**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

LC 63

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| In the Matter of<br><br>IDAHO POWER COMPANY, 2015<br><br>Integrated Resource Plan; | Staff's Final Comments |

Staff of the Public Utility Commission of Oregon (Staff) presents its Final Comments on Idaho Power Company's (Idaho Power or Company) *2015 Integrated Resource Plan* (IRP). Staff discusses its analyses and the bases for its recommendations. The Final Comments are separated by subject area and will be presented as follows:

I. Idaho Power's Adherence to Oregon Commission IRP Guidelines
II. Idaho Power's Compliance with Order No. 14-253 (Docket No. LC 58)
III. Action Plan Discussion
IV. Other Items
V. Conclusion and Summary of Recommendations

## I. Idaho Power's Adherence to Oregon Commission IRP Guidelines

Commission Order No. 89-507 established the guidelines for the IRP process. These guidelines were subsequently amended, most notably in Order No. 07-002. These Orders guided Staff in its review of the Company's IRP. As explained in these Final Comments, Staff finds that Idaho Power has complied with most, but not all, of the guidelines.

1. <u>Order 07-002 Guideline 1: Substantive Elements</u>

1. *All resources must be evaluated on a consistent and comparable basis.*
2. *Risk and uncertainty must be considered.*
3. *The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.*
4. *The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.*

Staff believes that Idaho Power's inclusion of customer-owned solar photovoltaic (PV) systems' capital expenditures in the Company's supply-side resource analysis does not comport with Section 1 of Guideline 1 because the results are inherently inconsistent and incomparable and do not reflect the realities of customer-owned resources.

Furthermore, such a classification is contrary to the very purpose of an IRP, which is to forecast “expected costs” *to the Company*, not to a subset of customers.[1] Idaho Power claims to otherwise classify these PV system’s costs is inconsistent with the levelized cost of electricity methodology the Company employs to determine cost inputs for all resources.[2] Staff appreciates Idaho Power’s good-faith efforts and does not want to punish but rather create an opportunity to determine a more realistic analysis of this new class of supply-side resource. Staff discusses this matter further in the “Other Items” section later in this report.

Staff finds that Idaho Power adhered to all other parts of guideline 1.

2. Order 07-002 Guideline 4: Plan Components

*l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers.*

Staff believes Idaho Power’s selection of its preferred portfolio P6(b) may not comport with Sections (l) and (n) of Guideline 4. Staff finds the resource decisions that lie outside the Company’s two-to-four year action plan are not the “best combination” according to Staff’s initial analysis and review of Idaho Power’s subsequent reply comments. Staff discusses this matter further in the “Other Items” section of this report.

3. Order 07-002 Guideline 12: Distributed Generation

*Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.*

As discussed under the section describing Guideline 1, Staff believes that Idaho Power’s efforts in developing an evaluation of supply-side resources that includes distributed generation ultimately produces results that are neither “on par” nor meaningful.

## II. Idaho Power’s Compliance with Order No. 14-253

In issuing Order No. 14-253 in Docket No. LC 58, the Commission accepted Idaho Power’s 2013 IRP with several directives and Commission recommendations. Below are Staff’s comments on the Company’s compliance with those items:

Pollution Control Investments in Coal Resources

The Commission directed Idaho Power “to work with stakeholders to explore options for how it plans to model and perform analysis in the 2015 IRP in order to comply with the

[1] This includes both residential and commercial and industrial facilities. *See* page 85 of Idaho Power’s IRP, Appendix C.
[2] Idaho Power’s reply comments, at pages 18-19, Docket No. LC 63, December 30, 2015.

applicable emissions requirements §111(d) of the Clean Air Act."[3] Staff finds that Idaho Power satisfied the first component of this directive by holding an inclusive and engaging stakeholder process, the IRP Advisory Council (IRPAC). Idaho Power presented the considerations and analyses of the Company's Coal Study Working Group at the September, 2014, IRPAC meeting. Additionally, Idaho Power welcomed and incorporated coal plant retirement date suggestions from IRPAC members. Staff also finds that Idaho Power satisfied the second component of this directive. To address uncertainty surrounding Clean Air Act Section111(d) (CAA Section 111(d)) and the joint ownership of Idaho Power's coal plants, Idaho Power analyzed 23 portfolios that contain various retirement dates for those facilities. Additionally, Idaho Power conducted a CAA Section 111(d) sensitivity on the 23 resource portfolios that consisted of seven different scenarios split into mass-based or rate-based. However, these analyses were conducted prior to the finalization of CAA Section 111(d). Due to this temporal issue, Staff will recommend additional analyses in Idaho Power's 2015 IRP update.

Gas Price Forecasts

Though not an explicit directive, Staff mentions the Commission's expectation that Idaho Power would address stakeholders' concerns regarding three aspects of the Company's natural gas price forecast because of its underlying role in the overarching IRP analysis. Staff finds that Idaho Power sufficiently addressed the concerns.

