BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 63

In the Matter of IDAHO POWER COMPANY, 2015 Integrated Resource Plan;	Staff's Opening Comments

Staff's initial comments and recommendations regarding Idaho Power Company's (Idaho Power or Company) 2015 Integrated Resource Plan (IRP) follow below. Staff's comments are grouped by subject. Before filing final comments and the Staff Report that will contain recommendations, Staff will continue to review the Company's filed plan, responses to data requests, and parties' comments.

Staff overall finds Idaho Power's 2015 IRP to be a more robust, comprehensive and broad analysis of current and future issues that affect the Company's resource planning and operations than provided in previous IRPs. Staff finds that by increasing the portfolios and subsequent resources analyzed as well as enhancing the assessment of risk and uncertainty, ratepayers and the Company stand to benefit. Staff notes a few areas amongst others that it was particularly impressed with: Company staff was responsive to participants' concerns and suggestions; included additional coal plan retirement scenarios; included more distributed energy resources in the resource stack, and a larger and more diverse range of portfolios considered.

Staff lists Commission resolutions and adopted recommendations regarding Idaho Power's 2013 IRP below:[1]

1. Idaho Power work with stakeholders to explore options for how it plans to model and perform analysis in the 2015 IRP in order to comply with Section 111(d) of the Clean Air Act;
2. The expectation that Idaho Power work with [Oregon Department of Energy] ODOE and provide results of Idaho Power's work on solar and other resources' capacity contribution;
3. The anticipation that Idaho Power will address the gas price forecast and analysis issues raised by stakeholders in the 2013 IRP;
4. The expectation that Idaho Power use stakeholder recommendations regarding the IRP flexibility guidelines in order to provide a compliant and more robust analysis;
5. Idaho Power provide a conservation voltage reduction (CVR) resource availability assessment in the 2015 IRP; and
6. Idaho Power limit its Action Plan to activities the Company plans to undertake in the next two to four years.

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

Staff is still reviewing item number four, but at this time believes the Company has sufficiently addressed all other resolutions and recommendations made by the Commission in Order No. 14-253. Staff remarks that, given the Company's renewed CVR effort described in its 2014 and 2015 *Smart Grid Reports*, the absence of the requested analysis is understandable and Staff will subsequently explain this in its Staff Report.

Staff below describes issues and concerns related to the 2015 IRP material.

Selection of Preferred Portfolio

Staff believes that a utility's preferred portfolio should be characterized by: 1) meeting IRP guidelines established in Commission Order Nos. 89-507, 07-002, 07-047, and 08-339; 2) reflecting least-cost, least-risk planning, and 3) being in accordance with State and Federal energy policy.

Staff is concerned with the Company's selection of portfolio P6(b) as the preferred portfolio, which the Company selected as a result of the "quantitative and qualitative analysis" conducted.[2] Staff finds that the supporting analysis does not clearly justify the Company's choice of P6(b) as the preferred portfolio. However, Staff emphasizes that it believes most of the analyses conducted are thorough and good; the Company's selection of the preferred portfolio despite results of the analyses is what concerns Staff. Below Staff presents its initial evaluation of each component that comprises the quantitative analysis.

Component 1) Quantitative – "2015 IRP portfolios, NPV years 2015-2034"[3]

Based on its analysis, the Company has chosen Portfolio P6(b) as its preferred portfolio.[4] However, portfolio P6(b) ranks only as the eighth least-cost resource from all of those considered.

Portfolio costs are calculated by adding the portfolio's variable costs (i.e., the operating costs modeled through AURORA) and total fixed costs, which are determined by industry sources or consultants hired by Idaho Power. Several portfolios rank as lower cost than the preferred portfolio, including the "status quo" portfolio and two portfolios that contain no coal capacity requirements. Staff does not acknowledge these three portfolios as reasonable options because of the existing state and federal policy

[2] Idaho Power's 2015 IRP, at page 130, Docket No. LC 63, June 30, 2015.
[3] Ibid., Table 9.3, at page 117.
[4] Ibid., at page 130.

landscape.[5] After eliminating these portfolios from further consideration, two categories of portfolios remain: two that retire the Valmy coal generating units in 2019 and 2025 (portfolios P8 and P9), and two that retire Jim Bridger units in 2023 and 2032 (portfolios P10 and P11). Staff refers to these four portfolios throughout the remaining comments.

Portfolio P9 is the least cost resource behind the status quo portfolio. Portfolio P9 differs from the preferred portfolio in that it retires one unit of the Valmy coal unit earlier, installs reciprocating engines instead of ice-thermal energy storage units, and constructs a single cycle combustion turbine (SCCT) instead of a combined cycle combustion turbine (CCCT), and is approximately $74,584,000 cheaper in total cost than the preferred portfolio. The other three viable portfolios range in lower costs.[6] All four of these alternate, less expensive portfolios provide sufficient flexibility and capability in meeting future resource needs. Portfolios P11 and P8 include no additional fossil-fueled plants, which provides additional benefits to Idaho Power customers. From a strict least-cost position, the choice of Portfolio P6(b) is unwarranted.

<u>Component 2) Quantitative – "Portfolio costs by CAA Section 111(d) sensitivity[7]</u>

Staff notes that Idaho Power conducted its CAA Section 111(d) (111(d)) analysis using values, assumptions and models provided or derived under the *draft* 111(d) rule. The State of Idaho's position in terms of compliance has improved since the release of the *final* 111(d) rule, but States where Idaho Power's partially owned coal units reside face varying compliance requirements.[8] Regardless of the change in compliance requirements mandated by the Environmental Protection Agency, Idaho Power's 111(d) analysis underscores Staff's opinion that the Company's preferred portfolio choice is quantitatively unsupported. The four least-cost portfolios discussed above are cheaper in every applicable 111(d) situation except one. In other words, out of 22 model comparisons, preferred portfolio P6(b) is more expensive than four viable alternatives in all but one case. In that one case, Idaho's preferred portfolio is outperformed by three of the four alternatives. Differences in present-value revenue requirement between portfolio P6(b) and the four alternatives range from $13 million to $74 million. When considering the risk and costs of meeting the possible requirements of 111(d), portfolio P6(b) fails to provide ratepayers with the best financial outcome because it is neither least cost nor least risk based on the results of the Company's modeling.

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[5] Staff chooses to discount portfolios P2(a) and P2(b), both of which do not retire any coal capacity, because of NV Energy's ongoing plan to retire Valmy in 2021 and 2025, and the requirements of various federal and state emissions' restrictions. The status quo exists for establishing a baseline and does not comply with any CAA Section 111(d) restrictions.

[6] Portfolio P8 costs approximately $20,721,000 less than preferred portfolio P6(b); Portfolio P10 costs approximately $13,997,000 less than preferred portfolio P6(b); Portfolio P11 costs approximately $45,794,000 less than preferred portfolio P6(b).

[7] Idaho Power's 2015 IRP, Table 9.4, at page 119, Docket No. LC 63, June 30, 2015.

[8] The Valmy coal generation station is located in Nevada and the Jim Bridger coal generation station is located in Wyoming.

Component 3: Quantitative – "Portfolio stochastic analysis"[9]

Idaho Power ran a set of 100 iterations based on three stochastic variables: natural gas price, customer load, and hydroelectric variability.[10] Scrutiny of the magnified inset of Figure 9.1, which plots the total portfolio costs of the ten modeled portfolios against 54 percent and 56 percent exceedance values, led Staff to submit a number of discovery requests regarding the results of the Company's stochastic modeling. Staff is still reviewing the Company's responses to the discovery in addition to original material provided, but preliminary analysis indicates that the preferred portfolio is outperformed by three of the four alternative resource portfolios (P8, P9 and P11) *in every single risk iteration*.[11] Furthermore, portfolios P8, P9, and P11 are lower cost than preferred portfolio P6(b) at the five percent exceedance value, which Staff considers an important benchmark in assessing a portfolio's risk.[12] Staff is concerned that Idaho Power is pursuing a resource portfolio that creates a riskier, and potentially more costly, scenario for ratepayers.

