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February 14, 2013

VIA ELECTRONIC AND U.S. MAIL

PUC Filing Center
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97308-2148

Re: Docket LC 53 - Idaho Power Company's 2011 Integrated Resource Plan ("IRP")

Enclosed for filing in the above-identified docket are an original and ten copies of Idaho Power Company's Application for Acknowledgment of 2011 Integrated Resource Plan Update. Please note that certain portions of the Wind Integration Study and Coal Study are confidential and are subject to Protective Order No. 11-327.

A copy of this filing has been served on all parties to this proceeding as indicated on the attached Certificate of Service.

Please contact this office with any questions.

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Office Manager

cc: Service List

Enclosures

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing documents on in Docket LC 53 on the following named persons on the date indicated below by e-mail addressed to said persons at his or her last-known address indicated below.

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BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

LC 53

In the Matter of IDAHO POWER COMPANY'S 2011 Integrated Resource Plan.	)))))	**APPLICATION FOR ACKNOWLEDGMENT OF 2011 INTEGRATED RESOURCE PLAN UPDATE**

Pursuant to OAR 860-027-0400(8) and Order No. 07-002,[1] Idaho Power Company ("Idaho Power" or "Company") hereby requests that the Public Utility Commission of Oregon ("Commission") issue an order acknowledging the revised action plan items in Idaho Power's 2011 Integrated Resource Plan ("IRP") Update. The Company's 2011 IRP Update includes the Company's most recent "Wind Integration Study Report," the "Coal Environmental Compliance Upgrade Investment Evaluation" prepared for Idaho Power by Science Application International Corporation ("SAIC"), and the Company's "Coal Unit Environmental Investment Analysis for the Jim Bridger and North Valmy Coal-Fired Power Plants" (collectively, both coal cost analyses are referred to herein as the "Coal Study"). The Coal Study is being submitted pursuant to Action Item 11 from the 2011 IRP acknowledgment order.[2]

The 2011 IRP Update comments on developments in resource planning that have occurred after the filing of the Company's 2011 IRP. The update also discusses the ongoing permitting, planning studies, and regulatory filings associated with the Boardman

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[1] *Re Investigation into Integrated Resource Planning*, Docket UM 1056, Order No. 07-002, Appendix A at 3-4 (Jan. 8, 2007).

[2] *Re Idaho Power Company's 2011 Integrate Resource Plan*, Docket LC 53, Order No. 12-177, Appendix A at 2 (May 21, 2012).

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to Hemingway transmission line, and the recent and anticipated filings relating to the Company's demand-response programs.

The IRP Update also includes a revised near-term action plan that addresses several emission control investments at the Company's coal-fired plants, as described in detail in the Coal Study. Because the 2011 IRP Update includes changes to the action plan acknowledged by the Commission in Order No. 12-177, Idaho Power requests that the Commission acknowledge the revised action plan items.[3]

I. BACKGROUND

The Commission acknowledged Idaho Power's 2011 IRP at a public meeting on February 14, 2012, and memorialized the acknowledgment in Order No. 12-177, which was issued on May 21, 2012. The acknowledged action plan included Action Item 11, which required Idaho Power to include in its 2011 IRP Update:

> . . . an Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants. The Evaluation will investigate whether there is flexibility in the emerging environmental regulations that would allow the Company to avoid early compliance costs by offering to shut down individual units prior to the end of their useful lives. The Company will also conduct further plant specific analysis to determine whether this tradeoff would be in the ratepayers' interest.[4]

The Coal Study that accompanies the 2011 IRP Update addresses the requirements of Action Item 11.

As a result of the Commission's direction in Order No. 12-177 and the results of the Coal Study conducted by Idaho Power, the 2011 IRP Update includes three new action items specifically addressing the anticipated emission control investments at the Jim

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[3] *See* OAR 860-027-0400(8) ("The energy utility may request acknowledgment of changes, identified in its update, to the IRP action plan.").

[4] Order No. 12-177, Appendix A at 2.

Bridger and North Valmy coal-fired power plants. These new action plan items are as follows:

- North Valmy Unit Number 1 ("NV1") Dry Sorbent Injection ("DSI")—To comply with the Mercury and Air Toxics Standards regulation, NV1 will require a DSI system to be operational by March 2015. Idaho Power anticipates the Company will be required to commit to the installation of the DSI system no later than the third quarter of 2013.

- Jim Bridger Unit Number 3 ("JB3") Selective Catalytic Reduction ("SCR")—To comply with the Regional Haze–Best Available Retrofit Technology regulation, JB3 will require SCR to be operational by December 31, 2015. Idaho Power anticipates the Company will be required to commit to the installation of the SCR by the second quarter of 2013.

- Jim Bridger Unit Number 4 ("JB4") SCR—To comply with the Regional Haze–Best Available Retrofit Technology regulation, JB4 will require SCR to be operational by December 31, 2016. Idaho Power anticipates the Company will be required to commit to the installation of the SCR by the second quarter of 2013.

In addition to these three new action plan items, the 2011 IRP Update also includes two items related to proposed transmission lines—Boardman to Hemingway and Gateway West—and one action item indicating that the Company intends to file its 2013 IRP by June 30, 2013.

II. DISCUSSION

A. Idaho Power's Coal Study Supports Continued Investment in Emission Controls.

Consistent with the Commission's request, the Coal Study analyzes the anticipated future investments required for environmental compliance in all six coal units in which the Company has an ownership interest.[5] This analysis considers numerous existing and

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[5] The North Valmy plant has two units (NV1 and NV2) and the Jim Bridger plant has four units (JB1, JB2, JB3, and JB4). Idaho Power owns a one-half interest in NV1 and NV2 and Idaho Power owns a one-third interest in JB1, JB2, JB3, and JB4. Idaho Power is not the operator of either plant.

emerging regulations, including the Final Mercury and Air Toxic Standards Rule, the National Ambient Air Quality Standards related to $PM_{2.5}$, NO_x, and SO_2, the Clean Water Act Section 316(b), New Source Performance Standards for Greenhouse Gas Emissions for New EGUs, the Clean Air Act - Regional Haze Rules, and Coal Combustion Residuals regulations. These regulations encompass all of the known and reasonably anticipated regulations that may materially impact the operation of the Company's coal units. As described in the Coal Study, compliance with these regulations will require the installation of the following controls: (1) SCR at all four Jim Bridger units; (2) $CaBr_2$, scrubber additive, activated carbon injection at all four Jim Bridger units; and (3) DSI at NV1.

The Coal Study compares the costs of these environmental control investments to the costs of three alternatives: (1) replacing the units with Combined Cycle Combustion Turbine ("CCCT") units; (2) converting the units to natural gas; or (3) delaying the coal unit investments required under the emerging environmental regulations and then shutting down the units. The hypothetical third alternative assumed that Idaho Power can successfully negotiate with state and federal regulators a five-year period where no additional environmental controls are installed in exchange for shutting the unit down at the end of the five-year period. The Coal Study focused on the potential economic benefits associated with this hypothetical scenario and assumes that Idaho Power can negotiate this delay. Notably, none of the relevant regulatory authorities have offered or agreed to any such delay, and the study does not conclude that Idaho Power can legally implement such a delay even if the plant operator agreed.

Idaho Power's Coal Study comprises two parts. The first part consists of SAIC's unit specific forecasted (static) annual generation analysis. This analysis includes Idaho Power's estimated capital costs and variable costs associated with the proposed environmental compliance upgrades, coal unit replacement with CCCT's, and natural gas conversion. SAIC's analysis develops the cost estimates for replacing the coal units' annual generation, under three different natural gas and three carbon futures. The results of the SAIC analysis serve as planning recommendations regarding the investment alternatives to be used in the second part of the study.

In the second part, the Coal Study includes an economically dispatched (dynamic) total portfolio resource cost analysis performed by Idaho Power using the SAIC study results as inputs. By employing the Company's power cost modeling software (AURORA), Idaho Power determined the total portfolio cost of each investment alternative analyzed by SAIC. The total portfolio cost is estimated over a twenty-year planning horizon (2013 through 2032).

Consistent with Action Item 11, the Company also modeled two additional alternatives referred to as the "Compliance Timing Alternatives" ("CTA") and an Enhanced Upgrade Alternative at the North Valmy plant. The CTA examines the costs associated with avoiding the installation of required or reasonably anticipated emission controls by delaying the compliance requirement by five years in exchange for shutting the unit down at the end of the five year period. While this course of action is not an option that is currently available to the Company,[6] the Coal Study nonetheless quantifies the financial results of these alternatives to allow a comparison with the currently existing alternatives set forth above.

The Enhanced Upgrade Alternative relates only to the North Valmy plant, which is subject to significantly fewer environmental regulations than the Jim Bridger plant. The Enhanced Upgrade Alternative presupposes that future environmental regulations would

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[6] The CTA are not presently viable options for several reasons, most notably because Idaho Power is not the operating partner for any of the Company's coal-fired plants. Not being an operating partner removes flexibility that other utilities may have for regulations allowing emission totaling, substitution or reductions at one facility to compensate for lower reductions at another plant, or the option of shutting down a unit or plant in place of reductions at another plant, or delaying installation of environmental controls for a guaranteed early shutdown. As Idaho Power is not the operating partner of Jim Bridger or North Valmy, it is highly unlikely the Company would have the ability to negotiate alternative scenarios as described above.

require the same general type of emission controls at the North Valmy plant as those that are anticipated for the Jim Bridger plant—notably, the installation of SCR and Wet Flue Gas Desulfurization ("WFGD" or "scrubber").

The Coal Study demonstrates that, for both the Jim Bridger and North Valmy plants, the emission control investments included in the 2011 IRP Update action plan are the least cost/least risk alternatives. For all four Jim Bridger units, the emission control investments are the lowest cost option for the majority of the carbon and natural gas scenarios. Indeed, in the most probable scenario—the Idaho Power planning scenario—the environmental upgrade option for these units is overwhelmingly the least cost option.

For JB1 and JB2, however, the installation of SCR, which is the most significant investment, is far enough in the future (2022 for JB1 and 2021 for JB2) that the forecast assumptions used in the Coal Study are highly speculative. Thus, Idaho Power will perform a more detailed analysis related to these two units, with updated assumptions, as the Company nears the actual SCR investment decision point for these units.

Because only JB3 and JB4 are expected to have SCRs installed in the near future (2015 for JB3 and 2016 for JB4), only these units were included in the CTA analysis. The results of this analysis also support the planned environmental control investments. Based on these results, Idaho Power recommends continuing to include all four Jim Bridger units in its resource portfolio for the 2013 IRP and future resource planning. And Idaho Power recommends proceeding with the environmental control investments for JB3 and JB4.

Similarly, the Coal Study demonstrates that the installation of the anticipated environmental controls at NV1 is the lowest cost result for most of the sensitivities analyzed by SAIC and four of the nine scenarios analyzed by Idaho Power, including the planning scenario. Based on the results of the study and in consideration of the fact that North Valmy is a critical facility for the reliability of the electric system in northern Nevada,

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Idaho Power concluded that the option to make the DSI investment represents a low cost approach to retain a diversified portfolio of generation assets including the capacity from NV1 for customers' benefit. Based on these results, Idaho Power recommends installing DSI and continuing to include NV1 in its resource portfolio for the 2013 IRP and future resource planning.

At this time, under current and proposed regulations, further environmental investment is not required for the continued operation of NV2. Thus, the Company will perform additional analysis if future regulations require significant environmental investments in NV2.

Finally, with respect to the Enhanced Upgrade Alternative for the North Valmy plant, which presupposes the installation of SCR and WFGD, under both the SAIC and Idaho Power analyses, proceeding with the enhanced environmental investments at NV1 and NV2 is not supported. However, because there are no current or proposed regulations requiring this investment, Idaho Power recommends continuing to include NV1 and NV2 in its planning and as part of Idaho Power's generation portfolio.

B. Permitting the Boardman to Hemingway Transmission Line Continues.

The Boardman to Hemingway transmission line ("B2H") was included in the Company's preferred portfolio in the 2011 IRP and is again being analyzed as an uncommitted resource in the 2013 IRP at the direction of the Commission. Since the 2011 IRP was prepared, the Company has made significant progress on the development of B2H. The Company has entered into a joint funding agreement with PacifiCorp and the Bonneville Power Administration ("BPA") to jointly pursue permitting of the project. Pursuant to that joint funding agreement, Idaho Power, PacifiCorp, and BPA also executed a Memorandum of Understanding ("MOU") that required the parties to negotiate agreements to allow BPA to meet its southeast Idaho load obligations. BPA announced on October 2, 2012, that its preference to meet its load obligation is B2H along with a

Transmission Asset Swap. These agreements demonstrate that B2H is an important regional project, substantiate the progress of the partnership conditions identified in the 2011 IRP, and substantiate that B2H continues as a viable resource for Idaho Power's preferred portfolio.

The 2011 IRP Update also discusses the considerable progress that has occurred since the 2011 IRP with respect to the permitting process. Indeed, in February 2013 Idaho Power anticipates filing its preliminary application for a site certificate with the Energy Facility Siting Council.

C. Suspension of Demand Response Programs is Reasonable.

The updated load and resource forecast from existing and committed resources that is being used in the 2013 IRP (which will be filed in June 2013) demonstrates that Idaho Power faces no near-term peak-hour deficits that would require additional supply-side generation capacity or capacity provided by the demand-response programs. This lack of near-term peak-hour capacity deficits is expected to persist until July 2016. Because the IRP modeling indicates that there are no peak-hour deficits, Idaho Power has concluded that it is reasonable and in customers' best interests to request authorization to temporarily suspend two of the Company's demand-response programs to allow Idaho Power time to work with stakeholders on potential program changes. Idaho Power has already requested authorization from the Idaho Public Utilities Commission to temporarily suspend for 2013 the A/C Cool Credit and Irrigation Peak Rewards programs. Idaho Power anticipates filing an Oregon tariff advice containing similar terms for review by the Commission shortly after the filing of this 2011 IRP Update.

D. The Company's Wind Integration Modeling is Reasonable.

Since 2008 Idaho Power has experienced rapid growth in wind generation. Indeed, as of January 2013, Idaho Power has 678 megawatts ("MW") of nameplate capacity wind generation on its system. As a result, Idaho Power must modify power system operations to successfully integrate such projects without impacting system reliability. Generally, such modifications are designed to schedule extra operating reserves into the Company's generation to allow dispatchable generators to respond to wind's variability and uncertainty. Idaho Power's "Wind Integration Study Report" is intended to quantify the increased operational costs to integrate wind on its system.

Idaho Power's analysis compares two scenarios: (1) a base scenario for which Idaho Power's system is not burdened with the incremental balancing reserves necessary for integrating wind; and (2) a test scenario for which the system is burdened with the incremental balancing reserves necessary for integrating wind. Generally, the wind integration costs, on a dollar per megawatt-hour ("MWh") basis, were calculated as the cost difference between these two scenarios. The Company also calculated wind integration costs for three different levels of wind penetration—800 MW, 1,000 MW, and 1,200 MW. The modeled integration costs vary from $8.06/MWh for 800 MW of wind penetration up to $19.01/MWh for 1,200 MW of wind penetration. The incremental wind integration costs range from $16.70/MWh to $49.46/MWh. These incremental costs are greater because current wind generators are not paying the full costs of integration.

The Company also modeled the wind integration costs including the proposed B2H transmission line. These results demonstrate that once B2H is on-line, the wind integration costs are expected to decrease.

It is also important to note that during low demand periods, the system of dispatchable resources often cannot provide the incremental balancing reserves that are necessary to integrate wind generation without creating an imbalance between generation and demand. When this occurs, it may be necessary to curtail wind generation. After wind penetration exceeds 800 MW, Idaho Power's modeling indicates that the frequency of curtailment will likely increase.

III. CONCLUSION

The Commission should acknowledge Idaho Power's revised action plan items related to environmental control investments at the Jim Bridger and North Valmy coal-fired power plants. The Company's detailed analysis demonstrates that the anticipated investments and the continued operation of the coal units represent the least cost/least risk alternative for Idaho Power's customers.

DATED this 14th day of February, 2013.

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2011 Integrated Resource Plan Update

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February 2013

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INTRODUCTION

This document is an update to the *2011 Integrated Resource Plan* (IRP) that Idaho Power filed with the regulatory commissions in Idaho and Oregon in June 2011 (Idaho PUC and Oregon PUC). This document fulfils regulatory requirements in Oregon and is an informational filing in Idaho. The Oregon requirements are described in Order 07-002 (Appendix A, pages 3 and 4, Guideline 3, Plan Filing, Review, and Updates, topics f and g):

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.*

Since the *2011 Integrated Resource Plan* was filed in June 2011, Idaho Power has added the Langley Gulch combined-cycle combustion turbine (CCCT) plant in western Idaho. The Langley Gulch plant is fully discussed in Case No. IPC-E-09-03 in Idaho:

http://www.puc.idaho.gov/internet/cases/summary/IPCE0903.htm

and Docket UE 248 in Oregon:

http://apps.puc.state.or.us/edockets/docket.asp?DocketID=17396

The major resource addition identified in the *2011 Integrated Resource Plan* near-term action plan is the Boardman to Hemingway transmission line. The Boardman to Hemingway transmission line is described in a separate section of this update.

In addition to the Langley Gulch and the Boardman to Hemingway resource additions, Idaho Power identified an 83 megawatt (MW) eastside power purchase in 2015 as part of the near-term action plan. Idaho Power intends to review the need for an eastside purchase as part of the *2013 Integrated Resource Plan*.

Idaho Power identified a solar demonstration project as part of the *2011 Integrated Resource Plan*. The solar demonstration project has a nameplate capacity between one-half and 1 MW and the project was expected to be online by the end of 2013. Since publishing the *2011 Integrated Resource Plan*, an independent power producer has contracted with Idaho Power to develop a 20-MW solar project in Idaho under the PURPA program. Idaho Power believed that the proposed 20-MW solar project would demonstrate many of the technical issues associated with solar power better than the smaller project proposed by Idaho Power in the *2011 Integrated Resource Plan*. The proposed solar project was expected to be on-line in January 2013. The developer of the project approached Idaho Power in January 2013 requesting to terminate the project. Idaho Power and the developer filed a confidential settlement agreement with the Idaho Public Utilities Commission (PUC) on January 24, 2013 (IPC-E-10-19). Idaho Power intends to revisit the concept of a solar demonstration project with the awareness that it may be beneficial to design a solar demonstration project consistent with the requirements identified in the Oregon Solar Incentive Program (Oregon House Bill 3039).

Idaho Power has begun work on the *2013 Integrated Resource Plan* and Idaho Power has conducted five meetings, one workshop, and one field trip with the Integrated Resource Plan Advisory Council (IRPAC). Idaho Power has worked with the Advisory Council regarding significant changes in the underlying forecasts for the *2013 Integrated Resource Plan*. Specifically, Idaho Power and the Advisory Council have discussed the following:

- Sales and load forecast for the Idaho Power service area
- Natural gas price forecast
- Carbon adder that will be used in the *2013 Integrated Resource Plan*
- Idaho water issues and the *2013 Integrated Resource Plan*

Each of the four topics is discussed separately in this *2011 Integrated Resource Plan* update.

Idaho Power recently filed a request with the Idaho PUC to modify the company's demand-response programs and expects to make a similar filing in the near future with the Oregon PUC. The request to modify the demand-response programs is explained in a separate section later in this 2011 IRP Update.

Finally, Idaho Power has completed two significant studies that directly affect the *2013 Integrated Resource Plan*:

- Coal Unit Environmental Investment Analysis for the Jim Bridger and North Valmy Coal-Fired Power Plants
- Wind Integration Study

The executive summary sections from each of the two studies are included as part of this update. The full documents for the Coal Unit Environmental Investment Analysis for the Jim Bridger and North Valmy Coal-Fired Power Plants and the Wind Integration Study have been filed as supporting documents with both the Idaho and Oregon PUCs.

Boardman to Hemingway

The proposed Boardman–Hemingway (B2H) project has been identified as part of the preferred portfolio in Idaho Power's 2011 IRP. The large project involves permitting, constructing, operating, and maintaining a new, single-circuit 500-kilovolt (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 the following:

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

Since the 2011 IRP has been completed, significant progress has been made on the B2H project. In January 2012, Idaho Power entered into a joint funding agreement with PacifiCorp and Bonneville Power Administration (BPA) to jointly pursue permitting of the project. The agreement designates Idaho Power as the Permitting Project Manager for B2H. Table 1 below shows each party's B2H capacity and permitting cost allocation.

Table 1 Boardman to Hemingway Capacity and Permitting Cost Allocation

	Idaho Power	BPA	PacifiCorp
Capacity (MW) West to East	350 200 winter/500 summer	400 550 winter/250 summer	300
Capacity (MW) East to West	85	97	618
Permitting Cost Allocation	21%	24%	55%

Additionally, a Memorandum of Understanding (MOU) was executed in connection with the joint funding agreement for B2H. The MOU provides that BPA, Idaho Power, and PacifiCorp will negotiate in good faith the terms of mutually satisfactory definitive agreements that would allow BPA to meet its load service obligations in southeast Idaho. The memorandum provides for exploring opportunities to establish eastern Idaho load service from the Hemingway substation in exchange for similar service from the Federal Columbia River Transmission System. The two options identified in the MOU were B2H with Open Access Transmission Tariff (OATT) service, or B2H with Transmission Asset Swaps.

BPA identified six different alternatives to meet its load service obligations in southeast Idaho, which included the two B2H options described above. BPA conducted their analysis of the six alternatives and presented the results in a public involvement process providing the opportunity for public comments regarding the six alternatives. Using the public comments, information provided by Idaho Power and PacifiCorp, and other information gathered by BPA, the six different alternatives were ranked primarily based on cost and ability to meet the BPA load service obligations in southeast Idaho. On October 2, 2012, BPA publically announced the preferred solution to be the Boardman to Hemingway transmission line with the Transmission Asset Swap.

The Permit Funding Agreement, the MOU, and the results of the BPA public process signify that B2H is an important regional project. The Permit Funding Agreement and the MOU substantiate the progress of the partnership conditions indentified in the 2011 IRP, and substantiate that B2H is a viable resource for Idaho Power's preferred portfolio.

Considerable progress has also been made with regards to the federal and state permitting processes. The federal permitting process is established by the National Environmental Policy Act (NEPA). The Bureau of Land Management (BLM) is the lead agency in administering the NEPA permitting. In July 2012, the BLM publically announced the routes that will be analyzed in the Draft Environmental Impact Statement (DEIS). Figure 1 below identifies the proposed transmission line routes. Public meetings were held to inform the stakeholders of the routes, and to let the stakeholders know that the DEIS will be released for public comment in mid-2013.

Idaho Power is planning on submitting the preliminary Application for Site Certificate (pASC) in February 2013 as part of the state permitting process. The B2H Team has been working with the different state agencies involved in the preparation of the pASC to identify the substantive issues that will be addressed in order to expedite the agencies' review of the document once it is submitted. The approach used by Idaho Power is similar to the approach used by Portland General Electric in the Cascade Crossing project.

Some items not yet resolved include the preferred termination point for the Boardman end of the project (Grassland Station, Horn Butte Station, or Longhorn Station), whether or not sage grouse will be listed as an endangered species by the time the permits are completed, how a sage grouse listing could affect the project and project construction, and the operations and maintenance agreements between Idaho Power, BPA and PacifiCorp. These items, along with many others, will be addressed as the permitting processes continue.

With the changes described above, particularly the BLM's announcement of the routes to be analyzed in the DEIS, Idaho Power considered that it would be prudent to analyze the permitting schedule and how the permitting schedule could affect the in-service date of B2H. Based on Idaho Power's assessment of the permitting and other factors, Idaho Power estimates that a project in-service date prior to 2018 is unlikely. The possible delay will be used in the 2013 IRP analysis to determine the effects, and to determine if additional actions will be required to ensure load service obligations can be reliably met.

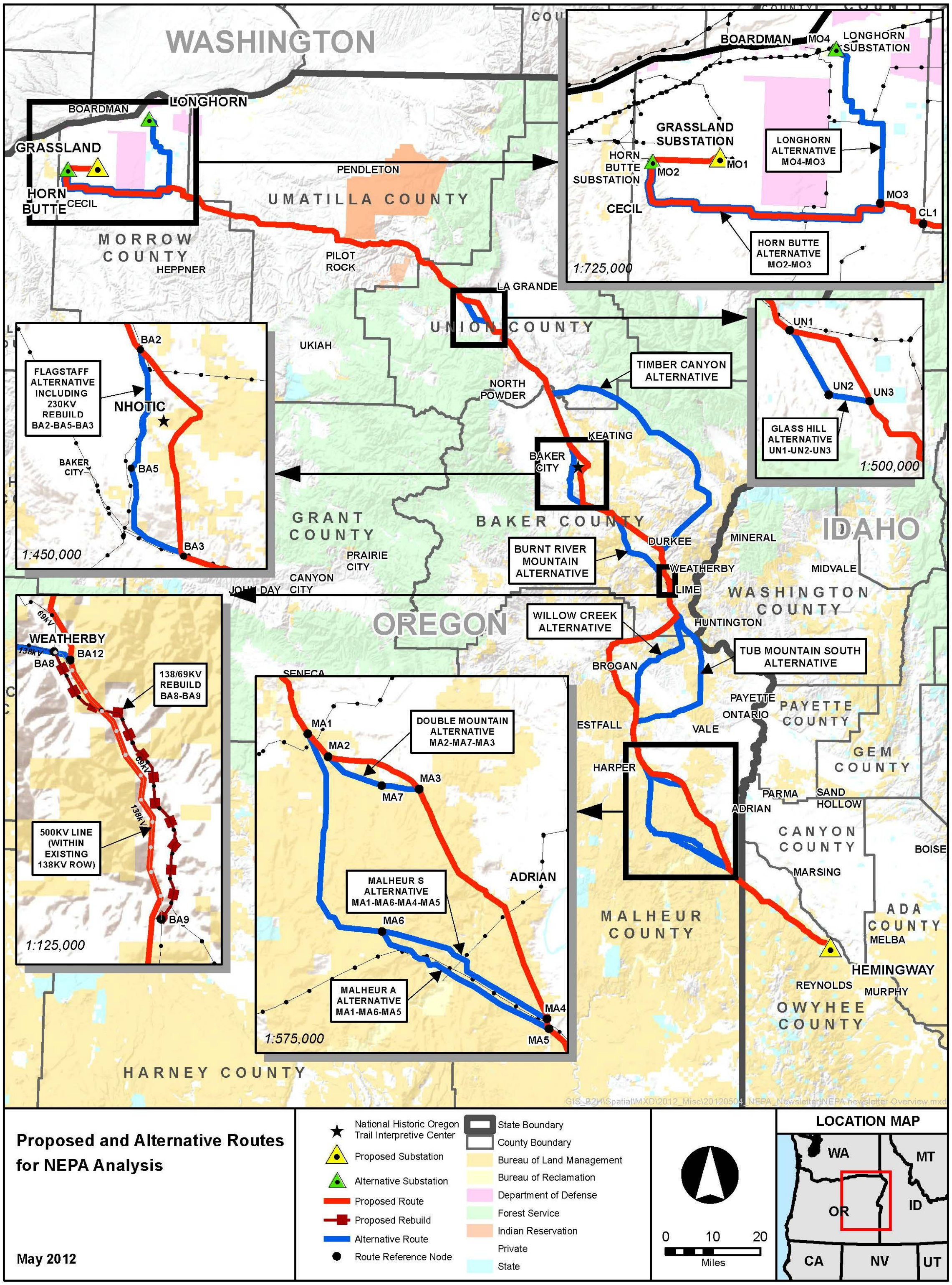

Figure 1 B2H Routes to be Analyzed in the DEIS

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SALES AND LOAD FORECAST

Highlights of the 2013 IRP sales and load forecast:

- Idaho Power's summer peak load record of 3,245 MW was set on July 12, 2012.
- The Idaho Power winter system peak record of 2,528 MW occurred on December 10, 2009, during several days of below-normal temperatures.
- The 2013 IRP load forecast includes the expected effects of electric vehicles.
- The 2013 IRP average system load forecast is lower than the 2011 IRP average system load forecast in all years of the forecast period.

Historically, Idaho Power has been a summer peaking utility with peak loads driven by irrigation pumps and air conditioning during 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 peak and average load are important in planning for future resources, and both peak and average load are part of the load forecast prepared for the 2013 IRP.

The 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 median forecast. Therefore, Idaho Power prepared two additional load forecasts that address the load variability associated with weather variability. 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.

The 2013 IRP average system load forecast is lower than the 2011 IRP average system load forecast in all years of the forecast period. Economic recovery is occurring at a slower pace than was forecast in the 2011 IRP. As a result, most of the economic variables used in the 2013 IRP forecast were lowered and improvement in economic conditions has been delayed in the 2013 load forecast. In the extended 20-year forecast period, higher anticipated retail electricity prices incorporating the effects of carbon legislation decrease the average load forecast, especially during the second ten years of the forecast period.

Significant factors and considerations that influenced the outcome of the 2013 IRP load forecast include the following:

- The sales and load forecast prepared for the 2011 IRP reflected the expected increase in demand for energy and peak capacity of Idaho Power's most recent special-contract customer, Hoku Materials, located in Pocatello, Idaho. During the time since the 2011 IRP, Hoku Materials was unable to complete the construction of its manufacturing facility and take service under the special-contract tariff. For the purposes of the 2013 IRP, Idaho Power has assumed that Hoku Materials will not come on-line and the 74 average MW (aMW) of energy and 82 MW of peak demand originally anticipated is no longer included in the sales and load forecast.
- In the 2011 IRP sales and load forecast, there was an additional customer referred to as "Special" included with the additional firm load category (special contracts), even though no long-term contract had been executed. When the 2011 IRP sales and load forecast was prepared in August 2010, several interested parties had taken significant steps towards locating their businesses within Idaho Power's service area. Idaho Power determined at the time of the

2011 IRP that there was a real possibility of the new large load materializing. During the time since the 2011 IRP, the likelihood of the new large load diminished. Additionally, the Oregon PUC noted in its order regarding the Idaho Power *2011 Integrated Resource Plan* that “it is appropriate to include an allowance for new large loads in the load forecast only if there is a signed energy service agreement” (Oregon Order 12-177, page 6). For the purposes of the 2013 IRP, Idaho Power has assumed that no “Special” contract will come on-line and the 54 aMW of energy and 60 MW of peak demand originally anticipated in the 2011 IRP is not included in the 2013 sales and load forecast.

- The load forecast used for the 2013 IRP reflects a near-term recovery in the service-area economy following the recession in 2008 and 2009. The decline in the housing sector in 2008 and 2009 slowed the growth in the number of new households, and consequently, the number of residential customers being added to Idaho Power’s service area. In late 2011 and 2012, residential and commercial customer growth has shown signs of recovery. By 2015, new residential and commercial customer additions are forecast to approach the growth that occurred in the 2000 through 2004 time period.
- The electricity price forecast used to prepare the sales and load forecast in the 2013 IRP reflects the additional plant investment and variable costs of integrating the resources identified in the 2011 IRP preferred portfolio, including the expected costs of carbon emissions. When compared to the electricity price forecast used to prepare the 2011 IRP sales and load forecast, the 2013 IRP price forecast includes higher future electricity prices. The retail prices are higher in the second ten years of the planning period and the higher prices decrease the sales forecast.
- Idaho Power used Itron Inc.’s residential Statistically Adjusted End-Use (SAE) and commercial SAE models to prepare the long-term sales forecasts in the residential and commercial sectors.
- Conservation effects, including demand-side management (DSM) energy efficiency programs and codes and standards are integrated into the sales forecast. The effect of demand-response programs is not included in the sales and load forecast. The demand-response programs are considered in the load and resource balance.
- In the near-term through 2015, the 2013 IRP irrigation sales forecast is slightly higher than the 2011 IRP forecast. Recent high commodity prices and changing crop patterns appear to be the main reasons behind the irrigation sales increase. After 2015, the irrigation sales forecast is slightly lower than the previous IRP forecast, mostly a result of higher real electricity prices decreasing irrigation demand.

