**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**LC 58**

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| In the Matter of<br><br>IDAHO POWER COMPANY<br><br>2013 Integrated Resource Plan | STAFF'S FINAL COMMENTS |

**Introduction**

Below are Staff's final comments and recommendations related to the Idaho Power 2013 Integrated Resource Plan (IRP). Staff discusses its analyses and the bases for its recommendations. In its public meeting memo, and in the proposed order, Staff will provide a comprehensive summary of parties' positions, including final comments.

As a general matter, Staff makes recommendations to the Commission regarding specific resource action items, as well as on other issues relevant to the IRP development process. Staff typically does not recommend acknowledgment of actions that fall within the scope of typical utility planning and regulatory activities (e.g., conduct wind integration study, file 2015 IRP). However, activities such as planning and regulatory filings for major projects may merit an acknowledgment-level recommendation due to the magnitude of the workload and costs incurred prior to construction and deployment of that specific resource.

In the Action Plan Items section below, Staff makes specific acknowledgment recommendations only for the resource actions proposed for the next two to four year period, consistent with the IRP guidelines.[1,2]

Staff recommends that the Commission acknowledge Idaho Power's 2013 IRP with action plan items (some revised) as reflected below.

**<u>Transmission Action Plan Items</u>**

The Company's action plan contains two items for Boardman to Hemingway (B2H), and one for Gateway West. In its November 8, 2013 reply comments, Idaho Power states that, "the Company again requests acknowledgement of the 2013 IRP, which includes

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[1] Order No. 07-047, Appendix A, Guideline 4(n), Plan Components: "An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP…"

[2] Action plan items are grouped and numbered for reference (the Company's action plan items are not numbered).

B2H in the preferred portfolio."[3] Staff believes this statement is confusing with regard to Oregon's view of IRPs, portfolios, and specific action items. Although Staff recommends that the Commission acknowledges the IRP, such acknowledgment is not acknowledgment of the acquisition of all resources or any particular resource in the IRP's preferred resource portfolio. Acknowledgment of the acquisition of a particular resource is done through the acknowledgment of a specific action item.

Staff addresses the Boardman to Hemingway action items as 1a and 1b below, followed by the Gateway West action item.

**<u>Item 1a</u>: Boardman to Hemingway - Ongoing permitting, planning studies, and regulatory filings (2013–2018)**

In its order regarding Idaho Power's 2011 IRP the Commission stated that it "acknowledge(d) Action Item 7 requiring the company to continue to make progress on the B2H transmission project as an uncommitted resource."[4] The ordering language states that the 2011 IRP "is acknowledged with conditions and exceptions contained in this order, with the action items and recommendations summarized in Appendix A."[5] Appendix A contains the following action item:

> Action Item 7 – Transmission – Continue to make progress on the Boardman to Hemingway project between now and the completion of the 2013 IRP, and plan to begin work on permitting and initial designs shortly after the completion of the 2013 IRP.
>
> As the Company proceeds with the B2H project, its project assumptions (for example, construction cost estimates, equity partnership estimates, third-party subscription estimates, and wheeling revenues) will be updated and analyzed in the 2013 IRP.

Subsequent to the filing of the 2011 IRP, the Company entered into a joint funding agreement with PacifiCorp and Bonneville Power Administration (BPA) for the permitting costs of the project.[6] Idaho Power's share of B2H capacity and permitting cost allocation is 21 percent. An agreement for allocation of construction costs has not been executed.

