BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. LC 74

In the Matter of IDAHO POWER COMPANY, 2019 Integrated Resource Plan.	Staff's Opening Comments

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Introduction

These are Staff's initial comments and recommendations regarding Idaho Power Company's (Idaho Power or Company) 2019 Integrated Resource Plan (IRP). Staff will continue to review the Company's filed plan, responses to data requests, and parties' comments before filing final comments in this docket on June 19, 2020, and a Staff Report on August 21, 2020. The Staff Report will have Staff's conclusions regarding whether the IRP satisfies the Commission's IRP guidelines and recommendations regarding acknowledgment of Idaho Power's Action Plan.

Amended Application

The 2019 IRP has been an iterative public process and longer than normal. In addition to traditional IRP Advisory Council (IRPAC) meetings and subsequent public input, upon filing its IRP on June 28, 2019, Idaho Power identified the need to suspend its filing due to material errors it discovered. The Company requested a suspension of its process in order to conduct additional analysis, and both the Idaho and Oregon Commissions approved the request. Idaho Power subsequently filed an Amended IRP and Amended Appendices C and D on January 31, 2020. Appendices A and B did not change and can be found in the Company's initial June 2019 filing.

In the 2019 IRP, Idaho Power utilized the AURORA software's Long Term Capacity Expansion (LTCE) capability for the first time for the purpose of creating its resource portfolios. Though it had used AURORA for forecasting power prices in the past, it used a manual process to craft its portfolios instead. Important to note is that the Company implemented the switch to this new approach due to a recommendation from the Oregon Commission. In Order No. 18-176, the Commission recommended that the Company explore capacity expansion in its 2019 IRP, and the Company complied by implementing an overhaul of its IRP process.

Shortly after Idaho Power filed its IRP in June 2019, the Company discovered critical issues related to its LTCE and determined that supplemental analysis was needed to correct errors in its analysis. The core problem with the new approach was that the LTCE implementation optimized for a broader, Western Electricity Coordinating Council (WECC) footprint rather than specifically optimizing for Idaho Power's customers. Thus, certain resource choices were selected by the model and subsequently included in the original Action Plan. However, they were optimal resource decisions for the WECC, and not Idaho Power's service territory and customers. Once this error was identified, Idaho Power asked to suspend its IRP process, and between July 2019 and January 2020, Idaho Power hosted additional IRPAC meetings and worked to correct its analysis.

While it is unfortunate that the Company discovered major optimization problems only after it filed its IRP, Staff commends the Company for undertaking great efforts to implement the Commission order, and subsequently notifying stakeholders upon discovering critical errors in its analysis.

IRP Action Plan

Notable in this IRP is that the only resource acquisition in its Action Plan for which the Company is seeking acknowledgment, other than Boardman-to-Hemingway (B2H), is Jackpot Solar, which is not a major resource buildout, but a solar Power Purchase Agreement (PPA). All other Action Items are either reiterations of previous-year IRP Action Items[1] or non-resource acquisitions, such as plans to conduct studies. For ease of reference, Idaho Power's Amended 2019 Action Plan is copy and pasted below. It contains a mix of action items and key deadlines in a descending timeframe.

1. Plan and coordinate with PacifiCorp and regulators for early exits from Jim Bridger units. Target dates for early exits are one unit during 2022 and a second unit during 2026. Timing of exit from second unit coincides with the need for a resource addition.
2. Incorporate solar hosting capacity into the customer-owned generation forecasts for the 2021 IRP.
3. Jackpot Solar PPA regulatory approval—on-line December 2022.
4. Exit Valmy Unit 1 by December 31, 2019.
5. Conduct ongoing B2H permitting activities. Negotiate and execute B2H partner construction agreement(s).
6. Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.
7. Monitor VER variability and system reliability needs, and study projected effects of additions of 120 MW of PV solar (Jackpot Solar) and early exit of Bridger units.
8. Exit Boardman December 31, 2020.
9. Bridger Unit 1 and Unit 2 Regional Haze Reassessment finalized.
10. Conduct a VER Integration Study.
11. Continue to evaluate and coordinate with PacifiCorp for timing of exit/closure of remaining Jim Bridger units.
12. Subject to coordination with PacifiCorp, exit Jim Bridger unit (as yet undesignated) by December 31, 2022.
13. Jackpot Solar 120 MW on-line December 2022.
14. Exit Valmy Unit 2 by December 31, 2025.
15. Subject to coordination with PacifiCorp, exit Jim Bridger unit (as yet undesignated) by December 31, 2026. Timing of the exit from the second Jim Bridger unit is tied to the need for a resource addition (B2H).

There is also one additional Action Item listed in the Amended IRP: "Procure or construct resources resulting from RFP (if needed)." Staff asked about this in a data request because the preferred portfolio made no mention of a request for proposal (RFP), nor was there any discussion of an RFP anywhere in the Amended IRP. The Company responded that this Action Item should be disregarded and was inadvertently left in from the IRP filed back in June 2019.[2] Staff appreciates this update.

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[1] Some of these repeated Action Items are slightly modified.

[2] See Staff Attachment A, Idaho Power Response to Staff DR 12.

Portfolio Modeling

Long Term Capacity Expansion

During the 2017 IRP, Staff and other stakeholders were concerned about the lack of diversity in resource combinations in the Company's portfolio designs. In the previous methodology, the Company designed 12 portfolios based on four different strategies for Jim Bridger combined with three different primary resources: Boardman to Hemingway (B2H), natural gas resources, and a combination of solar and natural gas.[3] Staff felt this design led to limited portfolio options and recommended that Idaho Power increase the diversity of portfolios by enhancing its portfolio selection methodology and potentially incorporating methods such as LTCE modeling.[4]

The Company responded to Staff's recommendation by utilizing AURORA's LTCE tool in the 2019 IRP. The Company used AURORA to create 24 portfolios that demonstrate a wider range of strategies on a WECC-optimized basis, then selected four "top performing" portfolios out of these results. The Company then manually adjusted an additional 20 portfolios based on various modifications to the four "top" portfolios. The total number of portfolios created was 44, but it was the latter 20 manually-adjusted portfolios that that the Company evaluated for purposes of the Action Plan and selection of a preferred portfolio.

Portfolio Type	Count
WECC-optimized portfolios	24
Additional manually adjusted portfolios	20
Total	44

Staff appreciates the Company's efforts to enhance its portfolio modeling. Staff finds the Company achieved Staff's desired result of creating a more complex portfolio design methodology with a wider range of portfolio designs that incorporate capacity expansion planning. However, Staff does have concerns about the design process and transparency behind some of the manual adjustments.

Application of LTCE for portfolio design in this manner appears novel. Generally, in order to find an optimized portfolio for a given utility, capacity expansion models should optimize based on that company's system. The buildout that would be most cost-effective to meet the Company's needs will not necessarily be consistent with the buildout that is most cost-effective for the entire WECC. Once the Company generated its initial 24 WECC-optimized portfolios under the AURORA LTCE tool, it ran these through four scenarios on an hourly level to compare the performance of portfolios across the four chosen scenarios. These scenarios were:

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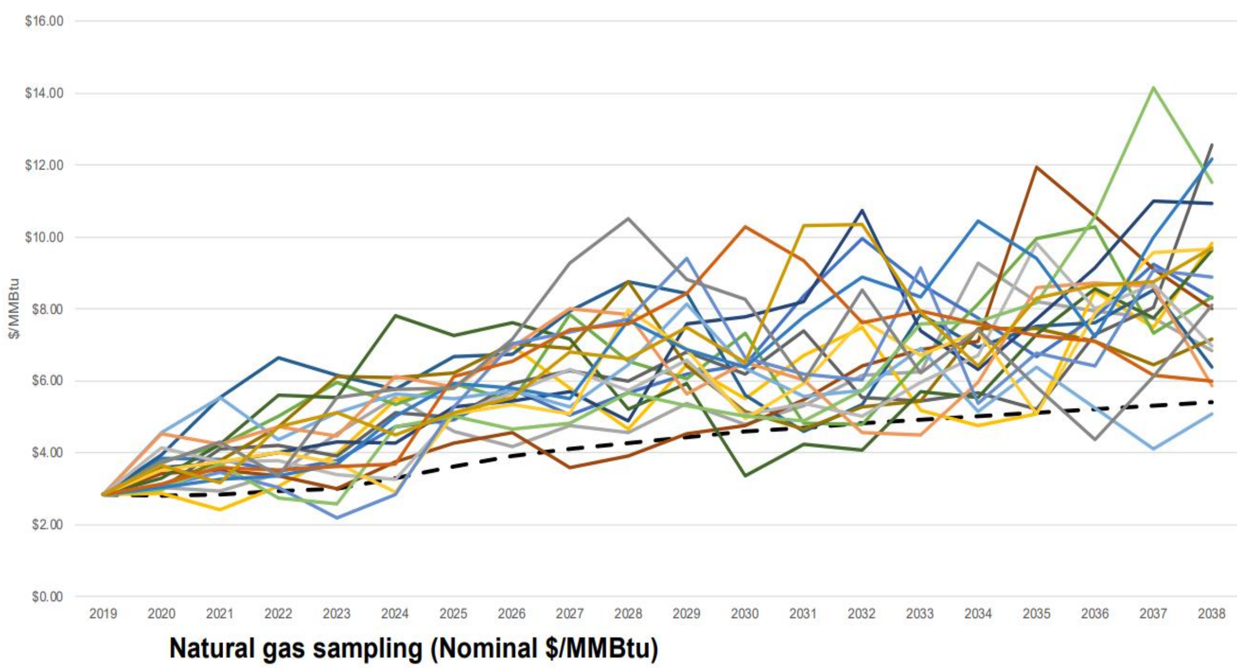
[3] LC 68, Idaho Power 2017 IRP, pp. 107-108.
[4] LC 68 Staff Report dated March 14, 2018, pp. 37-38.

- Planning Gas, Planning Carbon ("Planning scenario")
- Planning Gas, High Carbon
- High Gas, Planning Carbon
- High Gas, High Carbon[5]

"Planning Gas" is the base case gas price forecast, whereas "High Gas" involves a gas price forecast that assumes higher prices to account for risk. The Company hired a third-party vendor for its natural gas price forecast because many parties, including Staff, believed that the Company was under-forecasting its gas prices in the 2017 IRP. The results of the forecast are confidential, though an idea of the planning case can be seen in Figure 9.2 in the 2019 IRP, reproduced below.