Peak-Hour Load Forecast

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

Idaho Power’s system peak-hour load record, 3,245 MW, was recorded on Thursday, July 12, 2012, at 4:00 p.m. The previous summer peak demand was 3,214 MW and occurred on Monday, June 30, 2008, at 3:00 p.m. Summertime peak-hour load growth accelerated in the previous decade as air conditioning became standard in nearly all new residential home construction and in nearly all new commercial buildings. System peak demand slowed considerably in 2009, 2010, and 2011 due to the recession and the associated construction decline. Demand-response programs operating in the summertime have also reduced peak demand. The 2013 IRP load forecast projects peak-hour load to grow by approximately 55 MW per year throughout the planning period. The peak-hour load forecast does not reflect the company's demand-response programs, which are accounted for when calculating the load and resource balance.

Figure 2 and Table 2 summarize the median, 90th percentile, and 95th percentile weather effects on the annual peak-hour load forecast. Please note that Astaris ceased operations as a special contract customer in 2002 (Astaris was previously known as FMC). At one time, Astaris had a peak load of approximately 240 MW.

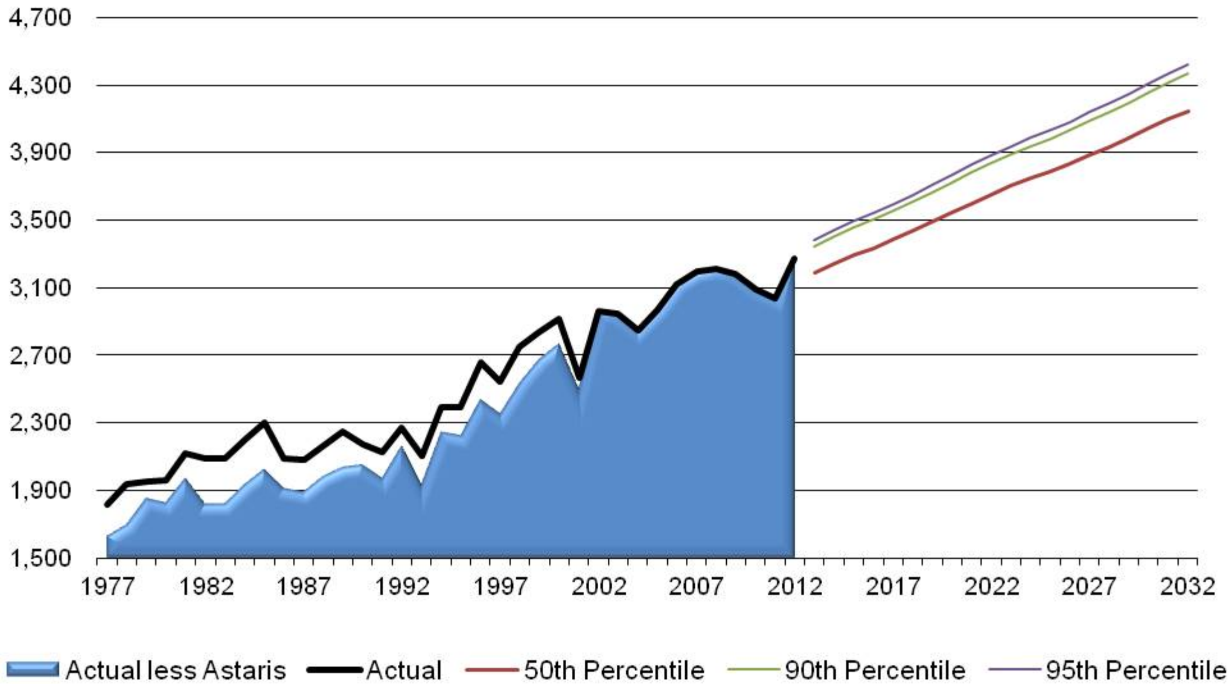

Figure 2 Peak-Hour Load Growth Forecast (MW)

Table 2 Load forecast—peak hour (MW)

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

The median peak-hour load forecast predicts peak-hour load will grow from 3,189 MW in 2013 to 4,147 MW in 2032, an average annual compound growth rate of 1.4 percent. The projected average annual compound growth rate of the 95th percentile peak forecast is also 1.4 percent. In the 95th percentile forecast, summer peak-hour load is expected to increase from 3,382 MW in 2013 to 4,418 MW in 2032. Historical peak-hour loads as well as the three forecast scenarios are shown in Figure 2.

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 irregularity of peak day temperatures in the winter months, which is far different than the consistently high peak-day temperatures experienced in the summer months.

Average-Energy Load Forecast

Potential monthly average energy use by customers in Idaho Power's service area is defined by two load forecasts that reflect load uncertainty resulting from differing weather-related assumptions. Figure 3 and Table 3 show the results of the two forecasts used in the 2013 IRP reported as annual system load growth over the planning period. There is approximately a 50-percent probability that Idaho Power's load growth will exceed the median forecast and a 30-percent probability of load growth exceeding the 70th percentile forecast. The projected 20-year average annual compound growth rate in the planning-load forecast is 1.1 percent.

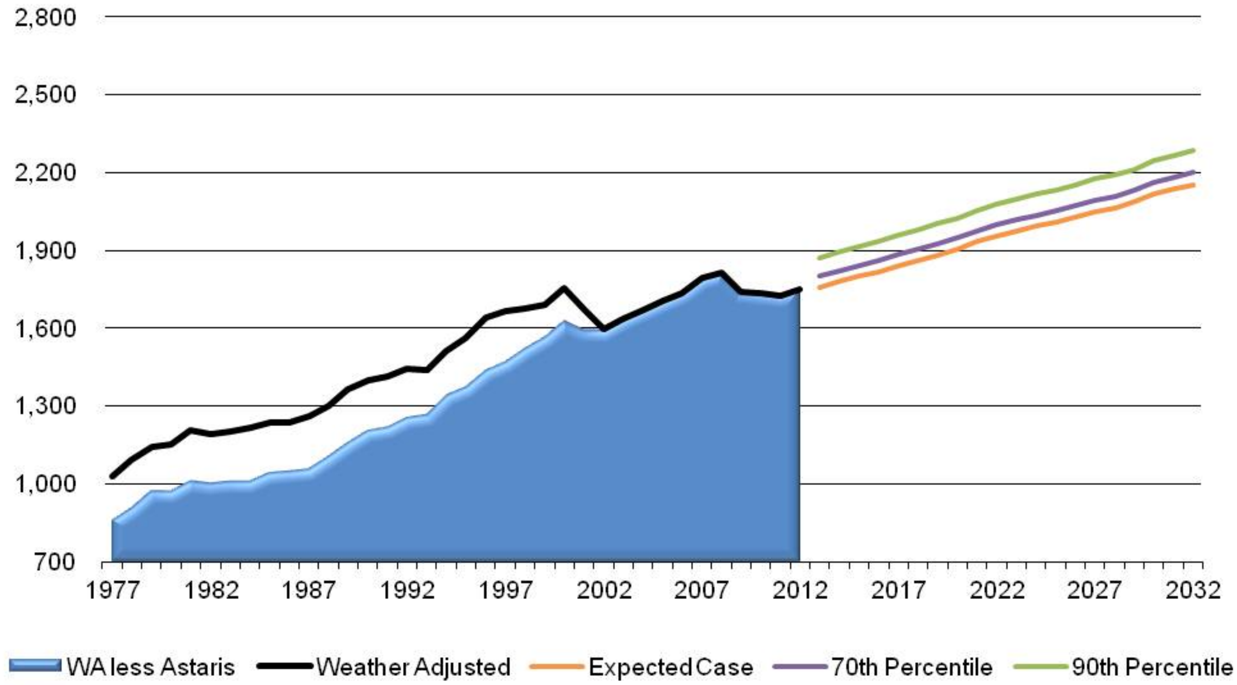

Figure 3 Average Monthly Load Growth Forecast (aMW)

Table 3 Load forecast—average monthly energy (aMW)

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

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DEMAND-RESPONSE PROGRAMS

As Idaho Power began updating the load and resource forecast from existing and committed resources for the 2013 IRP, it became apparent that there were no near-term peak-hour deficits that would require additional supply-side generation capacity or capacity provided by the demand-response programs. Idaho Power anticipates the lack of near-term peak-hour capacity deficits to exist until July 2016. With the 2013 IRP load and resource balance showing no peak-hour deficits for a few years, Idaho Power concluded that it would be in the best interests of its customers to request authorization to temporarily suspend two of the demand-response programs. The monthly capacity deficits are shown in Figure 4 below.

Idaho Power is committed to making prudent decisions regarding how the company manages the customer programs and how the company utilizes customer funds. With this commitment in mind, on December 21, 2012, Idaho Power made a filing with the Idaho PUC requesting a temporary suspension of the A/C Cool Credit and Irrigation Peak Rewards programs in 2013 with a decision requested by March 1, 2013. On February 6, 2013, Idaho Power participated in a Settlement Workshop regarding the temporary suspension of the two programs in 2013 (Idaho Case IPC-E-12-29). The Idaho PUC staff, Idaho Irrigation Pumpers Association, Idaho Power, the Idaho Conservation League, and the Snake River Alliance reached an agreement in principle for the 2013 summer season. On or about February 14, 2013, Idaho Power anticipates filing a stipulation evidencing the agreement in Idaho, and Idaho Power anticipates filing an Oregon tariff advice containing similar terms for review by the Oregon Commission shortly thereafter.

Idaho Power plans to work with interested stakeholders this spring and summer toward a longer term solution for operation of the A/C Cool Credit and Irrigation Peak Rewards programs in 2014 and beyond. A number of stakeholders, including staff members from the PUCs, are already aware of the lack of near-term capacity deficits identified in the current load and resource balance because they are members of the IRPAC and participated in the portfolio design workshop where the load and resource balance was described. In addition, during a recent webinar with the Energy Efficiency Advisory Group (EEAG), Idaho Power presented the load and resource balance indicating that the first capacity deficit does not occur until 2016 and the resulting need to evaluate the demand-response programs. Idaho Power expects that the collaborative approach with stakeholders will enable the company to file a request for approval of the changes made to the demand-response programs with sufficient time for Commission review prior to the 2014 summer season.

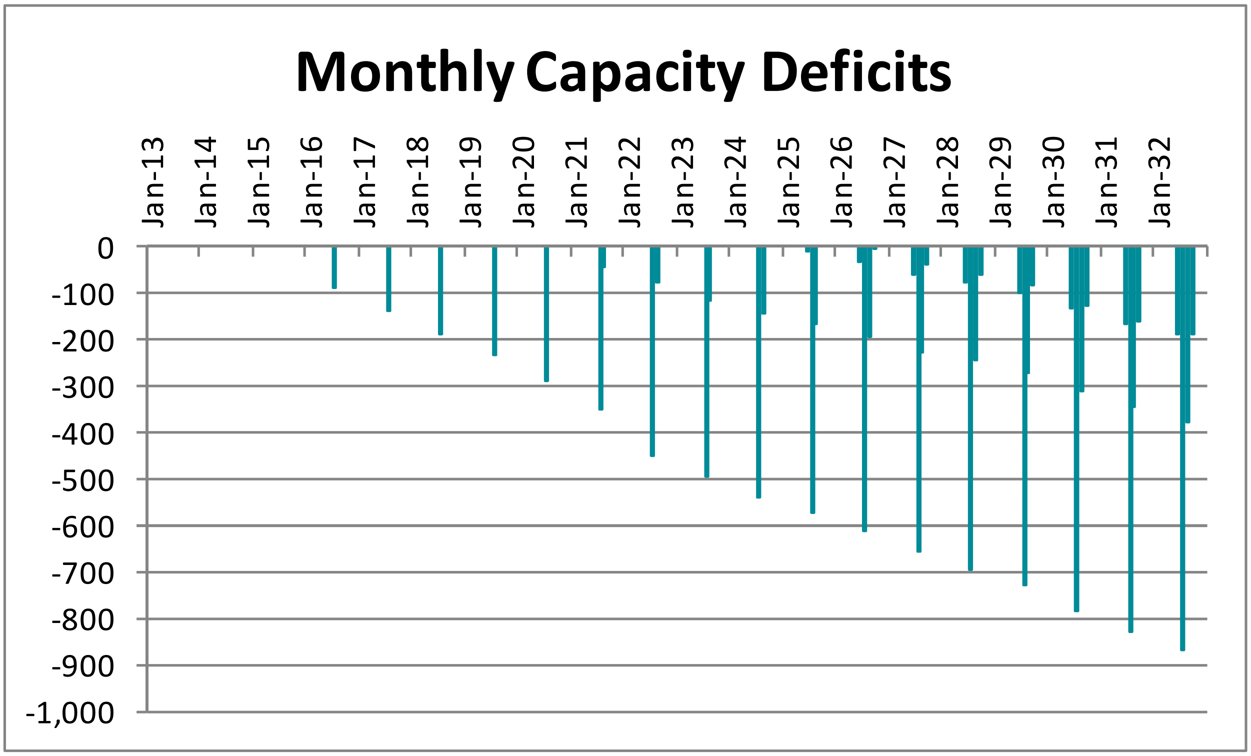

Figure 4 Monthly Capacity Deficits

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 Idaho PUC has recently ruled on avoided cost rate methodologies (Case Number GNR-E-11-03, Order Number 32697; December 18, 2012). In the order the Idaho PUC stated (page 16):

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

Idaho Power is using the US Energy Information Administration natural gas price forecast for integrated resource planning and avoided-cost calculations. The *Annual Energy Outlook 2013 Early Release Reference Case* was published by the US Energy Information Administration on December 5, 2012, and Idaho Power has used the Early Release forecast for the 2013 IRP. A graph of the forecasted Henry Hub natural gas prices is shown in Figure 4 below. Idaho Power computed a high and low natural gas price forecast by adjusting the EIA natural gas price forecast upward and downward by 30 percent. The high and low forecasts are also shown in Figure 4. Idaho Power applies a Sumas basis and transportation cost to the Henry Hub price to derive an Idaho city gate price. The Idaho city gate price is representative of the gas price delivered to the Idaho Power gas plants.

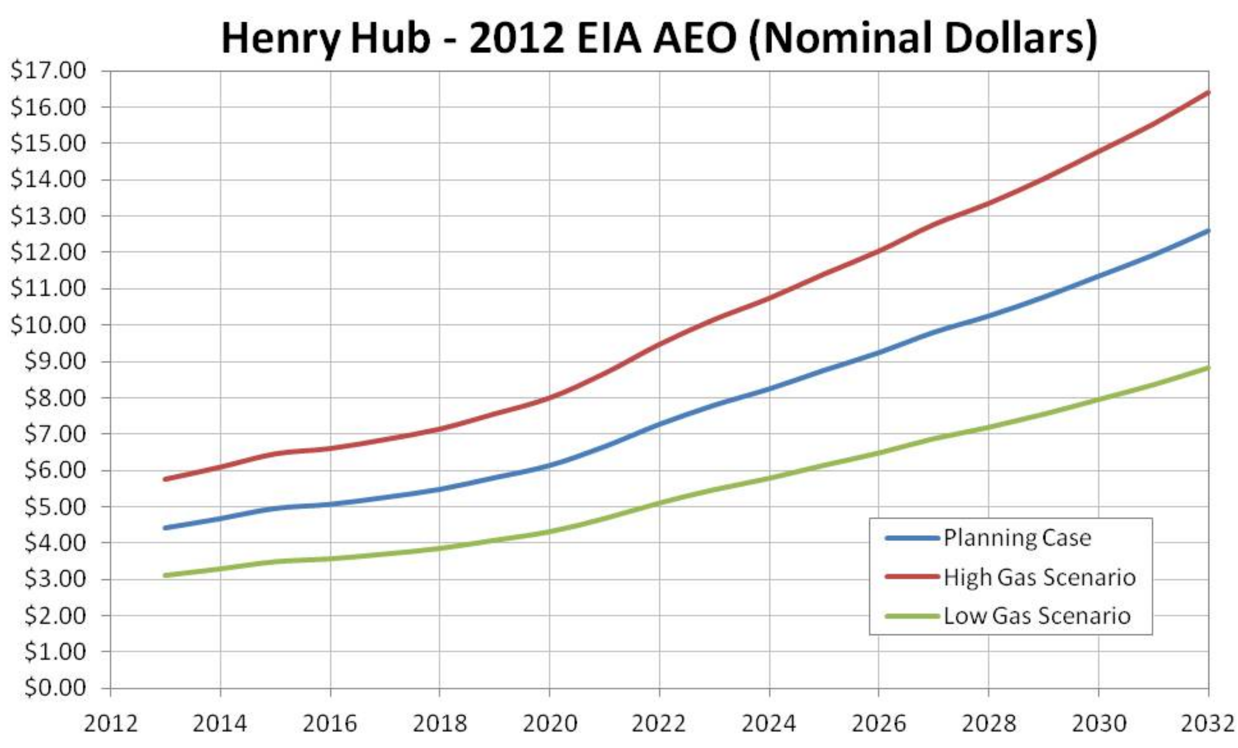

Figure 5 Henry Hub Price Forecast

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CARBON ADDER

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

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

1. The planning case starting at $14.64 per ton in 2018 and escalating at three percent annually (Planning Case)
2. The upper case starting at $35 per ton in 2018 and escalating at nine percent annually (High Carbon)
3. The zero-cost case where there is no future cost associated with carbon emissions (Low Carbon)

Idaho Power plans to use a three percent annual escalation rate to change nominal dollars to constant-year dollars. Please note that the carbon adder planning case is selected to be consistent with the $16.00 per ton value in 2021 used in the Coal Unit Environmental Investment Analysis for the Jim Bridger and North Valmy Coal-Fired Power Plants that accompanies this update.

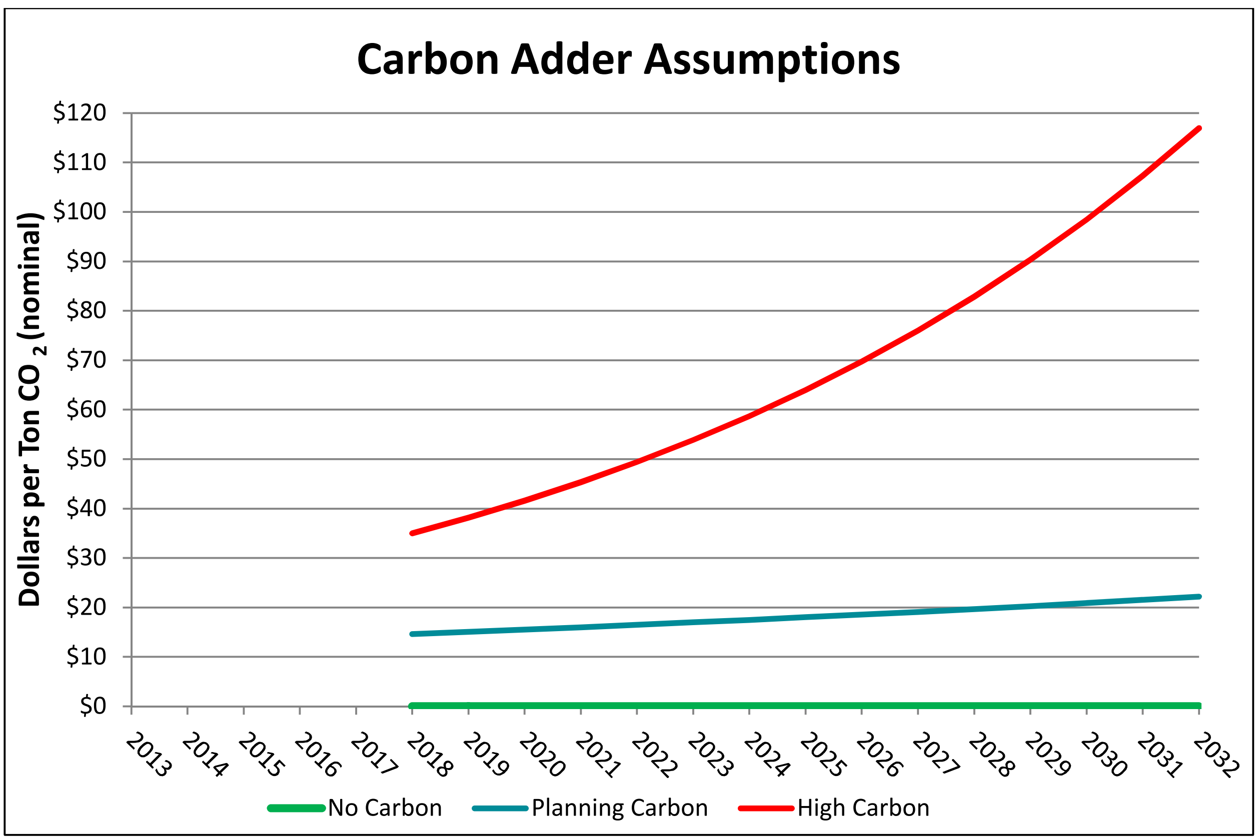

Figure 6 2013 IRP Carbon Adder

Table 4 Carbon adder scenarios

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

Idaho Water Issues

Power generation at Idaho Power's hydroelectric projects on the Snake River and its tributaries is dependent on the state water rights held by the company for these projects. The long-term sustainability of the Snake River Basin 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 affect Idaho Power's hydroelectric generation in the near term, but the company cannot predict the ultimate outcome of the legal and administrative water-rights proceedings. Idaho Power's ongoing participation in water-rights issues is intended to guarantee 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. The settlement also committed the state and Idaho Power to further discussions on important water-management issues concerning the Swan Falls Agreement and the management of water in the Snake River Basin. Idaho Power and the state are actively involved in those discussions. The settlement also recognizes water-management measures that enhance aquifer levels, springs, and river flows—such as aquifer-recharge projects—that benefit both agricultural development and hydroelectric generation. Both parties anticipate water-management measures will be developed in the implementation of the Eastern Snake River Plain Aquifer, Comprehensive Aquifer Management Plan (ESPA CAMP) as approved by the Idaho Water Resource Board (IWRB).

Idaho Power actively participated in proceedings associated with the ESPA CAMP. Given the high degree of interconnection between 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 had hoped that implementation of the ESPA CAMP would improve aquifer levels and

tributary spring flows to the Snake River. However, some of the Phase I recommendations, outlined in Table 5 (CAMP-1), have been slow to fully develop.

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

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

Table 5 CAMP-1. Phase I Measures Included in the ESPA CAMP

Measure	Target (Acft)	Estimated to Date (Acft)
Ground Water to Surface Water Conversions	100,000	19,156
Managed Aquifer Recharge	100,000	115,000*
Demand Reduction		
Surface Water Conservation	50,000	26,000
Crop Mix Modification	5,000	0
Rotating Fallowing, Dry-Year Lease, CREP	40,000	33,368
Weather Modification	50,000	50,000

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

For the 2013 IRP, Idaho Power has forecasted flows similar to those in the 2011 IRP; however, the declines in reach gains are extended through year 2027. Based on modeling under the 90 percent exceedance forecast, declining flows reach the Swan Falls 3,900 cfs minimum in 2027. At that time, Idaho Power assumes the State of Idaho will provide appropriate management and water rights administration, under the Swan Falls Agreement, to prevent further declines in surface water flows. Figure 7 provides the yearly inflow to Brownlee Reservoir as forecasted for the 2013 IRP.

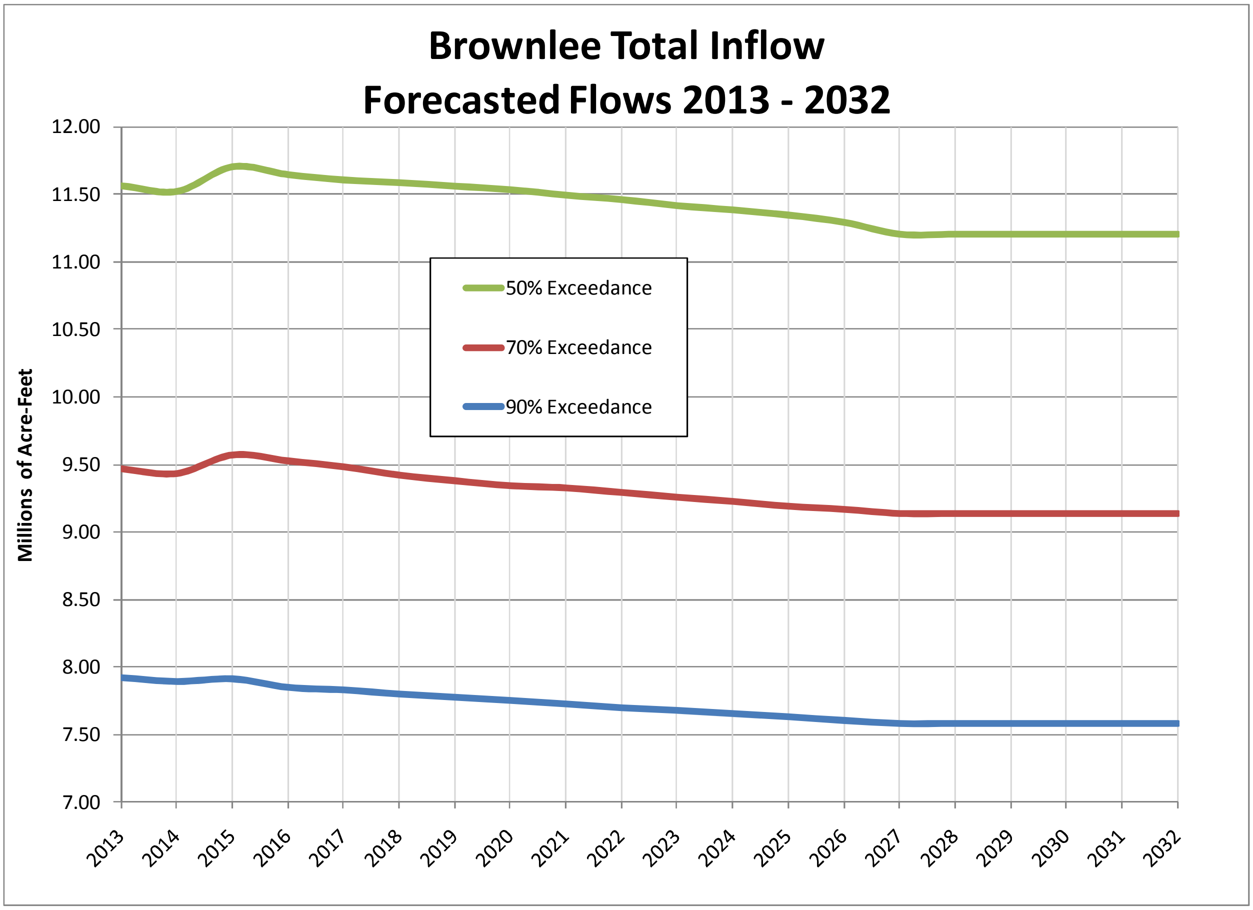

Figure 7 Brownlee Total Inflow—Forecasted Flows 2013–2032

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COAL UNIT ENVIRONMENTAL INVESTMENT ANALYSIS FOR THE JIM BRIDGER AND NORTH VALMY COAL-FIRED POWER PLANTS

Order No. 12-177 issued by the Oregon PUC on May 21, 2012, directed Idaho Power to complete an evaluation of environmental compliance costs for existing coal-fired plants. Action Item 11 in Appendix A of Order No. 12-177 stated the following:

> *In its next IRP Update, Idaho Power will include an Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants. The Evaluation will investigate whether there is flexibility in the emerging environmental regulations that would allow the Company to avoid early compliance costs by offering to shut down individual units prior to the end of their useful lives. The Company will also conduct further plant specific analysis to determine whether this tradeoff would be in the ratepayers' interest.*

In accordance with the Oregon PUC directive, the Coal Unit Environmental Investment Analysis details the analytical framework applied to evaluate the environmental compliance costs at the Jim Bridger and North Valmy coal-fired power plants and recommendations reached by that analysis. Because the Boardman plant is scheduled to cease coal-fired operations no later than December 31, 2020, the Boardman plant was excluded from the study.

The Coal Unit Environmental Investment Analysis (Study) examines future investments required for environmental compliance in existing coal units and compares those investments to the costs of two alternatives: 1) replacing such units with CCCT units or 2) converting the existing coal units to natural gas. Idaho Power used a combination of third-party analysis, operating partner input, and an Idaho Power analysis to ensure a complete and fair assessment of the alternatives.

This Study consists of two parts:

1. A unit specific forecasted (static) annual generation analysis performed by Science Applications International Corporation (SAIC). Idaho Power conducted a competitive procurement process to select SAIC.
2. An economically dispatched (dynamic) total portfolio resource cost analysis performed by Idaho Power using the SAIC study results.

The SAIC analysis included a review of Idaho Power's estimated capital costs and variable costs associated with the proposed environmental compliance upgrades, coal unit replacement with CCCTs and natural gas conversion. SAIC developed the cost estimates for replacing the coal units annual generation, under three natural gas and three carbon futures. These estimates served as the foundation for SAIC's capital investment analysis, which allowed assets with different lengths of operation as well as different implementation dates to be compared equitably. The results of the SAIC analysis served as planning recommendations regarding the three investment alternatives to be used in the second part of the comprehensive Study.

The second part of the Study performed by Idaho Power utilized the AURORAxmp® Model (AURORA) to determine the total portfolio cost of each investment alternative analyzed by SAIC. The total portfolio cost is estimated over a twenty-year planning horizon (2013 through 2032). The Key Assumptions section of this report provides additional details on the carbon-adder assumptions and natural-gas price forecasts.

Analysis Results for North Valmy

Currently, the only notable investment required at the North Valmy plant is to install a Dry Sorbent Injection (DSI) system for compliance with the Mercury and Air Toxic Standards (MATS) regulation on Unit Number 1. North Valmy is not subject to Regional Haze (RH) Best Available Retrofit Technology (BART) regulations; therefore, no additional controls will be required for compliance with this regulation. No other notable investments in environmental controls at the North Valmy plant are required at this time.

Installation of DSI was the lowest cost result for most of the sensitivities analyzed by SAIC, including the planning case scenario (planning case natural gas/planning case carbon). The AURORA analysis, performed by Idaho Power, shows installing DSI as the least cost option in four of the nine sensitivities analyzed, including the planning case scenario (planning case natural gas/planning case carbon). The scenarios in which DSI was not the preferred option are the extreme low natural gas and high carbon cases, which have a lower probability of occurring.

Idaho Power's conclusion is that installing the DSI system is a low-cost approach to retain a diversified portfolio of generation assets, including the 126 MWs of Unit Number 1 capacity for our customers' benefit. The continued operation of Unit Number 1 as a coal-fired unit will provide fuel diversity that can mitigate risk associated with high natural gas prices.

If North Valmy requires significant additional capital or operation and maintenance costs (O&M) expenditures for new environmental regulations, both the SAIC and the Idaho Power analyses advise further review to justify the additional investment.