Conservation Voltage Reduction (CVR)

Idaho Power was directed to include a CVR assessment in the 2015 IRP after failing to do so in the 2013 IRP. CVR efforts currently progressing at Idaho Power under the "CVR Enhancements Project" should be completed by 2016. Through its *2014 and 2015 Smart Grid Reports*, the Company has kept Staff and the Commission abreast of the renewed evaluation and possible integration of CVR into distribution system operations. Idaho Power did not include a CVR assessment due to the ongoing nature of the project, but did include a description of the current project on page 48 of the IRP. Staff recommends the Commission delay action on CVR until Staff has been able to review the Company's analysis in the CVR Enhancements Project report to be filed in the middle of 2016.

Action Plan Limits

The Commission stated that Idaho Power should limit its Action Plan to activities it plans to undertake in the next two to four years as well as enumerate them for ease of analysis. Idaho Power has done so.

## III. Action Plan Discussion

The Company offered the following Action Items for the time period 2015-2019.

[3] Commission Order No. 14-253, at page 8, Docket No. LC 58, July 8, 2014.

1. Boardman to Hemingway (B2H) Transmission Line

The Company requests acknowledgement of "ongoing permitting, planning studies, and regulatory filings."[4] In Order No. 14-253, the Commission acknowledged the same actions for B2H.[5]

As the designated permitting project manager, Idaho Power continues to work with the Bureau of Land Management (BLM), the US Forest Service, and the Oregon Department of Energy (ODOE) as well as numerous other federal, state and local agencies, to move the project through the various state and federal regulatory requirements. The major development to occur since the 2013 IRP is the BLM's issuance of the draft Environmental Impact Statement (EIS), which includes the agency's initial analysis on the proposed and alternative routes of the B2H line.[6] The commenting period for the draft EIS closed in March, 2015 and Idaho Power expects the BLM to issue a final EIS in 2016. Idaho Power also mentions that it will submit an amended preliminary Application for Site Certificate to ODOE prior to 2017. Because of the ongoing permitting process and the uncertainty of future delays, Idaho Power is unable to determine an in-service date for B2H, but forecasts it will be no sooner than 2021.

Idaho Power included B2H in all but four of the 23 resource portfolios and included in-services dates of 2021, 2023 and 2025 along with related coal plant retirements. Staff reiterates its recommendation that the Commission acknowledge Action Plan Item No. 1.[7]

2. Gateway West Transmission Line

The Company requests acknowledgement of "ongoing permitting, planning studies, and regulatory filings."[8] In Order No. 14-253, the Commission acknowledged the same actions for Gateway West.[9] The Commission also stated that for acknowledgement of any of Gateway West's construction, the Company would have to provide analysis on each line segment the Company owns to demonstrate need and specific constraint-related benefits.[10]

Idaho Power included a high-level analysis in the 2015 IRP that supports the improvements to two internal transmission paths, Boise East and Midpoint West, which are part of the Gateway West upgrade. Boise East, which connects the Mountain Home area, is currently being studied due to "large amounts of solar generation proposed to

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[4] Idaho Power's 2015 IRP, at page 142, Docket No. LC 63, June 30, 2015.
[5] Commission Order No. 14-253, at page 5, Docket No. LC 58, July 8, 2014.
[6] BLM's *Draft Environmental Impact Statement and Land Use Plan Amendments for the Boardman to Hemingway Transmission Line Project, DOI-BLM-OR-V000-2012-016-EIS,* December 19, 2014.
[7] Staff's opening comments, at page 15, Docket No. LC 63, June 30, 2015.
[8] Idaho Power's 2015 IRP, at page 142, Docket No. LC 63, June 30, 2015.
[9] Commission Order No. 14-253, at page 6, Docket No. LC 58, July 8, 2014.
[10] Ibid.

be sited around the Mountain Home area."[11] Though Midpoint West received two separate upgrades by the end of 2015 that increased the path rating from 1,027 MW to 1,710 MW, the specific line will still be constrained according to the Company. Gateway West upgrades will alleviate anticipated congestion for both of these segments.

Staff reiterates its recommendation that the Commission acknowledge Action Plan Item No. 2.[12]

3. Energy Efficiency

The Company requests acknowledgement of its "pursuit of cost-effective energy efficiency. The forecast reduction for 2015-2019 programs is 84 average megawatts (aMW) for energy demand and 126 MW for peak demand."[13]

As Staff noted in its opening comments, Idaho Power's energy efficiency target for the five year period from 2015 to 2019 is 22 percent higher than the five year window in the 2013 IRP. Staff is encouraged by this and will provide further comments in the Staff Report after review of stakeholders' and the Company's Final Comments.

Staff recommends that the Commission acknowledge Action Plan Item No. 3.

4. CAA Section 111(d)

The Company requests acknowledgement of its coordination with government agencies on implementation planning for CAA Section 111(d).

