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BEFORE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR AUTHORITY TO INCREASE ITS RATES FOR ELECTRIC SERVICE TO RECOVER COSTS ASSOCIATED WITH THE JIM BRIDGER POWER PLANT	CASE NO. IPC-E-21-17 JOINT COMMENTS OF IDAHO CONSERVATION LEAGUE AND SIERRA CLUB

Public Version

April 27, 2022

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JOINT COMMENTS OF IDAHO CONSERVATION LEAGUE AND SIERRA CLUB [PUBLIC VERSION]

I. Introduction

Idaho Conservation League ("ICL") and Sierra Club appreciate the opportunity to submit the following comments.[1] In this proceeding, Idaho Power Company ("IPC," "Idaho Power," or "Company") seeks Commission approval to accelerate depreciation on its coal-related investments at the Jim Bridger power plant and create a balancing account in order to track the incremental costs associated with the cessation of coal operations at the plant.[2]

As discussed below, the Commission should deny Idaho Power's application for at least three reasons. First, the Company has not secured a firm exit plan from Jim Bridger with Idaho Power's co-owner, PacifiCorp. The Company freely acknowledges that current contractual agreements do not permit the exit of one owner while another owner continues operations.[3] As a result, Idaho Power is seeking to guarantee its own cost recovery for prior investments in Jim Bridger through accelerated depreciation without guaranteeing any benefit to ratepayers resulting

[1] These comments were prepared with the assistance of Devi Glick at Synapse Energy Economics, Inc. and Ben Serrurier at RMI (formerly the Rocky Mountain Institute).
[2] Supplemental Direct Testimony of Matthew T. Larkin on Behalf of Idaho Power Company at 5:16-6:2 (Feb. 16, 2022) [hereinafter "Larkin Supplemental"].
[3] Direct Testimony of Ryan N. Adelman at 7:22-8:1 (June 2, 2021) [hereinafter "Adelman Direct"].

from early exit from the plant. Accelerated depreciation, which increases customer rates in order to ensure full recovery under a shorter time frame, should not be approved by this Commission until Idaho Power is able to guarantee that it will, in fact, exit the plant earlier than currently forecasted.

Second, Idaho Power's decision to spend nearly $110 million on selective catalytic reduction ("SCR") pollution control technology on Units 3 and 4 was imprudent. To put into context the significance of this expenditure, of the total coal-related Bridger costs from 2011 through 2020 for which Idaho Power seeks approval in this proceeding, the SCR investment alone represents approximately 50 percent. Despite the enormity of the investment, Idaho Power failed to keep abreast of rapidly changing economic conditions and took no action to avoid the expenditure even when it was no longer the lowest cost option compared to other options. In order to protect Idaho customers from the Company's imprudence, the Commission should disallow any rate of return on the SCRs. Doing so would be in line with actions other state utility commissions have taken to protect ratepayers from imprudent investment in these same SCRs.[4]

Finally, regardless of whether the SCRs are recovered, the Commission should not approve this application because Idaho Power has not explained why it has chosen an unusual form of rate recovery—accelerated depreciation—in place of lower cost, alternative forms of rate recovery, such as securitization. ICL and Sierra Club's analysis, conducted by RMI, demonstrates that securitizing these costs would save ratepayers approximately $63.7 million compared to accelerated depreciation. This level of savings should be taken seriously by Idaho

[4] *See, e.g., In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473 (Ore.P.U.C Dec. 18, 2020) (denying any return on equity in PacifiCorp's "return on" the SCR investment at Jim Bridger Units 3 and 4); *Washington Utilities and Transportation Commission v. Pacific Power & Light Company*, Docket No. UE-152253, Order No. 12 (Wash.U.T.C. Sept. 1, 2016) (denying any return on investment in SCRs on Jim Bridger Units 3 and 4).

Power, as securitization will achieve all of the utility's stated goals in this proceeding but at significantly lower cost to customers.

II. The Commission Should Not Guarantee Idaho Power Cost Recovery on its Jim Bridger Expenditures Prior to a Firm Commitment to Exit the Plant

Jim Bridger is a four unit coal-fired power plant located in Sweetwater County, Wyoming that is co-owned by Idaho Power and PacifiCorp. The plant consists of four generating units, of which Idaho Power owns a one-third stake (771 MW).[5] Although PacifiCorp operates the plant,[6] the two companies "work jointly to make decisions regarding the plant, including required investment and [future] retirement."[7] As noted above, no contractual provisions exist that would allow for one owner to end participation in a Bridger unit during a time when the other co-owner wishes to continue operations.[8]

The Jim Bridger plant is relatively expensive to own and operate. For instance, of PacifiCorp's entire coal fleet (10 plants comprising 22 units), Jim Bridger's four units are consistently some of the highest cost, largely due to fuel expense.[9] The Bridger Coal Company ("BCC" or "Bridger mine") and Black Butte mines are the plant's primary suppliers. BCC is a captive mine that is also co-owned by PacifiCorp and Idaho Power and exclusively services the Jim Bridger plant.[10] As with the plant, Idaho Power holds a one-third share in the Bridger mine. Although the Black Butte mine is third party owned, its primary customer is Jim Bridger. In fact,

[5] IPC Amended Application and Motion to Set Schedule at 3, ¶ 5 (Feb. 16, 2022) [hereinafter "Amended Application"].
[6] Amended Application at 3, ¶ 5.
[7] IPC Application at 3, ¶ 5.
[8] Adelman Direct at 7:11-19.
[9] *See, e.g., In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Opening Testimony Of Ed Burgess on Behalf of Sierra Club at 16:4-8 (Ore.P.U.C. June 9, 2021), *available at* https://edocs.puc.state.or.us/efdocs/HTB/ue390htb164812.pdf (explaining that on a $/MWh basis, coal burn expenses at Jim Bridger are significantly higher than costs of potential alternatives, including PacifiCorp's other coal plants, gas plants, and the new installation of renewable energy resources).
[10] *See, e.g.*, Amended Application at 4, ¶ 9.

in 2021, Jim Bridger was Black Butte's only customer.[11] Recent modeling in PacifiCorp's 2021 IRP suggests that assumed minimum required coal purchases from BCC and Black Butte are driving uneconomic generation at the plant and that without those constraints, generation at Jim Bridger would plummet.[12]

Installation of pollution control technology, such as SCR controls, also increases a plant's operating costs. This is true not only because construction and installation costs are high but also because these controls have ongoing operational costs. SCR pollution control technology requires large volumes of catalyst for the nitrogen oxide ("NOx") reduction reaction and these catalysts must be replaced on a regular basis.[13] As discussed more fully below, between 2013 and 2016, Idaho Power and PacifiCorp installed SCRs on Bridger units 3 and 4.[14] In combination with high fuel costs, SCRs on units 3 and 4 help to explain why Jim Bridger is such an expensive plant to own and operate.

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[11] Mine Profile: Black Butte & Leucite Hills Mine, S&P Global Market Intelligence https://www.capitaliq.spglobal.com/web/client?auth=inherit#coalMine/mineProfile?id=2423 (provided as ICL/SC Attachment 1).

[12] *In the Matter of Rocky Mountain Power's Filing for Acknowledgement of its 2021 Integrated Resource Plan*, Case No. PAC-E-21-19, Joint Comments of Sierra Club and Idaho Conservation League at 31-32 (Mar. 15, 2022), *available at* https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/PAC/PACE2119/Intervenor/ICL/20220315Joint%20Comments%20and%20Attachments-Redacted.pdf (describing generation at Jim Bridger under modeling conducted by PacifiCorp that removed minimum take requirements at Jim Bridger). *See also In the Matter of PacifiCorp's 2021 Integrated Resource Plan*, Docket No. 21-035-09, Redacted Reply Comments of Western Resource Advocates at 2 (Utah.P.S.C Apr. 7, 2022), *available at* https://pscdocs.utah.gov/electric/21docs/2103509/323381RdctdWRARplyCmnts4-7-2022.pdf (commenting on same "No Minimum Scenario" and concluding that "Jim Bridger Units 3 and 4 are so costly to operate that they would not be dispatched beyond 2030 in a least-cost optimization without constraining the model with minimum-take fuel requirements).

[13] *EPA Air Pollution Control Cost Manual*, U.S. EPA, Section 4, Chapter 2 at 2-10 (June 2019), *available at* https://www3.epa.gov/ttn/ecas/docs/SCRCostManualchapter7thEdition_2016.pdf. In fact, replacement of the catalyst for Unit 3's SCR controls is included in Idaho Power's application. Amended Application at 5, ¶ 10.

[14] Units 1 and 2 similarly have federally mandated SCR requirements by the end of the 2021 and 2022; however, neither co-owner has taken any action to install the SCRs on either unit. Idaho Power Company, *2021 Integrated Resource Plan* at 102 (Dec. 2021), *available at* https://docs.idahopower.com/pdfs/AboutUs/PlanningforFuture/irp/2021/2021%20IRP_WEB.pdf [hereinafter "2021 IPC IRP"].

Due to these costs, it is unsurprising that Idaho Power's latest IRP projects exiting from Units 3 and 4 by 2025 and 2028 and converting Units 1 and 2 to gas in 2024, with a 2034 exit date for those units.[15] ICL and Sierra Club support the Company's planned exit from Jim Bridger as it will benefit both ratepayers and the environment.[16] However, that exit is not yet guaranteed. Currently, Idaho Power and PacifiCorp forecast different futures for the plant. While Idaho Power is rightfully planning to exit Jim Bridger in the near-term, PacifiCorp's latest 2021 IRP continues to forecast operating units 3 and 4 through 2037—another 15 years.[17] For the planned gas conversions at Units 1 and 2, Idaho Power's IRP anticipates exit from these units in 2034, whereas PacifiCorp plans to operate them until 2037.[18]

These differences are important. As Mr. Adelman testified, PacifiCorp and Idaho Power "have not developed contractual terms that would be necessary to allow for the potential earlier exit of a Bridger unit by one co-owner, and not both Co-Owners."[19] As a result, Idaho Power is unable to provide any information on the terms of an exit agreement with PacifiCorp or what costs might be borne by Idaho ratepayers to facilitate the planned early exit. Put simply, Idaho Power is unable to ensure that it will exit from Jim Bridger in line with its most recent IRP or at what cost.

Nevertheless, rather than first securing a firm exit from the plant, Idaho Power instead asks this Commission to accept its anticipated exit dates as firmly set and authorize accelerated

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[15] *Id.* at 152.

[16] In fact, it's possible that leaving Jim Bridger even earlier would be the most economic outcome for ratepayers. Sierra Club and Idaho Conservation League's comments should not be construed as endorsing IPC's planned exit from Jim Bridger. IPC should continue to evaluate exit from the plant and exit earlier if doing so would be economic for ratepayers.

[17] PacifiCorp, *2021 Integrated Resource Plan*, Vol. I at 15 (Sept. 1, 2021), *available at* https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf.

[18] *Id.*

[19] Adelman Direct at 7:22-8:1.

depreciation. This approach is clearly advantageous for Idaho Power: it would guarantee the Company an accelerated recovery of its prior expenditures at the plant and further allow the Company to create a balancing account to recover future expenditures. However, this approach is less clearly advantageous for ratepayers, who would pay the costs of accelerated depreciation on previous and future expenditures without any assurance of an early exit from the plant, the reason used to justify the accelerated depreciation proposal in the first place. This puts tremendous risk on ratepayers while simultaneously removing both Idaho Power's risk and incentive to exit the plant.