Figure 1 – Natural Gas Pricing[6]



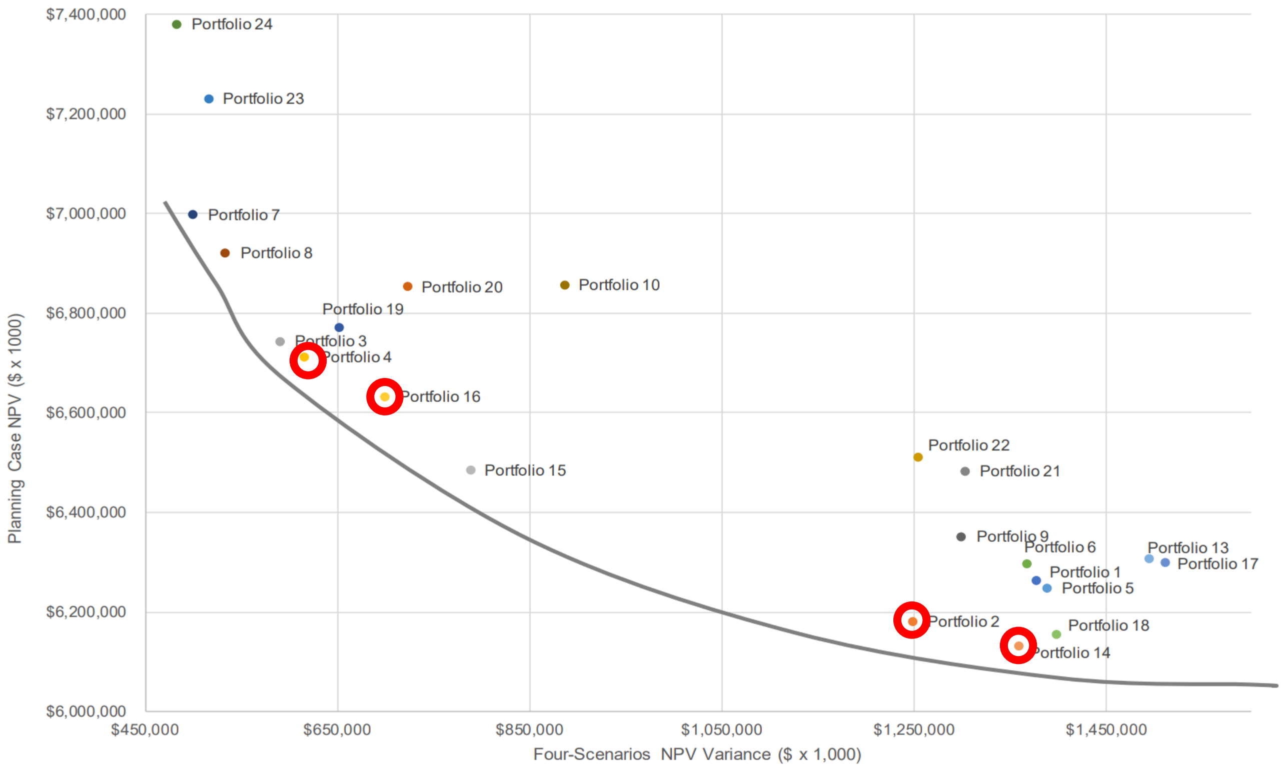
As seen above, the planning gas case continues to be on the low side with the majority of iterations landing above the planning case. Staff was concerned about this approach in the 2017 IRP.

For the 2019 IRP, in order to "filter out" which WECC-optimized portfolios would be best suited for additional manual analysis, the Company created two quantitative criteria to identify top performing portfolios: 1) the variance in the net present value (NPV) among the four scenarios (i.e., the cost deviation among the four hourly-level planning scenarios bulleted above), and 2) the NPV of the "planning scenario" costs. Upon performing its analysis in AURORA, the Company determined that portfolios 2, 4, 14, and 16 were the top-performing portfolios according to the criteria above. The

[5] LC 74, Idaho Power 2019 Amended IRP, pp. 105-106.
[6] LC 74, Idaho Power 2019 Amended IRP, p. 114.

relative differences among the portfolios are illustrated below. The four top-performing portfolios are circled in red.

Figure 2 – NPV vs. Cost Variance[7]



Staff is concerned with the use of variance across four scenarios to represent an informative measure of "risk." Additionally, it is unclear to Staff why portfolios 3 and 15, both on the left-hand side of the graph above, were not chosen for additional analysis when graphically they appear to be as viable as portfolios 4 and 16. In a data request, Staff asked the Company about its selection. In response, the Company described how it chose the best performing portfolios from the lowest risk group on the left and the lowest price group on the right: "Idaho Power chose portfolios with the best balance of cost and risk from each group with their matching B2H and non-B2H counterpart to be re-optimized."[8]

This response fails to explain the logic behind the selection and does not actually answer Staff's question. Staff will follow up with additional questions, but the Company should also provide additional description behind the portfolio selection criteria in its Reply Comments. Staff has requested the models and will review them to better understand the selection process.

The Company took Portfolios 2, 4, 14, and 16, and applied manual modifications to create an additional 20 portfolios. Other than the Jim Bridger retirement date specifications, it is unfortunately unclear whether Idaho Power made additional "manual adjustments" to create the new portfolios. It is also unclear how adjusting Jim Bridger retirement dates would have an impact on the removal of both Franklin Solar and an RFP from the Action Plan. As described in more detail elsewhere in these

[7] LC 74, Idaho Power 2019 Amended IRP, p. 108, Figure 9.1.
[8] See Staff Attachment A, Idaho Power Response to Staff DR 10.

comments, the Company also postponed the addition of demand response additions. In general, the Company provided little explanation around the mechanics of these adjustments, why these adjustments were made, and why they were selected. On page 109 of the IRP, the Company explains that the manual adjustments involved Jim Bridger retirement dates, but on page 117, the Company also lists a series of qualitative risk analysis that also seems to have influenced the reasoning behind the manual adjustments.

In the previous IRP, the Company described in detail the results of its review of qualitative benefits and risks by portfolio, including scoring by metric by portfolio.[9] After reviewing the provided analysis in the 2017 IRP, Staff recommended that the Company continue to provide the qualitative benefits and risks by portfolio.[10] Staff was disappointed to find that the 2019 IRP failed to provide a systematic qualitative risk review in its analysis and its impact on the preferred portfolio as it had in past IRPs. Staff is still interested in a systematic analysis of how the Company applied its qualitative analysis and will continue to review this in the IRP. Staff will likely recommend that the Company continue to provide this in the 2021 IRP.

Staff appreciates Idaho Power's work to begin utilizing capacity expansion software in this IRP and finds that a WECC-optimized method has helped produce a more systematic approach to creating portfolios. However, it is unclear whether manual adjustments were made to the WECC-optimized portfolios beyond Jim Bridger retirement dates. In future IRPs, the Company should utilize a model that more clearly optimizes resources for Idaho Power's service territory. Staff continues to investigate this and seeks further clarification on Idaho Power's manual adjustments in its Reply Comments.

Jim Bridger Exit Dates

Although Idaho Power and PacifiCorp are co-owners of the Jim Bridger coal plant, Idaho Power's preferred-portfolio exit dates for Jim Bridger are different from those in the PacifiCorp 2019 IRP. In PacifiCorp's 2019 IRP, Jim Bridger exit dates are the following:

Table 1 – PacifiCorp Jim Bridger Exit Dates

Unit 1	2023
Unit 2	2028
Unit 3	2037
Unit 4	2037

In Idaho Power's IRP, proposed Jim Bridger exit dates for manually adjusted portfolios are 2022, 2023, 2024, 2026, 2028, 2030, and 2034. Only one of these dates aligns with PacifiCorp. Idaho Power's preferred portfolio P16(4) selects the following dates:

[9] This analysis was presented to comply with Order No. 16-160.
[10] LC 68, Staff Final Comments, p. 42.

Table 2 – Idaho Power Jim Bridger Exit Dates

Unit	2022
Unit	2026
Unit	2028
Unit	2030

Notably, Idaho Power does *not* specify which exit dates are for which units. Staff asked the Company which units it was most likely to retire, to which the Company responded, "While left undetermined in Idaho Power's 2019 IRP, Units 1 and 2 will most likely be the first units to retire at the Jim Bridger plant. However, factors such as unit condition, unit efficiency, outage schedules, forecast capital expenditures, along with other relevant factors will be used to determine the actual unit retirement schedule."[11] The Company did not explain why Units 1 and 2 would be the units most likely to be retired first.

Given that PacifiCorp and Idaho Power's preferred exit dates for Jim Bridger are different, Idaho Power should perform an additional sensitivity analysis that considers the Jim Bridger retirement dates in PacifiCorp's 2019 IRP. This analysis will provide transparency into the resource additions that may be cost-effective if Idaho Power is unable to achieve its preferred Jim Bridger retirement dates.

Finally, Staff is investigating the reason for the earlier Jim Bridger unit exit dates selected in Idaho Power's 2019 IRP as compared to PacifiCorp's 2019 IRP. While it is possible that different exit dates could be optimal for Idaho Power's system than for PacifiCorp's system, the Company should clarify its coal cost assumptions and reliability assumptions in its 2019 IRP as potential drivers of the earlier exit dates. Staff has submitted discovery on this information and will provide further analysis in Final Comments.

If the Company believes it will be able to negotiate earlier exit dates from these units than PacifiCorp's planned exit dates, then the Company should explain its plans to accomplish this, and report any progress that has been made toward this goal.

Production Tax Credit and Investment Tax Credit

In addition to the concerns with LTCE, Idaho Power's 2019 IRP does not explicitly mention the Production Tax Credit (PTC) for wind or the Investment Tax Credit (ITC) for solar. The portfolios developed by the Company do not include any near-term wind or solar resources that might receive the ITC or PTC before their expiration in 2023 and 2024, respectively. If the Company has not considered them, then an additional capacity expansion analysis should be performed that considers the impact these substantial tax credits may have on resource selection in the AURORA long-term capacity expansion model.

Recommendations for Reply Comments:

- Clarify the mechanics of all manual adjustments made to the four WECC-optimized portfolios. The Company should clarify which adjustments were made over others, if any, and how

[11] See Staff Attachment A, Idaho Power Response to Staff DR 36.

qualitative risk played a role in informing manual adjustments to the WECC-optimized portfolios.

- Provide additional description behind the selection of the two risk criteria (NPV and NPV variance) in its Reply Comments.
- Address how it considered PTCs and ITCs in its capacity expansion analysis.
- Provide additional sensitivity analysis for portfolios P2, P4, P14, and P16 that shows the cost of each portfolio if the Jim Bridger retirement dates from PacifiCorp's 2019 IRP preferred portfolio are used.
- Report how it plans to exit the Jim Bridger units at the dates presented in its preferred portfolio, and why it selected the Jim Bridger retirement dates it did for the manual adjustments to the WECC-optimized portfolios.