Because the final version of CAA Section 111(d) had yet to be issued by the conclusion of Idaho Power's analysis window for the 2015 IRP, Idaho Power included assumptions and methodologies that were derived from the draft CAA Section 111(d) rules. Idaho Power analyzed its ownership roles of the Valmy and Jim Bridger coal generation stations, located in Nevada and Wyoming, respectively, through the lens of an analysis shaped by an anticipation of what the final CAA Section 111(d) rules will look like. As the IRP shows, a combination of an early retirement for the Valmy generating station coupled with an energerization of the B2H line provides flexibility in planning and reasonable performance in terms of net present value.

In addition to creating a diverse set of possible compliance options through coal retirement scenarios, Idaho Power also ran all resource portfolios through a set of CAA Section 111(d) sensitivities that were designed in order to capture the uncertainty of the requirements of the final CAA Section 111(d) rule. These sensitivities fall under four categories:

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[11] Idaho Power's 2015 IRP, at page 70, Docket No. LC 63, June 30, 2015.
[12] Staff's opening comments, at page 15, Docket No. LC 63, November 25, 2015.
[13] Idaho Power's 2015 IRP, at page 142, Docket No. LC 63, June 30, 2015.

A. Null sensitivity

This sensitivity was only applied to Portfolio P1, which is the status-quo portfolio. In Portfolio P1, no coal plants are forecasted to retire in the planning horizon besides Boardman in 2020 and output of an existing generation station is not restrained. Idaho Power created this sensitivity to create a baseline in order to compare and analyze portfolios subjected to the other sensitivities.

B. State-by-state mass-based compliance

Idaho Power is bound by a state-specific, state-wide carbon emission limit under this scenario. Because the draft CAA Section 111(d) rules left open the question whether the Langley Gulch combined cycle combustion turbine (CCCT) was subject to the rules due to the plant's online date of mid-2012, Idaho Power conservatively assumed that it would in fact be subject to the regulations. Therefore, the Company created three constrained capacity factor sensitivities for the plant: 30 percent, 55 percent, and 70 percent.

C. System-wide mass-based compliance

Idaho Power is bound to an emissions limit level set to a utility-scale system. "The assumed Idaho Power system-level limits were derived to be consistent with Environmental Protection Agency's (EPA) proposed sate-specific target reductions." Emissions from Valmy and Jim Bridger coal generating facilities are capped in addition to intrastate facilities like Langley Gulch.

D. Emissions intensity compliance using the EPA's compliance building blocks

Under this scenario, Idaho Power assumed that the North Valmy coal generation station would retire completely as early as 2019 or as late as 2025 and that Jim Bridger would have a production limit that would result in a partial re-dispatch to a CCCT. Additionally, Langley Gulch would be curtailed to 30 percent, 55 percent, or 70 percent assuming it falls under CAA Section 111(d) purview and that Idaho Power would construct renewable resources according to EPA's proposed targets.

For the initial portfolio cost analysis, which would later serve as the base for further cost comparisons between portfolios under the CAA Section 111(d) sensitivities and the stochastic risk analysis, Idaho Power selected a state-by-state mass-based scenario with a 30 percent capacity factor for Langley Gulch as the baseline.

Results from Idaho Power's CAA Section 111(d) stochastic modeling indicate that the Company would be able to meet the final CAA Section 111(d) despite uncertainties, including the status of the Langley Gulch generation station's classification and the final emissions goals. For the most part, the ranking of portfolio costs that was initially calculated using the above-mentioned baseline translated into similar rankings across the seven different CAA Section 111(d) sensitivities. In other words, the ten least-cost portfolios, as ranked by total net present value in Table 9.3, rank almost identically when assessed across the seven sensitivities. The sensitivities that modeled EPA building block compliance produced overall some of the lowest-cost scenarios for most portfolios. However, it also eliminated some portfolios that ranked much higher in the net present value (NPV) analysis because Idaho Power determined the baseline costs were too high. The 55 percent and 70 percent capacity factor sensitivities for Langley Gulch under the state-by-state mass-based compliance produced similar results in that portfolios containing expensive resources like battery or pumped storage were unable to be modeled.

Portfolio P1, the status-quo portfolio, has total costs of approximately $4,417 million under the null sensitivity. Of the ten lowest-cost portfolios from the portfolio NPV analysis, the least cost option was portfolio P9 with $4,408 million under the building blocks compliance scenario with Langley Gulch at a 55 percent capacity factor. The highest-cost sensitivity produced from the 10 lowest-NPV portfolios was portfolio P10 with $4,608 million under the state-by-state mass-based compliance scenario with Langley Gulch operating at a 30 percent capacity factor.