The Commission must condition any accelerated depreciation (or other financing) order on a firm exit plan, including contractual agreements with PacifiCorp that guarantee Idaho Power's timely exit from the plant. ICL and Sierra Club further recommend that the Commission require regular updates to inform the Commission as to the status of a firm exit agreement with PacifiCorp and only permit cost recovery based on accelerated depreciation once the agreement is finalized.

III. Idaho Power's Analysis of the Uneconomic SCR Project on Units 3 and 4 Was Insufficient and Resulted in the Imprudent Investment of Over 100 Million Dollars into Jim Bridger.

Idaho Power's decision to spend $58.29 million and $51.65 million on SCR controls at Units 3 and 4, respectively, were the largest expenditures made at the Jim Bridger plant since 2011.[20] At the time the expenditures were made, Idaho Power assumed an indefinite retirement date for these units. Now, in its current application, the Company seeks to accelerate

[20] Adelman Direct at 13:14-17.

depreciation on the investment, from 2034 to 2030,[21] due to its plans to stop taking power from Units 3 and 4, and thus no longer utilize the SCR equipment, by 2025 and 2028 respectively.

There is little dispute that the decision to install SCRs at Jim Bridger Units 3 and 4 was not economic for ratepayers. This is obvious for at least two reasons. First, while initial analysis showed that the SCR project was economic, the next lower cost option would have been conversion to natural gas. PacifiCorp, the majority owner and operator for the plant, forecasted that the "breakeven" levelized average cost for gas was \$4.86/MMBtu over PacifiCorp's planning period.[22] In other words, if gas prices stayed above \$4.86/MMBtu, the SCR installation was in ratepayers' economic interest; gas prices below this figure meant that the project would cost ratepayers more than other viable alternatives. Since 2015 and 2016, when the SCRs were installed on Units 3 and 4, gas prices have remained far below \$4.86 per MMBtu,[23] and only recently exhibited an upturn in response to the pandemic and the Russian war in Ukraine. Recent gas price forecasts project costs below \$4.00 per MMBtu at least through 2028, notably the date that Idaho Power now plans to exit from all coal operations.[24]

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[21] Amended Application at 6, ¶¶ 12-13.

[22] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Direct Testimony of Rick T. Link on Behalf of PacifiCorp (PAC/700) at 107:8-9 (Ore.P.U.C. Feb. 2020), *available at* https://edocs.puc.state.or.us/efdocs/UAA/ue374uaa145444.pdf (Mr. Link's testimony begins on PDF p. 437).

[23] U.S. Energy Information Administration (EIA), Idaho Natural Gas Prices, *available at* https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SID_a.htm (last accessed Apr. 26, 2022).

[24] U.S. EIA, *EIA forecasts natural gas prices to remain near \$4/MMBtu in 2022, slightly lower in 2023* (Jan. 14, 2022), *available at* https://www.eia.gov/todayinenergy/detail.php?id=50898.

Second, when Idaho Power decided to move forward with the SCR project, the Company assumed an indefinite closure date for coal operations at Jim Bridger.[25] Today, Idaho Power plans to exit from coal in 2023 (Units 1 and 2), 2025 (Unit 3), and 2028 (Unit 4). While exiting from Jim Bridger is in ratepayers' best interest, this decision also means that the SCRs useful life for Idaho ratepayers has been dramatically shortened.

The question for this Commission, then, is whether IPC's decisions related to the Jim Bridger SCRs were reasonable, even though they were wrong. Due to Idaho Power's failure to monitor rapidly changing economic conditions and change course when the SCRs were no longer economically viable, the clear answer is no. As a remedy, the Commission should disallow Idaho Power's return on investment in the SCRs, as other commissions have done pertaining to these same SCRs.

A. Idaho Power Failed to Robustly Reevaluate the Decision to Install SCR Updates at Units 3 and 4 at Decision Points that Would Have Allowed the Company to Avoid Substantial Project Costs, As Ordered by the Commission

As discussed above, PacifiCorp is the majority (two-thirds) owner of the Jim Bridger plant and also the plant operator. Idaho Power is the co-owner and is responsible for its one-third share of the plant costs, which it passes on to its ratepayers. Even though Idaho Power is not the plant operator, it still has a responsibility to ensure that the plant is operated prudently and that

[25] In three analyses between 2013 and 2017, Idaho Power evaluated the useful life of Jim Bridger through 2032, 2034, and 2037. *See In the Matter of Idaho Power Company's Application for a Certificate of Public Convenience and Necessity for the Investment in Selective Catalytic Reduction Controls on Jim Bridger Units 3 and 4*, Case No. IPC-E-13-16, Ex. 5A "Coal Environmental Compliance Upgrade Investment Evaluation" to the Direct Testimony of Tom Harvey at 3-8, 3-9("coal study" with a planning period through 2032), *available at* https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE1316/Company/20130927Redacted%20Harvey%20Exhibit%205A.pdf [hereinafter "IPC-E-13-16, Redacted SAIC 2013 Coal Study"]; Idaho Power Company, *2015 Integrated Resource Plan*, App. C at 121-130 (June 2015), *available at* https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE1519/CaseFiles/20150630IRP%20Appendix%20C%20Technical%20Report.pdf (analysis through 2034) [hereinafter "App. C to 2015 IPC IRP"]; Idaho Power Company, *2017 Integrated Resource Plan* at 83 (analysis through 2037). In each of these, Jim Bridger operated through the end of the planning period. Accordingly, no analysis identified a closure date for the plant.

its ratepayers do not incur unnecessary costs. IPC indicated that it works with PacifiCorp to make decisions regarding operations and planning at the plant.[26]

The co-ownership relationship does not appear to be in the best interest of Idaho ratepayers, particularly regarding the decision to install SCRs on Units 3 and 4. Rather, the Company's decisions at the plant regarding the SCR installation appear to be driven by PacifiCorp's actions, with its own analysis only conducted after-the-fact and designed to support a decision that had already been made. As evidence that the co-ownership is not in the best interest of Idaho Power customers, Idaho Power began seeking an exit path from the Jim Bridger plant in [redacted], [redacted], and [redacted].[27]

1. *The plant owners made the decision to move forward with the SCRs long before Idaho Power performed any analysis.*

The decision to move forward with the SCR project was made long before Idaho Power conducted any analysis. Specifically, in January 2011, PacifiCorp, in conjunction with the Wyoming Department of Environmental Quality ("DEQ"), agreed to install SCRs on Units 3 and 4 (and, potentially Units 1 and 2 at a later date) as part of its Regional Haze Implementation Plan ("FIP").[28] Less than a year later, in August 2012, PacifiCorp filed a CPCN with the Wyoming Commission for the SCRs and a voluntary request for approval with the Utah Commission. It wasn't until nearly a year later, in May 2013, that IPC filed a CPCN for the SCRs with the Idaho Commission. This application was filed the same month the Wyoming and Utah Commissions

[26] Amended Application at 3, ¶ 5.
[27] Confidential Attachments 1, 2, and 3 to IPC Response to Industrial Customer of Idaho Power Request No. 43 (provided as ICL/SC Attachment 2).
[28] IPC-E-13-16, Redacted SAIC 2013 Coal Study at 2-1.

both approved the CPCN applications for the SCRs in their respective states. A full regulatory timeline is listed in Table 1 below.

Table 1. Regulatory timeline for SCR approval for the Jim Bridger Plant

Date	Wyoming	Utah	Idaho
January, 2011	PacifiCorp, in conjunction with the Wyoming DEQ, agreed to install SCRs on Units 3 and 4 as part of Regional Haze FIP.[29]		
August, 2012	PacifiCorp filed a CPCN with the Wyoming Commission for the SCRs.[30]	PacifiCorp filed a voluntary request for approval of the SCRs with the Utah Commission.	
February, 2013			SAIC study is completed.
April, 2013	PacifiCorp issued an internal memo recommending the awarding of an Engineer, Procurement, and Construction ("EPC") Contract to Babcock and Wilcox Power Generation Group and the Perry Group.		
May, 2013	EPA approved and disapproved portions of the Wyoming Regional Haze SIP.[31] Wyoming Commission approved CPCN for SCRs in docket No. 200000-418 (Record No. 13314)[32]	Utah Commission issued its final order approving SCRs (Docket No. 12-035-92).[33]	
June 2013			IPC filed a CPCN with the Idaho Commission seeking authorization for investment in SCR controls.[34]

[29] IPC-E-13-16, Redacted SAIC 2013 Coal Study at 2-1.

[30] *In the Matter of Idaho Power Company's Application for a Certificate of Public Convenience and Necessity for the Investment in Selective Catalytic Reduction Controls on Jim Bridger Units 3 and 4*, Case No. IPC-E-13-16, Application at 4, ¶ 8(June 28, 2013), *available at* https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE1316/CaseFiles/20130701Application.pdf [hereinafter "CPCN Application"].

[31] *Id.* at 4, ¶ 7.

[32] *Id.* at 4, ¶ 8.

[33] *Id.*

[34] Adelman Direct at 17:20-24.

Date	Wyoming	Utah	Idaho
December, 2013			Idaho Commission issued order in Case No. IPC-E-13-16 (Order No. 32929) approving the company's application for a CPCN for the SCRs at Units 3 and 4. IPC gave PacifiCorp formal notice to support the issuance of a full notice to proceed ("FNTP") with the SCR project.
January, 2014	EPA issued final approval for the Wyoming strategy to install SCRs at Units 3 and 4 in 2015 and 2016 respectively, and for Units 1 and 2 in 2021 and 2022 respectively.[35]		
June, 2015			IPC's 2015 IRP is published with an updated SCR study in Appendix C.
December 31, 2015	Compliance deadline for Unit 3.[36] Construction on Unit 3 SCR is completed		
December 31, 2016	Compliance deadline for Unit 4.[37] Construction on Unit 4 SCR is completed.		

Securing approval from three state commissions and environmental agencies undoubtedly takes time and coordination, but it appears that IPC waited until the decision was already made in Utah and Wyoming before bringing its application to the Idaho Commission. By doing this, Idaho Power was not allowing the Idaho Commission to play a major role in the review and decision-making process for the SCR project. But even more concerning is that this timing gave the Company a strong incentive to make sure any analysis included with its application supported the position that installing the SCRs was the lowest cost option. Because any other result would

[35] Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze, 79 Fed. Reg. 5032 (Jan. 30, 2014).
[36] *Id.* at 5046.
[37] *Id.*

have contradicted the approvals that PacifiCorp had just received in Utah and Wyoming, it would have complicated things immensely for itself and PacifiCorp, and it would have made it challenging for the owners to comply with the EPA regulations by the now-required 2015 and 2016 dates.

2. The Commission warned Idaho Power that it was obligated to reevaluate alternatives as regulations changed and the Company was not guaranteed cost recovery.

