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November 8, 2013

VIA ELECTRONIC AND U.S. MAIL

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

Re: Docket LC 58 - Idaho Power Company's 2013 Integrated Resource Plan ("IRP")

Enclosed for filing in the above-identified docket are an original and five copies of Idaho Power Company's Reply Comments.

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

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

LC 58

In The Matter of: Idaho Power Company's 2013 Integrated Resource Plan.	**IDAHO POWER COMPANY'S REPLY COMMENTS**

I. INTRODUCTION

Idaho Power Company ("Idaho Power" or "Company") respectfully submits these Reply Comments to the Public Utility Commission of Oregon ("Commission"). These comments respond to the opening comments of the Public Utility Commission of Oregon Staff ("Staff"), the Citizens' Utility Board of Oregon ("CUB"), the Renewable Northwest Project ("RNP"), and the Oregon Department of Energy ("ODOE").

The Company appreciates the timely filing of opening comments and reiterates its support for the current procedural schedule that calls for final comments to be filed within the six month time period required by the Commission's rules.[1] The Company's planning process is extensive and timely resolution of this docket is necessary to allow Idaho Power to effectively incorporate the results of the 2013 IRP into the assumptions for the 2015 IRP.

II. DISCUSSION

A. The 2013 IRP is Reasonable and Satisfies the Commission's Guidelines.

Idaho Power requests that the Commission acknowledge the Company's 2013 Integrated Resource Plan ("IRP"). Commission acknowledgment confirms that the IRP satisfies the procedural and substantive requirements of the Commission's IRP Guidelines

[1] OAR 860-027-0400(5) ("Commission Staff and parties must file their comments and recommendations within six months of the IRP filing.").

and "seem[s] reasonable at the time acknowledgment is given."[2] Idaho Power's IRP is based upon the best information available at the time the IRP was prepared and the analysis was conducted. Moreover, the IRP complies with the Commission's IRP Guidelines and the additional requirements resulting from the Company's most recently acknowledged IRPs.[3] Therefore, the Commission should acknowledge the Company's 2013 IRP.

B. The Commission Should Acknowledge the Boardman to Hemingway Transmission Project as Part of the Company's Preferred Portfolio.

The Boardman to Hemingway Transmission Project ("B2H") is included in Idaho Power's preferred resource portfolio in its 2013 IRP. This means B2H is included in the resource stack that represents the lowest cost and least risk for Idaho Power's customers.[4] The IRP Action Plan indicates that the Company is continuing the permitting process for B2H and anticipates the transmission line will be in service in 2018. Recent developments in the permitting process that occurred after the IRP was filed last June have delayed the expected on-line date until 2020.[5] While this delay was not anticipated in the IRP, it does not significantly change the results of the IRP analysis as Idaho Power has demand response program capacity available to meet deficits that are forecast to occur in 2018 and 2019 as a result of the delay.

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[2] *Re Investigation into Integrated Resource Planning*, Docket UM 1056, Order No. 07-002 at 2 (Jan. 8, 2007); Re Portland General Electric Company 2007 Integrated Resource Plan, Docket LC 43, Order No. 08-246 (May 6, 2008).

[3] *See* 2013 Integrated Resource Plan, Appendix C at 137-168 ("2013 IRP").

[4] *See* Order No. 07-002 at 5 ("The primary goal [of the IRP process] must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.").

[5] These developments include most notably the announcement of delays by the Bureau of Land Management and new developments in the Energy Facility Siting Council process that were identified after mid-August.

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Pursuant to the Commission's direction in Idaho Power's last IRP, the Company treated B2H as an "uncommitted resource."[6] In the context of resource planning, Idaho Power considers an "uncommitted resource" to be a resource that is not included as part of the Company's existing resource portfolio in the IRP and therefore is subject to continued analysis in subsequent IRPs.[7] Accordingly in this most recent IRP, the Company analyzed four resource portfolios that specifically exclude B2H, thus allowing for a direct comparison of Idaho Power's system with and without B2H. The analytical results demonstrate resource portfolios that include B2H are lower cost than resource portfolios that meet the resource deficits with alternatives to B2H. Although Idaho Power is asking the Commission to acknowledge the B2H project as part of the preferred portfolio, the Company recognizes continued analysis in future IRP's will still be necessary.

RNP supports the development of B2H, asserting that the project will yield economic, environmental and reliability benefits for Idaho Power's customers and the region.[8] RNP also concludes that B2H will support greater renewable generation by providing much needed transmission capacity to allow renewable resources to serve the entire region.[9]

Staff also filed comments recognizing the importance of the B2H project. In particular, Staff pointed out the joint funding agreement for permitting costs between Idaho Power, PacifiCorp, and the Bonneville Power Administration ("BPA"),[10] and further observed that it is "noteworthy that of the six potential solutions for BPA to meets its South

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[6] *Re Idaho Power Company's 2011 Integrated Resource Plan*, Docket LC 53, Order No. 12-177 at 4 (May 21, 2012).

[7] This treatment contrasts with a "committed resource," which is a resource that is not yet operational but is included as part of the existing resource portfolio in the IRP. For example, in the 2013 IRP, the Shoshone Falls upgrade is the only "committed resource."

[8] Opening Comments of Renewable Northwest Project at 1-2 ("RNP Comments").

[9] RNP Comments at 2.

[10] Staff's Opening Comments at 1 ("Staff Comments").

Idaho load service obligations, B2H was identified as the preferred solution."[11]

However, Staff emphasized it was "continuing" to evaluate the Company's assumptions regarding B2H and the project timelines. For this reason, Staff stated that it was prepared to recommend acknowledgement only of "Idaho Power's plan to continue obtaining the necessary permits and regulatory approvals to construct B2H [and not] the construction phase of the project."[12] This recommendation to acknowledge only the permitting activities is inconsistent with the Commission's past acknowledgement of B2H and is unnecessary to ensure continued analysis of the project.

In LC 50, Idaho Power's 2009 IRP, the Commission recognized B2H was in its early stages of development and therefore the analysis necessarily included uncertainty related to key assumptions.[13] Nonetheless, the Commission observed this uncertainty was "tempered by risk analyses showing that the 'B2H portfolio' . . . is the best portfolio for customers over a range of capital costs and third-party subscription levels."[14] Therefore, the Commission specifically acknowledged B2H as part of the 2009 IRP subject to the requirement that B2H remain an uncommitted resource in the Company's 2011 IRP.[15]

Then, in the Company's 2011 IRP, LC 53, the Commission again acknowledged B2H subject to the same requirement that Idaho Power continue to treat B2H as an uncommitted resource in the 2013 IRP.[16]

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[11] Staff Comments at 1.

[12] Staff Comments at 1.

[13] *Re Idaho Power Company's 2009 Integrated Resource Plan*, Docket LC 50, Order No. 10-392 at 9 (Oct. 11, 2010).

[14] Order No. 10-392 at 9.

[15] Order No. 10-392 at 9.

[16] Order No. 12-177 at 4.