Staff preliminarily finds that these three quantitative analyses, considered both alone and together, are insufficient to support the choice of Portfolio P6(b) as the preferred portfolio. In fact, Staff believes that these analyses clearly support the selection of any of the four portfolios mentioned above as a preferred portfolio and more so for P8, P9, and P11 based on stochastic modeling results. Furthermore, IRP guidelines established in Order No. 07-047 state that 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."[13] Staff is concerned the Company failed to select a portfolio that serve customers' best interests. Staff believes the Company's "Qualitative Risk Analysis" is analogous to "uncertainties" found in the aforementioned Commission Order No. 07-047. Below is Staff's evaluation of the Company's "Qualitative Risk Analysis," which also consists of a number of components, not all of which Staff considers for review.

Component 4: Qualitative – "Fossil Fuel-Fired Power Generation and Proposed CAA Section 111(d) Regulation Risks"[14]

Staff questions why Idaho Power, in an attempt to mitigate risks of proposed regulations that address greenhouse gas emissions from existing generation resources, chose not

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[9] Idaho Power's 2015 IRP, Figure 9.1, at page 122, Docket No. LC 63, June 30, 2015.
[10] Ibid., at page 121.
[11] Idaho Power's response to Staff's IR 41, Attachment, Docket No LC. 63, November 13, 2015.
[12] The 5 percent exceedance level for a given portfolio defines both a measure of its risk or "badness" and the probability of having something that bad or worse.
[13] Commission Order No. 07-047, Appendix A, at Guideline 1, c., Docket No. UM 1056, February 09, 2007.
[14] Idaho Power's 2015 IRP, at page 127, Docket No. LC 63, June 30, 2015.

to proceed with a portfolio that consists of resources that are less carbon emitting than P6(b), such as portfolios P8 or P11. In the context of Idaho Power's analysis done under the construct of the *draft* 111(d) rules, carbon-mitigating or neutral resources such as photovoltaic (PV) systems, hydroelectric, combined heat and power, and greater accrual of energy efficiency resources would have possibly allowed the Company greater flexibility in navigating 111(d) constraints. Six out of the seven 111(d) compliance scenarios that the Company tested resource portfolios under involve decreasing the annual capacity factor at the Langley Gulch combined cycle combustion facility.[15] Incorporation of carbon-mitigating or neutral facilities would have reduced or potentially eliminated the need for capacity factor-altering options, and in doing so, also allowed for reduced costs to customers including reduced fuel expenditures and greater asset utilization.

Now that the final rule has been released, the State of Idaho compliance goals as they currently stand essentially eliminate any risk of 111(d) compliance. The State of Idaho, proceeding with "business as usual" as defined in the EPA's 111(d) final rule, will meet the state's assigned 2030 emissions compliance goal. Staff will continue to evaluate Idaho Power's 111(d) compliance analysis and deliberate how to address the differences in effects between the draft and final rules.

Component 5: Qualitative – "Regulatory Risk"[16]

Staff is perplexed by the inclusion of this risk due to: a) the Company's selection of the particular preferred portfolio; b) the history of Idaho Power's IRPs being acknowledged; and c) the scope of Idaho Power's action plan. First, the poor performance of the preferred portfolio in the respective quantitative analyses would seemingly indicate that the intentional selection of this portfolio that faces better performing alternatives would subsequently invite scrutiny. In that sense, the selection of Portfolios P8, P9, P10 and even P11 would have mitigated this risk. Second, Staff notes that "regulatory risk" has not appeared in previous IRP cycles. Subsequently, Staff finds the appearance of "regulatory risk" to be highly peculiar. The Company has not identified any regulatory risk beyond what is historical (risk of cost recovery, risk related to not receiving appropriate return on investment, environmental risk). Thus, the Company failed to identify any other regulatory risk not accounted for in its analysis that should deserve additional consideration and that would support the choice of portfolio P6(b) as the preferred portfolio. Finally, the action plan produced by the Company's 2015 IRP contains no significant planning or operational decisions that already were not established in previous IRPs, such as Jim Bridger modifications or the continued permitting of the Boardman-to-Hemingway transmission line (B2H). That said, little stands for the Commission's review and subsequent decision as far actionable items go.

[15] Ibid., at page 119.
[16] Ibid.

When Staff considers the situation in which the Company's preferred portfolio decision ultimately leads to more scrutiny, it cannot help but think that this "risk" is rendered moot. If the Company would like to avoid regulatory scrutiny, then selecting a portfolio that adheres to the guidelines, statutes and policies under which the regulators operate would best accomplish that. Portfolio P6(b) as Staff has stated, is not supported as the preferred portfolio.

Component 6: Qualitative – "Resource Commitment Risk"[17]

Staff first notes that it agrees with this risk, which involves "the timing of, and commitment to, new resources" that can be affected by factors such as "siting issues, partnership influences, and the performance of existing resources."[18] As Idaho Power indicates, a number of factors, some of which are not in the control of the Company, affect the timeline of a planned resource. However, Staff questions the use of this particular risk to justify the selection of preferred portfolio P6(b). This risk applies to all portfolios, scalable to the extent of how many additional resources are included in a particular portfolio.

Portfolio P9 is illustrative in demonstrating that consideration of this risk does not support the selection of P6(b) as the preferred portfolio. P9 differs from P6(b) in two ways: 1) it retires Valmy Unit 1 in 2019 rather than 2025, and 2) it relies on a combination of reciprocating engines and 15MW of additional demand response instead of ice-thermal energy storage units. Though Valmy Unit 1's early retirement in P9 proportionally reduces the time until the first capacity deficit, Idaho Power meets said deficit with a combination of reliable and known reciprocating engines and demand response. This is in contrast with the entire reliance on B2H in preferred portfolio P6(b), which given the projects complex and uncertain process, seems to have a far greater "commitment risk" than dispatchable and manageable resources like demand response or reciprocating engines. A dispatchable resource enables the Company to rely on its energy when needed, creating additional value in the form of reliability and capacity. If anything, P9 offers the Company greater certainty and flexibility in meeting resource needs as opposed to the continued reliance on B2H, whose complicated and involved permitting, evaluation and regulatory process engenders much uncertainty. Staff continues to analyze this particular qualitative risk.

Component 7: Qualitative – "PURPA Development"[19]

Staff recognizes that unbuilt Public Utilities Regulatory Policies Act generating units (PURPA resources) engender uncertainty for the Company's planning process.

[17] Ibid.
[18] Ibid., at page 127.
[19] Ibid., at page 128.

However, Staff underscores that this uncertainty is applicable to all resource portfolios under review by the Company and does not suffice alone as a reason to select portfolio P6(b) as the preferred portfolio. In fact, the table provided under the "PURPA Development" section in the IRP indicates that PURPA uncertainty is a reason *not* to select Portfolio P6(b) as the preferred portfolio when compared to other coal unit retirement scenarios.[20] Specifically, the first peak-hour capacity deficit occurs one year earlier for the preferred portfolio P6(b) due to the 141 MW PURPA deficit created by the withdrawal of four solar projects. At the same time, portfolios that retire Valmy Unit 1 in 2019 (P8, P9) or retire Jim Bridger units 1 and 2 in 2023 and 2032, respectively, (P10 and P11) are unaffected. In other words, preferred portfolio P6(b) is sensitive to a loss of PURPA resources whereas the other four portfolios are not. This analysis suggests that if the Company were to prioritize mitigating risk in planning resources due to PURPA uncertainty, the four alternative portfolios that Staff has identified throughout this analysis would provide better results for ratepayers in that it reduces risk for Company planning.