When the Idaho Commission ruled on IPC's CPCN application in December 2013, the Commission was clear in its final order that it was concerned about the economics of the conversion. It also indicated in its order that it expected the Company to regularly reevaluate the economics of the project and whether alternatives were more economic. Specifically, the Commission stated:

> It is not inconceivable that, during the installation of the SCRs, a tipping point could be reached making them uneconomic. It is in the best interest of the customers, the Company, and the Company's shareholders for Idaho Power to be continuously analyzing the impact of changing environmental regulations on its upgrade project. As the project moves toward completion over the next several years, we direct Idaho Power to return to the Commission if viable alternatives to the Bridger Units 3 and 4 upgrades become available.[38]

The Commission also expressed concern that future environmental regulations will make the plant more costly to operate, and thus threaten the economics of the plant:

> The Commission's primary concern is the possibility of more stringent environmental regulations that could make the Bridger upgrades, and thus the Company's investment, uneconomic.[39]

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[38] *In the Matter of Idaho Power Company's Application for a Certificate of Public Convenience and Necessity for the Investment in Selective Catalytic Reduction Controls on Jim Bridger Units 3 and 4*, Case No, IPC-E-123-16, Order No. 32929 at 11 (Dec. 2, 2013), *available at* https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE1316/OrdNotc/20131202final_order_no_32929.pdf [hereinafter "Order No. 32929"].

[39] *In the Matter of Idaho Power Company's Application for a Certificate of Public Convenience and Necessity for the Investment in Selective Catalytic Reduction Controls on Jim Bridger Units 3 and 4*, Case No, IPC-E-123-16, Order No. 32996 at 3 (Mar. 14, 2014), *available at* https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE1316/OrdNotc/20140314final_order_no_32996.pdf.

The Commission was clear in its final order that it was not guaranteeing recovery of the costs associated with the SCR:

> Because of the uncertain future of coal-fired generation, we find it unreasonable to prematurely commit ratepayer dollars to support Idaho Power's investment.[40]

Finally, the Commission required IPC to submit quarterly reports on the status of the project and any changes in environmental regulations that could impact the economics of the SCR investment relative to alternatives.

> We recognize that the future of coal-fired generation in the United States is uncertain at best. We admonish the Company to stay abreast of potential future environmental regulations that could negatively impact its investment in the Bridger upgrade. To that end, we direct the Company, as a condition of its CPCN (Idaho Code $ 6I-528), to submit quarterly reports updating the Commission on any changes to environmental policy or regulations as the Bridger upgrades are installed and placed in service.[41]

The Commission's direction in its CPCN order should have made clear to IPC that continuous analysis of the SCR project was necessary. While the Commission largely focused on the potential for new environmental regulations undermining the economics of the project, it is clear that the Commission's ultimate objective was to avoid unnecessary and expensive investment in an aging coal plant. The Commission's reference to "the uncertain future of coal-fired generation" foresaw that IPC may seek to exit the plant earlier than contemporary forecasts predicted, and, indeed, IPC now plans to exit from all coal operations at the plant by 2028. The need to seriously scrutinize continued investment in the plant was, thus, obvious. Although the Commission ultimately approved the CPCN, its order makes clear that IPC's diligence should have been heightened, not relaxed.

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[40] Order No. 32929 at 12.
[41] *Id.* at 11.

Yet, in the Company's required quarterly reports, the Company outlined progress on the project, but did not provide additional economic analysis of the project as a whole until June of 2015, a year and a half after the full notice to proceed was issued.[42] By this time, construction had been underway for over a year, and the ability to avoid additional costs at that time was much more limited than if the study had been conducted earlier. Specifically, 99 percent of Unit 3 and 60 percent of Unit 4's structural steel was in place, 70 percent of the reactor piping at Unit 3, and 30 percent of the overall electrical field work was completed. Additional equipment for Unit 3 had been ordered and shipped, and the order for Unit 4 was in process.[43]

It is unclear why the Company did not immediately begin the process of updating its analysis upon approval of the CPCN, and why it did not otherwise provide updated analysis in early 2014 to confirm that the project was still economic, when it still had an opportunity to avoid sinking tens of millions of ratepayer dollars into the plant. By delaying until the project was already underway, IPC had a strong incentive to deliver results showing the project was economic. Finding otherwise would mean admitting that a project that was actively underway and already incurred tens of millions of dollars, was no longer prudent.

B. Idaho Power Relied on Simplistic Screening Analysis in 2013 and then a Flawed Updated Analysis in 2015 to Justify its Decision to Move Forward with the SCR Project

Idaho Power relied on two different analyses to show, and then later confirm, that installing SCRs on Units 3 and 4 was the least cost and lowest risk option. However, the inputs and methodology used in each set of analysis undermined the final conclusions.

[42] App. C to 2015 IPC IRP at 121-130.

[43] *In the Matter of Idaho Power Company's Application for a Certificate of Public Convenience and Necessity for the Investment in Selective Catalytic Reduction Controls on Jim Bridger Units 3 and 4*, Case No, IPC-E-123-16, Idaho Power Company's 6th Quarterly Report (June 3, 2015), *available at* https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE1316/Company/20150603Sixth%20Quarterly%20Report.pdf [hereinafter "June 3, 2015 Quarterly Report"].

The first set of analysis was conducted in 2013 as part of the Company's application for a CPCN from the Idaho Commission for the SCRs. The analysis had two parts. The first part was conducted by Science Applications International Corporation ("SAIC") and published February 8, 2013 ("SAIC Study").[44] This study estimated the capital and variable costs associated with the proposed environmental upgrades and of the replacement option of a gas "combined cycle combustion turbine" ("CCCT") plant and also conversion to gas. The second part, which incorporated the results of the first, was completed by IPC using economic dispatch modeling tool Aurora ("2013 Portfolio Analysis").[45] This analysis evaluated the total portfolio cost over a twenty-year period of the options considered by SAIC. These results were combined and reported as the 2013 Coal Unit Environmental Investment Analysis.[46]

The second analysis was conducted in 2015 and was included in IPC's 2015 IRP ("2015 IRP Study").[47] As discussed above, construction had been underway for over a year at the time the study was conducted, [48] and therefore the ability to avoid additional costs at that time was more limited than if the study had been conducted earlier. As of June 30, 2015, the Company had already incurred actual costs equivalent to around [redacted] of the total project cost.[49]

Each of these studies contains assumptions and shortcomings that made the installation of SCRs and continued combustion of coal appear to be the most cost-effective option. Other data available at the time, however, calls that conclusion into question.

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[44] Confidential Attachment 2 to IPC Response to Sierra Club Request No. 18 (provided as ICL/SC Attachment 3) [hereinafter "Confidential SAIC Study"]. A redacted version of this study was provided as Ex. 5A "Coal Environmental Compliance Upgrade Investment Evaluation" to the Direct Testimony of Tom Harvey in IPC-E-13-16 and is referred to as "IPC-E-13-16, Redacted SAIC 2013 Coal Study" throughout these comments.
[45] Attachment 1 to IPC Response to Sierra Club Request No. 18 at 3 (provided as ICL/SC Attachment 4) [hereinafter "2013 Coal Unit Environmental Analysis"].
[46] CPCN Application at 4-5, ¶ 9. The public portion of the AURORA analysis was included in an update to IPC's 2011 IRP ("IRP Update")
[47] App. C to 2015 IPC IRP.
[48] June 3, 2015 Quarterly Report.
[49] Confidential Attachment 1 to IPC Response to Sierra Club Request No. 22 (provided as ICL/SC Attachment 5).

1. 2013 Coal Unit Environmental Investment Analysis

As discussed above, SAIC and IPC prepared a two-part analysis on the economics of installing SCRs at the Jim Bridger Plant. Each contained significant errors, particularly in regards to gas, coal, and CO_2 price assumptions, used in both part one and part two of the study and discussed below.

a. 2013 SAIC Study

The SAIC Study analyzed the SCR investments at Jim Bridger as part of a larger analysis conducted for all four units at the Jim Bridger plant and the two units at the North Valmy plant. In the study, SAIC evaluated the cost of three options: (1) installing environmental upgrades at the Bridger units so they could continue operating on coal; (2) replacing the units with a CCCT plant; and (3) converting the existing units to operate on gas.[50]

The most foundational issue with the SAIC study is that it's based upon a static forecast of future generation, regardless of the scenario. This sort of assumption is useful for screening analysis, but on its own, it is no basis for making multi-hundred-million-dollar power planning decisions. Capacity expansion or, at the very least, production cost modeling, which takes into account the cost of producing power in the context of other competing generators and changing system demands, is far better suited for this type of decision making.

Further, the SAIC study failed to examine the full range of options available to IPC, which also included closing Units 3 and 4 and either buying replacement energy in the capacity market or building non-CCCT resource portfolios that included wind, solar, storage, and energy efficiency. With such limited consideration of alternatives, there is no way to know whether installing SCRs on Units 3 and 4 was the least-cost option.

[50] ICL/SC Attach. 4, 2013 Coal Unit Environmental Analysis at 3.

In the study, SAIC also assumed that Jim Bridger would operate through at least 2034, consistent with IPC's current depreciation schedule, and conducted no evaluation of the cost and economics of installing the SCRs assuming an earlier retirement date. This is concerning because there was no evaluation of how an earlier retirement date for Units 3 and 4, such as IPC is planning now, would impact the decision to install SCRs. An earlier retirement date would decrease the number of years over which the SCRs would be depreciated and would reduce the revenue that Company projected would cover the cost of the controls.

b. Natural Gas Forecast

The natural gas fuel cost forecasts that SAIC and Idaho Power used in the 2013 Coal Unit Environmental Investment Analysis are unreasonably high and, surprisingly, different from one another. As IPC itself acknowledged in the Coal Unit Environmental Analysis, the natural gas forecast is one of the two most "influential inputs to the analysis" but also one of the least known over the long-term, [51] so this makes the inconsistency surprising and concerning (the other one being a CO_2 price, discussed below). The gas forecast is important in large part because the only alternatives to the SCRs that IPC considered were gas resources. A high gas forecast will put the gas-burning alternatives at a disadvantage and make them look relatively more expensive than they should be, and, in this case, more costly than the coal option.

Even more concerning is that the gas price forecast that SAIC used is different from the one that IPC used for part of the analysis conducted in Aurora. According to the 2011 IRP Update, the IPC used the EIA Annual Energy Outlook's Henry Hub ("EIA AEO") spot price for its "planning case" natural gas price forecast, adjusted to reflect an Idaho city gate delivery price. Figure 1 below clearly shows in green that the nominal price in the IRP Update's planning case

[51] ICL/SC Attach. 4, 2013 Coal Unit Environmental Analysis at 5.

begins at less than $5.00 and rises to a level just below $14.00.[52] Yet as Figure 1 shows in blue, the confidential SAIC Study shows [redacted][53]

Further, as Figure 1 also shows, both SAIC's base-case forecast and Idaho Power's forecast are substantially higher than the contemporaneous and previous years' EIA AEO projections for natural gas prices in the mountain region, especially in the later years.[54] It is not clear why Idaho Power's forecast combining AEO's Henry Hub forecast with an Idaho city gate adder and Sumas adjustment is so much higher than EIA's forecast for the Mountain Region, where these adders come from, or how they were developed.[55] But once again, this use of a high forecast as the base case made the CCCT and gas conversion options look artificially expensive compared to the SCR option. EIA's latest AEO forecast shows how much lower natural gas price forecasts have fallen in the intervening years.

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[52] ICL/SC Attach. 4, 2013 Coal Unit Environmental Analysis at 5.
[53] ICL/SC Attach. 3, Confidential SAIC Study at A-3.
[54] ICL/SC Attach. 3, Confidential SAIC Study at Table A-23; EIA AEO 2012; EIA AEO 2013. The AEO products archive is available at https://www.eia.gov/outlooks/aeo/archive.php.
[55] Confidential Attachment 3 to IPC Response to Sierra Club Request No. 28 (provided as ICL/SC Attachment 6).