Now that the EPA has published the final CAA Section 111(d) rules, Staff and other stakeholders have reviewed the consistency between the Company's sensitivities and the actual stipulations for the State of Idaho. In summary, Idaho's business as usual trajectory places Idaho under the 2030 emissions cap stipulated by the EPA. However, both Nevada and Wyoming face emission reductions in order to comply with EPA 2030 final goals. Nevada either must decrease its emission rate from a 2012 historical rate of 1,102 lbs/net MWh to 855 lbs/Net MWh by 2030, or decrease its total emissions mass from a 2012 historical level of 15,536,730 short tons to 13,523,584 short tons. Wyoming faces an even more aggressive reduction: Wyoming either must decrease its emission rate from a 2012 historical rate of 2,331 lbs/Net MWh to 1,299 lbs/Net MWh, or decrease its total emissions mass from a 2012 historical level of 49,998,736 short tons to 31,634,412 short tons.

We recommend that Idaho Power work with NV Energy and PacifiCorp on North Valmy and Jim Bridger, respectively, in order to determine if and how the Company's respective liabilities in the plants that are co-owned will be impacted by CAA Section 111(d), how much it will cost Idaho Power to comply with the final rules and how those costs will impact Idaho Power ratepayers. Staff recommends that Idaho Power include a status update of these efforts in the 2015 IRP interim update.

Idaho Power states that "the optimization of coal unit shutdown alternatives using computer modeling tools will not be possible until the proposed CAA Section 111(d) regulation is finalized…" Staff concurs and recommends the Commission direct Idaho Power to file an amended CAA Section 111(d) sensitivity analysis in the Company's 2015 IRP interim update. Aspects of the analysis should include possible compliance scenarios for Nevada and Wyoming, the accompanying data and communications between state agencies and utilities that support those compliance scenarios, and the net impacts of various compliance scenarios on Idaho Power customers.

Staff recommends that the Commission acknowledge Action Plan Item No. 4.

5. Shoshone Falls License Amendment

The Company requests acknowledgement of its plan to amend the Federal Energy Regulatory Commission (FERC) license regarding the Company's original plans to expand the existing Shoshone Falls facility by approximately 50 MW.

Idaho Power has included the 50 MW upgrade to the existing Shoshone Falls facility in the last several IRP filings. Because the actions related to the Shoshone Falls facility in the 2013 IRP fell outside the IRP guideline's two-to-four year acknowledgement window, the Commission declined to comment on the related action item.

Idaho Power's 2015 IRP analysis of the costs and benefits of the 50 MW expansion of the Shoshone Falls facility led the Company to conclude that a more cost-effective upgrade is appropriate. Though the 50 MW expansion does provide incremental benefits, 75 percent of the incremental energy production is forecast to occur from January through June, while substantially less production would occur from July through September. Due to timing of energy production, Idaho Power states that the 50 MW expansion "cannot be linked to an IRP-determined resource need, as it provides little to no capacity or energy during peak summer load months."[14]

Staff appreciates Idaho Power's pursuit of a more cost-effective upgrade that will ultimately benefit ratepayers despite the previous planning for the 50 MW. Such a change reflects the benefits to the Company and ratepayers of an ongoing and robust IRP process.

Staff recommends that the Commission acknowledge Action Plan Item No. 5. In addition, Staff requests that the Company keep Staff apprised of the results of the amendment process during the interim period between Commission acknowledgment of the 2015 IRP and the filing of the 2017 IRP.

6. Jim Bridger Unit 3

The Company requests acknowledgement of the completion of "selective catalytic reduction" (SCR) emission-control technology in 2015. The Commission did not acknowledge this same Action Plan item from the 2013 IRP in Commission Order No. 14-253 for three reasons specific to the Idaho 2013 IRP and for an additional four reasons that were pertinent to the PacifiCorp 2013 IRP.[15]

Despite the fact that Idaho Power proceeded with the installation of SCR at Jim Bridger unit 3, Staff would like to highlight that it believes the 2015 IRP largely satisfies the three concerns the Commission expressed in Order No. 14-253.
Staff recommends the Commission acknowledge Action Plan Item No. 6.

[14] Ibid., at page 131.
[15] Commission Order No. 14-253, at pages 10-11, Docket No. LC 58, July 8, 2014.

7. Shoshone Falls Upgrades Study

The Company requests acknowledgement of its plans to study options for smaller upgrades to the Shoshone Falls facility that range in size from 1.7 MW to approximately 4.0 MW.

Because the 50 MW expansion was deemed to be cost ineffective, Idaho Power has determined that a potential capacity upgrade to the facility ranging from 1.7 MW to 4.0 MW would fulfill streamflow use required by the license renewal as well as increase the facility's annual capacity factor. Costs range from $50/MWh to $65/MWh depending on the expansion size; Idaho Power anticipates the construction of the upgrade to begin in 2017 barring issues with amending the FERC license.

Staff recommends that the Commission acknowledge Action Plan Item No. 7. In addition, Staff requests that the Company provide any preliminary conclusions of the study during the interim period between Commission acknowledgment of the 2015 IRP and the filing of the 2017 IRP.