Idaho Power points to PURPA solar projects as one of the "risk exposure" factors associated with the selection of preferred portfolio P6(b).[21] Specifically, the Company states,

> "As unbuilt resources, uncertainty persists in relation to the remaining 320 MW of solar PURPA projects. Further contract terminations will lead to earlier onsets of system deficiencies and may ultimately require Idaho Power to construct system resources earlier than expected and with larger capacities."

Staff agrees that some level of uncertainty exists in the interim period between a Qualifying Facility (QF) contract execution date and the date the QF becomes operational. However, including contractually committed QF resources is reasonable, and is consistent with methods employed by at least one other Oregon utility.[22]

Finally, Staff notes that according to supplemental testimony filed in Docket UM 1725, Idaho Power recently executed contracts for 69 MW of solar QF capacity in Oregon, and has active requests for 11 additional Oregon contracts representing 87.4 MW. [23] The interim eligibility cap for standard contracts in Oregon is three MW, pending a Commission decision in that docket. [24] The same testimony indicates that the majority of QF contracts in progress in Idaho are now considered withdrawn or inactive, subsequent to the decision by the Idaho Public Utilities Commission to limit the

[20] Idaho Power 2015 IRP, Table 9.5, at page 128, Docket No. LC 63, June 30, 2015.
[21] Idaho Power 2015 IRP p. 141.
[22] e.g., PacifiCorp 2015 IRP, Table 5.7, Non-owned Solar Resources, includes 566 MW of solar QF capacity.
[23] Docket UM 1725, Idaho Power Company's Motion for Leave to File Supplemental Testimony, filed October 28, 2015.
[24] Order No. 15-199 at 7.

maximum contract term for “IRP-based” QF contracts to two years.[25] These changing factors related to QF policy in the two jurisdictions will impact future QF contract obligations, but do not significantly impact the likelihood that QFs with existing contracts will become operational.

Idaho Power discusses the likelihood of issues associated with energy oversupply that may result from under-forecasting PURPA development. In addition to the flexible-resource needs assessment in the 2015 IRP, Staff believes that Idaho Power’s potential participation in the CAISO energy imbalance market brings further opportunities to effectively manage energy oversupply events.

In conclusion, Staff believes the PURPA qualitative risk applies to all portfolios and is insufficient in justifying portfolio P6(b) as the preferred portfolio.

Component 8: Qualitative – “Demand-Side Management (DSM) implementation”[26]

Despite Idaho Power’s extensive experience implementing DSM, the Company notes risk associated with DSM, including varying program results. Staff notes that Idaho Power has had no issue with exceeding its own IRP targets for energy efficiency dating back as far as 2003.[27] Because of this consistent and impressive trend and due to the Company’s remarks in the analogous IRP docket at the Idaho Public Utility Commission, Staff believes this particular risk is insufficient in supporting the choice of portfolio P6(b) as the preferred portfolio.[28]

Staff Opening Comments’ Recommendation

Staff does not support the selection of portfolio P6(b) as the portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.

Demand-Side Management

Acquisition of 84 average megawatts (aMW) and 126 MW peak demand of cost effective energy efficiency over the action plan timeframe of 2015-2019 is a 22 percent increase over the 5 year efficiency targets from the 2013 IRP. This increase in cost effective resource is encouraging and Staff appreciates the work of the Company in reporting efficiency results (Appendix B) and in working with Applied Energy Group (AEG) to produce a comprehensive conservation potential study.

[25] Order 33357 at 32.
[26] Ibid., at page 130.
[27] Idaho Power’s 2015 IRP, Figure 4.1, at page 42, Docket No. LC 63, June 30, 2015.
[28] Idaho Power’s reply comments, at page 9, Docket No. IPC-E-15-19, October 19, 2015.

Over the next 20 years, the Company is planning to acquire all achievable cost effective efficiency. At this stage of review, Staff is focusing questions and additional review on four areas related to details of how that efficiency is determined and plans for acquisition of the resource.

1. The Company provided some clarification through its response to information request (IR) 19 related to how market transformation savings compare to acquisition savings within the conservation potential study and the action plan savings targets. Idaho power continues to support the work of Northwest Energy Efficiency Alliance (NEEA) and those savings should be reflected in the action plan targets as well as the 20 year potential assessment. Staff plans to seek further clarification regarding how what was described in the IR response as “pre 2010” NEEA reporting methodologies would impact the 2013 IRP and 2015 IRP and if NEEA savings are indeed reflected in both the potential study and the targets.

2. Staff would like a better understanding of how short term market dynamics of program activity and customer interest intersect with the ramp rates and acquisition targets resulting from the AEG conservation potential study. The Company notes that savings targets are calibrated to historical savings but the result was a target to acquire just 77 percent of what was acquired in the prior year. Staff understands timing challenges between assumptions used in studies compared to real time program acquisition but would like to better understand the extent to which the two can be better aligned prior to setting action plan targets.

3. The Company’s response to IR 24 noted the difference between cost-effective achievable savings potential noted in the overall summary of energy efficiency potential section of the AEG study and the 20 year acquisition plan is due to special contract customers. Staff would like to better understand how that savings was derived and the relative risk in acquisition of that savings.

4. The declining cumulative capacity contribution for efficiency resource acquisition was clarified by the Company in its response to IR 25 to not be caused by end of measure life impacts but due to year to year variation in when system peak occurs. However, Staff would now like to better understand how the monthly “forecast EE” in Appendix C, pp 29-48, relate to the existing DSM peak hour resource for similar time periods in pages 50-69.

Resource Stack Assumptions

Staff questions Idaho Power's inclusion of residential solar PV projects' plant capital costs as costs incurred by the Company.[29] Capital costs for solar PV projects related to any aspect of installation behind the meter (such as the panels, bill of supply, wiring, etc.) are borne by the customer. Resource planning costs should be costs from the utility's perspective; an Idaho Power customer who decides to install solar does so under her own financial agency. Staff firmly believes that costs related to residential solar PV installations are those explicitly described in either Oregon's or Idaho's respective net-metering statutes or laws.

Natural Gas and Electricity Price Forecast

The Company uses natural gas prices as inputs of its IRP modeling in Auroraxmp® (AURORA). AURORA, in turn, produces portfolio runs, including electricity prices.

In Idaho Power 2015 IRP, the Company used the Energy Information Administration (EIA) natural gas price forecast from the *Annual Energy Outlook 2014* published in April 2014. As represented in Figure 1 below, the Company used three forecasts of nominal natural gas prices representing low, medium, and high scenarios.

[29] Idaho Power's 2015 IRP, Appendix C, at page 85, Docket No. LC 63, June 30, 2015.