Analysis Results for Jim Bridger

Jim Bridger is currently required to install Selective Catalytic Reduction (SCR) on all four units for RH compliance and mercury controls for compliance with MATS. Both the SAIC and Idaho Power evaluations identify additional investments in environmental controls on all four Jim Bridger units as prudent decisions that represent the lowest cost and least risk option when compared to the other investment alternatives. Idaho Power recommends proceeding with the installation of SCR and other required controls on units Number 3 and Number 4 and including the continued operation of all four Jim Bridger units in Idaho Power's future resource planning.

Compliance Timing Alternatives

Idaho Power also evaluated the economic benefits of delaying coal unit investments required under the emerging environmental regulations. To perform this evaluation, Idaho Power assumed it could negotiate with state and federal entities a five-year period where no additional environmental controls are installed in exchange for shutting the unit down at the end of the five-year period. These compliance timing alternative cases are strictly hypothetical. Idaho Power may not have any basis under current regulations to negotiate this delay, and the relevant regulatory authorities have not offered any such delay.

Unit Ownership and Operation

It should be noted that, although a partial owner of the Jim Bridger (one-third) and the North Valmy (one-half) coal plants, Idaho Power does not operate any of the coal-fired units and Idaho Power does not have the sole rights to alter the compliance plan in place for these units. Any decision regarding environmental investments, plant retirement, or conversion to natural gas must be coordinated and agreed to by the other owners/operators of the plants and their regulators.

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WIND INTEGRATION

As a variable and uncertain generating resource, wind generators require Idaho Power to modify power system operations to successfully integrate such projects without impacting system reliability. The company must build into its generation scheduling extra operating reserves designed to allow dispatchable generators to respond to wind's variability and uncertainty.

Idaho Power, similar to much of the Pacific Northwest, has experienced rapid growth in wind generation over recent years. As of January 2013, Idaho Power has reached on-line wind generation totaling 678 MW of nameplate capacity. The rapid growth in wind generation is illustrated in Figure 8.

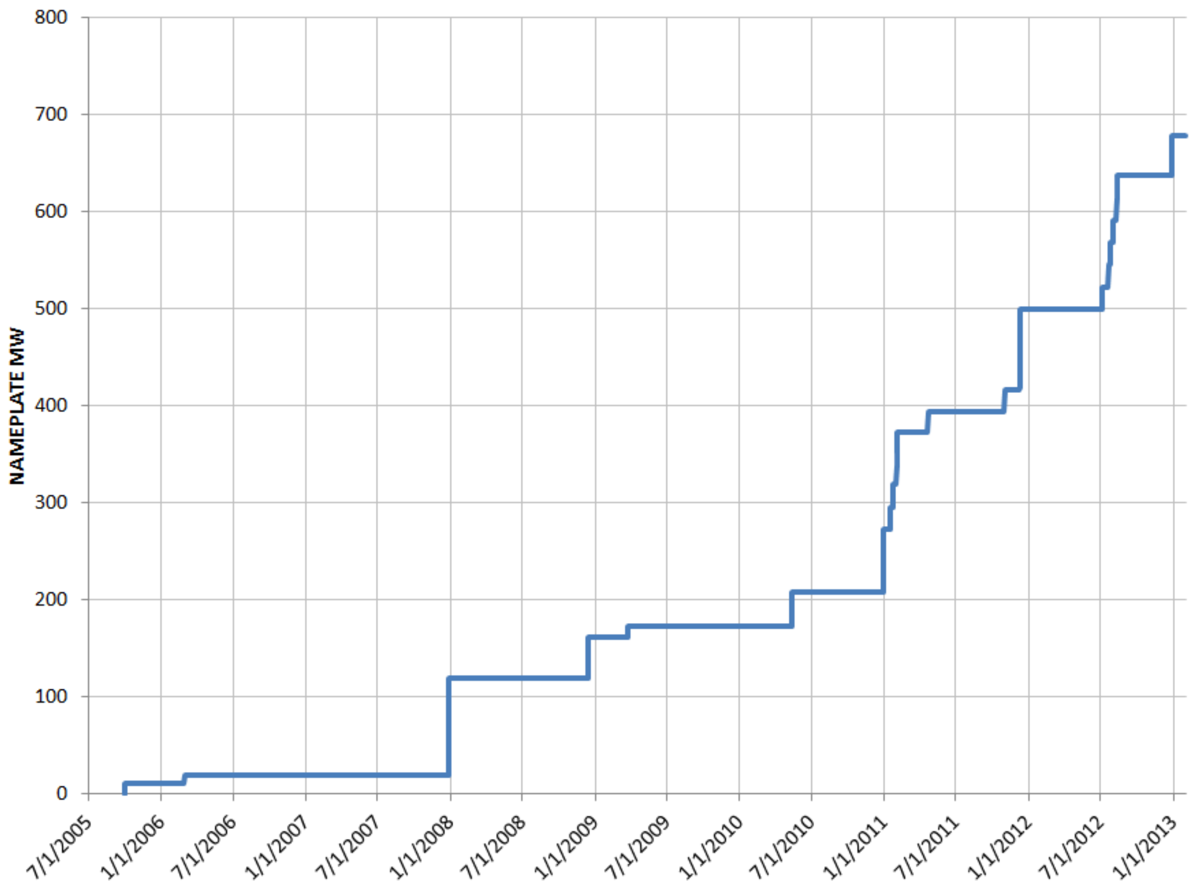

Figure 8 Installed Wind Capacity Connected to the Idaho Power System

This rapid growth has led to the recognition that Idaho Power's finite capability for integrating wind is nearing depletion. Even at the current level of wind penetration, dispatchable thermal and hydro generators are not always capable of providing the balancing reserves necessary to integrate wind. This situation is expected to worsen as wind penetration levels increase.

Balancing Reserves

This investigation determined wind integration costs for wind installed capacities of 800 MW, 1,000 MW, and 1,200 MW. Synthetic wind-generation data and corresponding day-ahead wind generation forecasts at these build-outs were provided by Energy Exemplar (formerly PLEXOS

Solutions) and 3TIER. Based on analysis of these data, the following monthly balancing reserves requirements were imposed in system modeling.

Table 6 Balancing reserves requirements (MW)

Wind Gen	800 MW		1,000 MW		1,200 MW	
	Reg Up	Reg Down	Reg Up	Reg Down	Reg Up	Reg Down
January	199	-262	246	-325	295	-390
February	252	-246	319	-297	379	-351
March	226	-295	281	-368	339	-444
April	255	-353	331	-450	395	-540
May	258	-290	328	-366	392	-439
June	266	-285	339	-363	409	-436
July	274	-256	355	-322	423	-384
August	172	-179	215	-224	257	-267
September	242	-219	309	-280	371	-337
October	217	-248	275	-308	329	-367
November	226	-336	277	-421	333	-507
December	267	-338	326	-424	394	-510

The term *Reg Up* is used for generating capacity that can be brought on-line in response to a drop in wind relative to the forecast. *Reg Down* is used for on-line generating capacity that can be turned down in response to a wind up-ramp. The balancing reserves requirements assume a 90 percent confidence level and thus are designed to cover deviations in wind relative to forecast except for extreme events comprising five percent at each end.

Study Design

The study employed the following two-scenario design:

- Base scenario for which the system is not burdened with the incremental balancing reserves necessary for integrating wind
- Test scenario for which the system is burdened with the incremental balancing reserves necessary for integrating wind

System simulations for the two scenarios were identical, except that generation scheduling for the test scenario included the condition that dispatchable thermal and hydro generators must provide the appropriate amount of incremental balancing reserves. Having the prescribed balancing reserves positions these generators such that they can respond to changing wind.

System simulations were conducted for a 2017 test year. Customer demand for 2017, as projected for the 2011 IRP, was used in system modeling. To investigate the effect of water conditions on wind integration, the study also considered Snake River Basin stream flows for three separate historic years representing low (2004), average (2009), and high (2006) water years.

Wind Integration Costs

The integration costs in Table 7 were calculated from the system simulations.

Table 7 Wind integration costs ($/MWh)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	$7.18	$11.94	$18.15
Low (2004)	$7.26	$12.44	$18.15
High (2006)	$9.73	$14.79	$20.73
Average	$8.06	$13.06	$19.01

Simulations with the proposed Boardman to Hemingway transmission line were also performed, yielding the results in Table 8.

Table 8 Wind integration costs with the Boardman to Hemingway transmission line ($/MWh)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	$6.51	$11.03	$16.38
Low (2004)	$6.66	$11.04	$16.67
High (2006)	$9.72	$13.78	$19.53
Average	**$7.63**	**$11.95**	**$17.53**

Curtailment

The study results indicate customer demand is a strong determinant of Idaho Power's ability to integrate wind. During low demand periods, the system of dispatchable resources often cannot provide the incremental balancing reserves paramount to successful wind integration without creating an imbalance between generation and demand. Under these circumstances, curtailment of wind generation is often necessary to maintain balance. Modeling demonstrates that the frequency of curtailment is expected to accelerate greatly beyond the 800 MW installed capacity level. While the maximum penetration level cannot be precisely identified, study results indicate wind development beyond 800 MW is subject to considerable curtailment risk. Importantly, curtailed wind generation was removed from the production cost analysis for the wind study modeling, and consequently had no effect on integration cost calculations. The curtailed wind generation simply cannot be integrated, and the cost-causing modifications to system operations designed to allow its integration are assumed to not be made. The curtailment of wind generation observed in the wind study modeling is shown in Figure 9.

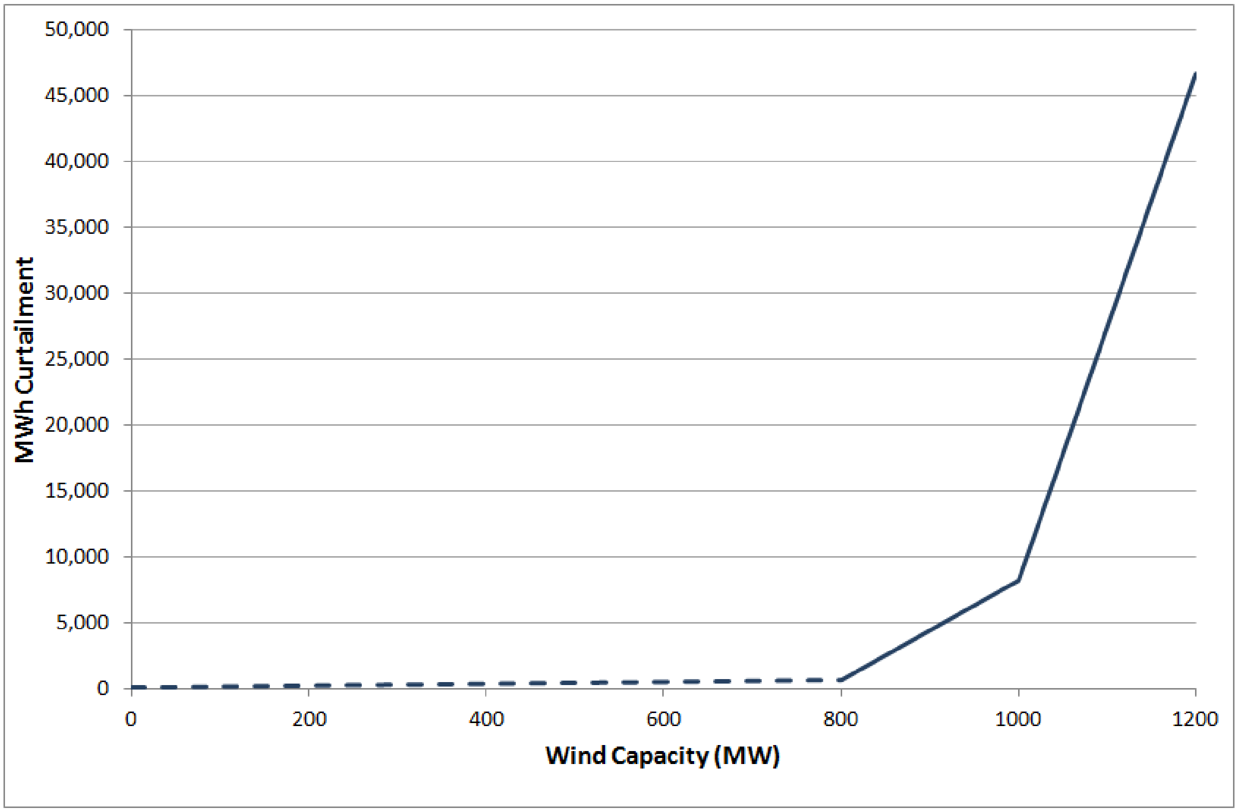

Figure 9 Curtailment of Wind Generation (average annual MWh)

Incremental Cost of Wind Integration

The integration costs previously provided in Tables 7 and 8 represent the cost per megawatt-hour (MWh) to integrate the full installed wind at the respective penetration levels studied. For example, the results of Table 7 indicate the full fleet of wind generators making up the 800-MW penetration level bring about costs of $8.06 for each MWh integrated. However, wind generators comprising the 678 MW of current installed capacity on the Idaho Power system are assessed an integration cost of only $6.50/MWh[1].

To fully cover the $8.06/MWh integration costs associated with 800 MW of installed wind capacity, wind generators in the increment between the current penetration level (678 MW) and the 800-MW penetration level will need greater assessed integration costs. Study analysis indicates that these generators will need to recognize integration costs of $16.70/MWh to allow full recovery of integration costs associated with 800 MW of installed wind capacity. Similarly, generators between the 800-MW and 1,000-MW penetration levels introduce incremental system operating costs requiring the assessment of integration costs of $33.42/MWh, and generators between 1,000 MW and 1,200 MW require incremental integration costs of $49.46/MWh. A graph showing both integration costs and incremental

[1] Integration cost stipulated by Idaho Public Utilities Commission Case No. IPC-E-07-03, Order No. 30488.

integration costs is provided in Figure 10 below. The incremental integration costs are summarized in Table 9.

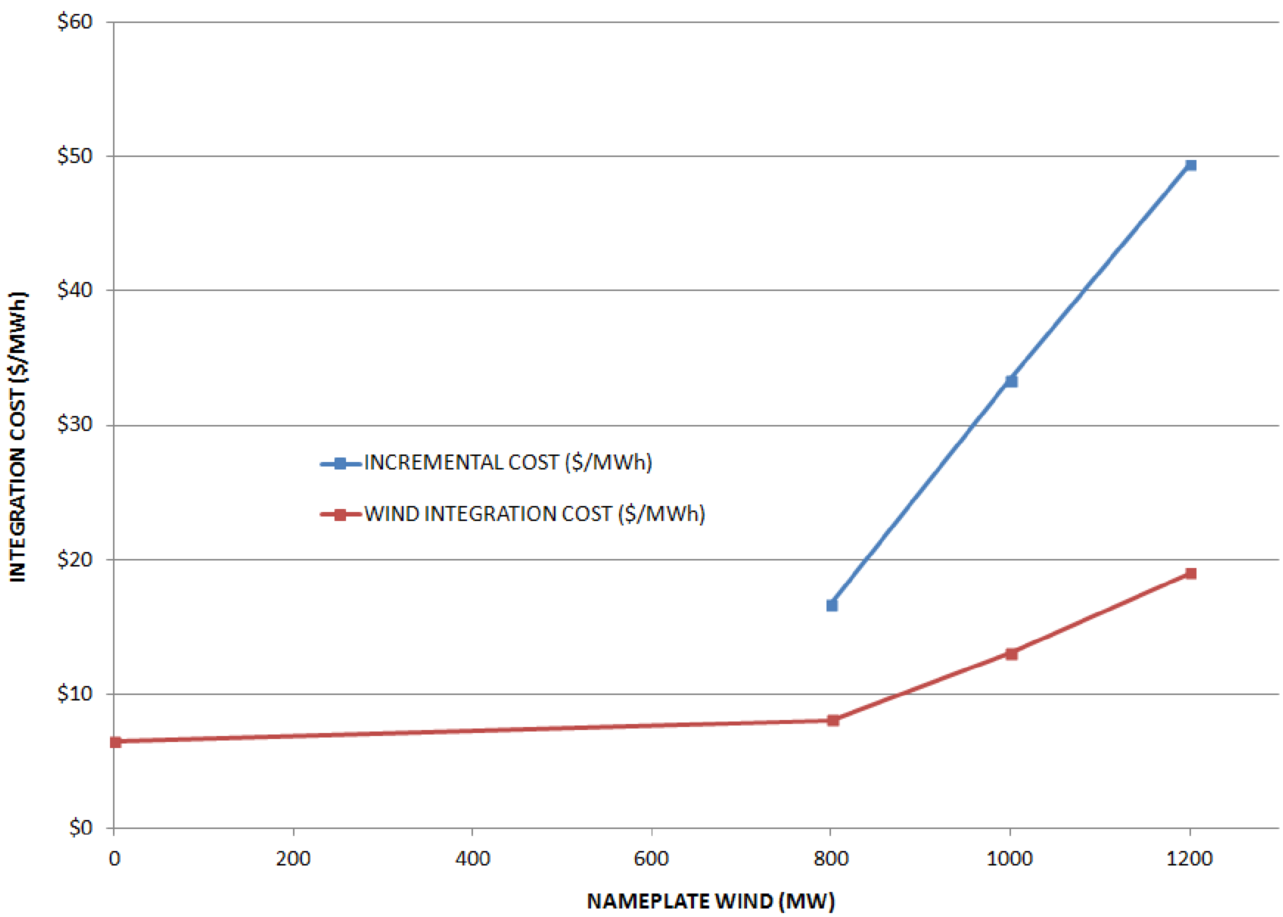

Figure 10 Integration Costs with Incremental Integration Costs ($/MWh)

Table 9 Incremental wind integration costs ($/MWh)

	Nameplate Wind		
	678–800 MW	**800–1,000 MW**	**1,000–1,200 MW**
Incremental cost per MWh	$16.70	$33.42	$49.46

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NEAR-TERM ACTION PLAN

Idaho Power has revised the near-term action as part of the 2011 IRP Update:

1. 2013 Integrated Resource Plan—Prepare and file by June 30, 2013.

2. Boardman to Hemingway Transmission Line—Ongoing permitting, planning studies, and regulatory filings.

3. Gateway West Transmission Line—Ongoing permitting, planning studies, and regulatory filings.

4. North Valmy Unit Number 1 (NV1) Dry Sorbent Injection (DSI)—To comply with the Mercury and Air Toxics Standards regulation, NV1 will require a DSI system to be operational by March 2015. Idaho Power anticipates the company will be required to commit to the installation of the DSI system no later than the third quarter of 2013.

5. Jim Bridger Unit Number 3 (JB3) Selective Catalytic Reduction (SCR)—To comply with the Regional Haze–Best Available Retrofit Technology regulation, JB3 will require SCR to be operational by December 31, 2015. Idaho Power anticipates the company will be required to commit to the installation of the SCR by the second quarter of 2013.

6. Jim Bridger Unit Number 4 (JB4) Selective Catalytic Reduction (SCR)—To comply with the Regional Haze–Best Available Retrofit Technology regulation, JB4 will require SCR to be operational by December 31, 2016. Idaho Power anticipates the company will be required to commit to the installation of the SCR by the second quarter of 2013.

Idaho Power intends to implement the six items identified in the near-term action plan.

The 2013 IRP will present the resource alternatives necessary to address the projected customer needs as well as contain a discussion of many of the topics in this 2011 IRP Update. Idaho Power anticipates filing the 2013 IRP in June 2013.

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Wind Integration Study Report

February 2013

Idaho Power, 1221 W Idaho Street, Boise, Idaho 83702

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EXECUTIVE SUMMARY

As a variable and uncertain generating resource, wind generators require Idaho Power to modify power system operations to successfully integrate such projects without impacting system reliability. The company must build into its generation scheduling extra operating reserves designed to allow dispatchable generators to respond to wind's variability and uncertainty.

Idaho Power, similar to much of the Pacific Northwest, has experienced rapid growth in wind generation over recent years. As of January 2013, Idaho Power has reached on-line wind generation totaling 678 megawatts (MW) of nameplate capacity. The rapid growth in wind generation is illustrated in Figure 1.

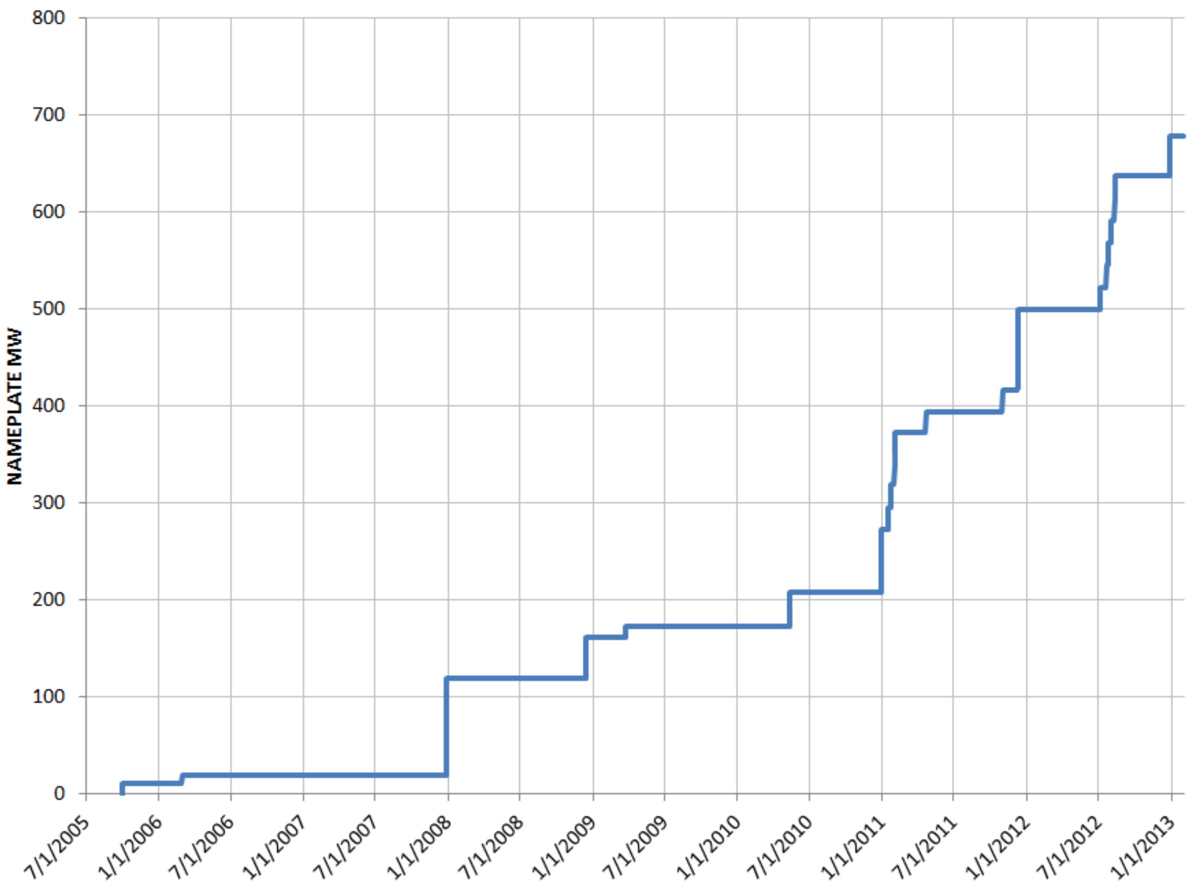

Figure 1 Installed wind capacity connected to the Idaho Power system

This rapid growth has led to the recognition that Idaho Power's finite capability for integrating wind is nearing depletion. Even at the current level of wind penetration, dispatchable thermal and hydro generators are not always capable of providing the balancing reserves necessary to integrate wind. This situation is expected to worsen as wind penetration levels increase.

Balancing Reserves

This investigation quantified wind integration costs for wind installed capacities of 800 MW, 1,000 MW, and 1,200 MW. Synthetic wind generation data and corresponding day-ahead wind generation forecasts at these build-outs were provided by Energy Exemplar (formerly PLEXOS

Solutions) and 3TIER. Based on analysis of these data, the following monthly balancing reserves requirements were imposed in system modeling.

Table 1 Balancing reserves requirements (MW)

Wind Gen	800 MW		1,000 MW		1,200 MW	
	Reg Up	Reg Down	Reg Up	Reg Down	Reg Up	Reg Down
January	199	-262	246	-325	295	-390
February	252	-246	319	-297	379	-351
March	226	-295	281	-368	339	-444
April	255	-353	331	-450	395	-540
May	258	-290	328	-366	392	-439
June	266	-285	339	-363	409	-436
July	274	-256	355	-322	423	-384
August	172	-179	215	-224	257	-267
September	242	-219	309	-280	371	-337
October	217	-248	275	-308	329	-367
November	226	-336	277	-421	333	-507
December	267	-338	326	-424	394	-510

The term *Reg Up* is used for generating capacity that can be brought online in response to a drop in wind relative to the forecast. *Reg Down* is used for on-line generating capacity that can be turned down in response to a wind up-ramp. The balancing reserves requirements assume a 90 percent confidence level and thus are designed to cover deviations in wind relative to forecast except for extreme events comprising 5 percent at each end.

Study Design

The study employed the following two-scenario design:

- Base scenario for which the system was not burdened with the incremental balancing reserves necessary for integrating wind
- Test scenario for which the system was burdened with the incremental balancing reserves necessary for integrating wind

System simulations for the two scenarios were identical, except that generation scheduling for the test scenario included the condition that dispatchable thermal and hydro generators must provide the appropriate amount of incremental balancing reserves. Having the prescribed balancing reserves positions these generators such that they can respond to changing wind.

System simulations were conducted for a 2017 test year. Customer demand for 2017, as projected for the *2011 Integrated Resource Plan* (IRP), was used in system modeling. To investigate the effect of water conditions on wind integration, the study also considered Snake River Basin stream flows for three separate historic years representing low (2004), average (2009), and high (2006) water years.

Wind Integration Costs

The integration costs in Table 2 were calculated from the system simulations.

Table 2 Wind integration costs ($/MWh)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	$7.18	$11.94	$18.15
Low (2004)	$7.26	$12.44	$18.15
High (2006)	$9.73	$14.79	$20.73
Average	**$8.06**	**$13.06**	**$19.01**

Simulations with the proposed Boardman to Hemingway transmission line were also performed, yielding the results in Table 3.

Table 3 Wind integration costs with the Boardman to Hemingway transmission line ($/MWh)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	$6.51	$11.03	$16.38
Low (2004)	$6.66	$11.04	$16.67
High (2006)	$9.72	$13.78	$19.53
Average	**$7.63**	**$11.95**	**$17.53**

Curtailment

The study results indicate customer demand is a strong determinant of Idaho Power's ability to integrate wind. During low demand periods, the system of dispatchable resources often cannot provide the incremental balancing reserves paramount to successful wind integration without creating an imbalance between generation and demand. Under these circumstances, curtailment of wind generation is often necessary to maintain balance. Modeling demonstrates that the frequency of curtailment is expected to accelerate greatly beyond the 800 MW installed capacity level. While the maximum penetration level cannot be precisely identified, study results indicate wind development beyond 800 MW is subject to considerable curtailment risk. Importantly, curtailed wind generation was removed from the production cost analysis for the wind study modeling, and consequently had no effect on integration cost calculations. The curtailed wind generation simply could not be integrated, and the cost-causing modifications to system operations designed to allow its integration were assumed to not be made. The curtailment of wind generation observed in the wind study modeling is shown in Figure 2.

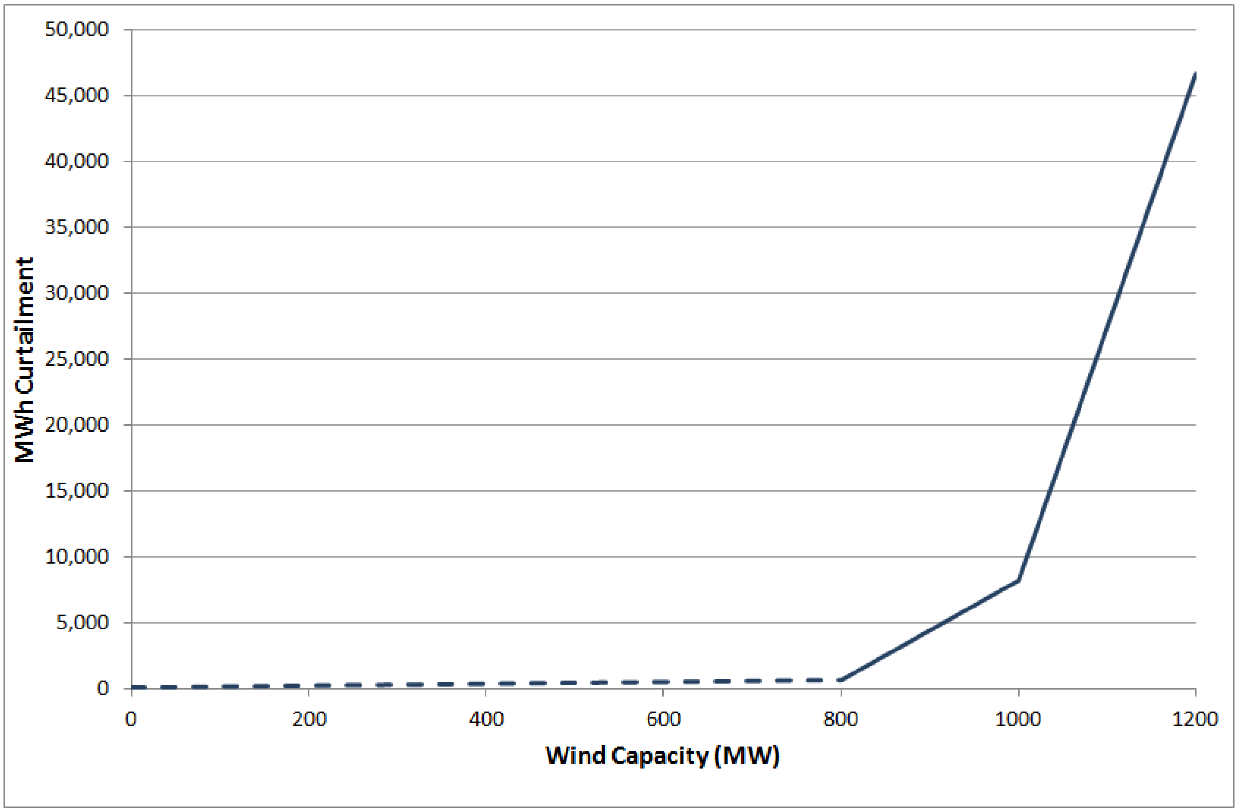

Figure 2 Curtailment of wind generation (average annual MWh)

Incremental Cost of Wind Integration

The integration costs previously provided in Tables 2 and 3 represent the cost per MWh to integrate the full installed wind at the respective penetration levels studied. For example, the results of Table 2 indicate that the full fleet of wind generators making up the 800 MW penetration level bring about costs of $8.06 for each MWh integrated. However, wind generators comprising the 678 MW of current installed capacity on the Idaho Power system are assessed an integration cost of only $6.50/MWh[1].

In order to fully cover the $8.06/MWh integration costs associated with 800 MW of installed wind capacity, wind generators in the increment between the current penetration level (678 MW) and the 800 MW penetration level will need greater assessed integration costs. Study analysis indicates that these generators will need to recognize integration costs of $16.70/MWh to allow full recovery of integration costs associated with 800 MW of installed wind capacity. Similarly, generators between the 800 MW and 1000 MW penetration levels introduce incremental system operating costs requiring the assessment of integration costs of $33.42/MWh, and generators between 1000 MW and 1,200 MW require incremental integration costs of $49.46/MWh. A graph showing both integration costs and incremental integration costs is provided in Figure 3 below. The incremental integration costs are summarized in Table 4.