B2H was included in five of the nine portfolios modeled in the 2013 IRP. The preferred portfolio and the next lowest "total costs portfolio" both included B2H.[7] The Company used the costs and benefits for its share of the project in its modeling. Net variable costs associated with wholesale power transactions are included in the analysis. These

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[3] Idaho Power Company's Reply Comments, LC 58, November 8, 2013, p. 2.
[4] Order No. 12-177, p. 4.
[5] Id., p. 9.
[6] 2013 IRP, p. 77.
[7] 2013 IRP, p. 98.

analyses are sufficient for Staff to recommend acknowledgment of the ongoing permitting, planning studies, and regulatory filings activities for B2H.
Data request No. 22 asked about the impact of B2H on the expected level of wind curtailment. In its response, the Company states that curtailment may be necessary in periods of low demand to balance generation with customer load, and that, "The expectation is that regional demand for energy is also low during these circumstances, and consequently B2H is not likely to significantly impact the level of wind generation curtailment." Staff would like the Company to explore this assertion further in its next wind integration study, along with the impacts of B2H on resource integration costs in general. Staff expects that even during low load periods, there will be benefits to load and variable resource diversity that are made possible by new regional transmission, sub-hourly scheduling, and new Energy Imbalance Markets (EIMs) within the Western Electricity Coordinating Council region. As indicated in the Company's 2013 IRP, "regional transmission allows the region to share regulation and provides capacity to help integrate intermittent resources…"[8]

Staff recommends acknowledgment of action plan item 1. In addition, Staff requests that the Company keep Staff apprised of the following three items during the interim period between Commission acknowledgment of the 2013 IRP and the filing of the 2015 IRP: 1) an updated project plan incorporating changes due to the referenced Bureau of Land Management delays and Energy Facilities Siting Council developments; 2) any final agreements on sharing of construction costs; and, 3) any significant regulatory decisions that impact the project schedule.

**<u>Item 1b</u>: Boardman to Hemingway - Transmission line complete and in service (2018)**

The Company states that, "Recent developments in the permitting process that occurred after the IRP was filed last June have delayed the expected on-line date until 2020."[9] This uncertainty places the completion of B2H beyond the timeframe for which Staff would typically make a recommendation for acknowledgement of a resource action.

As stated above in Item 1a, Idaho Power's partners in the development of B2H, PacifiCorp and BPA, are committed to share in the permitting costs of the project. However, those entities have not yet committed to sharing in the construction costs. Staff expects that B2H will be included in a subset of the Company's IRP portfolios in the 2015 IRP, and that the analysis will be based on updated project costs, partner commitments to shares of the construction costs, and updated project milestones. Staff believes that the current level of uncertainty regarding those aspects of B2H is

[8] IRP, p 71.
[9] Idaho Power Company's Reply Comments at 2: "Recent developments in the permitting process that occurred after the IRP was filed last June have delayed the expected on-line date until 2020." (per footnote: "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.")

significant. Therefore, Staff does not recommend acknowledgement of action plan item 6.

**Item 2: Gateway West - Ongoing permitting, planning studies, and regulatory filings (2013-)**

Gateway West is a multi-segment, multi-year joint transmission project between Idaho Power and PacifiCorp/Rocky Mountain Power. Idaho Power has an interest in specific segments as described on page 79 of the IRP.[10] Staff's final comments in PacifiCorp's IRP recommended continued permitting of specific segments of Gateway West, including Segment E, Populus to Hemingway.[11]

Data request (DR) 32 from Staff to the Company asked for financial analysis, cost-benefit analysis, economic analysis, and a detailed description of any analyses supporting each benefit. Idaho Power provided a confidential response that included project costs and other qualitative information, but no quantification of project benefits. The limited information available to Staff for Gateway West contrasts with the significant amount of cost and benefit information for B2H, as described above in Item 1a.

The information provided by the Company is not sufficient for Staff to recommend acknowledgment of ongoing permitting, planning studies, and regulatory filings for Gateway West. Therefore, Staff does not recommend acknowledgment of action plan item 2.

## Coal Resource Action Plan Items

The IRP contains five action plan items related to coal resources, which Staff references as items 3 through 7 below.