Here, the Company again requests acknowledgement of the 2013 IRP, which includes B2H in the preferred portfolio.[17] Like in past cases, the Company agrees that it will continue to treat B2H as an uncommitted resource in its next IRP and IRP update and the Company will continue to provide the Commission and stakeholders updated analyses related to the project. Moreover, to the extent the Commission wishes to provide specific acknowledgment related to the permitting process, the Commission can acknowledge the Company's B2H Action Plan item.[18] Providing full acknowledgment of the Company's preferred portfolio and specific acknowledgment of the B2H permitting process is consistent with Commission precedent and does not compromise the Commission's ability to continue its review of B2H in future IRP filings.[19]

C. The IRP's Treatment of Coal-Fired Plants is Reasonable.

1. The Commission Should Acknowledge the Company's Planned Emission Control Investments at the Jim Bridger Plant.

The Company's 2013 IRP includes in its Action Plan the commitment to install selective catalytic reduction ("SCR") emission-control technology at Units 3 and 4 of the Jim Bridger coal-fired power plant ("Jim Bridger") in 2013. SCR is required to comply with the Environmental Protection Agency's ("EPA") Regional Haze rules and the resulting

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[17] Order No. 07-002 at 25 ("We agree that, in an IRP, the Commission looks at the reasonableness of the individual actions in the context of the entire plan.").

[18] *See e.g.*, *Re Idaho Power Company's 2004 Integrated Resource Plan*, Docket LC 36, Order No. 05-785 at 15 (June 17, 2005) (acknowledging preferred portfolio that included new supply side resources and stating "we believe it is appropriate for IPCo to begin to perform the necessary steps to inventory potential site locations, permitting requirements, and transmission needs."); *Re Idaho Power Company's 2002 Integrated Resource Plan*, Docket LC 32, Order No. 03-389 (July 3, 2003) (acknowledging action plan calling for the Company to "Solicit proposals and initiate the siting and permitting of approximately 100 MW of a utility owned and operated peaking resource to be available in 2005.").

[19] The Company also requires acknowledgment of the IRP's preferred portfolio (and B2H) to facilitate the permitting process. To obtain a site certificate from the Energy Facility Siting Council ("EFSC"), Idaho Power must demonstrate that B2H is "needed" and EFSC's rules provide that the Company can demonstrate need if the transmission line is included in an acknowledged IRP. *See* OAR 345-023-0020.

Wyoming Regional Haze State Implementation Plan.

In the Company's 2011 IRP, CUB and RNP raised concerns related to the Company's proposed emission control investments at its coal plants. In response to these concerns, the Company agreed and the Commission 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.[20]

On February 14, 2013, the Company filed its 2011 IRP Update, which included the Company's "Coal Unit Environmental Investment Analysis for the Jim Bridger and North Valmy Coal-Fired Power Plants" (referred to herein as the "Coal Study"). Consistent with the Commission's request, the Coal Study analyzed the anticipated future investments required for environmental compliance in six coal units in which the Company has an ownership interest.[21] This analysis considered numerous existing and emerging regulations, including the 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

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

[21] 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.

Study, compliance with these regulations will require the installation of SCR at all four Jim Bridger units.[22]

The Coal Study compared the costs of the expected 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.[23] The Coal Study analyzed these alternatives over a range of future scenarios related to natural gas and carbon costs.[24]

The Coal Study concluded that the installation of SCR at Jim Bridger Units 3 and 4 represents the least cost/least risk option for Idaho Power's customers. Indeed, for all four Jim Bridger units, the emission control investments constitute the lowest cost option for the majority of the carbon and natural gas scenarios. And in the most probable scenario—the Idaho Power planning scenario—the environmental upgrade option for Units 3 and 4 constitutes the least cost option by an overwhelmingly large margin. Consequently, the

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[22] The Coal Study also concluded that additional emission control investments will be required at both Jim Bridger and the North Valmy plant.

[23] 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.

[24] 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).

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Company requested acknowledgment of its 2011 IRP Update, including these SCR investments.[25] Similarly, the Company's 2013 IRP requests acknowledgment of these same investments and relies largely on the Coal Study filed with the Commission as part of the 2011 IRP Update.[26]

CUB recommends that the Commission decline to acknowledge the installation of SCR at Jim Bridger Units 3 and 4 because, according to CUB, the Company has not considered a "proper phase-out analysis similar to the one completed on PGE's Boardman plant, which assumed a closure date of 10 years after the analysis . . ."[27] However, the Company's Coal Study examined precisely the type of phase-out that occurred for the Boardman plant. And the results of that study demonstrate that the installation of SCR at Jim Bridger Units 3 and 4 is by far the least cost option for Idaho Power's customers.

CUB also argues that PacifiCorp's phase-out analysis related to PacifiCorp's coal plants is deficient because the emission control investments have longer useful lives than the plants where they are installed and therefore the cost-effectiveness analysis of the controls is inaccurate.[28] Without providing any specific reference, CUB then claims that these "same arguments are also applicable to the analysis done in Idaho Power's 2013 IRP."[29] Consistent with the Commission's IRP Guidelines, the Coal Study's analysis examined the costs and benefits of each alternative over the IRP's 20-year planning

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[25] *Re Idaho Power Company 2011 Integrated Resource Plan*, Docket LC 53, Application for Acknowledgment of 2011 Integrated Resource Plan Update at 3 (Feb. 14, 2013).

[26] *See* 2013 IRP at 58-59. The procedural schedule in the 2011 IRP Update originally called for the Commission to address the update at its June 1, 2013, public meeting to allow the update to be fully submitted to the Commission prior to the Company's filing of its 2013 IRP. However, the procedural schedule in the 2011 IRP Update process was subsequently suspended pending the review of the same SCR investments in PacifiCorp's pending 2013 IRP, docket LC 57. *Re Idaho Power Company 2011 Integrated Resource Plan*, Docket LC 53, Ruling (Apr. 4, 2013). The Company requests that the Commission take official notice of the Coal Study pursuant to OAR 860-001-0460(1)(d).

[27] Opening Comments of Citizens' Utility Board of Oregon at 2-4 ("CUB Comments").

[28] CUB Comments at 3.

[29] CUB Comments at 3.

horizon.[30] In addition, the Company's analysis assumed that the emission control investment had the same useful life as the plant to which the control is attached. CUB's criticism also fails to consider that the Commission has recognized that Idaho Power and PacifiCorp are differently situated because PacifiCorp's analysis "cover[s] a fleet-wide investment in a number of plants," while Idaho Power's analysis is necessarily more limited.[31]

2. The Company will Continue to Update the Commission Regarding the Status of the North Valmy Plant.

Both Staff and CUB are critical of the IRP's treatment of the North Valmy coal-fired plant due to what they perceived as the decision by Idaho Power's co-owner, NV Energy, to decommission the plant. This criticism of the 2013 IRP arises primarily from confusion related to NV Energy's intentions with respect to its 50 percent ownership interest in the plant. In the spring of 2013, NV Energy announced decommissioning plans for two other coal plants (the Reid Gardiner and Navajo coal plants). However, there is currently no planned closure of the two units at the North Valmy power plant. NV Energy currently applies depreciation rates for North Valmy that are based upon end-dates of 2021 for Unit 1 and 2025 for Unit 2. Idaho Power currently uses end-dates of 2031 for Unit 1 and 2035 for Unit 2 in its currently approved depreciation rates. Both NV Energy and Idaho Power review their depreciation rates at differing intervals, as required by their respective state regulatory commissions. It is important to note that these dates are used for the sole purpose of establishing depreciable lives for accounting and ratemaking purposes and do

[30] Order No. 07-002 at 5.