Figure 1[30]
(Henry Hub Price Forecast)

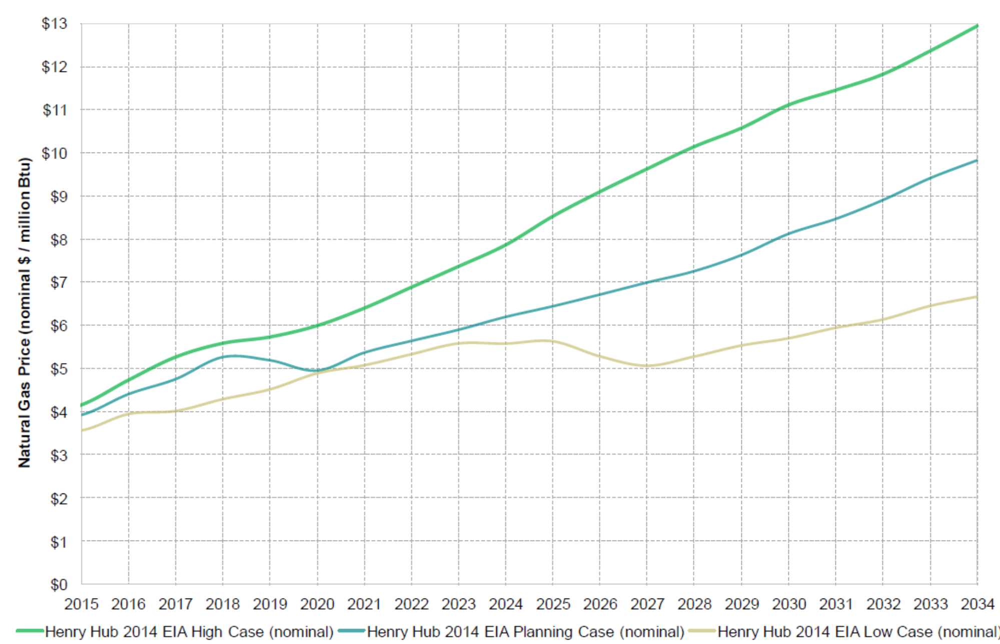
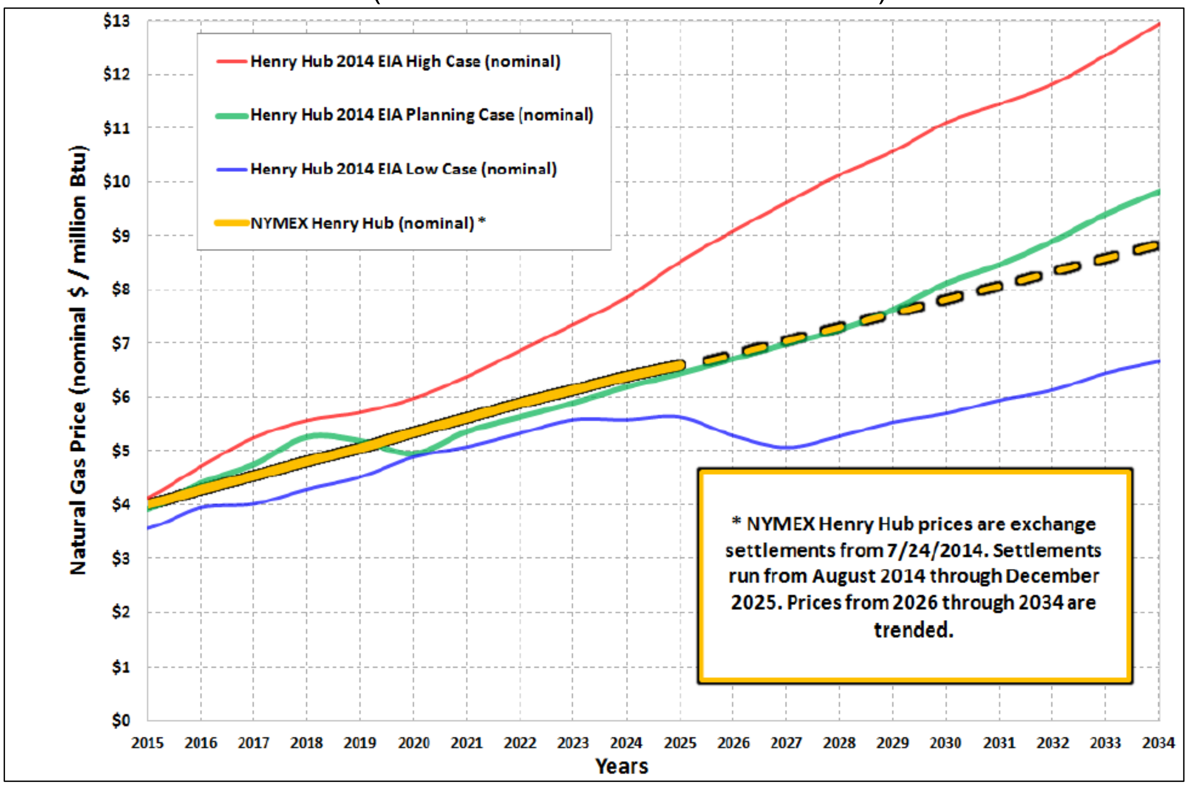


Figure 7.4 Henry Hub price forecast—EIA *Annual Energy Outlook 2014* (nominal dollars)

The Company contrasted the natural gas prices of EIA with NYMEX futures exchange settlements through December 2025 as shown in the figure below provided by the Company in response to Staff information request (IR) 2, included as pages 1-7 of Appendix 1 to these comments.

[30] Source: Page 85 of Idaho Power 2015 IRP at https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2015/2015IRP.pdf

Figure 2[31]
(NYMEX and EIA'S Price Forecasts)



The above figure shows that the medium (planning) natural gas price forecast is close to the NYMEX exchange settlements for the entire ten years of data.

In Idaho Power's 2013 IRP, Staff expressed concern about the Company's use of escalation factors in forecasting natural gas prices. Staff also was concerned about the Company's using symmetric adjustments to the base case to develop the high and low cases. These issues were corrected in Idaho Power's 2015 IRP by the Company directly using EIA's low, medium (planning or base), and high cases for the analysis.

Staff Opening Comments' Recommendation

Staff concludes that the Company's natural gas price forecast is not unreasonable.

<u>Hedging</u>

Staff reviewed how the Company addressed the Public Utility Commission of Oregon's (OPUC) guideline related to hedging. This guideline reads as follows:

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[31] Source: Page 4 of Appendix A to these comments.

> "*To address risk, the plan should include, at a minimum…[a] [d]iscussion of the proposed use and impact on costs and risks of physical and financial hedging.*"[32]

In page 182 of Appendix C to Idaho Power 2015 IRP, Idaho Power described as follows how the Company addressed the portion of guideline "c":

> "…*[t]he risks of physical and financial hedging are referenced to Idaho Power's Energy Risk Management Policy discussed in* ***Chapter 1 (Summary), in the last paragraph of section Introduction on page 2***." [33] (Emphasis added.)