**Item 3: North Valmy Unit 1 - Commit to the installation of dry sorbent injection emission-control technology (2013)**

From Staff's review of the IRP analysis and its confidential coal investments study,[12] it is clear that since Dry Sorbent Injection equipment (DSI) is a relatively small investment (Idaho Power's share is estimated to be between $5 and 10 million),[13] it is not the deciding factor on whether North Valmy Unit 1 (NV1) should continue to run as a coal-fired unit, be converted to a gas-fired unit, or be retired. The real drivers of the decision are gas prices, carbon prices, and the requirement of *additional* (potentially much more

[10] IRP, p. 79, "Idaho Power has a one-third interest in the segments between Midpoint and Hemingway, Cedar Hill and Hemingway, and Cedar Hill and Midpoint. Further, Idaho Power has sole interest in the segment between Borah and Midpoint, which is constructed as a 500 kW-line presently operating at 345 kV. The 345 kV line will be converted to 500 kV operation in the future."
[11] LC 57, Staff final comments, January 10, 2014, p. 18.
[12] LC 53, 2011 IRP Update, "Coal Unit Compliance Upgrade Investment Evaluation." February 8, 2013.
[13] This range is from a February 2013 coal study presentation to the IRP Advisory Council. Specific cost information is in the confidential coal investment report.

expensive) environmental retrofits. Forecasted gas prices will remain uncertain. Accordingly, it is resolution of some of the uncertainty regarding carbon prices and future environmental retrofit requirements that should make the conversion/retirement decision at NV1 more straightforward.

To illustrate this point, Staff notes that under the base case future and a number of others (including every high gas price future and every no carbon price future), installing the DSI and continuing to fire the plant with coal is the least cost option. However, under all scenarios where Selective Catalytic Reduction (SCR) equipment and Wet Flue Gas Desulfurization (WFGD) are also required (Idaho Power's "Enhanced Upgrade" scenarios), and under various scenarios that have some combination of low gas prices and high carbon prices, converting the unit to a gas-fired unit is the least cost option. Under no scenario is the DSI investment large enough to tip the scale one way or another. Therefore, even when one uses a cumulative investment analysis, the decision to convert or retire the plant is not affected by the DSI investment.

Because the price tag for DSI is relatively small, it is tough to argue that customers would be overly burdened by the cost of the DSI investment even if a policy is enacted after the DSI is installed that makes converting/retiring the plant the prudent decision. And, even though there is some risk of investing in this retrofit when it is possible the plant will ultimately be converted or retired early, it is also possible that the increase in carbon prices or more stringent regulations do not materialize, making continued operation of the plant the prudent option. Since the investment to convert or retire the unit is larger than the DSI investment, customers' rate burden in this case from "misplaced" investment would likely be larger if the unit were converted/retired now than if the DSI is installed and the plant is converted/retired thereafter.

Staff has also assessed the issue of the expected retirement date of the North Valmy Plant if it continues to fire as a coal unit. While Staff agrees with CUB that changing the useful life of plants changes the useful life of environmental investments, this issue is not a large enough concern to change the conclusion of the analysis in this particular case.

In summation, DSI installation on NV1 will allow IPC to "buy time" at a very reasonable price so that the decision to convert or retire the unit can be addressed at a future date with more certainty about carbon policy and the need for additional environmental retrofit investments. As such, the DSI investment is better seen as expectation that a more informed decision can be made in the future than an expectation that continuing to burn coal at NV1 until its expected retirement date is the least cost/least risk option for Oregon customers.

Staff recommends acknowledgment of Action Item 2.

**<u>Item 4</u>: Jim Bridger Units 3 & 4 - Commit to the installation of selective catalytic reduction emission-control technology (2013)**

Staff's assessment is that the Company has substantially complied with the Commission's requirement in Action Item 11 from LC 53, Idaho Power's 2011 IRP, from Order No. 12-177:

> Action Item 11 - Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants
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> 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 its confidential coal investment report,[14] the Company evaluated several scenarios with respect to the SCR investment at Jim Bridger Units 3 and 4 (JB 3 & 4): SCR equipment installation; retiring and replacing with a gas-fired combined cycle combustion turbine; and conversion to natural gas (refiring or converting satisfies the shut down option required in Order No. 12-177). Scenarios were evaluated on different carbon and gas sensitivities.