[31] *Re Idaho Power Company*, Docket UE 233, Order No. 13-132 at 6 (Apr. 11, 2013) ("Unlike our review in docket UE 246, which covered a fleet-wide investment in a number of plants, both the contemporaneous and the updated analyses for Bridger 3 showed benefits of such magnitude for the investment, as compared to a shutdown, that we cannot conclude that Idaho Power's actions caused harm to Oregon ratepayers. Even with more rigorous analyses, the investment would have still been the economic choice. We find that the investment in Bridger 3 was prudent.")

not represent agreed upon decommissioning dates between NV Energy and Idaho Power. Neither company can decommission a unit without the consent of the other partner. Idaho Power is currently working with NV Energy to determine what would be required to establish common depreciation dates for both parties, which would be beneficial in analyzing the future operation of the plant.

In the 2013 IRP, Idaho Power plans on continued operation of the North Valmy plant throughout the entire 20-year planning period and the preferred resource portfolio includes continued operation of Units 1 and 2 at the North Valmy plant. Idaho Power also specifically analyzed retirement of the North Valmy generation facility in resource portfolios 8 and 9 in order to quantify the impact of shutting the units down in 2021 and 2025. Neither of these portfolios were least cost, and therefore were not selected as the preferred portfolio.

In addition, the Idaho Power analysis associated with the emission control planning at the North Valmy coal plant is included in the Coal Study and the installation of dry sorbent injection at Valmy is included in the IRP action plan.

3. The 2013 IRP Appropriately Models Coal Transitions.

RNP faults the Company for not selecting as a preferred portfolio one of the four resource portfolios that included the retirement of the Company's coal plants.[32] RNP claims that only these four portfolios meet Idaho Power's Board of Director's goal to lower emission intensity levels by 10 to 15 percent relative to 2005 levels.[33] To reach this conclusion, RNP erroneously relied on total emissions (measured in pounds) and not emission intensity (measured in pounds per megawatt-hour).[34] Accounting for the proper measurement, all nine of the Company's modeled portfolios satisfy the Company's carbon

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[32] RNP Comments at 4.

[33] RNP Comments at 4.

[34] RNP relied on Table 9.2 on page 100 of the IRP.

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intensity goal. Indeed, the Company has consistently exceeded its carbon intensity goals:

> The current year-to-date and average 2010-2013 period-to-date CO2 emission intensity is updated monthly on a provisional basis and trued up to actual figures on an annual basis. . . . Idaho Power is on track to exceed the CO2 emission intensity reduction goal it established in 2009.
>
> Reflecting its further commitment to that goal, in November 2012 Idaho Power extended its goal to reduce its resource portfolio's average CO2 emission intensity to a level of 10 to 15 percent below its 2005 CO2 emission intensity through 2015.[35]

RNP next mistakenly criticizes the Company for failing to model the conversion of its coal units to natural gas.[36] However, the Company's Coal Study specifically analyzed the economics of natural gas conversion and concludes that natural gas conversion is not the least-cost alternative.

RNP also claims that the Company did not analyze a range of emission control costs.[37] However, the Company's modeling, both in the 2013 IRP and the Coal Study, included costs for other anticipated regulations and examined three levels of carbon adders to evaluate the potential impact of the regulation of carbon emissions. Moreover, the controls that the Company evaluated in the Coal Study have extensive operating history within the national coal fleet and the cost assumptions were vetted by SAIC, the independent consultant retained by Idaho Power to conduct a portion of the study.

Finally, RNP faults Idaho Power for failing to account for "recent progress on federal energy policy," such as the federal government's pronouncement in June 2013 that carbon dioxide emissions would be regulated.[38] Because the IRP was filed in June 2013, the Company could not have accounted for the June 2013 announcement without delaying the

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[35] https://www.idahopower.com/AboutUs/Sustainability/CO2Emissions/co2Intensity.cfm

[36] RNP Comments at 4.

[37] RNP Comments at 5.

[38] RNP Comments at 5.

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filing of the 2013 IRP. In addition, and more importantly, the announced regulations pertain only to new power plants and Idaho Power is not proposing any new coal plants in the 2013 IRP.

The 2013 IRP includes a range of future carbon costs, which are specifically intended to account for potential variations in the cost of carbon regulation. A consideration of climate change legislation introduced during the ongoing 113th United States Congress provides perspective for the IRP's carbon adder scenarios. As of September 2013, only one introduced bill during the 113th Congress, Senate bill 332 introduced by Senators Bernie Sander (I-VT) and Barbara Boxer (D-CA), attaches a price to greenhouse gas emissions. Senate bill 332, also known as the Climate Protection Act of 2013, stipulates a carbon emission fee of $20 per ton for the first year of enactment, with an annual increase of 5.6 percent through the first twelve years after enactment. After twelve years, the carbon tax stipulated by the Climate Protection Act of 2013 reaches just under $36.50 per ton.[39] By comparison, the IRP's upper case carbon tax reaches over $90 per ton in its twelfth year (2029), and continues to grow to $117 per ton by year fifteen.

Idaho Power shares RNP's concerns regarding the effect of federal energy policy on coal plant operating costs. However, as acknowledged by RNP in their comments, there is uncertainty regarding the stringency of future emissions regulations. This uncertainty was also noted in comments filed by staff of the Idaho Public Utilities Commission ("IPUC") in Idaho Power's 2013 IRP case before the IPUC. IPUC staff stated:

> The IRPAC vetted and generally supported this carbon adder. Staff believes the range of carbon scenarios (a low of $0 per ton to $35 per ton in 2018 escalated at 9%) is reasonable given the uncertainty surrounding future carbon regulations.[40]

