,216,381
2023	$4,412,245	$1,072,566	$5,603,945	$5,328,757	$16,417,514
2024	$3,895,382	$946,923	$4,947,483	$4,704,532	$14,494,319
2025	$3,343,536	$812,775	$4,246,589	$4,038,056	$12,440,957
2026	$2,755,074	$669,727	$3,499,190	$3,327,358	$10,251,349
2027	$2,128,295	$517,364	$2,703,124	$2,570,384	$7,919,167
2028	$1,461,429	$355,257	$1,856,145	$1,764,997	$5,437,828
2029	$752,636	$182,957	$955,915	$908,974	$2,800,481
2030	$0	$0	$0	$0	$0
20-Year NPV	**49398585.63**	**14229457.72**	**60885631.38**	**60023977.7**	**184537652.4**

Table DSM-7. Existing energy efficiency portfolio TRC 2011-2030

Year	Industrial	Irrigation	Commercial	Residential	Total All Sectors
2011	$10,378,144	$5,613,834	$10,688,073	$10,369,974	$37,050,025
2012	$9,798,697	$5,204,024	$11,235,421	$10,391,021	$36,629,164
2013	$9,175,144	$4,764,573	$11,739,780	$10,478,055	$36,157,552
2014	$9,450,398	$4,294,071	$12,091,974	$10,811,816	$36,648,259
2015	$9,733,910	$3,285,578	$12,454,733	$10,335,755	$35,809,976
2016	$10,025,928	$3,384,145	$12,828,375	$10,667,137	$36,905,585
2017	$10,326,705	$3,485,670	$13,213,226	$11,009,472	$38,035,073
2018	$10,636,507	$3,590,240	$13,609,623	$11,363,138	$39,199,507
2019	$10,955,602	$3,697,947	$14,017,912	$11,704,116	$40,375,577
2020	$11,284,270	$3,808,885	$14,438,449	$12,055,240	$41,586,844
2021	$10,460,518	$3,530,837	$13,384,442	$11,175,207	$38,551,004
2022	$9,577,185	$3,232,677	$12,254,200	$10,231,523	$35,295,586
2023	$8,631,438	$2,913,450	$11,044,098	$9,221,160	$31,810,147
2024	$7,620,327	$2,572,160	$9,750,361	$8,140,967	$28,083,816
2025	$6,540,781	$2,207,771	$8,369,060	$6,987,663	$24,105,275
2026	$5,389,603	$1,819,203	$6,896,105	$5,757,835	$19,862,747
2027	$4,163,469	$1,405,335	$5,327,241	$4,447,927	$15,343,972
2028	$2,858,915	$964,996	$3,658,039	$3,054,243	$10,536,194
2029	$1,472,341	$496,973	$1,883,890	$1,572,935	$5,426,140
2030	$0	$0	$0	$0	$0
20-Year NPV	**$96,635,806**	**$38,651,984**	**$119,966,128**	**$103,519,281**	**$358,773,200**

Table DSM-8. Existing energy efficiency portfolio avoided energy costs 2011-2030

Year	Industrial	Irrigation	Commercial	Residential	Total All Sectors
2011	$32,844,311	$7,358,378	$35,697,627	$21,464,719	$97,365,035
2012	$30,107,285	$6,622,540	$36,479,634	$21,068,162	$94,277,622
2013	$27,370,259	$5,886,702	$36,870,638	$20,711,920	$90,839,519
2014	$27,370,259	$5,150,864	$36,870,638	$20,735,849	$90,127,610
2015	$27,370,259	$3,826,356	$36,870,638	$19,035,142	$87,102,396
2016	$27,370,259	$3,826,356	$36,870,638	$19,059,891	$87,127,145
2017	$27,370,259	$3,826,356	$36,870,638	$19,085,062	$87,152,315
2018	$27,370,259	$3,826,356	$36,870,638	$19,110,660	$87,177,913
2019	$27,370,259	$3,826,356	$36,870,638	$19,110,749	$87,178,003
2020	$27,370,259	$3,826,356	$36,870,638	$19,110,749	$87,178,003
2021	$24,633,233	$3,443,721	$33,183,574	$17,199,674	$78,460,202
2022	$21,896,207	$3,061,085	$29,496,510	$15,288,599	$69,742,402
2023	$19,159,182	$2,678,449	$25,809,447	$13,377,524	$61,024,602
2024	$16,422,156	$2,295,814	$22,122,383	$11,466,449	$52,306,802
2025	$13,685,130	$1,913,178	$18,435,319	$9,555,375	$43,589,001
2026	$10,948,104	$1,530,543	$14,748,255	$7,644,300	$34,871,201
2027	$8,211,078	$1,147,907	$11,061,191	$5,733,225	$26,153,401
2028	$5,474,052	$765,271	$7,374,128	$3,822,150	$17,435,601
2029	$2,737,026	$382,636	$3,687,064	$1,911,075	$8,717,800
2030	$0	$0	$0	$0	$0
20-Year NPV	$257,704,824	$43,667,373	$335,208,357	$181,086,911	$817,667,465

Table DSM-9. Existing energy efficiency portfolio cost-effectiveness summary

	Impact	20-Year NPV Costs			UC		TRC	
	2030 Load (aMW)	Utility	Resource	Avoided Energy	B/C Ratio	Levelized ($/kWh)	B/C Ratio	Levelized Costs ($/kWh)
Industrial	66	$49,398,586	$96,635,806	$257,704,824	5.2	$0.015	2.7	$0.028
Irrigation	11	$14,229,458	$38,651,984	$43,667,373	3.1	$0.023	1.1	$0.061
Commercial	86	$60,885,631	$119,966,128	$335,208,357	5.5	$0.014	2.8	$0.027
Residential	28	$60,023,978	$103,519,281	$181,086,911	3.0	$0.040	1.7	$0.069
Total	191	$184,537,652	$358,773,200	$817,667,465	4.4	$0.019	2.3	$0.036

Table DSM-10. Cumulative new energy efficiency portfolio forecast 2011-2030

(aMW w/transmission losses)

Year	Industrial	Commercial	Residential	Total
2011	2	1	1	3
2012	3	1	1	5
2013	5	1	2	8
2014	6	2	3	11
2015	7	2	4	13
2016	8	3	5	15
2017	8	3	6	18
2018	9	4	7	20
2019	9	4	9	22
2020	10	5	10	25
2021	11	5	11	27
2022	11	5	13	29
2023	12	6	14	31
2024	12	6	15	33
2025	12	6	16	35
2026	13	6	18	37
2027	13	6	19	38
2028	13	7	20	40
2029	13	7	22	41
2030	13	7	23	42

Table DSM-11. New energy efficiency UC 2011-2030

Year	Industrial	Commercial	Residential	Total All Sectors
2011	$1,642,064	$479,932	$1,622,645	$3,744,641
2012	$1,496,173	$453,136	$1,873,579	$3,822,888
2013	$2,010,076	$424,300	$2,112,145	$4,546,521
2014	$1,380,252	$437,029	$2,666,461	$4,483,742
2015	$710,830	$450,140	$2,909,628	$4,070,597
2016	$732,155	$463,644	$3,173,904	$4,369,702
2017	$754,120	$477,553	$3,404,458	$4,636,130
2018	$776,743	$491,880	$3,554,156	$4,822,778
2019	$800,045	$506,636	$3,706,560	$5,013,242
2020	$824,047	$521,835	$3,889,291	$5,235,173
2021	$763,891	$483,741	$4,017,933	$5,265,565
2022	$699,385	$442,892	$4,076,109	$5,218,385
2023	$630,321	$399,156	$4,134,669	$5,164,146
2024	$556,483	$352,398	$4,193,613	$5,102,494
2025	$477,648	$302,475	$4,252,937	$5,033,060
2026	$393,582	$249,239	$4,312,642	$4,955,463
2027	$304,042	$192,537	$4,372,729	$4,869,308
2028	$208,776	$132,209	$4,433,200	$4,774,184
2029	$107,519	$68,088	$4,417,298	$4,592,905
2030	$0	$0	$4,396,453	$4,396,453
20-Year NPV	$10,293,124	$4,468,872	$35,582,870	$50,344,865

Table DSM-12. New energy efficiency TRC 2011-2030

Year	Industrial	Commercial	Residential	Total All Sectors
2011	$3,212,283	$924,431	$2,671,501	$6,808,215
2012	$2,926,884	$872,817	$3,190,869	$6,990,570
2013	$3,932,205	$817,274	$3,694,416	$8,443,895
2014	$2,700,114	$841,792	$4,903,200	$8,445,106
2015	$1,390,559	$867,046	$5,415,211	$7,672,816
2016	$1,432,275	$893,058	$5,973,476	$8,298,809
2017	$1,475,244	$919,849	$6,455,345	$8,850,437
2018	$1,519,501	$947,445	$6,755,376	$9,222,322
2019	$1,565,086	$975,868	$7,060,418	$9,601,373
2020	$1,612,039	$1,005,144	$7,432,207	$10,049,389
2021	$1,494,360	$931,769	$7,812,294	$10,238,423
2022	$1,368,169	$853,086	$8,041,475	$10,262,731
2023	$1,233,063	$768,844	$8,278,518	$10,280,425
2024	$1,088,618	$678,779	$8,523,748	$10,291,146
2025	$934,397	$582,619	$8,777,506	$10,294,522
2026	$769,943	$480,078	$9,040,150	$10,290,171
2027	$594,781	$370,860	$9,312,055	$10,277,696
2028	$408,416	$254,657	$9,593,615	$10,256,689
2029	$210,334	$131,149	$9,713,579	$10,055,061
2030	$0	$0	$9,832,105	$9,832,105
20-Year NPV	$20,135,886	$8,607,815	$69,027,549	$97,771,250

Table DSM-13. New energy efficiency avoided energy costs 2011-2030

Year	Industrial	Commercial	Residential	Total All Sectors
2011	$10,166,096	$3,284,431	$9,688,235	$23,138,763
2012	$8,993,085	$3,010,729	$11,886,107	$23,889,920
2013	$11,730,111	$2,737,026	$13,741,375	$28,208,512
2014	$7,820,074	$2,737,026	$18,590,724	$29,147,824
2015	$3,910,037	$2,737,026	$20,155,510	$26,802,573
2016	$3,910,037	$2,737,026	$21,803,334	$28,450,397
2017	$3,910,037	$2,737,026	$23,026,680	$29,673,743
2018	$3,910,037	$2,737,026	$23,444,101	$30,091,164
2019	$3,910,037	$2,737,026	$23,834,165	$30,481,227
2020	$3,910,037	$2,737,026	$24,425,904	$31,072,967
2021	$3,519,033	$2,463,323	$25,296,694	$31,279,050
2022	$3,128,030	$2,189,621	$25,585,141	$30,902,792
2023	$2,737,026	$1,915,918	$25,877,455	$30,530,399
2024	$2,346,022	$1,642,216	$26,173,719	$30,161,956
2025	$1,955,019	$1,368,513	$26,474,018	$29,797,549
2026	$1,564,015	$1,094,810	$26,778,442	$29,437,267
2027	$1,173,011	$821,108	$27,087,083	$29,081,202
2028	$782,007	$547,405	$27,400,039	$28,729,452
2029	$391,004	$273,703	$27,230,745	$27,895,451
2030	$0	$0	$27,061,451	$27,061,451
20-Year NPV	$56,034,905	$25,770,482	$228,851,046	$310,656,434

Table DSM-14. New energy efficiency cost-effectiveness summary 2011-2030

	Impact	20-Year NPV Costs			UC		TRC	
	2030 Load (aMW)	Utility	Resource	Avoided Energy	B/C Ratio	Levelized ($/kWh)	B/C Ratio	Levelized Costs ($/kWh)
Industrial	13	$10,293,124	$20,135,886	$56,034,905	5.4	$0.013	2.8	$0.026
Commercial	7	$4,468,872	$8,607,815	$25,770,482	5.8	$0.013	3.0	$0.025
Residential	23	$35,582,870	$69,027,549	$228,851,046	6.4	$0.045	3.3	$0.086
Total	42	$50,344,865	$97,771,250	$310,656,434	6.2	$0.026	3.2	$0.051

Table DSM-15. Total energy efficiency portfolio forecasted impact existing and new 2011-2030
(aMW w/transmission losses)

Year	Industrial	Irrigation	Commercial	Residential	Total
2011	7	1	6	3	18
2012	13	2	13	6	34
2013	20	3	19	9	51
2014	25	4	26	12	68
2015	30	5	32	15	83
2016	35	6	38	18	98
2017	41	6	45	21	113
2018	46	7	51	24	128
2019	51	8	58	27	143
2020	56	8	64	30	158
2021	60	9	70	33	172
2022	64	9	75	35	184
2023	68	10	79	38	195
2024	71	10	83	40	205
2025	73	11	87	42	213
2026	75	11	89	45	220
2027	77	11	91	46	225
2028	78	11	92	48	229
2029	78	11	93	50	232
2030	78	11	93	51	233

Table DSM-16. Demand response portfolio forecasted impact 2011-2030
(MW w/transmission losses)

Year	Commercial/Industrial	Irrigation	Residential	Total
2011	35	250	45	330
2012	35	224	51	310
2013	40	224	51	315
2014	40	224	51	315
2015	40	230	51	321
2016	40	260	51	351
2017	40	260	51	351
2018	40	260	51	351
2019	40	260	51	351
2020	40	260	51	351
2021	40	260	51	351
2022	40	260	51	351
2023	40	260	51	351
2024	40	260	51	351
2025	40	260	51	351
2026	40	260	51	351
2027	40	260	51	351
2028	40	260	51	351
2029	40	260	51	351
2030	40	260	51	351

Table DSM-17. Demand response portfolio UC 2011-2030

Year	Commercial/Industrial	Irrigation	Residential	Total All Sectors
2011	$2,247,361	$11,295,980	$2,836,308	$16,379,648
2012	$2,257,055	$10,142,226	$1,973,958	$14,373,239
2013	$2,554,314	$9,960,104	$2,007,751	$14,522,170
2014	$2,561,526	$9,990,770	$2,042,659	$14,594,955
2015	$2,568,688	$10,262,003	$2,078,732	$14,909,422
2016	$2,576,064	$10,303,688	$2,116,026	$14,995,779
2017	$2,583,662	$10,331,152	$2,153,998	$15,068,812
2018	$2,591,487	$10,421,500	$2,193,073	$15,206,060
2019	$2,599,548	$10,404,669	$2,233,853	$15,238,070
2020	$2,607,850	$10,423,523	$2,275,028	$15,306,401
2021	$2,616,401	$10,457,730	$2,317,860	$15,391,991
2022	$2,625,209	$10,510,168	$2,362,467	$15,497,844
2023	$2,634,281	$10,550,924	$2,408,035	$15,593,240
2024	$2,643,626	$10,582,001	$2,454,658	$15,680,285
2025	$2,653,250	$10,631,069	$2,503,167	$15,787,487
2026	$2,663,164	$10,675,465	$2,552,956	$15,891,585
2027	$2,673,374	$10,707,573	$2,603,851	$15,984,798
2028	$2,683,891	$10,851,976	$2,657,019	$16,192,886
2029	$2,694,724	$10,828,235	$2,711,791	$16,234,750
2030	$2,705,882	$10,891,789	$2,768,217	$16,365,887
20-Year NPV	$29,797,258	$122,250,426	$25,242,292	$177,289,977

Table DSM-18. Demand response portfolio TRC 2011-2030

Year	Commercial/Industrial	Irrigation	Residential	Total All Sectors
2011	$2,247,361	$11,295,980	$2,836,308	$16,379,648
2012	$2,257,055	$10,142,226	$1,973,958	$14,373,239
2013	$2,554,314	$9,960,104	$2,007,751	$14,522,170
2014	$2,561,526	$9,990,770	$2,042,659	$14,594,955
2015	$2,568,688	$10,262,003	$2,078,732	$14,909,422
2016	$2,576,064	$10,303,688	$2,116,026	$14,995,779
2017	$2,583,662	$10,331,152	$2,153,998	$15,068,812
2018	$2,591,487	$10,421,500	$2,193,073	$15,206,060
2019	$2,599,548	$10,404,669	$2,233,853	$15,238,070
2020	$2,607,850	$10,423,523	$2,275,028	$15,306,401
2021	$2,616,401	$10,457,730	$2,317,860	$15,391,991
2022	$2,625,209	$10,510,168	$2,362,467	$15,497,844
2023	$2,634,281	$10,550,924	$2,408,035	$15,593,240
2024	$2,643,626	$10,582,001	$2,454,658	$15,680,285
2025	$2,653,250	$10,631,069	$2,503,167	$15,787,487
2026	$2,663,164	$10,675,465	$2,552,956	$15,891,585
2027	$2,673,374	$10,707,573	$2,603,851	$15,984,798
2028	$2,683,891	$10,851,976	$2,657,019	$16,192,886
2029	$2,694,724	$10,828,235	$2,711,791	$16,234,750
2030	$2,705,882	$10,891,789	$2,768,217	$16,365,887
20-Year NPV	$29,797,258	$122,250,426	$25,242,292	$177,289,977

Table DSM-19. Demand response avoided capacity costs 2011-2030

Year	Commercial/Industrial	Irrigation	Residential	Total All Sectors
2011	$3,450,064	$21,808,244	$4,304,426	$29,562,735
2012	$3,467,767	$19,640,451	$4,847,528	$27,955,745
2013	$3,979,560	$19,721,715	$4,851,697	$28,552,973
2014	$3,991,512	$19,780,945	$4,854,736	$28,627,192
2015	$4,041,649	$20,029,412	$4,867,483	$28,938,545
2016	$4,054,703	$20,094,105	$4,870,802	$29,019,610
2017	$4,067,303	$20,156,544	$4,874,005	$29,097,853
2018	$4,079,498	$20,216,981	$4,877,106	$29,173,585
2019	$4,091,417	$20,276,049	$4,880,136	$29,247,603
2020	$4,104,769	$20,342,220	$4,883,531	$29,330,520
2021	$4,118,497	$20,410,249	$4,887,021	$29,415,767
2022	$4,127,211	$20,453,436	$4,889,237	$29,469,884
2023	$4,139,508	$20,514,376	$4,892,364	$29,546,248
2024	$4,153,749	$20,584,950	$4,895,984	$29,634,684
2025	$4,169,405	$20,662,540	$4,899,965	$29,731,910
2026	$4,185,278	$20,741,199	$4,904,001	$29,830,477
2027	$4,201,677	$20,822,471	$4,908,170	$29,932,318
2028	$4,219,495	$20,910,773	$4,912,700	$30,042,968
2029	$4,238,051	$21,002,731	$4,917,418	$30,158,200
2030	$4,257,124	$21,097,253	$4,922,268	$30,276,645
20-Year NPV	$46,640,850	$238,224,468	$52,905,340	$337,770,658

Table DSM-20. Demand response cost-effectiveness summary

		20-Year NPV Costs		TRC	
	2030 Load Impact(MW)	Resource	Avoided Energy	B/C Ratio	Levelized Costs ($/kWh)
Commercial/Industrial	40	$29,797,258	$46,640,850	1.6	$65
Irrigation	260	$122,250,426	$238,224,468	2.0	$45
Residential	51	$25,242,292	$52,905,340	2.1	$46
Total	351	$177,289,977	$337,770,659	1.9	$48

SUPPLY-SIDE RESOURCE DATA

Key Financial and Forecast Assumptions

Financing Cap Structure and Cost	
Composition	
Debt	50.73%
Preferred	0.00%
Common	49.27%
Total	100.00%
Cost	
Debt	5.93%
Preferred	0.00%
Common	10.50%
Average Weighted Cost	8.18%

Financial Assumptions and Factors	
Plant operating (book) life	30 Years
Discount rate (AKA WACC)	7.00%
Composite tax rate	39.10%
Deferred rate	35.00%
General O&M escalation rate	3.00%
Emissions adder escalation rate	2.50%
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)	7.00%
Production tax credits escalation rate	3.00%

Tax Credits (2011$)	
Wind and geothermal	$21/MWh first 10 Years of Operation
Hydro and in-stream generation	$10/MWh first 10 Years of Operation
Solar investment tax credit (ITC)	30% of depreciable investment

Emissions Adder Rates	
Carbon Dioxide (CO_2)	$20 per ton (2015 $)
Nitrogen Oxide (NO_x)	$2,600 per ton (2015 $)
Mercury (Hg)	$1,443 per ounce (2015 $)
Sulfur Oxide (SO_2)	$1.75 per ton (2011 $)

Emissions Limits (lbs per MWh by technology, adders brought into the analysis beginning in 2015)				
	CO_2	NO_x	HG	SO_2
Small aeroderivative SCCT	1,115	1.07052	N/A	0.0096
Large aeroderivative SCCT	1,047	1.00540	N/A	0.0090
Large frame SCCT	1,413	1.35615	N/A	0.0122
CCCT 1x1	809	0.77690	N/A	0.0070
CCCT 2x1	809	0.77690	N/A	0.0070
Combined heat and power (CHP)	1,047	1.00540	N/A	0.0090
Distributed generation–gas fired	1,115	1.07052	N/A	0.0096
Pulverized coal	1,901	3.38192	0.000050	8.5339
IGCC	2,279	0.21036	0.000006	0.1490
IGCC w/carbon sequestration	421	0.25874	0.000006	0.1833

Fuel Forecast Base Case (Nominal, $ per MMBtu)			
Year	Gas	Generic Coal	Nuclear
2011	$5.00	$2.26	$0.66
2012	$5.79	$2.38	$0.66
2013	$6.42	$2.43	$0.67
2014	$6.87	$2.54	$0.67
2015	$7.27	$2.50	$0.67
2016	$7.68	$2.53	$0.68
2017	$8.08	$2.63	$0.68
2018	$8.45	$2.67	$0.69
2019	$8.80	$2.69	$0.69
2020	$9.21	$2.81	$0.69
2021	$9.62	$2.90	$0.70
2022	$9.83	$2.99	$0.70
2023	$10.18	$3.08	$0.71
2024	$10.59	$3.18	$0.71
2025	$11.06	$3.28	$0.72
2026	$11.53	$3.39	$0.72
2027	$12.01	$3.49	$0.72
2028	$12.54	$3.61	$0.73
2029	$13.09	$3.72	$0.73
2030	$13.66	$3.84	$0.74
2031	$13.74	$3.86	$0.74
2032	$13.82	$3.89	$0.75
2033	$13.91	$3.91	$0.75
2034	$13.99	$3.93	$0.75
2035	$14.07	$3.96	$0.76
2036	$14.16	$3.98	$0.76
2037	$14.24	$4.00	$0.77
2038	$14.33	$4.03	$0.78
2039	$14.41	$4.05	$0.78
2040	$14.50	$4.08	$0.79

Cost Inputs and Operating Assumptions

(All costs in 2011 dollars)

Supply-Side Resources	Plant Capacity (MW)	Plant Capital ($/kW)[1,3]	Tranmission Capital $/kW	Total Capital $/kW	Total Investment $/kW[2]	Fixed O&M $/kW[3]	Varibale O&M $/kW	Emissions $/MWh	Heat Rate Btu/kWh
Wind	100	$1,450	$283	$1,733	$1,840	$35	$1	$0	NA
Wind Magic Valley	100	$1,450	$298	$1,748	$1,856	$35	$1	$0	NA
Wind Eastern Oregon	100	$1,450	$672	$2,122	$2,253	$35	$1	$0	NA
Geothermal Nevada	26	$6,250	$231	$6,481	$7,115	$136	$5	$0	NA
Geothermal Oregon	26	$6,250	$135	$6,385	$7,010	$136	$5	$0	NA
Geothermal Idaho	26	$6,250	$665	$6,915	$7,592	$136	$5	$0	NA
Solar–Parabolic Trough	150	$2,115	$258	$2,373	$2,737	$122	$0	$0	NA
Solar–Parabolic Trough, 12 hrs energy storage	150	$3,562	$258	$3,820	$4,407	$79	$0	$0	NA
Solar–Molten Salt Power Tower, 6.9 hrs energy storage	100	$3,220	$258	$3,478	$4,012	$55	$0	$0	NA
Solar–Flat Plate PV (Distributed)	1	$3,750	$0	$3,750	$3,816	$25	$0	$0	NA
Solar–Concentrating PV	5	$6,171	$50	$6,221	$6,443	$12	$0	$0	NA
Low Drop/Small Hydro New	10	$4,000	$50	$4,050	$4,672	$14	$3	$0	NA
Pumped Storage	25	$5,000	$0	$5,000	$5,768	$10	$6	$0	NA
SCCT–Small Aeroderivative	47	$1,050	$13	$1,063	$1,126	$13	$4	$15	9,370
SCCT–Large Aeroderivative	100	$1,130	$111	$1,241	$1,314	$8	$5	$11	8,800
SCCT–Industrial Frame	170	$610	$136	$746	$790	$4	$2	$19	11,870
CCCT (1x1) F Class	270	$1,120	$96	$1,216	$1,380	$7	$2	$11	6,800
CCCT (2x1) F Class	540	$1,050	$78	$1,128	$1,280	$12	$2	$11	6,800
CHP/Co-Generation	100	$1,860	$28	$1,888	$2,008	$8	$5	$0	9,200
Reciprocating Engines	25	$1,150	$134	$1,284	$1,354	$13	$10	$13	9,700
Distributed Generation (Option # 1) Load shed	10	$0	$0	$0	$0	$60	$0	$0	9,050
Distributed Generation (Option # 2) Grid synchronized	15	$0	$160	$160	$160	$60	$0	$0	9,050
Conventional Scrubbed Coal	600	$2,223	$730	$2,953	$3,499	$5	$28	$34	9,200
IGCC	550	$2,569	$730	$3,299	$4,026	$3	$40	$34	8,765
IGCC w/carbon sequestration	380	$3,776	$730	$4,506	$5,498	$5	$47	$7	10,781
Advanced Nuclear	250	$3,820	$283	$4,103	$5,965	$1	$92	$0	10,488
Boardman to Hemingway	450	$0	$510	$510	$580	$1	$0	$0	NA
Solar–Flat Plate PV (Utility)	1	$3,750	$0	$3,750	$3,816	$25	$0	$0	NA

[1] Plant costs include engineering development costs, generating and ancillary equipment purchase, and installation costs, as well as balance of plant construction.

[2] Total Investment includes capital costs and AFUDC.

[3] Fixed O&M excludes property taxes and insurance (separately calculated within the levelized resource cost analysis)

Levelized Cost of Production

30-Year Levelized Cost of Production (at stated capacity factors)

Supply-Side Resources	Cost of Capital	Non-Fuel O&M[1]	Fuel	Wholesale Energy	Emission Adders	Total Cost per MWh[1]	Capacity Factor
Advanced Nuclear (380 MW)	$85	$137	$8	$0	$0	$229	85%
CCCT 1x1 (270 MW)	$26	$6	$65	$0	$11	$108	65%
CCCT 2x1 (540 MW)	$24	$7	$65	$0	$11	$107	65%
CHP (100 MW)	$26	$10	$74	$0	$0	$111	93%
Distributed Generation–Grid Sync (15 MW)	$1,690	$8,478	$0	$0	$0	$10,168	0%
Distributed Generation–Load Shed (10 MW)	$0	$8,478	$0	$0	$0	$8,478	0%
Geothermal Idaho (26 MW)	$99	$25	$0	$0	$0	$124	92%
Geothermal Nevada (26 MW)	$93	$24	$0	$0	$0	$117	92%
Geothermal Oregon (26 MW)	$92	$24	$0	$0	$0	$116	92%
IGCC (550 MW)	$57	$61	$27	$0	$34	$179	85%
IGCC w/Carbon Sequestration (380 MW)	$78	$74	$33	$0	$7	$191	85%
Low Drop/Small Hydro New (10 MW)	$125	$19	$0	$0	$0	$144	45%
Pulverized Coal (750 MW)	$48	$44	$28	$0	$34	$154	88%
Pumped Storage (25 MW)	$134	$21	$0	$0	$0	$155	52%
Reciprocating Engines (25 MW)	$272	$70	$93	$0	$13	$449	6%
SCCT–Industrial Frame (170 MW)	$159	$25	$114	$0	$19	$316	6%
SCCT–Large Aero (100 MW)	$158	$32	$85	$0	$11	$286	10%
SCCT–Small Aero (47 MW)	$170	$45	$90	$0	$15	$319	8%
Solar–Concentrating PV (1 MW)	$135	$36	$0	$0	$0	$171	22%
Solar–Flat Plate PV (1 MW)	$105	$46	$0	$0	$0	$150	17%
Solar–Parabolic Trough No Storage (150 MW)	$56	$122	$0	$0	$0	$177	18%
Solar–Parabolic Trough, with Energy Storage (150 MW)	$70	$60	$0	$0	$0	$130	28%
Solar–Salt Power Tower (100 MW)	$64	$45	$0	$0	$0	$109	28%
Transmission–Boardman to Hemingway (450 MW)	$19	$1	$0	$64	$0	$83	32%
Wind (100 MW)	$69	$20	$0	$0	$0	$89	32%
Wind Eastern Oregon (100 MW)	$85	$21	$0	$0	$0	$106	32%
Wind Magic Valley (100 MW)	$70	$20	$0	$0	$0	$90	32%

[1] Includes emissions costs.

Supply-Side Resources	30-Year Levelized Capacity (fixed) Cost per kW/Month Cost of Capital	Non-Fuel O&M[1]	Fuel	Emission Adders	Total Cost per kW/Month
Advanced Nuclear (380 MW)	$52	$4	$0	$0	$57
CCCT 1x1 (270 MW)	$12	$2	$0	$0	$14
CCCT 2x1 (540 MW)	$11	$2	$0	$0	$14
CHP (100 MW)	$18	$2	$0	$0	$20
Distributed Generation–Grid Sync (15 MW)	$1	$7	$0	$0	$8
Distributed Generation–Load Shed (10 MW)	$0	$7	$0	$0	$7
Geothermal Idaho (26 MW)	$67	$21	$0	$0	$88
Geothermal Nevada (26 MW)	$63	$21	$0	$0	$83
Geothermal Oregon (26 MW)	$62	$21	$0	$0	$82
IGCC (550 MW)	$35	$3	$0	$0	$38
IGCC w/Carbon Sequestration (380 MW)	$48	$4	$0	$0	$53
Low Drop/Small Hydro New (10 MW)	$41	$5	$0	$0	$46
Pulverized Coal (750 MW)	$31	$3	$0	$0	$34
Pumped Storage (25 MW)	$51	$5	$0	$0	$56
Reciprocating Engines (25 MW)	$12	$2	$0	$0	$14
SCCT–Industrial Frame (170 MW)	$7	$1	$0	$0	$8
SCCT–Large Aero (100 MW)	$12	$2	$0	$0	$13
SCCT–Small Aero (47 MW)	$10	$2	$0	$0	$12
Solar–Concentrating PV (1 MW)	$57	$6	$0	$0	$62
Solar–Flat Plate PV (1 MW)	$34	$6	$0	$0	$39
Solar–Parabolic Trough No Storage (150 MW)	$24	$16	$0	$0	$40
Solar–Parabolic Trough, with Energy Storage (150 MW)	$39	$12	$0	$0	$51
Solar–Salt Power Tower (100 MW)	$35	$9	$0	$0	$45
Transmission–Boardman to Hemingway (450 MW)	$4	$0	$0	$0	$5
Wind (100 MW)	$16	$5	$0	$0	$22
Wind Eastern Oregon (100 MW)	$20	$6	$0	$0	$25
Wind Magic Valley (100 MW)	$16	$5	$0	$0	$22

Resource Advantages and Disadvantages

Resource Type	Advantages	Disadvantages
Geothermal	• Renewable resource • No harmful emissions • Minimum fuel risk (once developed) • Low, variable operating costs • Baseload generation (90%+ capacity factor)	• Limited number of sites • High exploration costs due to drilling risks • Uncertainty surrounding future tax incentives
Wind	• Renewable resource • No fuel cost • No harmful emissions • Low, variable operating costs	• Limited number of good sites in southern Idaho • Intermittent and non-dispatchable resource • Inefficient use of limited firm transmission capacity • Avian and aesthetic impacts • Uncertainty surrounding future tax incentives
Hydro	• Renewable resource • No fuel cost • No harmful emissions • Low, variable operating costs	• Limited number of sites • Future development is limited to small sites or at existing dams without power generation • Fish and other environmental issues

Resource Type	Advantages	Disadvantages
Solar (General)	• Renewable resource • No fuel cost • No harmful emissions • Low, variable operating costs • Generation would match well with summer peak loads.	• More expensive than other resource options • Poor generation during winter months • Intermittent and non-dispatchable resource • Inefficient use of limited firm transmission capacity • Limited utility scale projects exist
Parabolic Trough	• Can be built with thermal storage	• Utility scale production is limited
Power Tower	• By using molten salt, thermal storage can be built integrally into the system	• Utility scale production is unproven • Requires land slope of 1 percent of less
Parabolic Dish	• Off-grid electricity production in remote areas	• Not suitable for storage options • Unproven technology
Photovoltaic	• Proven & reliable technology • Suitable for distributed generation	• Cloud cover creates a rapid power drop-off • Utility scale projects are only practical up to 10 MW
Biomass	• Renewable resource • No harmful emissions • Minimum fuel risk • Low, variable operating costs • Baseload generation (90%+ capacity factor)	• Limited number of sites • Uncertainty surrounding future tax incentives • Fuel supply risk
In-stream Generation	• Renewable resource • No harmful emissions • No fuel cost	• Small size, many sites would be required • Environmental impact and permitting • High maintenance cost
Distributed Generation	• Utilize existing backup generators at customer sites • Dispatchable resource • Provides operating reserves	• More expensive than other resource options • Limited number of sites • Fuel price risk and volatility • Existing air quality permits may need to be modified • Small size, many sites would be required
Natural Gas		
Combined-Cycle Combustion Turbines (CCCT)	• Proven and reliable technology • Dispatchable resource • Provides operating reserves necessary for integration of renewable generation • More efficient than a SCCT • Greater than 50% reduction in CO_2 emissions per MWh of output compared to conventional pulverized coal technology	• Fuel price risk and volatility • Potential fuel supply and transportation issues
Simple-Cycle Combustion Turbines (SCCT)	• Dispatchable resource • Proven, reliable resource • Low capital cost • Short construction lead times • Ideal for peaking service	• High variable operating cost • Fuel price risk and volatility • Less efficient than a CCCT

Resource Type	Advantages	Disadvantages
Coal		
Pulverized	• Abundant, low cost fuel • Less price volatility than natural gas • Proven and reliable technology • Dispatchable resource • Well suited for baseload operations	• Potential lack of public acceptance • Significant particulate and gas emissions, particularly CO_2 • Significant capital investment • Long construction lead times • Lengthy environmental permitting and siting processes
Advanced Technology	• Abundant, low cost fuel • Potentially lower greenhouse gas emissions if CO_2 is sequestered • Potential for financial incentives • Dispatchable resource	• New, unproven technologies • Higher capital costs than pulverized coal • Long construction lead times
Nuclear	• Forecasted low fuel costs • Forecasted adequate fuel availability • Lack of greenhouse gas emissions • Potential low cost of production • Proven technology (existing reactor types)	• Lack of public acceptance • Safety concerns • Waste disposal • Construction cost uncertainties and the potential for construction cost overruns • Security concerns

Camp Process

The Eastern Snake Plain Aquifer (ESPA) serves nearly one million acres of ground water irrigated land, cities, industries, and thousands of domestic wells. Above American Falls, the ESPA supports spring discharge that provides natural flow for irrigated lands in the Magic Valley. The ESPA has experienced serious declines that began in the late 1970s and appear to be ongoing. Those declines have impacted spring discharge to the Snake River, including springs that provide irrigation water and flows of cold water that support fish hatcheries from Twin Falls to Hagerman. Flow from the ESPA also provides a significant portion of the flow in the Snake River at King Hill and below.

Declining spring discharge has created numerous water shortages resulting in water calls pitting senior spring and surface water users against junior ground water appropriators. Many of those water calls are still pending or have been only partially resolved through orders from the director of the Idaho Department of Water Resources (IDWR). Continued declines in spring flows are likely to exacerbate these ongoing conflicts over water use on the Eastern Snake River Plain (ESRP).

The 2007 Idaho Legislature tasked the Idaho Water Resource Board (IWRB) with developing an ESPA Comprehensive Aquifer Management Plan (CAMP). The charge of the legislature was to "establish public policy as a settlement framework for future management of the ESPA." To meet legislative goals, the IWRB established a 15-member committee representing various water user groups and other parties interested in the management of the ESPA. The goal of the committee was to develop an aquifer management plan to "sustain the economic viability and social and environmental health of the eastern Snake Plain by adaptively managing a balance between water use and supplies."

Table CAMP-1. Phase I Measures Included in the CAMP

Measure	Target (Acft)
Ground Water to Surface Water Conversions	100,000
Managed Aquifer Recharge	100,000
Demand Reduction	
Surface Water Conservation	50,000
Crop Mix Modification	5,000
Rotating Fallowing, Dry-Year Lease, CREP	40,000
Weather Modification	50,000

The committee met monthly starting in May 2007 continuing through September 2008. The CAMP committee first established a goal of producing an annual 600,000 acre-feet adjustment in the water budget of the ESRP. This water balance adjustment was adopted as the long-term hydrologic target; however, committee members recognized this adjustment would be achieved only after many years of implementation. The committee adopted an interim plan called Phase I that targets an annual water budget change of 200,000–300,000 acre-feet/year. The committee's goal is to have Phase I fully implemented in 10 years. Table CAMP-1 shows the measures anticipated under Phase I. The Phase I plan includes the implementation of a variety of measures to change the overall water budget of the ESRP.

CAMP was submitted to the 2009 Idaho Legislature for approval. Upon legislative approval of the plan, the IWRB began a process of selecting an implementation committee. The charge of that committee will be to "assist the Board in the prioritization, development, implementation, and monitoring and evaluation of management actions." The implementation committee will also develop a mechanism to fund measures implemented under CAMP. The successful implementation of any CAMP-recommended measure is dependent upon securing a long-term funding source. As such, the specific practices, their extent or location is unknown at this time. Additionally, some practices are likely to change as the feasibility and impact of specific practices is evaluated over the next five years. The legislative approval of CAMP was only the first step in implementing management practices on the ESPA.

Idaho Power recognizes the potential for declining spring flow below Milner Dam to impact generation capabilities. Idaho Power also recognizes the potential for management practices recommended and implemented through CAMP to impact generation capabilities. Those impacts could be either positive or negative. As such, Idaho Power has been an active member of the CAMP committee. Idaho Power was represented at every CAMP committee meeting, and the company representatives participated in several sub-committees. Idaho Power also developed the appropriate modeling techniques to assess the potential impacts of CAMP on river flows and spring discharge. The results of the modeling was provided to the CAMP committee and used during the decision-making process. Idaho Power has also suggested management alternatives and has agreed to provide technical and material support for a pilot weather modification program in the upper Snake River basin.

CAMP committee members recognize that the failure of proposed management practices to increase aquifer levels or improve spring discharge to the Snake River could result in continued legal action against junior ground water appropriators. Implementation of CAMP was not to supplant the need for litigation but to manage the aquifer such that water calls would be lessened. Ground water appropriators could be subjected to increased mitigation requirements or potential curtailment if CAMP fails to produce desired results.

Potential Impact of CAMP Implementation on Idaho Power

The implementation of CAMP practices impact hydropower generation in three different ways.

1) Managed recharge can increase spring discharge below Milner Dam, but those increases can occur only if water is diverted above Milner Dam and directed onto the ESRP and recharged to the aquifer. Conversions of ground water supplied irrigated land to surface supplied can also improve spring flow, but would require diversions of water from the Snake River above Milner Dam as well. Diversion for managed recharge and conversion projects have the potential to reduce the volume of water passing through numerous Idaho Power projects. Those diversions may have a negative impact to hydropower production on those facilities located between Milner Dam and King Hill. Additionally, while most of the water diverted for these projects comes back to the river as spring discharge, up to 10% of the water remains in the aquifer as long-term storage. These practices essentially shift water from one compartment, surface water, to another compartment, ground water. The net effect on the overall water budget is zero, but the diversions from the Snake River can have negative impacts to hydropower production.

2) Weather modification and practices that reduce consumptive use of ground water can increase water flowing through those generation facilities located on the Snake River above King Hill. These measures actually change the water budget by reducing consumptive demand or by increasing water supply in the basin. They can increase spring flow or tributary flow into the Snake River, but, unlike managed recharge or conversion projects, they require no diversions from the Snake River. These projects increase flows in the Snake River and could potentially benefit power generation.

3) Practices described in 1) and 2) are likely to be implemented in some combination. The relative extent of those practices will ultimately determine whether the impact is positive or negative for hydropower production. Diversions and increases in spring discharge may eventually balance, but the first five to ten years of implementation may produce a net negative effect on hydropower production.

The actual impact to hydropower production resulting from the implementation of the CAMP plan is uncertain. The availability of funding could drastically alter the implementation of the CAMP Phase I plan and long-standing water calls may eventually trump any plan proffered. Changing economic conditions may also alter decisions made by agriculture producers and their participation in current mitigation plans and other programs, such as the Conservation Reserve Enhancement Program (CREP). In evaluating the potential impacts of CAMP on hydropower production, the Phase I targets provide a basis for modeling and evaluation.

Modeled CAMP Scenario

Idaho Power developed modeling capabilities to help determine the potential impacts of CAMP on spring discharge and flows in the Snake River. Idaho Power modeled several different scenarios for the CAMP committee. The modeling incorporates the Enhanced Snake Plain Aquifer Model (ESPAM) and the Snake River Planning Modeling (SRPM). The modeling also incorporates information on canal capacities and sets limits for managed recharge, system conversions, and demand reduction activities. The modeling also includes estimates on increased water from weather-modification activities.

The scenario modeled for the IRP was the Phase I implementation plan proposed in CAMP. The parameters entered into the model were done to try and match the goals of the Phase I plan. Table CAMP-2 compares the results of the Phase I CAMP with the modeled results. The modeled scenario provides close approximation of the planned Phase I and allows for the examination of the impacts of CAMP on spring discharge and flows in the Snake River.

Table CAMP-2. CAMP Phase I Goals and Results of Modeling

Action	CAMP Goal (Average thousand acre-feet/year)	Modeled (Average thousand acre-feet/year)
Ground to Surface Water Conversions	100	81
Managed Recharge	100	140**
Demand Reduction	95*	45
Weather Modification	50	50

*Some demand reduction includes the purchase of subordination agreements from spring owners that cannot be modeled, but would have no impact on spring flows or Snake River Flows.

**This recharge also includes approximately 20 KAF/yr recharge on the Wood River system.

The SRPM uses a variety of data inputs to determine water availability for irrigation diversions as well as providing information on reservoir storage and river flows. The model allows for present conditioning of historic data. In other words, it applies today's level of development (irrigation diversions and storage), reach gains, and diversions to historic water availability. The model is currently calibrated to run from 1928 through 2005. This mode of operation allows for the comparison of a base case scenario to a variety of management scenarios. This provides a perspective on the degree to which different management scenarios may impact reservoir storage and river flows.

Table CAMP-3. Average Difference Between the CAMP Scenario and the Base Case Scenario for Flow at King Hill

July (acre-feet)	December (acre-feet)	Yearly (acre-feet)
7,700	10,900	66,600

A comparison was made for the months of July and December and total yearly flows for the base case scenario and the CAMP scenario. July and December were selected because they are critical months for power generation. The comparison of modeled data was for the King Hill gage on the Snake River (Table CAMP-3). The average flows for July increased 7,670 acre-feet/month, and December flows increased 10,880 acre-feet/month. The yearly average flows increased by 66,580 acre-feet/year, which is about 1 percent of the yearly average flow at the King Hill gage. These small increases reflect the nature of changes in the water budget for the upper Snake Basin as proposed through CAMP. The CAMP Phase I plan contains only 95,000 acft in new or additional water to the system. CAMP may increase spring discharge tributary to the Snake River, but those increases are dependent upon large diversion from the Snake River for managed recharge or system conversions. The overall increase in Snake River flow is dependent upon a reduction in consumptive use of water or increases related to water modification activities.

Brownlee Reservoir Inflow Record

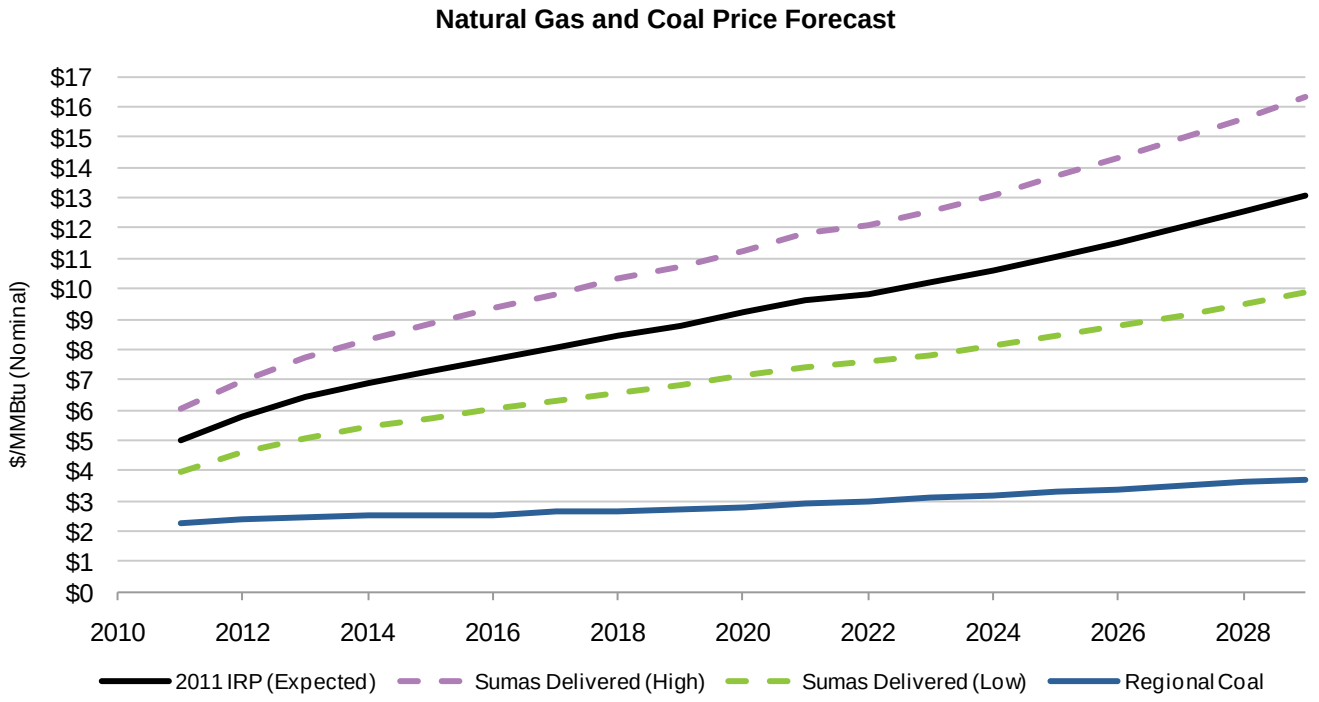
Record used for 2011 IRP Modeling of Idaho Power Hydropower System (Million Acre-Feet [MAF])					
CY	Brownlee April–July Inflow Volume (MAF)	Brownlee Annual Inflow Volume (MAF)	CY	Brownlee April–July Inflow Volume (MAF)	Brownlee Annual Inflow Volume (MAF)
1928	6.8	14.8	1969	6.9	15.3
1929	3.5	9.1	1970	6.3	14.9
1930	2.8	8.3	1971	10.3	22.8
1931	2.3	7.2	1972	7.9	20.2
1932	4.8	10.2	1973	4.0	11.4
1933	4.3	9.4	1974	9.8	20.1
1934	2.3	7.4	1975	8.1	17.6
1935	3.1	8.0	1976	7.3	16.5
1936	5.1	10.4	1977	2.2	7.8
1937	3.0	8.5	1978	5.3	12.0
1938	7.1	13.7	1979	4.0	10.7
1939	3.9	10.0	1980	6.1	13.3
1940	4.3	10.7	1981	4.4	11.5
1941	3.9	10.2	1982	9.3	21.2
1942	5.0	11.2	1983	10.0	23.5
1943	9.4	18.9	1984	11.5	24.3
1944	3.4	9.6	1985	5.5	13.5
1945	4.9	11.7	1986	8.6	20.7
1946	6.9	15.4	1987	3.0	9.3
1947	5.4	12.6	1988	2.7	7.9
1948	5.9	12.5	1989	4.4	10.7
1949	5.5	12.5	1990	3.2	8.7
1950	6.6	14.7	1991	2.9	8.2
1951	6.7	16.2	1992	2.0	6.8
1952	10.4	19.3	1993	6.3	13.0
1953	6.1	13.6	1994	2.8	8.5
1954	5.7	12.7	1995	6.9	14.1
1955	3.6	9.8	1996	8.3	19.0
1956	8.0	17.7	1997	10.5	24.0
1957	7.9	16.2	1998	8.6	17.7
1958	7.6	15.0	1999	7.9	17.8
1959	4.0	10.5	2000	4.7	12.1
1960	4.4	10.8	2001	2.6	7.8
1961	3.2	8.7	2002	3.5	8.8
1962	4.9	11.1	2003	3.7	9.2
1963	4.7	11.5	2004	3.3	8.8
1964	5.8	13.2	2005	3.8	8.9
1965	8.6	19.9	2006	8.8	16.8
1966	3.6	10.0	2007	2.8	8.5
1967	5.0	11.4	2008	4.5	10.0
1968	3.5	10.7	2009	5.6	11.3

Note: Based on normalized historical flows for 1928–2009 using the Snake River Planning Model.