Confidential Figure 1. Natural Gas Price Forecasts from 2013 SAIC Coal Unit Environmental Analysis vs EIA AEO Forecasts

[redacted]

Source: US Energy Information Administration (EIA) Annual Energy Outlook (AEO) Mountain Region Electric Sector Natural Gas Forecasts 2012, 2013, 2022.

As noted, gas prices had a substantial impact on the economics of the SCR project. PacifiCorp's analysis of the economics of the SCR project puts this into sharper focus. For instance, in March 2013, PacifiCorp's analysis showed a benefit of the SCR project of approximately $183 million.[56] However, just six months later, that value had dropped to $130 million based on September 2013 gas price forecasts.[57] Merely three months later, by December

[56] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Opening Testimony of Jeremy Fisher, PhD on Behalf of Sierra Club at 12:13-15 (Ore.P.U.C. June 4, 2020), *available at* https://edocs.puc.state.or.us/efdocs/HTB/ue374htb1518.pdf [hereinafter "UE 374, Fisher Opening Testimony"] (citing Redacted Rebuttal Testimony of Mr. Rick Link, *In The Matter of the Application of Rocky Mountain*
Power for Approval of a Certificate of Public Convenience and Necessity to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 And 4 Located Near Point of Rocks, Wyoming Docket No.20000-418-EA-12 at 1:22. (Wyo. Pub. Serv. Comm'n Mar. 2013).

[57] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, Direct Testimony of Rick T. Link on Behalf of PacifiCorp (PAC/700) at 107:13 (Ore.P.U.C. Feb. 2020), *available at* https://edocs.puc.state.or.us/efdocs/UAA/ue374uaa145444.pdf (Mr. Link's testimony begins on PDF p. 437).

2013, with continuing gas price forecast declines, the value dropped to just \$36.7 million.[58] In other words, in just one year, nearly all the projected economic value of the SCR project to ratepayers had vanished due to falling gas prices alone. This steep decline, which IPC would have been aware of had it properly and consistently evaluated the economics of the project, including communicating with its co-owner, should have caused the Company significant concern. At a minimum, it should have caused further analysis well before 2015, when IPC finally did reevaluate the economics of the project, because gas prices only continued to decline. Even when IPC finally did reevaluate the economics in 2015, its analysis was fundamentally flawed, as discussed further below in Section III(B)(2).

c. Coal Price Forecast

In stark contrast, the SAIC Study's coal price forecast appears to move in the opposite direction. The forecast used in the Study, which was later also used and extended in the IPC's Aurora modeling, is significantly lower in most years than what the EIA's AEO projected at the time for coal in the mountain region (as shown in Figure 3 below). Looking back now, the actual cost paid for coal by Units 3 and 4 was even higher than both forecasts.

[58] UE 374, Fisher Opening Testimony at 52:12-18.

Confidential Figure 2: Coal Price Forecast Used by IPC in 2013 Studies

[redacted]

Source: US Energy Information Administration (EIA) Annual Energy Outlook (AEO) Mountain Region Electric Sector Coal Forecast 2013; Confidential Attachment 1 to IPC Response to Sierra Club Request No. 24 – Bridger Coal Price Forecast (provided as ICL/SC Attachment 7); Confidential Attachment 2 to IPC response to Sierra Club Request No. 28 – JB Coal Aurora Vectors (provided as ICL/SC Attachment 8); EIA 923 Page 5 – Fuel Receipts and Costs 2015, 2016, 2017, 2018, 2019, 2020, 2021, 2022, available at https://www.eia.gov/electricity/data/eia923/.

d. <u>CO_2 Price Sensitivity</u>

SAIC also relied on simplified carbon intensities for coal and gas in its study that overstated the cost of gas and underestimated the cost of continuing to burn coal at Units 3 and 4. This was the second input that IPC identified as "influential" but "least known."[59] Specifically, in its calculations for future CO_2 costs, SAIC assumed that coal generation emits [redacted] and that natural gas emits [redacted][60] By multiplying these carbon intensities to a lower carbon price in the planning case and a higher carbon price in the high case, SAIC developed resource-specific "carbon adders" to assess the relative impact of the same carbon price on gas generation and coal generation.

[59] ICL/SC Attach. 4, 2013 Coal Unit Environmental Analysis at 5.

[60] ICL/SC Attach. 3, Confidential SAIC Study at Table A-25; ICL/SC Attach. 4, 2013 Coal Unit Environmental Analysis at 6.

In reality, publicly available emissions measurements from the U.S. Environmental Protection Agency ("EPA") Clean Air Markets Data ("CAMD") in the five years preceding the SAIC study showed that SAIC's carbon intensities were inaccurate. Jim Bridger Units 3 and 4 emitted a little more than one ton of CO_2 per MWh, and the carbon intensity for combined cycle natural gas resources in the U.S. in 2013 and 2014 was, on average, 0.465 tons CO_2 per MWh—about [redacted] than SAIC's assumed carbon intensity.

These may seem like small amounts, but they are significant when considering that each unit of Jim Bridger produces on the order of 3 million MWh per year and that SAIC's modeled carbon prices rise over time.[61] Multiplying more accurate carbon intensities by the same CO_2 prices used by SAIC, and scaling them over time as SAIC does, yields higher CO_2 costs for coal and lower CO_2 costs for gas in the planning and high-CO_2 scenarios.

On a net present value basis using the same discount rate as the SAIC study, SAIC overestimated the total cost of a carbon price on natural gas by over [redacted] nominal dollars in the planning case and approximately [redacted] nominal dollars in the high CO_2 price case from 2013 to 2032. The effect on coal is the opposite. SAIC's use of a simplified carbon intensity of [redacted] underestimates the cost of a carbon price on coal by over [redacted] in the planning scenario and over [redacted] in the high CO2 price scenario on a net present value basis. While not as dramatic as the overestimate for gas, this is yet another example of simplified or improper assumptions disadvantaging gas while giving advantage to coal generation. The combined effect is large enough to have a serious impact on the perceived

[61] EPA CAMD data shows that Units 3 and 4 together averaged 3,010,250 MWh of gross load per year from 2015 to 2021.

economics of investing in SCRs, which totaled $58.29 million and $51.65 million for Units 3 and 4, respectively.[62]

Confidential Table 2. SAIC's Total Overestimation, in Net Present Value, of the Cost Impact of a CO_2 Price on Natural Gas Generation and Underestimation of the Impact on Coal Generation

CO_2 Price Case	Overestimation of Cost to Gas (Million Nominal $)	Underestimation of Cost to Coal (Million Nominal $)
Planning	[redacted]	[redacted]
High	[redacted]	[redacted]

Source: EPA CAMD; ICL/SC Attach. 4, 2013 Coal Unit Environmental Analysis; EPA Greenhouse Gas Reporting Program Industrial Profile: Power Plants Sector

Taking a wider view, the total cost of the SAIC study's carbon adders on both coal and gas generation is so large that it begs a further question: how would the economics of the fossil-burning alternatives have measured against those of a non-emitting replacement option? As Table 3 shows, Applying SAIC's carbon adders to the actual coal-fired generation of Units 3 and 4 yields a total cost of between $[redacted] on a net present value basis in the planning and high CO_2-price cases. For a replacement gas resource, the cost was between $[redacted] on a net-present value basis. If IPC thought at the time that the carbon price scenarios examined by SAIC were realistic, reporting that continued fossil generation was the most economic choice was a dubious conclusion at best. Limiting SAIC's analysis to fossil-only options skewed the analysis in favor of the SCR option.

[62] Adelman Direct at 13:14-17.

Confidential Table 3. The total cost of the SAIC's carbon prices on Units 3 burning coal or gas

Resource	CO_2 Price Case	NPV of CO_2 Cost (Million Nominal $)
Coal	Planning	[redacted]
	High	
Gas	Planning	
	High	

Source: EPA CAMD; ICL/SC Attach. 4, 2013 Coal Unit Environmental Analysis; EPA Greenhouse Gas Reporting Program Industrial Profile: Power Plants Sector

2. *The 2015 IRP Study*

Between its 2013 analyses and 2015, IPC did not evaluate the economics of installing SCRs on Jim Bridger, despite this Commission's clear instruction to closely monitor the plant's economics and be cognizant of any tipping points which would make further investment in the plant uneconomic. When IPC finally did evaluate the economics of the SCR project in its Coal Study, performed for the 2015 IRP and included in IRP Appendix C, the Company examined an even more limited set of scenarios than the 2013 SAIC study. Specifically, it looked at (1) SCR installation, and (2) replacement of Units 3 and 4 with a CCCT.[63] This limited scope omitted the costs and benefits of other potential alternatives including the conversion of Units 3 and 4 to run on gas, and early retirement of either or both units and or procurement of other, non-gas capacity—including renewable energy—to replace the capacity of Units 3 and 4. As a result, the analysis was fundamentally flawed because it did not seriously consider alternatives to moving forward with the SCR project.

The analysis should have also compared the economics of moving forward with the SCR project to the economics of various early retirement dates for Units 3 and 4. In fact, IRP Appendix C includes the State of Oregon's Action Items Regarding Idaho Power's 2011 IRP,

[63] App. C to 2015 IPC IRP at 122.

where the State of Oregon commented that they were concerned with the limited nature of IPC's early retirement scenario analysis in 2011. Oregon expected IPC to model a broader range of early shutdown scenarios for the 2015 IRP.[64] Idaho Power's response pointed to the multiple retirement scenarios they included in Chapter 8 of the 2015 IRP, but IPC only modeled early retirement scenarios for Units 1 and 2 in Chapter 8.[65] For Units 3 and 4, IPC only considered SCR installation versus immediate replacement of Units 3 and 4 with a CCCT. IPC did not consider early retirement dates for Units 3 and 4.

It is possible that IPC did not conduct a thorough analysis because it was aware that the 2015 analysis was conducted too late in the proceeding to avoid substantial installation costs, regardless of the findings. Specifically, as discussed above, it was conducted when the steel in the ground for the SCRs at Unit 3 was essentially complete and was over half-way complete at Unit 3, and over [redacted] of the project costs had already been incurred.[66]

As a result, not only did IPC fail to evaluate a reasonable range of viable alternatives, but the analysis also itself made multiple faulty and questionable assumptions. For instance, the Coal Study neglected to examine any CO_2 price sensitivities.

Most concerning, in this study, IPC included the remaining book value of the plant in the retire and replace option. The book value consisted of costs incurred in the past to build the plant, upgrade the plant, install environmental controls. These costs have been incurred, and cannot be avoided, regardless of what happens going forward. The remaining book value accounts for the majority of the cost difference IPC calculates between installing SCRs and

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64 App. C to 2015 IPC IRP at 212.

65 Idaho Power Company, *2015 Integrated Resource Plan*, Chapter 8 (June 2015), *available at* https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE1519/CaseFiles/20150630Integrated%20Resource%20Plan%202015.pdf.

66 ICL/SC Attach. 5, Confidential Attachment 1 to IPC Response to Sierra Club Request No. 22.

continuing to operate Units 3 and 4 on coal and retiring Units 3 and 4 and building a new CCCT gas plant.

The remaining book value should not be included in these calculations for several reasons: (1) IPC is not guaranteed recovery of these costs; (2) the current balance is a sunk cost and, absent action from the Commission, will be incurred regardless of when the plant retires or continues to operate. The company should have considered in its analysis only costs that were avoidable at the time of its analysis.