Due in part to differing interpretations of the requirements in the order between Staff and Idaho Power, and due to the timing of the consultant's analysis, certain alternative scenarios were not included. For example, Staff expected the Company to consider alternatives consisting of installation of reduced environmental controls (but not zero controls) in exchange for an early shut down. This analysis would be based on tradeoffs between alternatives as quantified by tons of emissions and the respective changes in capital costs. Staff provided an example of this kind of alternative approach, based on installation of selective non-catalytic reduction (SNCR), in data request number 62(b) in the Company's 2011 IRP Update, filed in February 2013.

Staff recognizes that there are constraints inherent in being a minority owner of a generation resource, and believes that while there is room for improvement, the Company's independent coal investment analysis was adequate based on what was known at the time. However, Idaho Power will need to fully engage with Staff and stakeholders in a timely manner when designing coal investment analyses for future IRPs in order to ensure that an appropriate set of scenarios is included.

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Staff reviewed Idaho Power's coal investment report, and performed an independent sensitivity analysis on the economics of the capital investments at JB 3 and 4 under varying carbon and gas prices. Extensive analysis has also been performed on this

[14] LC 53, 2011 IRP Update, "Coal Unit Compliance Upgrade Investment Evaluation." February 8, 2013.

financially significant investment in PacifiCorp's IRP (LC 57) in the context of PacifiCorp's fleet of coal plants and its other resources. In Staff's final comments in LC 57,[15] Staff recommends acknowledgement of PacifiCorp's Bridger 3 and 4 SCR investments, while expressing concerns with gaps in PacifiCorp's analysis of investments at different units and its coal fleet as a whole.

On January 10, 2014, the EPA published its decision on Wyoming's State Implementation Plan confirming the requirement to add SCR technology to Jim Bridger units 3 and 4 by December 31, 2015 and December 31, 2016, respectively.[16] This removes uncertainty regarding the timing and level of control required at these two units. Therefore, Staff's position with regard to this investment is not changed by the information released by EPA.

Staff recommends acknowledgment of Action Item 4.

**<u>Item 5</u>: Jim Bridger Unit 2 - Commit to the installation of selective catalytic reduction emission-control technology (2019)**

and

**<u>Item 6</u>: Jim Bridger Unit 1 - Commit to the installation of selective catalytic reduction emission-control technology (2020)**

Action items 5 and 6 occur beyond the timeframe for which Staff would typically make a recommendation to the Commission on acknowledgement of a resource action. Staff does not recommend acknowledgment of action plan items 8 and 9.

Staff recommends that the Commission reiterate the requirement for the Company to perform a full analysis of the economics and risks of the SCR investment at Jim Bridger 1 and 2, in accordance with the coal plant analysis expectations established in LC 53. In addition, Staff expects that Idaho Power, as the minority owner of the Jim Bridger plant, will fully engage with the majority owner's analysis of the different options that will be available at Jim Bridger Units 1 and 2 well in advance of the date that investment commitments will be required.

As with Jim Bridger Units 3 and 4, the EPA's decision on Wyoming's State Implementation Plan removes considerable uncertainty regarding the timing of potential investments to mitigate regional haze.[17] Prior to the issuance of its 2015 IRP, Idaho Power should ensure that the best information regarding greenhouse gas and other

[15] LC 57, Staff final comments, January 10, 2014, p. 8.
[16] EPA-R08-OAR-2012-0026, FRL9905-42-R08, Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze, January 10, 2014.
[17] EPA-R08-OAR-2012-0026, FRL9905-42-R08, Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze, January 10, 2014.

regulation is incorporated into the analysis (e.g., EPA's upcoming carbon pollution standards for existing power plants[18]).