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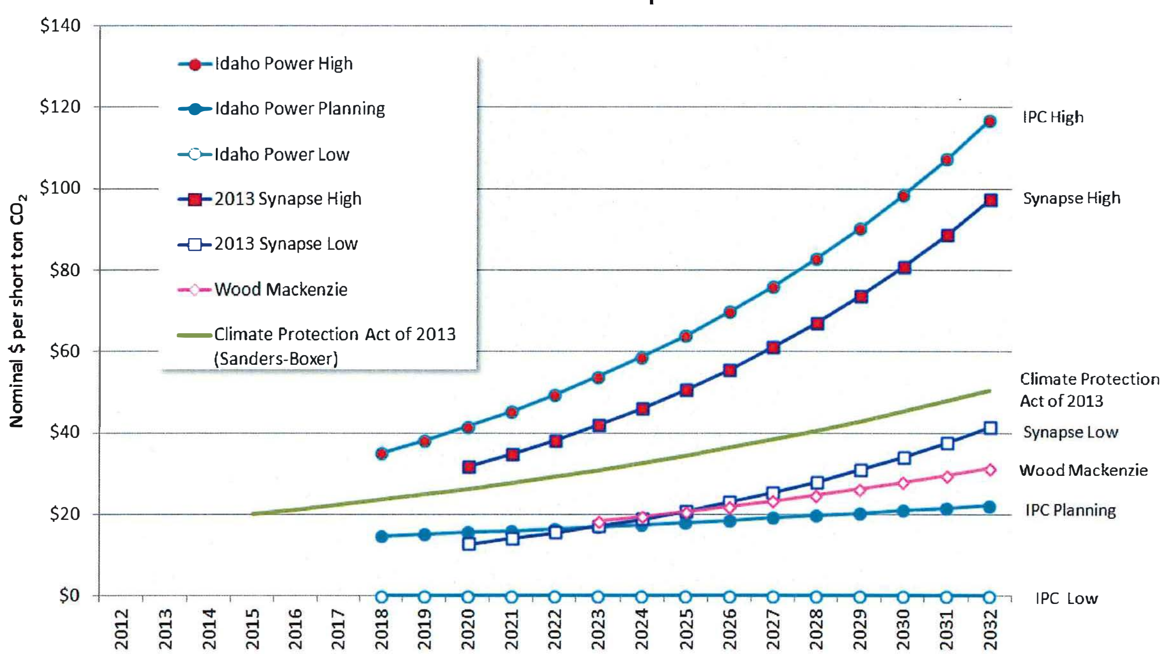
[39] http://www.sanders.senate.gov/imo/media/doc/0121413-ClimateProtectionAct.pdf

[40] Idaho Public Utilities Commission Staff Comments, Case No. IPC-E-13-15 at 6 (Nov. 5, 2013).

Given this uncertainty, Idaho Power strives to at least bracket the range of possible carbon tax levels. A comparison of carbon adders shown in the following chart indicates a high likelihood that the IRP's upper carbon case safely brackets the upper range of possible carbon costs. Idaho Power believes this wide range of carbon tax levels meets the requirements of Guideline 8, which requires Idaho Power to "develop several compliance scenarios ranging from the present CO2 regulatory level to the upper reaches of credible proposals by governing entities."[41]

Carbon Adder Comparison



D. The Company's Treatment of the Gateway West Transmission Project is Reasonable.

The Company's Action Plan includes an item calling for the continued planning and permitting of the Idaho Power-funded portions (three segments west of the Midpoint/Cedar Hill cut-plane to Hemingway Substation) of the Gateway West Transmission Project (Gateway West). Gateway West is a joint transmission project between Idaho Power and

[41] OPUC Order No. 08-339 Appendix C at 1.

PacifiCorp. The project is currently in the permitting phase and is not expected to be in-service until between 2019 and 2023. CUB offers no substantive criticism of the Company's analysis of Gateway West, but recommends against acknowledgement because it believes that the Company should have analyzed each segment of the project individually.[42] RNP "supports Idaho Power's continuing role in the development of Gateway West."[43]

Idaho Power views the Gateway West project as one distinct project with one purpose and need, and has not divided it into separate segments for purpose of the IRP.

E. The Commission Should Rely on Idaho Power's Load Forecasting and Assumptions.

Staff is concerned about the impact of summer peak loads on the peak hour deficits and suggests that the Company's forecast summer loads may be overstated because the "50th percentile summer load may grow at a slower rate than the Company expects."[44] Staff's concern over the 50th percentile summer load is unwarranted because peak-hour planning is based on the 95th percentile forecast, not the 50th percentile.[45]

Moreover, the 2013 IRP's forecast summer load growth is conservative. Recent events—and especially events occurring since the completion of the current IRP—suggest that summer loads (peak and average) will likely grow at a faster pace than was forecast in the 2013 IRP. For example, the Company experienced record system-peaks in both 2012 and 2013 and the 2013 actual peak exceeded the 2013 IRP's forecast peak-hour load. The Company experienced an all-time system peak of 3,245 MW on July 12, 2012.

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[42] CUB Comments at 5.

[43] RNP Comments at 3.

[44] Staff Comments at 4.

[45] 2013 IRP at 47, 51 ("The 70th-percentile and 90th-percentile load forecast scenarios were developed to assist Idaho Power's review of the resource requirements that would result from higher loads due to adverse weather conditions . . .Idaho Power uses the 95th-percentile forecast as the basis for peak-hour planning in the IRP.").

Then, on July 2, 2013, the Company experienced another all-time system peak of 3,407 MW—162 MW higher than the 2012 record system peak. For comparison, the forecast of system peak for July 2013 in the 2013 IRP (95th percentile scenario[46]) was 3,382 MW, which was 25 MW *less* than actual. Adjusting for demand response programs that were operating at the time of the actual system peak (and are not included in IRP peak forecast), the 2013 all-time system peak exceeded the 2013 IRP forecast (1 in 20 years) for July 2013 by approximately 57 MW. This evidence suggests strongly that the 2013 IRP, 95th percentile (1 in 20 years) peak forecast, was conservative.

Further, the recovering economy suggests that load growth will likely increase. First, actual residential customer counts have exceeded the forecasts in the 2013 IRP.[47] Second, the IRP forecast relies on a number of key economic variables from Moody's Analytics that have been revised upward, especially in the near-term. Specifically, Moody's Analytics has adjusted its housing stock metric, which drives the residential customer count forecast, and employment projections, which is a key driver of commercial/industrial sales.

Similarly, there are much clearer signs of a rebounding industrial sector than were anticipated a year ago. A number of existing industrial customers have announced plans for expansion and several new industrial customers have committed to locating in the service territory, each contributing to higher summer loads (peak and average). The Company is also in the final stages of adding a new special contract customer which is expected to be a net addition to peak and average energy.

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[46] Load Forecasting considers that the probability associated with this year's all-time peak was near or slightly above the 95th percentile, given the extremely dry conditions, hot temperatures, and timing at the peak of the irrigation pumping season.

[47] As of September 2013, the actual residential customer count exceeded the 2013 IRP residential customer count by 1,541 customers.

Finally, actual irrigation sales have exceeded forecasts.[48] Future irrigation forecasts will be influenced upward by the recent strength in irrigation sales, which impact the summer month peak demand and energy in the same direction.

Together, these factors suggest that the Company's summer load forecast is conservative and is likely to be greater in future IRPs.

F. Idaho Power Has Properly Considered Flexible Capacity Resources as Required by Order No. 12-013.

RNP has commended Idaho Power for continuing to expand its demand response program."[49] Idaho Power appreciates RNP's support and is continuing to assess current and potential demand response programs. Indeed, in proceedings before both the Commission and the IPUC,[50] Idaho Power held a series of five workshops during the summer of 2013 to explore the continuation of Idaho Power's Demand Response programs for 2014 and beyond. These workshops involved Idaho Power personnel, IPUC Staff, Commission Staff, and nearly 50 individuals representing 20 different organizations. During these workshops the participants explored many aspect of Demand Response including program cost-effectiveness and value, national trend in demand response, the potential of using demand response for non-spinning reserves and/or load following, and the impact and process of dispatching demand response on Idaho Power's system. The result of these workshops was a stipulation in Idaho and Oregon signed by the workshop participants with the intent of continuing Idaho Power's Demand Response programs in 2014 and through the IRP planning period. Both of these dockets are currently pending before both commissions.