In ***Chapter 1 (Summary), in the last paragraph of section Introduction on page 2,*** of Idaho Power 2015 IRP, the Company stated:

> "*IRPs address Idaho Power's long-term resource needs. Idaho Power plans for near-term energy and capacity needs in accordance with the Energy Risk management Policy and Standards. The risk management standards were collaboratively developed in 2002 between Idaho Power, IPUC staff, and interested customers (IPUC Case No. IPC-E-01-16). The Energy Risk Management Policy and Standards specifies an 18-month period, and Idaho Power assesses the resulting operation plant monthly.*"[34]

Apart from the above quotations, Staff did not find the discussion of the proposed use and impact on costs and risks of physical and financial hedging required in guideline "c"; therefore in Staff IR 3, Staff requested Idaho Power to provide a discussion of how the Company currently uses physical and financial instruments to hedge the price of electricity and natural gas. The Company provided the below explanation as included as pages 8-9 of Appendix 1 to these comments:

> "*Sections 5.1 – 5.5 from the Energy Risk Management Standards describe a three-tiered approach for managing risk in Idaho Power's portfolio. The strategy strives to balance Idaho Power's load and resource balance (portfolio), on a monthly basis, as various forecasts are updated (load, prices, hydro, etc.). Buy or sell market orders for specific months over the 18-month horizon are determined by economically dispatching all Company resources in relation to forward market prices. At a high level, risk is reduced by keeping generation resources and market buys and sells matched to within plus or minus 100 megawatts ("MW") of load on a monthly basis by buying or selling financial futures/swaps, physical electricity, or natural gas.*

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[32] Page 2 of 7 of Appendix A to Order No. 07-002 in Docket No. UM 1056 at http://apps.puc.state.or.us/orders/2007ords/07-002.pdf

[33] See at https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2015/2015_IRPAppC_Tech.pdf

[34] See page 2 of Idaho Power 2015 IRP at https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2015/2015IRP.pdf

Idaho Power uses financial and physical instruments as a means for fixing power supply costs and reducing exposure to changes in market prices. Idaho Power primarily buys or sells financial futures/swaps over the ICE exchange or from our bilateral counterparties. These derivatives are indexed to the day-ahead Mid-C physical market and Idaho Power will buy or sell the physical energy at index price in the day-ahead market to match the financial quantities previously bought or sold as part of our term hedging strategy that is outlined in the Energy Risk Management Policy and Standards.

While the Energy Risk Management Policy and Standards describe a planning horizon of 18-months that is updated on a monthly basis, the IRP has a 20-year planning horizon and is updated every two years. Hedging is not modeled in the IRP analysis; however, total portfolio cost is determined for each portfolio and then compared on a relative basis." [35]

Staff Opening Comments' Recommendation

Through discovery, the Company has provided a discussion addressing IRP guideline "c" related to the use of physical and financial hedging. However, for next IRP, Staff recommends the Company provide, in the body of the IRP, this description as well as the impact on costs and risks of physical and financial hedging.

Transmission Action Plan

The Company proposed the following transmission action items:

Table 1: Action Items Discussed by Staff

Year(s)	Resource	Action	Action Number
2015-2018	Boardman to Hemingway (B2H)	Ongoing permitting, planning studies, and regulatory filings	1
2015-2018	Gateway West	Ongoing permitting, planning studies, and regulatory filings	2

Action Item: B2H Ongoing Permitting, Planning Studies, and Regulatory Filings

Idaho Power requests the ongoing permitting, planning studies and regulatory filings of the B2H transmission line. In these comments, Staff refers as "permitting" efforts to the permitting, planning studies and regulatory filings of the B2H transmission line.

[35] See page 9 of Appendix A to these comments.

The B2H project consists of a single-circuit 500-kV transmission line of approximately 300 miles between the proposed Longhorn Station in the Boardman, Oregon area and the Hemingway Substation in southwest Idaho.[36]

Staff Opening Comments' Recommendation

Staff recommends that the Commission acknowledge the permitting efforts of the B2H transmission line as requested by the Company because this transmission line was part of the preferred resource portfolios of the Company's 2009, 2011, and 2013 IRPs, and is part of the five lowest-cost portfolios in this current 2015 IRP.[37]

Action Item: Gateway West Ongoing Permitting, Planning Studies, and Regulatory Filings

Idaho Power requests that the Commission acknowledge the permitting efforts of the Gateway West transmission line.

The Gateway West transmission line project is a joint project between Idaho Power and Rocky Mountain Power to build and operate approximately 1,000 miles of new transmission lines from the planned Windstar Substation near Glenrock, Wyoming, to the Hemingway Substation near Melba, Idaho.[38]

In the Company's IRP the Company provided the following benefits of this project:[39]

- Relieve Idaho Power's constrained transmission system between the Magic Valley area (Midpoint) and the Treasure Valley area (Hemingway). Transmission connecting the Magic Valley and Treasure Valley is part of Idaho Power's "core" transmission system, connecting two major Idaho Power load pockets;
- Provide the option to locate future generation resources east of the Treasury Valley;
- Provide future load-service capacity to the Magic Valley from the Cedar Hill Substation; and
- Transmission capability is needed to meet the transmission needs of the future, including transmission needs associated with intermittent resources.

[36] See pages 66 and 67 of Idaho Power 2015 IRP at https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2015/2015IRP.pdf
[37] See page 117 of Idaho Power 2015 IRP at https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2015/2015IRP.pdf
[38] See page 69 of Idaho Power 2015 IRP at https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2015/2015IRP.pdf
[39] See page 69 of Idaho Power 2015 IRP at https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2015/2015IRP.pdf

Staff Opening Comments' Recommendation

Staff recommends that the Commission acknowledge the permitting efforts of the Gateway West transmission line as requested by the Company because of the preliminary benefits that this transmission line presents.

This concludes Staff's Opening Comments.

Dated at Salem, Oregon, this 25th of November, 2015.

Michael Breish

Michael Breish
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<u>STAFF'S INFORMATION REQUEST NO. 2</u>:

NATURAL GAS PRICE FORECAST

Regarding Idaho Power 2015 IRP, page 84 and 85, where the Company represented:

> **"*… For the 2015 IRP, Idaho Power is using the US Energy Information Administration (EIA) natural gas price forecast…The natural gas price forecast was discussed during the first three monthly IRPAC meetings held in August through October 2014. During these discussions, Idaho Power provided comparisons of the EIA natural gas price forecast to an alternative forecast, as well as comparison to observed settlement prices for futures trading in the natural gas market.***
>
> ***The Annual Energy Outlook 2014, published by the EIA in April 2014, is the source for the natural gas price forecast for the 2015 IRP. For the 2015 IRP, Idaho Power uses nominal prices, as published by the EIA, as inputs to the analysis performed. Figure 7.4 shows forecast Henry Hub natural gas prices. The low- and high-case natural gas price forecasts used for the 2015 IRP and shown on the chart corresponds respectively to the high resource (high availability) and low resource (low availability) cases reported by the EIA in the Annual Energy Outlook 2014. Idaho Power applies a Sumas basis and transportation cost to the Henry Hub price to derive an Idaho Citygate price. The Idaho Citygate price is representative of the gas price delivered to Idaho Power's natural gas plants. The Idaho Citygate price forecast is provided in Appendix C – Technical Appendix.*"**

Please:

a. **Provide the values of each Henry Hub natural gas price forecast referenced in the above quotation (i.e., the high case, planning case, and low case in Figure 7.4 of Idaho Power 2015 IRP) for each year for the period of analysis of this current IRP (i.e., 2015 through 2034);**

b. **Provide copies of the relevant pages of the Annual Energy Outlook 2014 where the values provided by the Company in part "a" of this request can be identified;**

c. **Provide an explanation of how the Company derived the Citygate natural gas price values referenced in the above quotation (i.e., the high case, planning case, and low case in page 129 of Appendix C to of Idaho Power 2015 IRP) from the Henry Hub natural gas prices referenced in the above quotation (i.e., the high case, planning case, and low case in Figure 7.4 of Idaho Power 2015 IRP);**

d. **Provide the workpapers, in electronic spreadsheet format with cell references and formulae intact, used by the Company to derive the Idaho Citygate natural gas price values referenced in the above quotation (i.e., the high case, planning case, and low case in page 129 of Appendix C to of Idaho Power 2015 IRP) from the Henry Hub natural gas prices referenced in the above quotation (i.e., the high case, planning case, and low case in Figure 7.4 of Idaho Power 2015 IRP);**