**<u>Item 7</u>: Boardman - Coal-fired operations at the Boardman plant are scheduled to end by year-end 2020**

Idaho Power assumed that its share of the Boardman plant would not be available after December 2020 in its 2011 IRP, and the same assumption is carried forward into in the 2013 IRP. Staff recognizes the upcoming change, but this item does not meet the criteria for a resource action for which Staff would typically make a recommendation to the Commission. Therefore, Staff does not recommend acknowledgment of action plan item 7.

**<u>Other Action Items</u>**

**<u>Item 8</u>: Demand response - Have demand response capacity available to satisfy deficiencies up to approximately 150 MW. 2016–2017**

In UM 1653, the Commission addressed the redesign of Idaho Power's demand response programs for 2014 and beyond. Settlements were reached in UM 1653,[19] and in IPC-E-13-14 in Idaho, stating that the annual value of demand response is equal to the levelized annual cost of the minimum size deferred resource, or 170 MW.[20] Therefore, Staff proposes a change to this action plan item as follows:

> *5. Demand response: ~~Have demand response capacity available to satisfy deficiencies up to approximately 150 MW. 2016–2017~~ Include 170 MW of demand response capacity resource available beginning in 2014.*

Staff recommends that the Company update its assessment of demand response availability based on summer 2014 program participation and other relevant factors, by the end of 2014. The Energy Efficiency Advisory Group (EEAG) should review any revisions to the resource assessment, along with other relevant factors.[21]

The 170 MW demand response capacity resource should be included in the load/resource balance calculations as part of the 2015 IRP development process.

Staff recommends acknowledgment of Action Item 8 as revised.

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[18] http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.
[19] UM 1653, Investigation into Demand Response Programs, Staff and Oregon parties also participated as an observer in a parallel Idaho PUC case, IPC-E-13-14.
[20] Order No. 13-482 in UM 1653.
[21] Id., Appendix A: "The annual value calculation will be updated with each IRP based on changes that include, but are not limited to need, capital cost, or financial assumptions,"

**<u>Item 9</u>: Shoshone Falls - Shoshone Falls upgrade complete and in service. 2019**

The Shoshone Falls Upgrade replaces two turbine units at the 12.5 MW project that results in a net upgrade of 49 MW to 61.5 MW total. This upgrade has been included as a committed resource in the last several IRPs. In the 2009 and 2011 IRPs, this resource was scheduled to be complete in 2015. Idaho Power notified the Integrated Resource Planning Advisory Committee during the planning process for this IRP that the project is delayed and that the Company plans to ask FERC for another two year extension of the construction start date, from 2014 to 2016. If Idaho Power begins construction in 2016, the Company plans to have the additional capacity from the upgrade available starting 2019.

Staff does not regard the acknowledgment of resource actions in one IRP as endowing a permanent "committed resource" status. The fact the Commission acknowledged the Shoshone Falls upgrade for 2015 in a previous IRP does not obviate the need for analysis of the yet-to-be constructed project, particularly if the completion date is postponed by four years.

However, in this IRP, Idaho Power asks for acknowledgment of the upgrade's completion in 2019, which is beyond the timeframe for which Staff would typically make a recommendation for acknowledgement of a resource action. Accordingly, Staff does not recommend acknowledgment of Action Item 7. Staff recommends that the Company incorporate in its 2015 IRP a full economic analysis of Shoshone Falls upgrade, including updated costs, market forecasts, Renewable Energy Certificate prices, and status of water issues. Idaho Power notes in its IRP that it intends to complete such an analysis prior to asking for a Certificate of Public Convenience and Necessity with the IPUC.[22]

**<u>Item 10</u>: Demand response - Have demand response capacity available to satisfy deficiencies in 50-MW increments up to approximately 370 MW in 2031. 2024–2032**

This item is beyond the timeframe for which Staff would typically make a recommendation to the Commission on acknowledgement of a resource action. Therefore, Staff does not recommend acknowledgment of Action Plan item 11.

With regard to demand response resource availability, Staff expects that the fruitful process the Company engaged in with its stakeholders in the demand response program redesign cases during 2013 will be continued with the EEAG, and with other stakeholders as needed.