[1] Integration cost stipulated by Idaho Public Utilities Commission Case No. IPC-E-07-03, Order No. 30488.

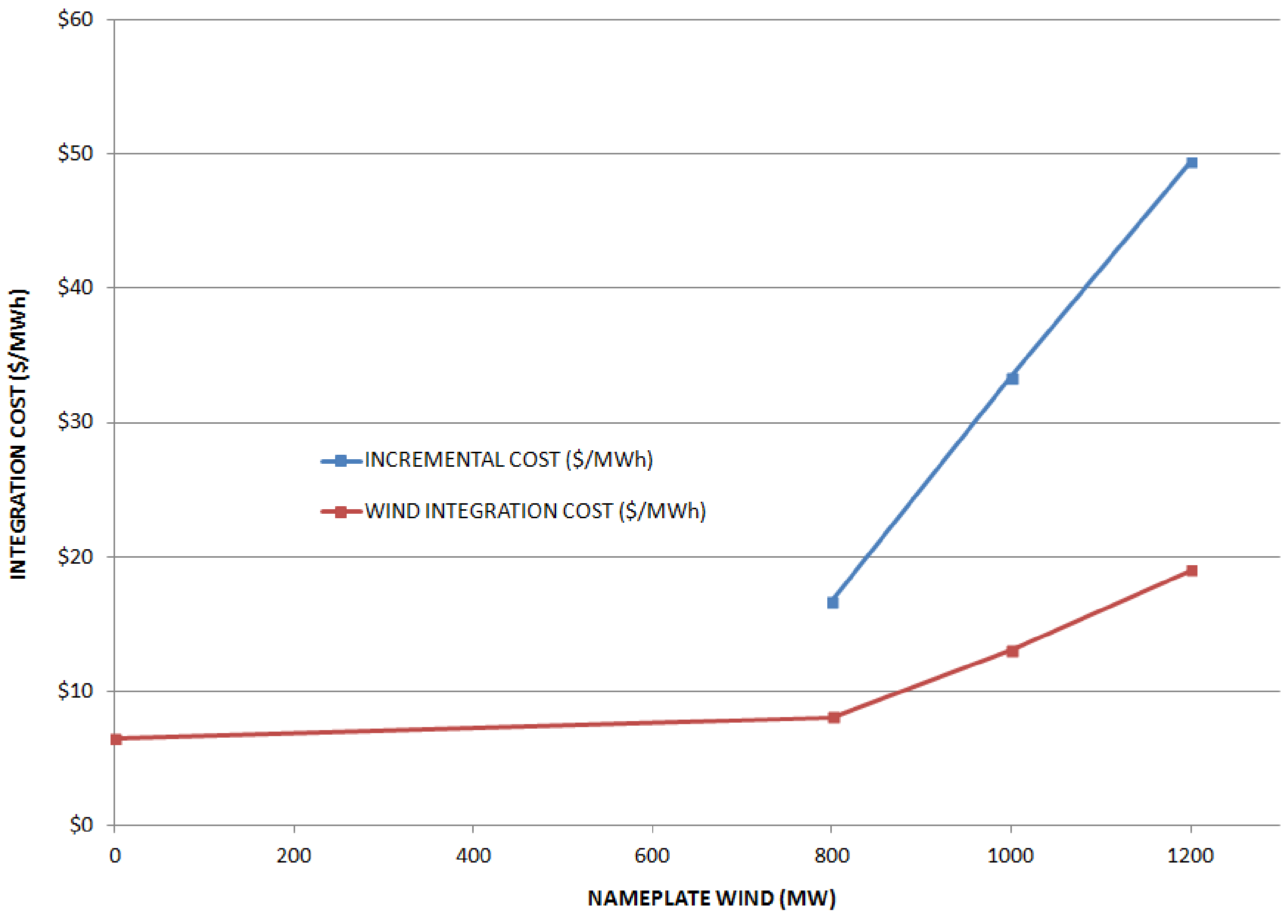

Figure 3 Integration costs with incremental integration costs ($/MWh)

Table 4 Incremental wind integration costs ($/MWh)

	Nameplate Wind		
	678 - 800 MW	**800 - 1,000 MW**	**1,000 - 1,200 MW**
Incremental cost per MWh	$16.70	$33.42	$49.46

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INTRODUCTION

Electrical power generated from wind turbines is commonly known to exhibit greater variability and uncertainty than that from conventional generators. Because of the incremental variability and uncertainty, it is widely recognized that electric utilities incur increased costs when their systems are called on to integrate wind power. These costs occur because power systems are operated less optimally to successfully integrate wind generation without compromising the reliable delivery of electrical power to customers. Idaho Power has studied the unique modifications it must make to power system operations to integrate the rapidly expanding amount of wind generation connecting to its system. The purpose of this report is to describe the operational modifications taken to integrate wind and the associated costs. The study of these costs is viewed by Idaho Power as an important part of efforts to ensure prices paid for wind power are fair and equitable to customers and generators alike.

Idaho Power first reported on wind integration in 2007. While there was a sizable amount of wind generation under contract in 2007, the amount of wind actually connected to the Idaho Power system at the time of the first study report was just under 20 MW nameplate. Over recent years, the amount of wind generation connected to the Idaho Power system has sharply risen. As of January 2013, Idaho Power has reached on-line wind generation totaling 678 MW nameplate. The rapid growth in wind generation is illustrated in Figure 4.

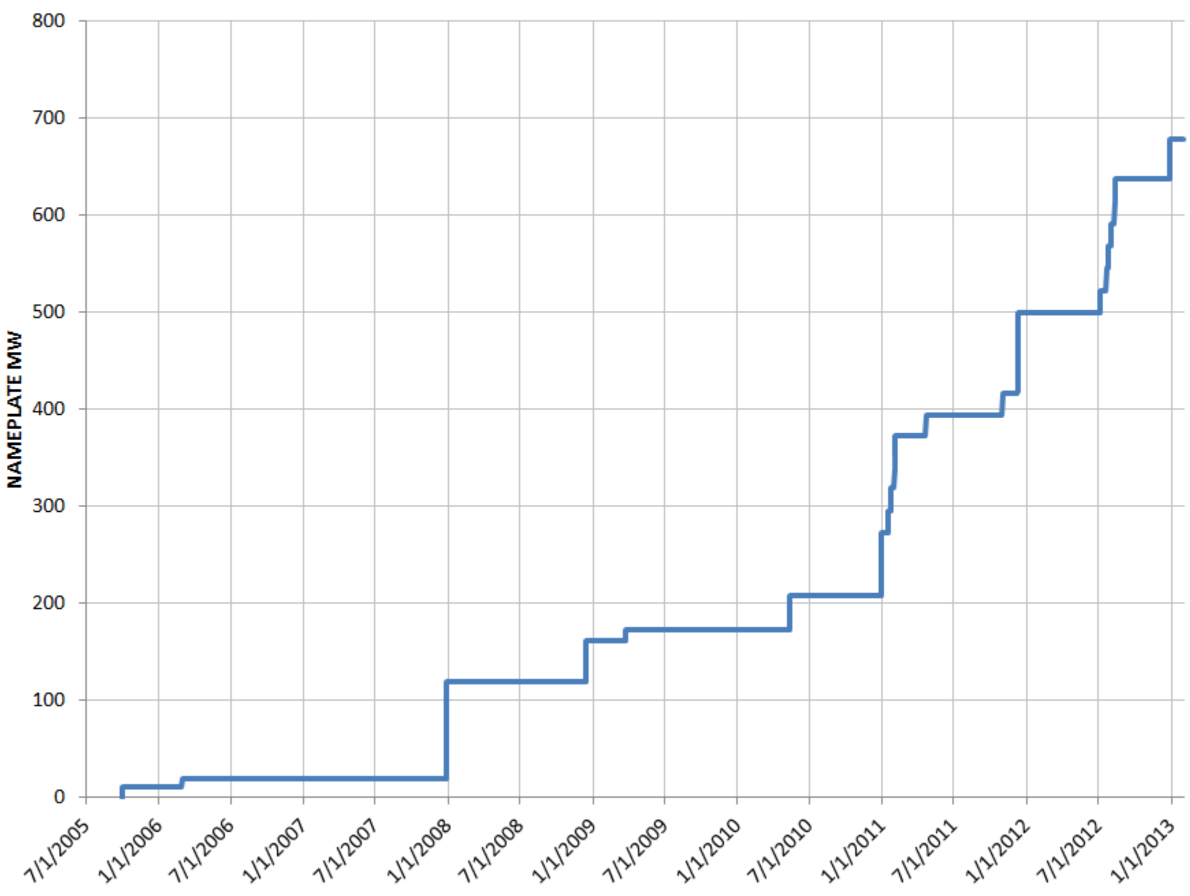

Figure 4 Installed wind capacity connected to the Idaho Power system (MW)

The steep upturn in wind generation has driven Idaho Power to expand its area of concern beyond the operational costs associated with wind integration to the consideration of the maximum wind penetration level its system can reliably integrate. Thus, the objective of the Idaho Power wind integration study is to answer the following two questions:

- What are the costs of integrating wind generation on the Idaho Power system?
- How much wind generation can the Idaho Power system accommodate without impacting reliability?

A critical principle in the operation of a bulk power system is that a balance between generation and demand must generally be maintained. Power system operators have long studied the variability and uncertainty present on the demand side of this balance, and as a matter of standard practice carry operating reserves on dispatchable generators designed to accommodate potential changes in demand. The introduction of significant wind power causes the variability and uncertainty on the generation side of the balance to markedly increase, requiring power system operators to plan for carrying incremental amounts of operating reserves, in this case necessary to accommodate potential changes in wind generation.

For the purposes of this study report, the term *balancing reserves* is used to denote the operating reserves necessary for integrating wind. A document review on wind integration indicates a variety of terms for this quantity. Regardless of term, the property being described is generally the flexibility a balancing authority must carry to reliably respond to variability and uncertainty in wind generation and demand.

A key component in the study of wind integration, as well as the successful in-practice operation of a power system integrating wind, involves the estimation of the additional balancing reserves dispatchable generators must carry to allow the balance between generation and demand to be maintained. Thus, three essential objectives of this report are to describe the analysis performed by Idaho Power to estimate the incremental balancing reserves requirements attributable to wind generation, describe the power system simulations conducted to model the scheduling of the reserves, and estimate associated costs. The study also evaluates situations where the incremental wind-caused balancing reserves exceed the capabilities of Idaho Power's dispatchable generators, putting the system in a position where it cannot accept additional output from wind generators without compromising reliability.

Technical Review Committee

Idaho Power held a public workshop on April 6, 2012, to discuss its work on wind integration. This workshop included a discussion of methodology and preliminary results, as well as a question and answer session. Following the workshop, the company began working with a technical review committee comprised of individuals selected by Idaho Power based on their knowledge of regional issues surrounding wind generation and the operation of electric power systems.

The following members agreed to serve on the committee:

- Ken Dragoon (Ecofys/Northwest Power and Conservation Council)
- Kurt Myers (Idaho National Laboratory [INL])
- Frank Puyleart (Bonneville Power Administration [BPA])
- Rick Sterling (Idaho Public Utilities Commission [IPUC])

The purpose of the work with the technical review committee was to describe in greater detail the study methodology, including an in-depth review of the model used for system simulations for the study. Given this information, the company asked the members of the committee for their specific comments upon release of this wind integration study report. These comments will be specially noted as having been provided by the technical review committee on the basis of its in-depth review of study methods.

Energy Exemplar Contribution

Idaho Power contracted with Energy Exemplar (formerly PLEXOS Solutions) for assistance with the wind integration study. Energy Exemplar's involvement was critical in the development of the wind generation data used for the study, particularly in the development of representative wind generation forecasts used in the analysis to estimate appropriate balancing reserves requirements. Energy Exemplar was also instrumental in the design of the study methodology, providing key counsel in the formulation of the two-scenario study design detailed later in this report.

With respect to system simulations for the wind study, Idaho Power has developed considerable expertise modeling the power system over recent years. In parallel with the Energy Exemplar efforts, Idaho Power developed a model that optimizes the wind, hydro, and thermal generation production. This internally-developed model was used for system simulations included in the wind study.

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IDAHO POWER SYSTEM OVERVIEW

Idaho Power serves approximately 500,000 customers in southern Idaho and eastern Oregon through the operation of a diversified power system composed of supply- and demand-side resources, as well as significant transmission and distribution infrastructure. From the supply-side perspective, Idaho Power relies heavily on generation from 17 hydroelectric plants on the Snake River and its tributaries. These resources provide the system with electrical power that is low-cost, dependable, and renewable. Idaho Power also shares joint ownership of three coal-fired generating plants and is the sole owner of three natural gas-fired generating plants, including the recently commissioned Langley Gulch Power Plant. With respect to demand-side resources, Idaho Power has received recognition for its demand response programs, particularly the part these dispatchable programs have played in meeting critical summertime capacity needs. Finally, Idaho Power maintains an extensive system of transmission and distribution resources, allowing it to connect to regional power markets, as well as distribute power reliably at the customer level.

Hydroelectric Generating Projects

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 average megawatts (aMW), or 8.5 million megawatt hours (MWh), under median water conditions. The backbone of Idaho Power's hydroelectric system is the Hells Canyon Complex (HCC) in the Hells Canyon reach of the Snake River. The HCC consists of Brownlee, Oxbow, and Hells Canyon dams and the associated generation facilities. In a normal water year, the three plants provide approximately 68 percent of Idaho Power's annual hydroelectric generation. Water storage in Brownlee Reservoir also enables the HCC projects to provide the major portion of Idaho Power's peaking and load-following capability. The capability to respond to varying load is increasingly being called on to regulate the variable and uncertain delivery of wind generation.

Hydro is Idaho Power's wind integration resource of choice because of its quick response capability as well as large response capacity. However, the capacity of the hydro system to respond to wind variability is recognized as finite; power-system operation, in practice and as simulated for this study, indicates the hydro system is not always able to sufficiently provide the balancing reserves needed for responding to wind. Using the hydro system for wind integration also limits its availability for other opportunities. The costs of these lost opportunities are a significant part of wind integration costs.

For the wind integration study, the hydroelectric generators at the Brownlee and Oxbow dams were designated in the modeling as available for providing wind-caused balancing reserves. This is consistent with system operation in practice, where the generators at these projects are dispatched to provide the overwhelming majority of operating reserves. Under standard operating practice, the remaining hydroelectric generators of the Idaho Power system are not called on for providing operating reserves. Generators at the Lower Salmon, Bliss, and C. J. Strike plants are capable of some ramping for responding to intra-day variation in load. However, under certain flow conditions, the flexibility of the smaller reservoirs to follow even load trends is greatly diminished, and the facilities are operated strictly as run-of-river (ROR) projects.

Coal-Fired Generating Projects

Idaho Power co-owns three coal-fired power plants having a total nameplate capacity of 1,118 MW. With relatively low operating costs, these plants have historically been a reliable source of stable baseload energy for the system. The output from these plants over recent years is somewhat diminished because of a variety of conditions, including relatively high Snake River and Columbia River stream flows, lagging regional demand for electricity associated with slow economic growth, and an oversupply of energy in the region. Idaho Power is currently studying the economics of operating its coal-fired plants, specifically the cost effectiveness of plant upgrades needed for environmental compliance at the Jim Bridger and North Valmy coal plants. The Boardman coal plant in northeastern Oregon will not operate beyond 2020 and Idaho Power's 64 MW share of the plant will no longer be available to serve customer load.

Coal is one of the thermal resources Idaho Power uses to integrate wind generation. Unlike hydro, the fuel for the coal plants comes at a cost. These fuel costs, as well as the lost opportunities created by using the coal capacity to integrate wind, make up another part of the wind integration costs. The coal generators do not have the large range and rapid response provided by the hydro units.

Natural Gas-Fired Generating Projects

Idaho Power owns and operates four simple-cycle combustion turbines totaling 416 MW of nameplate capacity, and recently commissioned a 300 MW combined-cycle combustion turbine. The simple-cycle combustion turbines (located at Danskin and Bennett Mountain project sites) have relatively low capital costs and high variable operating costs. As a consequence of the high operating costs, the simple-cycle turbines have been historically operated primarily in response to peak demand events and have seldom been dispatched to provide operating reserves. Expansion of their operation to provide balancing reserves for integrating wind is projected to lead to a substantial increase in power supply costs.

Idaho Power commissioned in July 2012 the 300 MW Langley Gulch Power Plant. As a combined-cycle combustion turbine, this generating facility has markedly lower operating costs than the simple-cycle units and is consequently expected to be a critical part of the fleet of generators dispatched to provide balancing reserves for responding to variable wind generation.

Transmission and Wholesale Market

Idaho Power has significant transmission connections to regional electric utilities and regional energy markets. The company uses these connections considerably as part of standard operating practice to import and export electrical power. Utilization of these paths on a day-to-day basis is typically driven by economic opportunities; energy is generally imported when prices are low and exported when prices are high. Transmission capacity across the connections does not reduce system balancing reserves requirements. Thus, balancing reserves necessary for reliable power system operation in practice are provided by dispatchable generators. The wholesale power market, as accessed through regional transmission connections, is not able to provide balancing reserves.

Idaho Power's existing transmission system spans southern Idaho from eastern Oregon to western Wyoming and is composed of transmission facilities having voltages ranging from 115 kilovolts (kV) to 500 kV. The sets of lines transmitting power from one geographic area to another are known as transmission paths. There are defined transmission paths to other states and between southern Idaho load centers such as Boise, Twin Falls, and Pocatello. Idaho Power's transmission system and paths are shown in Figure 5.

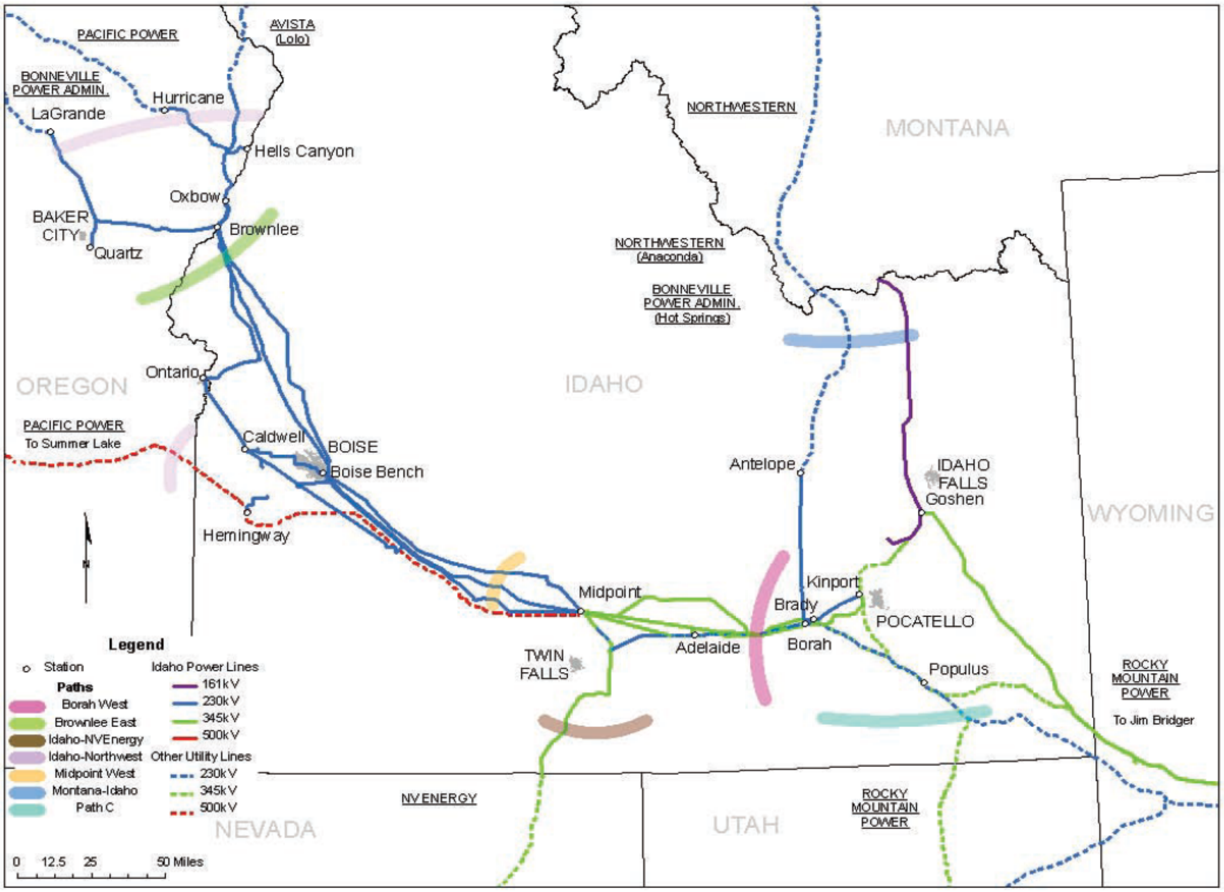

Figure 5 Idaho Power transmission paths

The critical paths from the perspective of providing access to the regional wholesale electricity market are the Idaho–Northwest, Idaho–Utah (Path C), and Idaho–Montana paths. The Boardman to Hemingway transmission line identified by Idaho Power in the preferred portfolio of its 2011 IRP will be an upgrade to the Idaho-Northwest path. The combination of these paths provides Idaho Power effective access to the regional market for the economic exchange of energy.

While Idaho Power does not consider the regional market part of its day-to-day solution for integrating wind generation, it may be necessary during extreme events to use the regional transmission connections and rely on the regional energy market to accommodate wind. The company expects that at times even the regional market will be insufficient to integrate wind. During these times when Idaho Power and the regional market have insufficient balancing reserves to successfully integrate wind generation, it may be necessary to curtail wind, or even curtail customer load, to maintain electrical system stability and integrity.

Power Purchase Agreements

In addition to power purchases in the wholesale market, Idaho Power purchases power pursuant to long-term power purchase agreements (PPA). The company has the following notable firm wholesale PPAs and energy exchange agreements:

- Raft River Energy I, LLC—For up to 13 MW (nameplate generation) from its Raft River Geothermal Power Plant Unit #1 located in southern Idaho. The contract term is through April 2033.
- Telocaset Wind Power Partners, LLC—For 101 MW (nameplate generation) from the Elkhorn Valley wind project located in eastern Oregon. The contract term is through 2027.
- USG Oregon LLC—For 22 MW (estimated average annual output) from the Neal Hot Springs geothermal power plant located near Vale, Oregon. The contract term is through 2037 with an option to extend.
- Clatskanie People's Utility District—For the exchange of up to 18 MW of energy from the Arrowrock project in southern Idaho for energy from Idaho Power's system or power purchased at the Mid-Columbia trading hub. The initial term of the agreement is January 1, 2010 through December 31, 2015. Idaho Power has the right to renew the agreement for two additional five-year terms.

System Demand

Idaho Power's all-time system peak demand is 3,245 MW, set on July 12, 2012, and the all-time winter peak demand is 2,527 MW, set on December 10, 2009. An important characteristic of the Idaho Power system is the intra-day range from minimum to maximum customer demand, which during the summer commonly reaches 1,000 MW and occasionally exceeds 1,200 MW. Thus, generating resources that can follow this demand as it systematically grows during the day are critical to maintaining reliable system operation. Hydro generators, particularly those of the HCC, provide much of the demand following capability. Recent natural gas-fired resource additions are also instrumental in allowing the system to reliably meet system demand. An additional resource available to the system is the targeted dispatch of demand response programs. These demand-side programs have proven to dependably reduce system demand during extreme summer load events. From the perspective of system reliability, the nature of Idaho Power's customer demand places a premium on the value associated with capacity-providing resources; energy resources, such as wind, contribute markedly less towards promoting system reliability.

It is recognized that production from wind projects does not dependably occur in concert with peak customer demand. In fact, there is a tendency to experience periods during which production from wind and hydro facilities is high and customer demand is low. The coincidence of these circumstances leads to an excess generation condition, where the capability of system generators to reduce their output in response to wind is severely diminished. Such excess generation events have been observed in recent years by Idaho Power and other balancing authorities in the Pacific Northwest. System stability for the balancing authority is maintained during these events through the curtailment of generation, including that from wind-powered facilities.

System Scheduling

Idaho Power schedules its system with the primary objective of ensuring the reliable delivery of electricity to customers at the lowest possible cost. System planning is conducted for multiple time frames ranging from years/months in advance for long-term planning to hour-ahead for real-time operations planning. A fundamental principle in system planning is that each time frame should be driven by the objective of readying the system for more granular time frames. Long-term resource planning (i.e., the IRP) should ensure the system has adequate resources for managing customer demand over the 18-month long-term operations planning window. Long-term operations planning should position the system such that customer demand can be managed over the balance-of-month perspective. Balance-of-month planning should result in a system that can manage demand when scheduling generation day-ahead. Day-ahead scheduling should enable operators to meet demand from a real-time perspective. Finally, real-time energy schedulers should ensure the system is positioned hour-ahead such that reliable service is maintained within the hour.

With the possible exception of the IRP, the scheduling horizons considered by Idaho Power involve transacting with the regional wholesale market. Where the economic scheduling of system generation is insufficient to meet demand, Idaho Power enters into contracts to purchase power off-system through its transmission connections. Conversely, where economically scheduled generation exceeds customer demand, surplus power is sold into the market. Importantly, Federal Energy Regulatory Commission (FERC) rules (FERC order nos. 888/890) stipulate that surplus power sales are sourced by generating resources that have been undesignated from network load service. Undesignation of a variable generating resource, such as wind, for sourcing a third-party sales transaction results in the transacted energy being given a dynamic tag, where tag is the North American Electricity Reliability Corporation (NERC) term representing an energy transaction in the wholesale electricity market.
Balancing authorities experience considerable difficulty attracting a purchaser of dynamically tagged energy. Therefore, as a standard operating practice, Idaho Power sources off-system power sale contracts from its fleet of hydro and thermal generators. With their recognized level of dependability, hydro and thermal generators can be undesignated for sourcing surplus power sales while allowing conventional tagging procedures to be followed.

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STUDY DESIGN

Idaho Power designed its wind integration study with the objective of isolating in its operations modeling the effects directly related to integrating wind generation. A common study design used towards meeting this objective, and employed by Idaho Power for this study, is to simulate system operations of a future year with projected wind build-outs under the following two scenarios:

- Base scenario for which the system is not burdened with the incremental balancing reserves necessary for integrating wind
- Test scenario for which the system is burdened with the incremental balancing reserves necessary for integrating wind

A critical feature of this design is to hold equivalent model parameters and inputs between these two scenarios except for balancing reserves. The incremental balancing reserves built into the test scenario simulation necessarily result in higher production costs for the system, a cost difference that can be attributed to wind integration.

The test year selected by Idaho Power for its study is 2017. While in-service for the 500-kV Boardman to Hemingway transmission line is not anticipated before 2018, the study still considered scenarios to investigate the effects of the expanded transmission on wind integration costs. The study assumed customer demand and Mid-Columbia trading hub wholesale prices as projected for 2017 in the 2011 IRP.

As noted previously, as of January 2013 Idaho Power has 678 MW of nameplate wind capacity. Future wind penetrations considered in the study are 800 MW, 1,000 MW, and 1,200 MW of nameplate capacity. The synthetic wind data at these penetration levels, as well as representative day-ahead forecasts, were provided by 3TIER and Energy Exemplar. The synthetic wind data were provided for 43 wind project locations requested by Idaho Power corresponding to project sites having a current purchase agreement with the company, as well as sites proposed to the company for future projects. Further discussion of the study wind data and associated day-ahead forecasts is provided in a May 9, 2012 explanation released by the company (Appendix A).

To investigate the effect of water conditions on wind integration, the study considered Snake River Basin stream flows for three separate historic scenarios representing low (2004), average (2009), and high (2006) water years. Because of their importance in providing balancing reserves to integrate wind, the HCC projects were simulated using the study model to determine their hydroelectric generation under the selected water years. Generation for the remaining hydroelectric projects, which are not in practice called on to provide balancing reserves for integrating wind, was entered for the study as recorded in actual operations for the water years selected.

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Balancing Reserves Calculations and Operating Reserves

Critical to the two-case study design is the calculation of the incremental balancing reserves necessary for successfully integrating the future wind penetration build-outs considered. The premise behind these calculations is that Idaho Power's dispatchable generators must have capacity in reserve, allowing them to respond at an acceptable confidence level to the variable and uncertain delivery of wind. Estimates of the appropriate amount of balancing reserves were based on an analysis of errors in day-ahead forecasts of system wind for the wind build-outs considered in the study. In addition to the synthetic time series of hourly wind-generation data, 3TIER provided a representative day-ahead forecast of hourly wind generation. To provide a larger sampling, Energy Exemplar created 100 additional day-ahead forecasts having similar accuracy as the 3TIER forecast. Summaries of the synthetic wind data and day-ahead forecasts are included in Appendix B. An illustration of this design is given in Figure 6.

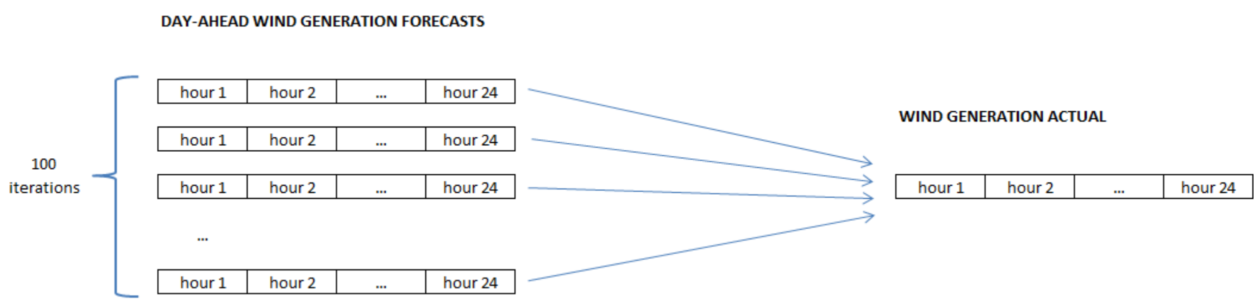

Figure 6 Wind-forecasting and generation data

In recognition of the seasonality of wind, the data were grouped by month, yielding balancing reserves estimates specific to each month. The sample size for each month was extremely large. As an example, for July there were 74,400 deviations between the day-ahead forecast and actual wind generation (100 forecasts × 31 days × 24 hours). The balancing reserves requirements were calculated as the bi-directional capacity covering 90 percent of the deviations. The use of the 90 percent confidence level for the wind integration analysis is consistent with the criterion used for hydro conditions in assessing peak-hour resource adequacy in integrated resource planning.

Figure 7 is an illustration of a full year of deviations for a single forecast iteration at the 1,200 MW penetration level. In this figure, the deviations on the positive side correspond to deviations where actual wind was lower than day-ahead forecast wind, while deviations on the negative side reflect instances where actual wind exceeded the forecast. Importantly, the balancing reserves requirements did not cover the full extent of the deviations, leaving extreme tail events in both directions uncovered.