e. **Provide the values of natural gas prices used by AURORA for each portfolio analyzed by the Company (i.e., each of the portfolios in Table 9.3 of Idaho Power 2015 IRP) and for each year for the period of analysis of this**

current IRP (i.e., 2015 through 2034). NOTE: In this request, Staff is not requesting the natural gas prices assumed as fuel for Idaho Power's generating fleet, but rather the fuel prices used by AURORA for the natural gas generation units in the WECC interconnection as referenced by the Company in page 113 of its 2015 IRP: "Multiple electricity markets, zones, and hubs can be modeled using AURORA. Idaho Power models the entire WECC system when evaluating the various resource portfolios for the IRP.";

f. Provide an explanation of the comparison to observed settlement prices referenced in the above quotation; please also include copies of the materials associated with natural gas forecasts in the three monthly IRPAC meetings held in August through October 2014;

g. An explanation of the differences between the methodologies and sources for forecasting natural gas prices in this current Idaho Power 2015 IRP and the methodologies[3] and sources used in the previous three IRPs;

h. Regarding the Company's response to part "g" of this data request, has any Commission (e.g., Idaho Public Utilities Commission, Oregon Public Utility Commission, etc.) ordered the Company to revise its natural gas forecast methodology?

  i. If the Company's response is "yes," please provide an comprehensive explanation whether the Company has addressed such Commission order;

  ii. If the Company's response is "no," please explain why not.

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S INFORMATION REQUEST NO. 2</u>:

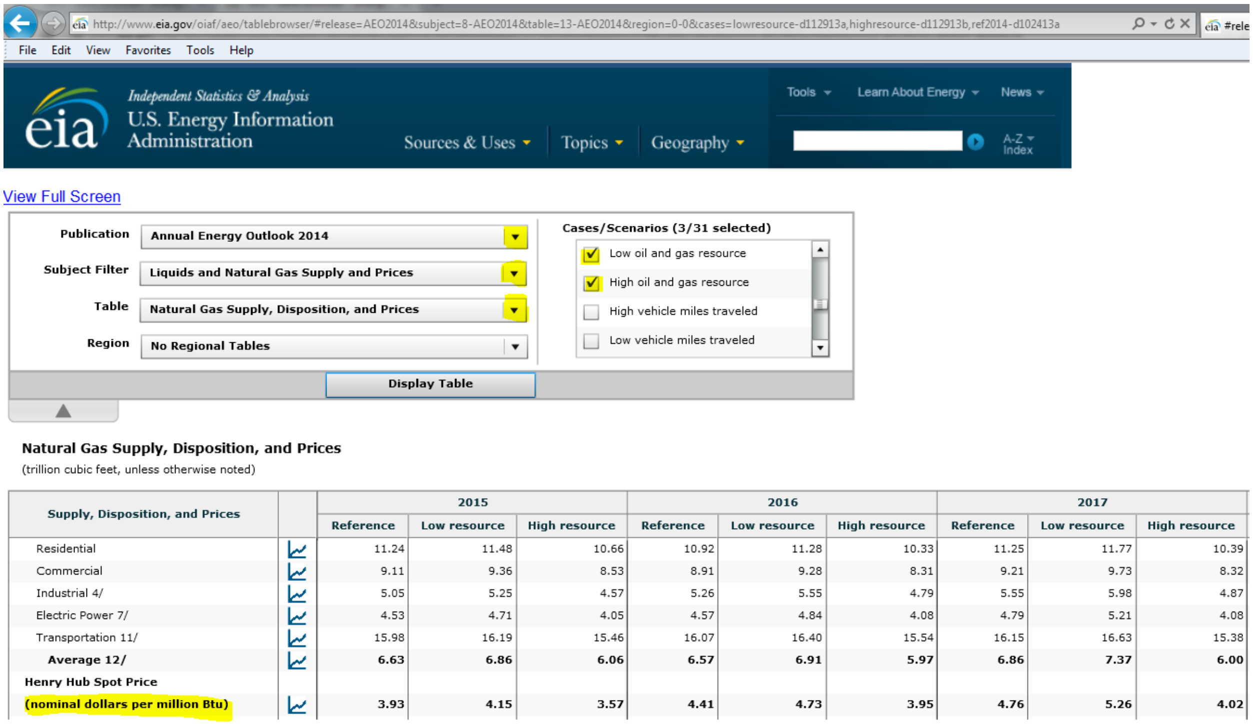
a. Please see Attachment 1 to the response to Staff's Information Request No. 2-a.

b. The Henry Hub natural gas price forecast for the 2015 IRP was taken from the 2014 Annual Energy Outlook published by the EIA on May 7, 2014. Idaho Power referenced the Henry Hub reference case, nominal spot price forecast that can be found on the EIA's website at: http://www.eia.gov/forecasts/archive/aeo14/excel/aeotab_13.xlsx

The high and low cases were taken from the EIA "Low oil and gas resource" and the "High oil and gas resource" cases, respectively. This data was taken from the EIA's website and can be found by copying and pasting the following link into a web browser: http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014&subject=8-AEO2014&table=13-AEO2014&region=0-0&cases=lowresource-d112913a,highresource-d112913b,full2013full-d102312a,ref2014-d102413a

[3] Examples of methodology could be: (1) the usage of an average of natural gas prices forecasts from different sources for the 20-year period of analysis ; (2) usage of a forecast for the next few years and escalating for the remaining years; (3) using price forecast in real values and expressing in nominal values by performing adjustments; etc.

Please see the screenshot below as an example of how to access the high and low scenarios:



Supply, Disposition, and Prices	2015 Reference	2015 Low resource	2015 High resource	2016 Reference	2016 Low resource	2016 High resource	2017 Reference	2017 Low resource	2017 High resource
Residential	11.24	11.48	10.66	10.92	11.28	10.33	11.25	11.77	10.39
Commercial	9.11	9.36	8.53	8.91	9.28	8.31	9.21	9.73	8.32
Industrial 4/	5.05	5.25	4.57	5.26	5.55	4.79	5.55	5.98	4.87
Electric Power 7/	4.53	4.71	4.05	4.57	4.84	4.08	4.79	5.21	4.08
Transportation 11/	15.98	16.19	15.46	16.07	16.40	15.54	16.15	16.63	15.38
Average 12/	**6.63**	**6.86**	**6.06**	**6.57**	**6.91**	**5.97**	**6.86**	**7.37**	**6.00**
Henry Hub Spot Price									
(nominal dollars per million Btu)	**3.93**	**4.15**	**3.57**	**4.41**	**4.73**	**3.95**	**4.76**	**5.26**	**4.02**

c. The Idaho Citygate natural gas price forecast is calculated by summing three components: the Henry Hub price forecast, the Sumas basis, and a transport cost. The Henry Hub component is the nominal forecast taken from the EIA's Annual Energy Outlook as described in part B of this request. The Sumas basis is calculated as a percentage differential between the EIA's forecast for "Henry Hub" and "West Coast". The third component of the Idaho Citygate price is the transport cost. The transport cost estimates the cost to deliver the fuel from the region into the Idaho Power service territory.

d. Please see confidential Attachment 2 to the response to Staff's Information Request No. 2-d.

e. Using the AURORA model, Idaho Power modeled electrical generators across the Western Electricity Coordinating Council ("WECC") in the portfolio and risk analyses in the 2015 IRP. Many of these generators are fueled by natural gas. All of these generators have a reference to the Henry Hub price forecast described in part B of this request. In addition to the Henry Hub forecast, EPIS, Inc. ("EPIS"), the software developer of AURORA, has regional basis adjustments made to reflect the delivered cost to the respective locations across the WECC. Idaho Power does not make changes to these adjustments in its portfolio analysis. The adjustments to the Henry Hub natural gas price in the AURORA model are shown in confidential Attachment 3 to the response to Staff's Information Request No. 2-e.