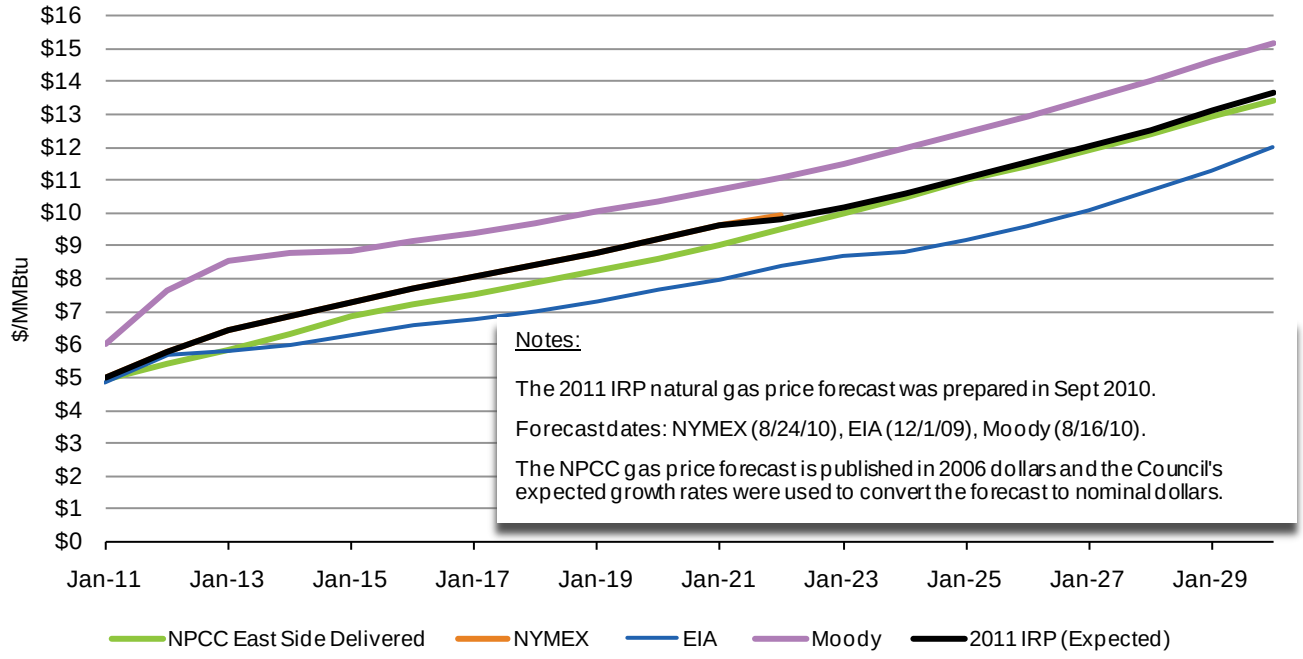
FUEL DATA

Natural Gas and Coal Price Forecast

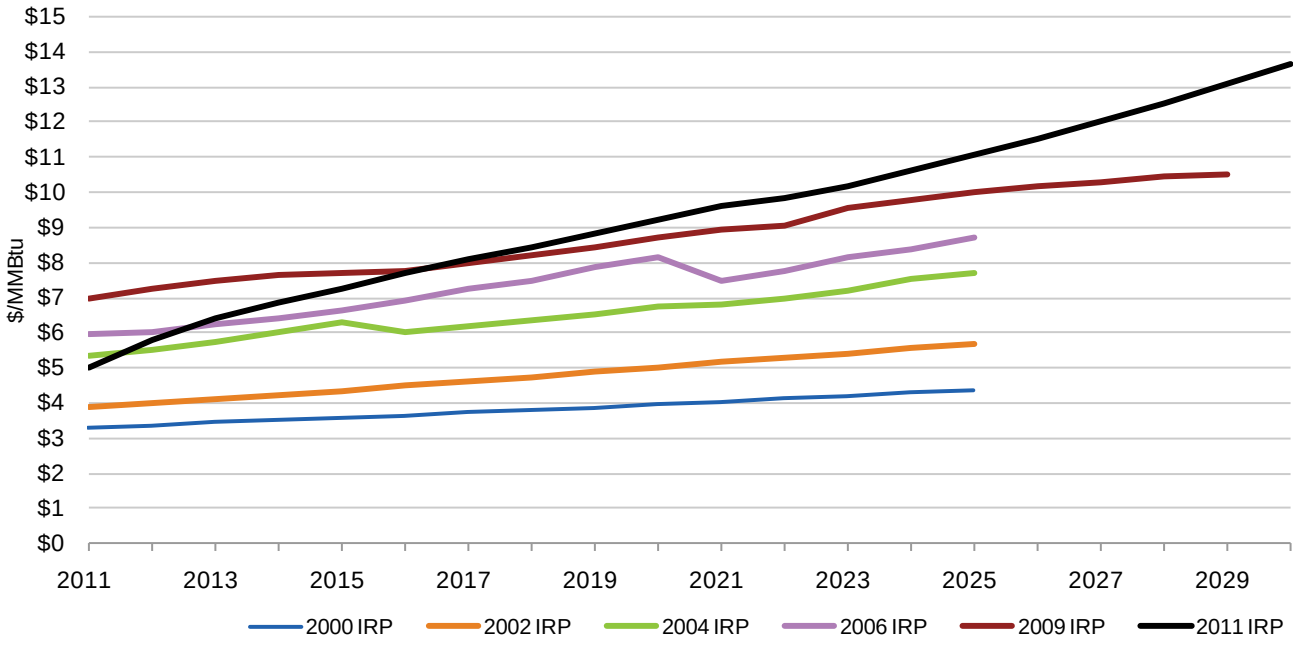
Year	Sumas	Sumas Delivered (Expected)	Sumas Delivered (High)	Sumas Delivered (Low)	Regional Coal
2011	$4.51	$5.00	$6.02	$3.99	$2.26
2012	$5.28	$5.79	$6.97	$4.60	$2.38
2013	$5.90	$6.42	$7.75	$5.09	$2.43
2014	$6.34	$6.87	$8.31	$5.43	$2.54
2015	$6.73	$7.27	$8.81	$5.72	$2.50
2016	$7.14	$7.68	$9.34	$6.03	$2.53
2017	$7.52	$8.08	$9.83	$6.32	$2.63
2018	$7.89	$8.45	$10.30	$6.59	$2.67
2019	$8.24	$8.80	$10.76	$6.84	$2.69
2020	$8.64	$9.21	$11.28	$7.14	$2.81
2021	$9.04	$9.62	$11.81	$7.43	$2.90
2022	$9.25	$9.83	$12.09	$7.57	$2.99
2023	$9.59	$10.18	$12.54	$7.81	$3.08
2024	$10.00	$10.59	$13.08	$8.10	$3.18
2025	$10.46	$11.06	$13.69	$8.43	$3.28
2026	$10.92	$11.53	$14.30	$8.76	$3.39
2027	$11.39	$12.01	$14.92	$9.10	$3.49
2028	$11.91	$12.54	$15.62	$9.47	$3.61
2029	$12.45	$13.09	$16.34	$9.85	$3.72
2030	$13.01	$13.66	$17.07	$10.24	$3.84



Natural Gas Price Forecast $/MMBtu (Nominal)



Natural Gas Price Forecast Comparison (expected case delivered)



EXISTING RESOURCE DATA

Hydroelectric and Thermal Plant Data

Hydroelectric Power Plants	Nameplate kVA	Nameplate kW	Normal Rating kW[4]	Emergency Rating kW[5]
American Falls	102,600	92,340	92,340	108,850
Bliss	86,250	75,000	75,000	76,470
Brownlee	650,444	585,400	585,400	746,570
Cascade	13,800	12,420	12,420	14,800
C.J. Strike	90,000	82,800	82,800	90,720
Clear Lake	3,125	2,500[1]	2,420	2,420
Hells Canyon	435,000	391,500	391,500	444,830
Lower Salmon	70,000	60,000	60,000	64,340
Malad–Lower	15,500	13,500	13,500	16,520
Malad–Upper	9,650	8,270	8,270	8,540
Milner	62,890	59,448	59,448	61,090
Oxbow	211,112	190,000	190,000	221,410
Shoshone Falls	14,900	12,500[1]	12,500	14,040
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	53,060
Upper Salmon “A”	18,000	18,000	18,000	18,930
Upper Salmon “B”	18,000	16,500	16,500	17,510
Total Hydro	**1,897,046**	**1,709,045**		

Thermal, Natural Gas, and Diesel Power Plants	Generator Nameplate Rating Gross kVA	Generator Nameplate Rating Gross kW	Net Dependable Capability (NDC)[6,7] kW	Net Dependable Capability (NDC)[6,7] Summer kW	Net Dependable Capability (NDC)[6,7] Winter kW
Bridger (Idaho Power share)	811,053	770,501		706,000	706,000
Boardman (Idaho Power share)	67,600	64,200		58,600	59,100
Valmy (Idaho Power share)	315,000	283,500		258,250	239,000
Total Thermal	**1,193,653**	**1,118,201**		1,022,850	1,004,100
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	45,236		
Evander Andrews Unit 3	51,000	45,900	45,236		
Total Natural Gas	**493,000**	**443,700**	**425,586**		
Salmon Diesel	6,880	5,000	5,500		
Total IPC Generation	**3,590,579**	**3,275,946**			

[1] A power factor rating of 0.8 is assumed on four units (Clear Lake, unit 2 at Shoshone Falls, and units 1 and 2 at Thousand Springs) with a total kVA rating of 6,127 kVA on which there is no nameplate kW rating.

[2] The two smaller units, 1 and 2, both having nameplate ratings of 1.25 MVA and 1 MW, have been taken out of service due to reduced flows from the springs and penstock integrity.

[3] The Swan Falls units have been limited to 24,170 kW as a result of vibration issues.

[4] Normal Rating is defined as 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 defined as the maximum kW output of the facility with all units on-line. The Emergency Rating is based on manufacturer guidelines, ANSI standards, and limited by auxiliary equipment ratings. To operate at the Emergency Rating, appropriate water conditions must exist and the FERC license requirements permit.

[6] 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

Projects under contract at time 2011 Forecast was prepared.

Project	MW	Contract On-line Date	Contract End Date	Project	MW	Contract On-line Date	Contract End Date
Hydro Projects							
Arena Drop	0.45	Sep-2010	Sep-2030	Lowline #2	2.79	Apr-1988	Apr-2023
Barber Dam	3.70	Apr-1989	Apr-2024	Lowline Canal	2.50	May-1985	Apr-2005
Birch Creek	0.05	Nov-1984	Oct-2019	Magic Reservoir	9.07	Jun-1989	May-2024
Black Canyon #3	0.14	Apr-1984	Apr-2019	Malad River	0.62	May-1984	Apr-2019
Blind Canyon	1.50	Dec-1994	Dec-2014	Marco Ranches	1.20	Aug-1985	Jul-2020
Box Canyon	0.36	Feb-1984	Feb-2019	Mile 28	1.50	Jun-1994	May-2029
Briggs Creek	0.60	Oct-1985	Oct-2020	Mitchell Butte	2.09	May-1989	May-2024
Bypass	9.96	Jun-1988	Jun-2023	Mora Drop	1.90	Oct-2006	Sep-2026
Canyon Springs	0.13	Oct-1984	Non firm	Mud Creek S&S	0.52	Feb-1982	Feb-2017
Cedar Draw	1.55	Jun-1984	May-2019	Mud Creek White	0.21	Jan-1986	Jan-2021
Clear Springs Trout	0.52	Nov-1983	Oct-2018	Owyhee Dam CSPP	5.00	Aug-1985	Aug-2015
Crystal Springs	2.44	Apr-1986	Mar-2021	Pigeon Cove	1.89	Oct-1984	Oct-2019
Curry Cattle Company	0.22	Jun-1983	Jun-2018	Pristine Springs	0.13	May-2005	Apr-2015
Dietrich Drop	4.50	Aug-1988	Aug-2023	Pristine Springs #3	0.20	May-2005	Apr-2015
Elk Creek	2.00	May-1986	May-2021	Reynolds Irrigation	0.26	May-1986	May-2021
Falls River	9.10	Aug-1993	Aug-2028	Rim View	0.20	Nov-2000	Non firm
Faulkner Ranch	0.87	Aug-1987	Aug-2022	Rock Creek #1	2.05	Sep-1983	Sep-2018
Fisheries Development Co	0.26	Jul-1990	Non firm	Rock Creek #2	1.90	Apr-1989	Mar-2024
Geo Bon #2	0.93	Nov-1986	Nov-2021	Sagebrush	0.43	Sep-1985	Aug-2020
Hailey CSPP	0.06	Jun-1985	Jun-2020	Sahko Hydro	0.50	Jun-2006	Feb-2021
Hazelton A	7.70	Jun-1990	Jun-2010	Schaffner	0.53	Aug-1986	Jul-2021
Hazelton B	7.60	May-1993	Apr-2028	Shingle Creek	0.22	Aug-1983	Jul-2018
Horseshoe Bend Hydroelectric	9.50	Sep-1995	Sep-2030	Shoshone #2	0.58	May-1996	Apr-2031
Jim Knight	0.34	Jun-1985	Jun-2020	Shoshone CSPP	0.37	Jun-1982	Jun-2017
Kasel and Witherspoon	0.90	Mar-1984	Feb-2019	Snake River Pottery	0.07	Nov-1984	Nov-2019
Koyle Small Hydro	1.25	Apr-1984	Mar-2019	Snedigar	0.54	Jan-1985	Dec-2019
Lateral # 10	2.06	May-1985	Apr-2020	Tiber Dam	7.50	Jun-2004	May-2024
Lemoyne	0.08	Jun-1985	Jun-2020	Trout—Co	0.24	Dec-1986	Nov-2021
Little Wood Rvr Res	2.85	Feb-1985	Feb-2020	Tunnel #1	7.00	Jun-1993	May-2028
Littlewood–Arkoosh	0.87	Aug-1986	Jul-2021	White Water Ranch	0.16	Aug-1985	Jul-2020
Lowline Midway Hydro	7.97	Aug-2007	Aug-2027	Wilson Lake Hydro	8.40	May-1993	May-2028
Total Hydro Nameplate Rating 141.0 MW							
Thermal Projects							
Magic Valley Natural Gas	10.00	Nov-1996	Nov-2016	TASCO—Nampa Natural Gas	2.00	Sep-2003	Auto Renewal
Magic West Natural Gas	10.00	Dec-1996	Nov-2016	TASCO—Twin Falls Natural Gas	2.00	Aug-2001	Auto Renewal
Simplot Pocatello Cogen	12.00	Mar-2006	Feb-2016				
Total Thermal Nameplate Rating 37.0 MW							

Project	MW	Contract On-line Date	Contract End Date	Project	MW	Contract On-line Date	Contract End Date
Biomass Projects							
B6 Anaerobic Digester	2.28	Aug-2009	Aug-2019	Pocatello Waste	0.46	Dec-1985	Dec-2020
Bettencourt Dry Creek	2.25	Aug-2008	Aug-2018	Rock Creek Dairy	4.00	May-2012	Estimated
Big Sky West Dairy Digester	1.50	Jan-2009	Jan-2029	Swager Farms	2.00	Oct-2011	Estimated
Double B Dairy	2.00	Dec-2012	Estimated	Tamarack CSPP	5.00	Jun-1983	May-2018
Hidden Hollow Landfill Gas	3.20	Oct-2006	Jan-2027				
Total Biomass Nameplate Rating 22.69 MW							
Wind Projects							
Bennett Creek Wind Farm	21.00	Dec-2008	Dec-2028	Notch Butte Wind	18.00	Aug-2011	Estimated
Burley Butte Wind	21.30	Feb-2011	Feb-2031	Oregon Trail Wind	13.50	Jan-2011	Jan-2031
Camp Reed Wind Park	22.50	Dec-2010	Dec-2030	Payne's Ferry Wind Park	21.00	Dec-2010	Dec-2030
Cassia Wind Farm	10.50	Mar-2009	Mar-2029	Pilgrim Stage Station Wind	10.50	Jan-2011	Jan-2031
Fossil Gulch Wind	10.50	Sep-2005	Sep-2025	Rockland Wind Project	80.00	Dec-2011	Estimated
Golden Valley Wind	12.00	Feb-2011	Feb-2031	Salmon Falls Wind	22.00	Jan-2011	Jan-2031
Horseshoe Bend Wind Park	9.00	Feb-2006	Feb-2026	Sawtooth Wind Project	21.00	Dec-2012	Estimated
Hot Springs Wind Farm	21.00	Dec-2008	Dec-2028	Thousand Springs Wind	12.00	Jan-2011	Jan-2031
Lava Beds Wind	18.00	Aug-2011	Estimated	Tuana Gulch Wind	10.50	Jan-2011	Jan-2031
Magic Wind Park	19.50	Aug-2011	Estimated	Tuana Springs Expansion	35.70	May-2010	Jun-2030
Milner Dam Wind	19.92	Feb-2011	Feb-2031	Yahoo Creek Wind Park	21.00	Dec-2010	Dec-2030
Total Wind Nameplate Rating 450.42 MW							
Solar Projects							
Grand View Solar	20.00	Dec-2012	Estimated				
Total Solar Nameplate Rating 20.00 MW							
Total Nameplate Rating 671.11 MW							

The above is a summary of the nameplate rating for the CSPP projects under contract with Idaho Power as of September 2010. 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. The application of this information to the portfolio of CSPP projects resulted in the average annual MW from CSPP projects being 167 MW in 2011.

Power Purchase Agreement Data

Idaho Power Company Power Purchase Agreements Status as of April 1, 2011

Project	MW	Contract On-Line Date	Contract End Date
Wind projects			
Elkhorn Wind Project	101	December 2007	December 2027
Total wind nameplate MW rating	101		
Geothermal Projects			
Raft River Unit 1	13	April 2008	April 2033
Neal Hot Springs	22	September 2012	September 2037
Total geothermal nameplate MW rating	35		
Total nameplate MW rating	136		

Above is a summary of the nameplate ratings for the Power Purchase Agreements under contract with Idaho Power. Nameplate ratings of the actual generation units are not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource-specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy the projects will produce.

Hydro Modeling Results (PDR580)

Average Megawatt (aMW) 50th Percentile Water, 50th Percentile Load

Resource	Type	1/2011	2/2011	3/2011	4/2011	5/2011	6/2011	7/2011	8/2011	9/2011	10/2011	11/2011	12/2011	aMW
Brownlee	HCC*	269.4	434.9	343.4	413.6	386.3	386.2	244.8	186.0	209.3	193.7	152.8	252.3	289.4
Oxbow	HCC	111.8	181.3	154.9	180.0	158.6	157.2	103.9	81.7	95.4	88.5	69.3	106.3	124.1
Hells Canyon	HCC	222.1	359.4	312.3	369.3	327.9	318.2	206.0	160.7	187.2	174.7	138.1	210.7	248.9
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	25.4	27.9	25.9	56.9	84.6	101.1	82.4	68.0	40.7	18.1	0.0	16.9	45.7
Bliss	ROR	49.7	52.3	45.9	51.3	49.3	48.6	36.3	37.7	37.8	40.4	38.2	46.9	44.5
C.J. Strike	ROR	66.4	69.5	60.5	68.4	62.5	61.1	39.4	42.3	45.3	51.5	50.2	61.2	56.5
Cascade	ROR	1.5	2.6	4.6	7.5	7.3	11.9	6.9	10.1	9.1	2.7	2.2	1.5	5.7
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	36.2	37.2	30.6	35.9	34.3	34.9	23.6	24.4	23.9	26.2	24.5	32.5	30.4
Milner	ROR	42.4	45.5	27.1	40.5	35.5	36.7	6.7	6.7	0.0	0.0	1.9	30.0	22.8
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	7.4	11.2	12.0	12.0	11.6
Swan Falls	ROR	21.3	22.3	20.0	22.0	20.1	19.6	13.6	14.1	14.8	16.4	16.3	19.7	18.4
Twin Falls	ROR	42.4	44.5	28.3	40.4	36.2	38.2	11.5	11.8	3.8	7.3	8.2	31.5	25.3
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	19.1	18.8	13.7	19.1	19.1	19.1	14.5	15.4	14.7	16.3	15.0	19.2	17.0
Upper Salmon 3&4	ROR	17.7	17.7	16.5	16.8	17.4	17.7	13.6	14.3	13.8	15.1	14.0	17.7	16.0
HCC Total		**603.3**	**975.6**	**810.6**	**962.9**	**872.8**	**861.6**	**554.7**	**428.4**	**491.8**	**456.9**	**360.2**	**569.3**	**662.3**
ROR Total		**359.8**	**375.9**	**311.4**	**396.1**	**405.9**	**427.5**	**286.4**	**283.4**	**239.6**	**232.8**	**206.5**	**314.9**	**320.0**
Total		**963.1**	**1351.5**	**1122.0**	**1359.0**	**1278.7**	**1289.1**	**841.1**	**711.8**	**731.3**	**689.7**	**566.7**	**884.2**	**982.3**

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

aMW 50th Percentile Water, 50th Percentile Load

Resource	Type	1/2012	2/2012	3/2012	4/2012	5/2012	6/2012	7/2012	8/2012	9/2012	10/2012	11/2012	12/2012	aMW
Brownlee	HCC*	269.2	434.7	343.2	413.2	386.5	386.0	244.7	185.9	208.9	193.9	152.6	251.9	289.2
Oxbow	HCC	111.7	181.2	154.9	179.8	158.6	157.1	103.8	81.7	95.2	88.6	69.3	106.1	124.0
Hells Canyon	HCC	221.9	359.2	312.1	368.9	328.1	318.0	205.9	160.6	186.8	174.8	138.0	210.3	248.7
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	25.4	27.8	25.9	56.9	84.6	101.1	82.4	68.0	40.8	18.2	0.0	16.8	45.7
Bliss	ROR	51.2	52.2	45.8	51.2	49.3	48.6	36.2	37.7	37.8	40.4	38.2	46.8	44.6
C.J. Strike	ROR	66.3	69.4	60.4	68.3	62.5	61.0	39.3	42.2	45.2	51.4	50.2	61.0	56.4
Cascade	ROR	1.5	2.6	4.6	7.5	7.3	11.9	6.9	10.1	9.1	2.7	2.2	1.5	5.7
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	36.2	37.1	30.6	35.8	34.2	34.8	23.5	24.4	23.9	26.2	24.4	32.3	30.3
Milner	ROR	42.4	45.4	27.1	40.4	35.5	36.7	6.7	6.7	0.0	0.0	1.9	29.7	22.7
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	7.3	11.2	12.0	12.0	11.5
Swan Falls	ROR	21.3	22.3	19.9	21.9	20.1	19.6	13.5	14.2	14.8	16.4	16.3	19.6	18.3
Twin Falls	ROR	42.3	44.4	28.3	40.3	36.2	38.2	11.5	11.7	3.8	7.3	8.0	31.2	25.3
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	19.1	19.1	19.2	19.1	17.6	19.1	14.5	15.3	14.6	16.3	14.9	19.2	17.3
Upper Salmon 3&4	ROR	17.7	17.7	17.7	17.7	17.7	16.2	13.6	14.3	13.7	15.1	14.0	17.7	16.1
HCC Total		**602.8**	**975.1**	**810.2**	**961.9**	**873.1**	**861.1**	**554.4**	**428.2**	**490.8**	**457.3**	**359.9**	**568.3**	**661.9**
ROR Total		**361.1**	**375.6**	**317.8**	**396.4**	**404.7**	**425.8**	**286.0**	**283.2**	**239.3**	**232.8**	**206.1**	**313.6**	**320.2**
Total		**963.9**	**1350.7**	**1128.0**	**1358.3**	**1277.8**	**1286.9**	**840.4**	**711.4**	**730.1**	**690.1**	**566.0**	**881.9**	**982.1**

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

Hydro Modeling Results (PDR 580) (continued)

aMW 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2013**	**2/2013**	**3/2013**	**4/2013**	**5/2013**	**6/2013**	**7/2013**	**8/2013**	**9/2013**	**10/2013**	**11/2013**	**12/2013**	**aMW**
Brownlee	HCC*	268.9	434.3	343.1	413.0	386.3	385.7	244.6	185.7	208.5	193.8	152.9	251.4	289.0
Oxbow	HCC	111.6	181.1	154.8	179.8	158.5	157.0	103.8	81.6	95.0	88.5	69.4	105.9	123.9
Hells Canyon	HCC	221.7	359.0	312.0	368.7	328.0	317.8	205.8	160.5	186.4	174.6	138.2	210.0	248.6
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	25.4	27.7	25.9	56.9	84.6	101.1	82.5	68.0	40.8	18.2	0.0	16.6	45.6
Bliss	ROR	51.1	52.1	45.8	51.2	49.2	48.6	36.2	37.7	37.8	40.3	38.1	46.6	44.6
C.J. Strike	ROR	66.3	69.3	60.4	68.2	62.4	61.0	39.3	42.2	45.1	51.4	50.1	60.8	56.4
Cascade	ROR	1.5	2.6	4.6	7.5	7.3	11.9	6.9	10.1	9.1	2.7	2.2	1.5	5.7
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	36.1	37.1	30.5	35.8	34.2	34.8	23.5	24.4	23.8	26.1	24.4	32.2	30.2
Milner	ROR	42.3	45.2	27.0	40.3	35.5	36.6	6.7	6.7	0.0	0.0	1.9	29.4	22.6
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	7.3	11.2	12.0	12.0	11.5
Swan Falls	ROR	21.3	22.2	19.9	21.9	20.1	19.5	13.5	14.2	14.7	16.4	16.3	19.6	18.3
Twin Falls	ROR	42.3	44.2	28.2	40.3	36.2	38.2	11.5	11.7	3.8	7.3	8.0	30.9	25.2
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	19.1	19.1	19.2	19.1	17.6	19.1	14.4	15.3	14.6	16.2	14.9	19.2	17.3
Upper Salmon 3&4	ROR	17.7	17.7	17.7	17.7	17.7	16.2	13.5	14.3	13.7	15.1	13.9	17.7	16.1
HCC Total		**602.2**	**974.4**	**809.9**	**961.5**	**872.7**	**860.5**	**554.2**	**427.8**	**489.9**	**456.9**	**360.5**	**567.3**	**661.5**
ROR Total		**360.8**	**374.8**	**317.5**	**396.2**	**404.5**	**425.6**	**285.9**	**283.2**	**239.0**	**232.5**	**205.8**	**312.3**	**319.8**
Total		**963.0**	**1349.2**	**1127.4**	**1357.7**	**1277.2**	**1286.1**	**840.1**	**711.0**	**728.8**	**689.4**	**566.3**	**879.6**	**981.3**

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

aMW 50th Percentile Water, 50th Percentile Load														
Resource	**Type**	**1/2014**	**2/2014**	**3/2014**	**4/2014**	**5/2014**	**6/2014**	**7/2014**	**8/2014**	**9/2014**	**10/2014**	**11/2014**	**12/2014**	**aMW**
Brownlee	HCC*	267.8	433.1	341.9	412.3	385.7	384.5	243.8	185.0	206.3	193.9	153.0	249.6	288.1
Oxbow	HCC	111.1	180.6	154.3	179.4	158.3	156.6	103.4	81.3	93.8	88.4	69.3	105.1	123.5
Hells Canyon	HCC	220.8	358.0	311.0	368.0	327.5	316.9	205.2	159.9	184.2	174.4	138.1	208.4	247.7
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	25.4	27.6	25.9	56.9	84.8	101.1	82.6	68.1	40.8	18.3	0.0	15.8	45.6
Bliss	ROR	50.9	51.5	45.5	50.8	49.0	48.3	36.0	37.5	37.6	40.1	37.9	45.8	44.2
C.J. Strike	ROR	65.9	68.6	60.1	67.8	62.5	60.7	39.0	41.9	44.9	51.1	49.9	59.7	56.0
Cascade	ROR	1.5	2.6	4.6	7.5	7.3	11.9	6.9	10.1	9.1	2.7	2.2	1.5	5.7
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	35.9	36.4	30.3	35.5	34.0	34.5	23.3	24.2	23.7	26.0	24.2	31.4	30.0
Milner	ROR	42.0	44.8	26.7	40.3	35.4	36.5	6.7	6.7	0.0	0.0	1.8	27.8	22.4
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	7.3	11.2	11.8	12.0	11.5
Swan Falls	ROR	21.2	22.1	19.8	21.8	20.0	19.5	13.4	14.1	14.7	16.4	16.2	19.3	18.2
Twin Falls	ROR	42.0	43.9	27.9	40.0	36.1	38.1	11.4	11.7	3.8	7.2	7.8	29.4	24.9
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	19.1	19.1	19.2	19.1	17.6	19.1	14.3	15.2	14.5	16.1	14.8	19.2	17.3
Upper Salmon 3&4	ROR	17.7	17.7	17.7	17.7	17.7	16.2	13.4	14.2	13.6	15.0	13.8	17.7	16.0
HCC Total		**599.7**	**971.7**	**807.2**	**959.7**	**871.5**	**858.0**	**552.4**	**426.2**	**484.3**	**456.7**	**360.4**	**563.1**	**659.2**
ROR Total		**359.3**	**371.9**	**316.0**	**394.7**	**404.0**	**424.5**	**284.9**	**282.3**	**238.3**	**231.7**	**204.4**	**305.4**	**318.1**
Total		**959.0**	**1343.6**	**1123.2**	**1354.4**	**1275.5**	**1282.5**	**837.3**	**708.5**	**722.6**	**688.4**	**564.8**	**868.5**	**977.4**

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

Hydro Modeling Results (PDR 580) (continued)

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*	266.5	431.6	341.4	410.0	387.2	383.3	243.1	184.3	204.2	194.3	153.0	247.8	287.2
Oxbow	HCC	110.6	180.0	154.0	186.2	158.9	156.1	103.1	81.0	92.7	88.4	69.3	104.3	123.7
Hells Canyon	HCC	219.8	356.8	310.5	376.1	328.6	316.0	204.5	159.3	182.0	174.5	138.1	206.9	247.8
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	25.4	27.6	25.9	56.8	84.9	101.2	82.7	68.2	40.9	18.4	0.0	14.9	45.6
Bliss	ROR	50.6	51.2	45.2	50.5	48.8	48.0	35.8	37.3	37.4	39.9	37.6	44.9	43.9
C.J. Strike	ROR	65.5	67.9	59.7	67.4	62.1	60.5	38.8	41.7	44.6	50.9	49.6	58.5	55.6
Cascade	ROR	1.5	2.6	4.6	7.5	7.3	11.9	6.9	10.1	9.1	2.7	2.2	1.5	5.7
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	35.6	36.0	30.0	35.3	33.8	34.3	23.2	24.0	23.5	25.8	24.0	30.6	29.7
Milner	ROR	41.7	44.5	26.4	40.0	35.4	36.4	6.7	6.7	0.0	0.0	1.8	25.9	22.1
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	7.2	11.1	11.3	12.0	11.5
Swan Falls	ROR	21.1	21.8	19.7	21.7	19.9	19.4	13.4	14.0	14.6	16.3	16.1	18.9	18.1
Twin Falls	ROR	41.8	43.6	27.6	39.7	36.0	38.0	11.4	11.7	3.7	7.2	7.3	27.7	24.6
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	19.1	19.1	19.2	19.1	17.6	19.1	14.2	15.1	14.4	16.0	14.6	19.2	17.2
Upper Salmon 3&4	ROR	17.7	17.7	17.7	17.7	17.7	16.2	13.3	14.1	13.5	14.9	13.7	17.7	16.0
HCC Total		**596.9**	**968.4**	**805.9**	**972.3**	**874.6**	**855.4**	**550.7**	**424.6**	**478.8**	**457.2**	**360.4**	**559.0**	**658.7**
ROR Total		**357.7**	**369.6**	**314.3**	**393.0**	**403.1**	**423.6**	**284.3**	**281.5**	**237.1**	**230.8**	**202.2**	**297.6**	**316.2**
Total		**954.6**	**1338.0**	**1120.2**	**1365.3**	**1277.7**	**1279.0**	**835.0**	**706.1**	**715.9**	**688.0**	**562.6**	**856.6**	**974.9**

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

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*	265.4	430.4	340.3	411.1	383.6	382.1	242.3	163.9	205.0	194.1	152.9	250.7	285.2
Oxbow	HCC	110.2	179.5	153.5	187.0	157.5	155.6	102.8	74.9	93.2	88.5	69.3	105.6	123.1
Hells Canyon	HCC	218.9	355.8	309.5	377.6	325.8	315.0	203.9	147.3	183.0	174.6	138.1	209.4	246.6
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	25.4	28.1	25.9	56.7	85.1	101.3	82.8	64.2	41.7	18.8	0.0	19.2	45.8
Bliss	ROR	50.3	51.5	45.0	50.2	48.6	47.7	35.6	33.6	37.2	39.8	38.0	47.2	43.7
C.J. Strike	ROR	65.1	68.2	59.4	67.1	61.4	60.1	38.5	36.8	44.5	50.8	49.8	61.8	55.3
Cascade	ROR	1.5	2.6	4.6	7.5	7.3	11.9	6.9	10.1	9.1	2.7	2.2	1.5	5.7
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	35.4	36.4	29.7	35.0	33.7	34.2	23.0	20.9	23.4	25.7	24.0	32.7	29.5
Milner	ROR	41.5	44.9	26.3	39.6	35.3	36.4	6.7	0.0	0.0	0.0	3.1	32.7	22.2
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	7.1	7.2	11.1	12.0	40.0	13.5
Swan Falls	ROR	21.0	21.9	19.6	21.6	19.8	19.3	13.3	12.5	14.6	16.2	16.2	19.9	18.0
Twin Falls	ROR	41.5	43.8	27.5	39.4	36.0	37.9	11.4	3.7	3.7	7.2	8.2	33.8	24.5
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	19.1	19.1	19.2	19.1	17.6	19.1	14.0	12.6	14.2	15.9	14.6	19.2	17.0
Upper Salmon 3&4	ROR	17.7	17.7	17.7	17.7	17.7	16.2	13.2	12.0	13.4	14.8	13.7	17.7	15.8
HCC Total		**594.5**	**965.7**	**803.3**	**975.7**	**866.9**	**852.7**	**549.0**	**386.1**	**481.2**	**457.2**	**360.3**	**565.7**	**654.9**
ROR Total		**356.2**	**371.8**	**313.2**	**391.2**	**402.1**	**422.7**	**283.3**	**240.1**	**237.3**	**230.6**	**205.8**	**351.5**	**317.2**
Total		**950.7**	**1337.5**	**1116.5**	**1366.9**	**1269.0**	**1275.4**	**832.3**	**626.2**	**718.5**	**687.8**	**566.1**	**917.2**	**972.0**

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

Hydro Modeling Results (PDR 580) (continued)

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*	264.2	429.3	339.2	409.0	385.4	380.9	241.6	163.2	203.1	194.2	152.9	249.7	284.4
Oxbow	HCC	109.7	179.0	153.0	185.7	158.2	155.1	102.5	74.6	92.2	88.4	69.3	105.1	122.7
Hells Canyon	HCC	217.9	354.9	308.4	375.1	327.2	314.1	203.3	146.7	181.1	174.4	138.0	208.5	245.8
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	25.4	28.1	25.9	56.6	85.2	101.5	82.9	64.3	41.8	18.9	0.0	18.3	45.7
Bliss	ROR	50.0	51.3	44.7	49.9	48.3	47.5	35.4	33.4	37.0	39.6	37.6	46.3	43.4
C.J. Strike	ROR	64.7	67.8	59.1	66.7	61.3	59.8	38.3	36.6	44.3	50.5	49.5	60.6	54.9
Cascade	ROR	1.5	2.6	4.6	7.5	7.3	11.9	6.9	10.1	9.1	2.7	2.2	1.5	5.7
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	35.1	36.2	29.5	34.7	33.4	34.0	22.8	20.7	23.2	25.5	23.8	31.9	29.2
Milner	ROR	41.2	44.6	26.0	39.1	35.3	36.4	6.7	0.0	0.0	0.0	3.0	30.9	21.9
Shoshone Falls	ROR	55.0	58.0	35.0	51.0	48.0	50.0	16.0	7.1	7.2	11.1	12.0	40.0	32.4
Swan Falls	ROR	20.9	21.8	19.5	21.5	19.7	19.2	13.2	12.5	14.5	16.2	16.1	19.5	17.9
Twin Falls	ROR	41.3	43.6	27.2	39.0	35.9	37.9	11.3	3.6	3.7	7.1	8.1	32.2	24.2
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	19.1	19.1	19.2	19.1	17.6	19.1	13.9	12.5	14.1	15.7	14.5	19.2	16.9
Upper Salmon 3&4	ROR	17.7	17.7	17.7	17.7	17.7	16.2	13.1	11.9	13.3	14.7	13.6	17.7	15.8
HCC Total		**591.8**	**963.2**	**800.6**	**969.8**	**870.7**	**850.1**	**547.4**	**384.5**	**476.3**	**457.0**	**360.2**	**563.3**	**652.9**
ROR Total		**397.6**	**416.4**	**334.7**	**428.1**	**437.3**	**460.1**	**286.4**	**239.3**	**236.4**	**229.6**	**204.4**	**343.9**	**334.3**
Total		**989.4**	**1379.6**	**1135.3**	**1397.9**	**1308.0**	**1310.2**	**833.8**	**623.8**	**712.7**	**686.6**	**564.6**	**907.2**	**987.2**

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

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*	263.0	427.8	338.6	408.1	384.5	379.7	240.8	162.5	200.2	194.8	153.1	247.9	283.4
Oxbow	HCC	109.2	178.4	152.7	185.3	157.8	154.7	102.2	74.3	90.6	88.4	69.3	104.3	122.3
Hells Canyon	HCC	216.9	353.7	307.9	374.3	326.4	313.2	202.7	146.1	178.0	174.4	138.0	207.0	244.9
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	25.4	27.7	25.9	56.4	85.3	101.6	83.1	64.4	41.8	19.0	0.0	17.3	45.7
Bliss	ROR	49.8	50.8	44.4	49.7	48.0	47.4	35.2	33.3	36.8	39.4	37.3	45.4	43.1
C.J. Strike	ROR	64.3	67.4	58.7	66.3	61.0	59.4	38.0	36.4	43.9	50.3	49.2	59.4	54.5
Cascade	ROR	1.5	2.6	4.6	7.5	7.3	11.9	6.9	10.1	9.1	2.7	2.2	1.5	5.7
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	34.9	35.9	29.2	34.4	33.2	33.8	22.7	20.5	23.0	25.3	23.6	31.1	29.0
Milner	ROR	40.9	43.7	25.6	38.7	35.2	36.4	6.7	0.0	0.0	0.0	2.3	29.2	21.6
Shoshone Falls	ROR	55.0	58.0	35.0	51.0	48.0	50.0	16.0	7.1	7.2	11.1	12.0	40.0	32.4
Swan Falls	ROR	20.8	21.7	19.4	21.4	19.6	19.1	13.1	12.4	14.4	16.1	16.0	19.2	17.8
Twin Falls	ROR	41.0	42.9	26.8	38.6	35.8	37.8	11.3	0.0	3.6	7.1	8.0	30.6	23.6
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	19.1	19.1	19.1	19.1	17.6	19.1	13.8	12.3	14.0	15.6	14.3	19.2	16.9
Upper Salmon 3&4	ROR	17.7	17.7	17.5	17.7	17.7	16.2	13.0	11.7	13.2	14.6	13.5	17.7	15.7
HCC Total		**589.1**	**959.9**	**799.2**	**967.7**	**868.7**	**847.6**	**545.7**	**382.9**	**468.7**	**457.6**	**360.4**	**559.2**	**650.6**
ROR Total		**396.1**	**413.1**	**332.5**	**426.1**	**436.3**	**459.3**	**285.7**	**234.8**	**235.3**	**228.8**	**202.4**	**336.4**	**332.0**
Total		**985.2**	**1373.0**	**1131.7**	**1393.8**	**1305.0**	**1306.9**	**831.4**	**617.7**	**704.0**	**686.4**	**562.8**	**895.6**	**982.6**

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

Hydro Modeling Results (PDR 580) (continued)

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*	262.1	425.8	339.2	407.8	383.8	378.8	240.2	162.1	197.9	195.0	153.1	246.6	282.7
Oxbow	HCC	108.8	177.5	152.8	185.1	157.5	154.3	101.9	74.0	89.4	88.3	69.2	103.8	121.9
Hells Canyon	HCC	216.2	351.9	308.1	374.0	325.9	312.5	202.2	145.7	175.6	174.2	137.9	205.9	244.2
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	25.4	27.6	25.8	56.3	85.4	101.7	83.2	64.4	41.9	19.1	0.0	16.6	45.6
Bliss	ROR	49.6	50.6	44.2	49.4	47.7	47.2	35.1	33.1	36.7	39.3	37.1	44.7	42.9
C.J. Strike	ROR	64.0	66.8	58.5	66.0	60.6	59.1	37.8	36.2	43.7	50.1	48.7	58.5	54.2
Cascade	ROR	1.5	2.6	4.6	7.5	7.3	11.9	6.9	10.1	9.1	2.7	2.2	1.5	5.7
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	34.7	35.5	29.0	34.2	33.1	33.7	22.6	20.4	22.9	25.2	23.4	30.5	28.8
Milner	ROR	40.7	43.5	25.4	38.4	35.2	36.3	6.7	0.0	0.0	0.0	1.8	27.8	21.3
Shoshone Falls	ROR	55.0	58.0	35.0	51.0	48.0	50.0	16.0	7.1	7.2	11.1	12.0	40.0	32.4
Swan Falls	ROR	20.4	21.5	19.3	21.3	19.5	19.0	13.1	12.3	14.3	16.1	15.9	18.9	17.6
Twin Falls	ROR	40.8	42.7	26.6	38.3	35.8	37.7	11.3	0.0	0.0	7.1	7.9	29.3	23.1
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	19.1	19.1	18.9	19.1	17.6	19.1	13.7	12.2	13.9	15.5	14.2	19.2	16.8
Upper Salmon 3&4	ROR	17.7	17.7	17.4	17.7	17.7	16.2	12.9	11.7	13.1	14.5	13.3	17.7	15.6
HCC Total		**587.1**	**955.2**	**800.1**	**966.9**	**867.2**	**845.6**	**544.3**	**381.8**	**462.9**	**457.5**	**360.2**	**556.3**	**648.8**
ROR Total		**394.6**	**411.2**	**331.0**	**424.5**	**435.5**	**458.5**	**285.2**	**234.1**	**231.0**	**228.3**	**200.5**	**330.5**	**330.2**
Total		**981.7**	**1366.4**	**1131.1**	**1391.4**	**1302.7**	**1304.1**	**829.5**	**615.9**	**693.9**	**685.8**	**560.7**	**886.8**	**979.0**

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

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*	261.4	425.2	338.7	407.3	383.3	378.1	239.8	161.7	196.5	195.1	153.6	245.1	282.2
Oxbow	HCC	108.5	177.2	152.6	184.9	157.3	154.0	101.7	73.9	88.6	88.3	69.4	103.1	121.6
Hells Canyon	HCC	215.7	351.4	307.7	373.6	325.5	312.0	201.9	145.4	174.2	174.1	138.3	204.7	243.7
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	25.4	27.6	25.8	56.2	85.4	101.8	83.2	64.5	41.9	19.1	0.0	16.0	45.6
Bliss	ROR	49.4	50.5	44.0	49.3	47.4	47.1	35.0	33.0	36.6	39.2	36.9	44.2	42.7
C.J. Strike	ROR	63.8	66.3	58.3	65.8	60.4	58.9	37.7	36.0	43.6	49.9	48.6	57.9	53.9
Cascade	ROR	1.5	2.6	4.6	7.5	7.3	11.9	6.9	10.1	9.1	2.7	2.2	1.5	5.7
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	34.5	35.3	28.9	34.0	33.0	33.5	22.5	20.3	22.8	25.1	23.3	30.0	28.6
Milner	ROR	40.6	43.3	25.2	38.2	35.1	36.3	6.7	0.0	0.0	0.0	1.8	26.7	21.2
Shoshone Falls	ROR	55.0	58.0	35.0	51.0	48.0	50.0	16.0	7.1	7.2	11.1	12.0	40.0	32.4
Swan Falls	ROR	20.4	21.4	19.2	21.3	19.4	18.9	13.0	12.3	14.3	16.0	15.9	18.7	17.6
Twin Falls	ROR	40.7	42.6	26.5	38.1	35.7	37.7	11.2	0.0	0.0	7.0	7.6	28.2	22.9
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	19.1	19.1	18.8	19.1	17.6	19.1	13.6	12.2	13.8	15.4	14.1	19.2	16.8
Upper Salmon 3&4	ROR	17.7	17.7	17.3	17.7	17.7	16.2	12.9	11.6	13.0	14.4	13.3	17.7	15.6
HCC Total		**585.6**	**953.8**	**799.0**	**965.8**	**866.1**	**844.1**	**543.4**	**381.0**	**459.3**	**457.5**	**361.3**	**552.9**	**647.5**
ROR Total		**393.8**	**410.0**	**329.9**	**423.5**	**434.7**	**458.0**	**284.6**	**233.7**	**230.5**	**227.5**	**199.7**	**325.9**	**329.1**
Total		**979.4**	**1363.8**	**1128.9**	**1389.3**	**1300.8**	**1302.1**	**828.0**	**614.7**	**689.8**	**685.0**	**561.0**	**878.8**	**976.6**

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

Hydro Modeling Results (PDR 580) (continued)

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*	261.0	424.8	338.2	407.4	383.0	377.7	239.5	161.5	195.8	195.3	153.4	244.6	281.8
Oxbow	HCC	108.4	177.1	152.3	184.9	157.2	153.9	101.6	73.8	88.3	88.3	69.3	102.9	121.5
Hells Canyon	HCC	215.3	351.1	307.2	373.6	325.3	311.7	201.6	145.1	173.4	174.1	138.0	204.2	243.4
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	25.4	27.4	25.8	56.3	85.5	101.8	83.3	64.5	41.9	19.2	0.0	15.7	45.6
Bliss	ROR	49.3	50.4	43.9	49.2	47.3	47.0	34.9	32.9	36.5	39.1	36.8	43.9	42.6
C.J. Strike	ROR	63.6	66.2	58.1	65.6	60.2	58.7	37.6	35.9	43.5	49.7	48.5	57.4	53.8
Cascade	ROR	1.5	2.6	4.6	7.5	7.3	11.9	6.9	10.1	9.1	2.7	2.2	1.5	5.7
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	34.4	35.1	28.8	33.9	32.9	33.5	22.4	20.3	22.7	25.1	23.3	29.7	28.5
Milner	ROR	40.5	42.9	25.1	38.0	35.1	36.3	6.7	0.0	0.0	0.0	1.8	26.0	21.0
Shoshone Falls	ROR	55.0	58.0	35.0	51.0	48.0	50.0	16.0	7.1	7.2	11.1	12.0	40.0	32.4
Swan Falls	ROR	20.3	21.4	19.1	21.2	19.4	18.9	13.0	12.2	14.2	15.9	15.8	18.6	17.5
Twin Falls	ROR	40.6	42.2	26.4	38.0	35.7	37.6	11.2	0.0	0.0	7.0	7.3	27.6	22.8
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	19.1	19.1	18.7	19.1	17.6	19.1	13.6	12.1	13.8	15.4	14.1	19.2	16.7
Upper Salmon 3&4	ROR	17.7	17.7	17.2	17.7	17.7	16.2	12.8	11.6	13.0	14.4	13.2	17.6	15.6
HCC Total		**584.7**	**953.0**	**797.7**	**965.9**	**865.5**	**843.3**	**542.7**	**380.4**	**457.4**	**457.7**	**360.7**	**551.7**	**646.7**
ROR Total		**393.1**	**408.6**	**329.0**	**422.8**	**434.4**	**457.6**	**284.3**	**233.3**	**230.1**	**227.2**	**199.0**	**323.0**	**328.3**
Total		**977.8**	**1361.6**	**1126.7**	**1388.7**	**1299.9**	**1300.9**	**827.0**	**613.7**	**687.5**	**684.9**	**559.7**	**874.7**	**975.1**