RNP recommends further refinement in the Company's flexibility analysis to include

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[48] Actual sales reached a record 2.048 million MWh in 2012 and are estimated to reach 2.145 million MWh in 2013.

[49] RNP Comments at 3-4.

[50] Docket UM 1653 and Idaho Case No. IPC-E-13-14.

energy storage.[51] RNP also argues that Idaho Power has not satisfied the Commission's flexibility analysis required by Order No. 12-013, which requires utilities to forecast the demand for and supply of flexible capacity and to evaluate flexible resources on a consistent and comparable basis.[52]

With respect to RNP's energy storage recommendation, Idaho Power agrees with RNP that there are multiple benefits that an energy storage project would provide to Idaho Power's system. RNP specifically references pumped storage, which the Company did include in the Resource Alternative section of the Company's 2013 IRP.[53] Idaho Power modeled many of the benefits specifically mentioned by RNP, such as the provision of peak capacity, flexible capacity, low variable cost balancing reserves, and arbitrage opportunities.

In particular, a pumped storage hydro project was modeled as a Resource Alternative and as a tool to assist in the integration of wind resources. To accomplish this, the modeling assumed that the light load energy from wind generators in southern Idaho and eastern Oregon could be used to pump water into storage, which could then be released to create energy during the next heavy load period. This methodology captured both the flexibility of the peaking capacity and helped to integrate the variable wind generation into the system. It also captured arbitrage market opportunities. An avoided wind integration credit was also applied to the light load energy that was used to pump water into storage to account for the fact that this generation was not used to serve load.

In addition to the benefits already described, the Company identified periods in the future when hourly pricing in the Mid-C market could potentially result in negative pricing. Transmission assumptions were made that would allow for this negatively-priced energy to

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[51] RNP Comments at 3-4.

[52] RNP Comments at 3-4; Order No. 12-013 at 16.

[53] *See* 2013 IRP at 83-87.

also be used to pump water into storage. The project was modeled to carry balancing reserves in a manner similar to the other load following hydro units within the system.

The Company maintains that the pumped storage modeling in the 2013 IRP addresses the concerns identified by RNP. The modeling captures flexible peaking capacity, arbitrage market opportunities, integration of renewables, low-cost reserve contributions, and ancillary benefits. Further, this pumped storage modeling also satisfies the flexibility analysis required by Order 12-013.[54]

G. The 2013 IRP Properly Accounts for Wind Resource Costs.

RNP claims that Idaho Power's assumed wind resource costs are inconsistent with the February 2012 report from the National Renewable Energy Laboratory ("NREL") that the IRP cites as its source for these costs.[55] The cost difference RNP identifies results from the conversion of the NREL report's capital costs from base 2009 dollars to base 2013 dollars, which is the common base for the IRP's comparison of resource costs. As noted by RNP, the NREL report identifies wind resource capital costs at $1,980/kW in base 2009 dollars.[56] Using the IRP's assumed escalation rate of 3 percent, the NREL-reported capital cost converts to the IRP wind resource capital cost of $2,229/kW. The NREL report adds that cost certainty for wind resources is relatively high, and that no cost improvements are projected through 2050.

RNP also claims that Idaho Power's wind resource costs are overstated because the Company used unsupported and unreasonably low wind capacity factors.[57] The 2013 IRP assumes a 26 percent capacity factor for new wind resources. As noted by RNP, NREL reports capacity factors of 33 to 37 percent for class 3 and 4 wind resources. Idaho Power

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[54] *See also* 2013 IRP 109-110; 2013 IRP, Appendix C at 155.

[55] RNP Comments at 6. RNP also made this same argument with respect to solar resources. The same response applies to both wind and solar resource capacity costs.

[56] RNP Comments at 7.

[57] RNP Comments at 7.

used a lower capacity factor because it is unlikely that new wind resources in southern Idaho will be class 3 and 4 wind resources. Actual Experience and NREL data indicates that the areas where Idaho Power is most likely to have future wind development are overwhelmingly designated as marginal to fair resource of wind class 2 and 3.[58]

Forecasting the projected generation from future wind projects is fraught with uncertainty, in part because the Company does not know where future projects may be located. Project location is driven by myriad factors in addition to simply the quality of wind. These factors include notably the proximity to transmission and the availability of land for development. Moreover, based on the expansion of wind capacity experienced over recent years, Idaho Power is likely to have no involvement in the selection process for project location. With the exception of the Elkhorn wind project, which Idaho Power selected through a rigorous RFP process after including utility-scale wind as part of the 2004 IRP's preferred portfolio, wind capacity connecting to Idaho Power's system has been the result of the Public Utility Regulatory Policies Act (PURPA). Under PURPA, the Company has no control over project location. Thus, given the uncertainty of production from future wind projects and the marginal to fair wind resource designation for much of southern Idaho, the Company contends that assuming capacity factors of 33 to 37 percent for IRP wind projects would clearly overstate the production that is likely to occur.

H. Idaho Power's Wind Integration Study is Reasonable.

RNP also argues that the Company's integration rate causes the 2013 IRP to overstate wind resource costs.[59] In particular, RNP asserts that costs from the Company's 2013 Wind Integration Study are overestimated as a result of flawed assumptions

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[58] http://www.windpoweringamerica.gov/images/windmaps/id_50m_800.jpg. The NREL study does not include capacity factors for class 2 wind resources. However, the study provides capacity factors of 33 percent for class 3 wind and 37 percent for class 4. Therefore, it is reasonable to assume that class 2 wind would have a capacity factor of less than 30 percent.

[59] RNP Comments at 7-8.

regarding the amount of balancing reserves necessary to integrate wind. RNP states in their comments that balancing reserve requirements should be based on hour-ahead wind forecast errors as opposed to day-ahead wind forecast errors.[60] The Company recognizes that errors for day-ahead wind forecasts are expected to be larger than errors for hour-ahead wind forecasts. However, basing balancing reserve requirements on an analysis of day-ahead wind forecast errors more accurately represents how the electrical system is operated in reality in regards to how a utility uses market purchases and sales to keep the system balanced.

Considering the implications of holding a smaller balancing reserve based on the hour-ahead errors in forecast wind demonstrates the appropriateness of using day-ahead errors. The Company is required to cover all deviations between forecast and actual wind production. If the balancing reserves were calculated using hour-ahead errors (and were therefore smaller), then when the system is scheduled day ahead, the dispatchable generators would be scheduled to carry a smaller amount of reserves. This means that the dispatchable generators would have the ability to cover deviations as determined from analysis of hour-ahead forecast errors. However, the dispatchable generators would not be scheduled to allow them to respond to day-ahead forecast errors. This means that the Company would be required to cover these larger errors by some other means, which in Idaho Power's case would too often translate to a risky reliance on the wholesale electric market. Consequently, the prudent simulation of day-ahead system scheduling should ensure dispatchable generators are capable of responding in real time to uncertainty in wind production as determined by analysis of day-ahead forecast errors.

Staff also recommends that Idaho Power continue to use a Technical Review Committee ("TRC") in the preparation of future wind integration studies.[61] The Company

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[60] RNP Comments at 8.