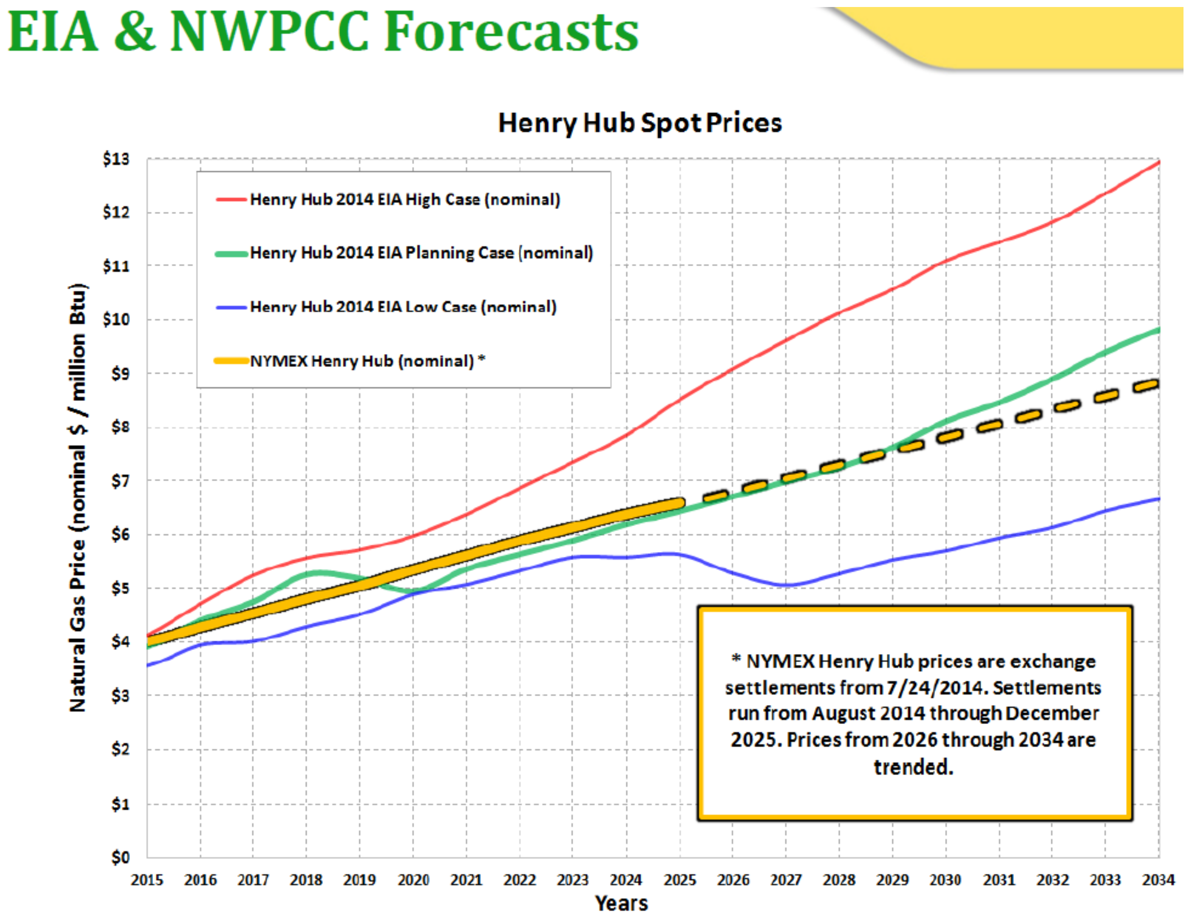
f. The following links are to the slides presented to the IRPAC on August 7, September 4, and October 2, 2014:

August 7, 2014 (refer to slides 57-62):
https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2015/Presentation080714.pdf

September 4, 2014 (refer to slides 44-48):
https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2015/agenda_presentation090414.pdf

October 2, 2014 (refer to slides 5-7):
https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2015/presentation100214.pdf

On October 2, 2014, the following slide was presented to the IRPAC.



The slide compares the planning, high and low cases Henry Hub forecast from EIA to the NYMEX future exchange settlements through December 2025. NYMEX exchange settlements beyond 2025 are extrapolated linearly. It is observed in the comparison that the planning natural gas price forecast is very close to the NYMEX exchange settlements for the entire 10 years of data. The linear extrapolation of the NYMEX settlements beyond 2025 is within $1.00 of the EIA's forecasted gas prices for every year of the 20-year forecast.

g. From Idaho Power's 2015 IRP (page 84):

> Future natural gas price assumptions significantly influence the financial results of the operational modeling used to evaluate and

> rank resource portfolios. For the 2015 IRP, Idaho Power is using the US Energy Information Administration (EIA) natural gas price forecast. Idaho Power also used the EIA as the source for the natural gas price forecast for the 2013 IRP and continues to use the EIA forecast for Idaho-jurisdiction avoided cost-calculation purposes. The natural gas price forecast was discussed during the first three monthly IRPAC meetings held in August through October 2014. During these discussions, Idaho Power provided comparisons of the EIA natural gas price forecast to an alternative forecast, as well as comparisons to observed settlement prices for futures trading in the natural gas market.
>
> The Annual Energy Outlook 2014, published by the EIA in April 2014, is the source for the natural gas price forecast for the 2015 IRP. For the 2015 IRP, Idaho Power uses nominal prices, as published by the EIA, as inputs to the analysis performed. Figure 7.4 shows forecast Henry Hub natural gas prices. The low- and high-case natural gas price forecasts used for the 2015 IRP and shown on the chart correspond respectively to the high resource (high availability) and low resource (low availability) cases reported by the EIA in the Annual Energy Outlook 2014. Idaho Power applies a Sumas basis and transportation cost to the Henry Hub price to derive an Idaho city-gate price. The Idaho city-gate price is representative of the gas price delivered to Idaho Power's natural gas plants. The Idaho city-gate price forecast is provided in Appendix C—Technical Appendix.

From Idaho Power's 2013 IRP (page 62):

> Idaho Power is using the US Energy Information Administration (EIA) natural gas price forecast for IRP and avoided-cost calculations. The Annual Energy Outlook 2012 Reference case was published by the EIA in June 2012, and Idaho Power used the Annual Energy Outlook 2012 forecast for the 2013 IRP. A graph of the forecasted Henry Hub natural gas prices is shown in Figure 5.6. Idaho Power computed a high and low natural gas price forecast by adjusting the EIA natural gas price forecast upward and downward by 30 percent. The high and low forecasts are also shown in Figure 5.6. Idaho Power applies a Sumas basis and transportation cost to the Henry Hub price to derive an Idaho city-gate price. The Idaho city-gate price is representative of the gas price delivered to the Idaho Power gas plants.

For several IRP's prior to Idaho Power's 2013 IRP, the Company used a composite natural gas price forecast as described in the 2011 IRP (page 69):

> Future natural gas price assumptions significantly influence the financial results of the operational modeling used to evaluate and rank resource portfolios. The 2011 IRP natural gas price forecast uses several outside public and private forecast sources to develop a composite future yearly Henry Hub price curve. The

forecast sources include the NPCC, the New York Mercantile Exchange (NYMEX), the Natural Gas Exchange, the Energy Information Administration (EIA), and Moody's Analytics, Inc.