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

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*	260.7	424.5	337.4	407.5	383.5	377.4	239.3	161.3	195.3	195.2	153.5	244.0	281.6
Oxbow	HCC	108.2	176.9	151.9	184.8	157.4	153.8	101.5	73.7	88.0	88.2	69.3	102.7	121.4
Hells Canyon	HCC	215.1	350.8	306.3	373.4	325.6	311.4	201.5	145.0	173.0	173.9	138.1	203.7	243.1
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	25.4	27.2	25.8	56.3	85.5	101.9	83.3	64.5	41.9	19.2	0.0	15.4	45.5
Bliss	ROR	49.2	50.3	43.9	49.1	47.2	47.0	34.9	32.9	36.5	39.1	36.8	43.6	42.5
C.J. Strike	ROR	63.5	66.1	57.9	65.5	60.0	58.6	37.5	35.9	43.4	49.7	48.4	57.1	53.6
Cascade	ROR	1.5	2.6	4.6	7.5	7.3	11.9	6.9	10.1	9.1	2.7	2.2	1.5	5.7
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	34.4	34.9	28.7	33.8	32.9	33.4	22.4	20.2	22.7	25.0	23.2	29.5	28.4
Milner	ROR	40.4	42.7	25.0	37.9	35.1	36.2	6.7	0.0	0.0	0.0	1.8	25.4	20.9
Shoshone Falls	ROR	55.0	58.0	35.0	51.0	48.0	50.0	16.0	7.1	7.2	11.1	12.0	40.0	32.4
Swan Falls	ROR	20.3	21.3	19.1	21.2	19.3	18.9	13.0	12.2	14.2	15.9	15.8	18.5	17.5
Twin Falls	ROR	40.5	41.9	26.3	37.9	35.7	37.6	11.2	0.0	0.0	7.0	7.3	27.2	22.7
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	19.1	19.1	18.7	19.1	17.6	19.1	13.6	12.1	13.7	15.4	14.0	19.0	16.7
Upper Salmon 3&4	ROR	17.7	17.7	17.2	17.7	17.7	16.2	12.8	11.5	13.0	14.3	13.2	17.5	15.5
HCC Total		**584.0**	**952.2**	**795.6**	**965.7**	**866.4**	**842.6**	**542.3**	**380.0**	**456.3**	**457.3**	**360.9**	**550.4**	**646.1**
ROR Total		**392.7**	**407.4**	**328.5**	**422.3**	**434.0**	**457.4**	**284.2**	**233.1**	**230.0**	**227.0**	**198.7**	**320.5**	**327.8**
Total		**976.7**	**1359.6**	**1124.1**	**1388.0**	**1300.4**	**1300.0**	**826.5**	**613.1**	**686.2**	**684.3**	**559.6**	**870.9**	**973.9**

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

Hydro Modeling Results (PDR 580) (continued)

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*	260.6	424.3	337.2	407.4	383.4	377.3	239.3	161.2	195.0	195.4	153.5	243.8	281.5
Oxbow	HCC	108.2	176.9	151.8	184.8	157.4	153.7	101.5	73.7	87.9	88.3	69.3	102.6	121.3
Hells Canyon	HCC	215.0	350.7	306.2	373.3	325.5	311.3	201.4	144.9	172.7	174.1	138.1	203.5	243.1
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	25.4	27.1	25.8	56.3	85.5	101.8	83.3	64.5	41.9	19.2	0.0	15.3	45.5
Bliss	ROR	49.2	50.2	43.8	49.1	47.1	46.9	34.9	32.9	36.5	39.0	36.8	43.5	42.5
C.J. Strike	ROR	63.5	66.0	57.8	65.5	59.9	58.6	37.5	35.9	43.4	49.6	48.4	57.0	53.6
Cascade	ROR	1.5	2.6	4.6	7.5	7.3	11.9	6.9	10.1	9.1	2.7	2.2	1.5	5.7
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	34.4	34.9	28.7	33.8	32.8	33.4	22.4	20.2	22.7	25.0	23.2	29.4	28.4
Milner	ROR	40.3	42.6	25.0	37.9	35.1	36.2	6.7	0.0	0.0	0.0	1.8	25.2	20.9
Shoshone Falls	ROR	55.0	58.0	35.0	51.0	48.0	50.0	16.0	7.1	7.2	11.1	12.0	40.0	32.4
Swan Falls	ROR	20.3	21.3	19.0	21.2	19.3	18.9	13.0	12.2	14.2	15.9	15.8	18.5	17.5
Twin Falls	ROR	40.5	41.8	26.2	37.8	35.7	37.6	11.2	0.0	0.0	7.0	7.3	27.0	22.7
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	19.1	19.1	18.7	19.1	17.6	19.1	13.5	12.1	13.7	15.4	14.0	18.9	16.7
Upper Salmon 3&4	ROR	17.7	17.7	17.2	17.7	17.7	16.2	12.8	11.5	12.9	14.3	13.2	17.4	15.5
HCC Total		**583.8**	**951.9**	**795.2**	**965.5**	**866.2**	**842.3**	**542.2**	**379.8**	**455.5**	**457.8**	**360.9**	**549.9**	**645.9**
ROR Total		**392.6**	**406.9**	**328.1**	**422.2**	**433.6**	**457.2**	**284.1**	**233.1**	**229.9**	**226.8**	**198.7**	**319.5**	**327.5**
Total		**976.4**	**1358.8**	**1123.3**	**1387.7**	**1299.8**	**1299.5**	**826.3**	**612.9**	**685.3**	**684.6**	**559.6**	**869.4**	**973.5**

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

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*	260.6	424.3	337.2	407.4	383.4	377.3	239.3	161.2	195.0	195.4	153.5	243.8	281.5
Oxbow	HCC	108.2	176.9	151.8	184.8	157.4	153.7	101.5	73.7	87.9	88.3	69.3	102.6	121.3
Hells Canyon	HCC	215.0	350.7	306.2	373.3	325.5	311.3	201.4	144.9	172.7	174.1	138.1	203.5	243.1
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	25.4	27.1	25.8	56.3	85.5	101.8	83.3	64.5	41.9	19.2	0.0	15.3	45.5
Bliss	ROR	49.2	50.2	43.8	49.1	47.1	46.9	34.9	32.9	36.5	39.0	36.8	43.5	42.5
C.J. Strike	ROR	63.5	66.0	57.8	65.5	59.9	58.6	37.5	35.9	43.4	49.6	48.4	57.0	53.6
Cascade	ROR	1.5	2.6	4.6	7.5	7.3	11.9	6.9	10.1	9.1	2.7	2.2	1.5	5.7
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	34.4	34.9	28.7	33.8	32.8	33.4	22.4	20.2	22.7	25.0	23.2	29.4	28.4
Milner	ROR	40.3	42.6	25.0	37.9	35.1	36.2	6.7	0.0	0.0	0.0	1.8	25.2	20.9
Shoshone Falls	ROR	55.0	58.0	35.0	51.0	48.0	50.0	16.0	7.1	7.2	11.1	12.0	40.0	32.4
Swan Falls	ROR	20.3	21.3	19.0	21.2	19.3	18.9	13.0	12.2	14.2	15.9	15.8	18.5	17.5
Twin Falls	ROR	40.5	41.8	26.2	37.8	35.7	37.6	11.2	0.0	0.0	7.0	7.3	27.0	22.7
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	19.1	19.1	18.7	19.1	17.6	19.1	13.5	12.1	13.7	15.4	14.0	18.9	16.7
Upper Salmon 3&4	ROR	17.7	17.7	17.2	17.7	17.7	16.2	12.8	11.5	12.9	14.3	13.2	17.4	15.5
HCC Total		**583.8**	**951.9**	**795.2**	**965.5**	**866.2**	**842.3**	**542.2**	**379.8**	**455.5**	**457.8**	**360.9**	**549.9**	**645.9**
ROR Total		**392.6**	**406.9**	**328.1**	**422.2**	**433.6**	**457.2**	**284.1**	**233.1**	**229.9**	**226.8**	**198.7**	**319.5**	**327.5**
Total		**976.4**	**1358.8**	**1123.3**	**1387.7**	**1299.8**	**1299.5**	**826.3**	**612.9**	**685.3**	**684.6**	**559.6**	**869.4**	**973.5**

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

Hydro Modeling Results (PDR 580) (continued)

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*	260.6	424.3	337.2	407.4	383.4	377.3	239.3	161.2	195.0	195.4	153.5	243.8	281.5
Oxbow	HCC	108.2	176.9	151.8	184.8	157.4	153.7	101.5	73.7	87.9	88.3	69.3	102.6	121.3
Hells Canyon	HCC	215.0	350.7	306.2	373.3	325.5	311.3	201.4	144.9	172.7	174.1	138.1	203.5	243.1
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	25.4	27.1	25.8	56.3	85.5	101.8	83.3	64.5	41.9	19.2	0.0	15.3	45.5
Bliss	ROR	49.2	50.2	43.8	49.1	47.1	46.9	34.9	32.9	36.5	39.0	36.8	43.5	42.5
C.J. Strike	ROR	63.5	66.0	57.8	65.5	59.9	58.6	37.5	35.9	43.4	49.6	48.4	57.0	53.6
Cascade	ROR	1.5	2.6	4.6	7.5	7.3	11.9	6.9	10.1	9.1	2.7	2.2	1.5	5.7
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	34.4	34.9	28.7	33.8	32.8	33.4	22.4	20.2	22.7	25.0	23.2	29.4	28.4
Milner	ROR	40.3	42.6	25.0	37.9	35.1	36.2	6.7	0.0	0.0	0.0	1.8	25.2	20.9
Shoshone Falls	ROR	55.0	58.0	35.0	51.0	48.0	50.0	16.0	7.1	7.2	11.1	12.0	40.0	32.4
Swan Falls	ROR	20.3	21.3	19.0	21.2	19.3	18.9	13.0	12.2	14.2	15.9	15.8	18.5	17.5
Twin Falls	ROR	40.5	41.8	26.2	37.8	35.7	37.6	11.2	0.0	0.0	7.0	7.3	27.0	22.7
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	19.1	19.1	18.7	19.1	17.6	19.1	13.5	12.1	13.7	15.4	14.0	18.9	16.7
Upper Salmon 3&4	ROR	17.7	17.7	17.2	17.7	17.7	16.2	12.8	11.5	12.9	14.3	13.2	17.4	15.5
HCC Total		**583.8**	**951.9**	**795.2**	**965.5**	**866.2**	**842.3**	**542.2**	**379.8**	**455.5**	**457.8**	**360.9**	**549.9**	**645.9**
ROR Total		**392.6**	**406.9**	**328.1**	**422.2**	**433.6**	**457.2**	**284.1**	**233.1**	**229.9**	**226.8**	**198.7**	**319.5**	**327.5**
Total		**976.4**	**1358.8**	**1123.3**	**1387.7**	**1299.8**	**1299.5**	**826.3**	**612.9**	**685.3**	**684.6**	**559.6**	**869.4**	**973.5**

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

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*	260.6	424.3	337.2	407.4	383.4	377.3	239.3	161.2	195.0	195.4	153.5	243.8	281.5
Oxbow	HCC	108.2	176.9	151.8	184.8	157.4	153.7	101.5	73.7	87.9	88.3	69.3	102.6	121.3
Hells Canyon	HCC	215.0	350.7	306.2	373.3	325.5	311.3	201.4	144.9	172.7	174.1	138.1	203.5	243.1
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	25.4	27.1	25.8	56.3	85.5	101.8	83.3	64.5	41.9	19.2	0.0	15.3	45.5
Bliss	ROR	49.2	50.2	43.8	49.1	47.1	46.9	34.9	32.9	36.5	39.0	36.8	43.5	42.5
C.J. Strike	ROR	63.5	66.0	57.8	65.5	59.9	58.6	37.5	35.9	43.4	49.6	48.4	57.0	53.6
Cascade	ROR	1.5	2.6	4.6	7.5	7.3	11.9	6.9	10.1	9.1	2.7	2.2	1.5	5.7
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	34.4	34.9	28.7	33.8	32.8	33.4	22.4	20.2	22.7	25.0	23.2	29.4	28.4
Milner	ROR	40.3	42.6	25.0	37.9	35.1	36.2	6.7	0.0	0.0	0.0	1.8	25.2	20.9
Shoshone Falls	ROR	55.0	58.0	35.0	51.0	48.0	50.0	16.0	7.1	7.2	11.1	12.0	40.0	32.4
Swan Falls	ROR	20.3	21.3	19.0	21.2	19.3	18.9	13.0	12.2	14.2	15.9	15.8	18.5	17.5
Twin Falls	ROR	40.5	41.8	26.2	37.8	35.7	37.6	11.2	0.0	0.0	7.0	7.3	27.0	22.7
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	19.1	19.1	18.7	19.1	17.6	19.1	13.5	12.1	13.7	15.4	14.0	18.9	16.7
Upper Salmon 3&4	ROR	17.7	17.7	17.2	17.7	17.7	16.2	12.8	11.5	12.9	14.3	13.2	17.4	15.5
HCC Total		**583.8**	**951.9**	**795.2**	**965.5**	**866.2**	**842.3**	**542.2**	**379.8**	**455.5**	**457.8**	**360.9**	**549.9**	**645.9**
ROR Total		**392.6**	**406.9**	**328.1**	**422.2**	**433.6**	**457.2**	**284.1**	**233.1**	**229.9**	**226.8**	**198.7**	**319.5**	**327.5**
Total		**976.4**	**1358.8**	**1123.3**	**1387.7**	**1299.8**	**1299.5**	**826.3**	**612.9**	**685.3**	**684.6**	**559.6**	**869.4**	**973.5**

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

Hydro Modeling Results (PDR 580) (continued)

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*	260.6	424.3	337.2	407.4	383.4	377.3	239.3	161.2	195.0	195.4	153.5	243.8	281.5
Oxbow	HCC	108.2	176.9	151.8	184.8	157.4	153.7	101.5	73.7	87.9	88.3	69.3	102.6	121.3
Hells Canyon	HCC	215.0	350.7	306.2	373.3	325.5	311.3	201.4	144.9	172.7	174.1	138.1	203.5	243.1
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	25.4	27.1	25.8	56.3	85.5	101.8	83.3	64.5	41.9	19.2	0.0	15.3	45.5
Bliss	ROR	49.2	50.2	43.8	49.1	47.1	46.9	34.9	32.9	36.5	39.0	36.8	43.5	42.5
C.J. Strike	ROR	63.5	66.0	57.8	65.5	59.9	58.6	37.5	35.9	43.4	49.6	48.4	57.0	53.6
Cascade	ROR	1.5	2.6	4.6	7.5	7.3	11.9	6.9	10.1	9.1	2.7	2.2	1.5	5.7
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	34.4	34.9	28.7	33.8	32.8	33.4	22.4	20.2	22.7	25.0	23.2	29.4	28.4
Milner	ROR	40.3	42.6	25.0	37.9	35.1	36.2	6.7	0.0	0.0	0.0	1.8	25.2	20.9
Shoshone Falls	ROR	55.0	58.0	35.0	51.0	48.0	50.0	16.0	7.1	7.2	11.1	12.0	40.0	32.4
Swan Falls	ROR	20.3	21.3	19.0	21.2	19.3	18.9	13.0	12.2	14.2	15.9	15.8	18.5	17.5
Twin Falls	ROR	40.5	41.8	26.2	37.8	35.7	37.6	11.2	0.0	0.0	7.0	7.3	27.0	22.7
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	19.1	19.1	18.7	19.1	17.6	19.1	13.5	12.1	13.7	15.4	14.0	18.9	16.7
Upper Salmon 3&4	ROR	17.7	17.7	17.2	17.7	17.7	16.2	12.8	11.5	12.9	14.3	13.2	17.4	15.5
HCC Total		**583.8**	**951.9**	**795.2**	**965.5**	**866.2**	**842.3**	**542.2**	**379.8**	**455.5**	**457.8**	**360.9**	**549.9**	**645.9**
ROR Total		**392.6**	**406.9**	**328.1**	**422.2**	**433.6**	**457.2**	**284.1**	**233.1**	**229.9**	**226.8**	**198.7**	**319.5**	**327.5**
Total		**976.4**	**1358.8**	**1123.3**	**1387.7**	**1299.8**	**1299.5**	**826.3**	**612.9**	**685.3**	**684.6**	**559.6**	**869.4**	**973.5**

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

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*	260.6	424.3	337.2	407.4	383.4	377.3	239.3	161.2	195.0	195.4	153.5	243.8	281.5
Oxbow	HCC	108.2	176.9	151.8	184.8	157.4	153.7	101.5	73.7	87.9	88.3	69.3	102.6	121.3
Hells Canyon	HCC	215.0	350.7	306.2	373.3	325.5	311.3	201.4	144.9	172.7	174.1	138.1	203.5	243.1
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	25.4	27.1	25.8	56.3	85.5	101.8	83.3	64.5	41.9	19.2	0.0	15.3	45.5
Bliss	ROR	49.2	50.2	43.8	49.1	47.1	46.9	34.9	32.9	36.5	39.0	36.8	43.5	42.5
C.J. Strike	ROR	63.5	66.0	57.8	65.5	59.9	58.6	37.5	35.9	43.4	49.6	48.4	57.0	53.6
Cascade	ROR	1.5	2.6	4.6	7.5	7.3	11.9	6.9	10.1	9.1	2.7	2.2	1.5	5.7
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	34.4	34.9	28.7	33.8	32.8	33.4	22.4	20.2	22.7	25.0	23.2	29.4	28.4
Milner	ROR	40.3	42.6	25.0	37.9	35.1	36.2	6.7	0.0	0.0	0.0	1.8	25.2	20.9
Shoshone Falls	ROR	55.0	58.0	35.0	51.0	48.0	50.0	16.0	7.1	7.2	11.1	12.0	40.0	32.4
Swan Falls	ROR	20.3	21.3	19.0	21.2	19.3	18.9	13.0	12.2	14.2	15.9	15.8	18.5	17.5
Twin Falls	ROR	40.5	41.8	26.2	37.8	35.7	37.6	11.2	0.0	0.0	7.0	7.3	27.0	22.7
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	19.1	19.1	18.7	19.1	17.6	19.1	13.5	12.1	13.7	15.4	14.0	18.9	16.7
Upper Salmon 3&4	ROR	17.7	17.7	17.2	17.7	17.7	16.2	12.8	11.5	12.9	14.3	13.2	17.4	15.5
HCC Total		**583.8**	**951.9**	**795.2**	**965.5**	**866.2**	**842.3**	**542.2**	**379.8**	**455.5**	**457.8**	**360.9**	**549.9**	**645.9**
ROR Total		**392.6**	**406.9**	**328.1**	**422.2**	**433.6**	**457.2**	**284.1**	**233.1**	**229.9**	**226.8**	**198.7**	**319.5**	**327.5**
Total		**976.4**	**1358.8**	**1123.3**	**1387.7**	**1299.8**	**1299.5**	**826.3**	**612.9**	**685.3**	**684.6**	**559.6**	**869.4**	**973.5**

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

Hydro Modeling Results (PDR 580) (continued)

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*	260.6	424.3	337.2	407.4	383.4	377.3	239.3	161.2	195.0	195.4	153.5	243.8	281.5
Oxbow	HCC	108.2	176.9	151.8	184.8	157.4	153.7	101.5	73.7	87.9	88.3	69.3	102.6	121.3
Hells Canyon	HCC	215.0	350.7	306.2	373.3	325.5	311.3	201.4	144.9	172.7	174.1	138.1	203.5	243.1
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	25.4	27.1	25.8	56.3	85.5	101.8	83.3	64.5	41.9	19.2	0.0	15.3	45.5
Bliss	ROR	49.2	50.2	43.8	49.1	47.1	46.9	34.9	32.9	36.5	39.0	36.8	43.5	42.5
C.J. Strike	ROR	63.5	66.0	57.8	65.5	59.9	58.6	37.5	35.9	43.4	49.6	48.4	57.0	53.6
Cascade	ROR	1.5	2.6	4.6	7.5	7.3	11.9	6.9	10.1	9.1	2.7	2.2	1.5	5.7
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	34.4	34.9	28.7	33.8	32.8	33.4	22.4	20.2	22.7	25.0	23.2	29.4	28.4
Milner	ROR	40.3	42.6	25.0	37.9	35.1	36.2	6.7	0.0	0.0	0.0	1.8	25.2	20.9
Shoshone Falls	ROR	55.0	58.0	35.0	51.0	48.0	50.0	16.0	7.1	7.2	11.1	12.0	40.0	32.4
Swan Falls	ROR	20.3	21.3	19.0	21.2	19.3	18.9	13.0	12.2	14.2	15.9	15.8	18.5	17.5
Twin Falls	ROR	40.5	41.8	26.2	37.8	35.7	37.6	11.2	0.0	0.0	7.0	7.3	27.0	22.7
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	19.1	19.1	18.7	19.1	17.6	19.1	13.5	12.1	13.7	15.4	14.0	18.9	16.7
Upper Salmon 3&4	ROR	17.7	17.7	17.2	17.7	17.7	16.2	12.8	11.5	12.9	14.3	13.2	17.4	15.5
HCC Total		**583.8**	**951.9**	**795.2**	**965.5**	**866.2**	**842.3**	**542.2**	**379.8**	**455.5**	**457.8**	**360.9**	**549.9**	**645.9**
ROR Total		**392.6**	**406.9**	**328.1**	**422.2**	**433.6**	**457.2**	**284.1**	**233.1**	**229.9**	**226.8**	**198.7**	**319.5**	**327.5**
Total		**976.4**	**1358.8**	**1123.3**	**1387.7**	**1299.8**	**1299.5**	**826.3**	**612.9**	**685.3**	**684.6**	**559.6**	**869.4**	**973.5**

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

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*	260.6	424.3	337.2	407.4	383.4	377.3	239.3	161.2	195.0	195.4	153.5	243.8	281.5
Oxbow	HCC	108.2	176.9	151.8	184.8	157.4	153.7	101.5	73.7	87.9	88.3	69.3	102.6	121.3
Hells Canyon	HCC	215.0	350.7	306.2	373.3	325.5	311.3	201.4	144.9	172.7	174.1	138.1	203.5	243.1
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	25.4	27.1	25.8	56.3	85.5	101.8	83.3	64.5	41.9	19.2	0.0	15.3	45.5
Bliss	ROR	49.2	50.2	43.8	49.1	47.1	46.9	34.9	32.9	36.5	39.0	36.8	43.5	42.5
C.J. Strike	ROR	63.5	66.0	57.8	65.5	59.9	58.6	37.5	35.9	43.4	49.6	48.4	57.0	53.6
Cascade	ROR	1.5	2.6	4.6	7.5	7.3	11.9	6.9	10.1	9.1	2.7	2.2	1.5	5.7
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	34.4	34.9	28.7	33.8	32.8	33.4	22.4	20.2	22.7	25.0	23.2	29.4	28.4
Milner	ROR	40.3	42.6	25.0	37.9	35.1	36.2	6.7	0.0	0.0	0.0	1.8	25.2	20.9
Shoshone Falls	ROR	55.0	58.0	35.0	51.0	48.0	50.0	16.0	7.1	7.2	11.1	12.0	40.0	32.4
Swan Falls	ROR	20.3	21.3	19.0	21.2	19.3	18.9	13.0	12.2	14.2	15.9	15.8	18.5	17.5
Twin Falls	ROR	40.5	41.8	26.2	37.8	35.7	37.6	11.2	0.0	0.0	7.0	7.3	27.0	22.7
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	19.1	19.1	18.7	19.1	17.6	19.1	13.5	12.1	13.7	15.4	14.0	18.9	16.7
Upper Salmon 3&4	ROR	17.7	17.7	17.2	17.7	17.7	16.2	12.8	11.5	12.9	14.3	13.2	17.4	15.5
HCC Total		**583.8**	**951.9**	**795.2**	**965.5**	**866.2**	**842.3**	**542.2**	**379.8**	**455.5**	**457.8**	**360.9**	**549.9**	**645.9**
ROR Total		**392.6**	**406.9**	**328.1**	**422.2**	**433.6**	**457.2**	**284.1**	**233.1**	**229.9**	**226.8**	**198.7**	**319.5**	**327.5**
Total		**976.4**	**1358.8**	**1123.3**	**1387.7**	**1299.8**	**1299.5**	**826.3**	**612.9**	**685.3**	**684.6**	**559.6**	**869.4**	**973.5**

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

Hydro Modeling Results (PDR 580) (continued)

aMW 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2011**	**2/2011**	**3/2011**	**4/2011**	**5/2011**	**6/2011**	**7/2011**	**8/2011**	**9/2011**	**10/2011**	**11/2011**	**12/2011**	**aMW**
Brownlee	HCC*	253.3	311.8	252.9	295.1	370.0	322.8	221.1	166.7	177.0	187.7	156.4	210.3	243.8
Oxbow	HCC	106.5	130.5	111.0	123.0	149.1	129.5	93.5	76.2	78.7	83.1	69.6	88.0	103.2
Hells Canyon	HCC	210.8	257.4	226.4	249.8	303.7	261.2	184.7	149.4	154.5	163.9	138.1	174.4	206.2
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	9.4	15.1	36.5	72.9	87.6	77.8	62.0	33.8	13.9	0.0	0.0	34.1
Bliss	ROR	38.6	40.7	39.7	37.3	42.0	41.3	35.7	37.4	37.0	39.3	37.2	38.0	38.7
C.J. Strike	ROR	50.0	52.6	53.5	50.1	53.7	49.1	38.2	41.2	44.2	50.3	48.4	49.9	48.4
Cascade	ROR	1.5	1.5	2.6	1.7	4.8	7.9	6.9	10.1	9.0	2.2	1.4	1.4	4.2
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	24.2	26.6	24.8	22.6	28.4	28.7	23.2	24.0	23.5	25.6	23.9	24.1	25.0
Milner	ROR	8.6	16.5	11.5	3.7	17.9	18.5	6.7	6.7	0.0	0.0	1.8	6.1	8.2
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	7.3	11.2	11.3	12.0	11.5
Swan Falls	ROR	16.1	17.3	17.6	16.9	17.5	16.3	13.2	13.8	14.4	16.0	15.8	16.2	15.9
Twin Falls	ROR	11.9	19.2	14.5	8.1	21.0	22.7	11.5	11.7	3.8	7.3	7.4	9.8	12.4
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	14.9	16.9	13.8	14.0	18.4	18.5	14.2	15.0	14.3	15.8	14.5	14.8	15.4
Upper Salmon 3&4	ROR	13.9	15.6	14.5	13.2	17.0	17.0	13.3	14.1	13.5	14.7	13.6	13.8	14.5
HCC Total		**570.6**	**699.7**	**590.3**	**667.9**	**822.8**	**713.5**	**499.3**	**392.3**	**410.2**	**434.7**	**364.1**	**472.7**	**553.2**
ROR Total		**217.4**	**253.9**	**245.9**	**241.4**	**333.2**	**346.2**	**278.6**	**274.6**	**229.0**	**223.9**	**199.3**	**211.9**	**254.6**
Total		**788.0**	**953.6**	**836.2**	**909.3**	**1156.0**	**1059.7**	**777.9**	**666.9**	**639.2**	**658.6**	**563.4**	**684.6**	**807.8**

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

aMW 70th Percentile Water, 70th Percentile Load														
Resource	**Type**	**1/2012**	**2/2012**	**3/2012**	**4/2012**	**5/2012**	**6/2012**	**7/2012**	**8/2012**	**9/2012**	**10/2012**	**11/2012**	**12/2012**	**aMW**
Brownlee	HCC*	253.4	310.8	252.7	294.4	370.3	322.6	221.0	166.5	177.1	186.9	156.6	209.5	243.5
Oxbow	HCC	106.6	130.1	110.9	122.7	149.2	129.4	93.5	76.1	78.7	82.8	69.6	87.7	103.1
Hells Canyon	HCC	211.0	256.6	226.2	249.2	303.9	261.1	184.6	149.2	154.6	163.2	138.2	173.8	206.0
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	9.4	14.8	36.5	72.9	87.7	77.8	62.0	33.7	13.9	0.0	0.0	34.1
Bliss	ROR	38.5	40.6	39.6	37.2	41.9	41.3	35.6	37.3	37.0	39.2	37.1	37.9	38.6
C.J. Strike	ROR	49.9	52.5	53.5	50.0	53.6	49.0	38.1	41.2	44.1	50.2	48.4	49.8	48.4
Cascade	ROR	1.5	1.5	2.6	1.7	4.8	7.9	6.9	10.1	9.0	2.2	1.4	1.4	4.2
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	24.2	26.5	24.6	22.6	28.4	28.7	23.1	24.0	23.5	25.5	23.9	24.1	24.9
Milner	ROR	8.6	16.2	11.2	3.7	17.9	18.5	6.7	6.7	0.0	0.0	1.8	6.0	8.1
Shoshone Falls	ROR	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	7.3	11.2	11.3	12.0	11.5
Swan Falls	ROR	16.0	17.3	17.6	16.9	17.4	16.3	13.1	13.8	14.4	15.9	15.8	16.2	15.9
Twin Falls	ROR	11.8	19.1	14.1	8.0	21.0	22.7	11.5	11.7	3.8	7.3	7.4	9.8	12.4
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	14.9	16.8	15.4	13.9	17.7	18.5	14.1	15.0	14.3	15.8	14.5	14.7	15.5
Upper Salmon 3&4	ROR	13.9	15.6	14.4	13.1	17.0	16.2	13.3	14.0	13.5	14.7	13.6	13.8	14.4
HCC Total		**571.0**	**697.5**	**589.8**	**666.3**	**823.3**	**713.1**	**499.1**	**391.8**	**410.4**	**432.9**	**364.4**	**471.0**	**552.5**
ROR Total		**217.0**	**253.1**	**246.1**	**240.9**	**332.2**	**345.4**	**278.1**	**274.4**	**228.9**	**223.5**	**199.2**	**211.5**	**254.2**
Total		**788.0**	**950.6**	**835.9**	**907.2**	**1155.5**	**1058.5**	**777.2**	**666.2**	**639.2**	**656.4**	**563.6**	**682.5**	**806.7**

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

Hydro Modeling Results (PDR 580) (continued)

aMW 70th Percentile Water, 70th Percentile Load

Resource	Type	1/2013	2/2013	3/2013	4/2013	5/2013	6/2013	7/2013	8/2013	9/2013	10/2013	11/2013	12/2013	aMW
Brownlee	HCC*	253.6	309.6	252.5	294.2	370.1	322.4	220.9	166.4	177.1	186.2	156.4	209.4	243.2
Oxbow	HCC	106.7	129.7	110.8	122.6	149.2	129.3	93.4	76.0	78.8	82.5	69.5	87.6	103.0
Hells Canyon	HCC	211.2	255.8	226.0	249.0	303.7	260.9	184.4	149.1	154.7	162.6	138.0	173.7	205.8
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	9.4	14.5	36.6	73.0	87.7	77.8	62.1	33.8	13.9	0.0	0.0	34.1
Bliss	ROR	38.4	40.4	39.6	37.0	41.9	41.3	35.6	37.3	37.0	39.2	37.1	37.8	38.6
C.J. Strike	ROR	49.8	52.4	53.4	49.9	53.5	48.9	38.1	41.1	44.1	50.2	48.3	49.7	48.3
Cascade	ROR	1.5	1.5	2.6	1.7	4.8	7.9	6.9	10.1	9.0	2.2	1.4	1.4	4.2
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	24.1	26.5	24.4	22.5	28.3	28.7	23.1	23.9	23.4	25.5	23.8	24.0	24.9
Milner	ROR	8.5	16.0	10.9	3.6	17.9	18.5	6.7	6.7	0.0	0.0	1.8	6.0	8.1
Shoshone Falls	ROR	12.0	12.0	12.0	11.9	12.0	12.0	12.0	12.0	7.3	11.2	11.3	12.0	11.5
Swan Falls	ROR	16.0	17.3	17.5	16.8	17.4	16.3	13.1	13.8	14.4	15.9	15.8	16.1	15.9
Twin Falls	ROR	11.8	18.9	14.0	7.9	21.0	22.7	11.5	11.7	3.8	7.2	7.4	9.8	12.3
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	14.8	16.8	15.3	13.8	17.7	18.4	14.1	15.0	14.3	15.7	14.5	14.7	15.4
Upper Salmon 3&4	ROR	13.9	15.6	14.3	13.0	16.9	16.2	13.3	14.0	13.4	14.7	13.6	13.8	14.4
HCC Total		**571.5**	**695.1**	**589.3**	**665.8**	**822.9**	**712.6**	**498.7**	**391.5**	**410.6**	**431.3**	**363.9**	**470.7**	**552.0**
ROR Total		**216.5**	**252.4**	**244.8**	**240.0**	**332.0**	**345.2**	**278.1**	**274.3**	**228.7**	**223.3**	**199.0**	**211.1**	**253.8**
Total		**788.0**	**947.5**	**834.1**	**905.8**	**1154.9**	**1057.8**	**776.8**	**665.8**	**639.3**	**654.6**	**562.9**	**681.8**	**805.8**

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

aMW 70th Percentile Water, 70th Percentile Load

Resource	Type	1/2014	2/2014	3/2014	4/2014	5/2014	6/2014	7/2014	8/2014	9/2014	10/2014	11/2014	12/2014	aMW
Brownlee	HCC*	254.3	303.2	251.6	292.9	370.1	321.3	220.1	165.8	172.7	184.8	156.8	207.8	241.8
Oxbow	HCC	107.2	127.2	110.3	122.0	149.1	128.9	93.1	75.7	78.4	81.8	69.6	86.9	102.5
Hells Canyon	HCC	212.1	251.1	225.2	247.8	303.8	260.1	183.8	148.6	153.8	161.2	138.2	172.4	204.8
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	9.0	14.4	35.6	73.1	87.8	77.9	62.1	33.8	14.0	0.0	0.0	34.0
Bliss	ROR	38.0	39.6	39.3	36.2	41.7	41.1	35.4	37.1	36.8	39.0	36.9	37.5	38.2
C.J. Strike	ROR	49.4	51.6	53.0	49.1	53.1	48.6	37.8	40.8	43.8	49.9	48.1	49.3	47.9
Cascade	ROR	1.5	1.5	2.6	1.7	4.8	7.9	6.9	10.1	9.0	2.2	1.4	1.4	4.2
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	23.8	25.9	23.9	22.0	28.2	28.5	22.9	23.8	23.2	25.3	23.6	23.8	24.6
Milner	ROR	8.2	15.0	10.5	0.0	17.9	18.5	6.7	6.7	0.0	0.0	1.8	5.7	7.6
Shoshone Falls	ROR	12.0	12.0	12.0	8.9	12.0	12.0	12.0	12.0	7.3	11.1	11.3	12.0	11.2
Swan Falls	ROR	15.9	17.1	17.4	16.7	17.3	16.2	13.0	13.7	14.3	15.9	15.7	16.0	15.8
Twin Falls	ROR	11.5	17.9	13.6	5.3	20.9	22.7	11.4	11.7	3.7	7.2	7.4	9.6	11.9
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	14.6	16.4	14.9	13.5	17.7	18.3	14.0	14.8	14.2	15.6	14.3	14.5	15.2
Upper Salmon 3&4	ROR	13.7	15.2	14.0	12.7	16.8	16.2	13.2	13.9	13.3	14.6	13.4	13.6	14.2
HCC Total		**573.6**	**681.5**	**587.1**	**662.7**	**823.0**	**710.3**	**497.0**	**390.1**	**404.9**	**427.8**	**364.6**	**467.1**	**549.1**
ROR Total		**214.3**	**246.8**	**241.9**	**227.0**	**331.1**	**344.4**	**277.1**	**273.3**	**227.7**	**222.4**	**197.9**	**209.2**	**251.1**
Total		**787.9**	**928.3**	**829.0**	**889.7**	**1154.1**	**1054.7**	**774.1**	**663.4**	**632.5**	**650.2**	**562.5**	**676.3**	**800.2**

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

Hydro Modeling Results (PDR 580) (continued)

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*	255.1	298.3	251.2	291.2	369.7	320.1	219.4	165.0	173.1	181.8	156.7	206.3	240.7
Oxbow	HCC	107.6	125.3	110.1	121.3	149.0	128.4	92.8	75.4	78.6	80.4	69.6	86.3	102.1
Hells Canyon	HCC	213.0	247.4	224.7	246.4	303.4	259.2	183.2	147.9	154.2	158.7	138.1	171.1	203.9
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	7.7	14.0	35.6	73.2	87.9	78.0	62.2	33.9	14.1	0.0	0.0	33.9
Bliss	ROR	37.7	38.9	39.0	36.0	41.5	40.9	35.2	36.8	36.6	38.8	36.7	37.2	37.9
C.J. Strike	ROR	49.0	50.6	52.5	47.9	52.7	48.3	37.6	40.6	43.5	49.7	47.7	48.9	47.4
Cascade	ROR	1.5	1.5	2.6	1.7	4.8	7.9	6.9	10.1	9.0	2.2	1.4	1.4	4.2
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	23.6	25.0	23.5	21.8	28.0	28.4	22.8	23.6	23.1	25.2	23.4	23.6	24.3
Milner	ROR	8.0	12.4	9.6	0.0	17.9	18.5	6.7	6.7	0.0	0.0	1.8	5.3	7.2
Shoshone Falls	ROR	12.0	12.0	12.0	8.4	12.0	12.0	12.0	12.0	7.2	11.1	11.2	12.0	11.2
Swan Falls	ROR	15.8	16.8	17.3	16.4	17.2	16.1	13.0	13.7	14.2	15.8	15.6	15.9	15.7
Twin Falls	ROR	11.1	15.7	12.6	4.7	20.9	22.6	11.4	11.6	3.7	7.2	7.3	9.3	11.5
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	14.4	15.7	14.6	13.3	17.7	18.2	13.9	14.7	14.0	15.5	14.1	14.3	15.0
Upper Salmon 3&4	ROR	13.5	14.6	13.7	12.6	16.7	16.2	13.1	13.8	13.2	14.5	13.3	13.5	14.1
HCC Total		**575.7**	**671.0**	**586.0**	**658.9**	**822.1**	**707.7**	**495.4**	**388.3**	**405.8**	**420.9**	**364.4**	**463.7**	**546.7**
ROR Total		**212.3**	**236.5**	**237.7**	**223.7**	**330.2**	**343.6**	**276.5**	**272.4**	**226.6**	**221.7**	**196.5**	**207.2**	**248.7**
Total		**788.0**	**907.5**	**823.7**	**882.6**	**1152.3**	**1051.3**	**771.9**	**660.7**	**632.4**	**642.6**	**560.9**	**670.9**	**795.4**

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

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*	255.9	296.7	250.6	290.0	369.1	319.0	218.7	152.2	176.7	181.4	156.7	208.1	239.6
Oxbow	HCC	108.0	124.7	109.8	120.7	148.7	128.0	92.5	69.3	78.6	80.3	69.6	87.1	101.4
Hells Canyon	HCC	213.7	246.1	224.2	245.4	302.9	258.3	182.6	136.4	154.4	158.4	138.2	172.6	202.8
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	10.6	15.0	36.6	73.4	88.1	78.1	58.7	34.6	14.5	0.0	0.0	34.1
Bliss	ROR	37.4	40.2	38.7	36.1	41.4	40.7	35.0	33.3	36.5	38.7	36.6	36.9	37.6
C.J. Strike	ROR	48.6	52.3	52.2	49.0	52.4	48.0	37.3	35.9	43.3	49.4	47.8	48.5	47.1
Cascade	ROR	1.5	1.5	2.6	1.7	4.8	7.9	6.9	10.1	9.0	2.2	1.4	1.4	4.2
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	23.3	26.5	23.8	21.8	27.9	28.2	22.6	20.4	22.9	25.0	23.4	23.3	24.1
Milner	ROR	7.7	17.4	10.6	2.6	17.9	18.5	6.7	0.0	0.0	0.0	1.8	5.0	7.4
Shoshone Falls	ROR	12.0	12.0	12.0	10.9	12.0	12.0	12.0	7.1	7.2	11.1	11.2	23.9	12.0
Swan Falls	ROR	15.7	17.1	17.2	16.4	17.1	16.1	12.9	12.2	14.2	15.7	15.6	15.8	15.5
Twin Falls	ROR	10.8	20.2	13.4	7.0	20.9	22.6	11.3	3.6	3.7	7.1	7.3	9.1	11.4
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	14.2	16.8	14.9	13.3	17.7	18.1	13.7	12.3	13.9	15.4	14.1	14.2	14.9
Upper Salmon 3&4	ROR	13.4	15.6	13.9	12.6	16.6	16.2	13.0	11.7	13.1	14.3	13.3	13.3	13.9
HCC Total		**577.6**	**667.5**	**584.6**	**656.1**	**820.7**	**705.3**	**493.8**	**357.9**	**409.7**	**420.1**	**364.5**	**467.8**	**543.8**
ROR Total		**210.3**	**255.8**	**240.6**	**233.3**	**329.7**	**343.0**	**275.4**	**231.9**	**226.7**	**221.0**	**196.5**	**217.2**	**248.5**
Total		**787.9**	**923.3**	**825.2**	**889.4**	**1150.4**	**1048.3**	**769.2**	**589.8**	**636.3**	**641.1**	**561.0**	**685.0**	**792.3**

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

Hydro Modeling Results (PDR 580) (continued)

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*	256.7	293.3	249.8	287.9	367.6	317.7	218.0	151.5	172.4	179.2	156.7	206.9	238.1
Oxbow	HCC	108.4	123.4	109.5	119.8	148.1	127.4	92.2	69.0	78.3	79.3	69.5	86.5	101.0
Hells Canyon	HCC	214.5	243.6	223.5	243.6	301.7	257.3	182.0	135.8	153.6	156.4	138.0	171.6	201.8
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	9.5	14.6	35.7	73.6	88.2	78.2	58.8	34.7	14.5	0.0	0.0	34.0
Bliss	ROR	37.1	39.6	38.4	35.7	41.2	40.5	34.8	33.1	36.3	38.5	36.4	36.7	37.4
C.J. Strike	ROR	48.3	51.2	51.8	48.0	52.1	47.7	37.1	35.6	43.1	49.2	47.3	48.2	46.6
Cascade	ROR	1.5	1.5	2.6	1.7	4.8	7.9	6.9	10.1	9.0	2.2	1.4	1.4	4.2
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	23.0	25.6	23.4	21.3	27.7	27.9	22.4	20.3	22.8	24.9	23.2	23.1	23.8
Milner	ROR	7.4	15.2	10.1	0.0	17.9	18.5	6.7	0.0	0.0	0.0	1.8	5.0	6.9
Shoshone Falls	ROR	18.8	47.4	27.6	7.8	27.0	30.6	14.1	8.2	7.2	11.0	11.3	23.9	19.4
Swan Falls	ROR	15.6	16.9	17.1	16.3	17.0	16.0	12.8	12.1	14.1	15.6	15.5	15.7	15.4
Twin Falls	ROR	10.5	18.3	13.0	4.1	20.9	22.5	11.3	0.0	3.7	7.1	7.2	9.1	10.6
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	14.0	16.1	14.5	13.0	17.7	17.8	13.6	12.1	13.8	15.2	14.0	14.0	14.7
Upper Salmon 3&4	ROR	13.2	15.0	13.6	12.3	16.5	16.2	12.8	11.6	13.0	14.2	13.2	13.2	13.7
HCC Total		**579.6**	**660.3**	**582.8**	**651.3**	**817.4**	**702.4**	**492.2**	**356.3**	**404.3**	**414.9**	**364.2**	**465.0**	**540.9**
ROR Total		**215.1**	**281.9**	**253.0**	**221.1**	**344.0**	**360.4**	**276.5**	**228.4**	**226.0**	**220.0**	**195.2**	**216.1**	**253.0**
Total		**794.7**	**942.2**	**835.8**	**872.4**	**1161.4**	**1062.8**	**768.7**	**584.7**	**630.2**	**634.9**	**559.4**	**681.1**	**793.9**

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

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*	257.4	288.0	248.7	287.0	365.6	316.3	217.2	150.8	177.0	168.4	156.7	205.0	236.5
Oxbow	HCC	108.9	121.4	108.9	119.4	147.3	126.9	91.8	68.7	78.8	77.6	69.4	85.7	100.4
Hells Canyon	HCC	215.4	239.6	222.4	242.8	300.2	256.3	181.4	135.2	154.9	152.9	137.9	170.0	200.7
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	9.2	14.5	36.2	73.7	88.4	78.3	58.8	34.7	14.6	0.0	0.0	34.0
Bliss	ROR	36.9	38.9	38.1	35.5	41.0	40.3	34.6	32.9	36.1	38.3	36.2	36.5	37.1
C.J. Strike	ROR	47.9	50.3	51.4	47.2	51.7	47.5	36.8	35.3	42.8	48.9	47.1	48.0	46.2
Cascade	ROR	1.5	1.5	2.6	1.7	4.8	7.9	6.9	10.1	9.0	2.2	1.4	1.4	4.2
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	22.8	25.1	23.2	21.1	27.5	27.7	22.3	20.1	22.6	24.7	23.0	22.9	23.6
Milner	ROR	7.1	14.3	9.7	0.0	17.9	18.5	6.7	0.0	0.0	0.0	1.8	5.0	6.8
Shoshone Falls	ROR	18.8	47.4	27.6	7.8	27.0	30.6	14.1	8.2	7.2	11.0	11.3	23.9	19.4
Swan Falls	ROR	15.4	16.7	17.0	16.1	17.0	15.9	12.8	12.0	14.1	15.6	15.4	15.6	15.3
Twin Falls	ROR	10.2	17.1	12.6	3.8	20.8	22.5	11.3	0.0	0.0	7.1	7.2	9.1	10.1
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	13.8	15.7	14.4	12.8	17.7	17.7	13.5	12.0	13.7	15.1	13.8	13.8	14.5
Upper Salmon 3&4	ROR	13.0	14.7	13.5	12.1	16.4	16.2	12.7	11.5	12.9	14.1	13.0	13.0	13.6
HCC Total		**581.7**	**649.0**	**580.0**	**649.2**	**813.0**	**699.5**	**490.4**	**354.7**	**410.6**	**398.9**	**364.0**	**460.7**	**537.6**
ROR Total		**213.1**	**276.5**	**250.9**	**219.5**	**343.1**	**359.8**	**275.8**	**227.4**	**221.4**	**219.2**	**194.1**	**215.0**	**251.2**
Total		**794.8**	**925.5**	**830.9**	**868.7**	**1156.1**	**1059.3**	**766.2**	**582.1**	**632.0**	**618.1**	**558.1**	**675.7**	**788.8**

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

Hydro Modeling Results (PDR 580) (continued)