Energy Efficiency and Demand Response

Energy Efficiency

Energy Efficiency in the 2017 IRP

In the 2017 IRP, Idaho Power proposed that energy efficiency reduces average annual loads by 273 aMW by 2036 and reduces peak by 483 MW by 2036.[12] The Action Plan also included the pursuit of cost-effective energy efficiency from 2017-2021.[13] In the previous IRP, Staff, along with Sierra Club, STOP B2H, and Mr. Carbiener expressed concerns that Idaho Power was not pursuing enough energy efficiency. Idaho Power agreed to work with other utilities in the region to explore an update to the Company's methodology and values used for transmission and distribution system deferral values for its energy efficiency avoided costs by its next IRP.[14] Staff ultimately recommended acknowledgement of Action Item 9 to "Continue the pursuit of cost-effective energy efficiency" with conditions that Idaho Power undertake greater studies of residential savings opportunities and update its transmission and distribution system deferral calculations.[15] The Commission decided to acknowledge the Action Item with the following modification:

> "In its 2019 IRP Idaho Power will report on future expanded energy efficiency opportunities and improvements to its avoided cost methodology." [16]

Energy Efficiency in the 2019 IRP

In the 2019 IRP, the preferred portfolio calls for 234 aMW of average annual load reduction, and 367 MW of peak reduction by 2038.[17] This is a reduction from the 2017 IRP (down from 273 aMW by 2036 and 483 MW peak reduction by 2036). Idaho Power attributes this decline to changes in the lighting market as well as some codes and standards updates.[18] Overall, these declines are consistent

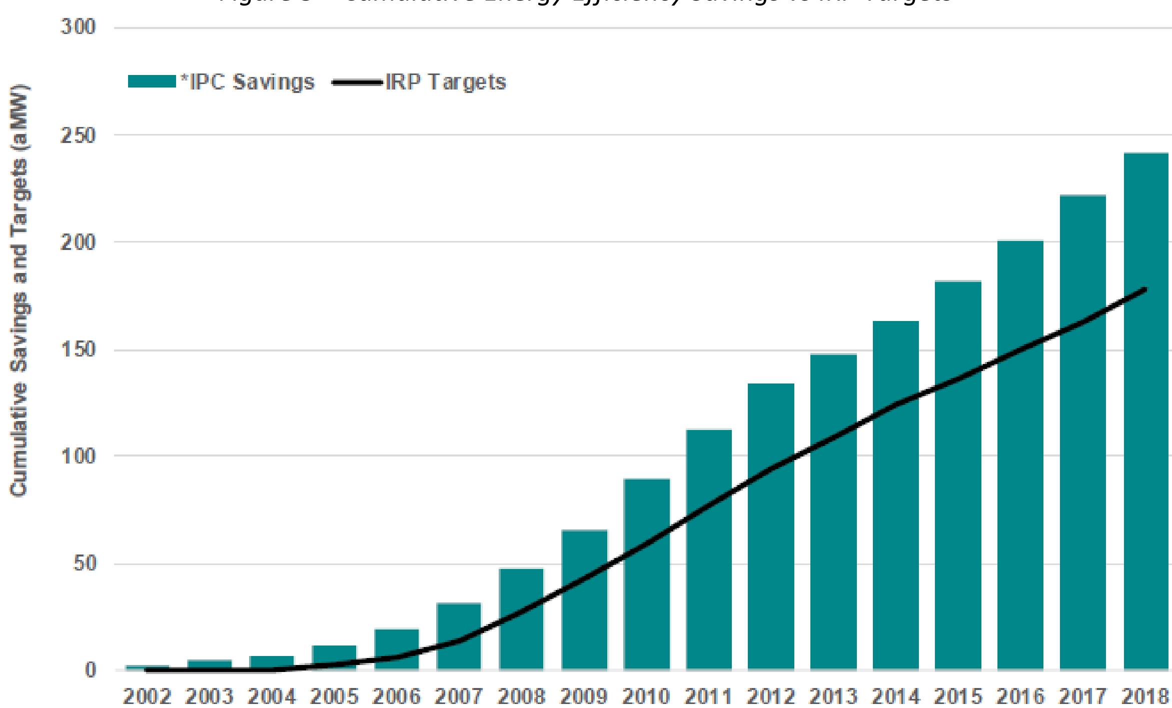
[12] LC 68, Idaho Power 2017 IRP, p.47.
[13] LC 68, Idaho Power 2017 IRP, p.8.
[14] LC 68, Idaho Power Reply Comments, p. 75.
[15] LC 68, Staff Final Comments pp. 34-35.
[16] Oder No. 18-176, p. 16.
[17] LC 74, Idaho Power 2019 Amended IRP, p. 55.
[18] LC 74, Idaho Power 2019 Amended IRP, p. 58.

with those experienced by other utilities. It is not clear what actions the Company took to "report on future expanded energy efficiency opportunities" as ordered through the amended 2017 IRP Action Item 9.[19] Staff requests that in Reply Comments, the Company describe what actions were taken to respond to this Order, and further to explain the drop in forecasted savings despite these efforts.

Idaho Power tested alternative approaches to selecting the appropriate level of energy efficiency: the "Sensitivity Modeling" approach and bundling the resources by cost. In the "Sensitivity Modeling" approach, the Company tested three scenarios of avoided cost. The Company presented these results to the Energy Efficiency Advisory Group (EEAG), but this approach was not used because the EEAG deemed it was not properly screening energy efficiency measures. In the second approach, the Company bundled resources by cost, but this method selected less energy efficiency than the standard approach. The Company did not specify where this research is or next steps. In Reply Comments, the Company should clarify key learnings and future plans for energy efficiency selection modeling.

In the 2017 IRP, stakeholders were concerned that the Company was not planning to acquire as much energy efficiency as possible and that the Company regularly exceeds its IRP targets.[20] Throughout 2017 and 2018, Idaho Power achieved approximately 220 aMW and 240 aMW in annual cumulative energy efficiency savings, respectively.[21] This continues a pattern of over 10 years in which Idaho Power savings exceed their IRP targets.[22] The following figure illustrates this point.

Figure 3 – Cumulative Energy Efficiency Savings vs IRP Targets[23]



[19] Oder No. 18-176, p. 16.
[20] LC 68, Idaho Power Reply Comments, p. 75.
[21] LC 74, Idaho Power 2019 IRP, Appendix B, p. 9.
[22] LC 74, Idaho Power 2019 IRP, Appendix B, p. 9.
[23] LC 74, Idaho Power 2019 IRP, p. 59, Figure 5.2.

While Staff is appreciative of the Company's effort to exceed energy efficiency goals, Staff believes an improvement in IRP forecasting of targets, so as to better reflect the cost-effectively achievable energy efficiency available may be necessary. Again, the Company should continue to acquire all cost-effective energy efficiency but should also consider how to better improve its forecasting methodology as it has resource impacts. In Reply Comments, the Company should respond to the issue of the divergence between energy efficiency targets and achievements as part of an improved IRP forecast.

Total Resource Cost (TRC) Will No Longer Be Used in Idaho for Selecting Measures
In January 2020, the Company informed OPUC Staff of a decision made by Idaho PUC directing the Company to apply the Utility Cost Test (UCT) as the primary test for energy efficiency screening, whereas previously, the Company used both the UCT and the TRC. The Company will still use the UCT and TRC on all measures for monitoring and incentive setting, and will use both tests when requesting measure-level exceptions from cost-effectiveness testing in Oregon.

In the next IRP, the method for forecasting energy efficiency will shift to UCT-based screening. This may result in a larger number of measure exception requests than typically seen by the Commission. It is unclear if this shift will result in changes to overall energy efficiency potential. In Reply Comments, Staff requests that the Company explain how this shift to UCT will impact savings forecasts.

Recommendations for Reply Comments:

- Describe how the Company complied with the order to report on future expanded energy efficiency opportunities.
- Clarify key learnings and future plans for energy efficiency selection modeling.
- Address the issue of repeated overshoot of its energy efficiency targets.
- Describe how dropping the TRC test will affect future energy efficiency potential.

Demand Response

In the 2017 IRP, Idaho Power proposed that demand response provide 390 MW of committed peak summer capacity.[24] The Action Plan did not include demand response action items.[25] In Final Comments regarding the 2017 IRP, Staff inquired as to why, despite a forecast of overall consistent load growth, demand response procurement remained flat. In the Company's Final Comments, it noted that demand response levels are set per Order No. 13-482 resulting from a stipulated settlement agreement;[26] there is no capacity deficit forecast until 2026; and in the Company's opinion, the demand response programs

[24] LC 68, Idaho Power 2017 IRP, p.47.
[25] LC 68, Idaho Power 2017 IRP, p.8.
[26] Order No. 13-482 is integral in understanding Idaho Power's demand response programs. Preparation for the 2013 IRP revealed that capacity deficits were no longer forecast for the near term, due in large part to lingering effects of the 2008 recession. In December 2012, the Company asked the IPUC and the OPUC to temporarily suspend two of three programs (the third was in the final year of contract with its third-party administrator and changes were already anticipated). The programs were suspended in 2013, pending the outcome of a series of stakeholder workshops evaluating the future of the programs. The workshops yielded a stipulated settlement agreement in November 2013 and the Order in December. Programs resumed in 2014, and have delivered substantial peak reduction capacity since.

perform best if not "overused." Demand response capacity was nearly 400 MW in 2017[27] and 382 MW in 2018.[28]

Demand Response in the 2019 IRP

The IRP originally filed in June 2019 included some demand response in the Action Plan (5 MW in 2026). However, the net present value (NPV) of the preferred portfolio in the Amended IRP increased by $900,000 without this resource.[29] The Amended IRP preferred portfolio includes a projected 420 MW of summer capacity reduction by 2038. This increase of 30 MW (up from 390 MW) of demand response capacity is added in increments of 5 MW per year beginning in 2031 and continues for 6 years.[30] The IRP is not clear if these additions represent new programs or expansions of existing programs.

The Company notes that existing demand response programs provide 390 MW of peak capacity in June and July throughout the IRP planning period, and the committed demand response included in the IRP has a capacity cost of $29 per kW-year.[31] The IRP goes on to describe the process for considering *additional* demand response:

> As part of the IRP's rigorous examination of the potential for expanded demand response, the company first evaluated additional demand-response capacity need outside of the AURORA model to determine any constraints needed in the modeling process. The company considered achievability and operability to properly model the potential expansion of demand response. Based on this analysis, the company made available 5 MWs of incremental new demand response each year for selection in AURORA starting in 2023.[32]

The Company modeled the cost of this expanded DR at $60 per kW-year[33] and explained the rationale for this cost:

> Because it is difficult to estimate the costs of a customer-based program 12 years in the future, Idaho Power used approximately one-half the price of a Simple Cycle Combustion Turbine of $136 per kilowatt ("kW")-year as a proxy cost for future DR. In comparison, in 2019, the capacity cost of all of the Company's DR programs was approximately $21 per kW-year; however, all equipment and set-up costs were incurred in prior years. An expanded or new program would likely include new equipment, additional administration cost, and all participants would most likely require increased incentive payments. It is for these reasons that the Company believes its proxy price of $60 per kW-year is reasonable.[34]

Staff would like to highlight that the incremental expansion of this resource is approximately 1.3 percent (5 MW added to 390 MW), yet the incremental cost increase of this resource is nearly 107 percent of the existing resource. Staff believes a more informative approach to modeling expanded DR would involve logical, step-wise incremental cost increases.