8. Jim Bridger Unit 4

The Company requests acknowledgement of the completion of selective catalytic reduction (SCR) emission control technology in 2016. The Commission did not acknowledge this same action item from the 2013 IRP in Commission Order No. 14-253 for three reasons specific to the Idaho 2013 IRP and for an additional four reasons that were pertinent to the PacifiCorp 2013 IRP.[16]

Mirroring the reasoning provided under Action Plan Item No. 6, Staff recommends the Commission acknowledge Action Plan Item No. 8.

9. North Valmy Units 1 and 2

The Company requests acknowledgement of its continued work with "NV Energy to synchronize depreciation dates and determine if a date can be established to cease coal-fired operations."

Staff has questioned the Company's choice of preferred portfolio, where both units in North Valmy retire in 2025, as compared to two options that appear less costly, less risky and that also have North Valmy unit 1 retiring in 2019. However, Staff discusses these concerns later in its Final Comments because Action Plan Item No. 9 would occur regardless if the Company were to continue with its preferred portfolio and shut down North Valmy in 2025 or shut down unit 1 of North Valmy in 2019.

Staff recommends the Commission acknowledge Action Plan Item No. 9.

[16] Commission Order No. 14-253, at pages 10-11, Docket No. LC 58, July 8, 2014.

10. Shoshone Falls 2017 Upgrade

The Company requests acknowledgment of its plan to commence construction of a smaller upgrade to facility in 2017.

Idaho Power is currently analyzing potential capacity upgrades to Shoshone Falls as part of the FERC licensing amendment process. Until Staff is able to review the full economic analysis regarding the yet to be determined upgrade to the facility, a recommendation to acknowledge construction is premature and cannot be made. Staff expects that a full economic analysis would include updated costs, market forecasts, renewable energy certificate prices, status of water issues, and a cost/benefit analysis. Staff encourages the Company to file a complete analysis during the interim period between Commission acknowledgment of the 2015 IRP and the filing of the 2017 IRP in order to allow time for a comprehensive and timely review.

Staff recommends the Commission not acknowledge Action Plan Item No. 10.

11. Jim Bridger units 1 and 2

The Company requests acknowledgement of the evaluation of SCR technology installation for units 1 and 2 at the Jim Bridger generation facility in the Company's 2017 IRP.

In the Company's 2013 IRP, the Company included the commitment to the installation of SCR technology for Jim Bridger units 1 and 2 for years 2019 and 2020, respectively. The Commission ultimately did not choose to acknowledge these two items because they lay outside the two to four year action plan window. However, Staff noted in its Final Comments that it expected Idaho Power to incorporate "the best information regarding greenhouse gas and other regulation" into the 2015 IRP analysis, in part due to the recently released EPA ruling on Wyoming's state implementation plan regarding regional haze and also in anticipation of pending regulation by the EPA.[17] Furthermore, one aspect of the concerns raised by the Commission in Order No. 14-253 regarding SCR technology applications to the Jim Bridger facility was that Idaho Power's evaluation and analysis did not fully align with that of PacifiCorp's.[18]

Staff finds that Idaho Power has satisfied these concerns in the 2015 IRP: the Company included resource portfolios and CAA Section 111(d) sensitivities that reflect the Company's best anticipations of what the final CAA Section 111(d) rule would look like. Idaho Power also included three portfolio variations that involve different retirements of Jim Bridger unit 1 in 2023 and Unit 2 in either 2028 or 2032; one also includes the retirement of North Valmy in 2025. Idaho Power included these portfolios to model and analyze the costs of an early retirement of Jim Bridger units 1 and 2 in order to avoid

[17] Staff's final comments, at page 7, Docket No. LC 58, January 15, 2014.
[18] Commission Order No. 14-253, at pages 10 and 11, Docket No. LC 58, July 8, 2014.

installing SCR technology. These portfolio options mirror the retirement portfolios that PacifiCorp considered in its 2015 IRP.[19]

The release of the final CAA Section 111(d) rules after the submission of the Company's 2015 IRP, and the needed determination of the best combination of shutting down or installing SCR on Jim Bridger units 1 and 2 and shutting down North Valmy, further underscores the need for the Company to run a comprehensive evaluation of resource portfolios during the interim period between Commission acknowledgment of the 2015 IRP and the filing of the 2017 IRP.

Staff recommends acknowledgement of Action Plan Item No. 11 with the additional recommendation that Idaho Power conduct an additional analysis of the resource portfolios analyzed in the stochastic sensitivity analysis using the final CAA Section 111(d) rules and any existing resource updates provided by PacifiCorp regarding the Jim Bridger generation station.

12. Shoshone Falls 2019 On-Line Date

The Company requests acknowledgement of a 2019 on-line date for the chosen smaller upgrade to the facility.