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*	257.8	283.1	248.4	285.6	364.2	315.2	216.7	150.4	177.2	166.4	156.8	204.3	235.5
Oxbow	HCC	109.1	119.4	108.8	118.8	146.7	126.5	91.6	68.5	79.0	76.7	69.5	85.4	100.0
Hells Canyon	HCC	216.0	235.9	222.2	241.7	299.0	255.4	181.0	134.8	155.2	151.1	138.0	169.4	200.0
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	7.5	14.2	36.8	73.8	88.4	78.3	58.8	34.7	14.7	0.0	0.0	33.9
Bliss	ROR	36.7	38.1	37.9	35.3	40.9	40.0	34.5	32.7	35.9	38.1	36.0	36.4	36.9
C.J. Strike	ROR	47.6	49.7	51.0	47.0	51.4	47.3	36.6	35.1	42.6	48.8	46.9	47.8	46.0
Cascade	ROR	1.5	1.5	2.6	1.7	4.8	7.9	6.9	10.1	9.0	2.2	1.4	1.4	4.2
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	22.7	24.0	22.9	20.9	27.4	27.5	22.2	20.0	22.5	24.6	22.8	22.7	23.4
Milner	ROR	6.9	11.4	9.3	0.0	17.9	18.5	6.7	0.0	0.0	0.0	1.8	5.0	6.5
Shoshone Falls	ROR	18.8	47.4	27.6	7.8	27.0	30.6	14.1	8.2	7.2	11.0	11.3	23.9	19.4
Swan Falls	ROR	15.4	16.3	16.9	16.0	16.9	15.8	12.7	12.0	14.1	15.5	15.3	15.6	15.2
Twin Falls	ROR	10.1	14.2	12.1	3.7	20.8	22.5	11.2	0.0	0.0	7.0	7.2	9.0	9.8
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	13.7	14.9	14.2	12.6	17.7	17.5	13.4	11.9	13.6	15.0	13.7	13.7	14.3
Upper Salmon 3&4	ROR	12.9	13.9	13.3	12.0	16.3	16.2	12.7	11.4	12.8	14.0	12.9	12.9	13.4
HCC Total		**582.9**	**638.4**	**579.4**	**646.1**	**809.9**	**697.1**	**489.3**	**353.7**	**411.3**	**394.2**	**364.3**	**459.1**	**535.5**
ROR Total		**212.0**	**264.5**	**248.3**	**219.0**	**342.5**	**358.8**	**275.1**	**226.7**	**220.7**	**218.5**	**193.2**	**214.2**	**249.3**
Total		**794.9**	**902.9**	**827.7**	**865.1**	**1152.4**	**1055.9**	**764.4**	**580.4**	**631.9**	**612.7**	**557.5**	**673.3**	**784.8**

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

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*	258.2	279.4	248.1	285.0	363.3	314.4	216.3	150.0	177.1	165.0	157.1	203.4	234.8
Oxbow	HCC	109.4	117.9	108.6	118.5	146.4	126.2	91.5	68.3	79.0	76.0	69.6	85.1	99.7
Hells Canyon	HCC	216.4	232.9	221.8	241.1	298.4	254.9	180.7	134.5	155.2	149.9	138.2	168.8	199.4
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	5.9	14.0	36.9	73.8	88.4	78.3	58.8	34.8	14.7	0.0	0.0	33.8
Bliss	ROR	36.6	37.6	37.6	35.2	40.8	39.9	34.4	32.6	35.8	38.0	35.9	36.3	36.7
C.J. Strike	ROR	47.3	49.1	50.6	46.9	51.3	47.2	36.5	34.9	42.5	48.6	46.8	47.7	45.8
Cascade	ROR	1.5	1.5	2.6	1.7	4.8	7.9	6.9	10.1	9.0	2.2	1.4	1.4	4.2
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	22.6	23.4	22.7	20.8	27.3	27.4	22.1	19.9	22.4	24.5	22.7	22.6	23.2
Milner	ROR	6.7	9.6	8.8	0.0	17.9	18.5	6.7	0.0	0.0	0.0	1.8	5.0	6.3
Shoshone Falls	ROR	18.8	47.4	27.6	7.8	27.0	30.6	14.1	8.2	7.2	11.0	11.3	23.9	19.4
Swan Falls	ROR	15.3	16.2	16.8	16.0	16.8	15.7	12.7	11.9	14.0	15.5	15.3	15.5	15.1
Twin Falls	ROR	9.9	12.6	11.6	0.0	20.8	22.4	11.2	0.0	0.0	7.0	7.1	9.0	9.3
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	13.6	14.4	14.0	12.5	17.6	17.4	13.3	11.8	13.5	14.9	13.6	13.6	14.2
Upper Salmon 3&4	ROR	12.9	13.5	13.2	11.9	16.3	16.1	12.6	11.3	12.7	14.0	12.8	12.8	13.3
HCC Total		**584.0**	**630.2**	**578.5**	**644.6**	**808.1**	**695.5**	**488.5**	**352.8**	**411.2**	**390.9**	**364.9**	**457.3**	**533.9**
ROR Total		**210.9**	**256.8**	**245.8**	**214.9**	**342.0**	**358.1**	**274.6**	**226.0**	**220.2**	**218.0**	**192.6**	**213.6**	**247.6**
Total		**794.9**	**887.0**	**824.3**	**859.5**	**1150.1**	**1053.6**	**763.1**	**578.8**	**631.4**	**608.9**	**557.5**	**670.9**	**781.5**

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

Hydro Modeling Results (PDR 580) (continued)

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*	258.4	270.2	247.7	276.1	363.0	314.0	216.0	149.7	176.9	164.5	156.9	203.1	233.0
Oxbow	HCC	109.5	117.5	108.4	118.2	146.3	126.0	91.3	68.2	78.9	75.8	69.5	84.9	99.5
Hells Canyon	HCC	216.6	233.9	221.5	242.3	298.1	254.5	180.4	134.3	154.9	149.3	137.9	168.5	199.4
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	5.7	13.9	36.9	73.8	88.5	78.3	58.7	34.7	14.7	0.0	0.0	33.8
Bliss	ROR	36.5	37.5	37.5	35.2	40.7	39.8	34.3	32.6	35.7	37.9	35.8	36.2	36.6
C.J. Strike	ROR	47.2	48.9	49.6	46.8	51.2	47.1	36.4	34.8	42.4	48.5	46.7	47.6	45.6
Cascade	ROR	1.5	1.5	2.6	1.7	4.8	7.9	6.9	10.1	9.0	2.2	1.4	1.4	4.2
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	22.5	23.2	22.6	20.7	27.3	27.3	22.0	19.8	22.3	24.4	22.6	22.5	23.1
Milner	ROR	6.6	9.3	8.4	0.0	17.9	18.5	6.7	0.0	0.0	0.0	1.8	5.0	6.2
Shoshone Falls	ROR	18.8	47.4	27.6	7.8	27.0	30.6	14.1	8.2	7.2	11.0	11.3	23.9	19.4
Swan Falls	ROR	15.3	16.1	16.3	15.9	16.8	15.6	12.7	11.9	14.0	15.4	15.3	15.4	15.1
Twin Falls	ROR	9.9	12.3	11.3	0.0	20.8	22.4	11.2	0.0	0.0	7.0	7.1	9.0	9.3
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	13.6	14.3	13.9	12.5	17.5	17.4	13.3	11.8	13.4	14.9	13.5	13.5	14.1
Upper Salmon 3&4	ROR	12.8	13.4	13.1	11.9	16.2	16.1	12.6	11.3	12.7	13.9	12.8	12.8	13.3
HCC Total		**584.5**	**621.6**	**577.6**	**636.6**	**807.4**	**694.5**	**487.7**	**352.2**	**410.6**	**389.6**	**364.3**	**456.5**	**531.9**
ROR Total		**210.4**	**255.2**	**243.1**	**214.6**	**341.7**	**357.8**	**274.3**	**225.7**	**219.7**	**217.5**	**192.2**	**213.1**	**247.0**
Total		**794.9**	**876.8**	**820.7**	**851.2**	**1149.0**	**1052.3**	**762.0**	**577.9**	**630.3**	**607.1**	**556.5**	**669.6**	**778.9**

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

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*	258.6	269.4	247.5	275.7	362.3	313.6	215.8	149.6	176.7	164.1	157.0	202.4	232.7
Oxbow	HCC	109.6	117.2	108.4	118.0	146.0	125.9	91.3	68.1	78.8	75.6	69.5	84.6	99.4
Hells Canyon	HCC	216.8	233.3	221.3	242.0	297.6	254.2	180.3	134.1	154.7	148.9	138.0	167.9	199.1
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	5.6	13.6	37.0	73.9	88.5	78.3	58.7	34.7	14.8	0.0	0.0	33.8
Bliss	ROR	36.5	37.4	37.5	35.1	40.7	39.8	34.3	32.5	35.7	37.9	35.8	36.2	36.6
C.J. Strike	ROR	47.1	48.7	48.8	46.7	51.1	47.0	36.4	34.8	42.3	48.5	46.6	47.4	45.5
Cascade	ROR	1.5	1.5	2.6	1.7	4.8	7.9	6.9	10.1	9.0	2.2	1.4	1.4	4.2
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	22.4	23.1	22.4	20.6	27.2	27.3	22.0	19.8	22.3	24.4	22.5	22.5	23.0
Milner	ROR	6.5	9.1	7.7	0.0	17.9	18.5	6.7	0.0	0.0	0.0	1.8	5.0	6.1
Shoshone Falls	ROR	18.8	47.4	27.6	7.8	27.0	30.6	14.1	8.2	7.2	11.0	11.3	23.9	19.4
Swan Falls	ROR	15.2	16.1	16.1	15.9	16.8	15.6	12.6	11.9	14.0	15.4	15.3	15.3	15.0
Twin Falls	ROR	9.8	12.0	10.5	0.0	20.7	22.4	11.2	0.0	0.0	7.0	7.1	9.0	9.1
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	13.5	14.2	13.7	12.4	17.5	17.3	13.2	11.8	13.4	14.9	13.5	13.5	14.1
Upper Salmon 3&4	ROR	12.8	13.3	13.0	11.8	16.2	16.0	12.5	11.3	12.7	13.9	12.7	12.8	13.3
HCC Total		**585.0**	**619.9**	**577.2**	**635.7**	**805.8**	**693.7**	**487.4**	**351.8**	**410.1**	**388.6**	**364.5**	**454.9**	**531.2**
ROR Total		**209.8**	**254.0**	**239.8**	**214.2**	**341.4**	**357.5**	**274.0**	**225.6**	**219.6**	**217.6**	**191.9**	**212.8**	**246.4**
Total		**794.8**	**873.9**	**817.0**	**849.9**	**1147.2**	**1051.2**	**761.4**	**577.4**	**629.7**	**606.2**	**556.4**	**667.7**	**777.6**

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

Hydro Modeling Results (PDR 580) (continued)

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*	258.6	269.1	247.4	275.6	362.2	313.5	215.8	149.5	176.6	163.7	157.3	202.1	232.6
Oxbow	HCC	109.6	117.1	108.3	118.0	145.9	125.8	91.2	68.1	78.8	75.4	69.6	84.5	99.4
Hells Canyon	HCC	216.9	233.1	221.2	241.9	297.5	254.1	180.2	134.1	154.7	148.6	138.2	167.7	199.0
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	5.5	13.4	37.0	73.9	88.5	78.3	58.7	34.7	14.8	0.0	0.0	33.7
Bliss	ROR	36.4	37.4	37.4	35.1	40.6	39.8	34.3	32.5	35.7	37.9	35.8	36.1	36.6
C.J. Strike	ROR	47.1	48.7	48.7	46.7	51.1	47.0	36.3	34.8	42.3	48.4	46.6	47.3	45.4
Cascade	ROR	1.5	1.5	2.6	1.7	4.8	7.9	6.9	10.1	9.0	2.2	1.4	1.4	4.2
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	22.4	23.0	22.2	20.6	27.2	27.3	21.9	19.8	22.3	24.4	22.5	22.5	23.0
Milner	ROR	6.5	9.0	7.3	0.0	17.9	18.5	6.7	0.0	0.0	0.0	1.8	5.0	6.1
Shoshone Falls	ROR	18.8	47.4	27.6	7.8	27.0	30.6	14.1	8.2	7.2	11.0	11.3	23.9	19.4
Swan Falls	ROR	15.2	16.1	16.1	15.9	16.8	15.6	12.6	11.9	14.0	15.4	15.3	15.3	15.0
Twin Falls	ROR	9.8	12.0	10.1	0.0	20.7	22.4	11.2	0.0	0.0	7.0	7.1	9.0	9.1
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	13.5	14.1	13.6	12.4	17.5	17.3	13.2	11.7	13.4	14.9	13.5	13.5	14.1
Upper Salmon 3&4	ROR	12.8	13.3	12.8	11.8	16.2	16.0	12.5	11.2	12.7	13.9	12.7	12.7	13.2
HCC Total		**585.1**	**619.3**	**576.9**	**635.5**	**805.5**	**693.4**	**487.2**	**351.7**	**410.0**	**387.7**	**365.1**	**454.3**	**531.0**
ROR Total		**209.7**	**253.6**	**238.1**	**214.2**	**341.4**	**357.5**	**273.8**	**225.4**	**219.6**	**217.5**	**191.9**	**212.5**	**246.1**
Total		**794.8**	**872.9**	**815.0**	**849.7**	**1146.9**	**1050.9**	**761.0**	**577.1**	**629.5**	**605.2**	**557.0**	**666.8**	**777.1**

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

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*	258.6	269.1	247.4	275.6	362.2	313.5	215.8	149.5	176.6	163.7	157.3	202.1	232.6
Oxbow	HCC	109.6	117.1	108.3	118.0	145.9	125.8	91.2	68.1	78.8	75.4	69.6	84.5	99.4
Hells Canyon	HCC	216.9	233.1	221.2	241.9	297.5	254.1	180.2	134.1	154.7	148.6	138.2	167.7	199.0
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	5.5	13.4	37.0	73.9	88.5	78.3	58.7	34.7	14.8	0.0	0.0	33.7
Bliss	ROR	36.4	37.4	37.4	35.1	40.6	39.8	34.3	32.5	35.7	37.9	35.8	36.1	36.6
C.J. Strike	ROR	47.1	48.7	48.7	46.7	51.1	47.0	36.3	34.8	42.3	48.4	46.6	47.3	45.4
Cascade	ROR	1.5	1.5	2.6	1.7	4.8	7.9	6.9	10.1	9.0	2.2	1.4	1.4	4.2
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	22.4	23.0	22.2	20.6	27.2	27.3	21.9	19.8	22.3	24.4	22.5	22.5	23.0
Milner	ROR	6.5	9.0	7.3	0.0	17.9	18.5	6.7	0.0	0.0	0.0	1.8	5.0	6.1
Shoshone Falls	ROR	18.8	47.4	27.6	7.8	27.0	30.6	14.1	8.2	7.2	11.0	11.3	23.9	19.4
Swan Falls	ROR	15.2	16.1	16.1	15.9	16.8	15.6	12.6	11.9	14.0	15.4	15.3	15.3	15.0
Twin Falls	ROR	9.8	12.0	10.1	0.0	20.7	22.4	11.2	0.0	0.0	7.0	7.1	9.0	9.1
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	13.5	14.1	13.6	12.4	17.5	17.3	13.2	11.7	13.4	14.9	13.5	13.5	14.1
Upper Salmon 3&4	ROR	12.8	13.3	12.8	11.8	16.2	16.0	12.5	11.2	12.7	13.9	12.7	12.7	13.2
HCC Total		**585.1**	**619.3**	**576.9**	**635.5**	**805.5**	**693.4**	**487.2**	**351.7**	**410.0**	**387.7**	**365.1**	**454.3**	**531.0**
ROR Total		**209.7**	**253.6**	**238.1**	**214.2**	**341.4**	**357.5**	**273.8**	**225.4**	**219.6**	**217.5**	**191.9**	**212.5**	**246.1**
Total		**794.8**	**872.9**	**815.0**	**849.7**	**1146.9**	**1050.9**	**761.0**	**577.1**	**629.5**	**605.2**	**557.0**	**666.8**	**777.1**

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

Hydro Modeling Results (PDR 580) (continued)

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*	258.6	269.1	247.4	275.6	362.2	313.5	215.8	149.5	176.6	163.7	157.3	202.1	232.6
Oxbow	HCC	109.6	117.1	108.3	118.0	145.9	125.8	91.2	68.1	78.8	75.4	69.6	84.5	99.4
Hells Canyon	HCC	216.9	233.1	221.2	241.9	297.5	254.1	180.2	134.1	154.7	148.6	138.2	167.7	199.0
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	5.5	13.4	37.0	73.9	88.5	78.3	58.7	34.7	14.8	0.0	0.0	33.7
Bliss	ROR	36.4	37.4	37.4	35.1	40.6	39.8	34.3	32.5	35.7	37.9	35.8	36.1	36.6
C.J. Strike	ROR	47.1	48.7	48.7	46.7	51.1	47.0	36.3	34.8	42.3	48.4	46.6	47.3	45.4
Cascade	ROR	1.5	1.5	2.6	1.7	4.8	7.9	6.9	10.1	9.0	2.2	1.4	1.4	4.2
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	22.4	23.0	22.2	20.6	27.2	27.3	21.9	19.8	22.3	24.4	22.5	22.5	23.0
Milner	ROR	6.5	9.0	7.3	0.0	17.9	18.5	6.7	0.0	0.0	0.0	1.8	5.0	6.1
Shoshone Falls	ROR	18.8	47.4	27.6	7.8	27.0	30.6	14.1	8.2	7.2	11.0	11.3	23.9	19.4
Swan Falls	ROR	15.2	16.1	16.1	15.9	16.8	15.6	12.6	11.9	14.0	15.4	15.3	15.3	15.0
Twin Falls	ROR	9.8	12.0	10.1	0.0	20.7	22.4	11.2	0.0	0.0	7.0	7.1	9.0	9.1
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	13.5	14.1	13.6	12.4	17.5	17.3	13.2	11.7	13.4	14.9	13.5	13.5	14.1
Upper Salmon 3&4	ROR	12.8	13.3	12.8	11.8	16.2	16.0	12.5	11.2	12.7	13.9	12.7	12.7	13.2
HCC Total		**585.1**	**619.3**	**576.9**	**635.5**	**805.5**	**693.4**	**487.2**	**351.7**	**410.0**	**387.7**	**365.1**	**454.3**	**531.0**
ROR Total		**209.7**	**253.6**	**238.1**	**214.2**	**341.4**	**357.5**	**273.8**	**225.4**	**219.6**	**217.5**	**191.9**	**212.5**	**246.1**
Total		**794.8**	**872.9**	**815.0**	**849.7**	**1146.9**	**1050.9**	**761.0**	**577.1**	**629.5**	**605.2**	**557.0**	**666.8**	**777.1**

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

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*	258.6	269.1	247.4	275.6	362.2	313.5	215.8	149.5	176.6	163.7	157.3	202.1	232.6
Oxbow	HCC	109.6	117.1	108.3	118.0	145.9	125.8	91.2	68.1	78.8	75.4	69.6	84.5	99.4
Hells Canyon	HCC	216.9	233.1	221.2	241.9	297.5	254.1	180.2	134.1	154.7	148.6	138.2	167.7	199.0
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	5.5	13.4	37.0	73.9	88.5	78.3	58.7	34.7	14.8	0.0	0.0	33.7
Bliss	ROR	36.4	37.4	37.4	35.1	40.6	39.8	34.3	32.5	35.7	37.9	35.8	36.1	36.6
C.J. Strike	ROR	47.1	48.7	48.7	46.7	51.1	47.0	36.3	34.8	42.3	48.4	46.6	47.3	45.4
Cascade	ROR	1.5	1.5	2.6	1.7	4.8	7.9	6.9	10.1	9.0	2.2	1.4	1.4	4.2
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	22.4	23.0	22.2	20.6	27.2	27.3	21.9	19.8	22.3	24.4	22.5	22.5	23.0
Milner	ROR	6.5	9.0	7.3	0.0	17.9	18.5	6.7	0.0	0.0	0.0	1.8	5.0	6.1
Shoshone Falls	ROR	18.8	47.4	27.6	7.8	27.0	30.6	14.1	8.2	7.2	11.0	11.3	23.9	19.4
Swan Falls	ROR	15.2	16.1	16.1	15.9	16.8	15.6	12.6	11.9	14.0	15.4	15.3	15.3	15.0
Twin Falls	ROR	9.8	12.0	10.1	0.0	20.7	22.4	11.2	0.0	0.0	7.0	7.1	9.0	9.1
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	13.5	14.1	13.6	12.4	17.5	17.3	13.2	11.7	13.4	14.9	13.5	13.5	14.1
Upper Salmon 3&4	ROR	12.8	13.3	12.8	11.8	16.2	16.0	12.5	11.2	12.7	13.9	12.7	12.7	13.2
HCC Total		**585.1**	**619.3**	**576.9**	**635.5**	**805.5**	**693.4**	**487.2**	**351.7**	**410.0**	**387.7**	**365.1**	**454.3**	**531.0**
ROR Total		**209.7**	**253.6**	**238.1**	**214.2**	**341.4**	**357.5**	**273.8**	**225.4**	**219.6**	**217.5**	**191.9**	**212.5**	**246.1**
Total		**794.8**	**872.9**	**815.0**	**849.7**	**1146.9**	**1050.9**	**761.0**	**577.1**	**629.5**	**605.2**	**557.0**	**666.8**	**777.1**

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

Hydro Modeling Results (PDR 580) (continued)

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*	258.6	269.1	247.4	275.6	362.2	313.5	215.8	149.5	176.6	163.7	157.3	202.1	232.6
Oxbow	HCC	109.6	117.1	108.3	118.0	145.9	125.8	91.2	68.1	78.8	75.4	69.6	84.5	99.4
Hells Canyon	HCC	216.9	233.1	221.2	241.9	297.5	254.1	180.2	134.1	154.7	148.6	138.2	167.7	199.0
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	5.5	13.4	37.0	73.9	88.5	78.3	58.7	34.7	14.8	0.0	0.0	33.7
Bliss	ROR	36.4	37.4	37.4	35.1	40.6	39.8	34.3	32.5	35.7	37.9	35.8	36.1	36.6
C.J. Strike	ROR	47.1	48.7	48.7	46.7	51.1	47.0	36.3	34.8	42.3	48.4	46.6	47.3	45.4
Cascade	ROR	1.5	1.5	2.6	1.7	4.8	7.9	6.9	10.1	9.0	2.2	1.4	1.4	4.2
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	22.4	23.0	22.2	20.6	27.2	27.3	21.9	19.8	22.3	24.4	22.5	22.5	23.0
Milner	ROR	6.5	9.0	7.3	0.0	17.9	18.5	6.7	0.0	0.0	0.0	1.8	5.0	6.1
Shoshone Falls	ROR	18.8	47.4	27.6	7.8	27.0	30.6	14.1	8.2	7.2	11.0	11.3	23.9	19.4
Swan Falls	ROR	15.2	16.1	16.1	15.9	16.8	15.6	12.6	11.9	14.0	15.4	15.3	15.3	15.0
Twin Falls	ROR	9.8	12.0	10.1	0.0	20.7	22.4	11.2	0.0	0.0	7.0	7.1	9.0	9.1
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	13.5	14.1	13.6	12.4	17.5	17.3	13.2	11.7	13.4	14.9	13.5	13.5	14.1
Upper Salmon 3&4	ROR	12.8	13.3	12.8	11.8	16.2	16.0	12.5	11.2	12.7	13.9	12.7	12.7	13.2
HCC Total		**585.1**	**619.3**	**576.9**	**635.5**	**805.5**	**693.4**	**487.2**	**351.7**	**410.0**	**387.7**	**365.1**	**454.3**	**531.0**
ROR Total		**209.7**	**253.6**	**238.1**	**214.2**	**341.4**	**357.5**	**273.8**	**225.4**	**219.6**	**217.5**	**191.9**	**212.5**	**246.1**
Total		**794.8**	**872.9**	**815.0**	**849.7**	**1146.9**	**1050.9**	**761.0**	**577.1**	**629.5**	**605.2**	**557.0**	**666.8**	**777.1**

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

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*	258.6	269.1	247.4	275.6	362.2	313.5	215.8	149.5	176.6	163.7	157.3	202.1	232.6
Oxbow	HCC	109.6	117.1	108.3	118.0	145.9	125.8	91.2	68.1	78.8	75.4	69.6	84.5	99.4
Hells Canyon	HCC	216.9	233.1	221.2	241.9	297.5	254.1	180.2	134.1	154.7	148.6	138.2	167.7	199.0
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	5.5	13.4	37.0	73.9	88.5	78.3	58.7	34.7	14.8	0.0	0.0	33.7
Bliss	ROR	36.4	37.4	37.4	35.1	40.6	39.8	34.3	32.5	35.7	37.9	35.8	36.1	36.6
C.J. Strike	ROR	47.1	48.7	48.7	46.7	51.1	47.0	36.3	34.8	42.3	48.4	46.6	47.3	45.4
Cascade	ROR	1.5	1.5	2.6	1.7	4.8	7.9	6.9	10.1	9.0	2.2	1.4	1.4	4.2
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	22.4	23.0	22.2	20.6	27.2	27.3	21.9	19.8	22.3	24.4	22.5	22.5	23.0
Milner	ROR	6.5	9.0	7.3	0.0	17.9	18.5	6.7	0.0	0.0	0.0	1.8	5.0	6.1
Shoshone Falls	ROR	18.8	47.4	27.6	7.8	27.0	30.6	14.1	8.2	7.2	11.0	11.3	23.9	19.4
Swan Falls	ROR	15.2	16.1	16.1	15.9	16.8	15.6	12.6	11.9	14.0	15.4	15.3	15.3	15.0
Twin Falls	ROR	9.8	12.0	10.1	0.0	20.7	22.4	11.2	0.0	0.0	7.0	7.1	9.0	9.1
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	13.5	14.1	13.6	12.4	17.5	17.3	13.2	11.7	13.4	14.9	13.5	13.5	14.1
Upper Salmon 3&4	ROR	12.8	13.3	12.8	11.8	16.2	16.0	12.5	11.2	12.7	13.9	12.7	12.7	13.2
HCC Total		**585.1**	**619.3**	**576.9**	**635.5**	**805.5**	**693.4**	**487.2**	**351.7**	**410.0**	**387.7**	**365.1**	**454.3**	**531.0**
ROR Total		**209.7**	**253.6**	**238.1**	**214.2**	**341.4**	**357.5**	**273.8**	**225.4**	**219.6**	**217.5**	**191.9**	**212.5**	**246.1**
Total		**794.8**	**872.9**	**815.0**	**849.7**	**1146.9**	**1050.9**	**761.0**	**577.1**	**629.5**	**605.2**	**557.0**	**666.8**	**777.1**

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

Hydro Modeling Results (PDR 580) (continued)

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*	258.6	269.1	247.4	275.6	362.2	313.5	215.8	149.5	176.6	163.7	157.3	202.1	232.6
Oxbow	HCC	109.6	117.1	108.3	118.0	145.9	125.8	91.2	68.1	78.8	75.4	69.6	84.5	99.4
Hells Canyon	HCC	216.9	233.1	221.2	241.9	297.5	254.1	180.2	134.1	154.7	148.6	138.2	167.7	199.0
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	5.5	13.4	37.0	73.9	88.5	78.3	58.7	34.7	14.8	0.0	0.0	33.7
Bliss	ROR	36.4	37.4	37.4	35.1	40.6	39.8	34.3	32.5	35.7	37.9	35.8	36.1	36.6
C.J. Strike	ROR	47.1	48.7	48.7	46.7	51.1	47.0	36.3	34.8	42.3	48.4	46.6	47.3	45.4
Cascade	ROR	1.5	1.5	2.6	1.7	4.8	7.9	6.9	10.1	9.0	2.2	1.4	1.4	4.2
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	22.4	23.0	22.2	20.6	27.2	27.3	21.9	19.8	22.3	24.4	22.5	22.5	23.0
Milner	ROR	6.5	9.0	7.3	0.0	17.9	18.5	6.7	0.0	0.0	0.0	1.8	5.0	6.1
Shoshone Falls	ROR	18.8	47.4	27.6	7.8	27.0	30.6	14.1	8.2	7.2	11.0	11.3	23.9	19.4
Swan Falls	ROR	15.2	16.1	16.1	15.9	16.8	15.6	12.6	11.9	14.0	15.4	15.3	15.3	15.0
Twin Falls	ROR	9.8	12.0	10.1	0.0	20.7	22.4	11.2	0.0	0.0	7.0	7.1	9.0	9.1
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	13.5	14.1	13.6	12.4	17.5	17.3	13.2	11.7	13.4	14.9	13.5	13.5	14.1
Upper Salmon 3&4	ROR	12.8	13.3	12.8	11.8	16.2	16.0	12.5	11.2	12.7	13.9	12.7	12.7	13.2
HCC Total		**585.1**	**619.3**	**576.9**	**635.5**	**805.5**	**693.4**	**487.2**	**351.7**	**410.0**	**387.7**	**365.1**	**454.3**	**531.0**
ROR Total		**209.7**	**253.6**	**238.1**	**214.2**	**341.4**	**357.5**	**273.8**	**225.4**	**219.6**	**217.5**	**191.9**	**212.5**	**246.1**
Total		**794.8**	**872.9**	**815.0**	**849.7**	**1146.9**	**1050.9**	**761.0**	**577.1**	**629.5**	**605.2**	**557.0**	**666.8**	**777.1**

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

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*	258.6	269.1	247.4	275.6	362.2	313.5	215.8	149.5	176.6	163.7	157.3	202.1	232.6
Oxbow	HCC	109.6	117.1	108.3	118.0	145.9	125.8	91.2	68.1	78.8	75.4	69.6	84.5	99.4
Hells Canyon	HCC	216.9	233.1	221.2	241.9	297.5	254.1	180.2	134.1	154.7	148.6	138.2	167.7	199.0
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	5.5	13.4	37.0	73.9	88.5	78.3	58.7	34.7	14.8	0.0	0.0	33.7
Bliss	ROR	36.4	37.4	37.4	35.1	40.6	39.8	34.3	32.5	35.7	37.9	35.8	36.1	36.6
C.J. Strike	ROR	47.1	48.7	48.7	46.7	51.1	47.0	36.3	34.8	42.3	48.4	46.6	47.3	45.4
Cascade	ROR	1.5	1.5	2.6	1.7	4.8	7.9	6.9	10.1	9.0	2.2	1.4	1.4	4.2
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	22.4	23.0	22.2	20.6	27.2	27.3	21.9	19.8	22.3	24.4	22.5	22.5	23.0
Milner	ROR	6.5	9.0	7.3	0.0	17.9	18.5	6.7	0.0	0.0	0.0	1.8	5.0	6.1
Shoshone Falls	ROR	18.8	47.4	27.6	7.8	27.0	30.6	14.1	8.2	7.2	11.0	11.3	23.9	19.4
Swan Falls	ROR	15.2	16.1	16.1	15.9	16.8	15.6	12.6	11.9	14.0	15.4	15.3	15.3	15.0
Twin Falls	ROR	9.8	12.0	10.1	0.0	20.7	22.4	11.2	0.0	0.0	7.0	7.1	9.0	9.1
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	13.5	14.1	13.6	12.4	17.5	17.3	13.2	11.7	13.4	14.9	13.5	13.5	14.1
Upper Salmon 3&4	ROR	12.8	13.3	12.8	11.8	16.2	16.0	12.5	11.2	12.7	13.9	12.7	12.7	13.2
HCC Total		**585.1**	**619.3**	**576.9**	**635.5**	**805.5**	**693.4**	**487.2**	**351.7**	**410.0**	**387.7**	**365.1**	**454.3**	**531.0**
ROR Total		**209.7**	**253.6**	**238.1**	**214.2**	**341.4**	**357.5**	**273.8**	**225.4**	**219.6**	**217.5**	**191.9**	**212.5**	**246.1**
Total		**794.8**	**872.9**	**815.0**	**849.7**	**1146.9**	**1050.9**	**761.0**	**577.1**	**629.5**	**605.2**	**557.0**	**666.8**	**777.1**

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

Hydro Modeling Results (PDR 580) (continued)

aMW 90th Percentile Water, 70th Percentile Load

Resource	Type	1/2011	2/2011	3/2011	4/2011	5/2011	6/2011	7/2011	8/2011	9/2011	10/2011	11/2011	12/2011	aMW
Brownlee	HCC*	258.2	159.9	202.7	242.6	273.2	222.4	205.5	155.3	165.0	148.7	158.7	195.0	198.9
Oxbow	HCC	110.9	72.6	85.3	99.9	112.8	91.6	86.5	70.8	75.1	67.8	69.8	81.2	85.4
Hells Canyon	HCC	218.5	144.8	173.9	203.2	231.5	184.2	170.1	138.7	147.1	134.0	138.2	160.6	170.4
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	5.7	29.3	68.4	78.6	69.6	50.5	25.8	9.4	0.0	0.0	28.1
Bliss	ROR	35.6	36.0	34.6	33.1	38.9	38.4	34.7	36.3	35.9	38.2	36.2	36.2	36.2
C.J. Strike	ROR	45.2	45.2	44.9	41.3	44.9	40.8	34.9	38.4	42.2	47.6	45.7	45.6	43.1
Cascade	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	22.7	23.3	21.2	20.4	26.3	26.5	22.5	23.4	22.7	24.8	23.0	23.1	23.3
Milner	ROR	6.1	6.5	2.0	0.0	13.9	14.4	6.7	6.2	0.0	0.0	1.8	5.1	5.2
Shoshone Falls	ROR	12.0	12.0	10.2	4.9	12.0	12.0	12.0	12.0	6.9	9.7	11.2	12.0	10.6
Swan Falls	ROR	15.2	15.3	15.2	14.2	15.3	14.6	12.3	13.2	14.0	15.4	15.4	15.4	14.6
Twin Falls	ROR	9.6	9.5	6.4	0.0	17.4	18.9	10.8	11.2	0.0	5.9	7.3	9.1	8.8
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	13.7	14.3	12.8	12.2	16.8	16.7	13.6	14.6	13.7	15.2	13.8	14.0	14.3
Upper Salmon 3&4	ROR	13.0	13.4	12.2	11.7	15.6	15.5	12.9	13.7	13.0	14.2	13.0	13.2	13.5
HCC Total		**587.6**	**377.3**	**461.9**	**545.7**	**617.5**	**498.2**	**462.1**	**364.8**	**387.1**	**350.5**	**366.7**	**436.8**	**454.7**
ROR Total		**200.2**	**202.5**	**192.9**	**193.7**	**298.7**	**307.2**	**262.9**	**255.9**	**209.7**	**209.5**	**192.7**	**200.9**	**227.2**
Total		**787.8**	**579.8**	**654.8**	**739.4**	**916.1**	**805.4**	**725.0**	**620.7**	**596.8**	**560.0**	**559.4**	**637.7**	**681.9**

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

aMW 90th Percentile Water, 70th Percentile Load

Resource	Type	1/2012	2/2012	3/2012	4/2012	5/2012	6/2012	7/2012	8/2012	9/2012	10/2012	11/2012	12/2012	aMW
Brownlee	HCC*	258.4	160.0	201.2	242.4	273.0	222.3	205.4	155.2	164.8	148.5	158.6	194.8	198.7
Oxbow	HCC	111.0	72.7	84.8	99.8	112.7	91.6	86.5	70.7	75.0	67.7	69.7	81.1	85.3
Hells Canyon	HCC	218.7	145.1	172.8	203.0	231.3	184.1	170.0	138.6	146.9	133.9	138.1	160.4	170.2
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	5.7	29.3	68.4	78.6	69.5	50.4	25.8	9.4	0.0	0.0	28.1
Bliss	ROR	35.6	35.9	34.6	33.0	38.8	38.4	34.7	36.3	35.9	38.2	36.2	36.1	36.1
C.J. Strike	ROR	45.1	45.1	44.8	41.3	44.8	40.7	34.9	38.3	42.2	47.5	45.7	45.5	43.0
Cascade	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	22.7	23.2	21.2	20.4	26.3	26.4	22.5	23.4	22.7	24.8	23.0	23.0	23.3
Milner	ROR	6.1	6.4	2.0	0.0	13.9	14.4	6.7	6.2	0.0	0.0	1.8	5.0	5.2
Shoshone Falls	ROR	12.0	12.0	10.2	4.9	12.0	12.0	12.0	12.0	6.9	9.6	11.2	12.0	10.6
Swan Falls	ROR	15.2	15.3	15.2	14.2	15.2	14.6	12.3	13.2	13.9	15.4	15.3	15.4	14.6
Twin Falls	ROR	9.5	9.4	6.4	0.0	17.4	18.8	10.8	11.2	0.0	5.9	7.3	9.0	8.8
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	13.7	14.3	12.8	12.2	16.8	16.7	13.6	14.6	13.7	15.2	13.8	13.9	14.3
Upper Salmon 3&4	ROR	12.9	13.4	12.2	11.6	15.6	15.5	12.8	13.7	12.9	14.2	13.0	13.1	13.4
HCC Total		**588.1**	**377.8**	**458.8**	**545.2**	**617.0**	**498.0**	**461.9**	**364.5**	**386.7**	**350.1**	**366.4**	**436.3**	**454.2**
ROR Total		**199.9**	**202.0**	**192.8**	**193.5**	**298.4**	**306.9**	**262.7**	**255.7**	**209.5**	**209.3**	**192.6**	**200.2**	**227.0**
Total		**788.0**	**579.8**	**651.6**	**738.7**	**915.4**	**804.9**	**724.6**	**620.2**	**596.2**	**559.4**	**559.0**	**636.5**	**681.2**

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

Hydro Modeling Results (PDR 580) (continued)

aMW 90th Percentile Water, 70th Percentile Load

Resource	Type	1/2013	2/2013	3/2013	4/2013	5/2013	6/2013	7/2013	8/2013	9/2013	10/2013	11/2013	12/2013	aMW
Brownlee	HCC*	258.5	160.1	200.0	242.1	272.8	222.2	205.2	155.1	164.7	148.0	158.9	194.5	198.5
Oxbow	HCC	111.1	72.8	84.3	99.7	112.7	91.5	86.4	70.6	74.9	67.5	69.8	81.0	85.2
Hells Canyon	HCC	218.8	145.2	171.9	202.8	231.2	184.0	169.9	138.5	146.8	133.4	138.3	160.2	170.1
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	5.7	29.3	68.5	78.6	69.5	50.4	25.8	9.4	0.0	0.0	28.1
Bliss	ROR	35.5	35.8	34.6	33.0	38.8	38.4	34.6	36.3	35.9	38.1	36.1	36.1	36.1
C.J. Strike	ROR	45.0	45.1	44.8	41.2	44.8	40.7	34.9	38.2	42.1	47.5	45.7	45.4	43.0
Cascade	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	22.6	23.1	21.2	20.3	26.2	26.4	22.4	23.4	22.6	24.8	22.9	23.0	23.2
Milner	ROR	6.0	6.4	2.0	0.0	13.9	14.4	6.7	6.2	0.0	0.0	1.8	4.9	5.2
Shoshone Falls	ROR	12.0	12.0	10.2	4.9	12.0	12.0	12.0	12.0	6.9	9.5	11.2	12.0	10.6
Swan Falls	ROR	15.2	15.2	15.2	14.1	15.2	14.5	12.3	13.1	13.9	15.3	15.3	15.3	14.6
Twin Falls	ROR	9.5	9.4	6.4	0.0	17.4	18.8	10.7	11.2	0.0	5.8	7.3	9.0	8.8
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	13.7	14.2	12.8	12.1	16.7	16.6	13.6	14.5	13.7	15.2	13.8	13.9	14.2
Upper Salmon 3&4	ROR	12.9	13.4	12.2	11.6	15.5	15.4	12.8	13.6	12.9	14.2	13.0	13.1	13.4
HCC Total		**588.4**	**378.1**	**456.2**	**544.6**	**616.6**	**497.7**	**461.5**	**364.2**	**386.4**	**348.9**	**367.0**	**435.7**	**453.8**
ROR Total		**199.5**	**201.6**	**192.8**	**193.1**	**298.1**	**306.6**	**262.4**	**255.3**	**209.3**	**208.9**	**192.4**	**199.9**	**226.7**
Total		**787.9**	**579.7**	**649.0**	**737.7**	**914.7**	**804.3**	**723.9**	**619.5**	**595.7**	**557.8**	**559.4**	**635.6**	**680.4**

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

aMW 90th Percentile Water, 70th Percentile Load

Resource	Type	1/2014	2/2014	3/2014	4/2014	5/2014	6/2014	7/2014	8/2014	9/2014	10/2014	11/2014	12/2014	aMW
Brownlee	HCC*	257.3	161.0	195.7	241.4	272.1	221.4	204.5	154.4	164.0	146.2	158.6	193.8	197.5
Oxbow	HCC	110.6	73.4	82.5	99.4	112.4	91.2	86.1	70.3	74.6	66.6	69.7	80.7	84.8
Hells Canyon	HCC	217.9	146.2	168.5	202.2	230.6	183.3	169.3	137.9	146.2	131.8	138.0	159.6	169.3
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	5.7	29.3	68.5	78.7	69.6	50.2	25.6	9.5	0.0	0.0	28.1
Bliss	ROR	35.2	35.5	34.4	32.8	38.6	38.2	34.5	36.1	35.7	37.9	35.9	35.7	35.9
C.J. Strike	ROR	44.6	44.6	44.5	41.0	44.4	40.3	34.6	38.0	41.9	47.2	45.6	45.1	42.7
Cascade	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	22.3	22.9	21.0	20.1	26.1	26.2	22.3	23.2	22.5	24.6	22.8	22.7	23.1
Milner	ROR	5.7	5.8	2.0	0.0	13.9	14.4	6.7	6.2	0.0	0.0	1.8	4.4	5.1
Shoshone Falls	ROR	12.0	12.0	10.2	4.9	12.0	12.0	12.0	12.0	6.8	9.3	11.2	12.0	10.5
Swan Falls	ROR	15.1	15.1	15.1	14.2	15.1	14.2	12.2	13.1	13.8	15.3	15.3	15.2	14.5
Twin Falls	ROR	9.3	9.1	6.4	0.0	17.3	18.6	10.7	11.1	0.0	5.6	7.3	8.8	8.7
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	13.5	14.0	12.7	12.0	16.6	16.5	13.5	14.4	13.6	15.0	13.6	13.7	14.1
Upper Salmon 3&4	ROR	12.7	13.2	12.0	11.5	15.4	15.3	12.7	13.5	12.8	14.0	12.9	12.9	13.2
HCC Total		**585.8**	**380.6**	**446.7**	**543.0**	**615.1**	**495.9**	**459.9**	**362.6**	**384.8**	**344.6**	**366.3**	**434.1**	**451.6**
ROR Total		**197.5**	**199.2**	**191.7**	**192.4**	**297.1**	**305.2**	**261.7**	**254.2**	**208.2**	**207.5**	**191.7**	**197.7**	**225.3**
Total		**783.3**	**579.8**	**638.4**	**735.4**	**912.1**	**801.1**	**721.6**	**616.8**	**592.9**	**552.1**	**558.0**	**631.8**	**676.9**

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

Hydro Modeling Results (PDR 580) (continued)

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*	256.2	161.7	191.0	240.7	271.4	220.6	203.8	153.7	163.2	144.5	158.7	192.6	196.5
Oxbow	HCC	110.1	73.8	80.6	99.1	112.1	90.9	85.8	70.0	74.3	65.8	69.7	80.2	84.4
Hells Canyon	HCC	217.0	147.1	164.8	201.6	230.0	182.7	168.7	137.3	145.5	130.2	138.0	158.6	168.5
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	5.7	29.3	68.6	78.7	69.7	50.2	25.5	9.6	0.0	0.0	28.1
Bliss	ROR	34.9	35.2	34.2	32.4	38.4	38.0	34.3	35.9	35.5	37.7	35.7	35.4	35.6
C.J. Strike	ROR	44.4	44.3	44.3	40.7	44.1	40.1	34.4	37.7	41.6	46.9	45.2	44.9	42.4
Cascade	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	22.1	22.6	20.9	19.9	25.9	25.9	22.1	23.0	22.3	24.4	22.6	22.4	22.8
Milner	ROR	5.4	5.5	2.0	0.0	13.9	14.4	6.7	6.2	0.0	0.0	1.8	4.0	5.0
Shoshone Falls	ROR	12.0	12.0	10.1	4.8	12.0	12.0	12.0	12.0	6.7	9.0	11.2	12.0	10.5
Swan Falls	ROR	15.0	15.0	15.0	14.1	15.0	14.1	12.1	13.0	13.8	15.4	15.2	15.1	14.4
Twin Falls	ROR	9.1	8.8	6.3	0.0	17.3	18.4	10.6	11.1	0.0	5.4	7.2	8.5	8.6
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	13.3	13.8	12.5	11.9	16.5	16.3	13.3	14.3	13.4	14.8	13.5	13.4	13.9
Upper Salmon 3&4	ROR	12.5	13.0	11.9	11.4	15.3	15.1	12.6	13.4	12.7	13.9	12.8	12.7	13.1
HCC Total		**583.3**	**382.6**	**436.4**	**541.4**	**613.4**	**494.2**	**458.3**	**361.0**	**383.0**	**340.5**	**366.4**	**431.4**	**449.3**
ROR Total		**195.8**	**197.2**	**190.6**	**191.1**	**296.2**	**303.8**	**260.7**	**253.2**	**207.0**	**206.2**	**190.5**	**195.6**	**224.0**
Total		**779.1**	**579.8**	**627.0**	**732.5**	**909.5**	**798.0**	**719.0**	**614.2**	**590.0**	**546.7**	**556.9**	**627.0**	**673.3**

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

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*	255.1	162.2	189.8	239.5	270.6	219.9	203.1	140.7	162.9	143.0	158.8	191.9	194.8
Oxbow	HCC	109.6	74.1	80.2	98.6	111.7	90.6	85.5	63.9	74.1	65.0	69.7	79.9	83.6
Hells Canyon	HCC	216.0	147.6	163.9	200.7	229.4	182.2	168.1	125.7	145.2	128.7	138.0	158.0	167.0
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	5.7	29.2	68.7	78.9	69.8	48.1	26.5	9.8	0.0	0.0	28.1
Bliss	ROR	34.6	35.0	34.0	32.3	38.2	37.8	34.1	32.3	35.3	37.5	35.5	35.2	35.2
C.J. Strike	ROR	44.0	43.9	44.0	40.5	43.9	39.8	34.1	33.1	41.4	46.8	45.1	44.6	41.8
Cascade	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	21.8	22.4	20.7	19.8	25.7	25.8	21.9	19.8	22.1	24.3	22.4	22.3	22.4
Milner	ROR	5.1	5.7	2.0	0.0	13.5	14.3	6.7	0.0	0.0	0.0	1.8	3.9	4.4
Shoshone Falls	ROR	12.0	12.0	10.1	4.8	12.0	12.0	12.0	6.8	6.9	9.4	11.1	12.0	10.1
Swan Falls	ROR	14.8	14.9	15.0	14.0	14.9	14.1	12.1	11.5	13.7	15.4	15.2	15.0	14.2
Twin Falls	ROR	9.0	8.8	6.3	0.0	17.2	18.3	10.6	0.0	0.0	5.7	7.2	8.3	7.6
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	13.1	13.6	12.4	11.7	16.4	16.2	13.2	11.8	13.3	14.8	13.4	13.3	13.6
Upper Salmon 3&4	ROR	12.4	12.8	11.8	11.2	15.2	15.0	12.5	11.3	12.6	13.8	12.7	12.6	12.8
HCC Total		**580.7**	**383.9**	**433.9**	**538.8**	**611.7**	**492.7**	**456.7**	**330.3**	**382.1**	**336.7**	**366.5**	**429.8**	**445.3**
ROR Total		**193.9**	**196.1**	**189.7**	**190.1**	**294.9**	**303.0**	**259.9**	**211.1**	**207.3**	**206.6**	**189.7**	**194.4**	**219.7**
Total		**774.6**	**580.0**	**623.6**	**728.9**	**906.5**	**795.7**	**716.6**	**541.4**	**589.4**	**543.3**	**556.2**	**624.2**	**665.0**

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

Hydro Modeling Results (PDR 580) (continued)