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[27] LC 74, Idaho Power 2019 IRP, Appendix B, p. 8.
[28] LC 74, Idaho Power 2019 IRP, Appendix B, p. 10.
[29] LC 74, Idaho Power 2019 Amended IRP, p. 126.
[30] LC 74, Idaho Power 2019 Amended IRP, p. 125.
[31] LC 74, Idaho Power 2019 Amended IRP, p. 61.
[32] LC 74, Idaho Power 2019 Amended IRP, p. 61.
[33] LC 74, Idaho Power 2019 Amended IRP, p. 61.
[34] See Staff Attachment A, Idaho Power Response to Staff DR 41.

In addition to 5 MW increments of demand response, the Preferred Portfolio added the following installations (in MW) of solar, battery, and demand response resources:

Table 3 – Solar, Battery, and Demand Response Additions[35]

	Solar	Battery	Demand Response
2029	40	30	--
2030	--	--	--
2031	--	--	5
2032	80	10	5
2033	80	20	5
2034	80	20	5
2035	--	--	5
2036	--	--	5

Staff posits that an effective demand response program could meet a need in a similar manner as batteries because it would also address a peak in demand. Demand response programs and battery resources each provide unique benefits in addition to addressing peak, though the two are not entirely interchangeable in all circumstances. Staff is willing to concede there may be benefits from battery resources that demand response programs simply cannot match.

The following levelized costs of capacity (LCOC)[36] for storage resources are from Figure 7.5 in the 2019 Amended IRP:[37]

Storage—Li Battery 4 hour (5 MW): $20
Storage—Zn Battery 4 hour (5 MW): $31
Storage—Li Battery 8 hour (5 MW): $46

The LCOC of demand response is not included in this discussion in the 2019 IRP, but it is included in Figure 7.5 in the 2017 IRP:[38]

Demand Response—Additional (25 MW): $5.

To present an apples-to-apples comparison of costs in the context of the 2019 IRP, Staff assumes the following:

- The per MW LCOC is scaled (up and down) to the amount of resource in the preferred portfolio.
- An inflation adjustment to the 2017 IRP demand response LCOC.[39]
- Table 10.2 in the 2019 Amended IRP does not explicitly list the storage resources in the preferred portfolio, but Staff chose the battery resource with the lowest LCOC.

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[35] LC 74, Idaho Power 2019 Amended IRP, p. 125.
[36] i.e., fixed.
[37] LC 74, Idaho Power 2019 Amended IRP, p. 92.
[38] LC 68, Idaho Power 2017 IRP, p.87.
[39] The U.S. Bureau of Labor Statistics Consumer Price Index rose 2.1 percent in 2017 and 1.9 percent in 2018 (see https://www.bls.gov/opub/ted/2019/consumer-price-index-2018-in-review.htm); ($1.00 X 1.021) X 1.019 = $1.04.

Table 4 – Staff LCOC Comparisons

	Battery (MW)	Battery LCOC (based on Li Battery 4 hour; $20 per 5 MW)	Demand Response (MW)	Demand response LCOC (based on $5 per 25 MW, and adjusted for inflation)
2029	30	$120	--	--
2030	--	--	--	--
2031	--	--	5	$1.04
2032	10	$40	5	$1.04
2033	20	$80	5	$1.04
2034	20	$80	5	$1.04
2035	--	--	5	$1.04
2036	--	--	5	$1.04

As demonstrated above, the cost of battery storage exceeds the cost of demand response on a LCOC basis. While Staff welcomes any feedback, correction, or clarification to Staff's understanding of this comparison, the fact that this was not explicitly done in the IRP stands in contrast to IRP Guideline 1, and the Company must address this deficiency in its analysis.

Given the cost difference illustrated above, it is possible that a future least-cost and least-risk outcome may include the pairing of solar with demand response first, then a pairing of solar and batteries in order to achieve any necessary benefits from battery storage.

Staff commends Idaho Power's continually successful demand response programs. However, Idaho Power's past comments suggest a paradigm in which the Company thinks about demand response as a resource *to be preserved*. See, for example, the Company's Final Comments for the 2017 IRP:

> Critically, the reliability and viability of DR programs are highly dependent on attracting and retaining participants. If these programs were called upon more in times of no need, such overuse would ultimately discourage long-term participation and deplete the available megawatt capacity when these programs are truly needed.[40]

Given increasing levels of intermittent resources, the capacity cost differences in storage and demand response, and the eventual return of capacity deficits, an evolution of the Company's "to be preserved" paradigm may be in order.

Recommendations for Reply Comments

- Rerun the model varying the cost of expanded DR using values less than $60 per kW-year. For example, $32 per kW-year (10 percent increase over the existing resource), $37 per kW-year (25 percent increase), $44 per kW-year (50 percent increase).
- Address 1) the extent to which demand response can provide similar services as battery storage; 2) the extent to which existing demand response programs may be able to provide more frequent and flexible services in the future.

[40] LC 68, Idaho Power Final Comments, p. 51.

- Address Staff's comparison of LCOCs of demand response programs and battery storage deployment; absent a fundamental misconception by Staff, address this deficiency in the analysis.

Capacity Value for Variable Energy Resources

In its 2019 IRP, the Company states: "For the 2019 IRP, Idaho Power updated the capacity value of solar using the 8,760-based method developed by [National Renewable Energy Laboratory (NREL) and detailed herein."[41] As is done in NREL's method, Idaho Power limits the approximation of solar capacity value to the highest 100 hours in the Company's load duration curve.[42,43] Staff expected some change in methodology given the Commission's standardization of capacity value methodology in Docket No. UM 1719. In Order No. 16-362, the Commission established two standards for estimating the capacity contribution of variable energy resources in IRP planning: Effective Load Carrying Capability (ELCC) or a Capacity Factor (CF) approximation.[44]

The Company appears not to be in compliance with the parties' stipulation in Docket No. UM 1719, which was approved by Commission order. In Docket No. UM 1719, parties stipulated that:

> Idaho Power's existing methodology for estimating capacity contribution of wind and solar generators for Integrated Resource Planning is an acceptable CF approximation methodology with the addition of an LOLP analysis that is based on all hours in a year.[45]

The Company should explain how NREL's approach of limiting the analysis to the highest 100 hours of load complies with the stipulation approved by Commission Order No. 16-326.

The 2019 IRP does not go into the same detail about the capacity valuation of wind resources as it did for solar.[46] The Company applies a five percent capacity factor for peak hours in contrast to a 35 percent average capacity factor for Idaho-sited wind turbines and 45 percent for those sited in Wyoming. In Reply Comments, the Company should explain how the methodology used to derive these numbers for wind capacity values complies with the stipulation approved by Commission Order No. 16-326.

Recommendations for Reply Comments

- Explain how NREL's approach of limiting the analysis of solar resource capacity value to the highest 100 hours of load complies with the stipulation approved by Commission Order No. 16-326.
- Explain how the methodology used to derive wind capacity values complies with the stipulation approved by Commission Order No. 16-326.

[41] LC 74, Amended 2019 Idaho Power IRP, p. 44.
[42] NREL. *8760-Based Method for Representing Variable Generation Capacity Value in Capacity Expansion Models* July 14, 2017, page 7.
[43] LC 74, Idaho Power 2019 Amended IRP, page 44.
[44] Order No. 16-326, p. 1.
[45] Order No. 16-326, Appendix A, p. 3.
[46] LC 74, Idaho Power 2019 Amended IRP, p. 49.

Resource Economics

Staff found most of the Company's resource cost assumptions to be reasonable but has identified a couple areas of concern. These concerns are related to the cost of gas and wind.

As mentioned previously, Idaho Power uses a third-party vendor to forecast natural gas prices.[47] On page 89 of the 2019 IRP, the Company states:

> To verify the reasonableness of the third-party vendor's forecast, Idaho Power compared the forecast to Moody's Analytics and the New York Mercantile Exchange (NYMEX) natural gas futures settlements. Based on a thorough examination of the forecasting methodology and comparative review of the other sources (i.e., Moody's and NYMEX), Idaho Power concluded that the third-party vendor's natural gas forecast is appropriate for the planning case forecast in the 2019 IRP.[48]

The 2019 IRP does not explain the criteria that was used to weigh the reasonableness of Idaho Power's third-party vendor forecast against that of Moody's Analytics and the forward curve on the NYMEX. The Company should explain in greater detail how its third-party vendor's forecast is reasonable.

Further, on page 125 of the 2019 IRP, the Company's preferred portfolio is shown to acquire 300 MW of gas generation in 2030. However, these additional natural gas-fired resources seem out-of-step with the Company's stated goal to provide "100% clean energy" by 2045.[49] Such additions are also inconsistent with Oregon Governor Kate Brown's Executive Order No. 20-04, which establishes targets of reducing greenhouse gas emissions by at least 45 percent below 1990 levels by 2035, and at least 80 percent below 1990 levels by 2050 across multiple industry sectors, including utility portfolios. This presents a possibility of a gas resource having a useful life of only 15 years, but the assumed useful life in the IRP's generic natural gas levelized cost of energy (LCOE) is twice as long at 30 years.[50] Staff sought clarification in an information request. Idaho Power replied, "The Company is looking for ways to meet or offset its future resource needs in accordance with its 2045 goals but acknowledges advances in technology may be required."[51]

This may mean the gas LCOE was modeled at too low a cost because if offsets are required, the price of those offsets must be reflected in the modeling. Or, if the plant will need to be retired after only 15 years of useful life, that shorter amortization period of fixed costs must be reflected in the LCOE of this resource. Further, adding new natural gas-fueled resources in 2030 and 2035 and retiring them by 2045 may cause ratepayers to bear the risk of accelerated depreciation of these resources as stranded assets. The Company should address these risks to customers in relation to how its carbon free plan affects the preferred portfolio's gas resource acquisition.