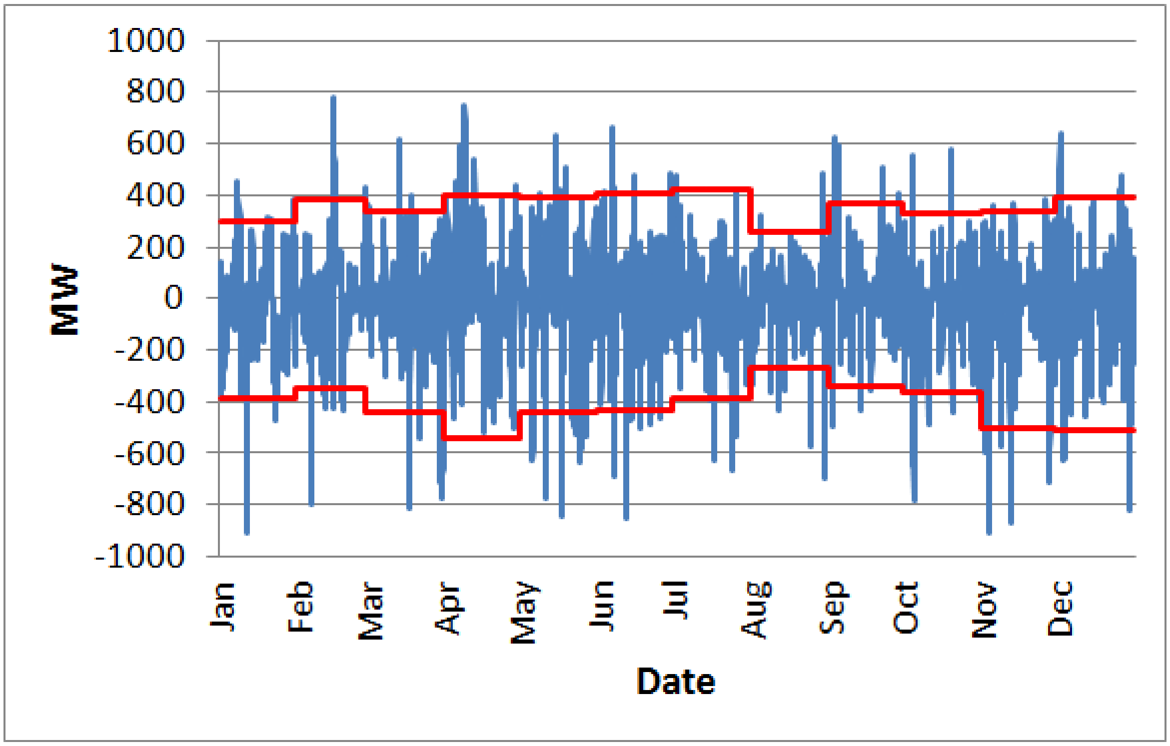

Figure 7 Deviations between forecast and actual wind generation with monthly balancing reserves requirements (MW)

The requirements are dynamic in that the forecast wind was taken into account in imposing the amount of balancing reserves. For example, the requirements suggest that for the 1,200 MW wind penetration level, 295 MW of unloaded generating capacity should be held as balancing reserves in January to guard against a drop in wind relative to the forecast. However, if the forecast wind generation is only 250 MW, then the most wind can drop relative to forecast is 250 MW, which is then the amount of balancing reserves built into the generation schedule. As a second example, if the forecast wind generation is 350 MW, the analysis of wind data indicates that balancing reserves should be held to guard against wind dropping to 55 MW. The likelihood of wind dropping below 55 MW is small (5 percent), and balancing reserves are not scheduled on dispatchable generators for covering a drop in wind to less than 55 MW.

The monthly requirements for balancing reserves are given in Table 5 for the wind penetration levels studied. The term *Reg Up* is used for generating capacity that can be brought online in response to a drop in wind relative to the forecast. *Reg Down* is used for online generating capacity that can be turned down in response to a wind up-ramp.

Table 5 Balancing reserve requirements (MW)

Wind Gen	800 MW		1,000 MW		1,200 MW	
	Reg Up	Reg Down	Reg Up	Reg Down	Reg Up	Reg Down
January	199	-262	246	-325	295	-390
February	252	-246	319	-297	379	-351
March	226	-295	281	-368	339	-444
April	255	-353	331	-450	395	-540
May	258	-290	328	-366	392	-439
June	266	-285	339	-363	409	-436
July	274	-256	355	-322	423	-384
August	172	-179	215	-224	257	-267
September	242	-219	309	-280	371	-337
October	217	-248	275	-308	329	-367
November	226	-336	277	-421	333	-507
December	267	-338	326	-424	394	-510

Balancing Reserves for Variability and Uncertainty in System Demand

As described previously, power system operation has long needed to hold bidirectional capacity for responding to variability and uncertainty in system demand. For the wind study modeling, Idaho Power imposed a balancing reserves requirement equal to 3 percent of the system demand as capacity reserved to allow for variability and uncertainty in load. This capacity was carried in equal amounts in the two scenarios modeled: the base scenario where the system was not burdened with wind-caused balancing reserves, and the test scenario where a wind-caused balancing reserves requirement was assumed necessary. For the test scenario modeling, the separate load- and wind-caused reserves components were added to yield the total bidirectional balancing reserves requirement. This approach for combining the reserves components is consistent with Idaho Power operations in practice for which system operators receive separate forecasts for wind and demand and combine the estimated uncertainty about these projections through straight addition.

Contingency Reserve Obligation

The variability and uncertainty in demand and wind are routine factors in power system operation and require a system to carry the bidirectional balancing reserves described in this section for maintaining compliance with reliability standards. However, balancing authorities, such as Idaho Power, are also required to carry unloaded capacity for responding to system contingency events, which have traditionally been viewed as large and relatively infrequent system disturbances affecting the production or transmission of power (e.g., loss of a major generating unit or major transmission line).
System modeling for the wind study imposed a contingency reserve intended to reflect this obligation equal to 3 percent of load and 3 percent of generation, setting aside this capacity for both scenarios (i.e., base and test). The requirement to carry at least half of the contingency reserve obligation on generators that are spinning and grid-synchronized was also captured in the modeling.

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SYSTEM MODELING

Idaho Power used an internally developed system operations model for this study. The model determines optimal hourly scheduling of dispatchable hydro and thermal generators with the objective of minimizing production costs while honoring constraints imposed on the system. System constraints used in the model capture numerous restrictions governing the operation of the power system, including the following:

- Reservoir headwater constraints
- Minimum reservoir outflow constraints
- Reservoir outflow ramping rate constraints
- Wholesale market activity constraints
- Generator minimum/maximum output levels
- Transfer capacity constraints over transmission paths
- Generator ramping rates

The model also stipulated that demand and resources were exactly in balance, and importantly that hourly balancing reserves requirements for variability and uncertainty in load and wind were satisfied. The incremental balancing reserves required for wind variability and uncertainty drove the production cost differences between the study's two cases.

Day-Ahead Scheduling

The hourly scheduling determined by the model was intended to represent the optimal day-ahead system dispatch. This dispatch schedule included generation scheduling for thermal and hydro generators, as well as market transactions. Key inputs to the generation scheduling were the forecasts for wind production and customer demand. These two elements of the generation/load balance commonly carry the greatest uncertainty for power system operation in practice. A fundamental premise of reliable operations for a balancing authority is the need to carry reasonable and prudent flexibility in the day-ahead generation schedule, allowing the system to respond to errors in demand and wind generation forecasts. This principle was built into the wind study modeling in the form of balancing reserves constraints the model must honor. In the two-case study design, the system modeling for the base case included constraints only for demand uncertainty, whereas constraints for the test case included the need to carry additional balancing reserves for wind uncertainty. The derivation of the balancing reserves constraints is described previously in this report.

The critical decision day-ahead generation schedulers must make involves how to schedule dispatchable generation units taking into account the following factors:

- Forecasts for demand and wind production
- Production from other non-dispatchable resources (e.g., PPAs)
- Production from ROR hydro resources
- Operating costs of thermal resources
- Water supply for dispatchable hydro resources

- Operating reserves for contingency events
- Flexibility in the schedule for dispatchable generation units allowing them to respond if necessary to deviations between forecast and actual conditions in load and wind

The essence of wind integration and the associated costs is that the amount of balancing reserves that must be carried is greater because of the uncertainty and variability of wind generation.

Demand and Wind Forecasts

The demand forecast used for the modeling was based on the projected hourly load used in the 2011 IRP for the calendar year 2017. The wind production forecast used for the modeling was based on the average of the 100 forecasts provided by 3TIER and Energy Exemplar.

The forecasts for both elements were identical between the study scenarios; the test scenario simply imposed greater balancing reserves constraints to allow for variability and uncertainty in the wind production forecast.

Transmission System Modeling

As noted in the Idaho Power System Overview section, the critical interconnections to the regional market are over the Idaho–Northwest, Idaho–Utah (Path C), and Idaho–Montana paths. For the wind-study modeling, the separate paths were combined to an aggregate path for off-system access. Every October, Idaho Power submits a request to secure firm transmission across its network based on its expected monthly import needs for the next 18 months. The maximum levels used in the modeling for firm import capacity were based on the October 2010 request. The modeling assumed additional import capacity using non-firm transmission. Non-firm imports were assessed a $50/MWh penalty designed to represent the less favorable economics associated with non-firm transmission and typical hourly pricing. The export limits were based on typical levels of outbound capacity observed in practice. The transmission constraints in Table 6 were used in the wind study modeling.

Table 6 Modeled transmission constraints (MW)

Month	Maximum Firm Import (MW)	Maximum Non-Firm Import (MW)	Maximum Export (MW)
January	179	300	500
February	35	300	500
March	0	300	500
April	0	300	500
May	320	300	500
June	262	300	500
July	149	300	500
August	230	300	500
September	217	300	500
October	0	300	500
November	113	300	500
December	325	300	500

Idaho Power's transmission network is a fundamental part of the vertically integrated power system, and allows the company to participate in the regional wholesale market to serve load or for economic benefit. However, Idaho Power does not view its transmission network with associated regional interconnections as a resource for providing balancing reserves allowing it to respond to variability and uncertainty in wind generation and customer demand. In the region, each balancing authority provides its own balancing reserves. Idaho Power provides its balancing reserves from company-owned dispatchable generation units (thermal and hydro).

Idaho Power also investigated scenarios with the 500-kV Boardman to Hemingway transmission line. For these scenarios, the maximum firm import constraint was increased by 500 MW during April through September and by 200 MW for the remainder of the year. The maximum export constraint was increased by 150 MW throughout the year. The following transmission constraints were used in the wind study modeling for the system with the proposed Boardman to Hemingway transmission line.

Table 7 Modeled transmission constraints—simulations with 500-kV Boardman to Hemingway transmission line (MW)

Month	Maximum Firm Import (MW)	Maximum Non-firm Import (MW)	Maximum Export (MW)
January	379	300	650
February	235	300	650
March	200	300	650
April	500	300	650
May	820	300	650
June	762	300	650
July	649	300	650
August	730	300	650
September	717	300	650
October	200	300	650
November	313	300	650
December	525	300	650

Overgeneration in System Modeling

At a fundamental level, the reliable scheduling of the power system is based on the following simple equation:

$$\textit{Forecast load} = \textit{Forecast generation}$$

An expanded form of this equation is as follows:

Forecast retail sales + Forecast wholesale sales

=

Forecast dispatchable generation + Forecast wind generation + Forecast other generation

In the expanded equation, dispatchable generation includes scheduled production from resources the balancing authority (i.e., Idaho Power) can vary at its discretion to achieve reliable and economic system operation. Built into this term of the equation is the bidirectional balancing reserves intended for use in case the forecasts for demand or wind generation are incorrect. The other generation in the expanded equation is the amount of energy that cannot be varied. This term includes minimum generation levels at baseload thermal plants, ROR hydro generation, and non-wind power purchased under contract.

At times, the left side of the equation can become very low; Idaho Power customer use is low and wholesale exports are capped by transmission capacity. During these times, providing the balancing reserves necessary for responding to wind, specifically for responding to wind up-ramps, is not possible without upsetting the balance between the two sides of this equation. In effect, the terms of the right side of the equation cannot be reduced enough to match the left. For these times, the wind study modeling assumed the wind, or potential wind, was excessive and could not be accepted; curtailment of wind energy was necessary to maintain balance. Further discussion of overgeneration and curtailment is provided in the following section.

RESULTS

As noted previously, the objective of this study is to answer two fundamental questions:

1. What are the costs of integrating wind generation for the Idaho Power system?

2. How much wind generation can the Idaho Power system accommodate without impacting reliability?

Thus, the results produced by the study's system modeling were designed to address these two questions.

Wind Integration Costs

From a cost perspective, a comparison of annual production costs between two scenarios having different balancing reserves requirements—where the difference in balancing reserves is related to wind's variability and uncertainty—was used to estimate the costs of integrating wind. The production cost difference between scenarios was divided by the annual MWh of wind generation to yield an estimated integration cost expressed on a per MWh basis. The integration cost calculation is summarized as follows:

- Base scenario for which the system was not burdened with incremental balancing reserves necessary for integrating wind (wind integration is "not our problem", a theoretical case used as a benchmark for comparing costs)
- Test scenario for which the system was burdened with incremental balancing reserves necessary for integrating wind

The wind integration cost is the net-cost difference of the two scenarios divided by the MWh of wind generation (the amount of wind generation was the same in both scenarios):

$$\textit{Wind integration cost} = \frac{\textit{Test scenario net cost - Base scenario net cost}}{\textit{Wind generation in MWh}}$$

As noted earlier, the study included three water years and three wind penetration levels. These conditions are shown in Table 8.

Table 8 Wind penetration levels and water conditions

Wind Penetration Level (MW Capacity)	Water Year
800	Low (2004)
1,000	Average (2009)
1,200	High (2006)

A matrix of the wind integration costs on a per MWh basis is given in Table 9. These costs are based on a system without the proposed Boardman to Hemingway transmission line.

Table 9 Integration costs ($/MWh)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	$7.18	$11.94	$18.15
Low (2004)	$7.26	$12.44	$18.15
High (2006)	$9.73	$14.79	$20.73
Average	**$8.06**	**$13.06**	**$19.01**

The addition of the Boardman to Hemingway transmission line reduced integration costs slightly. Table 10 provides the wind integration costs for a system having the proposed Boardman to Hemingway transmission line.

Table 10 Integration costs with the Boardman to Hemingway transmission line ($/MWh)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	$6.51	$11.03	$16.38
Low (2004)	$6.66	$11.04	$16.67
High (2006)	$9.72	$13.78	$19.53
Average	**$7.63**	**$11.95**	**$17.53**

Incremental Cost of Wind Integration

The integration costs previously provided in Tables 9 and 10 represent the cost per MWh to integrate the full installed wind at the respective penetration levels studied. For example, the results of Table 9 indicate that the full fleet of wind generators making up the 800 MW penetration level bring about costs of $8.06 for each MWh integrated. However, wind generators comprising the 678 MW of current installed capacity on the Idaho Power system are assessed an integration cost of only $6.50/MWh[2].

In order to fully cover the $8.06/MWh integration costs associated with 800 MW of installed wind capacity, wind generators in the increment between the current penetration level (678 MW) and the 800 MW penetration level will need greater assessed integration costs. Study analysis indicates that these generators will need to recognize integration costs of $16.70/MWh to allow full recovery of integration costs associated with 800 MW of installed wind capacity. Similarly, generators between the 800 MW and 1000 MW penetration levels introduce incremental system operating costs requiring the assessment of integration costs of $33.42/MWh, and generators between 1000 MW and 1,200 MW require incremental integration costs of $49.46/MWh. A graph showing both integration costs and incremental integration costs is provided in Figure 8 below. The incremental integration costs are summarized in Table 11.

[2] Integration cost stipulated by Idaho Public Utilities Commission Case No. IPC-E-07-03, Order No. 30488.

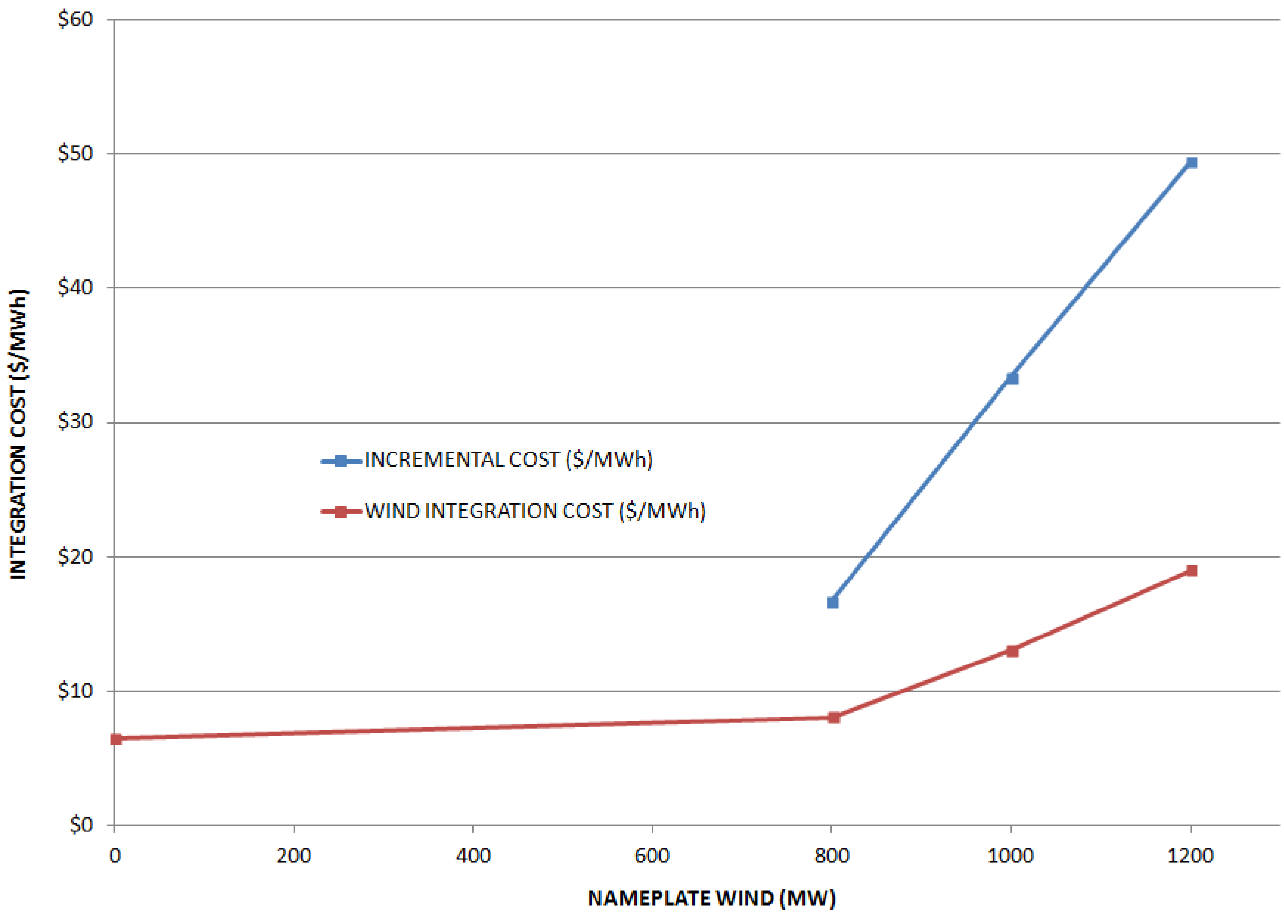

Figure 8 Integration costs with incremental integration costs ($/MWh)

Table 11 Incremental wind integration costs ($/MWh)

	Nameplate Wind		
	678 - 800 MW	**800 - 1,000 MW**	**1,000 - 1,200 MW**
Incremental cost per MWh	$16.70	$33.42	$49.46

Spilling Water

The modeling suggests that providing balancing reserves to integrate wind leads to increased spill at the HCC hydroelectric projects. Spill is observed in actual operations during periods of high Brownlee Reservoir inflow coupled with minimal capacity to store water in the reservoir. Minimal storage capacity at Brownlee occurs when the reservoir is nearly full or when the reservoir level is dictated by some other constraint, such as a flood control restriction. Flow through the HCC cannot be significantly reduced during these periods; the three-dam complex is essentially operated as a ROR project during these high-flow periods. As a consequence, holding generating capacity in reserve for balancing purposes is frequently achieved only through increasing project spill, rather than reducing turbine flow. Table 12 provides the total incremental HCC spill in thousands of acre-feet (kaf) associated with integrating wind.

Table 12 Incremental Hells Canyon Complex spill (thousands of acre-feet)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	534 kaf	949 kaf	1,446 kaf
Low (2004)	33 kaf	93 kaf	255 kaf
High (2006)	2,101 kaf	2,698 kaf	2,916 kaf

Simulations for the high water condition (2006) with 800 MW of wind capacity provide a good illustration of the effect of wind integration on spill. Under the base scenario, the theoretical “not our problem” case, wind study system simulation shows spill totaling 3,590 kaf at Brownlee alone. For reference, this simulated spill is within 5 percent of the actual total Brownlee spill in 2006, which was about 3,800 kaf. By comparison, the total Brownlee spill under the test scenario, where integrating wind is Idaho Power’s problem, is 4,475 kaf. The excess spill under the test scenario translates to about 185 gigawatt hours (GWh) of lost power production at Brownlee—energy that is no longer available for serving load or off-system sales.

Maximum Idaho Power System Wind Penetration

The capability of the Idaho Power system to integrate wind is finite. The rapid growth in wind capacity connecting to the system over recent years has heightened concern that the limits of this integration capability are being neared, and that development beyond these limits will severely jeopardize system reliability. The quantity of wind generation Idaho Power can integrate varies throughout the year as a function of customer load. During times of high load, Idaho Power can integrate more wind than during times of low load.

Modeling performed for the wind study has demonstrated the occurrence during low load periods where the balancing reserves necessary for responding to a wind up-ramp (i.e., generation that can be dispatched down in response to an increase in wind) cannot be provided without pushing the system to an overgeneration condition. Customer load for these periods, where load consists of sales to retail customers and to wholesale customers by way of regional transmission connections, is too low to allow for the integration of a significant quantity of wind. This situation requires curtailment of wind generation to maintain system balance. For the wind study modeling, the curtailed wind generation was removed from the production cost analysis and consequently did not affect the calculated integration cost. Curtailed wind was not integrated in the modeling and had no influence on the calculated integration costs. Not surprisingly, curtailment was found in the wind study modeling to have a strong correlation with customer load, water condition, and wind penetration levels. A summary of the amount of curtailment in the study is provided in Table 13.

Table 13 Curtailment of wind generation (annual MWh)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	738 MWh	8,755 MWh	48,942 MWh
Low (2004)	204 MWh	3,494 MWh	29,574 MWh
High (2006)	890 MWh	12,519 MWh	61,557 MWh
Average	**611 MWh**	**8,256 MWh**	**46,691 MWh**

Figure 9 illustrates the projected exponential increase in curtailment as a function of the wind penetration level.

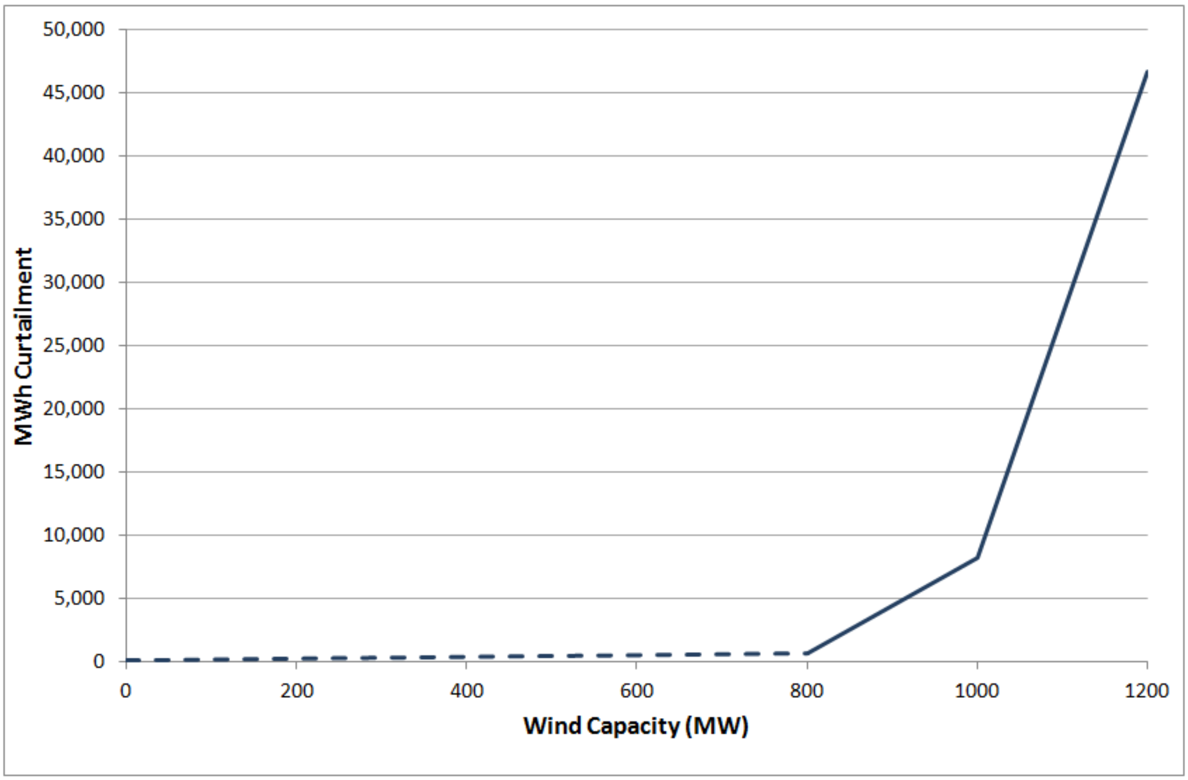

Figure 9 Curtailment of wind generation (average annual MWh)

A key feature of Figure 9 is the rapid acceleration of projected curtailment as installed wind capacity increases beyond the 800 MW level. The addition of 200 MW of installed wind capacity from 800 MW to 1,000 MW is projected to result in about 7,600 MWh of additional curtailment. Increasing the installed wind capacity 200 MW further to 1,200 MW is projected to result in another 38,000 MWh of curtailment. It is important to note the effect of a procedure for curtailment. Spreading the curtailed MWh over the full installed wind capacity of 1,200 MW results in a projected curtailment of about 1.5 percent of produced wind energy. However, if wind generators comprising the expansion from 1,000 MW to 1,200 MW are required under an established policy to shoulder the curtailment burden arising from their addition to the system, curtailment of their energy production is projected to reach nearly 8.5 percent.

The study results suggest that the occurrence of low load periods for which curtailment is necessary is likely to remain relatively infrequent for wind penetration levels of 800 MW or less. However, the results indicate that operational challenges are likely to grow markedly more severe with expanding wind penetration beyond 800 MW of installed nameplate capacity. The occurrence of low load periods for which balancing reserves cannot be provided without causing overgeneration is expected to become more frequent and require deeper curtailment of wind production. This is particularly true in that it is often necessary to maintain the operation of thermal (i.e., gas- and coal-fired) generators during periods of low load and high wind, in order to have the dispatchable generation from these resources available should customer loads increase or winds decrease.

Effect of Wind Integration on Thermal Generation

Idaho Power operates its coal resources to provide low-cost, dependable baseload energy. However, the study results suggest that the operation of the company's coal resources is likely to decrease on an annual basis with expanding wind penetration. The reduction in coal output is principally the result of displacement of coal generation by wind generation, as well as the displacement by flexible gas-fired plants required to help balance the variable and uncertain delivery of wind.

The operation of coal-fired generators has been affected by energy oversupply conditions over recent years in the Pacific Northwest. Coal plants have historically been operated less during periods of high hydro production, and maintenance is typically scheduled to coincide with spring runoff when customer demand is relatively low. However, the expansion of wind capacity over recent years in the region has caused overgeneration conditions to become more severe and longer lasting, leading to extended periods during which prices in the wholesale market have been very low or negative. The effect on coal plants has been a decline in annual energy production. However, during periods when customer load is high, such as during summer 2012, Idaho Power's coal fleet is consistently relied upon for energy to meet the high customer demand.

While the operation of baseload coal-fired power plants is expected to decline as a consequence of adding wind to a power system, this decline is offset by a marked increase in generation from gas-fired plants. The rapidly dispatched capacity from the gas-fired plants is widely recognized as critical to the successful integration of variable generation. Wind study modeling suggests that the need to dispatch gas-fired generators for balancing reserves is likely to displace the economic operation of coal-fired generators, particularly during times of acute transmission congestion.

This situation where relatively low-cost baseload resources are displaced by flexible cycling plants (i.e., gas-fired) is described in a 2010 NREL report (Denholm et al. 2010). Table 14 lists the annual generation from the wind study modeling for thermal resources for the case when Idaho Power is responsible for providing the balancing reserves and integrating the wind energy.

Table 14 Annual generation for thermal generating resources for the test case (GWh)

	Nameplate Wind		
Thermal Resource	**800 MW**	**1,000 MW**	**1,200 MW**
Coal-fired	7,568 GWh	7,291 GWh	6,851 GWh
Gas-fired	963 GWh	1,238 GWh	1,918 GWh

RECOMMENDATIONS AND CONCLUSIONS

Idaho Power has 678 MW of nameplate wind generation on its system. This is a growth in wind capacity of about 290 MW over the last two years, and 490 MW over the last three. The explosive growth in wind generation has heightened concerns that the finite capability of Idaho Power's system to integrate wind is being rapidly depleted. Because of these concerns, the objective of this investigation is to address not only the costs to modify operations to integrate wind, but also the wind penetration level at which system reliability becomes jeopardized. The questions that drove the investigation are the following:

1. What are the costs of integrating wind generation for the Idaho Power system?

2. How much wind generation can the Idaho Power system accommodate without impacting reliability?

The study utilized a two-scenario design, with a base scenario simulation of operations for a system that was not burdened with incremental balancing reserves for integrating wind and a test scenario simulation for a system burdened with incremental wind-caused balancing reserves. Averaged over the three water conditions considered, the estimated integration costs are $8.06/MWh at 800 MW of installed wind, $13.06/MWh at 1,000 MW of installed wind, and $19.01/MWh at 1,200 MW of installed wind. A summary of the estimated costs is given in Table 15.

Table 15 Integration costs ($/MWh)

	Nameplate Wind		
Water Condition	**800 MW**	**1,000 MW**	**1,200 MW**
Average (2009)	$7.18	$11.94	$18.15
Low (2004)	$7.26	$12.44	$18.15
High (2006)	$9.73	$14.79	$20.73
Average	**$8.06**	**$13.06**	**$19.01**

Importantly, the system modeling conducted for the study indicates a major determinant of ability to integrate is customer demand. This finding is not to be confused with the pricing of wind contracts and the wide recognition that wind occurring during low load periods is of little value. Instead, the study indicates that during periods of low load, the system of dispatchable resources often cannot provide the incremental balancing reserves paramount to successful wind integration without creating an imbalance between generation and demand. Modeling demonstrates that the frequency of these conditions is expected to accelerate greatly beyond the 800 MW installed capacity level, likely requiring a sharp increase in wind curtailment events. Even at current wind penetration levels, these conditions have been observed in actual system operations during periods of high stream flow and low customer demand. While the maximum penetration level cannot be precisely identified, study results indicate that wind development beyond 800 MW is subject to considerable curtailment risk. It is important to remember that curtailed wind generation was removed from the production cost analysis for the wind study modeling, and consequently had no effect on integration cost calculations. The curtailed wind generation simply could not be integrated, and the cost-causing modifications to system operations designed to allow its integration were not made. The curtailment of wind generation observed in the wind study modeling is shown in Figure 10.