[61] Staff Comments at 4.

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shares the view that the formation of a TRC is an important part of the integration study effort. The Company also notes Staff's comment that the TRC was less engaged than anticipated in the analysis used in the wind integration study underlying the 2013 IRP. The TRC's level of engagement was simply an issue of timing. The Commission directed Idaho Power to form a TRC in February 2012,[62] nearly a year after the Company had already begun work on the wind integration study. Thereafter Idaho Power announced the formation of a TRC at an April 6, 2012, public workshop. However, by this time in the process, the study was nearly complete and the Company was already presenting preliminary study results.

Idaho Power held regular meetings with the TRC following the April 6, 2012, public workshop. In these meetings, a detailed discussion of the study methodology was provided to the TRC. Given the near-completed state of the study at the time of the TRC's formation, Idaho Power and the TRC members agreed the primary role of the TRC would be to issue comments on the study methodology upon release of the study report.

Idaho Power continues to support TRC engagement through its recently initiated solar integration study, which began in August 2013. Idaho Power has solicited engagement from the TRC and observers from Staff of both the Idaho and Oregon Commissions are actively engaged in the study.

I. The 2013 IRP's Modeled Capacity Contribution for Renewable Resources is Appropriate.

ODOE recommends that the Commission direct Idaho Power to calculate the capacity contribution for solar, wind, and hydro resources using the Effective Load Carrying Capability ("ELCC") method.[63] Currently, Idaho Power calculates the on-peak

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[62] Order No. 12-177.

[63] Opening Comments of Oregon Department of Energy at 2-4 ("ODOE Comments").

capacity contribution of all types of resources using a 90-percent exceedance method.[64] Idaho Power' peak-hour demand drives the Company's need for additional capacity and the use of the 90-percent exceedance criterion means there is a 90 percent probability that the specific resource type will contribute to serve Idaho Power's peak-hour demand. For solar photovoltaic ("PV") resources, the on-peak capacity contribution credit of solar PV using the 90-percent exceedance method is calculated to be 32 percent for utility solar PV, and 39 percent for distributed solar PV.[65]

The Commission should approve the continued use of the 90-percent exceedance method. The Company has used this method, without controversy, since its 2002 IRP.[66] Moreover, this method is consistent with the ELCC because it determines the amount of a resource's nameplate capacity that "may be statistically relied upon" to serve peak load.[67] Adoption of ODOE's recommendation is also inconsistent with the Commission's IRP Guidelines because it would require Idaho Power to calculate the capacity contribution for solar, wind, and hydro resources using a different method than the method used for non-renewable resources.[68]

To support its recommendation, ODOE incorrectly suggests that the Company's method uses a capacity factor, rather than measuring the capacity contribution.[69] The

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[64] *See e.g.*, 2013 IRP at 55-56, 83.

[65] 2013 IRP at 84, Table 7.1.

[66] This is also the method that has been approved by the Idaho Public Utilities Commission for calculating the capacity contribution of Qualifying Facilities. *See* Order No. 32802 at 7 (May 6, 2013) ("The Commission further finds that it is just and reasonable to use a 90th percentile capacity factor in peak hour capacity factor calculations. If a QF is to be awarded payment for providing capacity, then the utility must be assured that the planned-on capacity will be available the vast majority of the time. Using a 90th percentile capacity factor minimizes the risk that planned-on capacity may not be available.").

[67] ODOE Comments at 3 (capacity contribution "is the percentage of nameplate value that 'may be statistically relied upon.'").

[68] Order No. 07-002 at 3 (Guideline 1 requires all resources to be "evaluated on a consistent and comparable basis").

[69] ODOE Comments at 3.

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capacity contribution is different from the capacity factor. The capacity factor is the average expected output of a generator and is usually calculated over an annual period. The capacity factor is also expressed as a percentage of the facility nameplate capacity. On the other hand, the capacity contribution that is incorporated into Idaho Power's 2013 IRP represents the amount of output from a resource that may statistically be relied upon to serve peak load, and is expressed as a percentage of the facility nameplate capacity.

The 2013 IRP provides capacity factors calculated by NREL for solar PVWatts at both a south and a southwest orientation.[70] The annual capacity factor of solar calculated by NREL, using all 8,760 hours of the year, is approximately 15 percent. As noted above, the capacity contribution used in the 2013 IRP is more than twice this amount—making clear that the 2013 IRP does not rely on capacity factors to determine a resource's capacity contribution.

J. The Company's Solar PV Modeling is Reasonable.

ODOE expresses concern in their comments that the IRP's analysis of solar resources is too focused on non-tracking systems with a due-south orientation.[71] Idaho Power acknowledges the effect of a southwest orientation, and includes in the 2013 IRP Technical Appendix a comparison of PV generation profiles for Boise, Idaho installations oriented to the south and to the southwest.[72] Timing of generation from the southwest-oriented installations coincides better with customer demand. However, because Idaho Power experiences peak customer demand as late as or after 6:00 p.m. (MDT), installations with a southwest orientation still require large amounts of nameplate capacity to contribute significantly to meeting peak demand.

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[70] 2013 IRP, Appendix C at 93-95.

[71] ODOE Comments at 4.

[72] 2013 IRP, Appendix C at 93-95.

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Idaho Power recognizes that solar as an energy resource comes with options, certainly more options than wind. An analysis exploring solar as an energy alternative must address numerous considerations such as tracking systems (one- or two-axis), resource orientation of non-tracking systems, and materials (c-Si, thin film, etc.). Among the myriad of options, for this IRP, Idaho Power chose to focus on non-tracking systems with a due-south orientation. ODOE's comments note that other resource options (e.g., natural gas) have lower costs for this IRP cycle, acknowledging that the beneficial attributes of southwest-oriented or tracking systems are not likely great enough to overcome these cost differences.[73]

Idaho Power is in agreement with ODOE that solar is a resource deserving further investigation in the future. Idaho Power is currently studying the impacts and costs of integrating solar. This effort will help the Company better understand the attributes of production from solar installations, knowledge which will inform the treatment of solar for the Company's 2015 IRP.

K. Idaho Power is Not Requesting Acknowledgment of its Full Action Plan.

Idaho Power's 2013 IRP includes an Action Plan that analyzes resource actions throughout the entire 20-year IRP planning horizon.[74] CUB recommends against acknowledgement of the entire Action Plan because the Action Plan stretches too far into the future and such long-term forecasts are "inappropriate for Action Plan acknowledgment."[75] While the 20-year Action Plan corresponds to the planning period, Idaho Power requests acknowledgment of only the Action Plan items that occur within the next two to four years, consistent with the Commission's IRP Guidelines.[76] Because the

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[73] RNP Comments at 5.

[74] 2013 IRP at 113; Order No. 07-002 at 5 (20-year planning horizon).

[75] CUB Comments at 4.

[76] Order No. 07-002 at 12; Order No. 12-177 at 6.