Finally, on page 24 of Appendix C, the Company presents an LCOE for Wyoming wind of $94 MWh. This is a significantly higher cost than is found in the resource economics literature. The high-end LCOE estimate for an unsubsidized wind resource from the investment bank Lazard is $54.[52] The LCOE

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[47] LC 74, Idaho Power 2019 Amended IRP, p. 88.
[48] LC 74, Idaho Power 2019 Amended IRP, p. 89.
[49] LC 74, Idaho Power 2019 Amended IRP, p.125.
[50] Idaho Power 2019 IRP Appendix C, p. 23.
[51] See Staff Attachment A, Idaho Power Response to Staff DRs 1-2.
[52] Lazard. Lazard's *Levelized Cost of Energy Analysis – Version 13.0* November 7, 2019, page 2.

estimate from the Energy Information Administration (EIA) is $34.10.[53] Further, PacifiCorp's IRP modeling finds Wyoming wind to be cheap enough to offset the economics of Gateway South due to the PTCs. Gateway South is proposed to be roughly 400 miles and is estimated to cost nearly $1.8 billion.[54] The Company must explain in its Reply Comments why its estimate is so much higher than the extant literature and the estimates from PacifiCorp's IRP (LC 70).

Recommendations for Reply Comments

- Explain how the Company's plan to be carbon free is reflected in the assumed cost of the preferred portfolio's gas resource acquisition.
- Explain why the 2019 IRP's estimate for the LCOE of Wyoming wind resources is so much higher than the extant literature and the estimates from PacifiCorp's IRP (LC 70).

Load Forecast

Idaho Power produces separate forecasts for each major customer class. The residential load forecast is the product of a use-per-customer and customer count forecast. The use-per-customer forecast is based on Itron's Statistically Adjusted End Use Model (SAE). This model utilizes an adoption rate forecast for energy efficient items like high efficiency washing machines and low energy light bulbs to inform the model on expected usage patterns of customers in Idaho Power's service territory. These forecasts of customer end-use demand are then used to inform a standard regression model to produce a use-per-customer amount. Industrial and Commercial sectors are broken down into services and manufacturing, then further broken down into 12 subsets like dairy, food packaging, etc. Historic usage, weather, and economic and demographic data are used to inform all of the models. The Company also utilizes separate forecasts for on-site generation and electric vehicles to adjust the use-per-customer forecast.

The strengths of the Company's methodology are based in the wide variety of reputable third-party data sources and the segmentation of data and variables of interest into smaller subsets. This allows the Company to identify relationships between load and economic, demographic, and weather data that may have been muddled in a more aggregated forecast. The Company's SAE model is an example of this because the underlying causes of demand for a customer are identified and analyzed. Further, the Commercial and Industrial sectors are not forecast as a group, but by economic activity. This can result in a unique relationship between customer load and applicable economic data. However, segmentation of the load forecasts from a single forecast of a company's load into customer classes, use-per-customer models, divisions based on economic activity, monthly vs. yearly, etc., are only meaningful if the input data is also sufficiently segmented to accommodate the divisions.

Staff reviewed the input data and found that the Company's use of demographic and economic data was sufficient to achieve the improvements in accuracy available via such a strategy, however, Staff found two potential issues in the Company's methodology. The first is the use of Itron for much of the Company's modeling. Although well-respected in the industry, Itron uses proprietary methods, and this results in a black box forecast for the majority of parties interested in review of the model. As noted in the Company's response to Staff DR No. 21, "much of the analysis and reporting that is represented in

[53] EIA. *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2020* February 2020, page 6.
[54] LC 70, PacifiCorp 2019 IRP, pp. 8 and 85.

this data is compiled through a database framework. The Company typically makes these sources available for on-site review at its corporate headquarters, if requested."[55] Staff is working with the Company to identify a viable means of review of the model given the current travel restrictions surrounding the COVID-19 pandemic.

The second issue is in regards to the Company's use of Ordinary Least Squares (OLS) and other non-time-series based regression models. Chronological data is unique in that the previous time period's data can often contain information relevant in the prediction of the current period because the data points did not occur simultaneously. This means that there is potential to incorporate this data into the forecast, and it also results in the potential to violate standard regression assumptions that can produce problems with the forecasts. The Company does incorporate some "lagged" input data (data from previous time periods) in its regressions, but it has not incorporated lags of the independent variables in a material manner in the methodology.

Further, in regards to the violation of standard regression assumptions, one of the major concerns is that of stationarity. In order to properly identify relationships between the inputs and output, econometric models require that the statistical properties of the underlying data remain constant over time. The presence of a "unit-root" can cause non-stationarity and produce problems with the model. The Company notes in its response to Staff DR 25, "The Company does not incorporate any unit-root functionality into its regression models. However, use of differing training periods within the regressions has been the Company's primary solution to the issues that would otherwise be covered with unit-roots."[56] In its response, the Company is generally saying that the forecasts have been analyzed compared to actuals, and the data has been chosen such that they do not believe that stationarity is an issue.

Staff believes there are better ways to address this concern and potentially produce a better forecast. One of the easiest ways to incorporate information from previous time periods and handle stationarity issues is through the use of Auto Regressive Integrated Moving Average (ARIMA) models. The models function very similarly to standard Ordinary Least Squares (OLS) models and incorporate all of the same economic data. ARIMA models include three additional terms beyond a regular OLS model: the auto-regressive (AR) term, moving average (MA) term, and the integration (I) term. The AR and MA terms determine the amount of information incorporated from previous time-periods, while the I term is the number of differences required in order to make the data stationary. Although more advanced versions of ARIMA models exist, Staff views the change to an ARIMA model to replace the standard OLS models as a reasonable and significant first step in improving the robustness of the forecast.

Recommendation for Reply Comments

- Respond to Staff's comments regarding the use of Itron for the Company's modeling and the use of OLS rather than time-series based regression models.

[55] See Staff Attachment A, Idaho Power Response to Staff DR 21.
[56] See Staff Attachment A, Idaho Power Response to Staff DR 25.

Miscellaneous Concerns

Resource Adequacy

In its 2017 IRP, the Company's Preferred Portfolio included a 300MW "1 x 1" combined cycle combustion turbine (CCCT) addition in 2033.[57] In the 2019 IRP Preferred Portfolio, the date of addition is advanced to 2030. Further, the Company's 2019 IRP Preferred Portfolio would add 111 MW of gas reciprocating engines in 2035.[58]

The Company asserts that it "considers these [natural gas fueled] resources proxies for future resources that can meet system needs and help accomplish the Company's clean energy goals while imposing the least cost on customers,"[59] but a CCCT may not be the most appropriate proxy resource for several reasons. First, a CCCT is unlikely to be the least-cost option. By definition, a CCCT incorporates at least one simple cycle combustion turbine (SCCT), so a stand-alone SCCT is always less expensive to build and maintain than a CCCT. Also, the costs of solar or wind plus storage have decreased significantly in recent years, and may be competitive as a least-cost, least-risk proxy depending upon other conditions in the utility's system. Further, the Company asserts that the timing of the new CCCT included in the manually adjusted Preferred Portfolio "coincides with the planned retirement of the final Bridger coal unit" in 2026, and that the CCCT "provides the flexibility required to integrate renewable resources and cannot be deferred with an earlier build of wind and solar."[60] However, a CCCT, and in particular a 1 x 1 model as contemplated in the Preferred Portfolio, is not an especially flexible resource. Only the SCCT component of the CCCT is capable of ramping, as the steam turbine component cannot ramp.[61]

Further, operating a CCCT as a flexible ramping resource increases operating and maintenance costs and increases risk of equipment failure.[62] Industry experience indicates that flexibility and ramping capability of a CCCT can be increased with a greater number of SCCT units, such that a 4 x 1 CCCT has greater ramping capability than a 3 x 1 or a 2 x 1, while a 1 x 1 CCCT like the proxy considered in this IRP would not offer as much ramping capability.[63]

Staff will likely recommend that in its next IRP, the Company reassess the need and timing for natural gas resource additions. Specifically, now that the Company will have more experience using the AURORA modeling tool,[64] it should conduct deeper analysis of alternatives to a natural gas proxy resource. Some the alternatives to consider include wind or solar generation plus storage. The Company should also

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[57] LC 68, Idaho Power 2017 IRP, p. 133.
[58] LC 74, Idaho Power 2019 Amended IRP, p. 125.
[59] See Staff Attachment A, Idaho Power response to Staff DR 1.
[60] See Staff Attachment A, Idaho Power response to Staff DR 3.
[61] See Calpine's presentation to PJM on its experience with CCCTs in a formal market, September 7, 2016, https://www.pjm.com/-/media/committees-groups/user-groups/ccoug/20160907/20160907-item-02a-pjm-calpine-experience-with-combined-cycle-plants-in-ercot.ashx.
[62] See Reinhart, Howell, and Kropf, "Unlocking the Potential of Combined Cycle Plants," Power Engineering, Issue 4, Vol. 122, April 1, 2018. https://www.power-eng.com/2018/04/01/unlocking-the-potential-of-combined-cycle-plants/#gref.
[63] See Calpine's presentation to PJM on its experience with CCCTs in a formal market, September 7, 2016, and Reinhart, Howell, and Kropf, "Unlocking the Potential of Combined Cycle Plants," Power Engineering, Issue 4, Vol. 122, April 1, 2018.
[64] LC 74, Idaho Power 2019 Amended IRP, p. 1.

consider pumped storage hydropower assets. In particular, a question to consider in future modeling might be: If the B2H transmission line is energized by 2026, and the 1,200 MW Goldendale pumped storage project in Washington is online by 2028, would access to this flexible resource eliminate or diminish the need for 300 MW of natural gas fueled resources in 2030?

Hydro modeling and Climate Change Policy Recommendations

In the previous IRP, Staff presented a series of questions about hydro analysis and its correlation with peak loads.[65] Staff noted that the Company has been conducting its capacity deficit analysis the same way since the early 2000's and that this analysis was inspired by high market prices in the summer of 2001. Staff had overall concerns that these assumptions were influenced by the 2001 energy crisis and might not have been reflective of long-term trends. As a result, Staff indicated that the IRP process warrants taking a fresh look at the conservative peak-hour assumptions in the 2019 IRP. The Company appears not to have addressed Staff's concerns from the 2017 Staff Report in this IRP.

In the 2019 IRP, Staff continues to have questions about hydro modeling. Idaho Power has increased the range of hydro data used from 1975-2015 in the previous IRP to 1971-2018 in this IRP, adding a total of seven years of data. Staff would like the Company to discuss in its Reply Comments whether there are any notable changes to capacity factors and other assumptions from the last IRP.

Related to this issue is Staff's recommendation, and the Commission's Order, that the Company develop a report to assess the risks and uncertainties associated with climate change to Idaho Power and its customers. The Company did briefly address this issue in the IRP by stating that it performed a climate change analysis using data from various sources[66] to analyze water availability in the Pacific Northwest under various climate change scenarios. On average, the Company found that July through January regulated streamflow is unaffected, February through May regulated streamflow shows an increase, and June shows a decrease in streamflow. In addition, most models demonstrated an average annual increase in streamflow volume.[67] It appears that Idaho Power did take into consideration climate change impacts into its IRP but did not develop a report to describe specifics or to address Staff's Recommendation from the Staff Report regarding hydro modeling. Staff is following up with the Company with some information requests to better understand how the Company is incorporating hydro modeling into the IRP, but the Company should expand upon its climate change impact analysis in its Reply Comments.