The individual annual forecasts from the outside sources are evaluated and weighted to calculate the composite forecast. The weighting is based on a combination of Idaho Power's expectation of price, the reasonableness of the forecasts when compared with others, and the current forward price of actual contracts being executed on various exchanges. In the near term forecast horizon, greater weight is given to actual commitment contracts being executed on the NYMEX compared to longer term forecasts that are weighted more heavily towards projected prices without underlying financial trades (EIA, Moody's, Inc.).

Regional price variability from the Henry Hub can be significant. Idaho Power uses a price adjustment (basis) based on the cost of delivering natural gas from the Sumas trading hub to model natural gas prices in southwest Idaho. The Sumas price adjustment incorporates the Pacific Northwest regional price variation from Henry Hub and the transportation charges from Northwest Pipeline Corporation to deliver natural gas to Idaho Power's service area. The 2011 IRP assumes existing pipeline transport capacity is sufficient to serve only existing demand. The cost of new gas resources includes an additional transportation cost to account for the cost of constructing new pipeline capacity. This additional cost is approximately twice the current tariff rate.

h. The passages below are taken from the final Public Utility Commission of Oregon ("OPUC") order and the final Idaho Public Utilities Commission ("IPUC") order on Idaho Power's 2013 IRP. Both Oregon and Idaho Staff recommended not using a separate escalation factor for natural gas prices. In addition, Oregon Staff recommended not using symmetric adjustments to the base case to develop the high and low risk analysis cases. These issues were resolved in Idaho Power's 2015 IRP by using the EIA nominal high, reference, and low cases for the analyses.

From OPUC Order No. 14-253 (page 14):

3. Gas Price Forecasts

a. Participants' Comments

Staff comments on three aspects of Idaho Power's natural gas price forecasts used in the IRP. Staff expresses concerns regarding the symmetric adjustments to the base case forecast, the escalation of the Energy Information Administration (EIA) reference case gas price forecast, and the high correlation between natural gas prices and wholesale electricity prices in the company's modeling. Staff identifies gas price forecasts as an issue to be analyzed during the development of the 2015 IRP. The company responds that its stochastic inputs are reasonable and that it will consider alternatives to deriving high and low gas price scenarios for future IRPs.

b. Commission Resolution

We anticipate that these analytical issues will be raised by Staff and addressed during the planning process for the 2015 IRP.

From IPUC Final Order No. 32980 (page 4):

2. <u>Natural Gas Forecasts</u>. Future natural gas price assumptions significantly influence how the Company evaluates and ranks resource portfolios. When forecasting natural gas prices, the Company uses gas forecasts provided by the U.S. Energy Information Administration's ("EIA") Annual Energy Outlook. See 2013 IRP at 62. Staff reviewed the Company's forecasts and says the Company should use the EIA's nominal forecast instead of applying the Company's own escalation factor to the 2010 constant dollar forecast. Staff believes the Company's escalation factor may overstate fuel costs for natural gas facilities. Staff Comments at 5-6.

In reply, the Company says it will use the EIA nominal forecast starting with the 2015 IRP. Company Reply at 18*.*

Attachments 2 and 3 produced in response to this Request are confidential and will be provided separately in accordance with the General Protective Order.

STAFF'S INFORMATION REQUEST NO. 3:

HEDGING

Regarding Idaho Power 2015 IRP, Appendix C, page 182, where Idaho Power described how the Company addressed the portion of guideline "c" related to hedging (i.e., the portion related to hedging of this guideline reads: "Discussion of the proposed use of and impact on costs and risks of physical and financial hedging.") as follows:

> **"…*The risks of physical and financial hedging are referenced to Idaho Power's Energy Risk Management Policy discussed in Chapter 1 (Summary), in the last paragraph of section Introduction on page 2.*" (Emphasis added)**

And,

Regarding Chapter 1 (Summary), in the last paragraph of section introduction on page 2 of Idaho Power 2015 IRP, where the Company represented:

> **"*IRPs address Idaho Power's long-term resource needs. Idaho Power plans for near-term energy and capacity needs in accordance with the Energy Risk management Policy and Standards. The risk management standards were collaboratively developed in 2002 between Idaho Power, IPUC staff, and interested customers (IPUC Case No. IPC-E-010-16). The Energy Risk Management Policy and Standards specifies an 18-month period, and Idaho Power assesses the resulting operation plant monthly.*" (Emphasis added)**

Please:

a. Provide a general discussion of how the Company currently uses physical and financial instruments to hedge the price of electricity and natural gas;
b. Provide a general discussion of how the Company in this current IRP proposes to use physical and financial instruments to hedge the price of electricity and natural gas;
c. Provide a copy of the Company's Energy Risk Management Policy;

In this request, by "general discussion," Staff expects the Company to provide a general discussion of the current or proposed use of physical and financial instruments to hedge the price of electricity and natural gas without only referring to the Energy Risk Management Policy and Standards.

An example of "general discussion" may cover: (1) the usage of physical and financial instruments from the short-, medium-, and long-term perspective;[4] (2) the rationale for targeting specific amounts of power or natural gas to be hedged for each perspective (e.g., short-, medium-, and long-term), say 20 percent of natural gas expected to be used in the next three years, 50 percent of natural gas expected to be used in the next year,

[4] By "short-term," "medium-term," and "long-term Staff refers to any period shorter than one year, approximately five years, and five years of longer respectively. However, Staff does not intend to constrain the Company to providing information only in a specific term basis which may not apply to the Company. Rather, Staff leaves it to the Company to define "short-term" "medium-term," and "long-term" in responding to this request.

100 percent of natural gas expected to be used in the next month, 50 percent of electricity purchases or sales expected to be needed in the next three years, 75 percent of electricity purchases or sales expected to be needed in the next year, 100 percent of electricity purchases and sales expected to be needed in the next month, etc.; (3) the risk management models used to determine the level of physical and financial instruments to hedge natural gas or electricity; etc.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S INFORMATION REQUEST NO. 3:

a. Sections 5.1 – 5.5 from the Energy Risk Management Standards describe a three-tiered approach for managing risk in Idaho Power's portfolio. The strategy strives to balance Idaho Power's load and resource balance (portfolio), on a monthly basis, as various forecasts are updated (load, prices, hydro, etc.). Buy or sell market orders for specific months over the 18-month horizon are determined by economically dispatching all Company resources in relation to forward market prices. At a high level, risk is reduced by keeping generation resources and market buys and sells matched to within plus or minus 100 megawatts ("MW") of load on a monthly basis by buying or selling financial futures/swaps, physical electricity, or natural gas.

   Idaho Power uses financial and physical instruments as a means for fixing power supply costs and reducing exposure to changes in market prices. Idaho Power primarily buys or sells financial futures/swaps over the ICE exchange or from our bilateral counterparties. These derivatives are indexed to the day-ahead Mid-C physical market and Idaho Power will buy or sell the physical energy at index price in the day-ahead market to match the financial quantities previously bought or sold as part of our term hedging strategy that is outlined in the Energy Risk Management Policy and Standards.

   While the Energy Risk Management Policy and Standards describe a planning horizon of 18-months that is updated on a monthly basis, the IRP has a 20-year planning horizon and is updated every two years. Hedging is not modeled in the IRP analysis; however, total portfolio cost is determined for each portfolio and then compared on a relative basis.

b. Idaho Power intends to continue following the existing Energy Risk Management Policy and Standards as it has historically. Future modifications to the policy as needed will be vetted through the Customer Advisory Group on which Oregon Staff participates.

c. Please see confidential Attachments 1 and 2 to the response to Staff's Information Request No. 3-c.

The attachments produced in response to this Request are confidential and will be provided separately in accordance with the General Protective Order.