C. The Limited Analyses Conducted by Idaho Power Regarding the SCRs Should Not Have Been Relied Upon to Make Such a Consequential Decision as Investing Over $100 Million of Ratepayer Dollars into Jim Bridger, and the Commission Must Now Protect Customers from the Company's Imprudence

As is evident, Idaho Power relied on two studies to support spending over $100 million of ratepayer dollars on SCRs for Jim Bridger Units 3 and 4. Both studies were marred by significant flaws designed to support the Company's foregone conclusion that it would install the SCRs regardless of other viable alternatives. Despite this Commission's explicit instruction that Idaho Power monitor the economics of the project and change course if doing so would be in the best interest of ratepayers, Idaho Power did not seriously question the prudence of installing the SCRs.

Idaho Power is limited to charging customers only for those investments that are "just and reasonable."[67] It is clear that faced with the decision to install SCRs at Jim Bridger today, the Company would not make such an investment. This is evident from Idaho Power and PacifiCorp's ongoing dispute with EPA regarding its federally mandated requirement to install SCRs on Units 1 and 2. Regardless, this Commission must determine whether, at the time Idaho

[67] IDAHO CODE ANN. § 61-301.

Power decided to spend hundreds of millions of dollars on SCRs for Units 3 and 4, the Company acted as a prudent business owner, impartially evaluating costs and changing previous plans when doing so made economic sense. The evidence demonstrates that Idaho Power did not. Instead, Idaho Power did not seriously question PacifiCorp's plans to install SCRs on Units 3 and 4, relying on a fundamentally flawed analysis in 2013. Not until 2015 did the Company again evaluate the SCRs, at which point it was all but too late to change course.

In order to protect Idaho customers from IPC's imprudence, this Commission should issue a disallowance, which will signal to the Company that imprudent decision making will not be rewarded. ICL and Sierra Club recommend that this Commission deny Idaho Power any rate of return on its SCR investment, a remedy that other commissions have imposed on PacifiCorp for its imprudence when investing in the same SCRs.

IV. Idaho Power Should Consider Securitizing Prudently Incurred Coal Debt on Jim Bridger

After determining the total amount of prudently incurred costs and establishing a firm exit date from Bridger, the next step is to adjust customer rates to reflect this new reality. ICL and Sierra Club propose that Idaho Power use Idaho's Utility Cost Reduction Bond statute to finance the prudently incurred debt for the Bridger plant.[68] Known broadly as securitization, this alternative to traditional utility financing can achieve Idaho Power's stated objectives—adjusting rates to reflect a shortened economic life for Bridger—while reducing costs for customers.

At the simplest level, this proceeding is about the most appropriate ratemaking method to finance, or refinance, utility infrastructure. As Idaho Power explained in 2011, which was the last time the Commission approved a general rate case settlement and rate of return, the goal of

[68] *See* IDAHO CODE ANN. § 61-1601, *et seq.*

ratemaking is to ensure "good access to capital markets under reasonable terms in order to finance needed investments in infrastructure."[69] In traditional utility ratemaking, these terms include the rates themselves, any mechanisms to address cost recovery uncertainty, and the level of ongoing regulatory support for cost recovery. When considering ongoing, full-scale utility infrastructure needs, there is inherent uncertainty about whether rates will provide for complete cost recovery by the utility. Thus, it can be appropriate to allow for a higher return on utility investment to ensure access to capital under reasonable terms. But there are other circumstances when the Commission can provide a far higher level of certainty that costs will be recovered in rates. In these circumstances, a lower return is sufficient to ensure access to capital markets. Idaho Power's request to exit the Bridger unit early is exactly one of those circumstances: a discrete capital need, driven by unique factors, that is outside the typical utility infrastructure needs. Fortunately, Idaho's Utility Cost Reduction Bond law codified at Title 61, Chapter 16, provides for a specific method to address this unique circumstance and allows the Commission to develop an order with reasonable terms that will ensure access to capital markets at lower costs than typical utility investments.

A. Securitization Is an Appropriate Ratemaking Tool to Address the Changing Economic Life of Bridger

Recovery of coal-related Bridger costs is a good fit for using securitization to refinance Idaho Power's interest in the plant. In 2014, RBC Capital Markets reviewed utility securitization history and trends, describing how utilities have used securitization to address unique situations like stranded assets from deregulatory actions, storm recovery costs, and large pollution control

[69] *See In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service to its Customers in the State of Idaho*, Case No. IPC-E-11-08, Direct Testimony of Darrel Anderson on Behalf of Idaho Power Company at 10:7-9 (June 1, 2011), *available at* https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE1108/Company/20110601Anderson%20Di.pdf.

costs.[70] After weighing the benefit of reduced customer costs versus the barriers of needing to carefully structure the transaction, the analysts concluded that securitization was best used "to finance projects associated with discrete, clearly identifiable public purposes" and that securitization is "more politically palatable if the projects financed are outside of the usual and customary capital improvement program of the utility."[71]

Bridger is a good fit under these criteria. First, exiting Bridger in order to save customers money and reduce future risks is a discrete and laudable public purpose.[72] Second, Idaho Power's proposal to accelerate Bridger depreciation is not part of a utility's customer capital improvement program. Since the Commission is already being asked to adopt a non-traditional ratemaking approach (accelerated depreciation), there is no reason not to explore another nontraditional ratemaking approach, particularly when such alternatives have the potential to maximize customer benefits.

The one missing piece to ensure securitization is the optimal ratemaking method to address Jim Bridger costs is to establish a firm exit timeline and total amount to be recovered. As discussed above, while Idaho Power seeks to adjust rates in this docket to address the shorter economic life at Bridger, the utility has not committed to an exit date for any unit. Nor does it have any agreement with PacifiCorp regarding cost allocation if the actual exit dates differ from the proposed exit dates. ICL and Sierra Club emphasize that cost recovery—whether under accelerated depreciation or securitization—should be contingent upon a firm and verifiable exit plan. Such a firm commitment should be viewed as a non-negotiable prerequisite included in any

[70] Chris Mauro, *Municipal Securitization – A New Financing Trend in the Municipal Market?*, RBC Capital Markets (Nov. 6, 2014), *available at* https://www.rbccm.com/municipalfinance/file-826934.pdf.
[71] *Id.* at 5.
[72] See Direct Testimony of Matthew T. Larkin on Behalf of Idaho Power Company at 6:3-7:3 (June 2, 2021) [hereinafter "Larkin Direct"].

Commission order authorizing a cost recovery framework for prior and future investments in the plant.

Nevertheless, just as Idaho Power did at the Valmy plant, the Company can seek a cost recovery framework from the Commission, then commit to exit dates and negotiate an exit agreement with PacifiCorp. Once done, this will provide more certainty for future capital needs at the plant, and this information can feed into Idaho's Utility Cost Reduction Bond process described below.

B. Idaho's Existing Securitization Legislation Provides an Optimal Ratemaking Treatment to Recover Jim Bridger Costs.

In 2005, the legislature passed Idaho's Utility Cost Reduction Bonds declaring "this type of securities legislation is in the public interest" because it provides "a method of . . . refinancing costs incurred or to be incurred by electric . . .utilities that will accrue benefits to Idaho consumers through reduced utility rates."[73] Despite the potentially significant public benefits, it does not appear that any Idaho utility has elected to use this authority to access lower cost financing for infrastructure needs. Idaho Power's need to refinance the Bridger plant costs due to changing economics of the plant is an excellent opportunity to put this existing authority into use.

The process revolves around a Cost Reduction Order from the Commission "authorizing the recovery of approved costs through the imposition and collection of a cost reduction rate."[74] This Order sets forth the approved costs the utility will recover, the timeline for recovery, and the method for determining the cost reduction rate paid by customers.[75] With the Order in hand, the utility then goes to the capital markets to seek financing from lenders by issuing a cost reduction

[73] IDAHO CODE ANN. § 61-1601.
[74] *Id.* § 61-1603(1).
[75] *Id.* § 61-1603(3).

instrument.[76] Lenders then provide financing to the utility in exchange for a property interest in the cost reduction order and the resulting right to receive the revenue from the cost reduction rate applied to customer bills.[77] Then, during the term of the Cost Reduction Order, the Commission will, at least annually, "approve adjustments to the cost reduction rates" paid by customers "to ensure timely and complete recovery of all approved costs that are the subject of the pertinent cost reduction order."[78] This structure ensures that the Commission has the authority to determine the "public interest would be served if the approved costs were recovered through a cost reduction rate"[79] and retains ongoing supervision to ensure customers pay no more and no less than the amounts necessary to recoup approved costs.[80]

This structure achieves Idaho Power's stated goals in this docket: addressing the reduced economic lifespan of the Jim Bridger plant, ensuring a stable stream of payments from customers, and providing a mechanism to ensure customers pay no more or no less than needed to recover prudently incurred Jim Bridger expenses.[81] The primary difference between Idaho Power's accelerated depreciation approach and securitization is the initial transaction costs necessary to refinance Jim Bridger costs through bonds. Even with expected transaction costs, securitization will be significantly more beneficial to customers than Idaho Power's proposed accelerated depreciation due to the lower interest rate customers will pay during the recovery period. In fact, analysis conducted by RMI, discussed below, suggests that securitization would save ratepayers approximately $63.7 million compared to accelerated depreciation.

[76] *Id.* § 61-1603(6).
[77] *Id.* § 61-1606.
[78] *Id.* § 61-1603(8).
[79] IDAHO CODE ANN. § 61-1603(2).
[80] *Id.* § 61-1605(5) (empowering the commission to determine how to "use any surplus cost reduction rate collections in excess of the amounts necessary to pay approved costs").
[81] *See* Larkin Direct at 30:7-22.

C. RMI Modeled the Benefits of Recovering Idaho Power's Bridger Costs Through Securitization and Found that Securitization Would Save Ratepayers $63.7 Million

ICL and Sierra Club worked with world-leading, independent analysts at RMI to assess the different costs for customers between Idaho Power's accelerated depreciation proposal and a securitization alternative. RMI has assessed securitization opportunities for over 14 different operating utilities in both legislative and regulatory contexts.[82] When RMI applied their analysis to Idaho Power's share of the Bridger plant they found that using Idaho's Utility Cost Reduction Bond statute could save customers over $63.7 million in reduced borrowing costs, compared to accelerated depreciation, as shown in ICL/SC Attachment 9.

This analysis makes a few necessary assumptions which are based on data provided by Idaho Power. First, the net plant balance to be recovered is $241.6 million based on Mr. Larkin's Supplemental Direct Testimony and Exhibit 1 as well as Mr. Adelman's Exhibit 3. This total does not include the $105 million in expected decommissioning costs described on pages 23 through 25 of Mr. Larkin's Direct Testimony.