Similar to Action Plan Item No. 10, Staff finds the request premature for the Commission's acknowledgement. An on-line date is precipitated by a construction date, which will not be known until the FERC grants the license amendment and Idaho Power conducts a comprehensive analysis to determine the exact capacity upgrade size. Staff anticipates Idaho Power will return with a specific and supported on-line date in its 2017 IRP.

Staff recommends the Commission not acknowledge Action Plan Item No. 12.

## IV. Other Items

A. Acknowledgement of the IRP

Staff concurs with Idaho Power regarding the temporal boundaries of the Commission's acknowledgment of any utility's IRP Action Plan. An Action Plan's limit of no more than four years is expressly stated in part (n) of Guideline 4.[20] Additionally, the limit's exceedance has been a concern of Staff, stakeholders and the Commission in Idaho Power's 2011 and 2013 IRP cycles. Staff appreciates Idaho Power's adherence to this rule, but is concerned by a notion found in Idaho Power's argument. Idaho Power notes that Staff's and the Citizens' Utility Board's (CUB) challenge to the long-term resource plan and not to the Action Plan "is important in the 2015 IRP because the action plan is not dependent on the selection of the long-term resource portfolio –*i.e.,* the near-term

[19] PacifiCorp's 2015 IRP, at page 148, Docket No. LC 62, March 31, 2015.
[20] Commission Order No. 07-002, Appendix A, at page 5, January 8, 2007.

action plan is the same for each of the portfolios the parties support."[21] Staff disagrees that a common action plan can dismiss concerns about the long-term resource plan. The goal of an IRP is to achieve long-run cost-risk optimality, which can only happen if an attempt to discern the best cost/risk portfolio occurs *first.* The utility *then* can ensure that the short-run action plans are consistent and compatible with such portfolios. Idaho Power's approach to IRP modeling presented at the beginning of nearly every IRPAC reflects this underlying notion. Action plans are dependent on the selection of the long-term resource portfolio because IRP short-run action plans otherwise lack relevance in the absence of long-term objectives.

B. Selection of Preferred Portfolio

In its opening comments, Staff presented its initial assertion that Idaho Power's selection of the preferred portfolio P6(b) is not in fact the least cost and risk portfolio available to the Company.[22] Staff analyzed the Company's supporting quantitative and qualitative components to argue that Portfolios P8, P9, P10, and P11 are less costly, least risky and more flexible in meeting Idaho Power's CAA Section 111(d) stochastic modeling. In its reply comments, Idaho Power disagreed with Staff's assertion and contends that Staff and CUB focused too narrowly on the quantitative cost and risk analysis.

*1. Portfolio NPV*

Idaho Power contends that the earlier retirement of North Valmy's unit 1 in 2019, found in portfolios P(8) and P(9), would place a greater burden on ratepayers in the short term due to accelerated depreciation. Idaho Power states that preferred portfolio P6(b)'s North Valmy retirement date would only increase the annual depreciation expense by $9 million, whereas the retirement of unit 1 in 2019 would increase the annual depreciation expense by an additional $6 million, bringing the total to $15 million. Additionally, incremental capital additions would be required for continued operations of North Valmy regardless of a 2019 or 2025 retirement date; these costs would further increase the higher annual depreciation expense if unit 1 were to retire early.

Idaho Power also presents Table 1, which depicts the relative net present cost differences between portfolios P6(b), P8, P9, P10 and P11. Portfolio P6(b)'s total net present cost lies within one percent of portfolios P8, P10 and P11 and is only 1.61 percent higher than portfolio P9.

Staff raises three concerns regarding Idaho Power's calculations. First, Staff notes that Idaho Power's emphasis on the short term burden of higher rates due to an earlier retirement date overlooks the role of discounting in the calculation of NPV. NPV calculations bring the "long-run," or 20-year horizon, costs into present day costs; the short-term is already considered in the overall long-run cost. However, the short-run

[21] Idaho Power's reply comments, at page 3, Docket No. LC 63, December 30, 2015.
[22] Staff's initial comments, at page 2, Docket No. LC 63, November 25, 2015.

burdens are given greater emphasis than the long-run benefits due to the very mathematical nature of discounting. The fact that portfolio P9 appears superior to preferred portfolio P6(b) despite the fact that portfolio P9's future advantages are discounted (i.e., reduced from their nominal values) strengthens the case against the Company's preferred portfolio. In other words, if the long-term had been given the same weight as the short-term, then, due to its greater future costs, the Company's preferred portfolio would compare even worse to portfolio P9 than as depicted with Idaho Power's NPV calculations.

Second, Staff finds any argument made about the potential effects on the short-term due to fixed-costs impacts from an early coal plant retirement to be incomplete and therefore unacceptable unless all fixed-cost impacts are calculated in a consistent manner. Table 8.1 on page 98 of the 2015 IRP shows five types of impacts, three of which produce cost savings. Staff cannot accept the short-term impacts of accelerated depreciation as a reason to avoid an earlier retirement if an analysis is not provided that shows the net impact on ratepayers from all identified fixed-cost impacts.