Recommendation for Reply Comments

- Discuss whether there are any notable changes to hydro capacity factors and other assumptions from the last IRP.
- Expand upon its climate change impact analysis, and if possible, produce a report on its findings from the IRP.

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[65] LC 68, Staff Final Comments pp. 40-41.
[66] Specifically, the Company mentioned the River Management Joint Operating Committee (RMJOC), Second Edition, Part 1 and the Snake River Planning Model (SRPM).
[67] LC 74, Idaho Power 2019 Amended IRP, p. 85.

Variable Energy Resource (VER) Action Item

One of Idaho Power's Action Items includes a request to conduct a VER Integration study. The Company has produced a number of these throughout the years, and its latest one was filed in 2018 as a result of Commission Order Nos. 17-075 and 17-223. The Company indicated in its latest VER study that Idaho Power's system may be nearing a point where current reserve-providing resources like dispatchable thermal and hydro will no longer be able to integrate additional VERs unless Idaho Power takes additional action to address potential reserve requirement shortfalls.[68] The Company does not specify what these actions are in the IRP, but additional details can be found in the 2018 VER report. This has implications for the IRP and future resource selection. AURORA is still selecting some solar while retiring thermal resources in this IRP, but it is necessary and appropriate for the Company to continue working with Staff in developing VER integration studies. Staff looks forward to working with the Company on this issue.

Clean by 2045

Although not officially part of the 2019 IRP process, in March 2019, Idaho Power announced its goal to provide 100 percent clean energy by 2045. This announcement was independent of the IRP, though it will inevitably impact future filings. Questions about the preferred portfolio arose in light of Idaho Power's announcement during the IRPAC process, but it was already too far along into the IRP, and the Company assured stakeholders that integration of this 100 percent goal would be incorporated into future IRPs. Upon suspending its June 2019 filing, the Company did not incorporate the 2045 goal in its Amended IRP.

While it is too late to incorporate this goal into the current IRP, Staff believes it is appropriate to raise the question of how such an aggressive goal will impact Idaho Power ratepayers. As mentioned above, Staff's concerns revolve around stranded costs, accelerated depreciation, and the appropriateness of using gas resources as an appropriate placeholder for meeting demand.

B2H Partnership and Gateway West

In 2018, the Oregon Commission acknowledged the construction of B2H as an Action Item. The Company's analysis continues to show B2H as a least-cost resource as compared to other resources. Analysis of Table 9.9 reveals that portfolios that select B2H tend to perform better than portfolios that do not. In addition, Jim Bridger Retirement Scenario 4, where units are retired in 2022, 2026, 2028, and 2030, also tend to perform better when compared to other portfolios. For example, the preferred portfolio P16(4) results in a $154,689,000 savings as compared to portfolio P4(4), which considers an identical retirement scenario, but excludes B2H and instead adds other resources like gas and solar.[69] The Company uniquely treats B2H as a resource, which is not entirely unreasonable. However, Staff cautions that in the next IRP, it may not be appropriate to include gas resources in alternative scenarios if Idaho Power wishes to continue with its 2045 goal. That is, an alternatives analysis that includes thermal resources provides little value if the Company has promoted a carbon-free goal by 2045.

[68] UM 1793, Idaho Power Company Application for Approval of Solar Integration Charge, p. 1.
[69] LC 74, Idaho Power 2019 IRP Appendix C, p. 67.

Although not mentioned in the originally filed 2019 IRP or Amended IRP, a material question arose among stakeholders in the IRPAC regarding project partners for B2H. A stakeholder asked about a recent Securities and Exchange Commission filing wherein Idaho Power contemplated doubling its ownership share of the B2H project.[70] When Staff inquired about this issue further in discovery, the Company indicated that it has been exploring additional participation in ownership beyond the initial three parties (Idaho Power, PacifiCorp, and BPA).[71] The Company also indicated that these discussions have not matured, but Staff was left with the impression that changes in ownership appear to be a possibility. Ownership changes may or may not introduce additional costs to Idaho Power. If a fourth owner were to split ownership with an existing partner, costs to Idaho Power may not change in a material way. However, if Idaho Power were to take on additional ownership, this would be a material change that would increase costs of the project for the Company and could impact the preferred portfolio and Action Plan. Given that one of the Company's Action Items is to "Negotiate and execute B2H partner construction agreement(s)," the Company should address this Action Item more clearly in its Reply Comments.

Regarding Gateway West, the Company excludes any Action Item related to this project from its Action Plan. In the 2017 IRP, the Company included ongoing permitting, planning studies, and regulatory filings for Gateway West as an Action Item. In its 2017 IRP Acknowledgment Order, the Commission modified acknowledgment of this Action Item by ordering Idaho Power to provide additional information on Energy Gateway's progress on an ongoing basis, Idaho Power's inclusion of it in a least-cost/least risk portfolio, and the status of co-participants and Energy Gateway's role in the IRP. Idaho Power did provide updates to Gateway West in the IRP and in Docket No. RE 136, but it is important to note that neither Idaho Power nor its partner in the project, PacifiCorp, included Gateway West as part of a preferred portfolio in its most recent IRPs.[72,73] This then raises questions as to how seriously this project is being considered as a least-cost/least-risk resource among both utilities.

Recommendation for Reply Comments

- The Company should respond to Staff's comments regarding B2H, Gateway West, and the role of thermal resources in alternatives analysis.

Jackpot Solar

For the 2019 IRP, the Company is requesting acknowledgment for a 120 MW solar power purchase agreement (PPA) called Jackpot Solar. On April 4, 2019, Idaho Power notified the Oregon Commission about its intent to acquire this resource because it was a "time limited opportunity."[74] Oregon utilities must comply with the competitive bidding requirements for acquisition of generation resources or contracts that are 80 MW or larger and five years or longer,[75] and Jackpot Solar meets this criteria. However, if a resource presents itself as a time-limited opportunity to acquire a resource of unique

[70] See SEC 8-K Filing, November 5, 2019. Accessible at https://otp.tools.investis.com/clients/us/idacorp/SEC/sec-show.aspx?FilingId=13719081&Cik=0001057877&Type=PDF&hasPdf=1#page=17.
[71] See Attachment A, Idaho Power Response to Staff DR 34.
[72] LC 70, PacifiCorp 2019 IRP, p. 247.
[73] LC 74, Idaho Power 2019 Amended IRP, pp. 124-126.
[74] LC 68, Idaho Power Company's Notice of Exception under OAR 860-089-0100. Accessible at https://edocs.puc.state.or.us/efdocs/HNA/lc68hna163119.pdf.
[75] OAR 860-089-100(1).

value to a utility's customers, a utility must file a report with the Oregon PUC explaining the relevant circumstances of the acquisition.[76,77] The Company stated in its April 2019 report that it was approached by Jackpot Solar in September 2018 and that "Jackpot Solar offered to sell to Idaho Power 120 MW of renewable solar generation with very low pricing, significantly below both market prices and Public Utility Regulatory Policies Act of 1978 ("PURPA") avoided cost rates."[78]

The PPA is for the purchase of 120 MW with an option to purchase an additional 100 MW at the Contract Price. Originally, this 100 MW of additional solar was included in the June 2019 IRP Action Plan as Franklin Solar, but as stated earlier in these comments, the Company later determined Franklin Solar was no longer needed after it performed additional analysis. In the April 2019 Notice of Exception Report, the Company presented the following cost comparisons:

Figure 4 – Idaho Power MWh Cost Comparisons Among Resources[79]

Pricing Methodology	First Contract Year (Dec. 2022 - Nov. 2023) Average Price	20-Year Levelized Price
	$/MWh	$/MWh
Jackpot Holdings, LLC - 120 MW	$21.75	$24.31
Jackpot Holdings, LLC - 220 MW	$23.11	$25.83
Oregon Standard Avoided Cost Price	$38.49	$53.74
Idaho Published Avoided Cost Price	$40.11	$80.27
Incremental Cost IRP Avoided Cost Methodology	$28.89	$58.54

The Jackpot Solar PPA is for a 20-year term that contains a first-year price of $21.75/MWh, escalated at 1.5 percent annually. The $21.75/MWh is the lowest price of the public values. The Company also compared the MWh cost of Jackpot Solar to Mid-Columbia market prices but these were confidential. Below is additional information about Jackpot Solar Staff obtained in discovery.

[76] OAR 860-089- 100(4).
[77] OAR 860-089-100(3)(b).
[78] LC 68, Idaho Power Company's Notice of Exception under OAR 860-089-0100. Accessible at https://edocs.puc.state.or.us/efdocs/HNA/lc68hna163119.pdf.
[79] LC 68, Idaho Power Company's Notice of Exception under OAR 860-089-0100, p. 4. Accessible at https://edocs.puc.state.or.us/efdocs/HNA/lc68hna163119.pdf.

Figure 5 – Contract Prices for Jackpot Solar[80]

Contract Price for 120 MW	
Year	**Cost/MWh**
1	21.75
2	22.08
3	22.41
4	22.75
5	23.09
6	23.44
7	23.79
8	24.15
9	24.51
10	24.88
11	25.25
12	25.63
13	26.01
14	26.40
15	26.80
16	27.20
17	27.61
18	28.02
19	28.44
20	28.87

Assuming these costs are true and accurate, the Jackpot Solar project does appear to be a low-cost resource in terms of $/MWh as compared to other resources in the 2019 IRP.[81] The next-lowest cost assumed in the IRP is B2H at $62/MWh.[82]

The Company has identified two Action Items pertaining to this resource: A 2019 Action Item that states "Jackpot Solar PPA regulatory approval—on-line December 2022," and a 2022 Action Item that states, "Jackpot Solar 120 MW on-line December 2022." Though Staff may ultimately recommend acknowledgment of the Jackpot Solar project, it may not be appropriate for Staff to recommend acknowledgment of an Action Item that has already passed. It also may be inappropriate for the Commission to acknowledge an Action Item associated with a Notice of Exception under the competitive bidding rules as the Company appears to be doing. The Company should clarify its Action Item requests in Reply Comments.

Recommendation for Reply Comments:

- Clarify or Remove Idaho Power's 2019 Action Item related to Jackpot Solar.

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[80] See Staff Attachment A, Idaho Power Response to Staff DR 35.

[81] For a comparison of other costs, see LC 74, Idaho Power 2019 Amended Appendix C, p. 24.

[82] See LC 74, Idaho Power 2019 Amended Appendix C, p. 24. These are in 2023 dollars and are levelized costs. The Jackpot Solar PPA starts at a non-levelized cost of $21.75/MWh and is escalated at 1.5 percent each year. The 2023 $/MWh cost of Jackpot Solar however is still the lowest at $22.08/MWh, and ends at $28.87/MWh, which is also still lower than the $62/MWh levelized cost of B2H.