IRP reflects planning at a given point in time and must adjust to changing circumstances, "…Idaho Power anticipates that the 2013 IRP Action Plan may be adjusted in the next IRP to be filed in 2015, in the 2013 IRP Update, or sooner if directed by the IPUC or OPUC."[77]

L. The 2013 IRP's Water and Weather Assumptions Include Median Forecasts.

The Company's IRP is based on hydrological generation forecasts developed using worse-than-median streamflow conditions.[78] CUB recommends that the Company's future IRPs also include an additional forecast that is based on expected streamflow conditions.[79] CUB reasons that "[t]his will allow stakeholders to distinguish resource decisions that are caused by load growth from resource decisions that are caused by hydro variability."[80]

Idaho Power agrees with CUB that median forecasting under normal conditions should also be included for comparison within the IRP and the Company has done so in the 2013 IRP. The median or expected case load forecast and the hydrologic modeling results for median water conditions are used to calculate capacity planning margin as shown in chapter 9 of the IRP and are presented in Appendix C -Technical Appendix.[81]

The appropriateness of Idaho Power's planning criteria can be assessed by examining the capacity planning margin calculations shown on pages 107 and 108 of the IRP in chapter 9. The capacity planning margin values are calculated using the median or 50th percentile, peak-hour load forecast as shown in the tables on pages 107 and 108. The capacity planning margin of the preferred resource portfolio varies from a high of 23 percent just after the increased import capacity of B2H is added to the Idaho Power system in 2018, to a low of 13 percent at the end of the planning period in 2032.

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[77] 2013 IRP at 115.

[78] 2013 IRP at 55.

[79] CUB Comments at 5.

[80] CUB Comments at 5.

[81] 2013 IRP, Appendix C at 12-21, 101-110.

M. The Company's Energy Efficiency Measures are Reasonable.

For the 2013 IRP, Idaho Power retained EnerNOC Utility Solutions Consulting to conduct a comprehensive 20-year study of the Company's energy efficiency potential. The study resulted in a forecast of achievable energy efficiency potential that was fully incorporated into the IRP planning process prior to the consideration of any new supply-side resources, which resulted in decreased forecast customer loads across all customer classes. The total energy efficiency forecast including the EnerNOC, Inc. achievable potential plus the additional forecast amount to account for future savings from special contracts totaled 261 aMW over the 20-year IRP planning period.

Staff is concerned that Idaho Power may reduce its support of the Northwest Energy Efficiency Alliance (NEEA).[82] The Company's critical evaluation of its continued relationship with NEEA is reasonable and reflects the Company's commitment to obtain cost-effective energy efficiency solutions for its customers. Staff points out that NEEA savings were more than 10 percent of the Company's energy efficiency savings since 2010.[83] However, these savings have not come without costs. Indeed, since 2002 NEEA energy efficiency savings have increased by 37 percent while NEEA funding has increased 141 percent.

As one of the original funding partners of NEEA in 1997, Idaho Power and its customers have historically found value in a relationship with NEEA. NEEA was created at a time when Idaho Power began to rebuild its Demand Side Management (DSM) portfolio offerings and NEEA has contributed to the increased awareness and adoption of DSM in the region. Over the past 15 years, Idaho Power has continued to build extensive programs and acquired significant energy efficiency savings through customer education and program participation. Idaho Power has gained expertise with program design,

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[82] Staff Comments at 2-3.

[83] Staff Comments at 2-3.

delivery, and evaluation and a good understanding of its customers' energy needs. Idaho Power has a solid understanding of the marketplace and works directly with its customers, as well as the Energy Efficiency Advisory Group, to identify and implement cost-effective solutions that provide the best value for customers.

During 2009, the year leading up to NEEA's current funding cycle, Idaho Power expressed its desire for NEEA to alter how NEEA designed its services and corresponding funding in the 2010 to 2014 business plan. Idaho Power sought to direct its funding toward those activities it believed would bring the most value to its customers. There were some aspects in this funding cycle that Idaho Power supported, such as regional research, especially with emerging technologies, regional training, and their "upstream" work with manufacturers. Idaho Power communicated to NEEA its preference for an alternative funding model that would allow Idaho Power's funds to be directed toward the costs of these supported activities. Idaho Power continues to seek a funding model that maximizes the investment of customer funds for DSM. In the meantime, Idaho Power provided advance notice of its intention to not pursue a commitment with NEEA for the next funding cycle of 2015-2019. Idaho Power will continue to participate in the current 2010-2014 funding cycle and actively participate as currently committed.

N. The Company will Continue to Evaluate Alternatives for Deriving High and Low Gas Price Scenarios.

The Company's high and low natural gas price forecasts were derived by adjusting the base case prices upward and downward by 30 percent.[84] Staff is evaluating this approach and suggests that it may be more reasonable to use asymmetric high and low forecasts because gas prices tend to have more upside risk.[85] The Company maintains that the 30 percent adjustment, even though it is symmetrical, represents a sufficiently

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[84] 2013 IRP at 62.

[85] Staff Comments at 3.

large variation to the planning forecast to provide reasonable bounds to the gas price for purposes of evaluating resource alternatives.[86] This methodology for establishing the high and low gas price scenarios, and the use of these scenarios for the resource alternatives analysis, was presented to the IRP Advisory Council and found to be reasonable. Idaho Power recognizes Staff's concerns regarding the symmetrical natural gas price distribution, and will consider alternatives for deriving high and low gas price scenarios for future IRPs.

O. The Company's Stochastic Inputs and Risk Analysis is Reasonable.

Staff raised a concern about the correlation between natural gas prices and market electricity prices, and a concern about the variability of gas prices across simulations.[87] Based on this concern, Idaho Power performed additional analyses to compare the range of gas prices and market prices simulated in the stochastic analysis. The results are shown in the figure below. Natural gas prices range from $2.00/MMBtu up to $20.00/MMBtu and market prices were simulated ranging from $20/MWh up to nearly $200/MWh. Idaho Power maintains that these ranges are reasonable and that based on the range of simulated gas and market prices that the stochastic analysis did not underestimate the upside risk of market prices as they pertain to the preferred portfolio selection process.