[22] 2013 IRP, p. 36.

## Other Issues

### Gas/Electricity Prices

Staff supports the Company's choice (as directed by the Idaho Commission) to use the Energy Information Administration (EIA) reference case gas price forecast from the Annual Energy Outlook (AEO) as its base case gas future. However, Staff is concerned that rather than using the latest vintage of the nominal EIA projection of prices at Henry Hub for its analysis, the Company used the real EIA gas forecast prices and escalated this real forecast in each future year by compounding its own, higher inflation rate. The result is that the Company's nominal prices, beginning in 2014, are significantly higher than EIA's.[23] This has significant potential to bias the results. Staff expects that the Company will use the nominal forecast in its 2015 IRP, or provide a rationale for using a different method.

Staff continues to be concerned with the high correlation in the Company's modeling between its natural gas prices and wholesale electricity prices. Staff's analysis shows that the correlation used by Idaho Power is significantly stronger than the actual correlations over the last five years. Staff believes this exaggerated correlation contributes to the result that the same portfolio is lowest cost in each of the 102 possible futures for which the Company simulated PVRRs. Staff recommends that the gas-to-electricity price correlation used in IPC's modeling for the 2015 IRP be brought closer in line with actual historical data.

### Energy Efficiency

As with other utilities in the region, and the Energy Trust of Oregon, Idaho Power's avoided energy cost is lower now than it was in the previous IRP. Staff is working with the Company, mainly via the EEAG, to evaluate the impacts of market changes and make program decisions that balance the need to keep programs viable with the less favorable economics of the revised avoided cost.

Staff is not persuaded by Idaho Power's argument regarding Northwest Energy Efficiency Alliance (NEEA) participation and funding. As noted in its reply comments, the Company is one of NEEA's original funders.[24] This means that Idaho Power has been a NEEA Board member since 1997. As a long standing Board member, Idaho Power has significant opportunity to help design NEEA initiatives and field work. If part of Idaho Power's decision to leave NEEA steams from concern over NEEA's program implementation, Idaho Power has had ample opportunity to help shape NEEA's programs.

[23]As indicated in the response to data request number 14, Idaho Power's nominal price at Henry Hub in 2032 is $12.61/mmBtu. EIA's Henry Hub price in the 2012 Annual Energy Outlook for 2032 is $9.81/mmBtu. EIA"s growth rate from 2010 to 2035 for Henry Hub prices is 2.1 percent, in contrast to Idaho Power's 3.0 percent.
[24] LC 58, Idaho Power Company's Reply Comments, November 8, 2013; p. 26.

Staff understands that NEEA is a regional cooperative effort, an alliance of interests. As a long standing NEEA Board member, Idaho Power understands that NEEA's value is in part based on regional value delivery to utilities with varying levels of energy efficiency program maturity. Idaho Power is aware that different utilities find different value propositions for their participation and funding of NEEA. That is, not all NEEA programs serve all utilities equally, but as long as NEEA remains cost effective, the funding of NEEA remains reasonable and beneficial to Idaho Power's ratepayers. In addition, NEAA savings attributed to Idaho Power's service area are very cost effective.

As Idaho Power is also aware, NEEA was created to aggregate and leverage to collective power of the region to influence larger and broader consumer markets, known as market transformation. Such consumer markets are not easily influenced by any single utility nor responsive to a single utility's energy efficiency interests. Thus the region, building on the collaborative successes demonstrated by the Northwest Power and Conservation Council and the Regional Technical Forum, created NEEA to address upstream consumer markets, and to influence the marketplace and the mix of available energy efficiency products and practices.