Second, RMI assumed the cost recovery period for accelerated depreciation to be 8 years, from 2023 through 2031. For the securitization analysis, RMI assumed a slightly longer time period of 12 years, 2023-2035, which aligns with the current depreciable life for Bridger. While Idaho Power's proposal would begin cost recovery in June of 2022, we assume it will take some extra time for Idaho Power to seek approval of the securitization approach from the Commission

[82] A good example of RMI's expertise is available in a report developed in partnership with Minnesota Power exploring the potential to securitize the unrecovered balance for the early retiring Boswell coal plant. *See* Rocky Mountain Institute, *Using Ratepayer-Backed Bond Securitization for Cost Recovery in Accelerated Asset Retirement* (Sept. 2020), filed in Minnesota PUC Docket EO15/RP-15-690, *available at* https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId=%7BD0ECE574-0000-C632-A755-ED5C185F08F5%7D&documentTitle=202010-167012-02. ICL and Sierra Club encourage the Commission to review this report which describes the history and current use of rate-payer backed securitization to refinance utility assets at lower costs for customers.

and then complete the transaction with future bondholders. Both Idaho Power's proposal and the securitization approach would extend cost recovery beyond the dates the Company intends to exit the plant. We believe it is reasonable to allow for a 12-year period for securitization because this aligns with current lifespan in rates and is more likely to attract bondholder interest than a shorter term period. A longer cost recovery period also reduces annual costs for customers.

Third, RMI's analysis assumes the interest rate on the bonds is 3.54% compared to Idaho Power's weighted average cost of capital of 7.86%. This bond interest rate assumption is based on the US Treasury yield curve on April 11, 2022, with an added risk premium to reflect AAA-rated debt, and looks forward over the recovery period. These assumptions are reasonable because Idaho Utility Cost Reduction Bond statute provides a level of certainty that should lead to highly rated bonds and the recovery period matches the current depreciable life of Bridger. Saber Partners, LLC maintains a list of 73 investor-owned utility securitization transactions from 1997 through present. That database shows that every transaction received a bond rating of AAA.[83] As explained by former Ohio Public Utilities Commissioner Cheryl Roberto,

> Ratepayer-backed bonds are extraordinarily low risk to investors because repayment of and a return on their investment is secured by a legally enforceable surcharge on customer bills which cannot be changed by the Commission, avoided by its customers, or diverted by the utility. Traditional utility debt investment does not enjoy this level of security because it is always dependent upon the utility's ability to pay.[84]

Given the extremely low-risk nature of securitization bonds, ICL and Sierra Club believe the assumed interest rate is conservative and it is possible that Idaho Power could secure interest rates below 3.54%. For instance, on March 11, 2022, Empire District Electric Company in

[83] Saber Partners, LLC, List of Investor-Owned Utility Securitization ROC/RRB Bond Transactions *available at* https://saberpartners.com/list-of-investor-owned-utility-securitization-rocrrb-bond-transactions-1997-present/.
[84] *In The Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just And Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return*, Docket No. E-01345A-19-0236, Direct Testimony of Cheryl Roberto on Behalf of Sierra Club at 50:18-51:3 (Ariz. Corp. Comm'n Oct. 2, 2020), *available at* https://docket.images.azcc.gov/E000009335.pdf?i=1651085493976.

Missouri submitted testimony from Goldman Sachs that assessed a securitization offering for an early retiring coal asset and provided an indicative bond structure of 2.47% interest and a 13 year recovery period.[85] Idaho's Utility Cost Reduction Bond statute has key elements present in Missouri and other states with successful securitization options namely, a predictable and non-avoidable rate paid by customers to the bond holders, Commission oversight of the annual rate collections, protection from utility bankruptcy, and a pledge of non interference by future legislative or regulatory decisions. If Idaho Power could secure similar interest rates as proposed in Minnesota, IPC's customers may realize even greater savings than the already estimated $63.7 million. With this level of savings potential, the Commission should direct Idaho Power to work with potential lenders to assess the interest rates and other lending terms available to reduce customer costs.

Fourth, RMI's analysis includes assumptions about the transaction costs, tax implications, and other impacts to the utility balance sheets as documented in ICL/SC Attachment 9. One of the major questions is whether the transaction costs of the securitization approach would exceed the savings from accessing lower cost capital. Based on RMI's expertise in securitization transactions, they assume $4.7 million in initial costs and annual costs of about $421,000 for the Jim Bridger securitization. Critically, the estimated $63.7 million in savings *already accounts* for these transaction costs.

ICL and Sierra Club offer this analysis as an estimate of the benefits to customers from securitization, recognizing that further investigation and refinement would be needed prior to

[85] See *In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Energy Transition Costs Related to the Asbury Plant*, Case No. EO-2022-0193, Direct Testimony of Katrina Niehaus on Behalf of The Empire District Electric Company d/b/a Liberty Utilities (MO.P.S.C. Mar. 2022), *available at* https://efis.psc.mo.gov/mpsc/commoncomponents/view_itemno_details.asp?caseno=EO-2022-0193&attach_id=2022016471.

implementing securitization. While RMI used inputs from Idaho Power's filing in this case and reasonable assumptions based on their expertise in this area, the specific savings for customers will depend on the results of the Cost Reduction Order issued by the Commission upon Idaho Power's request. Even if the exact numbers change through that process, the level of potential savings from securitization is significant and the Commission should encourage Idaho Power to use existing Idaho law to reduce costs for customers while facilitating the Company's exit from Bridger coal.

D. Idaho Power Should Explain Why it Is Not Considering Securitization that Could Save Ratepayers Tens of Millions of Dollars.

As explained above, using Idaho's Utility Cost Reduction Bonds laws to recover Bridger coal-related expenses achieves Idaho Power's goals while reducing costs for customers. However, Idaho's law makes clear that this approach is entirely voluntary for the utility. Only the utility may apply to the Commission for a cost reduction order and when issued, only the utility can choose to move forward or withdraw the request.[86] Even if the utility chooses not to follow through with the Cost Reduction Order, the Commission cannot deem that action as unreasonable or imprudent.[87] Nevertheless, the Commission does have the authority to approve or deny Idaho Power's request to accelerate depreciation and adjust customer rates accordingly. The Commission also has the authority to require Idaho Power to explain *why* they elected to use one non-traditional ratemaking approach—accelerated depreciation—instead of another approach—securitization—that achieves the exact same goals at lower costs for customers. ICL and Sierra Club recommend the Commission exercise their authority to deny Idaho Power's

[86] IDAHO CODE ANN. § 61-1603(4).
[87] *Id.* § 61-1603(5).

request and encourage the utility to protect customer's interest while allowing for access to capital markets on reasonable terms by utilizing Idaho's Utility Cost Reduction Bond authorities.

V. Conclusion

In conclusion, ICL and Sierra Club make the following recommendations:

1. Idaho Power should not be granted a new form of rate recovery–either accelerated depreciation or securitization–prior to a firm commitment to exit the Jim Bridger plant, including finalized, necessary contractual agreements with PacifiCorp;
2. This Commission should find that Idaho Power's investment in SCRs at Jim Bridger Units 3 and 4 were imprudent. As a remedy, this Commission should deny Idaho Power any rate of return on its investment;
3. This Commission should direct Idaho Power to explain why it is not pursuing securitization of past, prudently incurred expenditures at Jim Bridger, which would achieve Idaho Power's same stated goals as with accelerated depreciation at lower customer costs.

Dated: April 27, 2022

Respectfully submitted,

R Monahan

Rose Monahan (CA Bar No. 329861)
Sierra Club

Ben Otto

Benjamin Otto (ID Bar No. 8292)
Idaho Conservation League

Attachment 1

Mine Profile: Black Butte & Leucite Hills Mines (S&P Global Market Intelligence)

Black Butte & Leucite Hills Mines | Mine Profile

OWNER	ULTIMATE PARENT	OWNERSHIP (%)
Anadarko Petroleum Corp.	Occidental Petroleum Corp.	50.00
Lighthouse Resources Inc	Lighthouse Resources Inc	50.00

Operator

Black Butte Coal Company

Site Information

Mine State	WY
Mine County	Sweetwater
Latitude (degrees)	41.571231
Longitude (degrees)	-108.693305
Coal Type	Subbituminous
SNL Mine Operating Status	Active
Mine Type	Surface
Mine Operation Type	Strip Administrative
Mine District	Denver
Mine Producing Region	Southern Wyoming
MSHA ID	4801180

Recent News

EXCLUSIVE Energy sector faces a barrage of cyberattacks; MLP stocks gain on tax ruling 7/20/2018

Wyo. Q1'17 coal production up 23% over previous year 4/24/2017

EXTRA BLM issues invitation for Black Butte coal exploration in Wyoming 1/9/2015

EXCLUSIVE Vote set for private equity firm to take over Ambre Energy's US operations 11/28/2014

EXTRA Coal miner shortage prompts future production cuts at Wyo. operation 11/17/2014

Regulatory / Other

FEMA Region	VIII
MSHA Inspection Office	Craig

Fuel Delivery Summary

	2019	2020	2021
Number of Power Plants Served (actual)	2	2	1
Total Operating Capacity of Plants (MW)	2,645.0	2,641.0	2,119.0
Total Spot Purchases (1000 tons)	NA	NA	NA
Total Contract Purchases (1000 tons)	2,258.77	2,221.88	1,713.90
Total Coal Purchased (1000 tons)	2,258.77	2,221.88	1,713.90
Coal Delivered Heat Content (Btu/lb)	9,496	9,564	9,505
Average % Sulfur	0.45	0.45	0.44
Average % Ash	9.14	9.31	9.64
Average Delivered Spot Price ($/ton)	NA	NA	NA
Average Delivered Contract Price ($/ton)	48.42	45.91	46.15
Average Delivered Price ($/ton)	48.42	45.91	46.15
Average Estimated FOB Coal Price ($/ton)	36.59	36.04	40.86

Summary Production Data

	2019	2020	2021
Clean Coal Produced (tons)	2,307,947	2,216,235	1,771,411
Avg Number of Employees (actual)	162	147	134
Clean Coal Produced per Employee (tons)	14,246.59	15,076.43	13,219.49
Clean Coal Produced per Employee Hour (ton/hr)	7.72	7.85	7.24
Number of Injuries (actual)	1	3	2
Seam Height (inches)	60	60	60

Fuel deliveries are based on EIA-923 filings beginning in 2008 and FERC/EIA 423 filings for 2007 and earlier. The current year and, in some cases, the most recent full year deliveries only constitute the sample filers, which is not representative of all power plants that are required to file the annual 923. Once the annual 923 is received, the historical year will be populated with data for all power plants that are required to submit data with the EIA.

Attachment 2

Confidential Attachments 1, 2, and 3 to IPC Response to Industrial Customer of Idaho Power Request No. 43

ICL/SC Attachment 2 contains confidential information subject to the protective agreement in Case No. IPC-E-21-17 and has been served upon the Commission and eligible parties.

Attachment 3

Confidential Attachment 2 to IPC Response to Sierra Club Request No. 18 (“Confidential SAIC Study”)

ICL/SC Attachment 3 contains confidential information subject to the protective agreement in Case No. IPC-E-21-17 and has been served upon the Commission and eligible parties.

Attachment 4

Attachment 1 to IPC Response to Sierra Club Request No. 18 ("2013 Coal Unit Environmental Analysis")

2011 IRP UPDATE

Coal Unit Environmental Investment Analysis

For The

Jim Bridger and North Valmy

Coal-Fired Power Plants

TABLE OF CONTENTS

Executive Summary

The Coal Unit Environmental Investment Analysis (Study) examines future investments required for environmental compliance in existing coal units and compares those investments to the costs of two alternatives: (1) replace such units with Combined Cycle Combustion Turbine (CCCT) units or (2) converting the existing coal units to natural gas. Idaho Power used a combination of third-party analysis, operating partner input and an Idaho Power analysis to assure a complete and fair assessment of the alternatives.