Third, Staff believes that a more complete analysis regarding the annual accelerated depreciation expense is needed in order to consider the merits of Idaho Power's argument, especially in light of Staff's first and second point. Before Staff can acknowledge the financial argument made, some additional questions (e.g. involving impacts of coal facilities on customers' bills) must be asked.
Staff will send accompanying data requests to the Company shortly after filing these comments.

2. *Stochastic Risk Analysis*

Idaho Power states that just because preferred portfolio P6(b) was outperformed in every single risk iteration by P8, P9, and P11, this does not necessarily demonstrate that portfolio P6(b) is a higher risk portfolio. Idaho Power argues that if one of the stochastic variables differs from the planning assumptions, subsequently affecting one particular portfolio substantially more than other portfolios, then that affected portfolio is characterized as higher risk. In other words, the fact that the plotted lines in Figure 9.1 run mostly parallel means no portfolio is riskier than the others because each portfolio is affected to a similar degree by each modeled variable.

Staff disagrees with the context in which Idaho Power is using the term "riskier" to characterize the argument Staff made. Contrary to Idaho Power's assertion, the absence of such a crossing - that at every exceedance percentage, a given portfolio has a lower cost than another - means that, unambiguously, the subject portfolio has a lower risk. Risk is defined here as having a lower percentage chance of reaching a high (i.e., bad) cost. Staff refers to Idaho Power's response to Staff's data request number 42: At the five percent exceedance probability point, portfolio P9 has an NPV that is $50 million beneath that of the Company's preferred portfolio, P6(b). In other words, at that particular exceedance point, P9 is less risky than P6(b).

3. Qualitative Risks

Idaho Power claims that, counter to Staff's and CUB's concerns, the Company's risk assessment is an important factor in selecting a portfolio that best balances costs and risks because the "goal of the qualitative risk analysis is to select a portfolio like to withstand unforeseen events that cannot be quantified."[23] Due to the relatively small difference in NPV between portfolios P6(b) and portfolios P8-P11, the results of the qualitative analysis ultimately led the Company to choose portfolio P6(b).

Staff first must clarify that it never meant to imply that as a whole, Idaho Power's qualitative risk assessment is not important. In fact, Staff believes assessing qualitative risks is crucial in fulfilling the IRP guidelines established in Commission Order No. 07-002.[24] Staff's initial comments include occasions where Staff agrees with the inclusion of a particular qualitative risk assessment, such as resource commitment risk or Public Utility Regulatory Policies Act (PURPA) qualifying facility risk. However, Staff's consistent claim in the analysis of the Company's qualitative risk assessment is that Idaho Power's preferred portfolio P6(b) is not unique in addressing many of the qualitative risks that Idaho Power identifies. For example, the Company mentions that the portfolio P6(b)'s completion of B2H and the retirement of North Valmy in 2025 balances the risk of CAA Section 111(d) and intermittent and variable resources. Staff finds that portfolio P8 balances these very same qualitative risks despite the earlier closure of unit 1 of North Valmy. P8 is afforded the same load balancing capabilities by B2H seeing as both portfolios have identical energize dates. P8's installation of ice-based thermal energy storage units and an optimized, utility-scale solar PV 1-axis resource can reliably meet the peak hour deficit that occurs because of the earlier retirement of North Valmy unit 1 while also providing certainty to meeting CAA Section 111(d) because of access to zero emissions power.

Staff finds that examples like portfolio P8 lead Staff to conclude that Idaho Power is not systematic in describing why and how the quantitatively superior portfolios are inferior to the preferred portfolio with regard to the qualitative risk reducers that are discussed. Staff needs to see a more balanced and consistent comparison of qualitative benefits achievable by all portfolios to be convinced that clear, quantitative benefits alone do not justify a particular portfolio. Staff recommends Idaho Power include a more systematic evaluation of the qualitative benefits of the resource portfolios that Idaho Power analyses in the stochastic modeling in the 2017 IRP.

*4. PURPA Risks*

Staff appreciates the in-depth example that demonstrates the impact PURPA resources can have on timing and magnitude of capacity deficits. Staff would like to counter Idaho Power's example of complete removal of PURPA resources with a possibility similar to

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[23] Idaho Power's reply comments, at page 8, Docket No. LC 63, December 30, 2015.

[24] *See* Appendix A, guideline 1, part c: a utility's IRP's "primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."

the actual occurrence described on page 128 of the IRP. If Idaho Power were to receive a significant capacity of solar PV in a relatively short period of time, portfolios that have earlier retirements of existing coal resources like P8 or P9 would be suited to manage such an increase in supply. Staff finds that the possibility of Idaho Power receiving either a substantial loss or gain of PURPA contracts to be equal; therefore, the qualitative benefits of portfolios that retire coal earlier should be considered on par with those that do not.