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*	253.9	163.1	179.0	238.4	269.9	219.1	202.3	140.1	158.6	141.7	158.9	190.7	193.0
Oxbow	HCC	109.1	74.6	78.7	98.2	111.4	90.3	85.2	63.6	73.8	64.4	69.7	79.4	83.2
Hells Canyon	HCC	215.0	148.6	160.6	199.7	228.8	181.5	167.5	125.2	144.4	127.5	138.0	157.0	166.1
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	5.7	29.3	68.7	78.6	70.0	47.9	26.2	9.9	0.0	0.0	28.0
Bliss	ROR	34.4	34.7	33.8	32.0	37.8	37.5	33.9	32.1	35.1	37.3	35.4	35.0	34.9
C.J. Strike	ROR	43.7	43.4	43.8	40.2	43.6	39.6	33.8	32.8	41.1	46.5	44.8	44.3	41.5
Cascade	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	21.6	22.1	20.5	19.6	25.3	25.5	21.8	19.7	22.0	24.1	22.3	22.1	22.2
Milner	ROR	5.1	5.1	2.0	0.0	12.3	12.8	6.7	0.0	0.0	0.0	1.8	3.4	4.1
Shoshone Falls	ROR	12.0	12.0	10.0	4.7	20.0	22.0	14.0	6.8	6.9	9.2	11.1	12.0	11.7
Swan Falls	ROR	14.8	14.7	14.9	13.9	14.8	14.0	12.0	11.4	13.6	15.3	15.1	14.9	14.1
Twin Falls	ROR	8.9	8.5	6.2	0.0	16.0	17.5	10.5	0.0	0.0	5.6	7.1	8.0	7.4
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	12.9	13.4	12.3	11.6	16.0	15.9	13.1	11.7	13.2	14.6	13.3	13.2	13.4
Upper Salmon 3&4	ROR	12.2	12.7	11.7	11.1	14.9	14.8	12.4	11.2	12.5	13.7	12.5	12.5	12.7
HCC Total		**578.0**	**386.3**	**418.3**	**536.3**	**610.0**	**490.9**	**455.0**	**328.9**	**376.7**	**333.6**	**366.6**	**427.1**	**442.3**
ROR Total		**192.7**	**193.6**	**188.6**	**189.0**	**298.5**	**309.0**	**261.1**	**210.0**	**206.1**	**205.3**	**188.7**	**192.6**	**219.6**
Total		**770.7**	**579.9**	**606.9**	**725.3**	**908.5**	**799.9**	**716.1**	**538.9**	**582.7**	**538.9**	**555.3**	**619.7**	**661.9**

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

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*	252.8	163.7	174.1	238.1	269.1	218.4	201.6	139.4	157.8	140.0	159.0	189.9	192.0
Oxbow	HCC	108.6	75.0	76.6	98.0	111.1	90.0	84.9	63.3	73.4	63.6	69.7	79.0	82.8
Hells Canyon	HCC	214.0	149.2	156.6	199.5	228.2	181.0	166.9	124.6	143.7	126.0	138.0	156.4	165.3
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	5.7	29.3	68.7	78.4	70.1	48.0	26.1	9.9	0.0	0.0	28.0
Bliss	ROR	34.3	34.4	33.4	31.7	37.1	36.8	33.7	31.9	34.9	37.1	35.2	34.7	34.6
C.J. Strike	ROR	43.5	43.0	43.3	39.8	43.4	39.3	33.6	32.5	40.9	46.3	44.6	44.0	41.2
Cascade	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	21.5	21.8	20.3	19.4	24.7	24.9	21.6	19.5	21.8	23.9	22.1	21.9	22.0
Milner	ROR	5.1	5.0	2.0	0.0	11.5	11.9	6.7	0.0	0.0	0.0	1.8	3.1	3.9
Shoshone Falls	ROR	12.0	12.0	10.0	4.7	20.0	22.0	14.0	6.8	6.9	9.2	11.1	12.0	11.7
Swan Falls	ROR	14.7	14.6	14.7	13.8	14.7	14.0	11.9	11.3	13.5	15.2	15.0	14.8	14.0
Twin Falls	ROR	8.7	8.4	6.2	0.0	14.7	16.3	10.5	0.0	0.0	5.3	7.1	7.6	7.1
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	12.8	13.2	12.2	11.5	15.5	15.5	13.0	11.5	13.0	14.5	13.1	13.1	13.2
Upper Salmon 3&4	ROR	12.1	12.5	11.6	11.0	14.5	14.5	12.3	11.1	12.4	13.6	12.4	12.4	12.5
HCC Total		**575.4**	**387.9**	**407.3**	**535.6**	**608.4**	**489.4**	**453.4**	**327.3**	**374.9**	**329.6**	**366.7**	**425.3**	**440.1**
ROR Total		**191.8**	**191.9**	**187.1**	**187.8**	**294.0**	**304.4**	**260.3**	**209.0**	**205.0**	**204.1**	**187.7**	**190.8**	**217.8**
Total		**767.2**	**579.8**	**594.4**	**723.4**	**902.3**	**793.8**	**713.7**	**536.3**	**579.9**	**533.7**	**554.4**	**616.1**	**657.9**

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

Hydro Modeling Results (PDR 580) (continued)

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*	251.9	164.1	171.9	237.5	268.6	217.8	201.0	138.9	157.3	138.9	159.3	189.2	191.4
Oxbow	HCC	108.3	75.2	75.6	97.8	110.9	89.8	84.6	63.0	73.1	63.0	69.8	78.7	82.5
Hells Canyon	HCC	213.4	149.7	154.9	199.0	227.8	180.5	166.4	124.1	143.2	124.9	138.2	155.7	164.8
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	5.7	29.4	68.8	78.3	70.2	48.0	26.2	10.0	0.0	0.0	28.0
Bliss	ROR	34.1	34.2	33.2	31.5	36.6	36.3	33.5	31.8	34.8	37.0	35.0	34.4	34.4
C.J. Strike	ROR	43.3	42.7	42.8	39.5	43.1	39.1	33.4	32.2	40.7	46.1	44.4	43.8	40.9
Cascade	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	21.3	21.6	20.2	19.3	24.2	24.4	21.5	19.4	21.7	23.8	22.0	21.7	21.8
Milner	ROR	5.1	5.0	2.0	0.0	10.6	11.0	6.7	0.0	0.0	0.0	1.8	3.1	3.8
Shoshone Falls	ROR	12.0	12.0	10.0	4.7	20.0	22.0	14.0	6.8	6.9	9.2	11.1	12.0	11.7
Swan Falls	ROR	14.6	14.6	14.6	13.7	14.6	13.9	11.8	11.2	13.5	15.2	14.9	14.7	13.9
Twin Falls	ROR	8.6	8.3	6.1	0.0	13.8	15.3	10.5	0.0	0.0	5.3	7.1	7.5	6.9
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	12.7	13.0	12.0	11.4	15.2	15.1	12.9	11.4	13.0	14.4	13.0	12.9	13.1
Upper Salmon 3&4	ROR	12.0	12.4	11.5	10.9	14.2	14.1	12.2	11.0	12.3	13.5	12.4	12.3	12.4
HCC Total		**573.6**	**389.0**	**402.4**	**534.3**	**607.3**	**488.1**	**452.0**	**326.0**	**373.5**	**326.8**	**367.3**	**423.6**	**438.7**
ROR Total		**190.8**	**190.8**	**185.8**	**187.0**	**290.2**	**300.3**	**259.6**	**208.2**	**204.6**	**203.6**	**187.0**	**189.6**	**216.5**
Total		**764.4**	**579.8**	**588.2**	**721.3**	**897.5**	**788.4**	**711.6**	**534.2**	**578.1**	**530.4**	**554.3**	**613.2**	**655.1**

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

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*	251.3	164.5	170.3	237.0	268.1	217.4	200.6	138.6	156.9	138.2	159.3	188.7	190.9
Oxbow	HCC	108.0	75.4	74.9	97.6	110.7	89.6	84.5	62.9	73.0	62.7	69.8	78.5	82.3
Hells Canyon	HCC	212.8	150.1	153.6	198.6	227.5	180.2	166.1	123.8	142.9	124.3	138.2	155.4	164.5
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	5.7	29.4	68.8	78.2	70.1	48.1	26.2	10.1	0.0	0.0	28.1
Bliss	ROR	34.0	34.1	33.1	31.4	36.2	35.9	33.4	31.7	34.7	36.9	34.9	34.2	34.2
C.J. Strike	ROR	43.2	42.5	42.6	39.3	42.8	39.0	33.2	32.1	40.6	45.9	44.2	43.7	40.8
Cascade	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	21.2	21.5	20.1	19.2	23.9	24.1	21.4	19.3	21.6	23.7	21.9	21.7	21.6
Milner	ROR	5.1	4.7	2.0	0.0	10.0	10.4	6.7	0.0	0.0	0.0	1.8	3.0	3.6
Shoshone Falls	ROR	12.0	12.0	10.0	4.7	20.0	22.0	14.0	6.8	6.9	9.2	11.1	12.0	11.7
Swan Falls	ROR	14.6	14.5	14.6	13.7	14.6	13.7	11.6	11.2	13.4	15.1	14.9	14.7	13.9
Twin Falls	ROR	8.6	8.3	6.1	0.0	13.1	14.6	10.3	0.0	0.0	5.3	7.1	7.5	6.7
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	12.6	12.9	12.0	11.3	14.9	14.9	12.8	11.4	12.9	14.4	13.0	12.9	13.0
Upper Salmon 3&4	ROR	12.0	12.3	11.4	10.9	13.9	13.9	12.1	10.9	12.2	13.5	12.3	12.2	12.3
HCC Total		**572.1**	**390.0**	**398.8**	**533.2**	**606.3**	**487.2**	**451.2**	**325.3**	**372.7**	**325.2**	**367.3**	**422.6**	**437.7**
ROR Total		**190.4**	**189.8**	**185.3**	**186.5**	**287.4**	**297.5**	**258.5**	**207.9**	**204.0**	**203.2**	**186.5**	**189.1**	**215.5**
Total		**762.5**	**579.8**	**584.1**	**719.7**	**893.6**	**784.7**	**709.7**	**533.2**	**576.7**	**528.4**	**553.8**	**611.7**	**653.2**

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

Hydro Modeling Results (PDR 580) (continued)

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*	250.9	164.6	169.3	236.7	267.9	217.1	200.4	138.3	156.7	137.7	159.4	188.4	190.6
Oxbow	HCC	107.8	75.5	74.5	97.5	110.6	89.5	84.4	62.8	72.8	62.4	69.8	78.4	82.2
Hells Canyon	HCC	212.5	150.3	152.8	198.4	227.3	179.9	165.9	123.6	142.6	123.7	138.3	155.1	164.2
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	5.7	29.5	68.8	78.2	70.1	48.1	26.3	10.1	0.0	0.0	28.1
Bliss	ROR	33.9	34.0	33.1	31.3	36.0	35.7	33.4	31.6	34.6	36.8	34.9	34.1	34.1
C.J. Strike	ROR	43.1	42.4	42.5	39.2	42.8	38.9	32.9	32.0	40.5	45.8	43.9	43.6	40.6
Cascade	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	21.2	21.4	20.1	19.1	23.7	23.9	21.3	19.2	21.5	23.7	21.8	21.6	21.5
Milner	ROR	5.1	4.7	2.0	0.0	9.6	10.0	6.7	0.0	0.0	0.0	1.8	3.0	3.6
Shoshone Falls	ROR	12.0	12.0	10.0	4.7	20.0	22.0	14.0	6.8	6.9	9.2	11.1	12.0	11.7
Swan Falls	ROR	14.6	14.5	14.5	13.7	14.5	13.6	11.6	11.1	13.4	15.1	14.9	14.6	13.8
Twin Falls	ROR	8.6	8.3	6.1	0.0	12.7	14.2	10.3	0.0	0.0	5.2	7.0	7.5	6.7
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	12.5	12.9	11.9	11.2	14.8	14.7	12.7	11.3	12.8	14.3	12.9	12.8	12.9
Upper Salmon 3&4	ROR	11.9	12.2	11.4	10.8	13.8	13.8	12.1	10.9	12.2	13.4	12.2	12.2	12.2
HCC Total		**571.2**	**390.4**	**396.6**	**532.6**	**605.8**	**486.5**	**450.7**	**324.7**	**372.1**	**323.8**	**367.5**	**421.9**	**437.0**
ROR Total		**190.0**	**189.4**	**185.0**	**186.1**	**285.9**	**295.8**	**258.0**	**207.4**	**203.7**	**202.7**	**185.8**	**188.6**	**214.9**
Total		**761.2**	**579.8**	**581.6**	**718.7**	**891.6**	**782.3**	**708.7**	**532.1**	**575.7**	**526.5**	**553.3**	**610.5**	**651.8**

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

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*	250.6	164.7	168.7	236.5	267.7	217.0	200.2	138.1	156.4	137.5	159.3	181.1	189.8
Oxbow	HCC	107.7	75.6	74.3	97.4	110.5	89.4	84.3	62.7	72.7	62.3	69.8	78.3	82.1
Hells Canyon	HCC	212.2	150.5	152.3	198.2	227.1	179.8	165.7	123.4	142.4	123.6	138.1	154.6	164.0
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	5.7	29.6	68.9	78.3	70.2	48.1	26.3	10.1	0.0	0.0	28.1
Bliss	ROR	33.9	33.9	33.0	31.3	35.8	35.5	33.3	31.5	34.6	36.8	34.8	34.0	34.0
C.J. Strike	ROR	43.0	42.4	42.5	39.1	42.7	38.8	32.8	31.9	40.4	45.7	43.8	43.5	40.6
Cascade	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	21.1	21.3	20.0	19.1	23.5	23.7	21.3	19.2	21.5	23.6	21.8	21.6	21.5
Milner	ROR	5.1	4.7	2.0	0.0	9.3	9.6	6.7	0.0	0.0	0.0	1.8	3.0	3.5
Shoshone Falls	ROR	12.0	12.0	10.0	4.7	20.0	22.0	14.0	6.8	6.9	9.2	11.1	12.0	11.7
Swan Falls	ROR	14.5	14.5	14.5	13.6	14.5	13.6	11.6	11.1	13.4	15.1	14.8	14.6	13.8
Twin Falls	ROR	8.5	8.3	6.1	0.0	12.3	13.8	10.3	0.0	0.0	5.2	6.9	7.5	6.6
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	12.5	12.8	11.9	11.2	14.6	14.6	12.7	11.3	12.8	14.3	12.9	12.8	12.9
Upper Salmon 3&4	ROR	11.9	12.2	11.4	10.8	13.7	13.7	12.1	10.9	12.2	13.4	12.2	12.1	12.2
HCC Total		**570.5**	**390.8**	**395.3**	**532.1**	**605.3**	**486.2**	**450.2**	**324.2**	**371.5**	**323.4**	**367.2**	**414.0**	**435.9**
ROR Total		**189.6**	**189.1**	**184.8**	**186.0**	**284.5**	**294.4**	**257.9**	**207.2**	**203.6**	**202.5**	**185.4**	**188.3**	**214.4**
Total		**760.1**	**579.9**	**580.1**	**718.1**	**889.7**	**780.6**	**708.1**	**531.4**	**575.1**	**525.9**	**552.6**	**602.3**	**650.3**

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

Hydro Modeling Results (PDR 580) (continued)

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*	250.5	164.8	168.4	236.4	267.6	216.9	200.1	138.1	156.4	137.4	159.1	181.0	189.7
Oxbow	HCC	107.7	75.6	74.2	97.4	110.5	89.4	84.2	62.7	72.7	62.3	69.7	78.3	82.1
Hells Canyon	HCC	212.2	150.5	152.1	198.2	227.0	179.7	165.6	123.4	142.4	123.5	138.0	154.5	163.9
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	5.7	29.6	68.9	78.3	70.2	48.1	26.3	10.1	0.0	0.0	28.1
Bliss	ROR	33.9	33.9	33.0	31.3	35.8	35.4	33.3	31.5	34.5	36.7	34.8	34.0	34.0
C.J. Strike	ROR	43.0	42.4	42.4	39.0	42.7	38.8	32.8	31.9	40.4	45.7	43.8	43.5	40.5
Cascade	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	21.1	21.3	20.0	19.0	23.5	23.7	21.3	19.2	21.5	23.6	21.7	21.5	21.5
Milner	ROR	5.1	4.7	2.0	0.0	9.2	9.5	6.7	0.0	0.0	0.0	1.8	3.0	3.5
Shoshone Falls	ROR	12.0	12.0	10.0	4.7	20.0	22.0	14.0	6.8	6.9	9.2	11.1	12.0	11.7
Swan Falls	ROR	14.5	14.5	14.5	13.6	14.5	13.5	11.6	11.1	13.4	15.1	14.8	14.6	13.8
Twin Falls	ROR	8.5	8.3	6.1	0.0	12.2	13.8	10.3	0.0	0.0	5.2	6.9	7.5	6.6
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	12.5	12.8	11.9	11.2	14.6	14.6	12.7	11.3	12.8	14.2	12.9	12.8	12.9
Upper Salmon 3&4	ROR	11.9	12.1	11.4	10.8	13.7	13.7	12.1	10.8	12.1	13.4	12.2	12.1	12.2
HCC Total		**570.4**	**390.9**	**394.7**	**532.0**	**605.1**	**486.0**	**449.9**	**324.2**	**371.4**	**323.2**	**366.8**	**413.8**	**435.7**
ROR Total		**189.6**	**189.0**	**184.7**	**185.8**	**284.3**	**294.1**	**257.9**	**207.1**	**203.4**	**202.3**	**185.3**	**188.2**	**214.3**
Total		**760.0**	**579.9**	**579.4**	**717.8**	**889.4**	**780.1**	**707.8**	**531.3**	**574.8**	**525.5**	**552.1**	**602.0**	**650.0**

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

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*	250.5	164.8	168.4	236.4	267.6	216.9	200.1	138.1	156.4	137.4	159.1	181.0	189.7
Oxbow	HCC	107.7	75.6	74.2	97.4	110.5	89.4	84.2	62.7	72.7	62.3	69.7	78.3	82.1
Hells Canyon	HCC	212.2	150.5	152.1	198.2	227.0	179.7	165.6	123.4	142.4	123.5	138.0	154.5	163.9
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	5.7	29.6	68.9	78.3	70.2	48.1	26.3	10.1	0.0	0.0	28.1
Bliss	ROR	33.9	33.9	33.0	31.3	35.8	35.4	33.3	31.5	34.5	36.7	34.8	34.0	34.0
C.J. Strike	ROR	43.0	42.4	42.4	39.0	42.7	38.8	32.8	31.9	40.4	45.7	43.8	43.5	40.5
Cascade	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	21.1	21.3	20.0	19.0	23.5	23.7	21.3	19.2	21.5	23.6	21.7	21.5	21.5
Milner	ROR	5.1	4.7	2.0	0.0	9.2	9.5	6.7	0.0	0.0	0.0	1.8	3.0	3.5
Shoshone Falls	ROR	12.0	12.0	10.0	4.7	20.0	22.0	14.0	6.8	6.9	9.2	11.1	12.0	11.7
Swan Falls	ROR	14.5	14.5	14.5	13.6	14.5	13.5	11.6	11.1	13.4	15.1	14.8	14.6	13.8
Twin Falls	ROR	8.5	8.3	6.1	0.0	12.2	13.8	10.3	0.0	0.0	5.2	6.9	7.5	6.6
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	12.5	12.8	11.9	11.2	14.6	14.6	12.7	11.3	12.8	14.2	12.9	12.8	12.9
Upper Salmon 3&4	ROR	11.9	12.1	11.4	10.8	13.7	13.7	12.1	10.8	12.1	13.4	12.2	12.1	12.2
HCC Total		**570.4**	**390.9**	**394.7**	**532.0**	**605.1**	**486.0**	**449.9**	**324.2**	**371.4**	**323.2**	**366.8**	**413.8**	**435.7**
ROR Total		**189.6**	**189.0**	**184.7**	**185.8**	**284.3**	**294.1**	**257.9**	**207.1**	**203.4**	**202.3**	**185.3**	**188.2**	**214.3**
Total		**760.0**	**579.9**	**579.4**	**717.8**	**889.4**	**780.1**	**707.8**	**531.3**	**574.8**	**525.5**	**552.1**	**602.0**	**650.0**

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

Hydro Modeling Results (PDR 580) (continued)

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*	250.5	164.8	168.4	236.4	267.6	216.9	200.1	138.1	156.4	137.4	159.1	181.0	189.7
Oxbow	HCC	107.7	75.6	74.2	97.4	110.5	89.4	84.2	62.7	72.7	62.3	69.7	78.3	82.1
Hells Canyon	HCC	212.2	150.5	152.1	198.2	227.0	179.7	165.6	123.4	142.4	123.5	138.0	154.5	163.9
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	5.7	29.6	68.9	78.3	70.2	48.1	26.3	10.1	0.0	0.0	28.1
Bliss	ROR	33.9	33.9	33.0	31.3	35.8	35.4	33.3	31.5	34.5	36.7	34.8	34.0	34.0
C.J. Strike	ROR	43.0	42.4	42.4	39.0	42.7	38.8	32.8	31.9	40.4	45.7	43.8	43.5	40.5
Cascade	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	21.1	21.3	20.0	19.0	23.5	23.7	21.3	19.2	21.5	23.6	21.7	21.5	21.5
Milner	ROR	5.1	4.7	2.0	0.0	9.2	9.5	6.7	0.0	0.0	0.0	1.8	3.0	3.5
Shoshone Falls	ROR	12.0	12.0	10.0	4.7	20.0	22.0	14.0	6.8	6.9	9.2	11.1	12.0	11.7
Swan Falls	ROR	14.5	14.5	14.5	13.6	14.5	13.5	11.6	11.1	13.4	15.1	14.8	14.6	13.8
Twin Falls	ROR	8.5	8.3	6.1	0.0	12.2	13.8	10.3	0.0	0.0	5.2	6.9	7.5	6.6
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	12.5	12.8	11.9	11.2	14.6	14.6	12.7	11.3	12.8	14.2	12.9	12.8	12.9
Upper Salmon 3&4	ROR	11.9	12.1	11.4	10.8	13.7	13.7	12.1	10.8	12.1	13.4	12.2	12.1	12.2
HCC Total		**570.4**	**390.9**	**394.7**	**532.0**	**605.1**	**486.0**	**449.9**	**324.2**	**371.4**	**323.2**	**366.8**	**413.8**	**435.7**
ROR Total		**189.6**	**189.0**	**184.7**	**185.8**	**284.3**	**294.1**	**257.9**	**207.1**	**203.4**	**202.3**	**185.3**	**188.2**	**214.3**
Total		**760.0**	**579.9**	**579.4**	**717.8**	**889.4**	**780.1**	**707.8**	**531.3**	**574.8**	**525.5**	**552.1**	**602.0**	**650.0**

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

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*	250.5	164.8	168.4	236.4	267.6	216.9	200.1	138.1	156.4	137.4	159.1	181.0	189.7
Oxbow	HCC	107.7	75.6	74.2	97.4	110.5	89.4	84.2	62.7	72.7	62.3	69.7	78.3	82.1
Hells Canyon	HCC	212.2	150.5	152.1	198.2	227.0	179.7	165.6	123.4	142.4	123.5	138.0	154.5	163.9
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	5.7	29.6	68.9	78.3	70.2	48.1	26.3	10.1	0.0	0.0	28.1
Bliss	ROR	33.9	33.9	33.0	31.3	35.8	35.4	33.3	31.5	34.5	36.7	34.8	34.0	34.0
C.J. Strike	ROR	43.0	42.4	42.4	39.0	42.7	38.8	32.8	31.9	40.4	45.7	43.8	43.5	40.5
Cascade	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	21.1	21.3	20.0	19.0	23.5	23.7	21.3	19.2	21.5	23.6	21.7	21.5	21.5
Milner	ROR	5.1	4.7	2.0	0.0	9.2	9.5	6.7	0.0	0.0	0.0	1.8	3.0	3.5
Shoshone Falls	ROR	12.0	12.0	10.0	4.7	20.0	22.0	14.0	6.8	6.9	9.2	11.1	12.0	11.7
Swan Falls	ROR	14.5	14.5	14.5	13.6	14.5	13.5	11.6	11.1	13.4	15.1	14.8	14.6	13.8
Twin Falls	ROR	8.5	8.3	6.1	0.0	12.2	13.8	10.3	0.0	0.0	5.2	6.9	7.5	6.6
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	12.5	12.8	11.9	11.2	14.6	14.6	12.7	11.3	12.8	14.2	12.9	12.8	12.9
Upper Salmon 3&4	ROR	11.9	12.1	11.4	10.8	13.7	13.7	12.1	10.8	12.1	13.4	12.2	12.1	12.2
HCC Total		**570.4**	**390.9**	**394.7**	**532.0**	**605.1**	**486.0**	**449.9**	**324.2**	**371.4**	**323.2**	**366.8**	**413.8**	**435.7**
ROR Total		**189.6**	**189.0**	**184.7**	**185.8**	**284.3**	**294.1**	**257.9**	**207.1**	**203.4**	**202.3**	**185.3**	**188.2**	**214.3**
Total		**760.0**	**579.9**	**579.4**	**717.8**	**889.4**	**780.1**	**707.8**	**531.3**	**574.8**	**525.5**	**552.1**	**602.0**	**650.0**

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

Hydro Modeling Results (PDR 580) (continued)

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*	250.5	164.8	168.4	236.4	267.6	216.9	200.1	138.1	156.4	137.4	159.1	181.0	189.7
Oxbow	HCC	107.7	75.6	74.2	97.4	110.5	89.4	84.2	62.7	72.7	62.3	69.7	78.3	82.1
Hells Canyon	HCC	212.2	150.5	152.1	198.2	227.0	179.7	165.6	123.4	142.4	123.5	138.0	154.5	163.9
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	5.7	29.6	68.9	78.3	70.2	48.1	26.3	10.1	0.0	0.0	28.1
Bliss	ROR	33.9	33.9	33.0	31.3	35.8	35.4	33.3	31.5	34.5	36.7	34.8	34.0	34.0
C.J. Strike	ROR	43.0	42.4	42.4	39.0	42.7	38.8	32.8	31.9	40.4	45.7	43.8	43.5	40.5
Cascade	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	21.1	21.3	20.0	19.0	23.5	23.7	21.3	19.2	21.5	23.6	21.7	21.5	21.5
Milner	ROR	5.1	4.7	2.0	0.0	9.2	9.5	6.7	0.0	0.0	0.0	1.8	3.0	3.5
Shoshone Falls	ROR	12.0	12.0	10.0	4.7	20.0	22.0	14.0	6.8	6.9	9.2	11.1	12.0	11.7
Swan Falls	ROR	14.5	14.5	14.5	13.6	14.5	13.5	11.6	11.1	13.4	15.1	14.8	14.6	13.8
Twin Falls	ROR	8.5	8.3	6.1	0.0	12.2	13.8	10.3	0.0	0.0	5.2	6.9	7.5	6.6
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	12.5	12.8	11.9	11.2	14.6	14.6	12.7	11.3	12.8	14.2	12.9	12.8	12.9
Upper Salmon 3&4	ROR	11.9	12.1	11.4	10.8	13.7	13.7	12.1	10.8	12.1	13.4	12.2	12.1	12.2
HCC Total		**570.4**	**390.9**	**394.7**	**532.0**	**605.1**	**486.0**	**449.9**	**324.2**	**371.4**	**323.2**	**366.8**	**413.8**	**435.7**
ROR Total		**189.6**	**189.0**	**184.7**	**185.8**	**284.3**	**294.1**	**257.9**	**207.1**	**203.4**	**202.3**	**185.3**	**188.2**	**214.3**
Total		**760.0**	**579.9**	**579.4**	**717.8**	**889.4**	**780.1**	**707.8**	**531.3**	**574.8**	**525.5**	**552.1**	**602.0**	**650.0**

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

aMW 90th Percentile Water, 70th Percentile Load

Resource	Type	1/2028	2/2084	3/2028	4/2028	5/2028	6/2028	7/2028	8/2028	9/2028	10/2028	11/2028	12/2028	aMW
Brownlee	HCC*	250.5	164.8	168.4	236.4	267.6	216.9	200.1	138.1	156.4	137.4	159.1	181.0	189.7
Oxbow	HCC	107.7	75.6	74.2	97.4	110.5	89.4	84.2	62.7	72.7	62.3	69.7	78.3	82.1
Hells Canyon	HCC	212.2	150.5	152.1	198.2	227.0	179.7	165.6	123.4	142.4	123.5	138.0	154.5	163.9
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	5.7	29.6	68.9	78.3	70.2	48.1	26.3	10.1	0.0	0.0	28.1
Bliss	ROR	33.9	33.9	33.0	31.3	35.8	35.4	33.3	31.5	34.5	36.7	34.8	34.0	34.0
C.J. Strike	ROR	43.0	42.4	42.4	39.0	42.7	38.8	32.8	31.9	40.4	45.7	43.8	43.5	40.5
Cascade	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	21.1	21.3	20.0	19.0	23.5	23.7	21.3	19.2	21.5	23.6	21.7	21.5	21.5
Milner	ROR	5.1	4.7	2.0	0.0	9.2	9.5	6.7	0.0	0.0	0.0	1.8	3.0	3.5
Shoshone Falls	ROR	12.0	12.0	10.0	4.7	20.0	22.0	14.0	6.8	6.9	9.2	11.1	12.0	11.7
Swan Falls	ROR	14.5	14.5	14.5	13.6	14.5	13.5	11.6	11.1	13.4	15.1	14.8	14.6	13.8
Twin Falls	ROR	8.5	8.3	6.1	0.0	12.2	13.8	10.3	0.0	0.0	5.2	6.9	7.5	6.6
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	12.5	12.8	11.9	11.2	14.6	14.6	12.7	11.3	12.8	14.2	12.9	12.8	12.9
Upper Salmon 3&4	ROR	11.9	12.1	11.4	10.8	13.7	13.7	12.1	10.8	12.1	13.4	12.2	12.1	12.2
HCC Total		**570.4**	**390.9**	**394.7**	**532.0**	**605.1**	**486.0**	**449.9**	**324.2**	**371.4**	**323.2**	**366.8**	**413.8**	**435.7**
ROR Total		**189.6**	**189.0**	**184.7**	**185.8**	**284.3**	**294.1**	**257.9**	**207.1**	**203.4**	**202.3**	**185.3**	**188.2**	**214.3**
Total		**760.0**	**579.9**	**579.4**	**717.8**	**889.4**	**780.1**	**707.8**	**531.3**	**574.8**	**525.5**	**552.1**	**602.0**	**650.0**

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

Hydro Modeling Results (PDR 580) (continued)

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*	250.5	164.8	168.4	236.4	267.6	216.9	200.1	138.1	156.4	137.4	159.1	181.0	189.7
Oxbow	HCC	107.7	75.6	74.2	97.4	110.5	89.4	84.2	62.7	72.7	62.3	69.7	78.3	82.1
Hells Canyon	HCC	212.2	150.5	152.1	198.2	227.0	179.7	165.6	123.4	142.4	123.5	138.0	154.5	163.9
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	5.7	29.6	68.9	78.3	70.2	48.1	26.3	10.1	0.0	0.0	28.1
Bliss	ROR	33.9	33.9	33.0	31.3	35.8	35.4	33.3	31.5	34.5	36.7	34.8	34.0	34.0
C.J. Strike	ROR	43.0	42.4	42.4	39.0	42.7	38.8	32.8	31.9	40.4	45.7	43.8	43.5	40.5
Cascade	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	21.1	21.3	20.0	19.0	23.5	23.7	21.3	19.2	21.5	23.6	21.7	21.5	21.5
Milner	ROR	5.1	4.7	2.0	0.0	9.2	9.5	6.7	0.0	0.0	0.0	1.8	3.0	3.5
Shoshone Falls	ROR	12.0	12.0	10.0	4.7	20.0	22.0	14.0	6.8	6.9	9.2	11.1	12.0	11.7
Swan Falls	ROR	14.5	14.5	14.5	13.6	14.5	13.5	11.6	11.1	13.4	15.1	14.8	14.6	13.8
Twin Falls	ROR	8.5	8.3	6.1	0.0	12.2	13.8	10.3	0.0	0.0	5.2	6.9	7.5	6.6
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	12.5	12.8	11.9	11.2	14.6	14.6	12.7	11.3	12.8	14.2	12.9	12.8	12.9
Upper Salmon 3&4	ROR	11.9	12.1	11.4	10.8	13.7	13.7	12.1	10.8	12.1	13.4	12.2	12.1	12.2
HCC Total		**570.4**	**390.9**	**394.7**	**532.0**	**605.1**	**486.0**	**449.9**	**324.2**	**371.4**	**323.2**	**366.8**	**413.8**	**435.7**
ROR Total		**189.6**	**189.0**	**184.7**	**185.8**	**284.3**	**294.1**	**257.9**	**207.1**	**203.4**	**202.3**	**185.3**	**188.2**	**214.3**
Total		**760.0**	**579.9**	**579.4**	**717.8**	**889.4**	**780.1**	**707.8**	**531.3**	**574.8**	**525.5**	**552.1**	**602.0**	**650.0**

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

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*	250.5	164.8	168.4	236.4	267.6	216.9	200.1	138.1	156.4	137.4	159.1	181.0	189.7
Oxbow	HCC	107.7	75.6	74.2	97.4	110.5	89.4	84.2	62.7	72.7	62.3	69.7	78.3	82.1
Hells Canyon	HCC	212.2	150.5	152.1	198.2	227.0	179.7	165.6	123.4	142.4	123.5	138.0	154.5	163.9
1000 Springs	ROR**	6.0	5.8	5.7	5.3	5.6	6.0	5.8	6.0	6.4	6.4	5.4	6.1	5.9
American Falls	ROR	0.0	0.0	5.7	29.6	68.9	78.3	70.2	48.1	26.3	10.1	0.0	0.0	28.1
Bliss	ROR	33.9	33.9	33.0	31.3	35.8	35.4	33.3	31.5	34.5	36.7	34.8	34.0	34.0
C.J. Strike	ROR	43.0	42.4	42.4	39.0	42.7	38.8	32.8	31.9	40.4	45.7	43.8	43.5	40.5
Cascade	ROR	1.4	1.4	1.4	1.3	1.5	4.2	7.0	9.8	7.2	1.5	1.3	1.4	3.3
Clear Lake	ROR	1.7	1.7	1.7	1.4	1.6	1.4	1.4	1.6	1.6	1.7	1.6	1.7	1.6
Lower Malad	ROR	11.4	11.5	12.1	11.7	12.9	11.9	11.8	12.1	13.0	12.9	10.6	11.5	12.0
Lowe Salmon	ROR	21.1	21.3	20.0	19.0	23.5	23.7	21.3	19.2	21.5	23.6	21.7	21.5	21.5
Milner	ROR	5.1	4.7	2.0	0.0	9.2	9.5	6.7	0.0	0.0	0.0	1.8	3.0	3.5
Shoshone Falls	ROR	12.0	12.0	10.0	4.7	20.0	22.0	14.0	6.8	6.9	9.2	11.1	12.0	11.7
Swan Falls	ROR	14.5	14.5	14.5	13.6	14.5	13.5	11.6	11.1	13.4	15.1	14.8	14.6	13.8
Twin Falls	ROR	8.5	8.3	6.1	0.0	12.2	13.8	10.3	0.0	0.0	5.2	6.9	7.5	6.6
Upper Malad	ROR	6.6	6.7	6.9	6.8	7.6	7.2	6.8	6.9	7.2	6.6	6.3	6.5	6.8
Upper Salmon 1&2	ROR	12.5	12.8	11.9	11.2	14.6	14.6	12.7	11.3	12.8	14.2	12.9	12.8	12.9
Upper Salmon 3&4	ROR	11.9	12.1	11.4	10.8	13.7	13.7	12.1	10.8	12.1	13.4	12.2	12.1	12.2
HCC Total		**570.4**	**390.9**	**394.7**	**532.0**	**605.1**	**486.0**	**449.9**	**324.2**	**371.4**	**323.2**	**366.8**	**413.8**	**435.7**
ROR Total		**189.6**	**189.0**	**184.7**	**185.8**	**284.3**	**294.1**	**257.9**	**207.1**	**203.4**	**202.3**	**185.3**	**188.2**	**214.3**
Total		**760.0**	**579.9**	**579.4**	**717.8**	**889.4**	**780.1**	**707.8**	**531.3**	**574.8**	**525.5**	**552.1**	**602.0**	**650.0**

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

PORTFOLIO ANALYSIS, RESULTS, AND SUPPORTING DOCUMENTATION

Initial Resource Portfolios (2011–2020)

1-1 Sun & Steam		1-2 Solar		1-3 B2H		1-4 SCCT		1-5 CCCT	
2011		2011		2011		2011		2011	
2012	Solar PV-1	2012		2012		2012		2012	
2013	Solar PV-5	2013		2013		2013		2013	
2014	CHP-75	2014	Solar PV-5	2014		2014		2014	
2015	Solar PV-30	2015	Solar PT-100	2015	Eastside Purchase	2015	SCCT Frame	2015	CCCT
2016	CHP-100	2016	Solar PT-100	2016	B2H-450	2016		2016	
2017	Geothermal-52	2017	Solar PT-125	2017		2017	SCCT Frame	2017	
2018	Solar PT-125	2018	Solar PV-50	2018		2018		2018	
2019	Solar PV-30	2019	Solar PT-100	2019		2019	SCCT S Aero-94	2019	SCCT Frame
2020	Solar PT-75	2020	Solar PV-50	2020		2020		2020	
MW	**493**	**MW**	**530**	**MW**	**450**	**MW**	**434**	**MW**	**470**

1-6 CHP		1-7 Balanced		1-8 Pumped Storage		1-9 Distributed Gen	
2011		2011		2011		2011	
2012		2012		2012		2012	Dist Gen-10
2013		2013		2013		2013	
2014		2014		2014		2014	
2015	CHP-100	2015	CHP-100	2015	Pump St-80	2015	SCCT Frame
2016	SCCT Frame	2016	SCCT Frame	2016	SCCT Frame	2016	
2017		2017	Solar PV-10	2017		2017	SCCT Frame
2018	CHP-50	2018	Solar PT-100	2018	Pump St-80	2018	
2019	CHP-50	2019	Geothermal-26	2019	SCCT S Aero-47	2019	SCCT S Aero-94
2020	SCCT S Aero-94	2020	SCCT S Aero-47	2020	Pump St-80	2020	
MW	**464**	**MW**	**453**	**MW**	**457**	**MW**	**444**

Initial Resource Portfolios (2021–2030)

2-1 Nuclear		2-2 IGCC		2-3 SCCT/Wind		2-4 CCCT/Wind		2-5 Hydro/CHP	
2021	Solar PT-100	2021	Geothermal-52	2021	SCCT S Aero-141	2021	CCCT	2021	Hydro Sm-60
2022	Pump St-50	2022	SCCT Frame	2022	Wind-100	2022	Wind-150	2022	CHP-75
2023	Solar PT-100	2023		2023	SCCT S Aero-141	2023		2023	Pump St-80
2024	Nuclear	2024	CHP-50	2024	Wind-100	2024		2024	CHP-100
2025		2025	Solar PT-75	2025	SCCT S Aero-94	2025		2025	Hydro-40
2026		2026	IGCC w/CS	2026	Wind-100	2026	CCCT	2026	Pump St-80
2027		2027		2027	SCCT S Aero-141	2027		2027	Hydro Sm-100
2028	Nuclear	2028	Solar PT-75	2028	SCCT S Aero-141	2028	Wind-150	2028	SCCT S Aero-141
2029	Pump St-50	2029		2029	SCCT S Aero-94	2029	SCCT Frame	2029	Hydro Sm-80
2030		2030		2030		2030		2030	Hydro Sm-60
MW	**800**	**MW**	**802**	**MW**	**1,052**	**MW**	**1,070**	**MW**	**816**

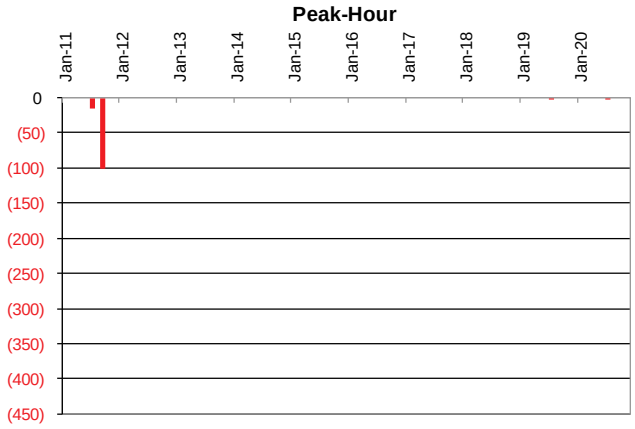
2-6 Balanced 1		2-7 Balanced 2		2-8 PNW Transmission		2-9 E/S Transmission		2-10 Renewable	
2021	Geothermal-52	2021	Geothermal-52	2021	Geothermal-52	2021	Geothermal-52	2021	CHP-75
2022	SCCT Frame	2022	CHP-75	2022	PNW Purchase	2022	E/S Purchase	2022	Pump St-80
2023		2023	SCCT Frame	2023		2023		2023	Solar PT-150
2024	Solar PT-50	2024		2024		2024		2024	
2025	CCCT	2025	Geothermal-52	2025		2025		2025	CHP-75
2026		2026	CHP-75	2026		2026		2026	Solar PT-150
2027		2027	Hydro Sm-60	2027	Solar PV-20	2027	Solar PV-20	2027	Solar PV-150
2028	Hydro Sm-60	2028	CCCT	2028	Geothermal-52	2028	Geothermal-52	2028	Geothermal-52
2029	SCCT Frame	2029		2029	SCCT Frame	2029	SCCT Frame	2029	Hydro Sm-100
2030		2030		2030		2030		2030	Solar PV-200
MW	**802**	**MW**	**784**	**MW**	**794**	**MW**	**794**	**MW**	**1,032**

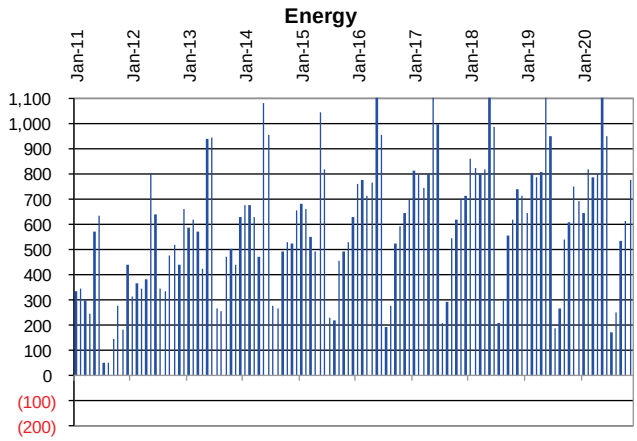
Detailed Resource Portfolio Design Sheets

1-1 Sun and Steam

						Cumm.							Capital Cost	
Year	Resource	MW	E	P	Type	E	P	REC Req.	Existing RECs	New RECs	Total RECs	REC Position	$/kW	Total $
2011		0	0	0		0	0	–	44	0	44	44		
2012	Solar PV-1	1	0	1	R*	0	1	26	69	0	70	44	$3,750	$3,750,000
2013	Solar PV-5	5	1	3	R	1	3	27	70	1	71	43	$3,750	$18,750,000
2014	CHP-75	75	70	75		71	78	57	78	1	79	21	$1,888	$141,600,000
2015	Solar PV-30	30	4	17	R	75	95	60	104	5	109	49	$3,750	$112,500,000
2016	CHP-100	100	93	100		168	195	62	104	5	109	48	$1,888	$188,800,000
2017	Geothermal-52	52	48	52	R	216	247	95	113	53	166	71	$6,385	$332,020,000
2018	Solar PT-125	125	35	114	R	251	361	97	119	88	207	109	$3,220	402,500,000
2019	Solar PV-30	30	4	17	R	255	377	133	128	92	220	87	$3,750	$112,500,000
2020	Solar PT-75	75	21	68	R	276	445	136	129	113	242	106	$3,220	$241,500,000
	Total	**193**	**276**	**445**										**$1,553,920,000**

* R=Renewable Resource

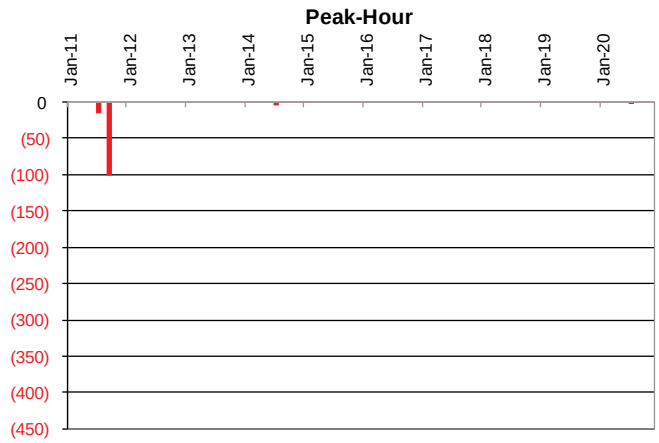


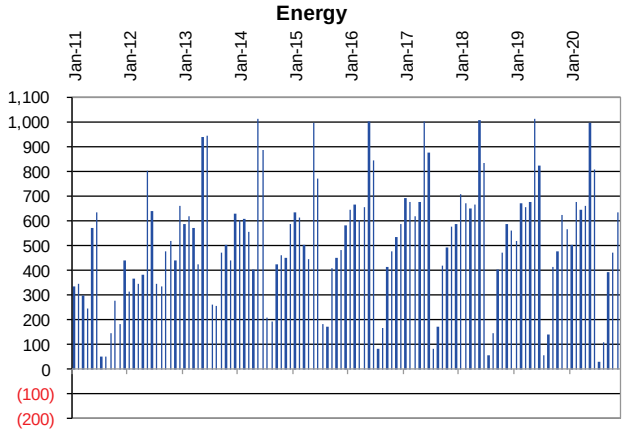


1-2 Solar

Year	Resource	MW	E	P	Type	Cumm. E	Cumm. P	REC Req.	Existing RECs	New RECs	Total RECs	REC Position	Capital Cost $/kW	Capital Cost Total $
2011		0	0	0		0	0	–	44	0	44	44		
2012		0	0	0		0	0	26	69	0	69	43		
2013		0	0	0		0	0	27	70	0	70	43		
2014	Solar PV-5	5	1	3	R	1	3	57	78	1	78	21	$3,750	$18,750,000
2015	Solar PT-100	100	28	91	R	29	94	60	104	29	132	73	$3,220	$322,000,000
2016	Solar PT-100	100	28	91	R	57	185	62	104	57	161	99	$3,220	$322,000,000
2017	Solar PT-125	125	35	114	R	92	299	95	113	92	205	110	$3,220	$402,500,000
2018	Solar PV-50	50	7	28	R	99	326	97	119	99	217	120	$3,750	$187,500,000
2019	Solar PT-100	100	28	91	R	127	417	133	128	127	255	122	$3,220	$322,000,000
2020	Solar PV-50	50	7	28	R	134	445	136	129	134	263	127	$3,750	$187,500,000
	Total	**530**	**134**	**445**										**$1,762,250,000**