This Study consists of two parts:

1. A unit specific forecasted (static) annual generation analysis performed by Science Applications International Corporation (SAIC). Idaho Power conducted a competitive procurement process to select SAIC.

2. An economically dispatched (dynamic) total portfolio resource cost analysis performed by Idaho Power using the SAIC study results.

The SAIC analysis included a review of Idaho Power's estimated capital costs and variable costs associated with the proposed environmental compliance upgrades, coal unit replacement with CCCT's and natural gas conversion. SAIC developed the cost estimates for replacing the coal units annual generation, under three natural gas and three carbon futures. These estimates served as the foundation for SAIC's capital investment analysis which allowed assets with different lengths of operation as well as different implementation dates to be compared equitably. The results of the SAIC analysis served as planning recommendations regarding the three investment alternatives to be used in the second part of the comprehensive Study.

The second part of the Study performed by Idaho Power utilized the AURORAxmp® Model (AURORA) to determine the total portfolio cost of each investment alternative analyzed by SAIC. The total portfolio cost is estimated over a twenty-year planning horizon (2013 through 2032).

The Key Assumptions section of this report provides additional details on the carbon adder assumptions and natural gas price forecasts.

Analysis Results for North Valmy

Currently, the only notable investment required at the North Valmy plant is to install a Dry Sorbent Injection (DSI) system for compliance with the Mercury and Air Toxic Standards (MATS) regulation on Unit #1. North Valmy is not subject to Regional Haze (RH) Best Available Retrofit Technology (BART) regulations; therefore, no additional controls will be required for compliance with this regulation. No other notable investments in environmental controls at the North Valmy plant are required at this time.

Installation of DSI was the lowest cost result for most of the sensitivities analyzed by SAIC including the planning case scenario (planning case natural gas/planning case carbon). The AURORA analysis, performed by Idaho Power, shows installing DSI as the least cost option in four of the nine sensitivities analyzed including the planning case scenario (planning case natural gas/planning case carbon). The scenarios in which

DSI was not the preferred option are the extreme low natural gas and high carbon cases, which have a lower probability of occurring.

Idaho Power's conclusion is that installing the DSI system is a low cost approach to retain a diversified portfolio of generation assets including the 126 MW's of Unit #1's capacity for our customers benefit. The continued operation of Unit #1 as a coal-fired unit will provide fuel diversity that can mitigate risk associated with high natural gas prices.

In the event that North Valmy requires significant additional capital or operation and maintenance costs (O&M) expenditures for new environmental regulations, both the SAIC and the Idaho Power analyses advise further review to justify the additional investment.

Analysis Results for Jim Bridger

Jim Bridger is currently required to install Selective Catalytic Reduction (SCR) on all four units for RH compliance and mercury controls for compliance with MATS. Both the SAIC and Idaho Power evaluations identify additional investments in environmental controls on all four Jim Bridger units as prudent decisions that represent the lowest cost and least risk option when compared to the other investment alternatives. Idaho Power recommends proceeding with the installation of SCR and other required controls on Units #3 and #4 and including the continued operation of all four Jim Bridger units in Idaho Power's future resource planning.

Compliance Timing Alternatives

Idaho Power also evaluated the economic benefits of delaying coal unit investments required under the emerging environmental regulations. To perform this evaluation Idaho Power assumed that it could negotiate with state and federal entities a five-year period where no additional environmental controls are installed in exchange for shutting the unit down at the end of the five-year period. These compliance timing alternative cases are strictly hypothetical. Idaho Power may not have any basis under current regulations to negotiate this delay and the relevant regulatory authorities have not offered any such delay. These alternatives are included in the alternatives summary table.

Unit Ownership and Operation

It should be noted that, although a partial owner of the Jim Bridger (one-third) and the North Valmy (one-half) coal plants, Idaho Power does not operate any of the coal-fired units and Idaho Power does not have the sole rights to alter the compliance plan in place for these units. Any decision regarding environmental investments, plant retirement or conversion to natural gas must be coordinated and agreed to by the other owners/operators of the plants and their regulators.

Key Assumptions

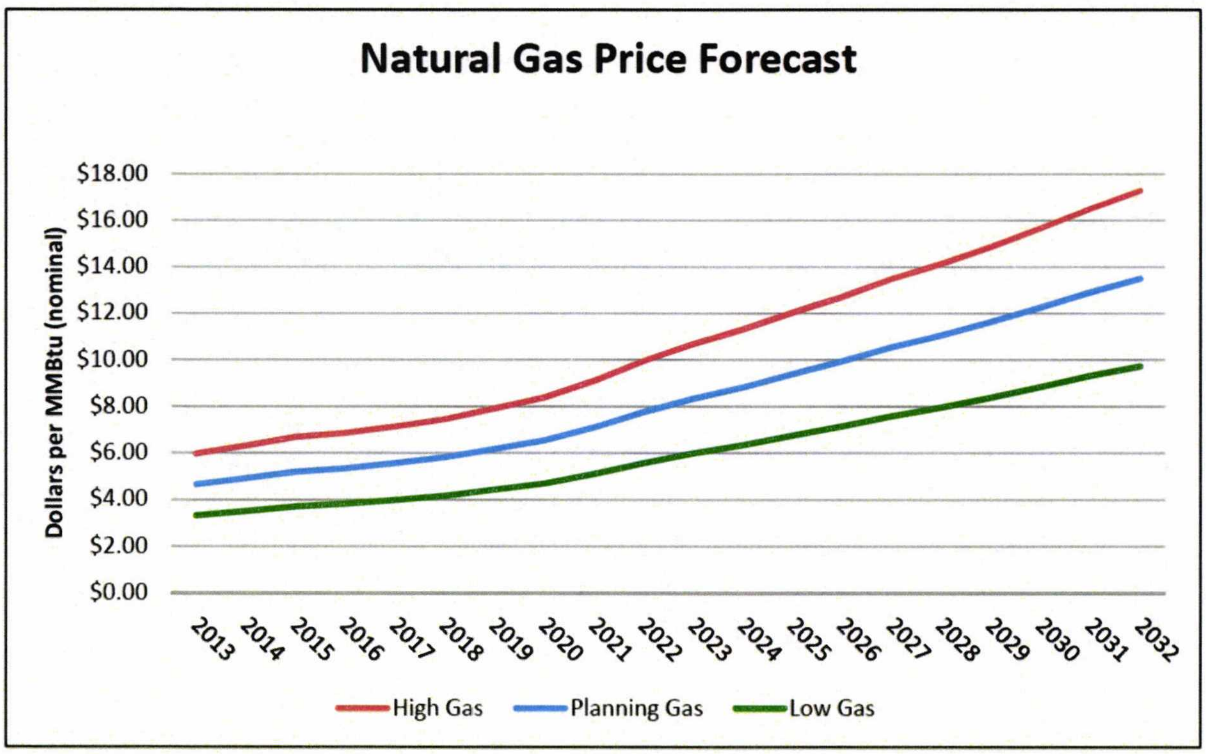
The undertaking of any analysis of this nature requires that assumptions be made regarding uncertain costs and regulations that may impact the economics of the coal plants. In fact, two of the most influential inputs to the analysis are also among the least known over the long-run and are related to future carbon regulation and future natural gas prices. In order to evaluate these uncertainties Idaho Power has used low, planning and high case natural gas and carbon adder futures. These forecasts provide a range of outcomes to assess the impact of natural gas price and carbon adder uncertainty on the economic evaluation of the investment alternatives.

Idaho Power is currently preparing its 2013 IRP covering the 2013-2032 planning horizon. As that process is well underway, key assumptions for this Study are aligned with the 2013 IRP assumptions.

These key assumptions include:

Natural Gas Price Forecast - For the purpose of being consistent with Idaho Case No. GNR-E-11-03, Order No. 32697 (December 18, 2012), Idaho Power is using the Energy Information Administration (EIA) Annual Energy Outlook (Henry Hub spot price) for the 2013 IRP planning case natural gas price forecast. The high and low cases are +/- 30% from the planning case forecast. All cases were adjusted to reflect an Idaho citygate delivery price. These forecasts are provided in Figure 1.

Figure 1. Natural Gas Price Forecast



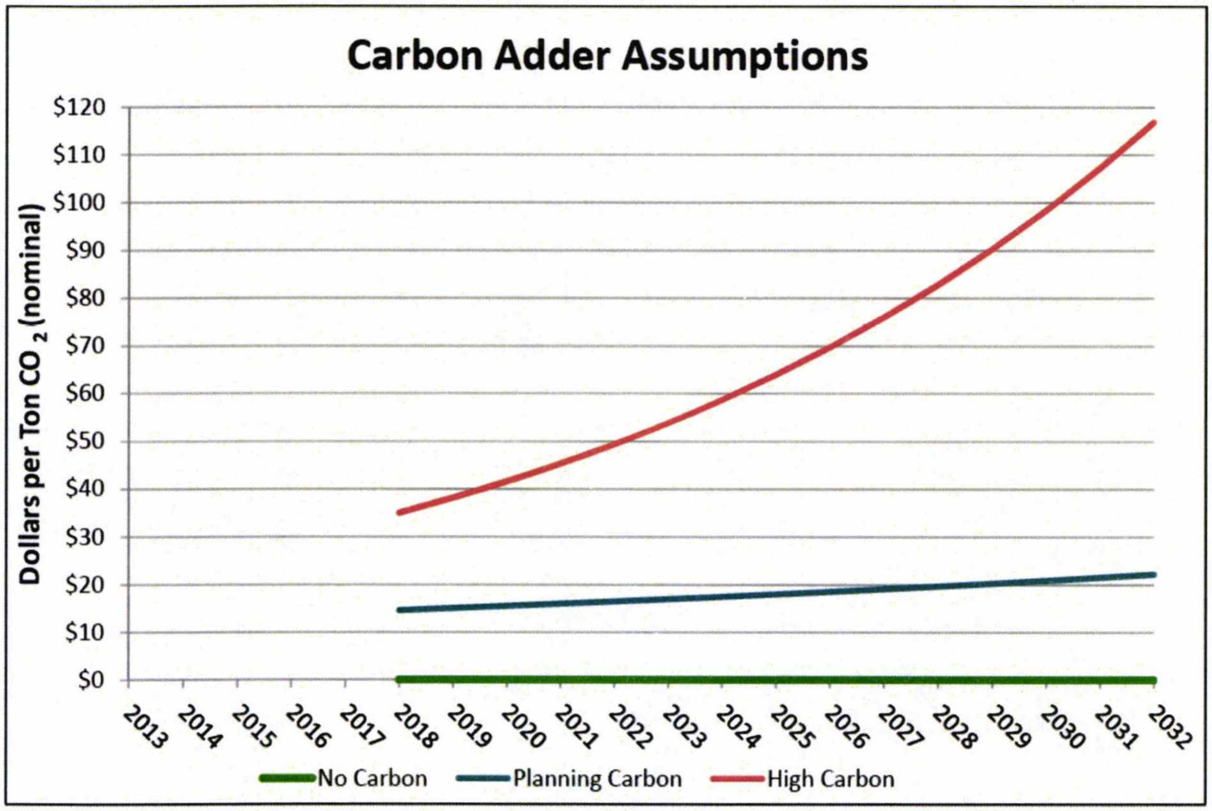
Load Forecast - The 2013 IRP load forecast is Idaho Power's most current load forecast and was used in the preparation of this Study.