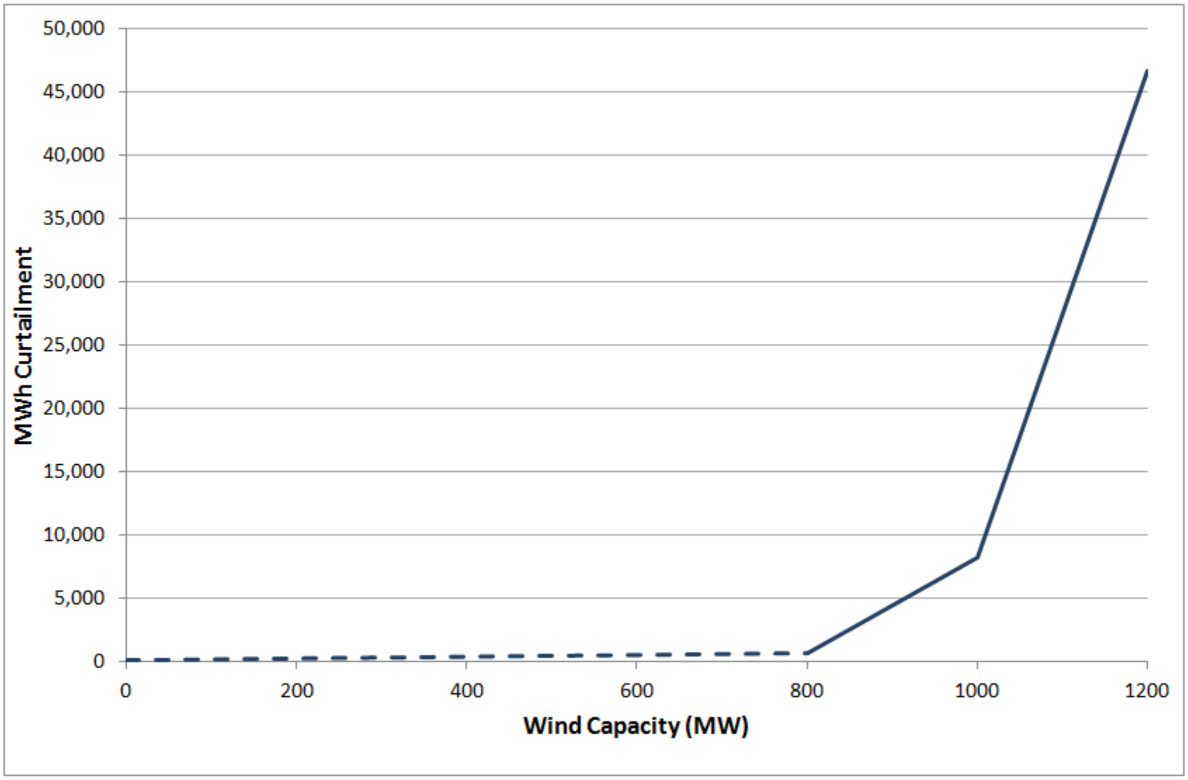

Figure 10 Curtailment of wind generation (average annual MWh)

Conversely, during periods of high customer demand, the dispatchable resources providing the balancing reserves for integrating wind are needed and thus are positioned at levels where they are ready to respond to changes in wind. While the costs to integrate wind still exist during these higher customer demand periods, the system can much more easily accommodate high levels of wind without impacting system reliability.

Issues Not Addressed by the Study

The focus of this study was the variability and uncertainty of wind generation. The study then established that these attributes of wind bring about the need to have balancing reserves at the ready on system dispatchable resources, and finally that having balancing reserves for integrating wind brings about greater costs of production for the system. A consideration not addressed by the study is the increased maintenance costs expected to occur for thermal generating units called on to frequently adjust their output level in response to changes in wind production or that are switched on and off on a more frequent basis. The effect of wind integration on these costs is likely to become evident and better understood with the expanded cycling of these thermal generators accompanying the growth in wind generation over recent years.

The control of system voltage and frequency is receiving considerable attention in the wind integration community. It is widely recognized that the addition of wind generation to a power system has an impact on grid stability. On some transmission systems, controlling system voltage and frequency during large ramps in generation within acceptable limits can be challenging. Idaho Power's system has not yet exhibited this problem at current wind penetration levels. However, growth in wind penetration beyond the current level will lead to greater challenges in maintaining system voltage and frequency within control specifications of the electric system, and likely increase the incidence of excursions where system frequency deviates from normal bands. The effects of frequency excursions may extend to customer equipment and operations.

Measures Facilitating Wind Integration

Idaho Power recognizes the importance of staying current as operating practices evolve and innovations enabling wind integration are introduced. Some changes in operating parameters include mechanisms such as Dynamic Scheduling System (DSS), ACE Diversity Interchange (ADI), and intra-hour markets. Further development of these measures will, to varying degrees, make it easier for balancing authorities to integrate the variable and uncertain delivery of wind generation. At this time, it is Idaho Power's judgment that the effect of these measures is not substantial enough to warrant their inclusion in the modeling performed for this study.

An additional measure that has been studied over recent years as a Western Electricity Coordinating Council (WECC) field trial is reliability-based control (RBC). The essential effect of RBC on operations is that a balancing authority is permitted to carry an imbalance between generation and demand if the imbalance helps achieve wider system stability across the aggregated balancing area of the participating entities. In effect, the balancing authority area is expanded, and the diversity of the expanded area allows an aggregate balance to be more readily maintained. Idaho Power has participated in the RBC field trial since the program's inception, and has recognized a resulting decrease in the amount of cycling required of generating units for balancing purposes. However, the effect of RBC was not included in the modeling for this study. This omission is in part related to the status of the program as a field trial, and related uncertainty regarding the structure of RBC in the future, or whether RBC will exist at all. Moreover, while RBC may allow balancing reserves-carrying generators to not respond to changes in load or wind in real-time operations, the scheduling of these generators must still include appropriate amounts of balancing reserves because it is not known at the time of scheduling to what extent an imbalance between generation and load will be permitted.

Future Study of Wind Integration

Idaho Power continues to grapple with new challenges associated with wind integration. The expansion in installed wind capacity over recent years has made the establishment of a best management plan for integrating wind problematic; the amount of installed wind simply keeps growing. It is commonly understood that wind does not always blow, leading to the legitimate concern about having backup capacity in place for when wind generators are not producing. Somewhat ironically, integration experience over recent years throughout the Pacific Northwest has led to heightened concerns about what to do when wind generators are producing and that production is not needed and unable to be stored in regional reservoirs because of minimal storage capacity, and the balancing reserves carried on dispatchable generators only add to the amount of unneeded generation. While it has been recognized that balancing reserves need to be carried for responding to wind up-ramps (i.e., balancing reserves need to be bidirectional), it has only recently become apparent that the Idaho Power system, and even the larger regional system, at times cannot provide these balancing reserves. This experience has shown that it is difficult to predict the integration challenges of tomorrow, but it is safe to say that there will be a need for continued analysis as additional tools, methods, and practices for integrating wind become available.

Idaho Power has experienced success in wind-production forecasting. The company has developed an internal forecast model which system operators are using with increasing confidence. It is likely that the future study of wind integration will make use of this forecast model, specifically in that its relative accuracy will ultimately lead to a reduction in the balancing reserves requirement for wind integration.

However, even accurate wind forecasting cannot eliminate the need for curtailment when wind generation creates a significant imbalance between load and generation.

Finally, the wider region beyond Idaho has added considerable wind capacity over recent years, much of the growth driven by requirements associated with state-legislated renewable portfolio standards. Most of the wind generation has been added outside of local or regional integrated resource planning efforts. The addition of this generating capacity has resulted in recurring energy oversupply issues for the region, a situation that has led the BPA to propose a protocol for managing oversupply (BPA 2013). Regional market prices during these oversupply periods have experienced pronounced declines to very low or even negative levels. Sometimes even the larger regional system and larger regional market cannot successfully integrate all of the wind energy that is produced. It is critical that future modeling for studying wind integration continues to capture the regional expansion of wind generation and its effect on the wholesale market.

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Appendix A. May 9, 2012, Explanation on wind data

WIND INTEGRATION WORKSHOP

STUDY WIND DATA EXPLANATION

MAY 9, 2012

Idaho Power received questions during the April 6 wind integration workshop related to the synthetic wind data used for its study of wind integration. The company recognizes the importance of using high-quality wind data, and consequently indicated at the workshop that it would thoughtfully review the wind data in an effort to address the questions raised. As stated at the workshop, the wind data used for the study were provided by 3TIER. 3TIER provided these data for 43 wind project locations requested by Idaho Power corresponding to project sites having a current purchase agreement with the company, as well as sites proposed to the company for purchase agreement. The 43 wind project locations are given as Attachment No. 3 to comments filed by Idaho Power with the IPUC on December 22, 2010[3]. It is important to note that 3TIER did not select from the more than 32,000 existing or hypothetical wind project sites used for the Western Wind and Solar Integration Study (WWSIS), but instead pulled new time series directly from the WWSIS gridded model data set precisely at the 43 locations requested by Idaho Power. **Thus, the geographic diversity of the synthetic wind data provided by 3TIER is representative of the geographic diversity for projects proposed to Idaho Power.**

3TIER also provided a synthetic day-ahead forecast for the wind generation time series. In providing this forecast, 3TIER notes that a bias found in the forecast during completion of the WWSIS was corrected on a site-by-site basis for the Idaho Power wind study, as opposed to the regional bias correction used for the WWSIS. The site specific correction is preferable to the regional correction because it mimics real forecasting practice, where project data at each site would be used to eliminate long-term bias from the forecast. With respect to accuracy of the synthetic day-ahead forecast, 3TIER reports that hourly wind speed forecast errors for ten operational sites in Idaho or neighboring states were compared to similarly calculated errors for the synthetic day-ahead forecast. 3TIER reports that this comparison yielded values for mean absolute error and root mean squared error for the synthetic day-ahead forecast only about 15% higher than equivalent statistics for the real errors at the ten operational sites in the Idaho vicinity. **This result suggests that the error characteristics of the synthetic forecasts are very similar to those of actual wind forecasts.**

To validate the synthetic actual wind time series, 3TIER has completed validation reports describing the results of comparisons between the synthetic wind data and public tower data. The complete set of validation reports for the WWSIS can be found through the NREL website[4]. Five of the validation towers are located in Idaho. Review of these reports indicates that the synthetic actual wind time series capture the seasonal and diurnal wind cycles fairly well; however, the synthetic time series are consistently low biased, at a 3TIER-reported average level of about -1.2 m/s at the five validation sites. There is basis in suggesting that the low bias, while reducing the total production of modeled wind projects, would have minimal impact on the overall variability of the synthetic actual wind time series, and would consequently have little effect on the estimated integration cost.

[3] Idaho Power Comments, Idaho Public Utilities Commission Case GNR-E-10-04, Attachment No. 3.

[4] http://wind.nrel.gov/public/WWIS/ValidationReports/wwis_vrpts.html#vmap

However, Idaho Power recognizes the critical nature of the synthetic wind data used for the study, and will discuss this low bias further with the technical review committee it has formed.

Finally, the synthetic actual wind time series created for the WWSIS have been found to exhibit excessive ramping as described in the WWSIS final report and as reported by NREL[5]. The excessive ramping in the WWSIS wind data occurs because the mesoscale model used to generate the synthetic wind data was run in 3-day sections. Smoothing techniques were used to reduce the ramping across the seam at the end of each third day; however, 3TIER reports that excessive variability remains in the WWSIS wind data. 3TIER also reports that review of the synthetic actual wind time series data pulled for the Idaho Power study indicates similar excessive ramping, with ramps tending to be 1.5 to 2.0 times larger from two hours before to eight hours after the start of every third day. While Idaho Power intends to discuss this condition with its technical review committee, the company believes that only a small fraction of hours are affected, and that consequently the impacts on integration cost are likely small.

Idaho Power hopes that this follow-up helps to address questions on the wind data raised at the April 6 workshop. We value the questions and feedback received from workshop participants, and welcome remaining questions related to the wind data or other features of the wind study. We are planning a meeting with our technical review committee in early May, and are looking forward to the added value this group will bring to our effort.

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[5] http://www.nrel.gov/wind/integrationdatasets/pdfs/western/2009/western_dataset_irregularity.pdf

Appendix B. Wind data summaries

Table B1 Monthly and annual capacity factors (percent of installed nameplate capacity)

	Nameplate Wind		
Month	**800 MW**	**1,000 MW**	**1,200 MW**
January	30%	30%	30%
February	20%	20%	19%
March	31%	32%	32%
April	38%	38%	37%
May	24%	24%	24%
June	29%	29%	29%
July	20%	19%	19%
August	17%	17%	17%
September	18%	18%	18%
October	23%	23%	23%
November	36%	35%	35%
December	38%	38%	38%
Annual	27%	27%	27%

Note: Wind generation data for study provided by 3TIER.

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2011 IRP UPDATE

Coal Unit Environmental Investment Analysis

For The

Jim Bridger and North Valmy

Coal-Fired Power Plants

TABLE OF CONTENTS

Executive Summary

The Coal Unit Environmental Investment Analysis (Study) examines future investments required for environmental compliance in existing coal units and compares those investments to the costs of two alternatives: (1) replace such units with Combined Cycle Combustion Turbine (CCCT) units or (2) converting the existing coal units to natural gas. Idaho Power used a combination of third-party analysis, operating partner input and an Idaho Power analysis to assure a complete and fair assessment of the alternatives.

This Study consists of two parts:

1. A unit specific forecasted (static) annual generation analysis performed by Science Applications International Corporation (SAIC). Idaho Power conducted a competitive procurement process to select SAIC.

2. An economically dispatched (dynamic) total portfolio resource cost analysis performed by Idaho Power using the SAIC study results.

The SAIC analysis included a review of Idaho Power's estimated capital costs and variable costs associated with the proposed environmental compliance upgrades, coal unit replacement with CCCT's and natural gas conversion. SAIC developed the cost estimates for replacing the coal units annual generation, under three natural gas and three carbon futures. These estimates served as the foundation for SAIC's capital investment analysis which allowed assets with different lengths of operation as well as different implementation dates to be compared equitably. The results of the SAIC analysis served as planning recommendations regarding the three investment alternatives to be used in the second part of the comprehensive Study.

The second part of the Study performed by Idaho Power utilized the AURORAxmp® Model (AURORA) to determine the total portfolio cost of each investment alternative analyzed by SAIC. The total portfolio cost is estimated over a twenty-year planning horizon (2013 through 2032).

The Key Assumptions section of this report provides additional details on the carbon adder assumptions and natural gas price forecasts.

Analysis Results for North Valmy

Currently, the only notable investment required at the North Valmy plant is to install a Dry Sorbent Injection (DSI) system for compliance with the Mercury and Air Toxic Standards (MATS) regulation on Unit #1. North Valmy is not subject to Regional Haze (RH) Best Available Retrofit Technology (BART) regulations; therefore, no additional controls will be required for compliance with this regulation. No other notable investments in environmental controls at the North Valmy plant are required at this time.

Installation of DSI was the lowest cost result for most of the sensitivities analyzed by SAIC including the planning case scenario (planning case natural gas/planning case carbon). The AURORA analysis, performed by Idaho Power, shows installing DSI as the least cost option in four of the nine sensitivities analyzed including the planning case scenario (planning case natural gas/planning case carbon). The scenarios in which

DSI was not the preferred option are the extreme low natural gas and high carbon cases, which have a lower probability of occurring.

Idaho Power's conclusion is that installing the DSI system is a low cost approach to retain a diversified portfolio of generation assets including the 126 MW's of Unit #1's capacity for our customers benefit. The continued operation of Unit #1 as a coal-fired unit will provide fuel diversity that can mitigate risk associated with high natural gas prices.

In the event that North Valmy requires significant additional capital or operation and maintenance costs (O&M) expenditures for new environmental regulations, both the SAIC and the Idaho Power analyses advise further review to justify the additional investment.

Analysis Results for Jim Bridger

Jim Bridger is currently required to install Selective Catalytic Reduction (SCR) on all four units for RH compliance and mercury controls for compliance with MATS. Both the SAIC and Idaho Power evaluations identify additional investments in environmental controls on all four Jim Bridger units as prudent decisions that represent the lowest cost and least risk option when compared to the other investment alternatives. Idaho Power recommends proceeding with the installation of SCR and other required controls on Units #3 and #4 and including the continued operation of all four Jim Bridger units in Idaho Power's future resource planning.

Compliance Timing Alternatives

Idaho Power also evaluated the economic benefits of delaying coal unit investments required under the emerging environmental regulations. To perform this evaluation Idaho Power assumed that it could negotiate with state and federal entities a five-year period where no additional environmental controls are installed in exchange for shutting the unit down at the end of the five-year period. These compliance timing alternative cases are strictly hypothetical. Idaho Power may not have any basis under current regulations to negotiate this delay and the relevant regulatory authorities have not offered any such delay. These alternatives are included in the alternatives summary table.

Unit Ownership and Operation

It should be noted that, although a partial owner of the Jim Bridger (one-third) and the North Valmy (one-half) coal plants, Idaho Power does not operate any of the coal-fired units and Idaho Power does not have the sole rights to alter the compliance plan in place for these units. Any decision regarding environmental investments, plant retirement or conversion to natural gas must be coordinated and agreed to by the other owners/operators of the plants and their regulators.

Key Assumptions

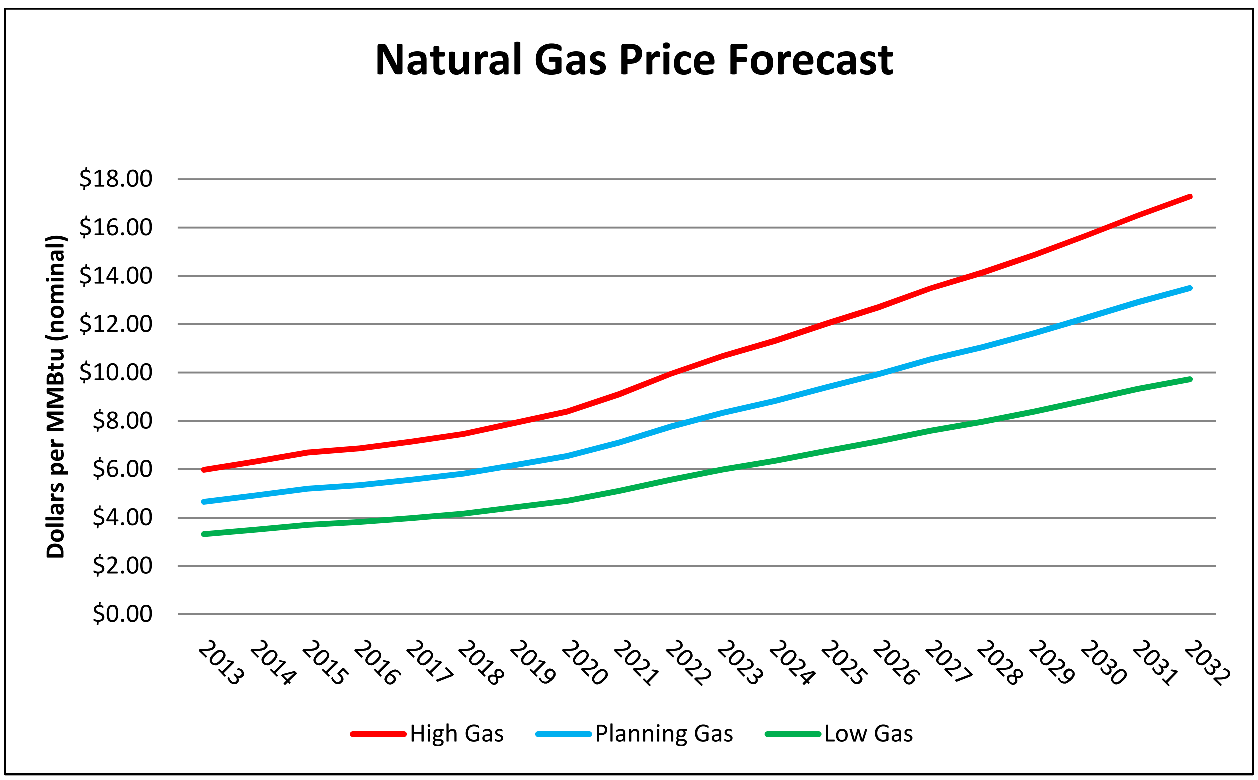
The undertaking of any analysis of this nature requires that assumptions be made regarding uncertain costs and regulations that may impact the economics of the coal plants. In fact, two of the most influential inputs to the analysis are also among the least known over the long-run and are related to future carbon regulation and future natural gas prices. In order to evaluate these uncertainties Idaho Power has used low, planning and high case natural gas and carbon adder futures. These forecasts provide a range of outcomes to assess the impact of natural gas price and carbon adder uncertainty on the economic evaluation of the investment alternatives.

Idaho Power is currently preparing its 2013 IRP covering the 2013-2032 planning horizon. As that process is well underway, key assumptions for this Study are aligned with the 2013 IRP assumptions.

These key assumptions include:

Natural Gas Price Forecast - For the purpose of being consistent with Idaho Case No. GNR-E-11-03, Order No. 32697 (December 18, 2012), Idaho Power is using the Energy Information Administration (EIA) Annual Energy Outlook (Henry Hub spot price) for the 2013 IRP planning case natural gas price forecast. The high and low cases are +/- 30% from the planning case forecast. All cases were adjusted to reflect an Idaho citygate delivery price. These forecasts are provided in Figure 1.

Figure 1. Natural Gas Price Forecast



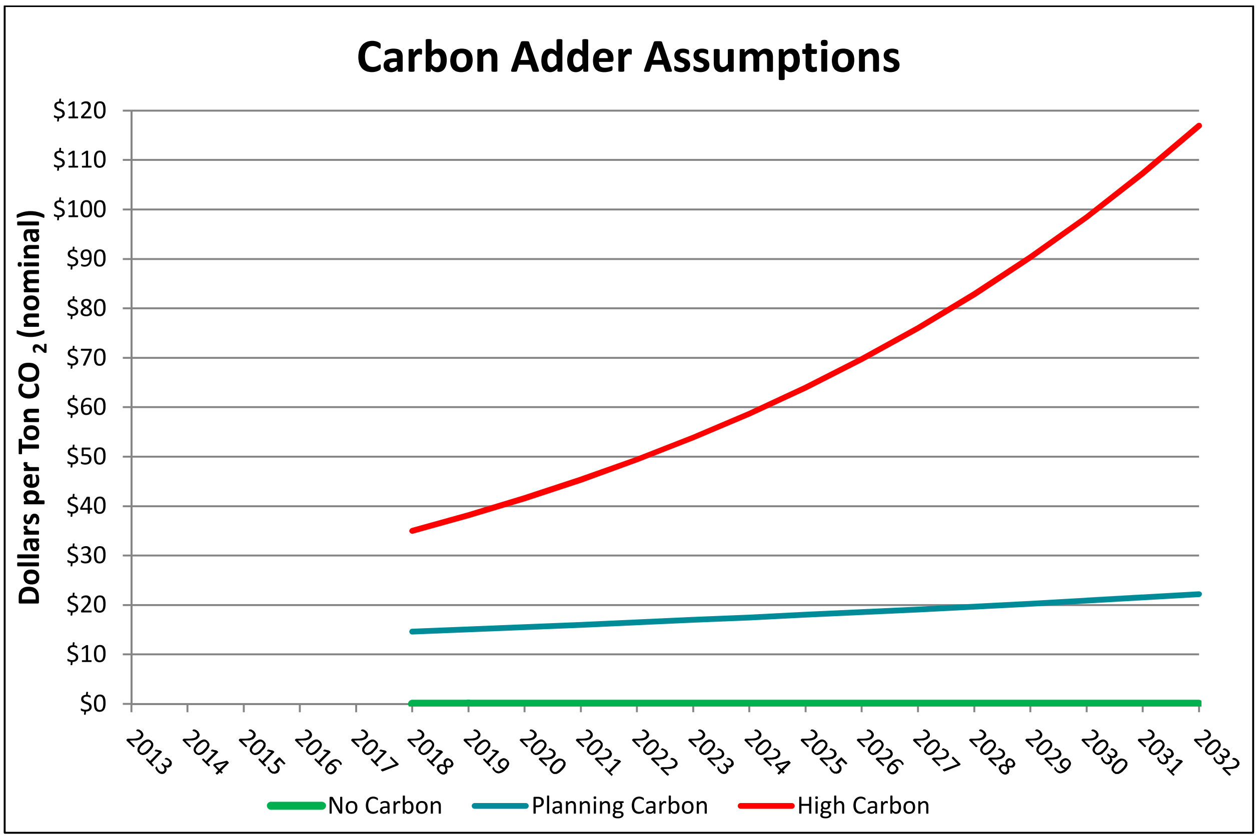
Load Forecast - The 2013 IRP load forecast is Idaho Power's most current load forecast and was used in the preparation of this Study.

Financial and Economic Assumptions - The 2013 IRP financial and economic assumptions were also used for this Study.

Carbon Adder Assumptions - For the 2013 IRP, three carbon adder assumptions have been developed and include a low case of no carbon tax, a planning case with a 2018 start date at $14.64 per ton of CO_2 emitted escalated at 3% and a high case with a 2018 start date at $35.00 per ton of CO_2 emitted escalated at 9%.

These forecasts are provided in Figure 2.

Figure 2. Carbon Adder Assumptions



Description and Existing Major Environmental Investments in Coal Units

Jim Bridger

The Jim Bridger coal-fired power plant consists of four units and is located near Rock Springs, Wyoming. Idaho Power owns one-third of Jim Bridger with the other two-thirds owned by PacifiCorp. PacifiCorp is the operator of the Jim Bridger plant.

These units have the following current net dependable capacity ratings:

Jim Bridger unit #1 (JB1)	531 MW
Jim Bridger unit #2 (JB2)	527 MW
Jim Bridger unit #3 (JB3)	530 MW
Jim Bridger unit #4 (JB4)	523 MW
Total Plant –	2,111 MW (703.7 MW Idaho Power Share)

The following major emission control equipment has been previously installed on each unit at the Jim Bridger plant:

Pollutants	Controls	Current Emission Limits
NO_x	New Generation Low NO_x Burners	0.26 lb/MMBtu
Opacity	Electrostatic Precipitators	20% Opacity
SO_2	Wet Scrubbers	0.15 lb/MMBtu

North Valmy

The North Valmy coal-fired power plant consists of two units and is located near Winnemucca, Nevada. Idaho Power owns one-half of North Valmy with the other one-half owned by NV Energy. NV Energy is the operator of the North Valmy plant.

These units have the following current net dependable capacity ratings:

North Valmy unit #1 (NV1)	252 MW
North Valmy unit #2 (NV2)	272 MW
Total Plant –	524 MW (262 MW Idaho Power Share)

The following major emission control equipment has been previously installed at the North Valmy plant:

Pollutants	Controls	Current Emission Limits
NO_x	Early Generation Low NO_x Burners	0.46 lb/MMBtu (averaged)
Opacity	Baghouse	20% Opacity
SO_2 (Unit 2)	Dry Lime Scrubber	70% removal

Recent Environmental Regulations

The new regulations that have been proposed by the Environmental Protection Agency (EPA) over the last few years have caused great concern among utilities that own coal-fired generation. The impact of the proposed regulations will require extensive installation of emissions controls in a short period of time. In addition, these proposed regulations often override state decisions relating to control requirements. The effectiveness of the regulations on health and visibility is controversial and highly debated.

Final Mercury and Air Toxic Standards (MATS) Rule**:** In April 2010, the U.S. District Court for the District of Columbia approved, by consent decree, a timetable that would require the EPA to finalize a standard to control mercury emissions from coal-fired power plants by November 2011. In March 2011, the EPA released the rule to control emissions of mercury and other Hazardous Air Pollutants (HAPs) from coal- and oil-fired Electric utility steam Generating Units (EGUs) under the federal Clean Air Act (CAA). In the same notice, the EPA further proposed to revise the New Source Performance Standards (NSPS) for fossil fuel-fired EGUs. Both the proposed HAPs regulation and the associated NSPS revisions were finalized on February 16, 2012. The regulation imposes maximum achievable control technology and NSPS on all coal-fired EGUs and replaces the former Clean Air Mercury Rule. Specifically, the regulation sets numeric emission limitations on coal-fired EGUs for total particulate matter (a surrogate for non-mercury HAPs), hydrochloric acid (HCL), and mercury. In addition, the regulation imposes a work practice standard for organic HAPs, including dioxins and furans. For the revised NSPS, for EGUs commencing construction of a new source after publication of the final rule, the EPA has established amended emission limitations for particulate matter, sulfur dioxide, and nitrogen oxides. Utilities have three years for compliance, with a one year compliance extension for any utility or plant that cannot feasibly install the pollution controls during the three year compliance window. Idaho Power does not need nor can Idaho Power qualify for the one year extension, so all controls were assumed to be completed within the three year time frame.

National Ambient Air Quality Standards (NAAQS): The CAA requires the EPA to set ambient air quality standards for six "criteria" pollutants considered harmful to public health and the environment. The six pollutants are carbon monoxide, lead, ozone, particulate matter, nitrogen dioxide, and sulfur dioxide. States are then required to develop emission reduction strategies through State Implementation Plans (SIP) based on attainment of these ambient air quality standards. Recent developments related to three of the pollutants - $PM_{2.5}$, NO_x, and SO_2 are relevant to Idaho Power.

- ***Particular Matter ($PM_{2.5}$)*****.** In 1997, the EPA adopted NAAQS for fine particulate matter of less than 2.5 micrometers in diameter ($PM_{2.5}$ standard), setting an annual limit of 15 micrograms per cubic meter ($\mu g/m^3$), calculated as a three-year average. In 2006, the EPA adopted a 24-hour NAAQS for $PM_{2.5}$. of 35 $\mu g/m^3$. All of the counties in Nevada, Oregon, and Wyoming have been designated as "attainment" with these $PM_{2.5}$ standards. However, on December 14, 2012, the EPA released final revisions to the $PM_{2.5}$ NAAQS. The revised annual standard is 12 $\mu g/m^3$, calculated as a three-year average. The EPA retained the existing 24-hour standard of 35 $\mu g/m^3$. Now that the $PM_{2.5}$ NAAQS has been finalized, states will make recommendations to the EPA regarding designations of attainment or non-attainment. States also will be required to review, modify, and supplement their SIPs, which could require the installation of additional controls and requirements for Idaho Power's coal-fired generation plants, depending on the level ultimately finalized. The revised NAAQS would also have an impact on the applicable air permitting requirements for new and modified facilities. The EPA has stated that it plans to issue nonattainment designations by late 2014, with states having until 2020 to comply with the standards.

- ***NO_x*.** In 2010, the EPA adopted a new NAAQS for NO_x at a level of 100 parts per billion averaged over a one-hour period. In connection with the new NAAQS, in February 2012 the EPA issued a final rule designating all of the counties in Nevada, Oregon, and Wyoming as “unclassifiable/attainment” for NO_x. The EPA indicated it will review the designations after 2015, when three years of air quality monitoring data are available, and may formally designate the counties as attainment or non-attainment for NO_x. A designation of non-attainment may increase the likelihood that Idaho Power would be required to install costly pollution control technology at one or more of its plants.