When one member of this unique alliance looks to detach from this regional collaborative effort, that member risks the benefits that accrue to not only its own ratepayers but other ratepayers of utilities that contribute to the Alliance. These include other Idaho utilities, Bonneville Power Administration and Oregon ratepayers served by PacifiCorp and PGE. By proposing to defund NEEA, Idaho Power jeopardizes the cost effective energy efficiency savings provided by NEEA to Oregon's other ratepayers, and the investments made by other NEEA funders. Additionally, market transformation work influences broad markets, markets greater than any one utility service territory. For example, NEEA has influenced the development and deployment and market uptake of ductless heat pumps. NEEA has worked with national retailers to carry this product. These retailers will not simply forego stocking the product just in Idaho Power's service territory. This is similar with NEEA's Energy Efficient Television Initiative or other soon to be deployed residential commercial product initiatives being developed by NEEA in collaboration with the region. By leaving NEEA, Idaho Power would become a free rider and benefit from the investments made by other utility ratepayers, without sharing in the costs.

Idaho Power notes that, "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."[25] Idaho Power's own *Demand Side Management 2012 Annual Report*[26] shows that much of Idaho Power's energy efficiency program build out was a direct result of their investment in NEEA. In 2002 NEEA accounted for roughly 77% of Idaho Power's programmatic savings activity, then 64% in 2003, 69% in 2004, 43% in 2005, 28% in 2006, 31% in 2007, and so on. In total from 2002 – 2012, NEEA savings alone accounted for over 18% of Idaho Power's energy efficiency savings.

[25] LC 58, Idaho Power Reply Comments at 26, November 8, 2013.
[26] *Demand Side Management 2012 Annual Report,* p. 156.

A further look at Idaho Power's energy efficiency programs evidences NEEA's influence on Idaho Power's program design, implementation and program genesis. Its residential *Energy Efficiency Lighting* program is directly related to the regional collaboration conducted with and through NEEA to influence the design and availability of compact florescent lamps in the Northwest and Idaho's retail marketplace. Idaho Power's own submitted description of the *Energy Efficiency Lighting* program is replete with references to NEEA's work including NEEA's recent *2011 Residential Building Stock Assessment: Single-Family Characteristics and Energy Use* study.[27] *Energy Star Homes Northwest* is a program initiated by NEEA and conducted in partnership with Idaho Power.[28] The program's upstream work influenced the U.S. Environmental Protection Agency to create a Northwest-specific energy efficient home building specification,[29] which in turn promoted the use of a building guideline among home builders in the region, including Idaho Power's service territory, and influenced building code development in Idaho and the region.[30]

Idaho Power's *Home Products Program* is a "midstream incentives offer"[31] meant to influence consumer appliance purchase choices. Yet, without Idaho Power's participation in NEEA and NEEA's work upstream to develop specifications for products such as Energy Star clothes washers and water heaters, the much needed upstream aspect would be missing. Arguably the program would be less effective and less cost effective without Idaho Power's participation in the NEEA partnership.

Idaho Power's *Rebate Advantage*, a manufactured homes program, is built on the work of the Northwest Energy Efficient Manufactured (NEEM) housing program.[32] NEEA created the first specification used by NEEM and was a founding member of NEEM. Idaho Power's *Building Efficiency* program is in part coordinated and supported through NEEA's BetterBricks program.[33] Idaho's Integrated Design Lab, "which provides technical assistance"[34] for the *Building Efficiency Program*, was initiated and is currently significantly funded by NEEA.

Lastly, Idaho Power's *Custom Efficiency Program* is built on the concepts of Strategic Energy Management, a product and strategy originally developed by NEEA and piloted, tested and refined by NEEA in Idaho Power's service territory in collaboration with J.R. Simplot, Con Agra Foods, Basic American Foods and others.