Conclusion

In conclusion, the Company has done quite a bit of work in correcting its analysis from the originally filed 2019 IRP. Staff appreciates the Company's forthrightness in bringing material errors to the attention of Staff and Stakeholders, but Staff also has a series of initial concerns that Company should address in Reply Comments. Staff asks that Idaho Power:

- Clarify the mechanics of all manual adjustments made to the four WECC-optimized portfolios. The Company should clarify which adjustments were made over others, if any, and how qualitative risk played a role in informing manual adjustments to the WECC-optimized portfolios.
- Provide additional description behind the selection of the two risk criteria (NPV and NPV variance) in its Reply Comments.
- Address how it considered PTCs and ITCs in its capacity expansion analysis.
- Provide additional sensitivity analysis for portfolios P2, P4, P14, and P16 that shows the cost of each portfolio if the Jim Bridger retirement dates from PacifiCorp's 2019 IRP preferred portfolio are used.
- Report how it plans to exit the Jim Bridger units at the dates presented in its preferred portfolio, and why it selected the Jim Bridger retirement dates it did for the manual adjustments to the WECC-optimized portfolios.
- Describe how the Company complied with the order to report on future expanded energy efficiency opportunities.
- Clarify key learnings and future plans for energy efficiency selection modeling.
- Address the issue of repeated overshoot of its energy efficiency targets.
- Describe how dropping the TRC test will affect future energy efficiency potential.
- Rerun the model varying the cost of expanded DR using values less than $60 per kW-year. For example, $32 per kW-year (10% increase over the existing resource), $37 per kW-year (25 percent increase), $44 per kW-year (50 percent increase).
- Address 1) the extent to which demand response can provide similar services as battery storage; 2) the extent to which existing demand response programs may be able to provide more frequent and flexible services in the future.
- Address Staff's comparison of LCOCs of demand response programs and battery storage deployment; absent a fundamental misconception by Staff, address this deficiency in the analysis.
- Explain how NREL's approach of limiting the analysis of solar resource capacity value to the highest 100 hours of load complies with the stipulation approved by Commission Order No. 16-326.
- Explain how the methodology used to derive wind capacity values complies with the stipulation approved by Commission Order No. 16-326.
- Explain how the Company's plan to be carbon free is reflected in the assumed cost of the preferred portfolio's gas resource acquisition.
- Explain why the 2019 IRP's estimate for the LCOE of Wyoming wind resources is so much higher than the extant literature and the estimates from PacifiCorp's IRP (LC 70).

- Respond to Staff's comments regarding the use of Itron for the Company's modeling and the use of OLS rather than time-series based regression models.
- Discuss whether there are any notable changes to hydro capacity factors and other assumptions from the last IRP.
- Expand upon its climate change impact analysis and if possible produce a report on its findings from the IRP.
- The Company should respond to Staff's comments regarding B2H, Gateway West, and the role of thermal resources in alternatives analysis.
- Clarify or Remove Idaho Power's 2019 Action Item related to Jackpot Solar.

This concludes Staff's opening comments.

Dated at Salem, Oregon, this 1st day of April, 2020.

Nadine Hanhan

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Nadine Hanhan
Senior Utility Analyst
Energy Resources and Planning Division

March 10, 2020

Subject: Docket No. LC 74 – 2019 Integrated Resource Plan ("IRP")
Idaho Power Company's Responses to the Public Utility Commission of Oregon Staff's ("Staff") Data Request Nos. 1-4

TOPIC OR KEYWORD: CAPACITY; RESOURCE ADEQUACY; PORTFOLIO MODELING

STAFF'S DATA REQUEST NO. 1:

Of the 24 portfolios modeled, none of the portfolios consider the possibility of no new gas turbines (CCCT or SCCT) or reciprocating engines added over the planning period, despite Idaho Power's goal to achieve "100 percent clean energy" by 2045. Please provide the rationale for not modeling any such portfolio or scenario.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 1:

Natural gas resources are identified in the modeled portfolios, but Idaho Power Company ("Idaho Power" or "Company") considers these resources proxies for future resources that can meet system needs and help accomplish the Company's clean energy goals while imposing the least cost on customers. The Company is looking for ways to meet or offset its future resource needs in accordance with its 2045 goals but acknowledges advances in technology may be required.

TOPIC OR KEYWORD: CAPACITY; RESOURCE ADEQUACY; PORTFOLIO MODELING

STAFF’S DATA REQUEST NO. 2:

Related to the above, the preferred portfolio would add a CCCT in 2030 and natural gas-fueled reciprocating engines in 2035. What would be the costs associated with these potentially stranded assets, if they are retired in 2045, long before the end of their expected useful lives?

IDAHO POWER COMPANY’S RESPONSE TO STAFF’S DATA REQUEST NO. 2:

Please see the Company’s response to Staff’s Information Request No. 1 regarding natural gas resources, 2030 and beyond as proxy resources.

TOPIC OR KEYWORD: CAPACITY; RESOURCE ADEQUACY; PORTFOLIO MODELING

STAFF'S DATA REQUEST NO. 3:

See page 124. Related to the above, the manually adjusted preferred portfolio delays the expansion of wind and solar resources past that the WECC-optimized portfolio selected. How has the manual modeling of the delayed addition of renewable resources affected the preferred portfolio's selection of a 300 MW CCCT in 2030?

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

As seen on page 49 of Amended IRP – Appendix C, the Western Electricity Coordinating Council optimized portfolio 16 included a CCCT in 2031 and the delayed addition of renewable resources in the preferred portfolio changed the need for the 300 megawatt ("MW") CCCT to 2030, as shown on page 67 of Amended IRP – Appendix C. The 300 MW flexible resource identified in 2030 coincides with the planned retirement of the final Bridger coal unit in the manually-adjusted preferred portfolio. It provides the flexibility required to integrate renewable resources and cannot be deferred with an earlier build of wind and solar. While the preferred portfolio limits the expansion of wind and solar early in the planning horizon, the expansion of wind and solar resources in the 2030's is considered to align well with Idaho Power's goal of 100 percent clean energy by 2045.

TOPIC/KEYWORD: METHODOLOGY, ACTION PLAN, PORTFOLIOS, MISCELLANEOUS

STAFF'S DATA REQUEST NO. 10:

See page 109.

a. **Why are the P4 and P16 portfolios limited to four portfolios? In what way would limiting these options to four limit the Company's analysis?**

b. **What was the Company's reasoning behind selecting WECC-optimized portfolios 2, 4, 14, and 16? For example, in Figure 9.1, Portfolio 15 appears to be a lower cost portfolio than P16 and P4.**

c. **Please explain the following statement: "In addition, a 15-percent planning margin was preserved while generally retaining the resource mix of the WECC-optimized portfolio." Please also explain the reasoning behind selecting a 15-percent planning margin (including any studies or analysis the Company used to support this number). Please also explain what is meant by "generally retaining."**

d. **In Tables 9.5, 9.6, 9.7, and 9.8, the Company provides changes in cost percentages. Please provide additional explanation as to these numbers. For example, is Staff correct in assuming that the percentage "-.6%" for scenario P2(1) (planning gas, planning carbon) means that compared to the base WECC case P2, if one Bridger unit were to retire in 2022, then under a planning gas, planning carbon scenario, the WECC portfolio would cost .6 percent more than if the Jim Bridger unit were not retired (under a planning gas, planning carbon scenario)? So the comparison would be $61,808,980,000 vs. $61,438,126,120?**

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 10:

a. Scenarios 5 and 6 focused on moving the retirement of one Bridger unit from year 2022 to year 2023 and from year 2022 to year 2024, respectively. This sensitivity analysis was only performed on Portfolios 2 and 14 under the planning gas and planning carbon scenarios, because these are the scenarios the Company believes to be most likely in the near term. In high gas scenarios, coal generation would be more attractive, therefore the Company did not believe these scenarios extending the life of coal units would provide any additional insight. Given a limited analysis timeline these scenarios were eliminated because they would have provided little insight.

b. Figure 9.1 illustrates the Net Present Value ("NPV") versus the cost variance for the 24 WECC optimized portfolios. The plot of all portfolios fit into two distinct groupings: one in the upper left corner, representing higher cost but lower NPV variance between the four cost scenarios and one in the lower right corner, representing lower cost but higher variance between the four cost scenarios. Idaho Power chose portfolios with the best balance of cost and risk from each group with their matching B2H and non-B2H counterpart to be reoptimized. B2H Portfolio 15 and its non-B2H counterpart did not fall into the groupings in the same manner as Portfolios 2, 4, 14, and 16. Manual adjustments were made to the four selected portfolios to ensure a least cost portfolio for the Company.

c. The WECC-optimized portfolios identified some resources in years earlier than capacity needs on Idaho Power's system. In an effort to reduce portfolio NPV cost, these resources were manually adjusted to maintain a 15 percent planning margin while "generally retaining" a similar generation resource mix to the WECC-optimized portfolio.

Please see page 97 of the Amended IRP for a description of the 15 percent planning margin and why it was selected to be used in the 2019 IRP.

d. Staff's assumption is correct. The value for the WECC-optimized Portfolio 2 is $6,180,898,000, and the matching value for the manually-built Portfolio 2 Scenario 1 is $6,145,102,000, which equates to a -0.6 percent difference (0.6 percent is the difference between $6,145,102,000 and $6,180,898,000) as shown in Table 9.5 on pages 109-110. All the values in Tables 9.5, 9.6, 9.7, and 9.8 are compared to the WECC-optimized portfolios.

TOPIC/KEYWORD: METHODOLOGY, ACTION PLAN, PORTFOLIOS, MISCELLANEOUS

STAFF'S DATA REQUEST NO. 12:

See Action Item number 14 (Procure or constrict resources resulting from RFP).

a. Please provide specifics. What is this RFP tied to? How many MW is the RFP expected to be? How does this RFP align with the action plan?

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 12:

Please disregard this action plan item as it was intended to be removed. It erroneously references an action plan item in the IRP filed in June that was removed in the Amended IRP.

TOPIC/KEYWORD: SALES AND LOAD FORECAST, NATURAL GAS, RESOURCE ADEQUACY, PORTFOLIOS, AURORA

STAFF'S DATA REQUEST NO. 21:

See Appendix A, pages 17-31.

a. Please provide all workpapers used to create the each of the Company's class sales forecasts. Please provide all data used in electronic format with cell formulae intact.

b. Please also provide all output (i.e. numbers used) in the tables and graphs in excel spreadsheet format.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 21:

a. Please see the Company's response to Staff's Request No. 20 a–g for the workpaper's associated with the Company's sales and load forecast included in the 2019 IRP.

b. Please see the Excel attachment for all the visuals and associated data included in Appendix A of the 2019 IRP. As mentioned in the Company's response to 20 a-g, much of the analysis and reporting that is represented in this data is compiled through a database framework. The Company typically makes these sources available for on-site review at its corporate headquarters, if requested. However, given current physical access restrictions associated with the COVID-19 outbreak, the Company requests that Staff contact Kelley Noe at (208) 388-5736 or knoe@idahopower.com to explore alternative options for review, in the event that Staff would like to review these materials.