*5. Solar PV Capital Cost Modeling*

As mentioned earlier under the Guidelines section of these comments, Staff believes that the Company's consideration of a residential or commercial PV system's capital expenditures as an incurrence to the Company itself is inconsistent and unreflective of reality. Idaho Power contends that to do so is reasonable and creates "meaningful cost comparisons between resources."[25] Staff does not understand how Idaho Power's logic can be considered meaningful in this particular situation. Were the fixed costs of solar PV to drop precipitously such that by the 2017 IRP, residential solar PV became the least-cost supply-side resource, how would Idaho Power proceed with procuring whatever amount of capacity was determined prudent assuming residential solar PV was part of the preferred portfolio acknowledged by the Commission? Staff believes that including a supply-side resource that requires the significant expenditure on the customer's behalf ultimately creates a meaningless comparison between resources. Furthermore, the very presence of residential or commercial PV solar in the resource stack creates a meaningless comparison because unlike all other supply side resources, costs and risks ultimately flow to the customer. If the Langley Gulch CCCT were to suffer a catastrophic failure, the costs and risks are borne by all customers who have paid for the facility. The same Idaho Power customers do not pay for the failure of a commercial solar PV system, only the owner does. Neither PacifiCorp nor Portland General Electric include residential or commercial solar PV as a supply-side resource at this time.

For purposes of the IRP, Staff would like Idaho Power to consider the capacity and energy contribution potential of residential and commercial solar PV in a way that better reflects the realities of both the costs and benefits to the Company, participating customers and non-participating customers. At this time, Staff believes that classifying residential and commercial solar PV as a demand-side resource could alleviate some of Staff's concerns. Idaho Power could forecast the potential for residential and commercial solar PV using various "ramp rates," determine the necessary policy and program actions that would best acquire the forecasted potential and then model the contributions to the load-resource balance similar to how the Company incorporates energy efficiency.

[25] Idaho Power's reply comments, at page 19, Docket No. LC 63, December 30, 2015.

### 6. *CAISO Energy Imbalance Market (EIM)*

Idaho Power recently announced that instead of joining the Northwest Power Pool's centrally cleared energy dispatch market, the Company is now evaluating whether to join CAISO's EIM.[26] Staff recommends that the Company include an analysis of the benefits and costs of forming joining CAISO's Energy Imbalance Market in the 2015 IRP update.

## V. Concluding Comment and Recommendation

Staff recommends acknowledgement of Idaho Power's 2015 Action Plan with the recommendations contained herein, and summarized below:

| Action Item | Description | Staff Recommendation |
|---|---|---|
| 1 | B2H Transmission Line | Acknowledge |
| 2 | Gateway West Transmission Line | Acknowledge |
| 3 | Cost-effective Energy Efficiency | Acknowledge |
| 4 | CAA Section 111(d) | Acknowledge with Recommendations |
| 5 | Shoshone Falls License Amendment | Acknowledge |
| 6 | Jim Bridger 3 – Complete SCR | Acknowledge |
| 7 | Shoshone Falls Upgrades Study | Acknowledge |
| 8 | Jim Bridger 4 – Complete SCR | Acknowledge |
| 9 | North Valmy – NV Energy Collaboration | Acknowledge with Recommendations |
| 10 | Shoshone Falls 2017 Upgrade | Do not acknowledge |
| 11 | Jim Bridger 1 & 2 – SCR evaluation | Acknowledge with Recommendations |
| 12 | Shoshone Falls 2019 On-line Date | Do not acknowledge |

Recommendations

In addition to acknowledgement of the Action Plan items, Staff recommends that the Commission direct the Company to:

- Include a status update in the 2015 IRP Update of how the Company's respective liabilities in North Valmy and Jim Bridger will be impacted by CAA Section 111(d), how much it will cost Idaho Power to comply with the final rules, and how those costs will impact Idaho Power ratepayers;
- File an amended CAA Section 111(d) sensitivity analysis in the Company's 2015 IRP Update;

[26] SNL Energy, "NWPP members ask FERC to halt work on new market inquiry," last accessed on January 14, 2016, https://www.snl.com/InteractiveX/article.aspx?ID=34765556&KPLT=2.

- Keep Staff apprised of the results of the Shoshone Falls licensing amendment process during the interim period between Commission acknowledgment of the 2015 IRP and the filing of the 2017 IRP;
- Provide any preliminary conclusions of the Shoshone Falls upgrade study during the interim period between Commission acknowledgement of the 2015 IRP and the filing of the 2017 IRP;
- Include a more systematic evaluation of the qualitative benefits of the resource portfolios that Idaho Power analyses in the stochastic modeling in the 2017 IRP;
- Explore the possibility of considering residential and commercial Solar PV as a demand-side resource;
- And include an analysis of the benefits and costs of joining CAISO's EIM in the 2015 IRP update.

This concludes Staff's Final Comments.

Dated at Salem, Oregon, this 22nd day of January, 2016.

Michael Breish

Michael Breish
Utility Analyst
Energy Resources and Planning Division