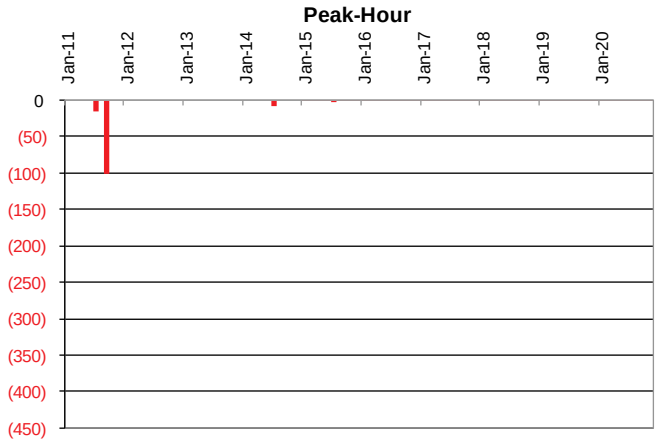
* R=Renewable Resource

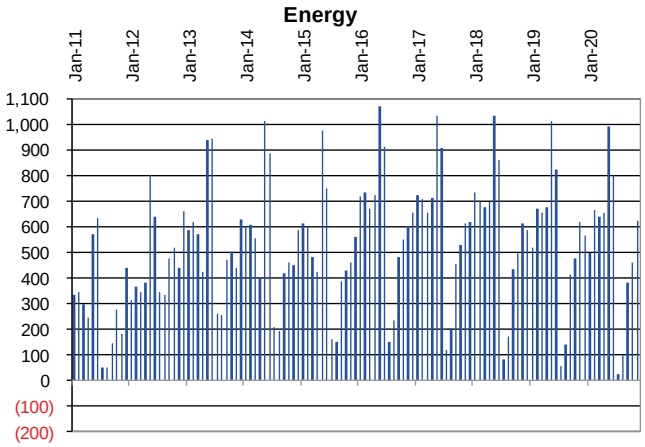




1-3 Boardman to Hemingway

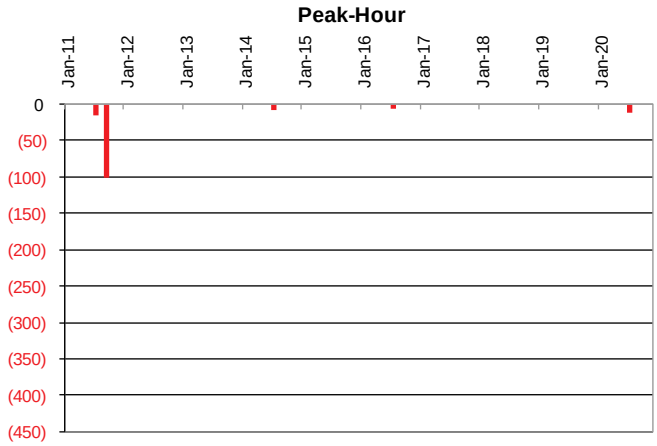
Year	Resource	MW	E	P	Type	Cumm. E	Cumm. P	REC Req.	Existing RECs	New RECs	Total RECs	REC Position	Capital Cost $/kW	Capital Cost Total $
2011		0	0	0		0	0	–	44	0	44	44		
2012		0	0	0		0	0	26	69	0	69	43		
2013		0	0	0		0	0	27	70	0	70	43		
2014		0	0	0		0	0	57	78	0	78	21		
2015	Eastside Purchase	83	8	83		8	83	60	104	0	104	44	$–	$–
2016	B2H-450	367	117	367		126	450	62	104	0	104	43	$381	$247,214,209
2017		0	0	0		126	450	95	113	0	113	18		
2018		0	0	0		126	450	97	119	0	119	21		
2019		0	0	0		126	450	133	128	0	128	(5)		
2020		0	0	0		126	450	136	129	0	129	(7)		
	Total	**450**	**126**	**450**										**$247,214,209**

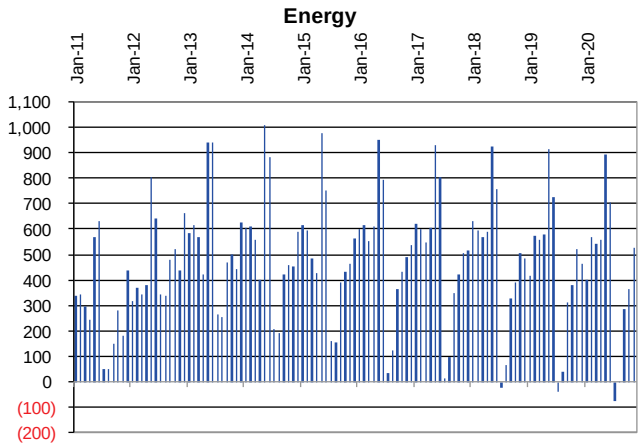




1-4 SCCT

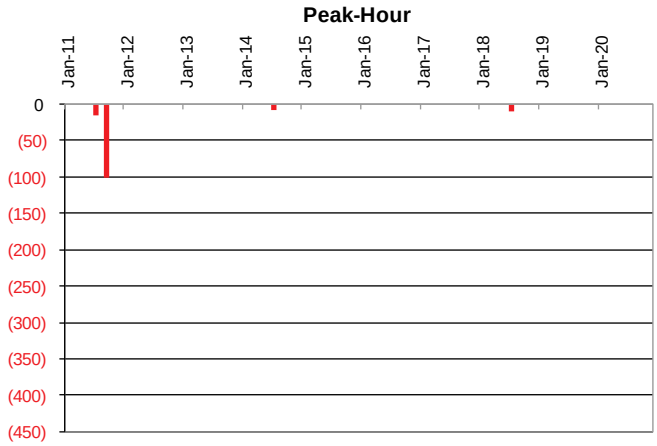
						Cumm.							Capital Cost	
Year	Resource	MW	E	P	Type	E	P	REC Req.	Existing RECs	New RECs	Total RECs	REC Position	$/kW	Total $
2011		0	0	0		0	0	–	44	0	44	44		
2012		0	0	0		0	0	26	69	0	69	43		
2013		0	0	0		0	0	27	70	0	70	43		
2014		0	0	0		0	0	57	78	0	78	21		
2015	SCCT Frame	170	10	170		10	170	60	104	0	104	44	$746	$126,820,000
2016		0	0	0		10	170	62	104	0	104	43		
2017	SCCT Frame	170	10	170		20	340	95	113	0	113	18	$746	$126,820,000
2018		0	0	0		20	340	97	119	0	119	21		
2019	SCCT S Aero-94	94	8	94		28	434	133	128	0	128	(5)	$1,063	$99,922,000
2020		0	0	0		28	434	136	129	0	129	(7)		
	Total	**434**	**28**	**434**										**$353,562,000**

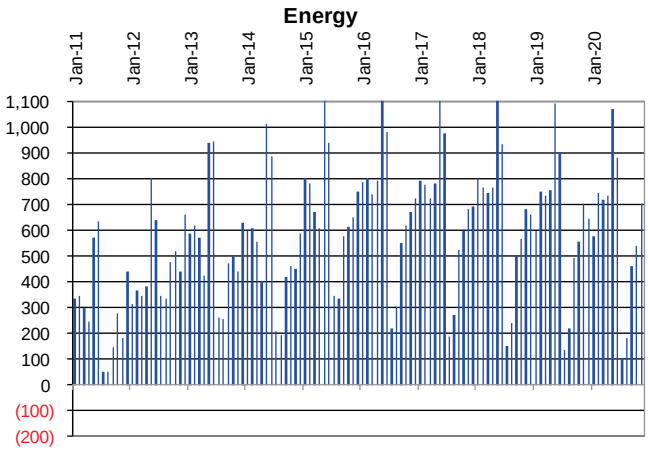




1-5 CCCT

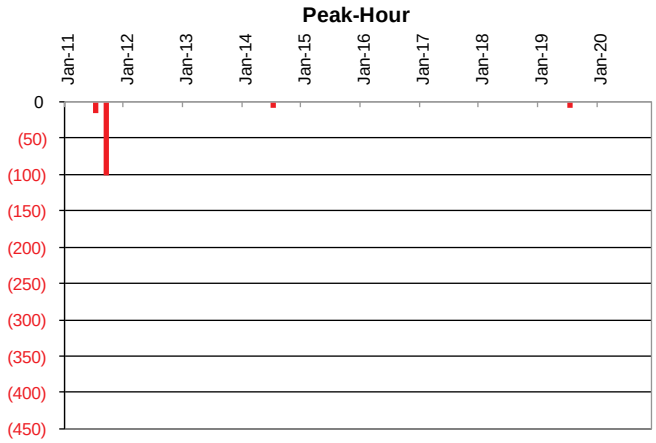
Year	Resource	MW	E	P	Type	Cumm. E	Cumm. P	REC Req.	Existing RECs	New RECs	Total RECs	REC Position	Capital Cost $/kW	Capital Cost Total $
2011		0	0	0		0	0	–	44	0	44	44		
2012		0	0	0		0	0	26	69	0	69	43		
2013		0	0	0		0	0	27	70	0	70	43		
2014		0	0	0		0	0	57	78	0	78	21		
2015	CCCT	300	195	300		195	300	60	104	0	104	44	$1,216	$364,800,000
2016		0	0	0		195	300	62	104	0	104	43		
2017		0	0	0		195	300	95	113	0	113	18		
2018		0	0	0		195	300	97	119	0	119	21		
2019	SCCT Frame	170	10	170		205	470	133	128	0	128	(5)	$746	$126,820,000
2020		0	0	0		205	470	136	129	0	129	(7)		
	Total	**470**	**205**	**470**										**$491,620,000**

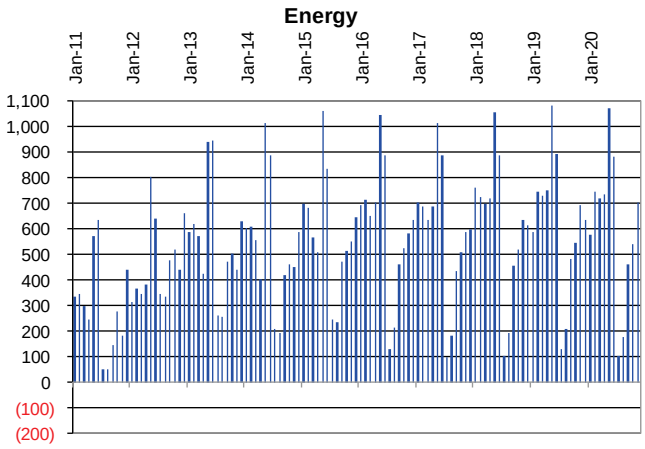




1-6 CHP

Year	Resource	MW	E	P	Type	Cumm. E	Cumm. P	REC Req.	Existing RECs	New RECs	Total RECs	REC Position	Capital Cost $/kW	Capital Cost Total $
2011		0	0	0		0	0	–	44	0	44	44		
2012		0	0	0		0	0	26	69	0	69	43		
2013		0	0	0		0	0	27	70	0	70	43		
2014		0	0	0		0	0	57	78	0	78	21		
2015	CHP-100	100	93	100		93	100	60	104	0	104	44	$1,888	$188,800,000
2016	SCCT Frame	170	10	170		103	270	62	104	0	104	43	$746	$126,820,000
2017		0	0	0		103	270	95	113	0	113	18		
2018	CHP-50	50	47	50		150	320	97	119	0	119	21	$1,888	$94,400,000
2019	CHP-50	50	47	50		196	370	133	128	0	128	(5)	$1,888	$94,400,000
2020	SCCT S Aero-94	94	8	94		204	464	136	129	0	129	(7)	$1,063	$99,922,000
	Total	**464**	**204**	**464**										**$604,342,000**

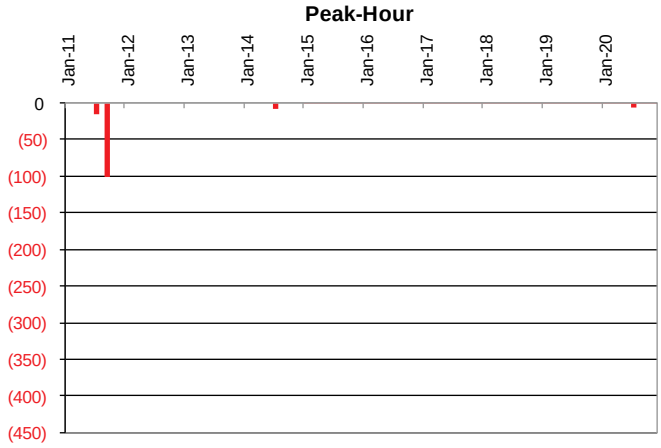


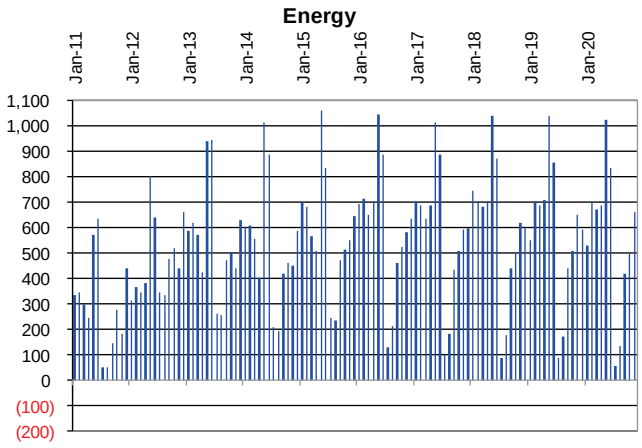


1-7 Balanced

Year	Resource	MW	E	P	Type	Cumm. E	Cumm. P	REC Req.	Existing RECs	New RECs	Total RECs	REC Position	Capital Cost $/kW	Capital Cost Total $
2011		0	0	0		0	0	–	44	0	44	44		
2012		0	0	0		0	0	26	69	0	69	43		
2013		0	0	0		0	0	27	70	0	70	43		
2014		0	0	0		0	0	57	78	0	78	21		
2015	CHP-100	100	93	100		93	100	60	104	0	104	44	$1,888	$188,800,000
2016	SCCT Frame	170	10	170		103	270	62	104	0	104	43	$746	$126,820,000
2017	Solar PV-10	10	1	6	R	105	276	95	113	1	114	19	$3,750	$37,500,000
2018	Solar PT-100	100	28	91	R	133	367	97	119	29	148	51	$3,220	$322,000,000
2019	Geothermal-26	26	24	26	R	157	393	133	128	53	182	48	$6,385	$166,010,000
2020	SCCT S Aero-47	47	4	47		160	440	136	129	53	182	46	$1,063	$49,961,000
	Total	**453**	**160**	**440**										**$891,091,000**

* R=Renewable Resource

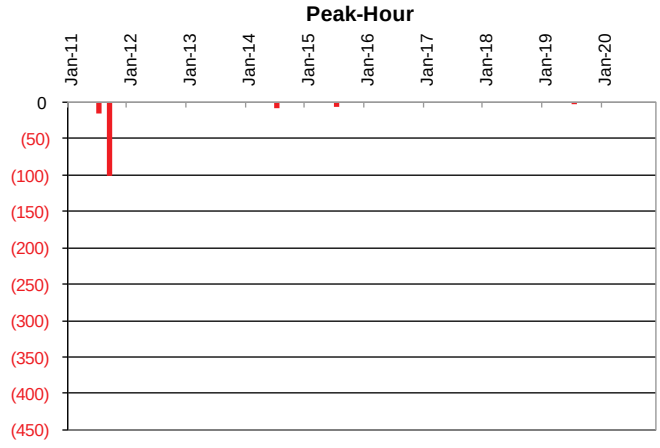


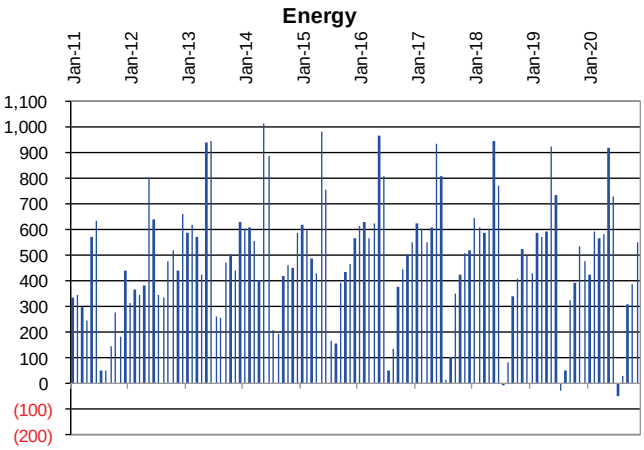


1-8 Pumped Storage

Year	Resource	MW	E	P	Type	Cumm. E	Cumm. P	REC Req.	Existing RECs	New RECs	Total RECs	REC Position	Capital Cost $/kW	Capital Cost Total $
2011		0	0	0		0	0	–	44	0	44	44		
2012		0	0	0		0	0	26	69	0	69	43		
2013		0	0	0		0	0	27	70	0	70	43		
2014		0	0	0		0	0	57	78	0	78	21		
2015	Pump St-80	80	13	80	R	13	80	60	104	13	116	57	$5,000	$400,000,000
2016	SCCT Frame	170	10	170		23	250	62	104	13	117	55	$746	$126,820,000
2017		0	0	0		23	250	95	113	13	126	31		
2018	Pump St-80	80	13	80	R	36	330	97	119	26	144	47	$5,000	$400,000,000
2019	SCCT S Aero-47	47	4	47		40	377	133	128	26	154	21	$1,063	$49,961,000
2020	Pump St-80	80	13	80	R	52	457	136	129	38	167	31	$5,000	$400,000,000
	Total	**457**	**52**	**457**										**$1,376,781,000**

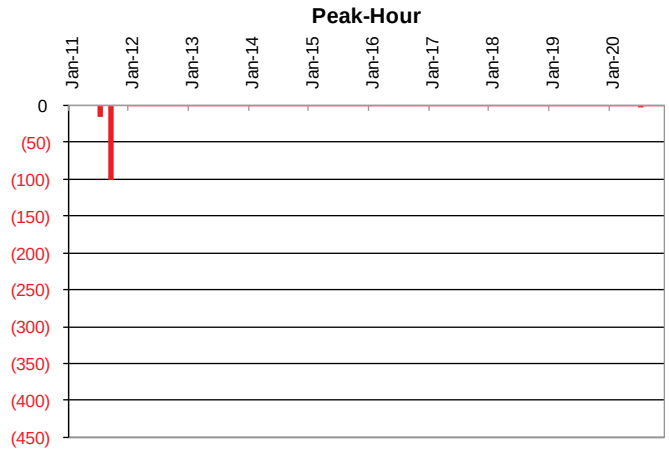
* R=Renewable Resource

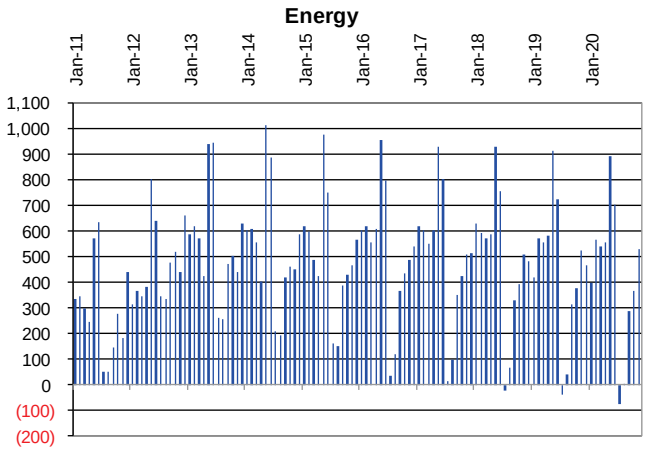




1-9 Distributed Generation

Year	Resource	MW	E	P	Type	Cumm. E	Cumm. P	REC Req.	Existing RECs	New RECs	Total RECs	REC Position	Capital Cost $/kW	Capital Cost Total $
2011		0	0	0		0	0	–	44	0	44	44		
2012	Dist Gen-10	10	0	10		0	10	26	69	0	69	43	$–	$–
2013		0	0	0		0	10	27	70	0	70	43		
2014		0	0	0		0	10	57	78	0	78	21		
2015	SCCT Frame	170	10	170		10	180	60	104	0	104	44	$746	$126,820,000
2016		0	0	0		10	180	62	104	0	104	43		
2017	SCCT Frame	170	10	170		20	350	95	113	0	113	18	$746	$126,820,000
2018		0	0	0		20	350	97	119	0	119	21		
2019	SCCT S Aero-94	94	8	94		28	444	133	128	0	128	(5)	$1,063	$99,922,000
2020		0	0	0		28	444	136	129	0	129	(7)		
	Total	**444**	**28**	**444**										**$353,562,000**

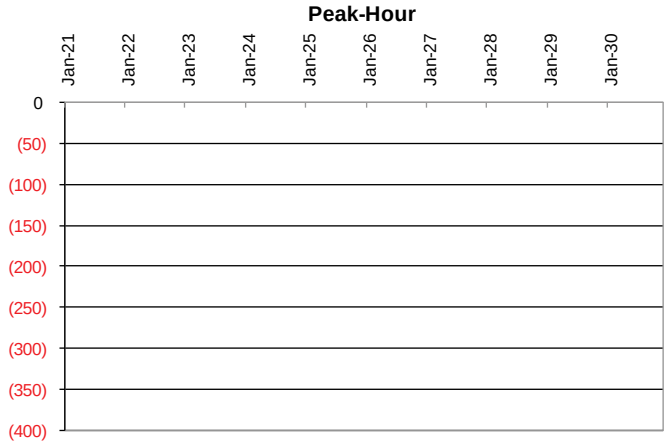


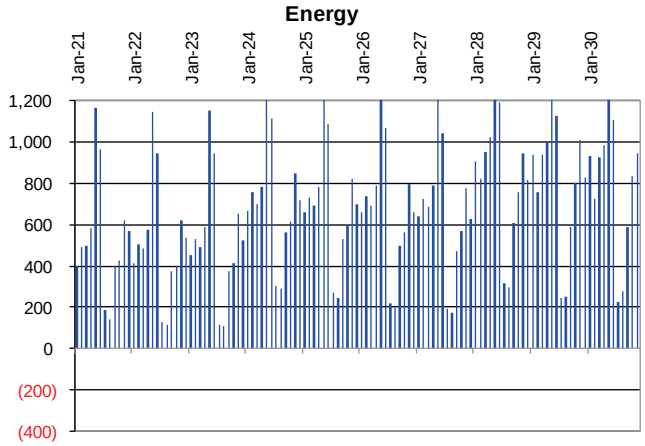


2-1 Nuclear

Year	Resource	MW	E	P	Type	Cumm. E	Cumm. P	REC Req.	Existing RECs	New RECs	Total RECs	REC Position	Capital Cost $/kW	Capital Cost Total $
2021	Solar PT-100	100	28	91	R	28	91	174	139	28	167	(7)	$3,220	$322,000,000
2022	Pump St-50	50	8	50	R	36	141	178	140	36	176	(2)	$5,000	$250,000,000
2023	Solar PT-100	100	28	91	R	64	232	182	141	64	205	23	$3,220	$322,000,000
2024	Nuclear	250	213	250		277	482	185	142	64	206	21	$4,103	$1,025,750,000
2025		0	0	0		277	482	189	143	64	207	18		
2026		0	0	0		277	482	193	144	64	208	15		
2027		0	0	0		277	482	196	145	64	209	13		
2028	Nuclear	250	213	250		489	732	202	113	64	177	(25)	$4,103	$1,025,750,000
2029	Pump St-50	50	8	50	R	497	782	206	114	72	186	(20)	$5,000	$250,000,000
2030		0	0	0		497	782	211	115	72	187	(24)		
	Total	**800**	**497**	**782**										**$3,195,500,000**

* R=Renewable Resource

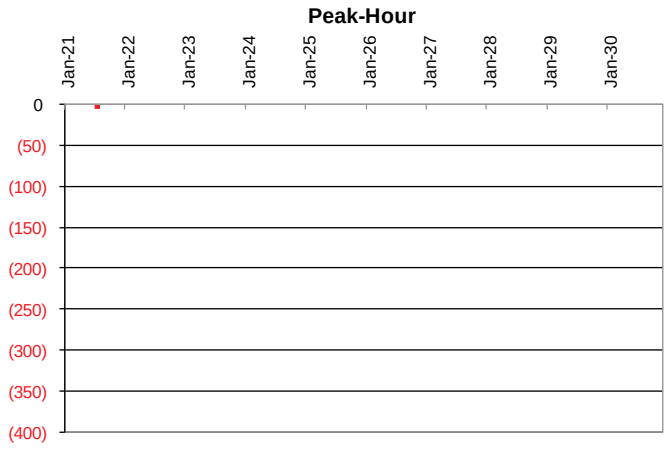


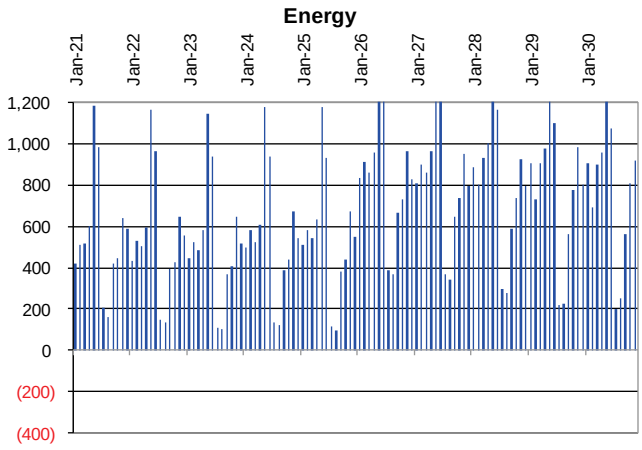


2-2 IGCC

Year	Resource	MW	E	P	Type	Cumm. E	Cumm. P	REC Req.	Existing RECs	New RECs	Total RECs	REC Position	Capital Cost $/kW	Capital Cost Total $
2021	Geothermal-52	52	48	52	R	48	52	174	139	48	187	13	$6,385	$332,020,000
2022	SCCT Frame	170	10	170		58	222	178	140	48	188	10	$746	$126,820,000
2023		0	0	0		58	222	182	141	48	189	7		
2024	CHP-50	50	47	50		105	272	185	142	48	190	5	$1,888	$94,400,000
2025	Solar PT-75	75	21	68	R	126	340	189	143	69	212	23	$3,220	$241,500,000
2026	IGCC w/CS	380	323	380		449	720	193	144	69	213	20	$4,506	$1,712,280,000
2027		0	0	0		449	720	196	145	69	214	18		
2028	Solar PT-75	75	21	68	R	470	789	202	113	90	202	1	$3,220	$241,500,000
2029		0	0	0		470	789	206	114	90	204	(3)		
2030		0	0	0		470	789	211	115	90	205	(6)		
	Total	**802**	**470**	**789**										**$2,748,520,000**

* R=Renewable Resource

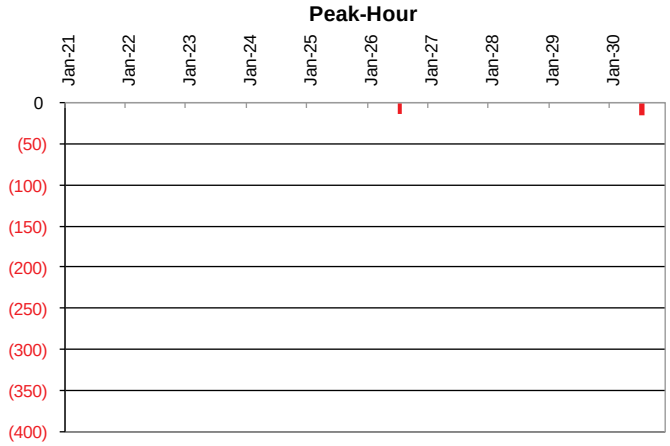


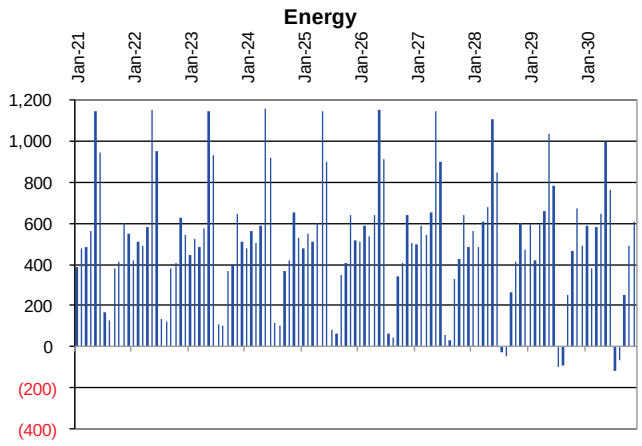


2-3 SCCT/Wind

Year	Resource	MW	E	P	Type	Cumm. E	Cumm. P	REC Req.	Existing RECs	New RECs	Total RECs	REC Position	Capital Cost $/kW	Capital Cost Total $
2021	SCCT S Aero-141	141	11	141		11	141	174	139	0	139	(35)	$1,063	$149,883,000
2022	Wind-100	100	32	5	R	43	146	178	140	32	172	(6)	$1,733	$173,300,000
2023	SCCT S Aero-141	141	11	141		55	287	182	141	32	173	(9)	$1,063	$149,883,000
2024	Wind-100	100	32	5	R	87	292	185	142	64	206	21	$1,733	$173,300,000
2025	SCCT S Aero-94	94	8	94		94	386	189	143	64	207	18	$1,063	$99,922,000
2026	Wind-100	100	32	5	R	126	391	193	144	96	240	47	$1,733	$173,300,000
2027	SCCT S Aero-141	141	11	141		137	532	196	145	96	241	45	$1,063	$149,883,000
2028	SCCT S Aero-141	141	11	141		149	673	202	113	96	209	7	$1,063	$149,883,000
2029	SCCT S Aero-94	94	8	94		156	767	206	114	96	210	4	$1,063	$99,922,000
2030		0	0	0		156	767	211	115	96	211	(0)		
	Total	**1,052**	**156**	**767**										**$1,319,276,000**

* R=Renewable Resource

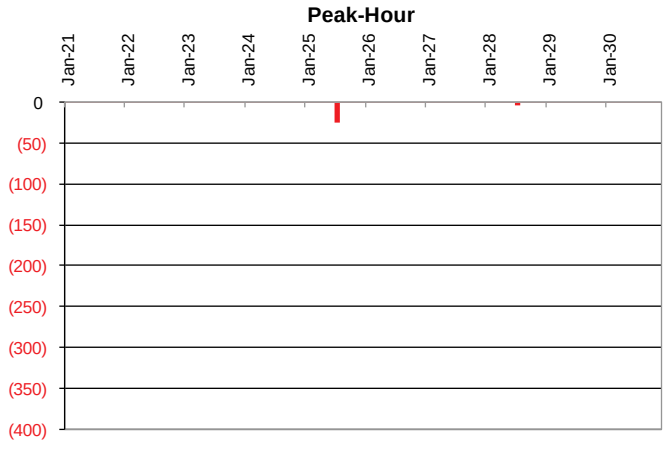


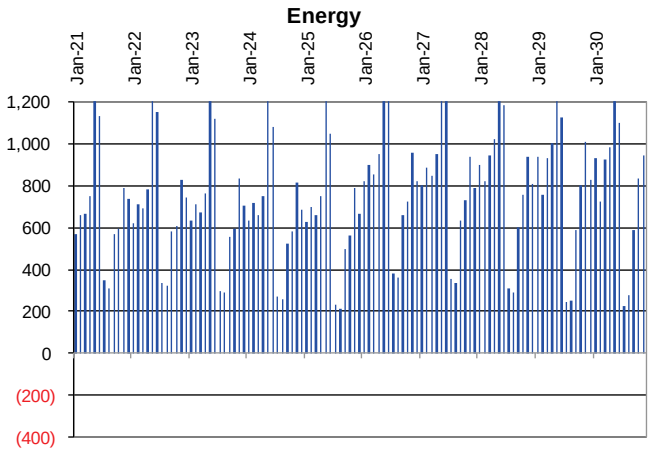


2-4 CCCT/Wind

Year	Resource	MW	E	P	Type	Cumm. E	Cumm. P	REC Req.	Existing RECs	New RECs	Total RECs	REC Position	Capital Cost $/kW	Capital Cost Total $
2021	CCCT	300	195	300		195	300	174	139	0	139	(35)	$1,216	$364,800,000
2022	Wind-150	150	48	8	R	243	308	178	140	48	188	10	$1,733	$259,950,000
2023		0	0	0		243	308	182	141	48	189	7		
2024		0	0	0		243	308	185	142	48	190	5		
2025		0	0	0		243	308	189	143	48	191	2		
2026	CCCT	300	195	300		438	608	193	144	48	192	(1)	$1,216	$364,800,000
2027		0	0	0		438	608	196	145	48	193	(3)		
2028	Wind-150	150	48	8	R	486	615	202	113	96	209	7	$1,733	$259,950,000
2029	SCCT Frame	170	10	170		496	785	206	114	96	210	4	$746	$126,820,000
2030		0	0	0		496	785	211	115	96	211	(0)		
	Total	**1,070**	**496**	**785**										**$1,376,320,000**

* R=Renewable Resource

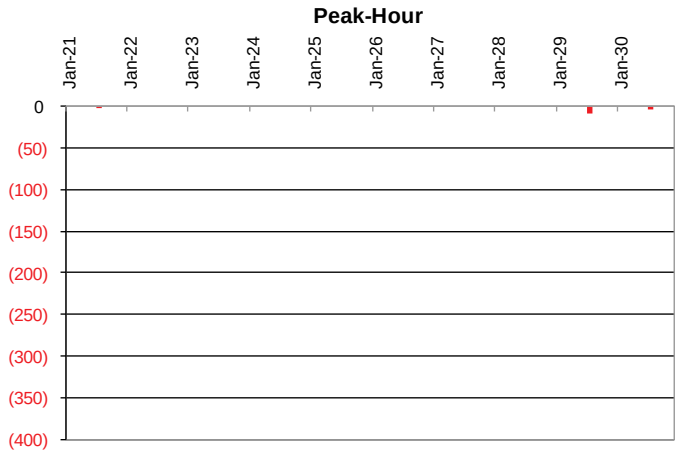


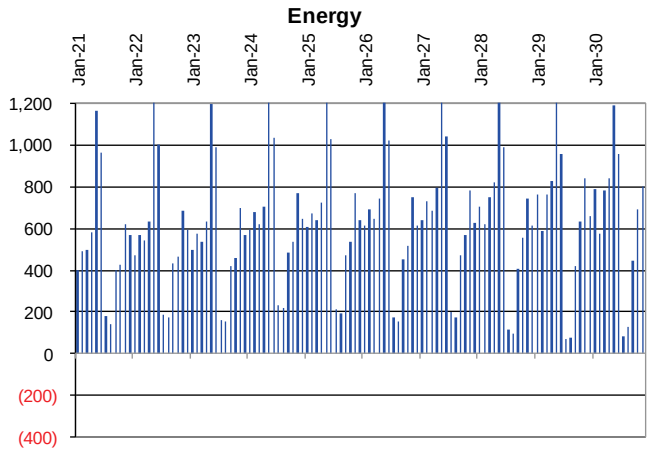


2-5 Hydro/CHP

Year	Resource	MW	E	P	Type	Cumm. E	Cumm. P	REC Req.	Existing RECs	New RECs	Total RECs	REC Position	Capital Cost $/kW	Capital Cost Total $
2021	Hydro Sm-60	60	27	54	R	27	54	174	139	27	166	(8)	$4,000	$240,000,000
2022	CHP-75	75	70	75		97	129	178	140	27	167	(11)	$1,888	$141,600,000
2023	Pump St-80	80	13	80	R	110	209	182	141	40	181	(1)	$5,000	$400,000,000
2024	CHP-100	100	93	100		203	309	185	142	40	182	(3)	$1,888	$188,800,000
2025	Hydro-40	40	18	32	R	221	341	189	143	58	201	12	$4,000	$160,000,000
2026	Pump St-80	80	13	80	R	233	421	193	144	71	215	22	$5,000	$400,000,000
2027	Hydro Sm-100	100	45	90	R	278	511	196	145	116	261	64	$4,000	$400,000,000
2028	SCCT S Aero-141	141	11	141		290	652	202	113	116	228	26	$1,063	$149,883,000
2029	Hydro Sm-80	80	36	72	R	326	724	206	114	152	265	59	$4,000	$320,000,000
2030	Hydro Sm-60	60	27	54	R	353	778	211	115	179	294	83	$4,000	$240,000,000
	Total	**816**	**353**	**778**										**$2,640,283,000**

* R=Renewable Resource

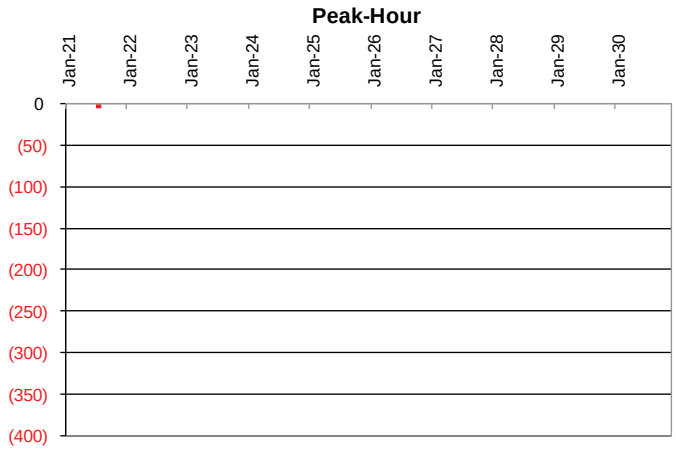


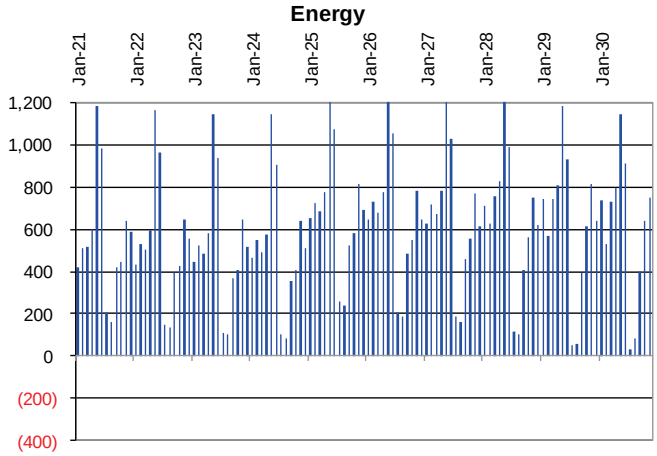


2-6 Balanced 1

Year	Resource	MW	E	P	Type	Cumm. E	Cumm. P	REC Req.	Existing RECs	New RECs	Total RECs	REC Position	Capital Cost $/kW	Capital Cost Total $
2021	Geothermal-52	52	48	52	R	48	52	174	139	48	187	13	$6,385	$332,020,000
2022	SCCT Frame	170	10	170		58	222	178	140	48	188	10	$746	$126,820,000
2023		0	0	0		58	222	182	141	48	189	7		
2024	Solar PT-50	50	14	46	R	72	268	185	142	62	204	19	$3,220	$161,000,000
2025	CCCT	300	195	300		267	568	189	143	62	205	16	$1,216	$364,800,000
2026		0	0	0		267	568	193	144	62	206	13		
2027		0	0	0		267	568	196	145	62	207	11		
2028	Hydro Sm-60	60	27	54	R	294	622	202	113	89	201	(0)	$4,000	$240,000,000
2029	SCCT Frame	170	10	170		304	792	206	114	89	203	(4)	$746	$126,820,000
2030		0	0	0		304	792	211	115	89	204	(7)		
	Total	**802**	**304**	**792**										**$1,351,460,000**

* R=Renewable Resource

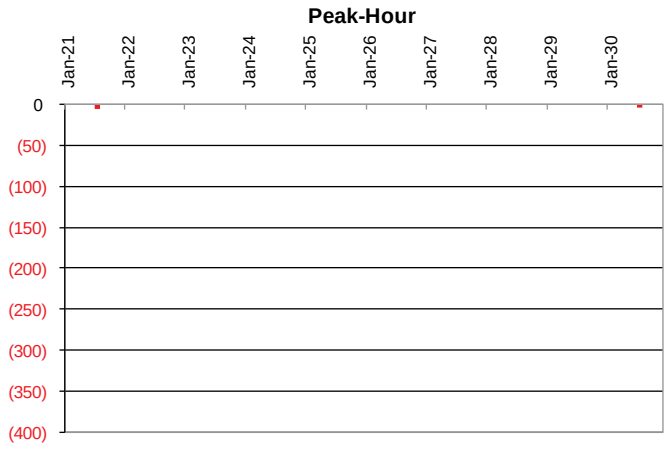


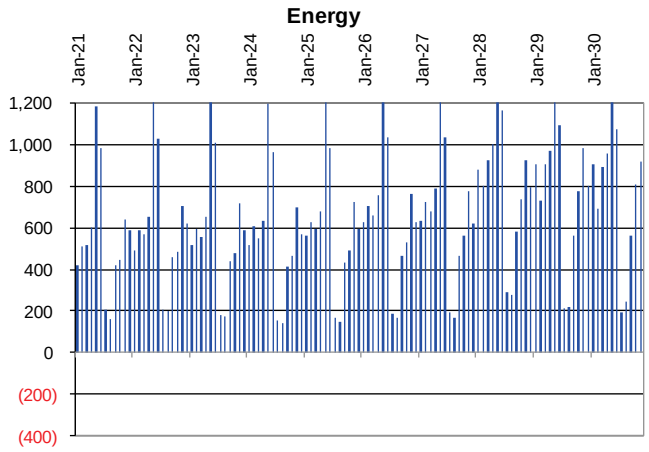


2-7 Balanced 2

Year	Resource	MW	E	P	Type	Cumm. E	Cumm. P	REC Req.	Existing RECs	New RECs	Total RECs	REC Position	Capital Cost $/kW	Capital Cost Total $
2021	Geothermal-52	52	48	52	R	48	52	174	139	48	187	13	$6,385	$332,020,000
2022	CHP-75	75	70	75		118	127	178	140	48	188	10	$1,888	$141,600,000
2023	SCCT Frame	170	10	170		128	297	182	141	48	189	7	$746	$126,820,000
2024		0	0	0		128	297	185	142	48	190	5		
2025	Geothermal-52	52	48	52	R	176	349	189	143	96	239	50	$6,385	$332,020,000
2026	CHP-75	75	70	75		245	424	193	144	96	240	47	$1,888	$141,600,000
2027	Hydro Sm-60	60	27	54	R	272	478	196	145	123	268	71	$4,000	$240,000,000
2028	CCCT	300	195	300		467	778	202	113	123	235	34	$1,216	$364,800,000
2029		0	0	0		467	778	206	114	123	236	30		
2030		0	0	0		467	778	211	115	123	238	27		
	Total	**784**	**467**	**778**										**$1,678,860,000**

* R=Renewable Resource

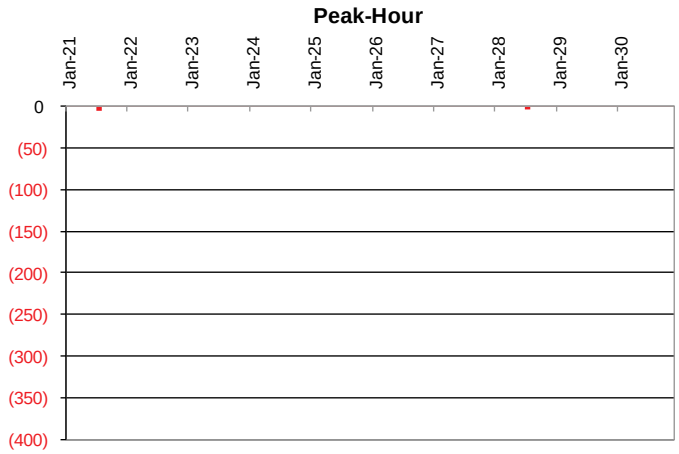


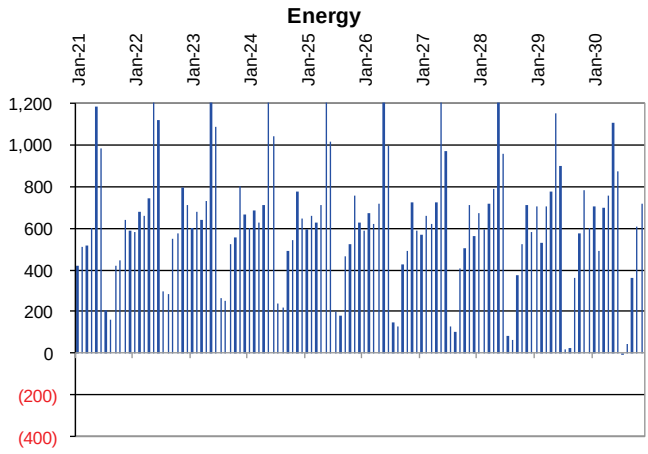


2-8 Pacific Northwest Transmission

						Cumm.							Capital Cost	
Year	Resource	MW	E	P	Type	E	P	REC Req.	Existing RECs	New RECs	Total RECs	REC Position	$/kW	Total $
2021	Geothermal-52	52	48	52	R	48	52	174	139	48	187	13	$6,385	$332,020,000
2022	PNW Purchase	500	160	500		208	552	178	140	48	188	10	$381	$190,500,000
2023		0	0	0		208	552	182	141	48	189	7		
2024		0	0	0		208	552	185	142	48	190	5		
2025		0	0	0		208	552	189	143	48	191	2		
2026		0	0	0		208	552	193	144	48	192	(1)		
2027	Solar PV-20	20	3	11	R	211	563	196	145	51	196	(1)	$3,750	$75,000,000
2028	Geothermal-52	52	48	52	R	258	615	202	113	98	211	9	$6,385	$332,020,000
2029	SCCT Frame	170	10	170		269	785	206	114	98	212	6	$746	$126,820,000
2030		0	0	0		269	785	211	115	98	214	2		
	Total	**794**	**269**	**785**										**$1,056,360,000**

* R=Renewable Resource

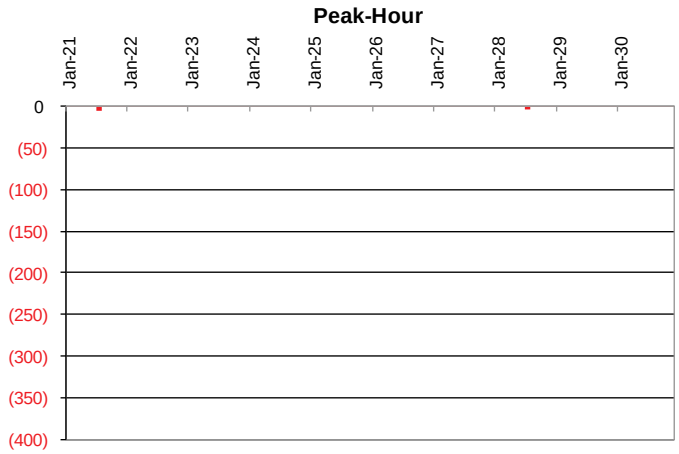


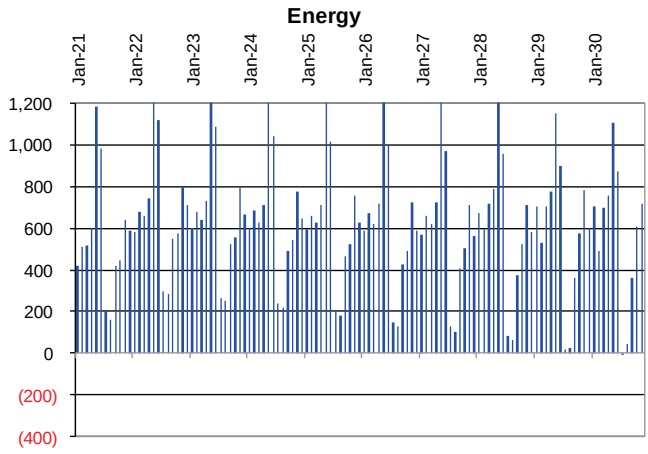


2-9 Eastside Transmission

						Cumm.							Capital Cost	
Year	Resource	MW	E	P	Type	E	P	REC Req.	Existing RECs	New RECs	Total RECs	REC Position	$/kW	Total $
2021	Geothermal-52	52	48	52	R	48	52	174	139	48	187	13	$6,385	$332,020,000
2022	E/S Purchase	500	160	500		208	552	178	140	48	188	10	$381	$190,500,000
2023		0	0	0		208	552	182	141	48	189	7		
2024		0	0	0		208	552	185	142	48	190	5		
2025		0	0	0		208	552	189	143	48	191	2		
2026		0	0	0		208	552	193	144	48	192	(1)		
2027	Solar PV-20	20	3	11	R	211	563	196	145	51	196	(1)	$3,750	$75,000,000
2028	Geothermal-52	52	48	52	R	258	615	202	113	98	211	9	$6,385	$332,020,000
2029	SCCT Frame	170	10	170		269	785	206	114	98	212	6	$746	$126,820,000
2030		0	0	0		269	785	211	115	98	214	2		
	Total	**794**	**269**	**785**										**$1,056,360,000**