In addition, all tables included in Appendix A are embedded text in the narrative that is derived from data included in Appendix C Technical Report pages 5 - 17.

UE 366 – 2020 APCU - Responses to Staff's Data Request Nos. 55-60

TOPIC OR KEYWORD: LOAD FORECAST

STAFF'S DATA REQUEST NO. 60:

Please provide a narrative description of any load forecast model changes made since the Company's last acknowledged IRP. Please include explanation and empirical evidence of why the changes were made. If the Company produces both a short-term and long-term forecast, please only include changes to the short-term model.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 60:

The Company produces a long-term forecast that extends 20+ years into the future. The near-term or short-term sales forecast is taken directly from the early stages of the long-term sales forecast. Hence, all models are used for both short- and long-term forecasting.

To determine and/or identify potential changes or updates to the forecast models, the Company has relied on in- and out-of-sample testing techniques to determine the optimal performance and behavior of the models, considering mean absolute percentage errors (MAPE) (residuals), t and p- scores, and adjusted r squared.

Residential

The residential sales forecast is estimated using Itron's Statistically Adjusted End-Use (SAE) model. The Itron SAE model used in the 2020 forecast is essentially identical in structure to the SAE model used to prepare the 2017 IRP forecast, the Company's last acknowledged IRP. However, each year the residential SAE spreadsheets and models are updated based on the Energy Information Administration's (EIA) Annual Energy Outlook (AEO). Changes to the residential SAE during this process include, but are not limited to: updated equipment efficiency trends; updated equipment and appliance saturation trends; updated annual heating, cooling, water heating, and non-HVAC indices; as well as updated regional sales. In addition, the Company has updated the model's appliance shares to reflect appliance share estimates derived from the results of the Company's 2016 Residential End-Use Survey.

Final sales to residential retail customers are based on an equation that considers several factors affecting electricity sales to the residential sector. Residential sales are a function of Heating Degree Day (HDD) (wintertime); Cooling Degree Day (CDD) (summertime); historical energy efficiency trends in Idaho Power's residential customer base; saturation and replacement cycle of appliances; the number of service-area households; the real price of electricity; and the real price of natural gas, to name a few. Input files into the SAE framework are adapted to reflect Idaho Power's sales, customers, weather, and service-area economic drivers.

These updates to the SAE model then become part of a traditional econometric framework. For validation and refinement, the residential regression models rely on the use of indicator variables. Most indicator variables are used to explain significant deviations between actual and predicted values. These binaries, or indicators, are introduced and tested in model specification scoping to handle high errors due to extreme weather impacts, billing irregularities, seasonal deviations in residuals, and changes in use-per-customer trends and can differ from one forecast iteration to the next.

The 2017 IRP residential SAE model was estimated over the period January 2005 through June 2016 (138 adjusted observations). Three indicators were included in the final model specification, including: January months; November 2013; and June 2014.

The 2020 residential SAE model was estimated over the period January 2008 through May 2019 (137 adjusted observations). The shortened training period was used as it produced marginally better results, using the discussed statistical feedback. The estimation period begins after the housing market collapse and after the period of the Great Recession. Six statistically significant indicators were included in the final model specification, including: January months; November 2013; June 2014; October and November 2017; before 2012; and 2018 onward. The November 2013, June 2014, and October and November 2017 indicator variables were included because of the large residuals in those months, most likely due to extreme weather. The pre-2012 indicator was included to pick up the shifts in use-per-customer as evidenced by the number and magnitude of positive residuals occurring prior to 2012. The post-2018 indicator was included to pick up the shifts in use-per-customer as evidenced by the number and magnitude of negative residuals occurring in 2018 and 2019.

Irrigation

The 2017 IRP irrigation regression model was estimated over the period 1992 through 2015 (24 years). The 2017 IRP irrigation regression model included a lagged real electricity price term that was removed in the 2020 irrigation model due to a lack of significance. The 2017 IRP irrigation regression model also included an indicator variable to account for the unusually low electricity consumption in the 2001 crop year due to a voluntary load-reduction program. This indicator was eliminated in the 2020 irrigation regression model since the regression training period began in 2002. The 2020 irrigation sales forecast model was estimated over the period 2002 through 2018 (17 years). The annual maximum irrigation customer count was added as an explanatory variable and Moody's Gross Product: Agriculture, for Idaho was removed as an explanatory variable since the most recently acknowledged IRP.

Commercial and Industrial

As referenced in Staff Data Request No. 59, commercial and industrial modeling consists of a series of analytical modeling steps that begin with segmentation of industrial economic/energy use profiles. (These are: Services: Education, Health Care, Retail Goods and Services, Offices/Assembly/Lodges or Lodging, Data Centers, Warehousing and Manufacturing: Dairy, Food Packaging, Food Processing, Sugar, Base Manufacturing, Construction, Electronics/Tech, and Other/Miscellaneous).

The primary purpose for developing these models is to best understand the dynamics of causation to the components of the aggregated segments (manufacturing, service). Due to the large number of detailed segment models, the following narrative will focus on changes in the published models included in the APCU since the most recently acknowledged IRP.

Commercial Manufacturing Model: A concerted effort has been made in the current model to include a price variable in the model specification. This effort has resulted in dropping a macro variable (Gross Metro Product) in favor of agricultural activity variables. Additionally, improvements in classification algorithm resulted in reclassification of manufacturing customers to service, which changed the time-series values of the independent variable, reducing the energy value by approximately 35 percent in the manufacturing segment and increasing by an equivalent amount in the service segment. The change resulted in no significant change in adjusted R squared but a higher MAPE (from 0.57 to 1.12).

Commercial Service Model: As indicated above, better intel resulted in moving some customers to this service model from manufacturing. Additionally, the inclusion of a price variable and weather variables (HDD60 and CDD60) improved the adjusted R squared (from 0.96 to 0.99) and reduced the MAPE (from 0.71 to 0.43).

Industrial Service Model: No changes to model.

Industrial Manufacturing Model: The primary change was dropping of a model variable for Government GDP contribution in favor of manufacturing company earnings variable. While government investment in the service territory is significant, it was felt that the Moody's variable resulted in a growth level that was higher than supported by segment model indications. The change reduced the next-year forecast by approximately 4 percent. Both adjusted R squared and MAPE improved.

TOPIC/KEYWORD: PORTFOLIOS

STAFF'S DATA REQUEST NO. 34:

Is Idaho Power anticipating any changes to ownership in the B2H line? If so, please explain.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 34:

Idaho Power, Bonneville Power Administration, and PacifiCorp have had and continue to have discussions with other electric power providers in the region in efforts to determine if there is interest in additional participation in ownership beyond the initial three parties. Any additional participation could result in a change to the overall ownership of the project. While discussions among the three parties continue over possible ownership changes based on each party's customer needs, these discussions have not matured but could present a change in overall ownership.

TOPIC/KEYWORD: PORTFOLIOS

<u>STAFF'S DATA REQUEST NO. 35</u>:

Regarding the Jackpot Solar project:

- **a.** **What is the cost per MWh that was assumed for the purchase power agreement for this resource?**
- **b.** **Please provide any workpapers related to calculating the cost of this resource.**

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 35</u>:

Regarding the Jackpot Solar Project:

a. The Jackpot Solar costs per MWh identified in the purchase power agreement are as follows:

Contract Price for 120 MW

Year	**Cost/MWh**
1	21.75
2	22.08
3	22.41
4	22.75
5	23.09
6	23.44
7	23.79
8	24.15
9	24.51
10	24.88
11	25.25
12	25.63
13	26.01
14	26.40
15	26.80
16	27.20
17	27.61
18	28.02
19	28.44
20	28.87

b. The agreement is for a 20-year term that contains a first-year price of $21.75/MWh, escalated at 1.5 percent annually. The non-levelized prices are fixed for the term of the agreement. Idaho Power filed a Report with the Commission regarding Idaho Power's Notice of Exception pursuant to OAR 860-089-100 on April 4, 2019. The Excel attachment provided with this response contains the estimated obligation of the Jackpot Solar Power Purchase Agreement.

TOPIC/KEYWORD: PORTFOLIOS

STAFF'S DATA REQUEST NO. 36:

Please see PacifiCorp's 2019 IRP, pages 22 and 23.

a. Has Idaho Power coordinated with PacifiCorp on Jim Bridger coal retirement dates? If so, how?

b. Which Jim Bridger unit is Idaho Power planning on retiring in 2022?

c. Which Jim Bridger unit is Idaho Power planning on retiring in 2026?

d. Why do Idaho Power's Jim Bridger coal unit retirements fail to align with those of PacifiCorp?

e. Please explain why Idaho Power is not naming individual unit retirements in its Action Plan.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 36:

a. Idaho Power and PacifiCorp have had preliminary, high-level discussions regarding potential retirement dates for Jim Bridger units. Discussion will continue as both companies proceed with their planning processes.

b, c, & e. While left undetermined in Idaho Power's 2019 IRP, Units 1 and 2 will most likely be the first units to retire at the Jim Bridger plant. However, factors such as unit condition, unit efficiency, outage schedules, forecast capital expenditures, along with other relevant factors will be used to determine the actual unit retirement schedule.

d. Both companies continue to independently analyze the retirement dates that result in the best mix of cost and risk to the Company and its customers, resulting in different retirement dates. Idaho Power and PacifiCorp will continue discussions to address potential retirement dates.

TOPIC/KEYWORD: DEMAND RESPONSE

STAFF'S DATA REQUEST NO. 41:

Please reference the Demand Response Resource Potential section on page 61 of the 2019 Amended 2019 IRP. The second paragraph notes that the expanded demand response was modeled in AURORA at a cost of $60 per kW-year. Please provide a narrative description of the assumptions explaining the selection of $60 per kW-year as the modeled cost.

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S DATA REQUEST NO. 41:

Because it is difficult to estimate the costs of a customer-based program 12 years in the future, Idaho Power used approximately one-half the price of a Simple Cycle Combustion Turbine of $136 per kilowatt ("kW")-year as a proxy cost for future DR. In comparison, in 2019, the capacity cost of all of the Company's DR programs was approximately $21 per kW-year; however, all equipment and set-up costs were incurred in prior years. An expanded or new program would likely include new equipment, additional administration cost, and all participants would most likely require increased incentive payments. It is for these reasons that the Company believes its proxy price of $60 per kW-year is reasonable.