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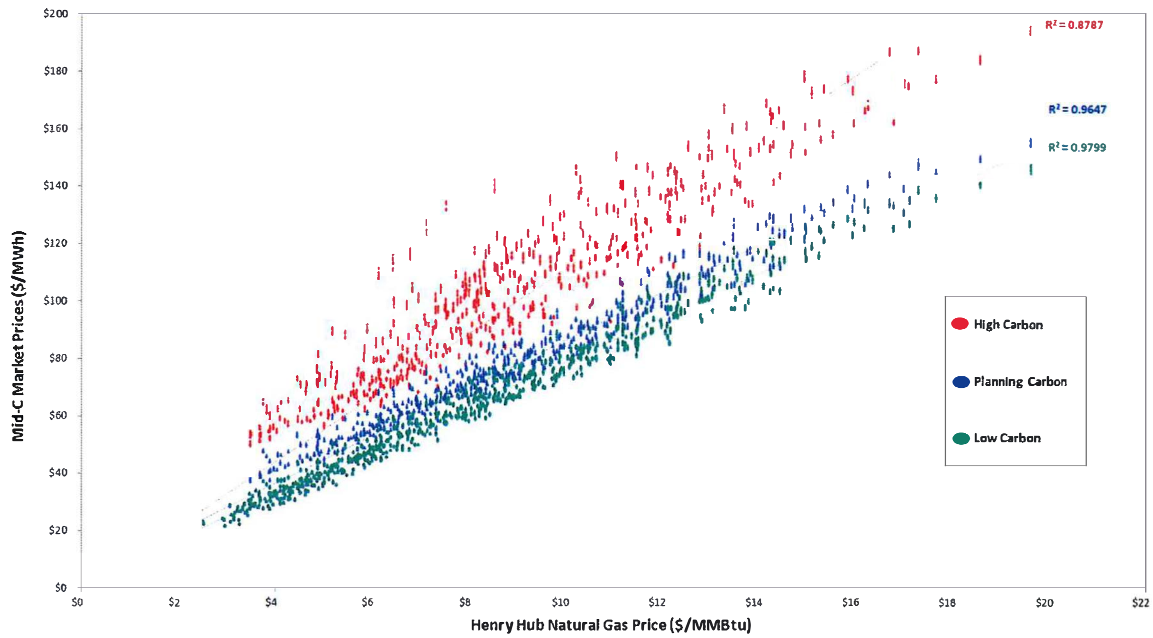
[86] *See* 2013 IRP, Chapter 7.

[87] Staff Comments at 3.



Staff was also concerned that the net present value ("NPV") spread for each portfolio was underestimated.[88] The NPV range for the IRP's portfolios is found in Figure 9.6 on page 104 of the IRP. This figure shows the range of NPVs is large, ranging from less than $2 billion to more than $10 billion (2013 NPV). Idaho Power regards this large range of possible NPVs as a sufficiently rigorous test of the preferred portfolio to the others analyzed in the 2013 IRP; the analyzed risk factors caused portfolio operating costs to vary across a wide range, demonstrating their effectiveness as long-term indicators of portfolio risk.

P. The Company's Reliance on NREL to Establish Resource Costs is Appropriate.

Staff is concerned about the vintage of the NREL data that the Company used to establish its resource cost assumptions.[89] The Company used an NREL report published in 2012 that relied on data from late 2009 and early 2010. Staff specifically mentions the recent drop in solar PV panel costs, suggesting that the resource costs in the NREL report are outdated. Idaho Power shares Staff's view with respect to capturing cost trends, and

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[88] Staff Comments at 3.

[89] Staff Comments at 4.

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recognizes the importance of using accurate resource cost data. However, the Company views the NREL cost report as an appropriate source for resource cost data for the 2013 IRP as it was the best available information at the time cost estimates had to be finalized for the IRP.

Further, the accuracy of the NREL cost data for distributed solar installations is confirmed by the Commission's January 2013 legislative report on the Solar Photovoltaic Volumetric Incentive Program.[90] Summary statistics for Idaho Power customers for 25 small systems installed in 2010-11 show average costs of $5.65 per watt (dc); these costs align well with the IRP's cost estimate of $5,610 per kW.

Q. The Company's Evaluation of Conservation Voltage Reduction (CVR) is Consistent with the Commission's Requirement in Order No. 12-177.

In Order No. 12-177 the Commission required Idaho Power to include in its next IRP: (1) an assessment of the available cost-effective CVR resource potential in Idaho Power's service area; (2) a proposed action item related to CVR; and (3) the planned energy savings and reduced peak demand in the Company's load-resource balance forecasts.[91] Staff claims that Idaho Power has not satisfied these requirements because, according to Staff, the Company has not included in the IRP an assessment of the available cost-effective CVR resources. However, as described in the 2013 IRP, the Company is in the process of conducting this assessment now.[92] Idaho Power believes that it is in the interest of its customers to more accurately identify the benefits and risks of the CVR program before Idaho Power expands the CVR program to other facilities where the implementation costs are greater.

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[90] http://library.state.or.us/repository/2013/201301101142514/

[91] Order No. 12-177 at 5.

[92] 2013 IRP at 45.

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By way of background, Idaho Power participated in the NEEA Distribution Efficiency Initiative (DEI) Project in 2007. Idaho Power's participation involved implementing CVR at a single substation in the Boise area. The study involved a "one day on – one day off" CVR control and measurement method. In other words, the CVR controls were used every other day so that their impact could be compared to the days where the CVR controls were off. The Company was then able to use the data from the "one day on – one day off" to estimate a range of CVR factors for the Boise substation.

Since 2007, Idaho Power has expanded the CVR program to other substations with minimal capital expense. To date, low cost CVR implementation has involved changes to substation transformer load tap changer controller settings without end-of-line voltage monitoring. However, additional CVR implementation will require significant distribution feeder upgrades that will not be undertaken until thorough cost-effectiveness analysis has been conducted and this analysis requires the use of validated CVR factors. The CVR factors calculated in the NEEA DEI Project, discussed above, were specific to the one urban substation that was involved and cannot serve as the basis for evaluation a more expansive CVR program. Moreover, the DEI Project was limited and did not account for weather influences and load characteristics representative of the entire Idaho Power system. The cost effectiveness for any substation across the Company's service area should be based on valid CVR factors incorporating local weather and load characteristics.

In the process of assessing available potential cost effective CVR resources, the Company has encountered several unanticipated obstacles that delayed the process. For example, due to technological limitations, the Company was unable to measure the actual peak reduction or energy savings of the current CRV implementation. In addition, the Company has been unable to monitor actual customer voltages along the feeder. Therefore, customer voltages remain unknown during peak load or abnormal system configurations. During abnormal system conditions, switching the loads between CVR and non-CVR feeders adds complexity to the reliable operation of the distribution system.

The Company is currently utilizing new technologies and methods of measurement that are now available to assess the energy savings and reduced peak demand, in an effort to further validate CVR benefits. For example, by January 2014 the Company expects to have weather normalized hourly load data from 2011 and 2012. In addition, daily voltage readings for a limited number of meters are now available through the Company's advanced meter infrastructure (AMI). The Company is also now able to better characterize load and measure actual energy and power reductions with CVR through substation meter functionality. Finally, the Company is evaluating new distributed Volt/VAr equipment that can improve a feeder voltage profile and provide a more effective implementation of CVR.

With the understanding that the new technologies and methods can mitigate the obstacles described above, Idaho Power proposes the following course of action for assessing potential cost-effective CVR resources:

- Validate the benefit, reduced peak demand and energy savings, of the existing CVR program before expanding it beyond the initial area,
- Analyze two existing CVR substations load characteristics, quantify CVR effects on the load and calculate their CVR factors,
- Determine CVR factors for each geographic region of the service area,
- Pilot new volt/VAr technologies that improve feeder voltage profiles,
- Proceed with a volt/VAr optimization research project, and
- Complete the existing CVR analysis by 2016 in preparation for extending the CVR measures to other Idaho Power facilities.

III. CONCLUSION

The Company appreciates the opportunity to file these comments and respond to concerns and issues raised by Staff, CUB, ODOE and RNP. The Company requests that the Commission acknowledge its 2013 IRP, including its Boardman to Hemingway preferred portfolio.

Respectfully submitted this 8th day of November 2013.

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CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing documents in Docket LC 58 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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