- ***SO_2*.** In 2010, the EPA adopted a new NAAQS for SO_2 at a level of 75 parts per billion averaged over a one-hour period. In 2011, the states of Nevada, Oregon, and Wyoming sent letters to the EPA recommending that all counties in these states be classified as "unclassifiable" under the new one-hour $S0_2$ NAAQS because of a lack of definitive monitoring and modeling data.

***Clean Water Act Section 316(b)*:** In March 2011, the EPA issued a proposed rule that would establish requirements under Section 316(b) of the federal Clean Water Act for all existing power generating facilities and existing manufacturing and industrial facilities that withdraw more than two million gallons per day (MGD) of water from waters of the U.S. and use at least 25 percent of the water they withdraw exclusively for cooling purposes. The proposed rules would establish national requirements applicable to the location, design, construction, and capacity of cooling water intake structures at these facilities by setting requirements that reflect the Best Technology Available (BTA) for minimizing adverse environmental impact. In June 2012, the EPA released new data, requested further public comment, and announced it plans to finalize the cooling water intake structures rule by June 2013.

New Source Performance Standards (NSPS) for Greenhouse Gas Emissions for New EGUs: In March 2012, the EPA proposed NSPS limiting Carbon Dioxide (CO_2) emissions from new fossil fuel-fired power plants. The proposed requirements would require new fossil fuel-fired EGUs greater than 25 MW to meet an output-based standard of 1,000 pounds of CO_2 per MWh. The EPA did not propose standards of performance for existing EGUs whose CO_2 emissions increase as a result of installation of pollution controls for conventional pollutants.

Clean Air Act (CAA) - Regional Haze Rules: In accordance with federal regional haze rules under the CAA, coal-fired utility boilers are subject to RH BART if they were permitted between 1962 and 1977 and affect any Class I areas. This includes all four units at the Jim Bridger plant. However, North Valmy is not subject to the regulation as it was permitted after 1977. Under the CAA, states are required to develop a SIP to meet various air quality requirements and submit them to the EPA for approval. The CAA provides that if the EPA deems a SIP submittal to be incomplete or "unapprovable," then the EPA will promulgate a federal implementation plan (FIP) to fill the deemed regulatory gap. In May 2012, the EPA proposed to partially reject Wyoming's regional haze SIP, submitted in January 2011, for NO_x reduction at the Jim Bridger plant, instead proposing to substitute the EPA's own RH BART determination and FIP. The EPA's primary proposal would result in an acceleration of the installation of Selective Catalytic Reduction (SCR) additions at JB1 and

JB2 to within five years after the FIP, or a SIP revised to be consistent with the proposed FIP, is adopted by the EPA. The EPA had stated that it planned to adopt the FIP, or approve the revised Wyoming SIP, by late 2012. However, in December 2012 the EPA announced that it would re-propose the plant-specific NO_x control provisions of its RH FIP in March 2013 and would not finalize the RH FIP until September 2013.

Coal Combustion Residuals (CCR): The EPA has proposed federal regulations to govern the disposal of coal ash and other CCR's under the Resource Conservation and Recovery Act (RCRA). The agency is weighing two options: regulating CCR's as hazardous waste under RCRA Subtitle C, or regulating them as non-hazardous waste under RCRA Subtitle D. EPA is not expected to issue a final rule sometime in 2013.

As a result of recent environmental regulation, Idaho Power's coal-fired plants will require additional investment in environmental control technology as described below:

Jim Bridger will require the installation of the following controls to meet the RH BART and MATS regulations:

Unit	Pollutants	Controls	Regulation	New Emission Limits
JB1	NO_x	SCR (2022)	RH	0.07 lb/MMBtu
JB2	NO_x	SCR (2021)	RH	0.07 lb/MMBtu
JB3	NO_x	SCR (2015)	RH BART	0.07 lb/MMBtu
JB4	NO_x	SCR (2016)	RH BART	0.07 lb/MMBtu
All Units	Mercury	$CaBr_2$, scrubber additive, activated carbon injection (2015)	MATS	1.0 lb/TBtu

North Valmy will require the installation of a DSI system, for controlling HCL for acid gas compliance, to meet MATS regulations:

Unit	Pollutants	Control	Regulation	New Emission Limits
NV1	HCL	DSI (2015)	MATS	0.0020 lb/MMBtu

Investment Alternatives

Base Alternatives

The Study analyzes three base alternatives for each unit. Each alternative is analyzed under the three carbon and three natural gas sensitivities.

The alternatives include:

1) **Install environmental upgrade** - Install the required environmental controls to comply with a current, proposed or reasonably anticipated regulation. For Jim Bridger this includes cost for compliance with RH, MATS, CCR and the Clean Water Act Section 316(b). For North Valmy this includes the cost for compliance with MATS

2) **Retire the unit and replace with a CCCT** - The capital cost estimate for the CCCT capacity used to replace the retired coal-fired capacity in this Study was based on the installed cost of Idaho Power's Langley Gulch plant that became commercially operational in June 2012.

   The CCCT's are sized to replace the capacity of Idaho Power's share of the coal unit being replaced. For example, if a 100 MW coal-fired unit is retired, it is replaced with 100 MW of CCCT capacity at a Langley Gulch cost per kW. Of course, actual costs may be different, but for this Study however, we believe that using the Langley Gulch cost per kW is a reasonable assumption. The CCCT units are assumed to be located within the Idaho Power service territory.

3) **Conversion of the unit to burn natural gas** - Natural gas for Jim Bridger is assumed to be provided by a pipeline approximately two miles from the plant. Natural gas for North Valmy is assumed to be provided by a pipeline located approximately 13 miles north of the plant. The natural gas conversion capital and O&M costs used in this Study included installing a pipeline to the plant, modifications to the boiler, and changes in heat rate or capacity due to firing with natural gas instead of coal.

The following table summarizes the base alternatives that were analyzed. Included are the potential compliance deadlines for installing environmental controls and effective dates for the retirement and replacement with CCCT and natural gas conversion alternatives:

Base Alternatives	Environmental Compliance Deadline	Retire/Replace w/CCCT & Natural Gas Conversion Effective Date
North Valmy Unit #1		
Install DSI	3/31/2015	
Retire/Replace with CCCT (DSI not installed)		4/1/2015
Natural gas conversion (DSI not installed)		4/1/2015
Jim Bridger Unit #1		
Install SCR	12/31/2022	
Retire/Replace with CCCT (SCR not installed)		1/1/2023
Natural gas conversion (SCR not installed)		1/1/2023
Jim Bridger Unit #2		
Install SCR	12/31/2021	
Retire/Replace with CCCT (SCR not installed)		1/1/2022
Natural gas conversion (SCR not installed)		1/1/2022
Jim Bridger Unit #3		
Install SCR	12/31/2015	
Retire/Replace with CCCT (SCR not installed)		1/1/2016
Natural gas conversion (SCR not installed)		1/1/2016
Jim Bridger Unit #4		
Install SCR	12/31/2016	
Retire/Replace with CCCT (SCR not installed)		1/1/2017
Natural gas conversion (SCR not installed)		1/1/2017

In addition to the base alternatives, Idaho Power was directed in Order No. 12-177, issued by the Public Utilities Commission of Oregon (OPUC or Commission) in Action item 11 as follows:

> "In its next IRP Update, Idaho Power will include an Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants. The Evaluation will investigate whether there is flexibility in the emerging environmental regulations that would allow the Company to avoid early compliance costs by offering to shut down individual units prior to the end of their useful lives. The Company will also conduct further plant specific analysis to determine whether this tradeoff would be in the ratepayers' interest."

In accordance with the Commission's directive Idaho Power analyzed hypothetical scenarios including compliance timing and the enhanced upgrade alternatives described below.

Compliance Timing Alternatives (CTA)

In addition to the base alternatives, Idaho Power analyzed avoiding the installation of required or reasonably anticipated emission controls by delaying the compliance requirement by five years in exchange for shutting the unit down at the end of the five year period. A negotiated delay is not an option that currently exists but the Study quantifies the financial results of these alternatives.

Idaho Power co-owns all of its coal-fired generation, and Idaho Power is not the operating partner for any of the coal-fired plants. Not being an operating partner removes flexibility that other utilities may have for regulations allowing emission totaling, substitution or reductions at one facility to compensate for lower reductions at another plant, or the option of shutting down a unit or plant in place of reductions at another plant, or delaying installation of environmental controls for a guaranteed early shutdown. As IPC is not the operating partner of Jim Bridger or North Valmy, it is highly unlikely Idaho Power would have the ability to negotiate alternative scenarios as described above.

The following table summarizes the CTA alternatives that were analyzed. Included are the potential compliance deadlines for installing environmental controls and effective dates for the retirement and replacement with CCCT and natural gas conversion alternatives:

Compliance Timing Alternatives (CTA)	Environmental Compliance Deadline	Retire/Replace w/CCCT & Natural Gas Conversion Effective Date
North Valmy Units #1 & #2		
Retire both units	12/31/2022	
Retire/Replace with CCCT (SCR & WFGD not installed)		1/1/2023
Natural Gas Conversion (SCR & WFGD not installed)		1/1/2023
Jim Bridger Units #3 & #4		
Retire both units	12/31/2020 & 12/31/2021	
Retire/Replace with CCCT (SCR not installed)		1/1/2021 & 1/1/2022
Natural Gas Conversion (SCR not installed)		1/1/2021 & 1/1/2022

Enhanced Alternatives

The enhanced upgrade alternative was included for North Valmy which takes into account the possibility of future environmental regulations that would require the installation of SCR and Wet Flue Gas Desulfurization (WFGD) for compliance. At this time, there are no regulations requiring the installation of the emission controls that are included in the enhanced upgrade alternative. Any future regulations are expected to have at least a five- year compliance period. A five- year compliance window would require any investment or replacement to be installed and in-service by 2018. The following table summarizes the enhanced alternatives:

Enhanced Alternatives	Environmental Compliance Deadline	Retire/Replace w/CCCT & Natural Gas Conversion Effective Date
North Valmy Unit #1		
Enhanced Upgrade (installation of SCR & WFGD)	12/31/2017	
Retire/Replace with CCCT (SCR & WFGD not installed)		1/1/2018
Natural gas conversion (SCR & WFDG not installed)		1/1/2018
North Valmy Unit #2		
Enhanced Upgrade (installation of SCR & WFGD)	12/31/2017	
Retire/Replace with CCCT (SCR & WFGD not installed)		1/1/2018
Natural gas conversion (SCR & WFGD not installed)		1/1/2018

Results

SAIC Individual Unit Analysis

The SAIC analysis included the following objectives:

- Review Idaho Power's assumptions for capital costs of the proposed environmental compliance upgrades, including SCR, DSI, WFGD, and other systems, as well as the costs of replacement capacity.
- Review Idaho Power's assumptions for variable costs of the proposed environmental compliance upgrades, coal replacement with CCCT's and natural gas conversion. Idaho Power provided SAIC forecasted generation output for each unit from AURORA. Idaho Power also provided plant operational data obtained from the coal unit's co-owner and operator; PacifiCorp for the Jim Bridger units and NV Energy for the North Valmy units.
- Develop cost estimates for replacing the coal units annual generation, under three natural gas and three carbon futures, with three investment alternatives: (1) installing environmental compliance upgrades, (2) retiring the unit and replacing with CCCT or (3) converting the unit to natural gas. These total costs include capital costs, O&M, decommissioning costs and unrecovered investments of the existing coal units.
- Develop a capital investment analysis allowing assets with different lengths of operation as well as different implementation dates to be compared equitably.
- Provide planning recommendations regarding the three investment alternatives.

The following table summarizes the results from the SAIC analysis. The left column groups each unit with the investment alternatives. The columns to the right show the net present value (NPV) of operating and capital costs over the twenty-year period 2013-2032 in 2013 dollars. The green highlighted cell indicates the least cost option for the unit under each scenario. SAIC's investment recommendations, which can be found in their report Coal Environmental Compliance Upgrade Investment Evaluation Section 5 Conclusions.

The SAIC results are summarized in Figure 3 below:

Figure 3. SAIC Analysis Summary Results by Scenario for the 2013-2032 Forecast Period ($2013 Millions)

Present Value Power Costs by Scenario ($2013 M)	Low Gas No Carbon	Low Gas Base Carbon	Low Gas High Carbon	Base Gas No Carbon	Base Gas Base Carbon	Base Gas High Carbon	High Gas No Carbon	High Gas Base Carbon	High Gas High Carbon
North Valmy 1 Upgrade (DSI)	$430	$405	$314	$543	$585	$493	$602	$688	$747
North Valmy 1 2015 NG Conversion	$441	$348	$196	$760	$723	$447	$1,032	$1,052	$897
North Valmy 1 2015 Retire/Replace	$455	$403	$303	$671	$661	$488	$857	$886	$811
North Valmy 1 Enhanced Upgrade (DSI+SCR+WFGD)	$604	$569	$466	$728	$764	$653	$789	$873	$920
North Valmy 1 2018 NG Conversion	$445	$353	$200	$735	$698	$422	$961	$980	$825
North Valmy 1 2018 Retire/Replace	$478	$426	$326	$684	$674	$502	$847	$877	$802
North Valmy 2 Enhanced Upgrade (SCR+WFGD)	$586	$516	$462	$687	$726	$584	$719	$795	$760
North Valmy 2 NG Conversion	$430	$294	$205	$683	$663	$354	$868	$889	$635
North Valmy 2 Retire/Replace	$486	$406	$351	$659	$660	$469	$782	$811	$668
Jim Bridger 1 Upgrade (SCR)	$538	$664	$655	$560	$707	$988	$573	$723	$1,070
Jim Bridger 1 NG Conversion	$797	$842	$636	$973	$1,039	$1,103	$1,136	$1,206	$1,342
Jim Bridger 1 Retire/Replace	$774	$851	$722	$899	$997	$1,127	$1,014	$1,116	$1,311
Jim Bridger 2 Upgrade (SCR)	$540	$650	$610	$571	$708	$929	$592	$740	$1,069
Jim Bridger 2 NG Conversion	$797	$828	$577	$1,003	$1,058	$1,068	$1,195	$1,261	$1,378
Jim Bridger 2 Retire/Replace	$787	$842	$787	$931	$1,013	$1,071	$1,065	$1,158	$1,323
Jim Bridger 3 Upgrade (SCR)	$561	$670	$570	$598	$740	$939	$617	$767	$1,087
Jim Bridger 3 NG Conversion	$822	$836	$506	$1,130	$1,185	$1,120	$1,422	$1,491	$1,568
Jim Bridger 3 Retire/Replace	$835	$861	$787	$1,051	$1,111	$1,100	$1,251	$1,322	$1,426
Jim Bridger 4 Upgrade (SCR)	$542	$628	$511	$597	$715	$798	$620	$761	$1,043
Jim Bridger 4 NG Conversion	$773	$760	$426	$1,105	$1,111	$897	$1,397	$1,439	$1,455
Jim Bridger 4 Retire/Replace	$791	$796	$787	$1,023	$1,047	$920	$1,221	$1,273	$1,332

Idaho Power Portfolio Analysis

Idaho Power utilized the AURORA model to determine the total portfolio cost of each investment alternative analyzed by SAIC. The total portfolio cost is estimated over a twenty-year planning horizon (2013 through 2032). Idaho Power used the simulated operational performance of each investment alternative relative to the existing resource under varying future natural gas price forecasts and carbon adder assumptions. Idaho Power conducted the simulation using the AURORA model. The AURORA model applies economic assumptions and dispatch cost simulations to model the relationships between generation, transmission, and demand to forecast future electric market prices. AURORA is Idaho Power's primary tool used to simulate the economic performance of different resource portfolios evaluated in the Integrated Resource Planning (IRP) process.

The fixed costs used by SAIC are incorporated into the Idaho Power Study. SAIC reviewed the fixed costs of each investment alternative and scheduled the costs annually for the various investment alternatives for the twenty-year study period. These annual costs included environmental capital investments, ongoing capital expenditures, unit replacement capital and the fixed O&M costs for the specific unit configuration. The Idaho Power Study combines the Net Present Value (NPV) of the fixed costs from the SAIC model; with the NPV of the twenty-year Aurora generated total portfolio cost to form the basis for the quantitative evaluation of the investment alternatives.

Figure 4, below, summarizes the combined NPV results of Idaho Power's Aurora analysis and SAIC's fixed costs analysis for each investment option under varying carbon and natural gas futures. The planning case (planning case carbon/planning case natural gas) is denoted in bold.

The left column groups each unit with the investment alternatives. The columns to the right show the NPV of the total portfolio costs over the twenty-year period (2013-2032) in 2013 dollars. The green highlighted cell indicates the least cost option for the unit under that scenario. The preponderance of least cost outcomes and the relative cost difference between alternatives helps determine the investment recommendation.

Figure 4. Total Portfolio Costs

Idaho Power Company
Coal Environmental Investment Modeling Results
Total Portfolio Costs (Aurora Portfolio Cost + SAIC Fixed Costs)
For the 20 year forecast period 2013-2032
NPV in 2013 $Millions

	NPV of the Total Portfolio Cost for the 3 natural gas and 3 carbon adder futures								
Investment Alternatives	NG High CO_2 $0	NG High CO_2 $14	NG High CO_2 $35	NG Low CO_2 $0	NG Low CO_2 $14	NG Low CO_2 $35	NG Planning CO_2 $0	NG Planning CO_2 $14	NG Planning CO_2 $35
Valmy 1 (V1) DSI	3,659	4,549	6,805	3,965	4,800	6,889	3,857	**4,731**	6,879
V1 2015 retire/replace with CCCT	4,079	4,800	6,637	3,922	4,623	6,543	4,032	**4,749**	6,631
V1 2015 natural gas conversion	3,869	4,681	6,775	3,920	4,722	6,786	3,927	**4,732**	6,797
V1 V2 Enhanced Upgrade (SCR & WFGD) 2018	4,275	5,167	7,388	4,580	5,372	7,439	4,474	**5,332**	7,428
V1 V2 retire/replace with CCCT 2018	4,403	5,124	6,961	4,283	4,983	6,903	4,379	**5,096**	6,978
V1 V2 natural gas conversion 2018	4,335	5,063	6,927	4,164	4,879	6,969	4,287	**5,009**	6,979
CTA - V1 V2 Enhanced Upgrade (SCR & WFGD) 2023	4,176	5,063	7,316	4,512	5,315	7,370	4,373	**5,255**	7,371
CTA - V1 V2 retire/replace with CCCT 2023	4,256	5,041	6,976	4,265	4,983	6,959	4,307	**5,081**	7,007
CTA - V1 V2 natural gas conversion 2023	4,301	5,093	7,047	4,275	5,000	7,075	4,335	**5,113**	7,108
Jim Bridger 1 (JB1) Install SCR	3,625	4,514	6,771	3,930	4,765	6,855	3,823	**4,696**	6,845
JB1 retire/replace with CCCT 2023	4,054	4,879	6,962	4,156	4,942	6,847	4,149	**4,966**	6,943
JB1 natural gas conversion 2023	4,084	4,911	7,005	4,165	4,965	6,943	4,167	**4,984**	7,012
Jim Bridger 2 (JB2)Install SCR	3,655	4,544	6,800	3,960	4,795	6,885	3,852	**4,726**	6,874
JB2 retire/replace with CCCT 2022	4,117	4,935	7,009	4,198	4,981	6,860	4,201	**5,015**	6,980
JB2 natural gas conversion 2022	4,105	4,928	7,008	4,162	4,969	6,935	4,179	**4,992**	7,009
Jim Bridger 3 (JB3) Install SCR	3,663	4,552	6,808	3,968	4,803	6,893	3,860	**4,734**	6,882
JB3 retire/replace with CCCT 2016	4,231	5,016	7,022	4,201	4,947	6,758	4,253	**5,030**	6,931
JB3 natural gas conversion 2016	4,207	4,989	7,020	4,154	4,927	6,853	4,210	**4,988**	6,969
Jim Bridger 4 (JB4) Install SCR	3,663	4,552	6,808	3,968	4,803	6,893	3,860	**4,734**	6,882
JB4 retire/replace with CCCT 2017	4,205	4,985	6,984	4,189	4,935	6,736	4,235	**5,009**	6,903
JB4 natural gas conversion 2017	4,180	4,961	6,983	4,141	4,915	6,825	4,195	**4,971**	6,934
CTA - JB3 JB4 Install SCR	3,894	4,783	7,040	4,199	5,034	7,124	4,092	**4,965**	7,114
CTA - JB3 JB4 retire/replace w CCCT 2020-21	4,895	5,576	7,351	4,539	5,209	6,785	4,742	**5,426**	7,106
CTA - JB3 JB4 natural gas conversion 2020-21	4,980	5,698	7,545	4,572	5,300	7,086	4,807	**5,512**	7,354

Conclusions and Recommendations

North Valmy Unit #1

North Valmy is a critical facility for the reliability of the electric system in northern Nevada.

With the exception of the installation of DSI for MATS compliance, under current and proposed regulations further environmental investment is not required for the continued operation of NV1. Installation of DSI was the lowest cost result for most of the sensitivities analyzed by SAIC. The SAIC results show installing DSI as the least cost option in six of the nine sensitivities analyzed including the planning scenario (planning natural gas/planning carbon).

The AURORA analysis, performed by Idaho Power, shows installing DSI as the least cost option in four of the nine sensitivities analyzed including the planning scenario (planning natural gas/planning carbon). The majority of scenarios not supporting the installation of DSI are the extreme low natural gas and high carbon cases which have a lower probability of occurring.

Idaho Power's conclusion is that the option to make the DSI investment represents a low cost approach to retain a diversified portfolio of generation assets including the 126 MW's of NV1 capacity for our customers benefit. The continued operation of NV1 as a coal-fired unit will provide fuel diversity that can mitigate risk associated with high natural gas prices. While noting that Idaho Power does not recommend the retire/replace with CCCT option or the conversion of the unit to natural gas, it is also important to recognize that such replacements and conversions do not happen instantaneously. Conversion to natural gas could require from three to six years for permitting, installation of the natural gas pipeline, and boiler modifications. Permitting and construction of a CCCT would require approximately four years.

Based on these results, Idaho Power recommends installing DSI and continuing to include NV1 in its generation portfolio for the 2013 IRP and future resource planning.

Figure 5 illustrates the results of the Study for installation of DSI at NV1 and Figure 6 contains a comparison of the costs of the DSI investment to the retire/replace with CCCT and natural gas conversion alternatives:

Figure 5. NV1 DSI Installation Results

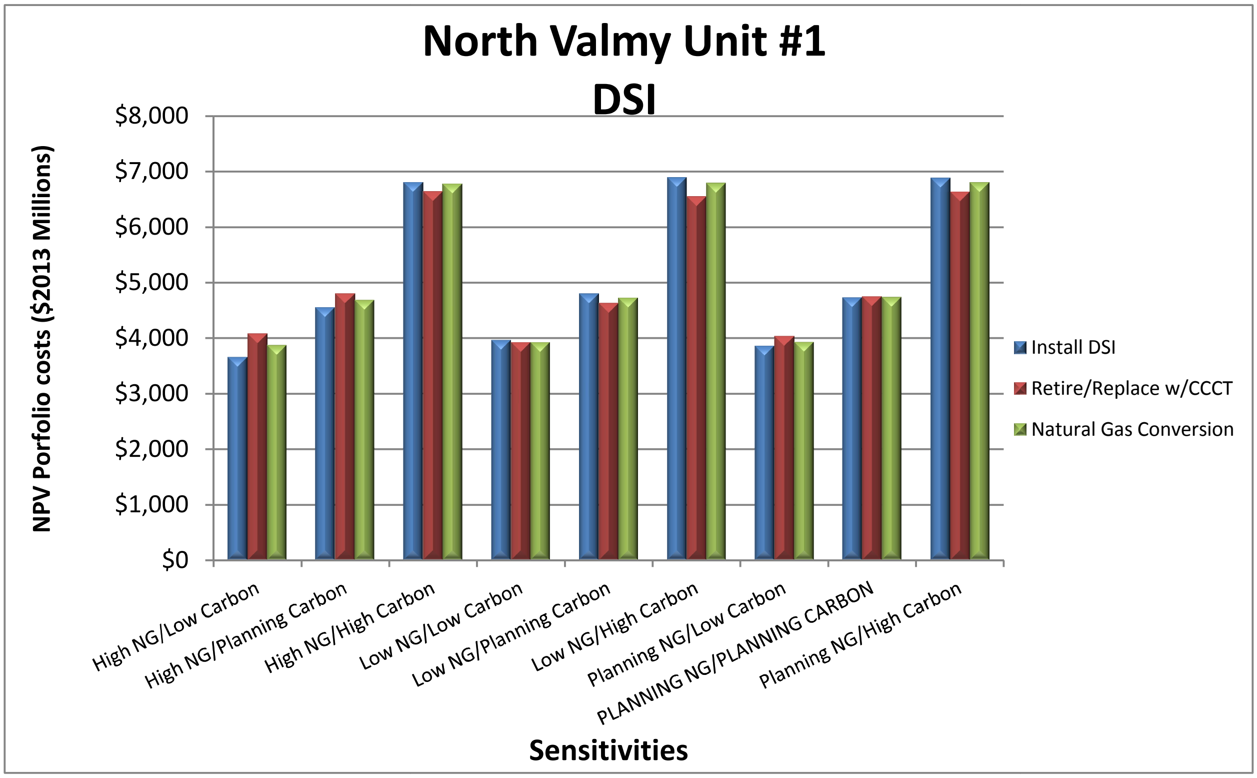


Figure 6. NV1 DSI Installation Cost Deltas

Total Portfolio Costs NPV ($ 2013 Millions)									
	High NG Low CO_2	High NG Planning CO_2	High NG High CO_2	Low NG Low CO_2	Low NG Planning CO_2	Low NG High CO_2	Planning NG Low CO_2	**PLANNING NG PLANNING CO_2**	Planning NG High CO_2
Install DSI	$3,659	$4,549	$6,805	$3,965	$4,800	$6,889	$3,857	**$4,731**	$6,879
Retire/Replace w/CCCT	$4,079	$4,800	$6,637	$3,922	$4,623	$6,543	$4,032	**$4,749**	$6,631
Natural Gas Conversion	$3,869	$4,681	$6,775	$3,920	$4,722	$6,786	$3,927	**$4,732**	$6,797
Cost Delta's by Scenario ($ 2013 Millions)									
Install DSI-Retire/Replace CCCT	(420)	(252)	168	42	177	347	(175)	**(18)**	248
Install DSI- NG conversion	(210)	(132)	30	45	78	104	(71)	**(2)**	82

North Valmy Unit #2

At this time, under current and proposed regulations, further environmental investment is not required for the continued operation of NV2. Additional analysis will be performed if future regulations require significant environmental investments in NV2.

Idaho Power recommends including NV2 in its generation portfolio for the 2013 IRP and future resource planning.

North Valmy Units #1 and #2 (Combined Analysis)

The assumption in the North Valmy Enhanced Upgrade alternative is both units are upgraded, replaced or converted to burn natural gas at the same time. The Enhanced Upgrade alternative includes installation of SCR and WFGD. Consequently, a combined investment analysis is made for both units.

Under both the SAIC and AURORA analyses, proceeding with the Enhanced Upgrade environmental investments at NV1 and NV2 are not supported. However, as there are no current or proposed regulations requiring this investment, Idaho Power recommends including NV1 and NV2 in its planning and as part of Idaho Power's generation portfolio.

Figure 7 illustrates the results of the Study for the Enhanced Upgrade at NV1 and NV2 and Figure 8 contains a comparison of the Enhanced Upgrade costs to the retire/replace with CCCT and natural gas conversion:

Figure 7. NV1 and NV2 Enhanced Upgrade Results

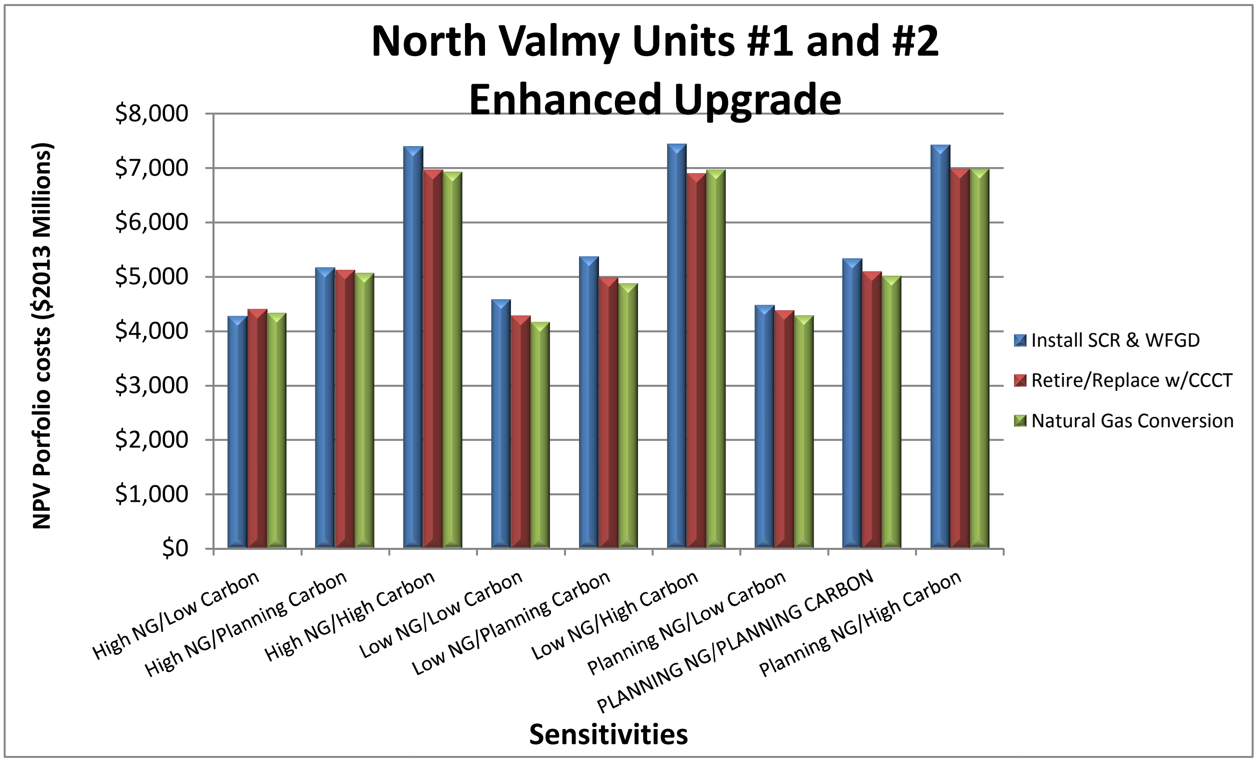


Figure 8. NV1 and NV2 Enhanced Upgrade Installation Cost Deltas

Total Portfolio Costs NPV ($ 2013 Millions)									
	High NG Low CO_2	High NG Planning CO_2	High NG High CO_2	Low NG Low CO_2	Low NG Planning CO_2	Low NG High CO_2	Planning NG Low CO_2	**PLANNING NG PLANNING CO_2**	Planning NG High CO_2
Install SCR & WFGD	$4,275	$5,167	$7,388	$4,580	$5,372	$7,439	$4,474	**$5,332**	$7,428
Retire/Replace w/CCCT	$4,403	$5,124	$6,961	$4,283	$4,983	$6,903	$4,379	**$5,096**	$6,978
Natural Gas Conversion	$4,335	$5,063	$6,927	$4,164	$4,879	$6,969	$4,287	**$5,009**	$6,979
Cost Delta's by Scenario ($ 2013 Millions)									
Install SCR & WFGD-Retire/Replace	($128)	$43	$427	$298	$389	$536	$95	**$236**	$450
Install SCR & WFGD-NG conversion	($60)	$103	$460	$416	$493	$470	$187	**$324**	$450

Additional analysis was performed using the compliance timing alternative. The results of delaying the implementation date do not support proceeding with the Enhanced Upgrade environmental investments on NV1 and NV2.