* R=Renewable Resource

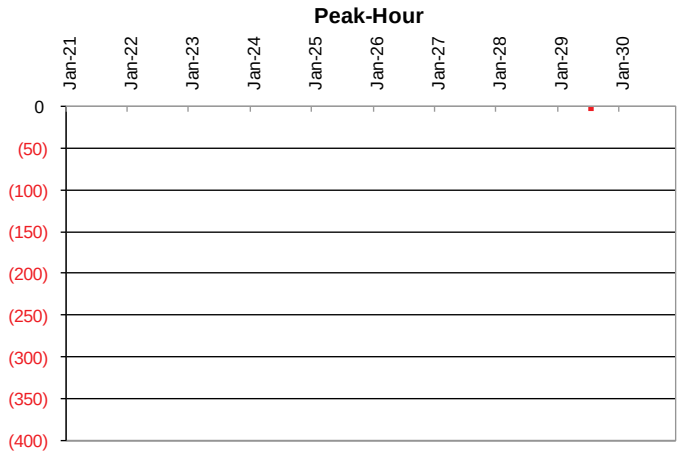


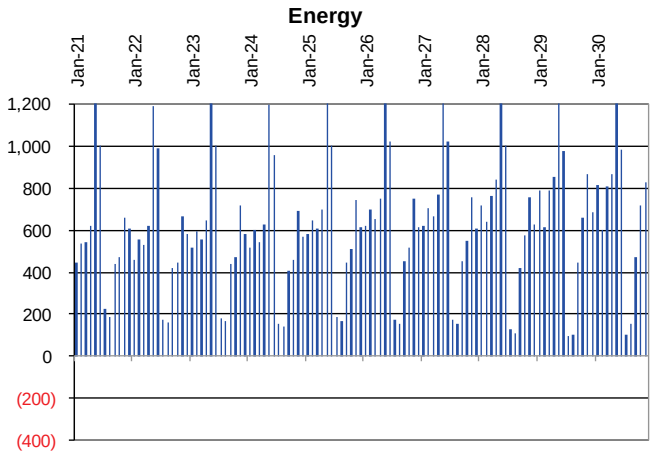


2-10 Renewable

Year	Resource	MW	E	P	Type	Cumm. E	Cumm. P	REC Req.	Existing RECs	New RECs	Total RECs	REC Position	Capital Cost $/kW	Capital Cost Total $
2021	CHP-75	75	70	75		70	75	174	139	0	139	(35)	$1,888	$141,600,000
2022	Pump St-80	80	13	80	R	83	155	178	140	13	153	(25)	$5,000	$400,000,000
2023	Solar PT-150	150	42	137	R	125	292	182	141	55	196	14	$3,220	$483,000,000
2024		0	0	0		125	292	185	142	55	197	12		
2025	CHP-75	75	70	75		194	367	189	143	55	198	9	$1,888	$141,600,000
2026	Solar PT-150	150	42	137	R	236	503	193	144	97	241	48	$3,220	$483,000,000
2027	Solar PV-150	150	21	83	R	257	586	196	145	118	263	67	$3,750	$562,500,000
2028	Geothermal-52	52	48	52	R	305	638	202	113	166	278	77	$6,385	$332,020,000
2029	Hydro Sm-100	100	45	90	R	350	728	206	114	211	324	118	$4,000	$400,000,000
2030	Solar PV-200	200	28	110	R	378	838	211	115	239	354	143	$3,750	$750,000,000
	Total	**1,032**	**378**	**838**										**$3,693,720,000**

* R=Renewable Resource





Stochastic Analysis Results

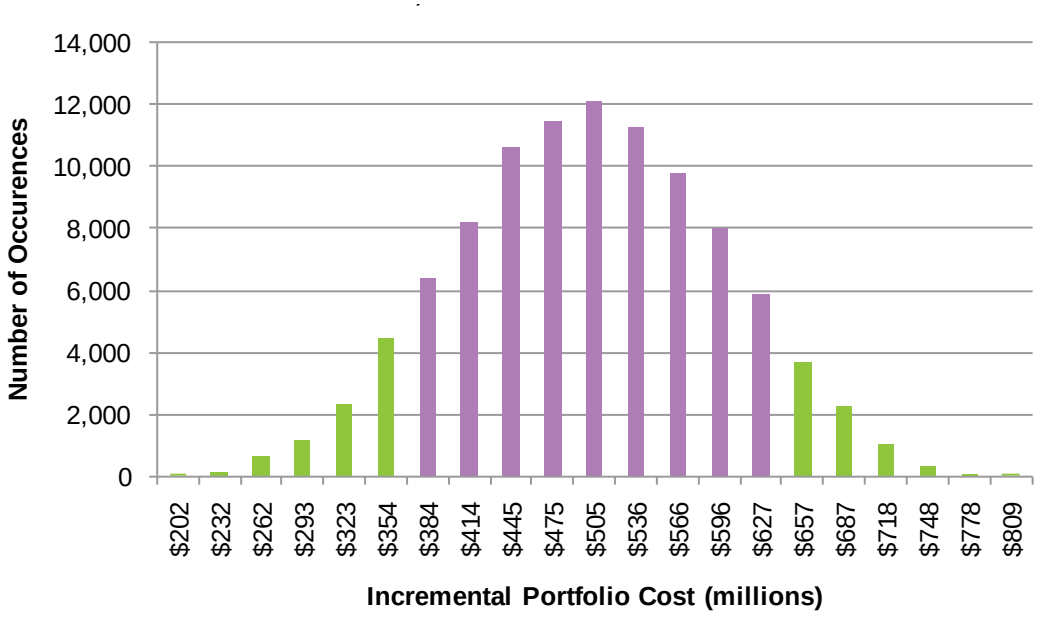
1-1 Sun and Steam (2011–2020)

Base Portfolio Cost[1]=$496,198[2]

	Adjustment to Base Incremental Portfolio Cost		Incremental Portfolio Cost Range	
Risk Factor Adjustments	**Low**	**High**	**Low**	**High**
Natural gas	-$54,445	$61,186	$441,753	$557,384
REC	-$47,738	$23,869	$448,460	$520,067
Carbon	-$5,748	$31,584	$490,450	$527,782
Load	-$2,281	$2,516	$493,917	$498,714
DSM	-$48,508	$100,453	$447,690	$596,651
Capital	-$135,692	$92,944	$360,506	$589,142
Total	**-$294,412**	**$312,552**	**$201,786**	**$808,750**

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.
[2] All numbers in thousands

Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



1-2 Solar (2011–2020)

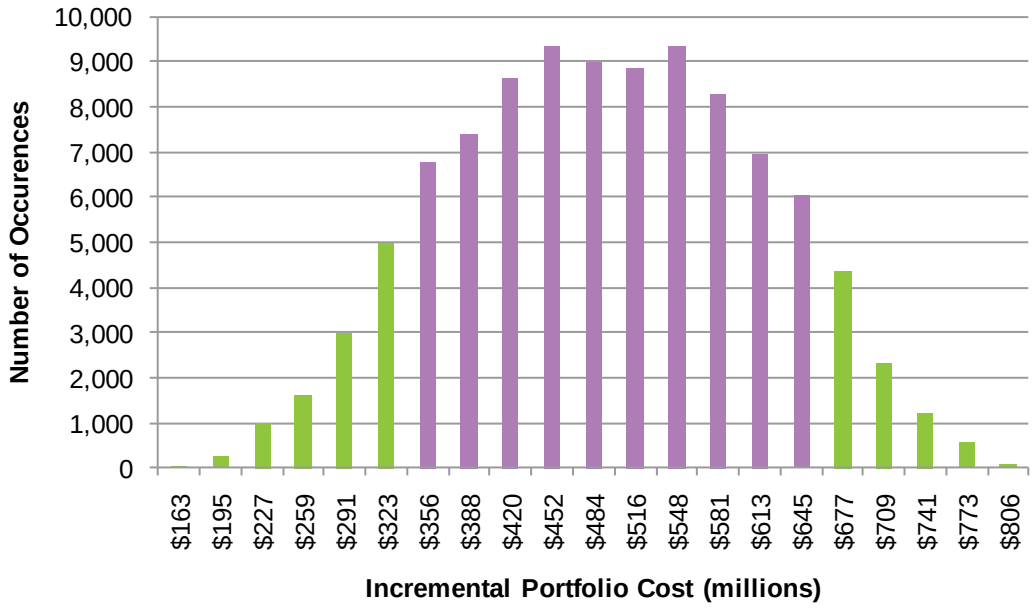
Base Portfolio Cost[1]=$505,407[2]

Risk Factor Adjustments	Adjustment to Base Incremental Portfolio Cost Low	Adjustment to Base Incremental Portfolio Cost High	Incremental Portfolio Cost Range Low	Incremental Portfolio Cost Range High
Natural gas	-$742	$515	$504,665	$505,922
REC	-$63,012	$31,506	$442,395	$536,913
Carbon	-$12,519	$36,499	$492,888	$541,906
Load	-$3,623	$2,122	$501,784	$507,529
DSM	-$50,344	$100,172	$455,063	$605,579
Capital	-$212,449	$129,300	$292,958	$634,707
Total	**-$342,689**	**$300,114**	**$162,718**	**$805,521**

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



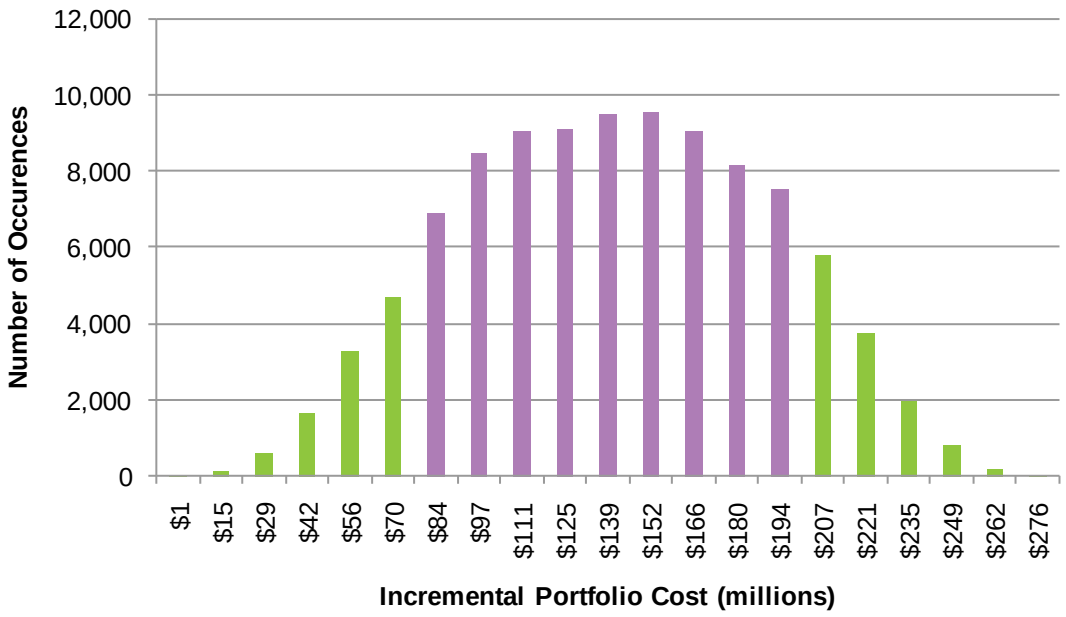
1-3 Boardman to Hemingway (2011–2020)

Base Portfolio Cost[1]=$86,079[2]

Risk Factor Adjustments	Adjustment to Base Incremental Portfolio Cost		Incremental Portfolio Cost Range	
	Low	High	Low	High
Natural gas	$0	$21,793	$86,079	$107,872
REC	-$18,827	$9,413	$67,252	$95,492
Carbon	-$3,542	$20,399	$82,537	$106,478
Load	$0	$19,089	$86,079	$105,168
DSM	-$47,727	$99,606	$38,352	$185,685
Capital	-$14,840	$19,785	$71,239	$105,864
Total	**-$84,936**	**$190,085**	**$1,143**	**$276,164**

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.
[2] All numbers in thousands

Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



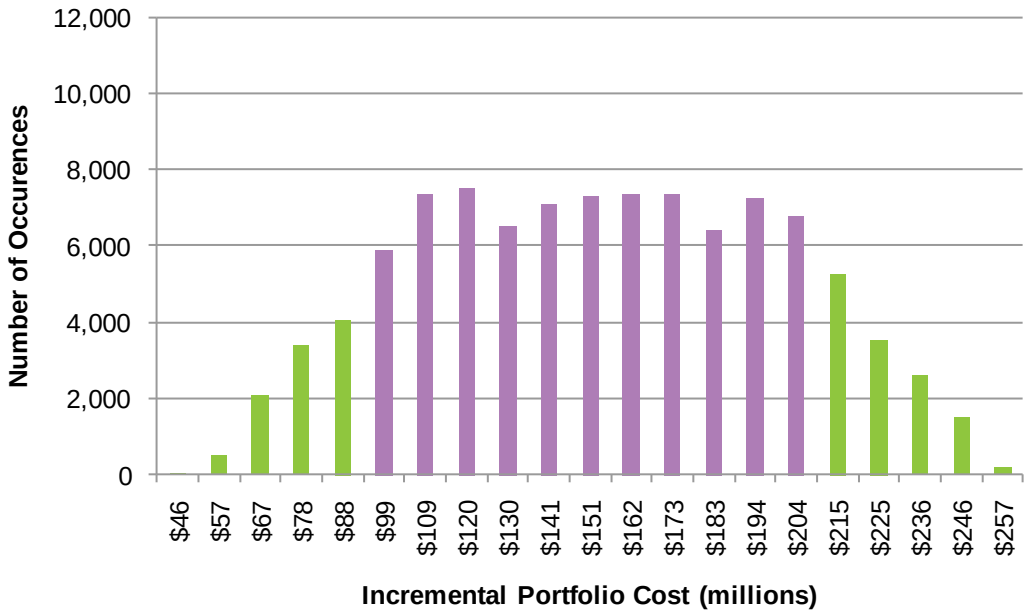
1-4 SCCT (2011–2020)

Base Portfolio Cost[1]=$129,443[2]

	Adjustment to Base Incremental Portfolio Cost		Incremental Portfolio Cost Range	
Risk Factor Adjustments	**Low**	**High**	**Low**	**High**
Natural gas	$0	$1,853	$129,443	$131,296
REC	-$18,826	$9,413	$110,617	$138,856
Carbon	$0	$3,473	$129,443	$132,916
Load	-$337	$1,639	$129,106	$131,082
DSM	-$47,895	$100,184	$81,548	$229,627
Capital	-$16,325	$10,884	$113,118	$140,327
Total	**-$83,383**	**$127,446**	**$46,060**	**$256,889**

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.
[2] All numbers in thousands

Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



1-5 CCCT (2011–2020)

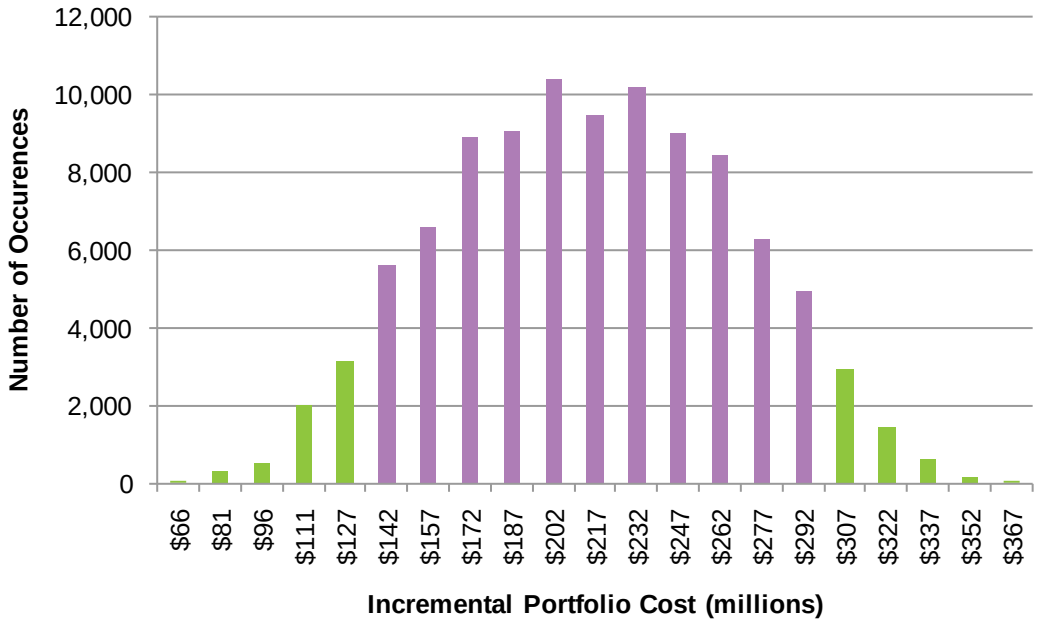
Base Portfolio Cost[1]=$222,177[2]

	Adjustment to Base Incremental Portfolio Cost		Incremental Portfolio Cost Range	
Risk Factor Adjustments	**Low**	**High**	**Low**	**High**
Natural gas	-$55,246	$3,167	$166,931	$225,344
REC	-$18,827	$9,413	$203,350	$231,590
Carbon	-$3,158	$3,282	$219,019	$225,459
Load	-$1,364	$2,170	$220,813	$224,347
DSM	-$48,975	$101,023	$173,202	$323,200
Capital	-$28,262	$27,371	$193,915	$249,548
Total	**-$155,832**	**$146,426**	**$66,345**	**$368,603**

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



1-6 CHP (2011–2020)

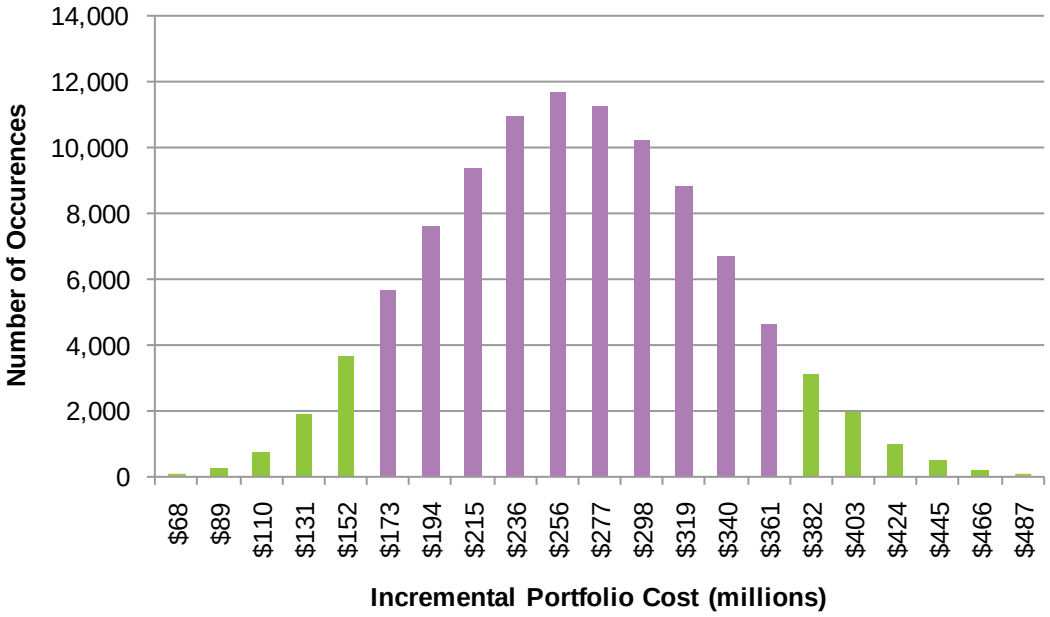
Base Portfolio Cost[1]=$267,462[2]

	Adjustment to Base Incremental Portfolio Cost		Incremental Portfolio Cost Range	
Risk Factor Adjustments	**Low**	**High**	**Low**	**High**
Natural gas	-$63,805	$66,362	$203,657	$333,824
REC	-$18,827	$9,413	$248,635	$276,875
Carbon	-$412	$11,109	$267,050	$278,571
Load	-$1,632	$3,561	$265,830	$271,023
DSM	-$49,437	$103,010	$218,025	$370,472
Capital	-$28,566	$25,850	$238,896	$293,312
Total	**-$162,679**	**$219,305**	**$104,783**	**$486,767**

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



1-7 Balanced (2011–2020)

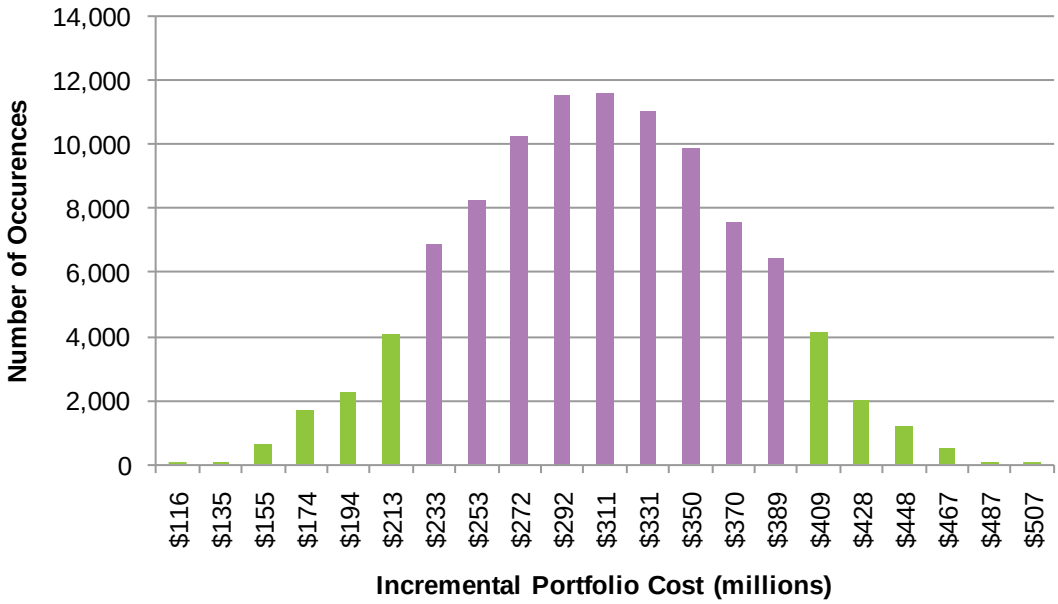
Base Portfolio Cost[1]=$288,613[2]

	Adjustment to Base Incremental Portfolio Cost		Incremental Portfolio Cost Range	
Risk Factor Adjustments	**Low**	**High**	**Low**	**High**
Natural gas	-$30,861	$37,401	$257,752	$326,014
REC	-$29,714	$14,858	$258,899	$303,471
Carbon	$0	$15,355	$288,613	$303,968
Load	-$190	$2,437	$288,423	$291,050
DSM	-$48,139	$100,745	$240,474	$389,358
Capital	-$63,931	$47,593	$224,682	$336,206
Total	**-$172,835**	**$218,389**	**$115,778**	**$507,002**

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



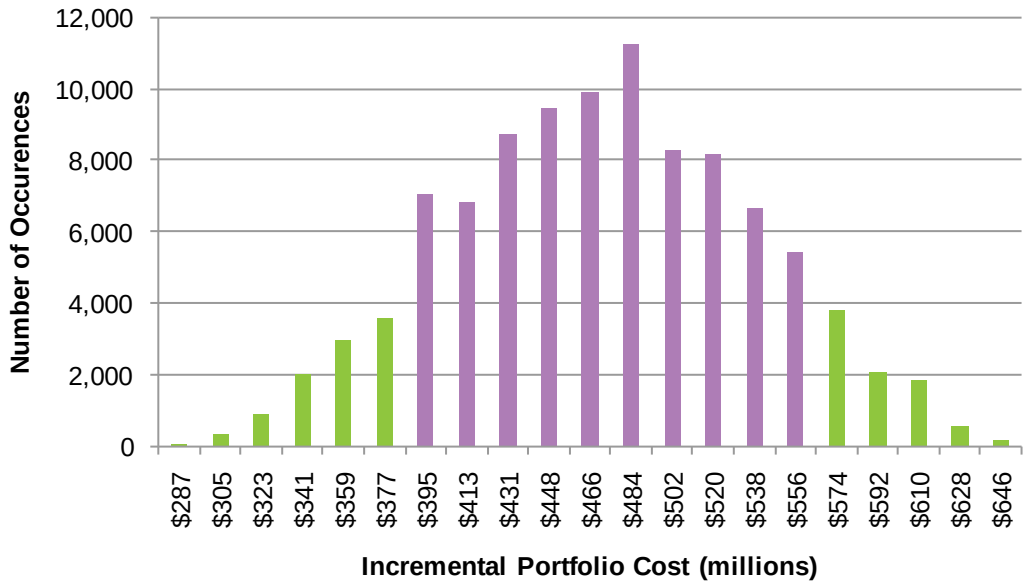
1-8 Pumped Storage (2011–2020)

Base Portfolio Cost[1]=$426,601[2]

	Adjustment to Base Incremental Portfolio Cost		Incremental Portfolio Cost Range	
Risk Factor Adjustments	**Low**	**High**	**Low**	**High**
Natural gas	$0	$2,111	$426,601	$428,712
REC	-$29,358	$14,680	$397,243	$441,281
Carbon	-$609	$2,871	$425,992	$429,472
Load	-$177	$2,289	$426,424	$428,890
DSM	-$46,741	$100,939	$379,860	$527,540
Capital	-$62,533	$96,069	$364,068	$522,670
Total	**-$139,418**	**$218,959**	**$287,183**	**$645,560**

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.
[2] All numbers in thousands

Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



1-9 Distributed Gen (2011–2020)

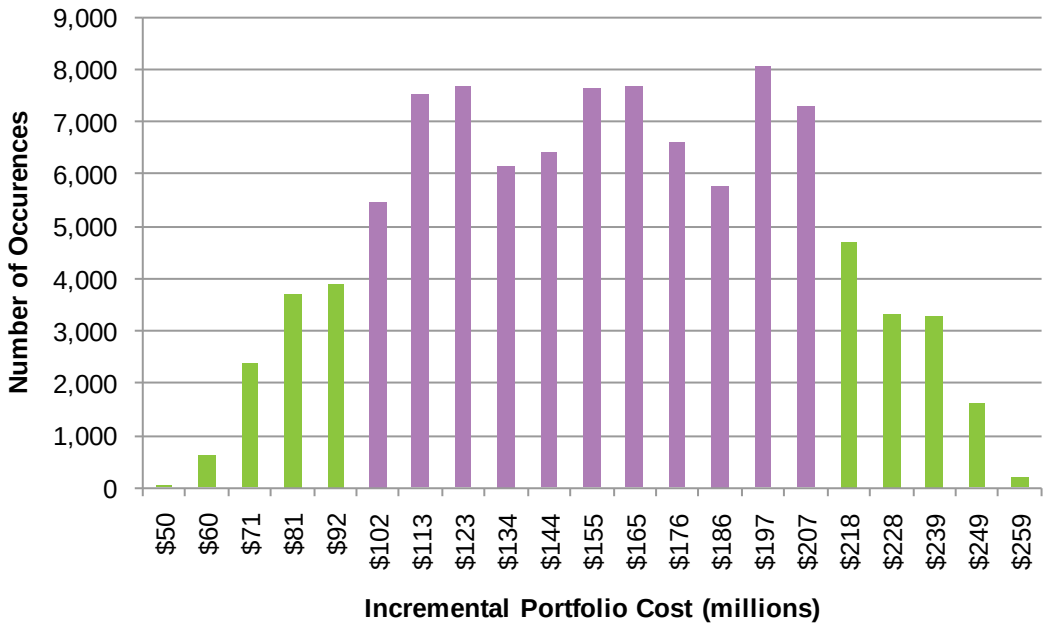
Base Portfolio Cost[1]=$135,055[2]

	Adjustment to Base Incremental Portfolio Cost		Incremental Portfolio Cost Range	
Risk Factor Adjustments	**Low**	**High**	**Low**	**High**
Natural gas	$0	$1,043	$135,055	$136,098
REC	-$18,827	$9,413	$116,228	$144,468
Carbon	$0	$2,678	$135,055	$137,733
Load	-$424	-$123	$134,631	$134,932
DSM	-$49,333	$100,263	$85,722	$235,318
Capital	-$16,592	$11,149	$118,463	$146,204
Total	**-$85,176**	**$124,423**	**$49,879**	**$259,478**

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



2-1 Nuclear (2021–2030)

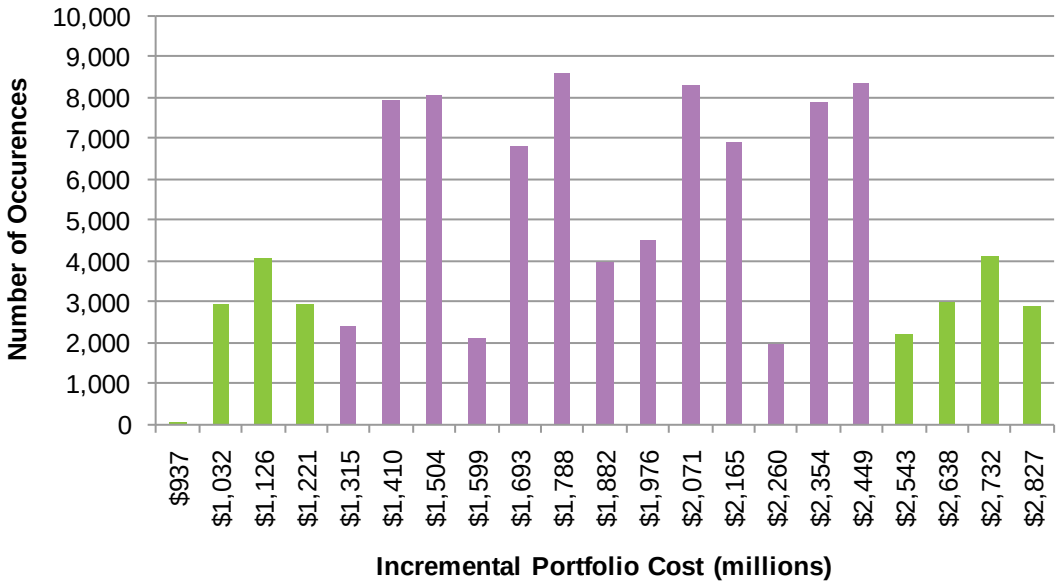
Base Portfolio Cost[1]=$1,323,279[2]

	Adjustment to Base Incremental Portfolio Cost		Incremental Portfolio Cost Range	
Risk Factor Adjustments	**Low**	**High**	**Low**	**High**
Natural gas	-$3,545	$5,887	$1,319,734	$1,329,166
REC	-$1,426	$713	$1,321,853	$1,323,992
Carbon	-$82,907	$138,144	$1,240,372	$1,461,423
Load	-$20,601	$7,743	$1,302,678	$1,331,022
DSM	-$2,183	$18,523	$1,321,096	$1,341,802
Capital	-$275,138	$1,332,273	$1,048,141	$2,655,552
Total	**-$385,800**	**$1,503,283**	**$937,479**	**$2,826,562**

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



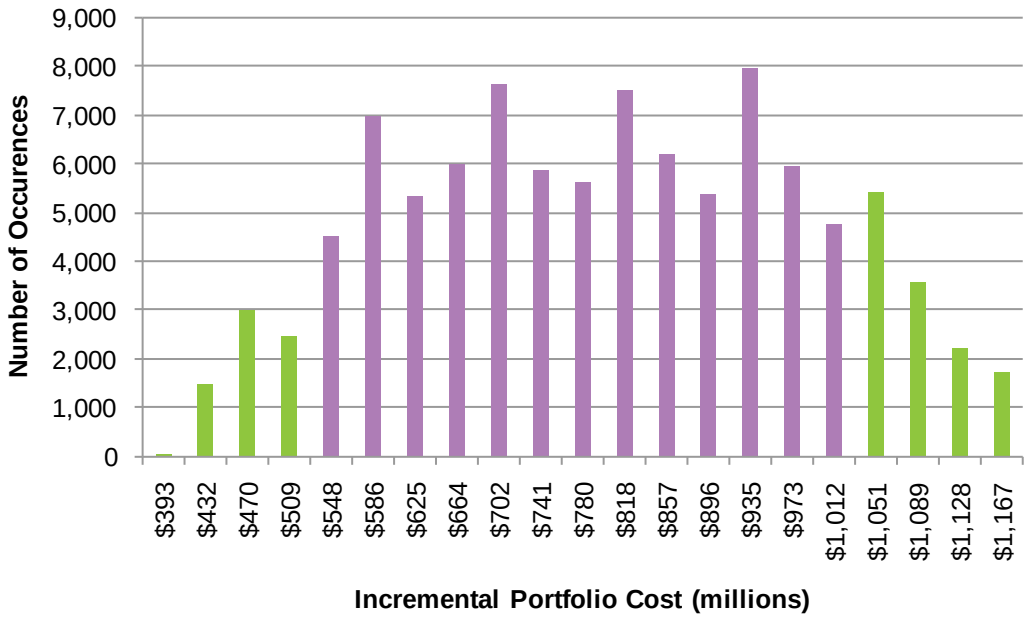
2-2 IGCC (2021–2030)

Base Portfolio Cost[1]=$625,319[2]

Risk Factor Adjustments	Adjustment to Base Incremental Portfolio Cost Low	Adjustment to Base Incremental Portfolio Cost High	Incremental Portfolio Cost Range Low	Incremental Portfolio Cost Range High
Natural gas	-$31,374	-$5,816	$593,945	$619,503
REC	-$5,816	$2,907	$619,503	$628,226
Carbon	-$66,620	$102,031	$558,699	$727,350
Load	-$17,198	$2,835	$608,121	$628,154
DSM	-$1,438	$15,377	$623,881	$640,696
Capital	-$147,025	$458,193	$478,294	$1,083,512
Total	**-$269,471**	**$575,527**	**$355,848**	**$1,200,846**

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.
[2] All numbers in thousands

Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



2-3 SCCT and Wind (2021–2030)

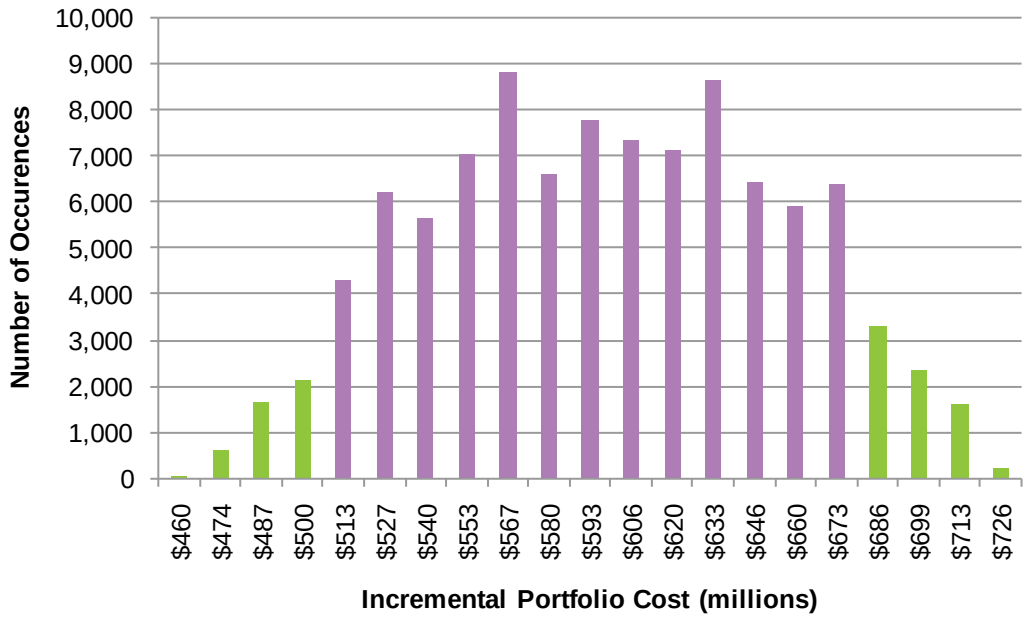
Base Portfolio Cost[1]=$564,334 [2]

	Adjustment to Base Incremental Portfolio Cost		Incremental Portfolio Cost Range	
Risk Factor Adjustments	**Low**	**High**	**Low**	**High**
Natural gas	$0	$2,979	$564,334	$567,313
REC	-$5,090	$2,546	$559,244	$566,880
Carbon	-$20,394	$33,400	$543,940	$597,734
Load	-$12,334	$85	$552,000	$564,419
DSM	$0	$11,526	$564,334	$575,860
Capital	-$66,147	$111,065	$498,187	$675,399
Total	**-$103,965**	**$161,601**	**$460,369**	**$725,935**

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



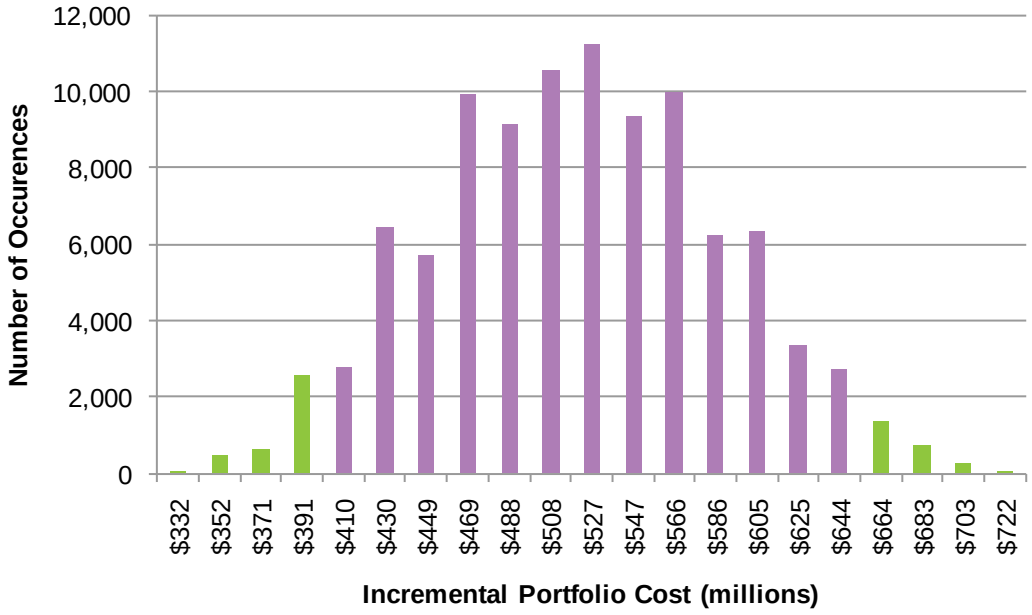
2-4 CCCT and Wind (2021–2030)

Base Portfolio Cost[1]=$565,377 [2]

	Adjustment to Base Incremental Portfolio Cost		Incremental Portfolio Cost Range	
Risk Factor Adjustments	**Low**	**High**	**Low**	**High**
Natural gas	-$125,279	$6,247	$440,098	$571,624
REC	-$247	$493	$565,130	$565,870
Carbon	-$23,134	$29,801	$542,243	$595,178
Load	-$19,581	$3,153	$545,796	$568,530
DSM	-$1,600	$15,457	$563,777	$580,834
Capital	-$63,506	$101,560	$501,871	$666,937
Total	**-$233,347**	**$156,711**	**$332,030**	**$722,088**

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.
[2] All numbers in thousands

Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



2-5 Hydro and CHP (2021–2030)

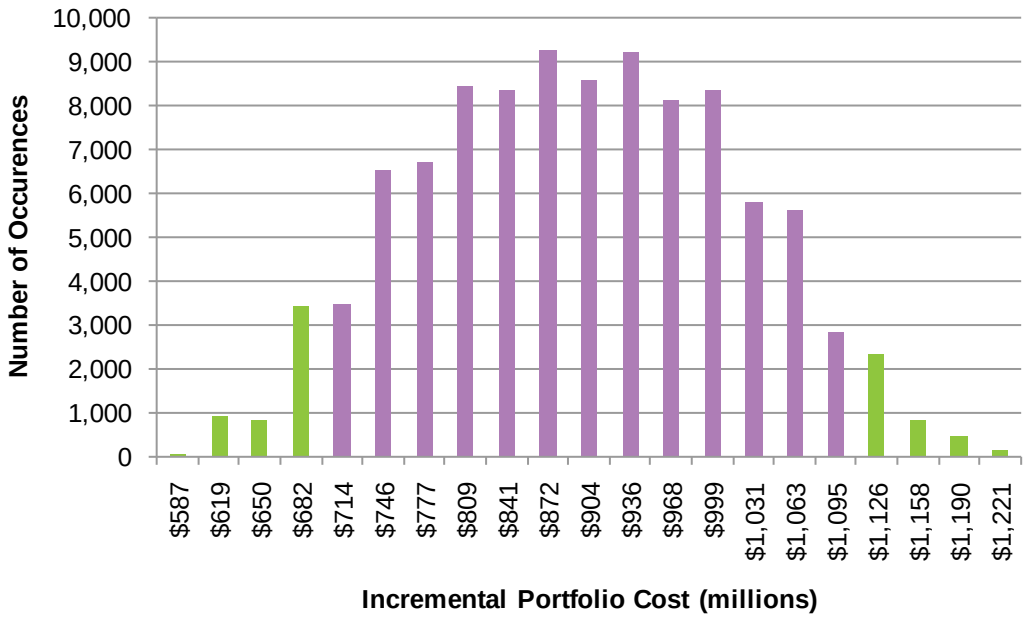
Base Portfolio Cost[1]=$860,503 [2]

Risk Factor Adjustments	Adjustment to Base Incremental Portfolio Cost Low	Adjustment to Base Incremental Portfolio Cost High	Incremental Portfolio Cost Range Low	Incremental Portfolio Cost Range High
Natural gas	-$90,313	$89,874	$770,190	$950,377
REC	-$13,337	$6,669	$847,166	$867,172
Carbon	-$17,244	$27,143	$843,259	$887,646
Load	-$18,627	$2,041	$841,876	$862,544
DSM	-$2,014	$14,674	$858,489	$875,177
Capital	-$132,066	$220,580	$728,437	$1,081,083
Total	**-$273,601**	**$360,981**	**$586,902**	**$1,221,484**

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



2-6 Balanced 1 (2021–2030)

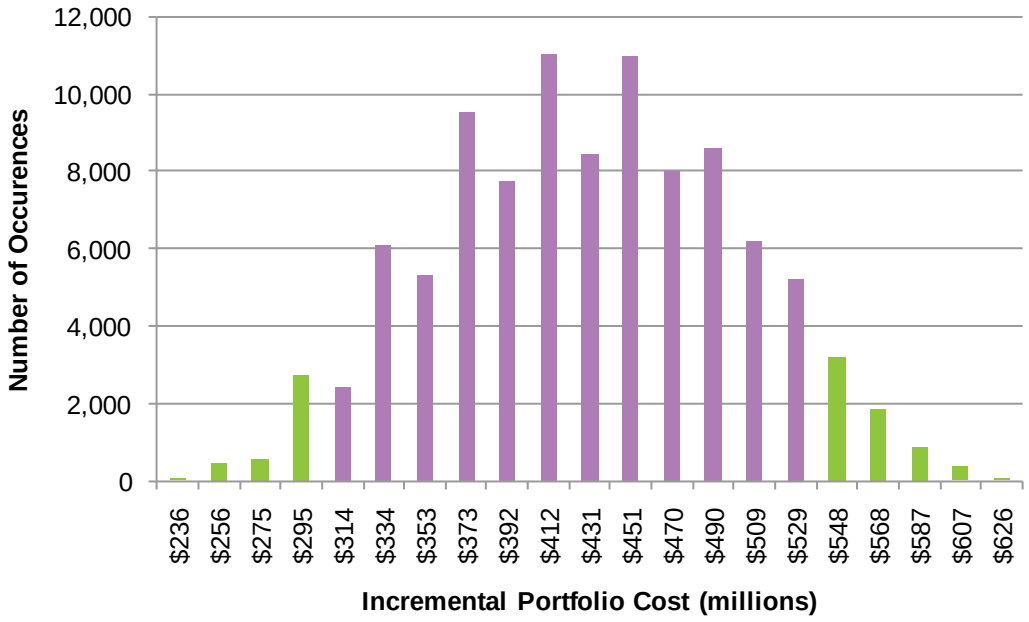
Base Portfolio Cost[1]=$445,704 [2]

	Adjustment to Base Incremental Portfolio Cost		Incremental Portfolio Cost Range	
Risk Factor Adjustments	**Low**	**High**	**Low**	**High**
Natural gas	-$60,770	$21,871	$384,934	$467,575
REC	-$5,292	$2,646	$440,412	$448,350
Carbon	-$27,539	$41,639	$418,165	$487,343
Load	-$17,483	$2,948	$428,221	$448,652
DSM	-$784	$15,763	$444,920	$461,467
Capital	-$97,378	$95,892	$348,326	$541,596
Total	**-$209,246**	**$180,759**	**$236,458**	**$626,463**

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



2-7 Balanced 2 (2021–2030)

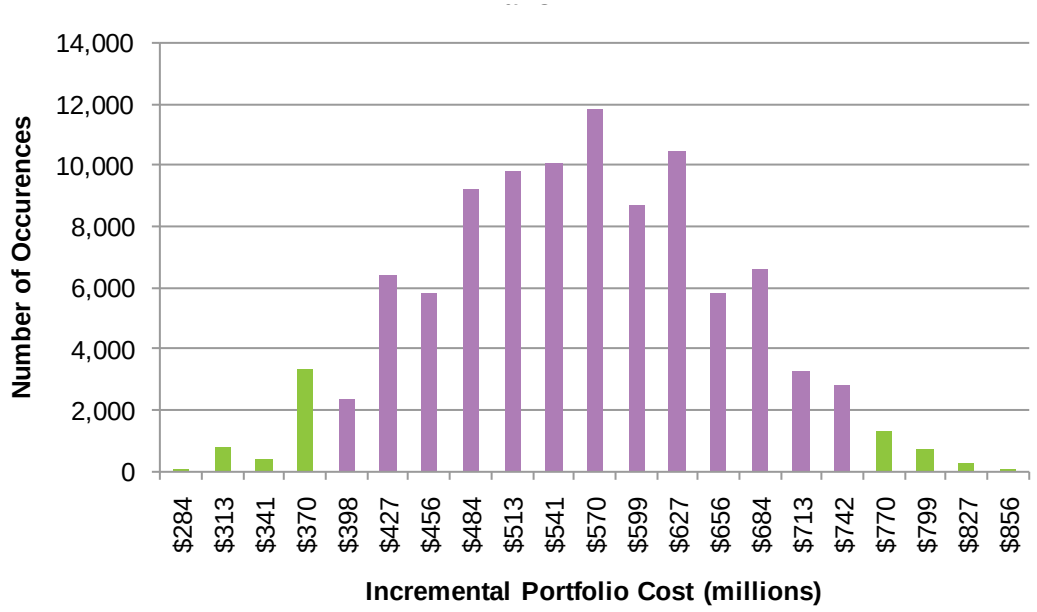
Base Portfolio Cost[1]=$567,780 [2]

	Adjustment to Base Incremental Portfolio Cost		Incremental Portfolio Cost Range	
Risk Factor Adjustments	**Low**	**High**	**Low**	**High**
Natural gas	-$100,644	$86,232	$467,136	$654,012
REC	-$17,679	$8,840	$550,101	$576,620
Carbon	-$32,720	$52,081	$535,060	$619,861
Load	-$18,735	$3,957	$549,045	$571,737
DSM	-$2,067	$16,029	$565,713	$583,809
Capital	-$111,939	$120,961	$455,841	$688,741
Total	**-$283,784**	**$288,100**	**$283,996**	**$855,880**

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



2-8 Pacific Northwest Transmission (2021–2030)

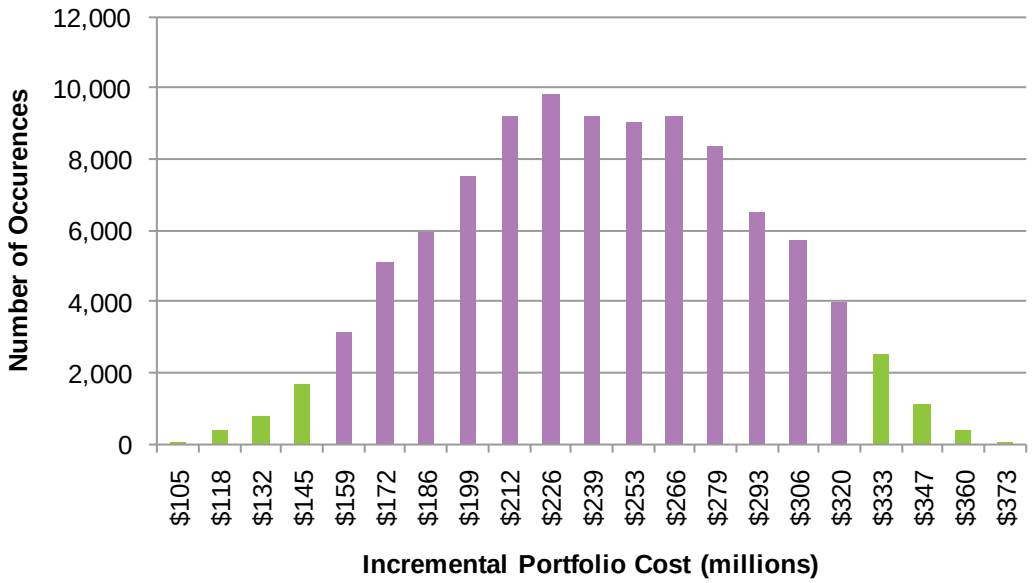
Base Portfolio Cost[1]=$240,492 [2]

Risk Factor Adjustments	Adjustment to Base Incremental Portfolio Cost		Incremental Portfolio Cost Range	
	Low	High	Low	High
Natural gas	-$12,338	$15,040	$228,154	$255,532
REC	-$3,545	$1,773	$236,947	$242,265
Carbon	-$27,435	$34,509	$213,057	$275,001
Load	-$16,963	-$278	$223,529	$240,214
DSM	-$2,142	$13,059	$238,350	$253,551
Capital	-$73,081	$68,842	$167,411	$309,334
Total	**-$135,504**	**$132,945**	**$104,988**	**$373,437**

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



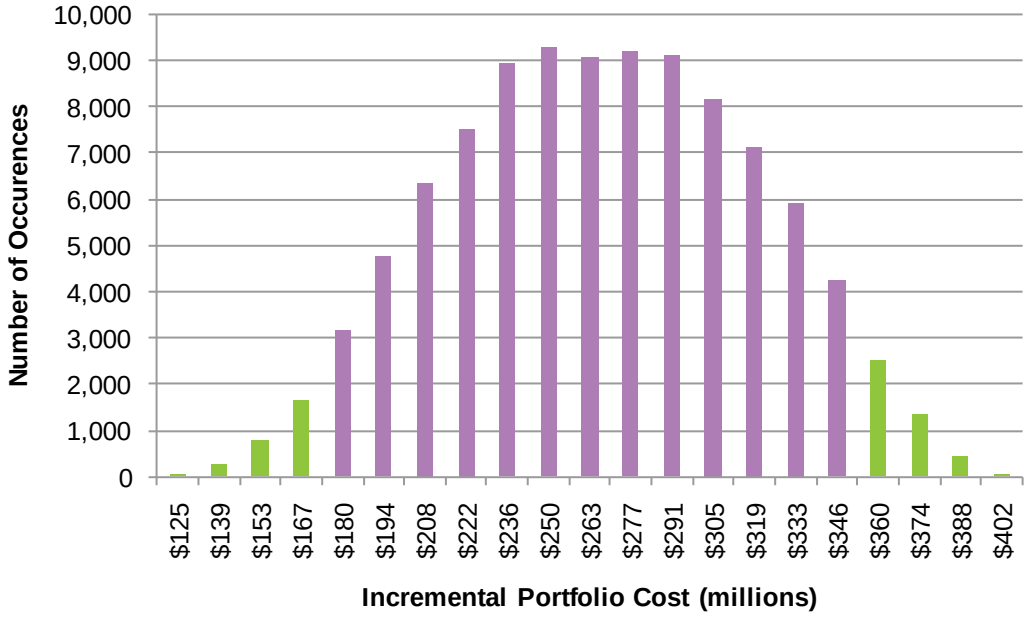
2-9 Eastside Transmission (2021–2030)

Base Portfolio Cost[1]=$260,903 [2]

Risk Factor Adjustments	Adjustment to Base Incremental Portfolio Cost Low	Adjustment to Base Incremental Portfolio Cost High	Incremental Portfolio Cost Range Low	Incremental Portfolio Cost Range High
Natural gas	-$9,856	$10,461	$251,047	$271,364
REC	-$3,545	$1,773	$257,358	$262,676
Carbon	-$25,113	$39,456	$235,790	$300,359
Load	-$19,808	$1,783	$241,095	$262,686
DSM	-$1,301	$14,522	$259,602	$275,425
Capital	-$76,125	$72,900	$184,778	$333,803
Total	**-$135,748**	**$140,895**	**$125,155**	**$401,798**

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.
[2] All numbers in thousands

Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



2-10 Renewable (2021–2030)

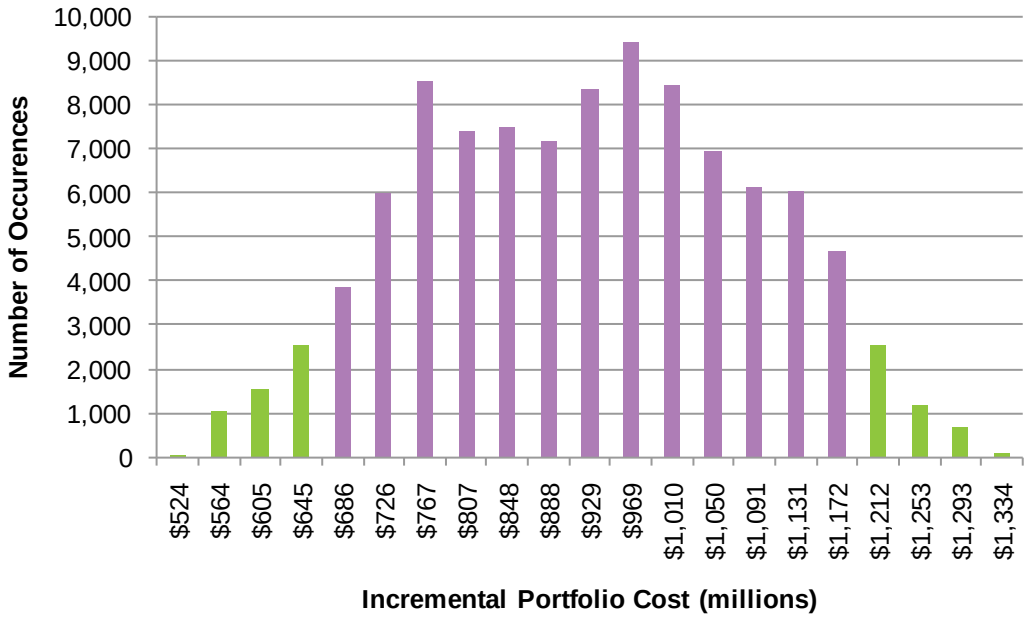
Base Portfolio Cost[1]=$966,716 [2]

	Adjustment to Base Incremental Portfolio Cost		Incremental Portfolio Cost Range	
Risk Factor Adjustments	**Low**	**High**	**Low**	**High**
Natural gas	-$82,345	$80,758	$884,371	$1,047,474
REC	-$23,073	$11,537	$943,643	$978,253
Carbon	-$32,724	$42,734	$933,992	$1,009,450
Load	-$21,036	$2,232	$945,680	$968,948
DSM	-$1,710	$14,726	$965,006	$981,442
Capital	-$282,005	$215,025	$684,711	$1,181,741
Total	**-$442,893**	**$367,012**	**$523,823**	**$1,333,728**

[1] Incremental cost of portfolio under base-case assumptions for risk factors considered.