When Staff looked yet closer at Idaho Power's total suite of energy efficiency programs, it became clear that those programs influenced, initiated, conducted or developed in partnership with NEEA have higher cost effectiveness ratios than the totality of programs developed exclusively by Idaho Power. Given this, and the history of

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[27] See Idaho Power Company, Demand –Side Management 2012 Annual Report, at p.35
[28] Id at p.37
[29] Id
[30] Id at p. 41-43.
[31] Id at p.51
[32] Id at p. 57
[33] Id at p. 77
[34] Id.

collaborative program development with NEEA, Staff is concerned that part of Idaho Power's justification for leaving NEEA is that Idaho Power's expertise in program design has matured enough to not need to fund NEEA.[35] This seems counter to the evidence provided by Idaho Power in its *Demand-Side Management 2012 Annual Report*. Further, because so many of the programs offered by Idaho Power were or are influenced, initiated, conducted or developed in partnership with NEEA, Staff is concerned that by leaving NEEA, Idaho Power's pipeline of energy efficiency products, practice and programs will become significantly less robust.

Taken in totality, the energy savings acquired through NEEA over the years, the programs currently offered by Idaho Power that were influenced or initiated by NEEA, the broader market influence and leverage offered by NEEA, and the regional collaborative cost sharing nature of the Alliance, Staff is at a loss as to why Idaho Power would want to discontinue funding NEEA.

## 2013 IRP Action Plan: Summary of Staff Recommendations

| **Action Item #[36]** | **Dates** | **Summary** | **Staff recommendation** |
|---|---|---|---|
| Item 1a. | 2013–2018 | Boardman to Hemingway: Ongoing permitting, planning studies, and regulatory filings. | Staff recommends acknowledgment |
| Item 1b. | 2013– | Gateway West<br>Ongoing permitting, planning studies, and regulatory filings. | Staff does not recommend acknowledgment |
| Item 3. | 2013 | North Valmy Unit 1<br>Commit to the installation of dry sorbent injection emission-control technology. | Staff recommends acknowledgment |
| Item 4 | 2013 | Jim Bridger Units 3 & 4:<br>Commit to the installation of selective catalytic reduction emission-control technology. | Staff recommends acknowledgement |

[35] Supra Note 1 at 26.
[36] The summary table lists action items in same order as pages 9 and 113 of the IRP. Numbering was applied by Staff for ease of reference between comments and the summary table.

| Action Item #[37] | Dates | Summary | Staff recommendation |
|---|---|---|---|
| Item 8. | 2016–2017 | Demand response:<br>Have demand response capacity available to satisfy deficiencies up to approximately 150 MW. | Staff recommends acknowledgment of revised action item:<br>*5. Demand response: ~~Have demand response capacity available to satisfy deficiencies up to approximately 150 MW. 2016–2017~~ Include 170 MW of demand response capacity resource available beginning in 2014.* |
| Item 1b. | 2018 | Boardman to Hemingway<br>Transmission line complete and in service. | Staff does not recommend acknowledgment |
| Item 9. | 2019 | Shoshone Falls:<br>Shoshone Falls upgrade complete and in service. | Staff does not recommend acknowledgment |
| Item 5. | 2019 | Jim Bridger Unit 2:<br>Commit to the installation of selective catalytic reduction emission-control technology. | Staff does not recommend acknowledgment |
| Item 6. | 2020 | Jim Bridger Unit 1:<br>Commit to the installation of selective catalytic reduction emission-control technology. | Staff does not recommend acknowledgment |
| Item 7. | 2020 | Boardman:<br>Coal-fired operations at the Boardman plant are scheduled to end by year-end 2020. | Staff does not recommend acknowledgment |
| Item 10. | 2024–2032 | Demand response:<br>Have demand response capacity available to satisfy deficiencies in 50-MW increments up to approximately 370 MW in 2031. | Staff does not recommend acknowledgment |

[37] The summary table lists action items in same order as pages 9 and 113 of the IRP. Numbering was applied by Staff for ease of reference between comments and the summary table.

This concludes Staff's Final Comments.

Dated at Salem, Oregon, this 15th day of January, 2014.

Brittany Andrus
Sr. Utility Analyst
Energy Resources & Planning

CERTIFICATE OF SERVICE

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I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 15th day of January, 2014 at Salem, Oregon

Kay Barnes

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