In the event additional environmental controls are required for NV1 and NV2, the compliance requirements and available control technologies will be analyzed to determine whether installing the environmental controls are the least cost/least risk option.

Figure 9 illustrates the results of the Study for the Enhanced Upgrade compliance timing alternative at NV1 and NV2 and Figure 10 contains a comparison of the compliance timing alternative Enhanced Upgrade costs to the retire/replace with CCCT and natural gas:

Figure 9. NV1 and NV2 Enhanced Upgrade Compliance Timing Alternative Results

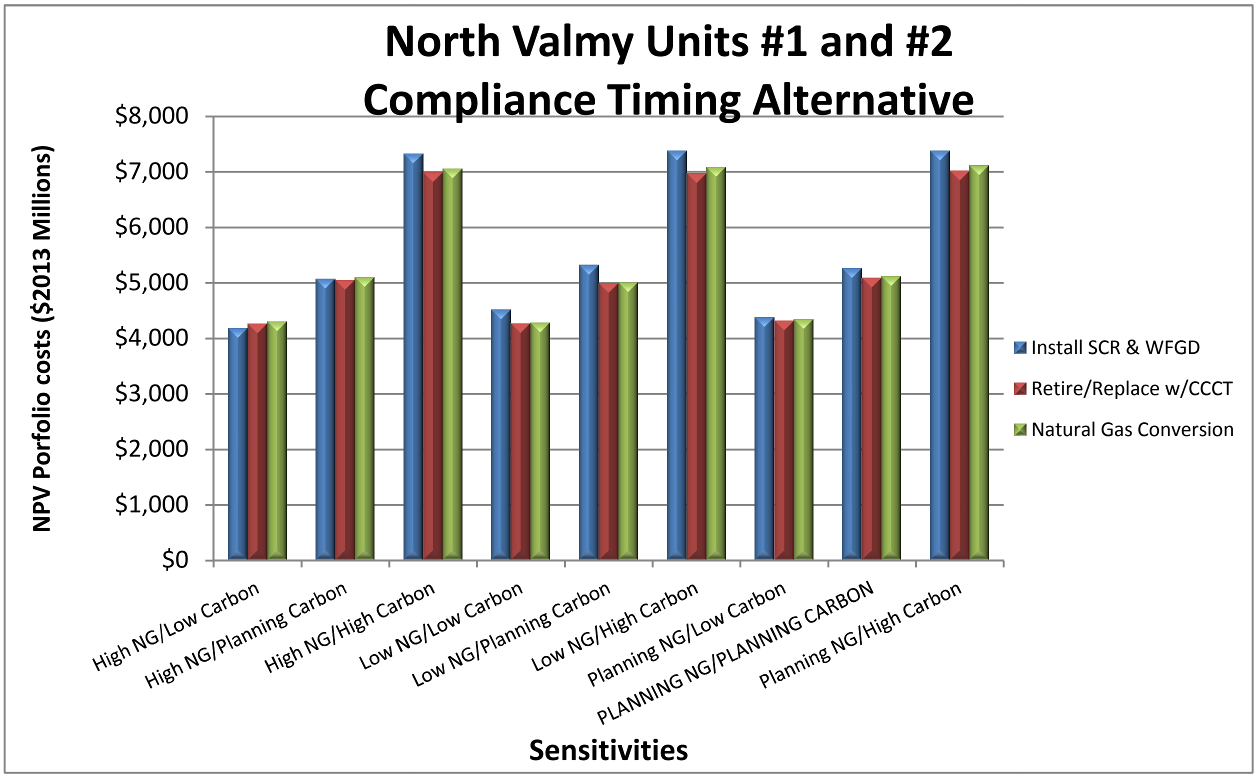


Figure 10. NV1 and NV2 Enhanced Upgrade Compliance Timing Alternative Cost Deltas

Total Portfolio Costs NPV ($ 2013 Millions)									
	High NG Low CO_2	High NG Planning CO_2	High NG High CO_2	Low NG Low CO_2	Low NG Planning CO_2	Low NG High CO_2	Planning NG Low CO_2	**PLANNING NG PLANNING CO_2**	Planning NG High CO_2
Install SCR & WFGD	$4,176	$5,063	$7,316	$4,512	$5,315	$7,370	$4,373	**$5,255**	$7,371
Retire/Replace w/CCCT	$4,256	$5,041	$6,976	$4,265	$4,983	$6,959	$4,307	**$5,081**	$7,007
Natural Gas Conversion	$4,301	$5,093	$7,047	$4,275	$5,000	$7,075	$4,335	**$5,113**	$7,108
Cost Delta's by Scenario ($ 2013 Millions)									
Install SCR & WFGD-Retire Replace	($80)	$21	$339	$248	$332	$411	$66	**$174**	$364
Install SCR & WFGD-NG conversion	($124)	($31)	$269	$237	$315	$294	$38	**$142**	$263

Jim Bridger Unit #1

Under both the SAIC and AURORA analyses, proceeding with environmental investments at JB1 is the lowest cost option for the majority of the carbon and natural gas scenarios. In the most probable scenario, the Idaho Power planning scenario which identifies a planning carbon and planning natural gas future, the environmental upgrade option is overwhelmingly the least cost option.

The installation of SCR, which is the most significant of the environmental investments analyzed, is far enough in the future to make the forecast assumptions highly speculative. As Idaho Power nears the actual SCR investment decision point, a more detailed analysis will be performed with updated assumptions.

Based on these results, Idaho Power recommends continuing to include JB1 in its generation portfolio for the 2013 IRP and future resource planning.

Figure 11 illustrates the results of the Study for installation of required environmental controls at JB1 and Figure 12 contains a comparison of the installation of required emission controls to the retire/replace with CCCT and natural gas conversion options:

Figure 11. JB1 Results

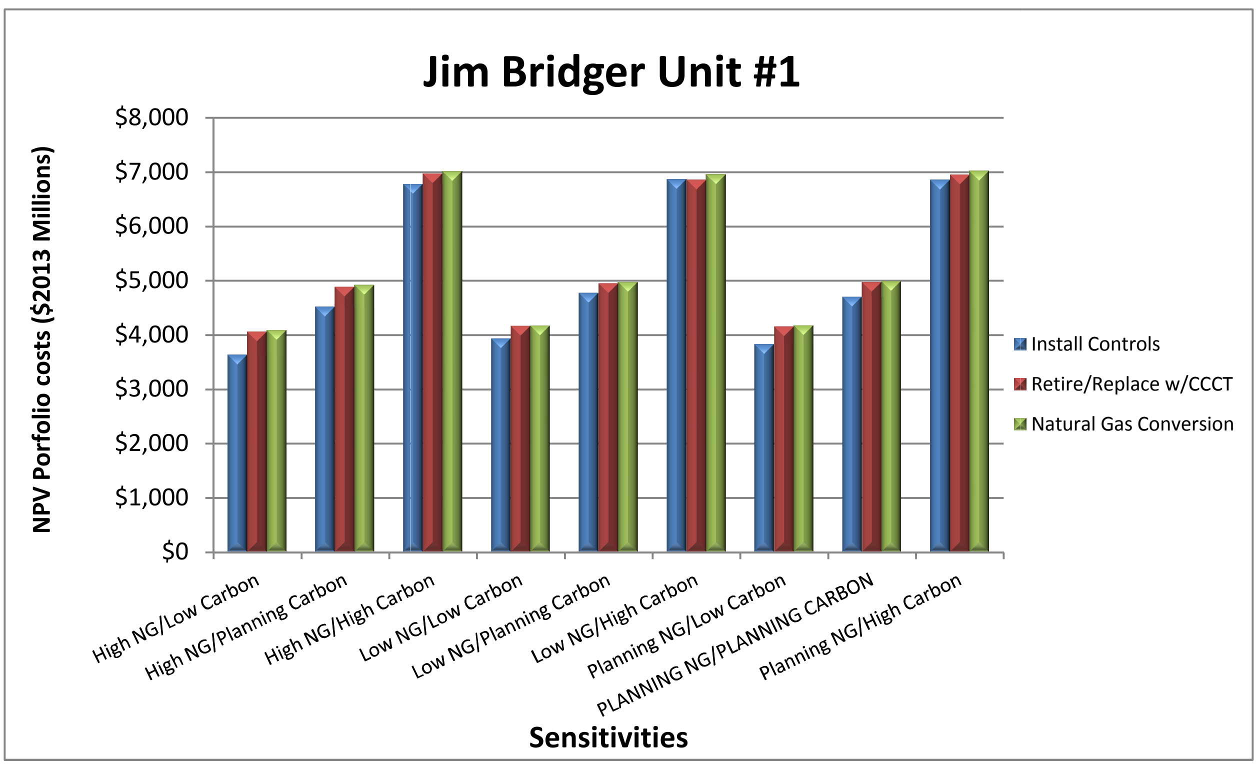


Figure 12. JB1 installation of Emission Controls Cost Deltas

Total Portfolio Costs NPV ($ 2013 Millions)									
	High NG Low CO_2	High NG Planning CO_2	High NG High CO_2	Low NG Low CO_2	Low NG Planning CO_2	Low NG High CO_2	Planning NG Low CO_2	**PLANNING NG PLANNING CO_2**	Planning NG High CO_2
Install Controls	$3,625	$4,514	$6,771	$3,930	$4,765	$6,855	$3,823	**$4,696**	$6,845
Retire/Replace w/CCCT	$4,054	$4,879	$6,962	$4,156	$4,942	$6,847	$4,149	**$4,966**	$6,943
Natural Gas Conversion	$4,084	$4,911	$7,005	$4,165	$4,965	$6,943	$4,167	**$4,984**	$7,012
Cost Delta's by Scenario ($ 2013 Millions)									
Install controls-Retire/Replace CCCT	($429)	($365)	($191)	($225)	($177)	$8	($326)	**($270)**	($98)
Install controls- NG conversion	($459)	($397)	($235)	($234)	($200)	($88)	($345)	**($287)**	($167)

Jim Bridger Unit #2

Under both the SAIC and AURORA analyses, proceeding with environmental investments at JB2 is the lowest cost option for the majority of the carbon and natural gas scenarios. In the most probable scenario, the Idaho Power planning scenario which identifies a planning carbon and planning natural gas future, the environmental upgrade option is overwhelmingly the least cost option.

The installation of SCR, which is the most significant of the environmental investments analyzed, is far enough in the future to make the forecast assumptions highly speculative. As Idaho Power nears the actual SCR investment decision point, a more detailed analysis will be performed with updated assumptions.

Based on these results, Idaho Power recommends continuing to include JB2 in its generation portfolio for the 2013 IRP and future resource planning.

Figure 13 illustrates the results of the Study for installation of required environmental controls at JB2 and Figure 14 contains a comparison of the installation of required emission controls to the retire/replace with CCCT and natural gas conversion options:

Figure 13. JB2 Results

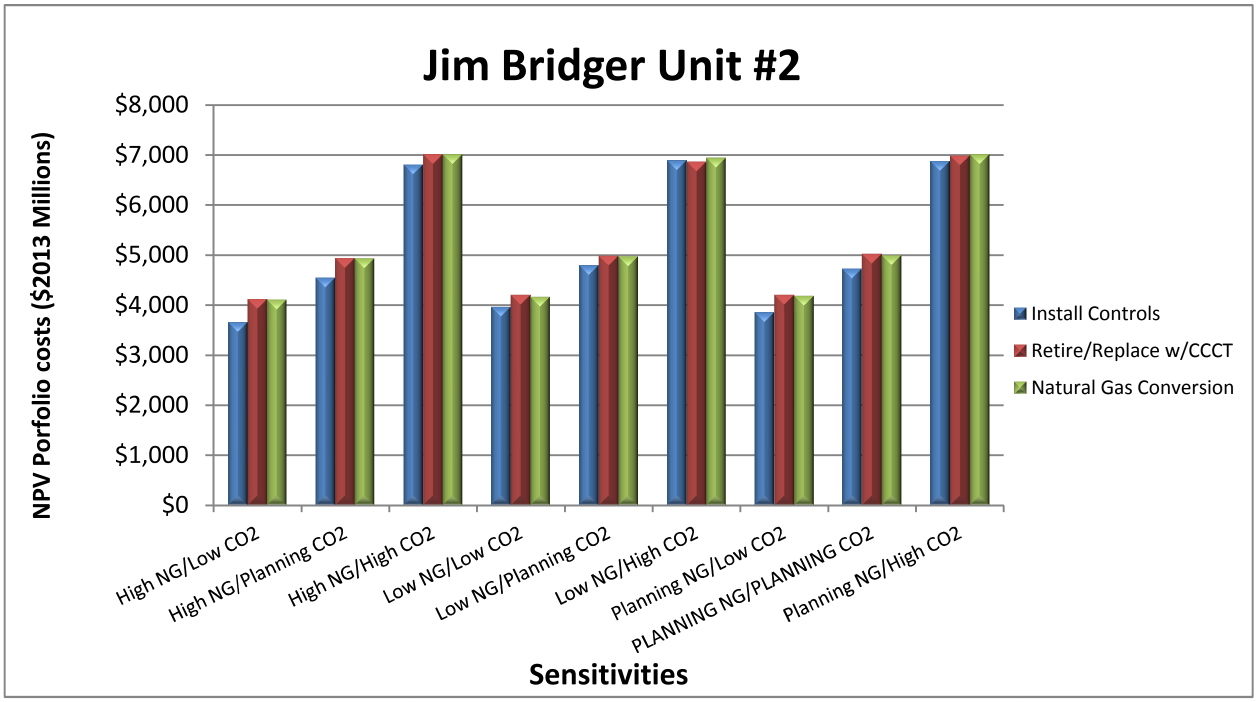


Figure 14. JB2 installation of Emission Controls Cost Deltas

Total Portfolio Costs NPV ($ 2013 Millions)									
	High NG Low CO_2	High NG Planning CO_2	High NG High CO_2	Low NG Low CO_2	Low NG Planning CO_2	Low NG High CO_2	Planning NG Low CO_2	**PLANNING NG PLANNING CO_2**	Planning NG High CO_2
Install Controls	$3,655	$4,544	$6,800	$3,960	$4,795	$6,885	$3,852	**$4,726**	$6,874
Retire/Replace w/CCCT	$4,117	$4,935	$7,009	$4,198	$4,981	$6,860	$4,201	**$5,015**	$6,980
Natural Gas Conversion	$4,105	$4,928	$7,008	$4,162	$4,969	$6,935	$4,179	**$4,992**	$7,009
Cost Delta's by Scenario ($ 2013 Millions)									
Install controls-Retire/Replace CCCT	($462)	($391)	($209)	($238)	($187)	$25	($349)	**($289)**	($105)
Install controls-NG conversion	($450)	($384)	($208)	($202)	($174)	($50)	($327)	**($266)**	($135)

Jim Bridger Unit #3

Under both the SAIC and AURORA analyses proceeding with environmental investments at JB3 is the lowest cost option for the majority of the carbon and natural gas scenarios. In the most probable scenario, the Idaho Power planning scenario which identifies a planning carbon and planning natural gas future, the environmental upgrade option is overwhelmingly the least cost option. Based on these results Idaho Power concludes that making the environmental investments in JB3 is the most prudent action and provides the lowest cost and least risk option.

Based on these results, Idaho Power recommends proceeding with the installation of all identified environmental controls (including SCR) and continuing to include JB3 in its generation portfolio for the 2013 IRP and future resource planning.

Figure 15 illustrates the results of the Study for installation of required environmental controls at JB3 and Figure 16 contains a comparison of the installation of required emission controls to the retire/replace with CCCT and natural gas conversion options:

Figure 15. JB3 Results

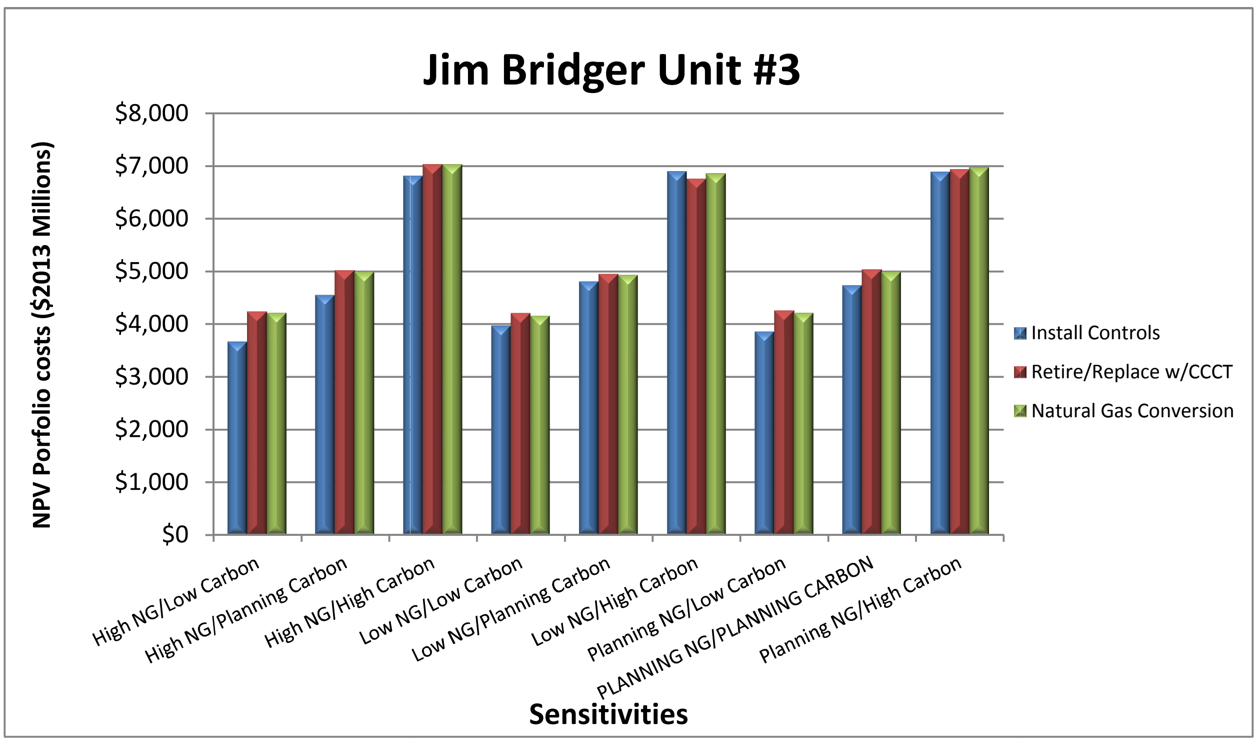


Figure 16. JB3 installation of Emission Controls Cost Deltas

Total Portfolio Costs NPV ($ 2013 Millions)									
	High NG Low CO_2	High NG Planning CO_2	High NG High CO_2	Low NG Low CO_2	Low NG Planning CO_2	Low NG High CO_2	Planning NG Low CO_2	**PLANNING NG PLANNING CO_2**	Planning NG High CO_2
Install Controls	$3,663	$4,552	$6,808	$3,968	$4,803	$6,893	$3,860	**$4,734**	$6,882
Retire/Replace w/CCCT	$4,231	$5,016	$7,022	$4,201	$4,947	$6,758	$4,253	**$5,030**	$6,931
Natural Gas Conversion	$4,207	$4,989	$7,020	$4,154	$4,927	$6,853	$4,210	**$4,988**	$6,969
Cost Delta's by Scenario ($ 2013 Millions)									
Install controls-Retire/Replace CCCT	($568)	($464)	($214)	($233)	($144)	$135	($393)	**($296)**	($49)
Install controls-NG conversion	($544)	($437)	($211)	($186)	($124)	$39	($350)	**($254)**	($87)

Jim Bridger Unit #4

Under both the SAIC and AURORA analyses proceeding with environmental investments at JB4 is the lowest cost option for the majority of the carbon and natural gas scenarios. In the most probable scenario, the Idaho Power planning scenario which identifies a planning carbon and planning natural gas future, the environmental upgrade option is overwhelmingly the least cost option. Based on these results Idaho Power concludes that making the environmental investments in JB4 is the most prudent action and provides the lowest cost and least risk option.

Based on these results, Idaho Power recommends proceeding with the installation of all identified environmental controls (including SCR) and continuing to include JB4 in its generation portfolio for the 2013 IRP and future resource planning.

Figure 17 illustrates the results of the Study for installation of required environmental controls at JB4 and Figure 18 contains a comparison of the installation of required emission controls to the retire/replace with CCCT and natural gas options:

Figure 17. JB4 Results

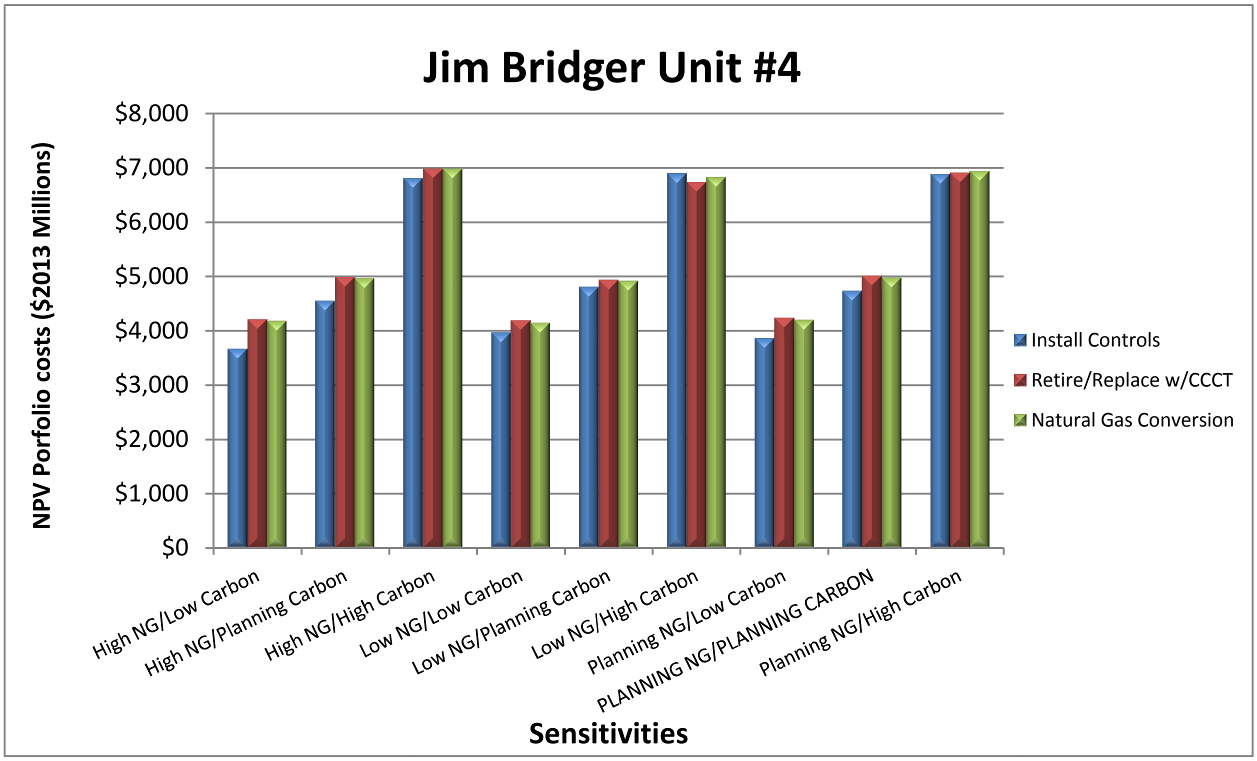


Figure 18. JB4 installation of emission controls Cost Deltas

Total Portfolio Costs NPV ($ 2013 Millions)									
	High NG Low CO_2	High NG Planning CO_2	High NG High CO_2	Low NG Low CO_2	Low NG Planning CO_2	Low NG High CO_2	Planning NG Low CO_2	**PLANNING NG PLANNING CO_2**	Planning NG High CO_2
Install Controls	$3,663	$4,552	$6,808	$3,968	$4,803	$6,893	$3,860	**$4,734**	$6,882
Retire/Replace w/CCCT	$4,205	$4,985	$6,984	$4,189	$4,935	$6,736	$4,235	**$5,009**	$6,903
Natural Gas Conversion	$4,180	$4,961	$6,983	$4,141	$4,915	$6,825	$4,195	**$4,971**	$6,934
Cost Delta's by Scenario ($ 2013 Millions)									
Install controls- Retire/Replace CCCT	($542)	($433)	($175)	($221)	($132)	$157	($375)	**($275)**	($21)
Install controls- NG conversion	($518)	($409)	($175)	($173)	($112)	$68	($335)	**($237)**	($52)

Jim Bridger Units #3 and #4 (Combined Analysis)

The assumption in the compliance timing alternative is both JB3 and JB4 are not upgraded and are replaced or converted to burn natural gas with a five year delay. Consequentially, a combined investment analysis is made for both units.

As shown in the figure above, the results of the compliance timing alternative still support the installation of emission controls on JB3 and JB4.

Figure 19 illustrates the results of the Study for the installation of controls compliance timing alternative at JB3 and JB4 and Figure 20 contains a comparison of the compliance timing alternative costs to the retire/replace with CCCT and natural gas conversion options:

Figure 19. JB3 and JB4 Compliance Timing Alternative Results

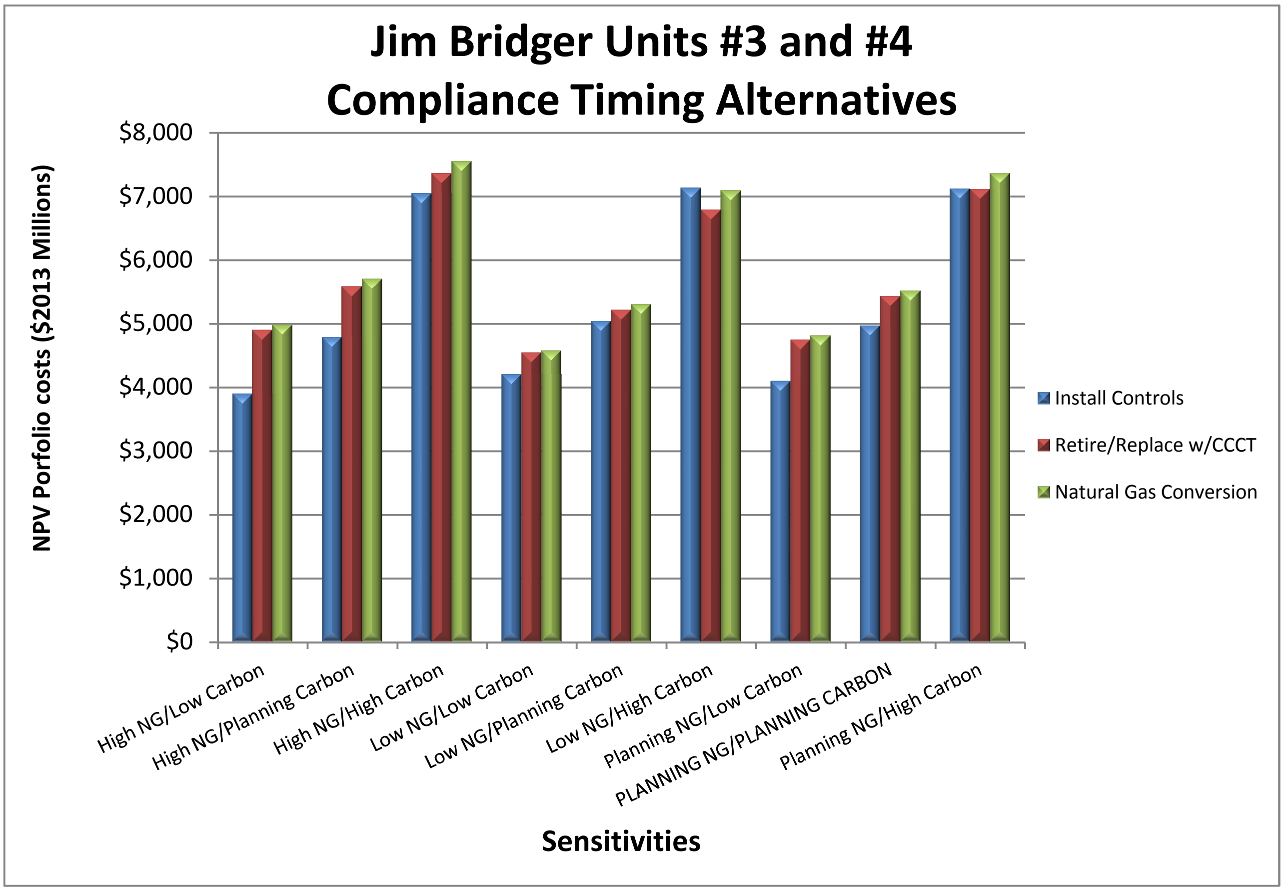


Figure 20. JB3 and JB4 Compliance Timing Alternative Cost Deltas

Total Portfolio Costs NPV ($ 2013 Millions)									
	High NG Low CO_2	High NG Planning CO_2	High NG High CO_2	Low NG Low CO_2	Low NG Planning CO_2	Low NG High CO_2	Planning NG Low CO_2	**PLANNING NG PLANNING CO_2**	Planning NG High CO_2
Install Controls	$3,894	$4,783	$7,040	$4,199	$5,034	$7,124	$4,092	**$4,965**	$7,114
Retire/Replace w/CCCT	$4,895	$5,576	$7,351	$4,539	$5,209	$6,785	$4,742	**$5,426**	$7,106
Natural Gas Conversion	$4,980	$5,698	$7,545	$4,572	$5,300	$7,086	$4,807	**$5,512**	$7,354
Cost Delta's by Scenario ($ 2013 Millions)									
Install controls-Retire/Replace CCCT	($1,001)	($793)	($312)	($339)	($175)	$339	($650)	**($460)**	$8
Install controls-NG conversion	($1,086)	($915)	($505)	($373)	($266)	$38	($715)	**($547)**	($240)

Review Process and Action Plan

The objective of this Study is to ensure a reasonable balance between protecting the interests of customers, meeting the obligation to serve the current and reasonably projected future demands of customers, and complying with environmental requirements, while recognizing that the regulatory environment is uncertain. In a commitment to honor these goals Idaho Power intends to perform systematic reviews, similar to this analysis, whenever certain triggering events occur. These triggering events include:

- A significant change in the current state of environmental regulation
- A significant change in the estimated cost of anticipated environmental controls
- Within a year of committing to a major environmental upgrade
- Whenever Idaho Power files an Integrated Resource Plan

In conclusion, this Study shows the economics of incremental environmental investments is highly dependent upon the assumptions for both natural gas and carbon adders. This Study highlights the challenge in making investment decisions today in the face of significant uncertainties. Despite these uncertainties, certain environmental control equipment investment decisions must be made in the near-term. Idaho Power will continue to work with regulatory agencies and stakeholders to analyze these major investment decisions prior to commitment and implementation.