[2] All numbers in thousands

Distribution of Incremental Portfolio Cost for 100,000 Stochastic Draws



Regulatory Environmental Compliance Costs

	2011$s—000's			
Expected Case 2011–2020 Portfolios	**NO_x[1]**	**SO_2[2]**	**Hg[3]**	**CO_2[4]**
1-1 Sun and Steam	$91,290	$124	$2,259	$605,384
1-2 Solar	$89,818	$124	$2,260	$555,413
1-3 Boardman to Hemingway	$89,798	$124	$2,327	$555,740
1-4 SCCT	$90,168	$125	$2,281	$557,397
1-5 CCCT	$90,534	$124	$2,240	$578,372
1-6 CHP	$90,961	$124	$2,257	$599,447
1-7 Balanced	$90,835	$125	$2,257	$588,094
1-8 Pumped Storage	$90,121	$125	$2,251	$558,767
1-9 Distributed Gen	$90,216	$125	$2,250	$557,458
Expected Case 2021–2030 Portfolios				
2-1 Nuclear	$99,226	$74	$1,504	$761,248
2-2 IGCC	$100,599	$75	$2,031	$798,966
2-3 SCCT and Wind	$99,903	$74	$1,567	$764,301
2-4 CCCT and Wind	$100,428	$75	$1,465	$804,847
2-5 Hydro and CHP	$100,969	$75	$1,471	$826,847
2-6 Balanced 1	$99,432	$74	$1,440	$779,020
2-7 Balanced 2	$100,379	$75	$1,438	$816,536
2-8 Pacific Northwest Transmission	$99,082	$74	$1,463	$763,495
2-9 Eastside Transmission	$98,812	$73	$1,395	$757,107
2-10 Renewable	$100,537	$75	$1,428	$818,227
Low Case 2011–2020 Portfolios				
1-1 Sun and Steam	$68,468	$93	$1,694	$427,944
1-2 Solar	$67,364	$93	$1,695	$392,826
1-3 Boardman to Hemingway	$67,349	$93	$1,745	$393,070
1-4 SCCT	$67,626	$93	$1,710	$394,313
1-5 CCCT	$67,900	$93	$1,680	$409,167
1-6 CHP	$68,221	$93	$1,692	$423,540
1-7 Balanced	$68,127	$93	$1,692	$415,882
1-8 Pumped Storage	$67,590	$94	$1,688	$395,262
1-9 Distributed Gen	$67,662	$94	$1,687	$394,323
Low Case 2021–2030 Portfolios				
2-1 Nuclear	$74,419	$55	$1,128	$448,091
2-2 IGCC	$75,449	$56	$1,523	$468,986
2-3 SCCT and Wind	$74,927	$56	$1,175	$449,817
2-4 CCCT and Wind	$75,321	$56	$1,099	$473,483
2-5 Hydro and CHP	$75,727	$56	$1,103	$485,554
2-6 Balanced 1	$74,574	$55	$1,080	$457,832
2-7 Balanced 2	$75,285	$56	$1,078	$479,178
2-8 Pacific Northwest Transmission	$74,312	$55	$1,097	$449,233
2-9 Eastside Transmission	$74,109	$55	$1,046	$445,686
2-10 Renewable	$75,403	$56	$1,071	$480,823

[1] NO_x=Nitrogen Oxides, [2] SO_2=Sulfur Oxides, [3] Hg=Mercury, [4] CO_2=Carbon Dioxide

	2011$s—000's			
High Case 2011–2020 Portfolios	**NO_x**	**SO_2**	**Hg**	**CO_2**
1-1 Sun and Steam	$114,113	$155	$2,822	$803,059
1-2 Solar	$112,273	$155	$2,824	$736,402
1-3 Boardman to Hemingway	$112,248	$155	$2,907	$736,818
1-4 SCCT	$112,710	$156	$2,850	$738,882
1-5 CCCT	$113,167	$155	$2,799	$766,656
1-6 CHP	$113,702	$155	$2,820	$795,577
1-7 Balanced	$113,544	$156	$2,820	$779,836
1-8 Pumped Storage	$112,651	$156	$2,813	$740,737
1-9 Distributed Gen	$112,770	$156	$2,811	$739,022
High Case 2021–2030 Portfolios				
2-1 Nuclear	$124,032	$92	$1,879	$1,211,169
2-2 IGCC	$125,749	$93	$2,537	$1,274,632
2-3 SCCT and Wind	$124,879	$93	$1,958	$1,216,209
2-4 CCCT and Wind	$125,535	$93	$1,831	$1,281,220
2-5 Hydro and CHP	$126,211	$94	$1,838	$1,318,497
2-6 Balanced 1	$124,290	$92	$1,800	$1,241,332
2-7 Balanced 2	$125,474	$93	$1,797	$1,303,001
2-8 Pacific Northwest Transmission	$123,853	$92	$1,828	$1,215,227
2-9 Eastside Transmission	$123,516	$92	$1,743	$1,204,482
2-10 Renewable	$125,672	$93	$1,784	$1,303,934

Portfolio Incremental Transmission Analysis

Idaho Power Transmission Rate Approximation for 2011 IRP Analysis Portfolio 1-1 Sun and Steam	
Project capital cost	
Local interconnection costs	$46,000,000
Network upgrades	$27,600,000
Annual Revenue Requirements	
Existing revenue requirements	$106,758,681
Existing revenue credits	($10,585,006)
Existing net revenue requirements	$96,173,675
New Project Capital	**$73,600,000**
New revenue requirements for project(s)	$11,176,616
New net revenue requirements	$107,350,291
System In Use (MW)	
Existing system peak demand	5,612
Future additional Idaho Power network use	**450**
New system demand—including new uses	6,062
Point-to-Point Transmission Rate (Dollars/kW-year)	
a) Existing rate	$17.14
b) New rate without third-party use	$17.71
Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits	
Change in existing uses (increase > 100%)	100%
Existing uses adjusted at new rate b)	($353,043)
Network Transmission Revenue Requirements	
a) Existing	
BPA load ratio share	$4,114,966
Long-term point-to-point revenue	$12,270,198
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$72,788,511
b) Future—new projects without additional participation	
BPA load ratio share	$4,218,663
Long-term point-to-point revenue	$12,679,447
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$83,452,181
Net change	**$10,663,670**

Idaho Power Transmission Rate Approximation for 2011 IRP Analysis Portfolio 1-2 Solar	
Project capital cost	
Local interconnection costs	$39,537,000
Network upgrades	$273,687,209
Annual Revenue Requirements	
Existing revenue requirements	$106,758,681
Existing revenue credits	($10,585,006)
Existing net revenue requirements	$96,173,675
New Project Capital	**$313,224,209**
New revenue requirements for project(s)	$47,565,038
New net revenue requirements	$143,738,713
System In Use (MW)	
Existing system peak demand	5,612
Future additional Idaho Power network use	**450**
New system demand—including new uses	6,062
Point-to-Point Transmission Rate (Dollars/kW-year)	
a) Existing rate	$17.14
b) New rate without third-party use	$23.71
Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits	
Change in existing uses (increase > 100%)	100%
Existing uses adjusted at new rate b)	($4,060,702)
Network Transmission Revenue Requirements	
a) Existing	
BPA load ratio share	$4,114,966
Long-term point-to-point revenue	$12,270,198
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$72,788,511
b) Future—new projects without additional participation	
BPA load ratio share	$5,507,193
Long-term point-to-point revenue	$16,977,387
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$114,254,133
Net change	**$41,465,622**

Idaho Power Transmission Rate Approximation for 2011 IRP Analysis Portfolio 1-3 with additional Boardman to Hemingway Third-Party Subscription	
Project capital cost	
Local interconnection costs	$228,837,209
Network upgrades	$18,377,000
Annual Revenue Requirements	
Existing revenue requirements	$106,758,681
Existing revenue credits	($10,585,006)
Existing net revenue requirements	$96,173,675
New Project Capital	**$247,214,209**
New revenue requirements for project(s)	$37,541,010
New net revenue requirements	$133,714,685
System In Use (MW)	
Existing system peak demand	5,612
Future additional Idaho Power network use	**450**
New system demand—including new uses	6,062
Point-to-Point Transmission Rate (Dollars/kW-year)	
a) Existing rate	$17.14
b) New rate without third-party use	$22.06
Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits	
Change in existing uses (increase > 100%)	100%
Existing uses adjusted at new rate b)	($3,039,342)
Network Transmission Revenue Requirements	
a) Existing	
BPA load ratio share	$4,114,966
Long-term point-to-point revenue	$12,270,198
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$72,788,511
b) Future—new projects without additional participation	
BPA load ratio share	$5,152,238
Long-term point-to-point revenue	$15,793,420
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$105,769,027
Net change	**$32,980,516**

Idaho Power Transmission Rate Approximation for 2011 IRP Analysis Portfolio 1-4 SCCT	
Project capital cost	
Local interconnection costs	$–
Network upgrades	$47,150,000
Annual Revenue Requirements	
Existing revenue requirements	$106,758,681
Existing revenue credits	($10,585,006)
Existing net revenue requirements	$96,173,675
New Project Capital	**$47,150,000**
New revenue requirements for project(s)	$7,160,020
New net revenue requirements	$10,333,695
System In Use (MW)	
Existing system peak demand	5,612
Future additional Idaho Power network use	**450**
New system demand—including new uses	6,062
Point-to-Point Transmission Rate (Dollars/kW-year)	
a) Existing rate	$17.14
b) New rate without third-party use	$17.05
Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits	
Change in existing uses (increase > 100%)	100%
Existing uses adjusted at new rate b)	$56,213
Network Transmission Revenue Requirements	
a) Existing	
BPA load ratio share	$4,114,966
Long-term point-to-point revenue	$12,270,198
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$72,788,511
b) Future—new projects without additional participation	
BPA load ratio share	$4,076,434
Long-term point-to-point revenue	$12,205,036
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$80,052,225
Net change	**$7,263,714**

Idaho Power Transmission Rate Approximation for 2011 IRP Analysis Portfolio 1-5 CCCT	
Project capital cost	
Local interconnection costs	$–
Network upgrades	$47,150,000
Annual Revenue Requirements	
Existing revenue requirements	$106,758,681
Existing revenue credits	($10,585,006)
Existing net revenue requirements	$96,173,675
New Project Capital	**$47,150,000**
New revenue requirements for project(s)	$7,160,020
New net revenue requirements	$10,333,695
System In Use (MW)	
Existing system peak demand	5,612
Future additional Idaho Power network use	**450**
New system demand—including new uses	6,062
Point-to-Point Transmission Rate (Dollars/kW-year)	
a) Existing rate	$17.14
b) New rate without third-party use	$17.05
Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits	
Change in existing uses (increase > 100%)	100%
Existing uses adjusted at new rate b)	$56,213
Network Transmission Revenue Requirements	
a) Existing	
BPA load ratio share	$4,114,966
Long-term point-to-point revenue	$12,270,198
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$72,788,511
b) Future—new projects without additional participation	
BPA load ratio share	$4,076,434
Long-term point-to-point revenue	$12,205,036
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$80,052,225
Net change	**$7,263,714**

Idaho Power Transmission Rate Approximation for 2011 IRP Analysis Portfolio 1-6 CHP	
Project capital cost	
Local interconnection costs	$4,370,000
Network upgrades	$29,900,000
Annual Revenue Requirements	
Existing revenue requirements	$106,758,681
Existing revenue credits	($10,585,006)
Existing net revenue requirements	$96,173,675
New Project Capital	**$34,270,000**
New revenue requirements for project(s)	$5,204,112
New net revenue requirements	$101,377,787
System In Use (MW)	
Existing system peak demand	5,612
Future additional Idaho Power network use	**450**
New system demand—including new uses	6,062
Point-to-Point Transmission Rate (Dollars/kW-year)	
a) Existing rate	$17.14
b) New rate without third-party use	$16.72
Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits	
Change in existing uses (increase > 100%)	100%
Existing uses adjusted at new rate b)	$255,503
Network Transmission Revenue Requirements	
a) Existing	
BPA load ratio share	$4,114,966
Long-term point-to-point revenue	$12,270,198
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$72,788,511
b) Future—new projects without additional participation	
BPA load ratio share	$4,007,174
Long-term point-to-point revenue	$11,974,018
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$78,396,595
Net change	**$5,608,084**

Idaho Power Transmission Rate Approximation for 2011 IRP Analysis Portfolio 1-7 Balanced	
Project capital cost	
Local interconnection costs	$12,897,500
Network upgrades	$28,600,000
Annual Revenue Requirements	
Existing revenue requirements	$106,758,681
Existing revenue credits	($10,585,006)
Existing net revenue requirements	$96,173,675
New Project Capital	**$41,497,500**
New revenue requirements for project(s)	$6,301,653
New net revenue requirements	$102,475,328
System In Use (MW)	
Existing system peak demand	5,612
Future additional Idaho Power network use	**450**
New system demand—including new uses	6,062
Point-to-Point Transmission Rate (Dollars/kW-year)	
a) Existing rate	$17.14
b) New rate without third-party use	$16.90
Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits	
Change in existing uses (increase > 100%)	100%
Existing uses adjusted at new rate b)	$143,673
Network Transmission Revenue Requirements	
a) Existing	
BPA load ratio share	$4,114,966
Long-term point-to-point revenue	$12,270,198
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$72,788,511
b) Future—new projects without additional participation	
BPA load ratio share	$4,046,039
Long-term point-to-point revenue	$12,103,651
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$79,325,637
Net change	**$6,537,127**

Idaho Power Transmission Rate Approximation for 2011 IRP Analysis Portfolio 1-8 Pumped Storage	
Project capital cost	
Local interconnection costs	$15,525,000
Network upgrades	$34,500,000
Annual Revenue Requirements	
Existing revenue requirements	$106,758,681
Existing revenue credits	($10,585,006)
Existing net revenue requirements	$96,173,675
New Project Capital	**$50,025,000**
New revenue requirements for project(s)	$7,596,606
New net revenue requirements	$103,770,281
System In Use (MW)	
Existing system peak demand	5,612
Future additional Idaho Power network use	**450**
New system demand—including new uses	6,062
Point-to-Point Transmission Rate (Dollars/kW-year)	
a) Existing rate	$17.14
b) New rate without third-party use	$17.12
Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits	
Change in existing uses (increase > 100%)	100%
Existing uses adjusted at new rate b)	$11,729
Network Transmission Revenue Requirements	
a) Existing	
BPA load ratio share	$4,114,966
Long-term point-to-point revenue	$12,270,198
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$72,788,511
b) Future—new projects without additional participation	
BPA load ratio share	$4,091,894
Long-term point-to-point revenue	$12,256,602
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$80,421,786
Net change	**$7,633,275**

Idaho Power Transmission Rate Approximation for 2011 IRP Analysis Portfolio 1-9 Distributed Generation	
Project capital cost	
Local interconnection costs	$–
Network upgrades	$47,150,000
Annual Revenue Requirements	
Existing revenue requirements	$106,758,681
Existing revenue credits	($10,585,006)
Existing net revenue requirements	$96,173,675
New Project Capital	**$47,150,000**
New revenue requirements for project(s)	$7,160,020
New net revenue requirements	$103,333,695
System In Use (MW)	
Existing system peak demand	5,612
Future additional Idaho Power network use	**450**
New system demand—including new uses	6,062
Point-to-Point Transmission Rate (Dollars/kW-year)	
a) Existing rate	$17.14
b) New rate without third-party use	$17.05
Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits	
Change in existing uses (increase > 100%)	100%
Existing uses adjusted at new rate b)	$56,213
Network Transmission Revenue Requirements	
a) Existing	
BPA load ratio share	$4,114,966
Long-term point-to-point revenue	$12,270,198
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$72,788,511
b) Future—new projects without additional participation	
BPA load ratio share	$4,076,434
Long-term point-to-point revenue	$12,205,036
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$80,052,225
Net change	**$7,263,714**

Idaho Power Transmission Rate Approximation for 2011 IRP Analysis Portfolio 2-1 Nuclear	
Project capital cost	
Local interconnection costs	$39,652,000
Network upgrades	$570,767,399
Annual Revenue Requirements	
Existing revenue requirements	$106,758,681
Existing revenue credits	($10,585,006)
Existing net revenue requirements	$96,173,675
New Project Capital	**$610,419,399**
New revenue requirements for project(s)	$92,695,970
New net revenue requirements	$188,869,645
System In Use (MW)	
Existing system peak demand	5,612
Future additional Idaho Power network use	**1,168**
New system demand—including new uses	6,780
Point-to-Point Transmission Rate (Dollars/kW-year)	
a) Existing rate	$17.14
b) New rate without third-party use	$27.86
Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits	
Change in existing uses (increase > 100%)	100%
Existing uses adjusted at new rate b)	($6,621,196)
Network Transmission Revenue Requirements	
a) Existing	
BPA load ratio share	$4,114,966
Long-term point-to-point revenue	$12,270,198
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$72,788,511
b) Future—new projects without additional participation	
BPA load ratio share	$6,385,760
Long-term point-to-point revenue	$19,945,526
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$155,538,359
Net change	**$82,749,848**

Idaho Power Transmission Rate Approximation for 2011 IRP Analysis Portfolio 2-2 IGCC	
Project capital cost	
Local interconnection costs	$57,592,000
Network upgrades	$1,066,803,876
Annual Revenue Requirements	
Existing revenue requirements	$106,758,681
Existing revenue credits	($10,585,006)
Existing net revenue requirements	$96,173,675
New Project Capital	**$1,124,395,876**
New revenue requirements for project(s)	$170,746,484
New net revenue requirements	$266,920,159
System In Use (MW)	
Existing system peak demand	5,612
Future additional Idaho Power network use	**1,168**
New system demand—including new uses	6,780
Point-to-Point Transmission Rate (Dollars/kW-year)	
a) Existing rate	$17.14
b) New rate without third-party use	$39.37
Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits	
Change in existing uses (increase > 100%)	100%
Existing uses adjusted at new rate b)	($13,731,672)
Network Transmission Revenue Requirements	
a) Existing	
BPA load ratio share	$4,114,966
Long-term point-to-point revenue	$12,270,198
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$72,788,511
b) Future—new projects without additional participation	
BPA load ratio share	$8,871,411
Long-term point-to-point revenue	$28,188,029
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$222,860,720
Net change	**$150,072,209**

Idaho Power Transmission Rate Approximation for 2011 IRP Analysis Portfolio 2-3 SCCT/Wind	
Project capital cost	
Local interconnection costs	$39,077,000
Network upgrades	$599,079,709
Annual Revenue Requirements	
Existing revenue requirements	$106,758,681
Existing revenue credits	($10,585,006)
Existing net revenue requirements	$96,173,675
New Project Capital	**$638,156,709**
New revenue requirements for project(s)	$96,908,052
New net revenue requirements	$193,081,727
System In Use (MW)	
Existing system peak demand	5,612
Future additional Idaho Power network use	**1,168**
New system demand—including new uses	6,780
Point-to-Point Transmission Rate (Dollars/kW-year)	
a) Existing rate	$17.14
b) New rate without third-party use	$28.48
Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits	
Change in existing uses (increase > 100%)	100%
Existing uses adjusted at new rate b)	($7,004,921)
Network Transmission Revenue Requirements	
a) Existing	
BPA load ratio share	$4,114,966
Long-term point-to-point revenue	$12,270,198
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$72,788,511
b) Future—new projects without additional participation	
BPA load ratio share	$6,519,900
Long-term point-to-point revenue	$20,390,342
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$159,171,485
Net change	**$86,382,974**

Idaho Power Transmission Rate Approximation for 2011 IRP Analysis Portfolio 2-4 CCCT/Wind	
Project capital cost	
Local interconnection costs	$32,177,000
Network upgrades	$599,079,709
Annual Revenue Requirements	
Existing revenue requirements	$106,758,681
Existing revenue credits	($10,585,006)
Existing net revenue requirements	$96,173,675
New Project Capital	**$631,256,709**
New revenue requirements for project(s)	$95,860,245
New net revenue requirements	$193,033,920
System In Use (MW)	
Existing system peak demand	5,612
Future additional Idaho Power network use	**1,168**
New system demand—including new uses	6,780
Point-to-Point Transmission Rate (Dollars/kW-year)	
a) Existing rate	$17.14
b) New rate without third-party use	$28.32
Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits	
Change in existing uses (increase > 100%)	100%
Existing uses adjusted at new rate b)	($6,909,465)
Network Transmission Revenue Requirements	
a) Existing	
BPA load ratio share	$4,114,966
Long-term point-to-point revenue	$12,270,198
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$72,788,511
b) Future—new projects without additional participation	
BPA load ratio share	$6,486,531
Long-term point-to-point revenue	$20,279,688
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$158,267,700
Net change	**$85,479,189**

Idaho Power Transmission Rate Approximation for 2011 IRP Analysis Portfolio 2-5 Hydro/CHP	
Project capital cost	
Local interconnection costs	$72,772,000
Network upgrades	$572,514,709
Annual Revenue Requirements	
Existing revenue requirements	$106,758,681
Existing revenue credits	($10,585,006)
Existing net revenue requirements	$96,173,675
New Project Capital	**$645,286,709**
New revenue requirements for project(s)	$97,990,787
New net revenue requirements	$194,164,462
System In Use (MW)	
Existing system peak demand	5,612
Future additional Idaho Power network use	**1,168**
New system demand—including new uses	6,780
Point-to-Point Transmission Rate (Dollars/kW-year)	
a) Existing rate	$17.14
b) New rate without third-party use	$28.64
Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits	
Change in existing uses (increase > 100%)	100%
Existing uses adjusted at new rate b)	($7,103,559)
Network Transmission Revenue Requirements	
a) Existing	
BPA load ratio share	$4,114,966
Long-term point-to-point revenue	$12,270,198
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$72,788,511
b) Future—new projects without additional participation	
BPA load ratio share	$6,554,382
Long-term point-to-point revenue	$20,504,684
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$160,105,396
Net change	**$87,316,886**

Idaho Power Transmission Rate Approximation for 2011 IRP Analysis Portfolio 2-6 Balanced 1	
Project capital cost	
Local interconnection costs	$57,994,500
Network upgrades	$332,337,209
Annual Revenue Requirements	
Existing revenue requirements	$106,758,681
Existing revenue credits	($10,585,006)
Existing net revenue requirements	$96,173,675
New Project Capital	**$390,331,709**
New revenue requirements for project(s)	$59,274,290
New net revenue requirements	$155,447,965
System In Use (MW)	
Existing system peak demand	5,612
Future additional Idaho Power network use	**1,168**
New system demand—including new uses	6,780
Point-to-Point Transmission Rate (Dollars/kW-year)	
a) Existing rate	$17.14
b) New rate without third-party use	$22.93
Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits	
Change in existing uses (increase > 100%)	100%
Existing uses adjusted at new rate b)	($3,576,450)
Network Transmission Revenue Requirements	
a) Existing	
BPA load ratio share	$4,114,966
Long-term point-to-point revenue	$12,270,198
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$72,788,511
b) Future—new projects without additional participation	
BPA load ratio share	$5,321,390
Long-term point-to-point revenue	$16,416,039
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$126,710,536
Net change	**$53,922,026**

Idaho Power Transmission Rate Approximation for 2011 IRP Analysis Portfolio 2-7 Balanced 2	
Project capital cost	
Local interconnection costs	$63,342,000
Network upgrades	$330,037,209
Annual Revenue Requirements	
Existing revenue requirements	$106,758,681
Existing revenue credits	($10,585,006)
Existing net revenue requirements	$96,173,675
New Project Capital	**$393,379,209**
New revenue requirements for project(s)	$59,737,072
New net revenue requirements	$155,910,746
System In Use (MW)	
Existing system peak demand	5,612
Future additional Idaho Power network use	**1,168**
New system demand—including new uses	6,780
Point-to-Point Transmission Rate (Dollars/kW-year)	
a) Existing rate	$17.14
b) New rate without third-party use	$23.00
Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits	
Change in existing uses (increase > 100%)	100%
Existing uses adjusted at new rate b)	($3,618,610)
Network Transmission Revenue Requirements	
a) Existing	
BPA load ratio share	$4,114,966
Long-term point-to-point revenue	$12,270,198
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$72,788,511
b) Future—new projects without additional participation	
BPA load ratio share	$5,336,128
Long-term point-to-point revenue	$16,464,911
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$127,109,708
Net change	**$54,321,197**

Idaho Power Transmission Rate Approximation for 2011 IRP Analysis Portfolio 2-8 PNW Transmission	
Project capital cost	
Local interconnection costs	$55,694,500
Network upgrades	$614,467,399
Annual Revenue Requirements	
Existing revenue requirements	$106,758,681
Existing revenue credits	($10,585,006)
Existing net revenue requirements	$96,173,675
New Project Capital	**$670,161,899**
New revenue requirements for project(s)	$101,768,239
New net revenue requirements	$197,941,914
System In Use (MW)	
Existing system peak demand	5,612
Future additional Idaho Power network use	**1,168**
New system demand—including new uses	6,780
Point-to-Point Transmission Rate (Dollars/kW-year)	
a) Existing rate	$17.14
b) New rate without third-party use	$29.19
Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits	
Change in existing uses (increase > 100%)	100%
Existing uses adjusted at new rate b)	($7,447,689)
Network Transmission Revenue Requirements	
a) Existing	
BPA load ratio share	$4,114,966
Long-term point-to-point revenue	$12,270,198
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$72,788,511
b) Future—new projects without additional participation	
BPA load ratio share	$6,674,681
Long-term point-to-point revenue	$20,903,600
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$163,363,632
Net change	**$90,575,121**

Idaho Power Transmission Rate Approximation for 2011 IRP Analysis Portfolio 2-9 Eastside Transmission	
Project capital cost	
Local interconnection costs	$55,694,500
Network upgrades	$976,337,209
Annual Revenue Requirements	
Existing revenue requirements	$106,758,681
Existing revenue credits	($10,585,006)
Existing net revenue requirements	$96,173,675
New Project Capital	**$1,132,031,709**
New revenue requirements for project(s)	$156,720,413
New net revenue requirements	$252,894,088
System In Use (MW)	
Existing system peak demand	5,612
Future additional Idaho Power network use	**1,168**
New system demand—including new uses	6,780
Point-to-Point Transmission Rate (Dollars/kW-year)	
a) Existing rate	$17.14
b) New rate without third-party use	$37.30
Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits	
Change in existing uses (increase > 100%)	100%
Existing uses adjusted at new rate b)	($12,453,884)
Network Transmission Revenue Requirements	
a) Existing	
BPA load ratio share	$4,114,966
Long-term point-to-point revenue	$12,270,198
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$72,788,511
b) Future—new projects without additional participation	
BPA load ratio share	$8,424,727
Long-term point-to-point revenue	$26,706,809
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$210,762,552
Net change	**$137,974,041**

Idaho Power Transmission Rate Approximation for 2011 IRP Analysis Portfolio 2-10 Renewable	
Project capital cost	
Local interconnection costs	$85,767,000
Network upgrades	$302,437,209
Annual Revenue Requirements	
Existing revenue requirements	$106,758,681
Existing revenue credits	($10,585,006)
Existing net revenue requirements	$96,173,675
New Project Capital	**$388,204,209**
New revenue requirements for project(s)	$58,951,216
New net revenue requirements	$155,124,891
System In Use (MW)	
Existing system peak demand	5,612
Future additional Idaho Power network use	**1,168**
New system demand—including new uses	6,780
Point-to-Point Transmission Rate (Dollars/kW-year)	
a) Existing rate	$17.14
b) New rate without third-party use	$22.88
Point-to-Point Revenue Adjustments (Incremental Change to Existing Revenue Credits	
Change in existing uses (increase > 100%)	100%
Existing uses adjusted at new rate b)	($3,547,018)
Network Transmission Revenue Requirements	
a) Existing	
BPA load ratio share	$4,114,966
Long-term point-to-point revenue	$12,270,198
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$72,788,511
b) Future—new projects without additional participation	
BPA load ratio share	$5,311,101
Long-term point-to-point revenue	$16,381,921
Legacy contract revenue	$7,000,000
Assigned to Idaho Power retail load service	$126,431,869
Net change	**$53,643,359**

Loss of Load Expectation Analysis

Loss of Load Expectation Summary Data–Preferred Portfolio (1-3 Boardman to Hemmingway and 2-6 Balanced 1)*

Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2011	2.05	0.00	0.00	0.00	0.00	0.00	0.08	1.68	0.15	0.13	0.00	0.00	0.01
2012	0.62	0.00	0.00	0.00	0.00	0.00	0.01	0.57	0.03	0.00	0.00	0.00	0.00
2013	1.54	0.00	0.00	0.00	0.00	0.00	0.03	1.42	0.08	0.01	0.00	0.00	0.00
2014	1.65	0.00	0.00	0.00	0.00	0.00	0.15	1.39	0.08	0.03	0.00	0.00	0.00
2015	1.92	0.00	0.00	0.00	0.00	0.00	0.38	1.40	0.06	0.08	0.00	0.00	0.00
2016	0.21	0.00	0.00	0.00	0.00	0.00	0.01	0.19	0.01	0.00	0.00	0.00	0.00
2017	0.21	0.00	0.00	0.00	0.00	0.00	0.01	0.18	0.02	0.00	0.00	0.00	0.00
2018	0.40	0.00	0.00	0.00	0.00	0.00	0.00	0.37	0.02	0.00	0.00	0.00	0.00
2019	0.75	0.00	0.00	0.00	0.00	0.00	0.02	0.69	0.04	0.00	0.00	0.00	0.00
2020	2.17	0.00	0.00	0.00	0.00	0.00	0.07	2.01	0.08	0.01	0.00	0.00	0.00
2021	2.05	0.00	0.00	0.00	0.00	0.00	0.11	2.93	0.17	0.01	0.00	0.00	0.00
2022	0.62	0.00	0.00	0.00	0.00	0.00	0.04	1.16	0.08	0.00	0.00	0.00	0.00
2023	1.54	0.00	0.00	0.00	0.00	0.00	0.05	1.21	0.20	0.01	0.00	0.00	0.00
2024	1.65	0.00	0.00	0.00	0.00	0.00	0.04	1.51	0.10	0.01	0.00	0.00	0.00
2025	2.15	0.00	0.00	0.00	0.00	0.00	0.01	0.31	0.02	0.00	0.00	0.00	0.00
2026	0.88	0.00	0.00	0.00	0.00	0.00	0.02	0.95	0.04	0.00	0.00	0.00	0.00
2027	1.85	0.00	0.00	0.00	0.00	0.00	0.04	1.59	0.07	0.00	0.00	0.00	0.00
2028	2.06	0.00	0.00	0.00	0.00	0.00	0.03	0.92	0.14	0.00	0.00	0.00	0.00
2029	2.33	0.00	0.00	0.00	0.00	0.00	0.01	0.47	0.02	0.00	0.00	0.00	0.00
2030	1.51	0.00	0.00	0.00	0.00	0.00	0.03	0.88	0.06	0.00	0.00	0.00	0.00

* With CBM@330 MW and 83 MW & 158 MW Jul Eastside Purchases in 2013/2014.

Loss of Load Expectation Summary Data–Alternate Portfolio (1-4 SCCT)*

Year	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2011	2.05	0.00	0.00	0.00	0.00	0.00	0.08	1.68	0.15	0.13	0.00	0.00	0.01
2012	0.62	0.00	0.00	0.00	0.00	0.00	0.01	0.57	0.03	0.00	0.00	0.00	0.00
2013	1.54	0.00	0.00	0.00	0.00	0.00	0.03	1.42	0.08	0.01	0.00	0.00	0.00
2014	1.65	0.00	0.00	0.00	0.00	0.00	0.15	1.39	0.08	0.03	0.00	0.00	0.00
2015	1.21	0.00	0.00	0.00	0.00	0.00	0.09	1.06	0.05	0.01	0.00	0.00	0.00
2016	1.95	0.00	0.00	0.00	0.00	0.00	0.18	1.63	0.11	0.02	0.00	0.00	0.00
2017	0.95	0.00	0.00	0.00	0.00	0.00	0.04	0.77	0.13	0.01	0.00	0.00	0.00
2018	1.69	0.00	0.00	0.00	0.00	0.00	0.03	1.58	0.07	0.01	0.00	0.00	0.00
2019	1.38	0.00	0.00	0.00	0.00	0.00	0.04	1.24	0.08	0.01	0.00	0.00	0.00
2020	1.38	0.00	0.00	0.00	0.00	0.00	0.04	1.24	0.08	0.01	0.00	0.00	0.00

* With CBM@330 MW

Loss of Load Expectation Summary Data–Alternate Portfolio (2-8 Pacific Northwest Transmission)*													
Year	**Annual**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**
2021	2.05	0.00	0.00	0.00	0.00	0.00	0.11	2.93	0.17	0.01	0.00	0.00	0.00
2022	0.62	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00
2023	1.54	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	0.00	0.00
2024	1.65	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00
2025	2.38	0.00	0.00	0.00	0.00	0.00	0.01	0.17	0.01	0.00	0.00	0.00	0.00
2026	2.07	0.00	0.00	0.00	0.00	0.00	0.01	0.55	0.02	0.00	0.00	0.00	0.00
2027	2.05	0.00	0.00	0.00	0.00	0.00	0.02	0.89	0.03	0.00	0.00	0.00	0.00
2028	1.72	0.00	0.00	0.00	0.00	0.00	0.01	0.53	0.07	0.00	0.00	0.00	0.00
2029	2.01	0.00	0.00	0.00	0.00	0.00	0.00	0.25	0.01	0.00	0.00	0.00	0.00
2030	1.36	0.00	0.00	0.00	0.00	0.00	0.01	0.53	0.03	0.00	0.00	0.00	0.00

* With CBM@330 MW

Boardman to Hemingway Tipping Point Analysis Data

Market Price Increase Tipping Point Calculation				
	Unit	**1-3 Boardman to Hemingway**	**1-4 SCCT**	**Variance**
Total portfolio cost (from Table 9.2)	2011 $s—000's	$3,177,308	$3,220,672	$43,364
2016-2020 market purchases (from AURORA)	MWh	6,826,175	6,763,722	(62,453)

Note: Market price increase necessary to make total portfolio cost equivalent: $694 $/MWh ($43,364,000/62,453 MWh)

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 09 2007.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

Adopted IRP Guidelines

Guideline 1: Substantive Requirements

a. All resources must be evaluated on a consistent and comparable basis.

- *All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.*
- *Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.*
- *Consistent assumptions and methods should be used for evaluation of all resources.*
- *The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.*

b. Risk and uncertainty must be considered.

- *At a minimum, utilities should address the following sources of risk and uncertainty:*
  1. *Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.*
  2. *Natural gas utilities: demand (peak, swing and base-load), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.*
- *Utilities should identify in their plans any additional sources of risk and uncertainty.*

c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and

associated risks and uncertainties for the utility and its customers.[1]

- *The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.*

- *Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.*

- *To address risk, the plan should include, at a minimum:*

  1. *Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.*

  2. *Discussion of the proposed use and impact on costs and risks of physical and financial hedging.*

- *The utility should explain in its plan how its resource choices appropriately balance cost and risk.*

d. *The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.*

Guideline 2: Procedural Requirements.

a. *The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.*

[1] We sometimes refer to this portfolio as the "best cost/risk portfolio."

b. While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.

c. The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.

Guideline 3: Plan Filing, Review, and Updates.

a. A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.

b. The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.

c. Commission staff and parties should complete their comments and recommendations within six months of IRP filing.

d. The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.

e. The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.

f. Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.

g. *Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:*

- *Describes what actions the utility has taken to implement the plan;*
- *Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and*
- *Justifies any deviations from the acknowledged action plan.*

Guideline 4: Plan Components.

At a minimum, the plan must include the following elements:

a. *An explanation of how the utility met each of the substantive and procedural requirements;*

b. *Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;*

c. *For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;*

d. *For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;*

e. *Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;*

f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;

g. Identification of key assumptions about the future(e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;

h. Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;

i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;

j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;

k. Analysis of the uncertainties associated with each portfolio evaluated;

l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;

m. Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and

n. An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.

Guideline 5: Transmission.

Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote

locations, acquiring alternative fuel supplies, and improving reliability.

Guideline 6: Conservation.

a. *Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.*

b. *To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.*

c. *To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:*

   - *Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and*

   - *Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.*

Guideline 7: Demand Response.

Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).

Guideline 8: Environmental Costs.

Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential CO_2 regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.

Guideline 9: Direct Access Loads.

An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.

Guideline 10: Multi-state Utilities.

Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.

Guideline 11: Reliability.

Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.

Guideline 12: Distributed Generation.

Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.

Guideline 13: Resource Acquisition.

a. *An electric utility should, in its IRP:*

   - *Identify its proposed acquisition strategy for each resource in its action plan.*
   - *Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.*
   - *Identify any Benchmark Resources it plans to consider in competitive bidding.*

b. *Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.*

SUMMARY OF NORTHWEST UTILITY PLANNING CRITERIA

Utility	Planning Criteria
Avista Corporation	*Peak Load*—The maximum one-hour obligation, including operating reserves, on the expected average coldest day in January and the average hottest day in August.[1]
	Peak Resource Capability—The maximum one-hour generation capability of company resources, including net contract contribution, at the time of the one-hour system peak, and excluding resources that are on maintenance during peak load periods.[1]
	Planning Reserve—Set at a level equal to 15% planning reserve margin during the company's peak load hour.[1]
	Confidence Interval—Ninety percent confidence interval based on the monthly variability of load and the 10th percentile of monthly historical hydro energy. This results in a 10% chance of load exceeding the planning criteria for each month. In other words, there is a 10% chance that the company would need to purchase energy from the market in any given month.[1]
Bonneville Power Administration	*Load Forecast*—Based on normal weather conditions.[2]
	Hydro Conditions—Firm hydro energy and capacity estimates based on 1937 critical water conditions.[2]
	Hydro Energy—Based on current generation capability under average monthly river discharge. Uses operating year (OY) 1937 water conditions (the 12-month period from August 1936 through July 1937) to estimate the firm hydro energy capability in low water conditions.[2]
	Federal Firm Energy Surplus Analysis—The amount of generation that can be produced in excess of firm loads using 1937 critical water conditions.[2]
	Hydroelectric Capacity—The monthly instantaneous capacity of hydroelectric projects is defined as the full-gate-flow maximum generation at mid-month reservoir elevation using 1929 through 1998 historical water conditions.[2]
Idaho Power	*Hydro Conditions*—70th percentile hydro conditions based on historical data from 1928–2009.[3]
	Load Forecast—Based on 50th percentile weather conditions.[3]
	Monthly Average Energy—Based on 70th percentile water and 70th percentile average load conditions.[3]
	Capacity—Based on monthly peak-hour Northwest transmission deficit assuming 90th percentile water, 70th percentile average load, and 95th percentile peak-hour load conditions.[3]
Northwest Power and Conservation Council	*Uses a fully probabilistic model*—Prospective plans are tested against 20 years of future conditions. The test process uses random simulations of the principal sources of uncertainty, including hydro conditions, regional electric loads, fuel prices, CO_2 control requirements, import and export markets, resource availability, and other factors. The council's analytical process creates a 2-dimensional mathematical surface defined by portfolio cost and portfolio risk. A subset of resource portfolios along the mathematical cost–risk frontier are selected for further consideration. The preferred portfolio is selected from the set of finalist portfolios using qualitative criteria.[4]
PacifiCorp	*Thermal*—Maximum dependable capacity for peak-hour assessment. Energy assessments used maximum dependable capacity de-rated for forced outages and maintenance.[5]
	Hydro Conditions—Critical water conditions. For peak hour assessment, decision support software is used to shape critical hydro energy to estimate maximum capability sustainable for one hour.[5]
	Loads—Average energy requirements based on normal weather conditions.[5]
	Planning Reserve—Planning reserve margin of 13% assumed for energy and peak-hour assessments.[5]

[1] 2009 Integrated Resource Plan, Avista Utilities, August 2009, Chapter 2.

[2] 2009 Pacific Northwest Loads and Resources Study, Bonneville Power Administration, July 2009, Sections 2 & 4.

[3] 2011 Integrated Resource Plan, Idaho Power Company, June 2011.

[4] Sixth Northwest Power Plan, Northwest Power and Conservation Council, February 2010.

[5] 2011 Integrated Resource Plan, PacifiCorp, March 31, 2011, Chapter 5.

Utility	Planning Criteria
Portland General Electric Company (PGE)	*Hydro Conditions*—Normal hydro conditions.[6]
	Loads—PGE identifies annual energy needs under a reference case (i.e., expected or most likely) and high-load and low-load forecasts, assuming normal weather conditions.[6]
	Capacity—PGE evaluates peaking needs by comparing the annual one-hour maximum load inclusive of 12% reserves (6% operating margin, 6% planning margin), calculated on a 1-in-2 or average basis, to the capability of energy-producing resources. Reports both the winter and the summer peak loads.[6]
Puget Sound Energy	*Loads*—For capacity, power demand was estimated at normal winter minimum temperature (23° F) plus a 15% planning margin. Five different economic growth scenarios were modeled in the resource plan.[7]
	Hydro—For capacity resource need, hydro projects assumed at full-capacity output.[7]
	Thermal—For capacity resource need, thermal projects assumed at full-capacity output.[7]

[6] PGE 2009 Integrated Resource Plan, Portland General Electric, November 2009, Chapter 3.

[7] Integrated Resource Plan, Puget Sound Energy, July 2009, Chapters 5 & 8.

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