Financial and Economic Assumptions - The 2013 IRP financial and economic assumptions were also used for this Study.

Carbon Adder Assumptions - For the 2013 IRP, three carbon adder assumptions have been developed and include a low case of no carbon tax, a planning case with a 2018 start date at $14.64 per ton of CO_2 emitted escalated at 3% and a high case with a 2018 start date at $35.00 per ton of CO_2 emitted escalated at 9%.

These forecasts are provided in Figure 2.

Figure 2. Carbon Adder Assumptions



Description and Existing Major Environmental Investments in Coal Units

Jim Bridger

The Jim Bridger coal-fired power plant consists of four units and is located near Rock Springs, Wyoming. Idaho Power owns one-third of Jim Bridger with the other two-thirds owned by PacifiCorp. PacifiCorp is the operator of the Jim Bridger plant.

These units have the following current net dependable capacity ratings:

Jim Bridger unit #1 (JB1)	531 MW
Jim Bridger unit #2 (JB2)	527 MW
Jim Bridger unit #3 (JB3)	530 MW
Jim Bridger unit #4 (JB4)	523 MW
Total Plant –	2,111 MW (703.7 MW Idaho Power Share)

The following major emission control equipment has been previously installed on each unit at the Jim Bridger plant:

Pollutants	Controls	Current Emission Limits
NO_x	New Generation Low NO_x Burners	0.26 lb/MMBtu
Opacity	Electrostatic Precipitators	20% Opacity
SO_2	Wet Scrubbers	0.15 lb/MMBtu

North Valmy

The North Valmy coal-fired power plant consists of two units and is located near Winnemucca, Nevada. Idaho Power owns one-half of North Valmy with the other one-half owned by NV Energy. NV Energy is the operator of the North Valmy plant.

These units have the following current net dependable capacity ratings:

North Valmy unit #1 (NV1)	252 MW
North Valmy unit #2 (NV2)	272 MW
Total Plant –	524 MW (262 MW Idaho Power Share)

The following major emission control equipment has been previously installed at the North Valmy plant:

Pollutants	Controls	Current Emission Limits
NO_x	Early Generation Low NO_x Burners	0.46 lb/MMBtu (averaged)
Opacity	Baghouse	20% Opacity
SO_2 (Unit 2)	Dry Lime Scrubber	70% removal

Recent Environmental Regulations

The new regulations that have been proposed by the Environmental Protection Agency (EPA) over the last few years have caused great concern among utilities that own coal-fired generation. The impact of the proposed regulations will require extensive installation of emissions controls in a short period of time. In addition, these proposed regulations often override state decisions relating to control requirements. The effectiveness of the regulations on health and visibility is controversial and highly debated.

***Final Mercury and Air Toxic Standards (MATS) Rule*:** In April 2010, the U.S. District Court for the District of Columbia approved, by consent decree, a timetable that would require the EPA to finalize a standard to control mercury emissions from coal-fired power plants by November 2011. In March 2011, the EPA released the rule to control emissions of mercury and other Hazardous Air Pollutants (HAPs) from coal- and oil-fired Electric utility steam Generating Units (EGUs) under the federal Clean Air Act (CAA). In the same notice, the EPA further proposed to revise the New Source Performance Standards (NSPS) for fossil fuel-fired EGUs. Both the proposed HAPs regulation and the associated NSPS revisions were finalized on February 16, 2012. The regulation imposes maximum achievable control technology and NSPS on all coal-fired EGUs and replaces the former Clean Air Mercury Rule. Specifically, the regulation sets numeric emission limitations on coal-fired EGUs for total particulate matter (a surrogate for non-mercury HAPs), hydrochloric acid (HCL), and mercury. In addition, the regulation imposes a work practice standard for organic HAPs, including dioxins and furans. For the revised NSPS, for EGUs commencing construction of a new source after publication of the final rule, the EPA has established amended emission limitations for particulate matter, sulfur dioxide, and nitrogen oxides. Utilities have three years for compliance, with a one year compliance extension for any utility or plant that cannot feasibly install the pollution controls during the three year compliance window. Idaho Power does not need nor can Idaho Power qualify for the one year extension, so all controls were assumed to be completed within the three year time frame.

National Ambient Air Quality Standards (NAAQS): The CAA requires the EPA to set ambient air quality standards for six "criteria" pollutants considered harmful to public health and the environment. The six pollutants are carbon monoxide, lead, ozone, particulate matter, nitrogen dioxide, and sulfur dioxide. States are then required to develop emission reduction strategies through State Implementation Plans (SIP) based on attainment of these ambient air quality standards. Recent developments related to three of the pollutants - $PM_{2.5}$, NO_x, and SO_2 are relevant to Idaho Power.

- ***Particular Matter ($PM_{2.5}$)***. In 1997, the EPA adopted NAAQS for fine particulate matter of less than 2.5 micrometers in diameter ($PM_{2.5}$ standard), setting an annual limit of 15 micrograms per cubic meter ($\mu g/m^3$), calculated as a three-year average. In 2006, the EPA adopted a 24-hour NAAQS for $PM_{2.5}$. of 35 $\mu g/m^3$. All of the counties in Nevada, Oregon, and Wyoming have been designated as "attainment" with these $PM_{2.5}$ standards. However, on December 14, 2012, the EPA released final revisions to the $PM_{2.5}$ NAAQS. The revised annual standard is 12 $\mu g/m^3$, calculated as a three-year average. The EPA retained the existing 24-hour standard of 35 $\mu g/m^3$. Now that the $PM_{2.5}$ NAAQS has been finalized, states will make recommendations to the EPA regarding designations of attainment or non-attainment. States also will be required to review, modify, and supplement their SIPs, which could require the installation of additional controls and requirements for Idaho Power's coal-fired generation plants, depending on the level ultimately finalized. The revised NAAQS would also have an impact on the applicable air permitting requirements for new and modified facilities. The EPA has stated that it plans to issue nonattainment designations by late 2014, with states having until 2020 to comply with the standards.

- ***NO_x***. In 2010, the EPA adopted a new NAAQS for NO_x at a level of 100 parts per billion averaged over a one-hour period. In connection with the new NAAQS, in February 2012 the EPA issued a final rule designating all of the counties in Nevada, Oregon, and Wyoming as "unclassifiable/attainment" for NO_x. The EPA indicated it will review the designations after 2015, when three years of air quality monitoring data are available, and may formally designate the counties as attainment or non-attainment for NO_x. A designation of non-attainment may increase the likelihood that Idaho Power would be required to install costly pollution control technology at one or more of its plants.

- ***SO_2***. In 2010, the EPA adopted a new NAAQS for SO_2 at a level of 75 parts per billion averaged over a one-hour period. In 2011, the states of Nevada, Oregon, and Wyoming sent letters to the EPA recommending that all counties in these states be classified as "unclassifiable" under the new one-hour SO_2 NAAQS because of a lack of definitive monitoring and modeling data.

Clean Water Act Section 316(b): In March 2011, the EPA issued a proposed rule that would establish requirements under Section 316(b) of the federal Clean Water Act for all existing power generating facilities and existing manufacturing and industrial facilities that withdraw more than two million gallons per day (MGD) of water from waters of the U.S. and use at least 25 percent of the water they withdraw exclusively for cooling purposes. The proposed rules would establish national requirements applicable to the location, design, construction, and capacity of cooling water intake structures at these facilities by setting requirements that reflect the Best Technology Available (BTA) for minimizing adverse environmental impact. In June 2012, the EPA released new data, requested further public comment, and announced it plans to finalize the cooling water intake structures rule by June 2013.

New Source Performance Standards (NSPS) for Greenhouse Gas Emissions for New EGUs: In March 2012, the EPA proposed NSPS limiting Carbon Dioxide (CO_2) emissions from new fossil fuel-fired power plants. The proposed requirements would require new fossil fuel-fired EGUs greater than 25 MW to meet an output-based standard of 1,000 pounds of CO_2 per MWh. The EPA did not propose standards of performance for existing EGUs whose CO_2 emissions increase as a result of installation of pollution controls for conventional pollutants.

Clean Air Act (CAA) - Regional Haze Rules: In accordance with federal regional haze rules under the CAA, coal-fired utility boilers are subject to RH BART if they were permitted between 1962 and 1977 and affect any Class I areas. This includes all four units at the Jim Bridger plant. However, North Valmy is not subject to the regulation as it was permitted after 1977. Under the CAA, states are required to develop a SIP to meet various air quality requirements and submit them to the EPA for approval. The CAA provides that if the EPA deems a SIP submittal to be incomplete or "unapprovable," then the EPA will promulgate a federal implementation plan (FIP) to fill the deemed regulatory gap. In May 2012, the EPA proposed to partially reject Wyoming's regional haze SIP, submitted in January 2011, for NO_x reduction at the Jim Bridger plant, instead proposing to substitute the EPA's own RH BART determination and FIP. The EPA's primary proposal would result in an acceleration of the installation of Selective Catalytic Reduction (SCR) additions at JB1 and

JB2 to within five years after the FIP, or a SIP revised to be consistent with the proposed FIP, is adopted by the EPA. The EPA had stated that it planned to adopt the FIP, or approve the revised Wyoming SIP, by late 2012. However, in December 2012 the EPA announced that it would re-propose the plant-specific NO_x control provisions of its RH FIP in March 2013 and would not finalize the RH FIP until September 2013.

Coal Combustion Residuals (CCR): The EPA has proposed federal regulations to govern the disposal of coal ash and other CCR's under the Resource Conservation and Recovery Act (RCRA). The agency is weighing two options: regulating CCR's as hazardous waste under RCRA Subtitle C, or regulating them as non-hazardous waste under RCRA Subtitle D. EPA is not expected to issue a final rule sometime in 2013.

As a result of recent environmental regulation, Idaho Power's coal-fired plants will require additional investment in environmental control technology as described below:

Jim Bridger will require the installation of the following controls to meet the RH BART and MATS regulations:

Unit	Pollutants	Controls	Regulation	New Emission Limits
JB1	NO_x	SCR (2022)	RH	0.07 lb/MMBtu
JB2	NO_x	SCR (2021)	RH	0.07 lb/MMBtu
JB3	NO_x	SCR (2015)	RH BART	0.07 lb/MMBtu
JB4	NO_x	SCR (2016)	RH BART	0.07 lb/MMBtu
All Units	Mercury	$CaBr_2$, scrubber additive, activated carbon injection (2015)	MATS	1.0 lb/TBtu

North Valmy will require the installation of a DSI system, for controlling HCL for acid gas compliance, to meet MATS regulations:

Unit	Pollutants	Control	Regulation	New Emission Limits
NV1	HCL	DSI (2015)	MATS	0.0020 lb/MMBtu

Investment Alternatives

Base Alternatives

The Study analyzes three base alternatives for each unit. Each alternative is analyzed under the three carbon and three natural gas sensitivities.

The alternatives include:

1) **Install environmental upgrade** - Install the required environmental controls to comply with a current, proposed or reasonably anticipated regulation. For Jim Bridger this includes cost for compliance with RH, MATS, CCR and the Clean Water Act Section 316(b). For North Valmy this includes the cost for compliance with MATS

2) **Retire the unit and replace with a CCCT** - The capital cost estimate for the CCCT capacity used to replace the retired coal-fired capacity in this Study was based on the installed cost of Idaho Power's Langley Gulch plant that became commercially operational in June 2012.

   The CCCT's are sized to replace the capacity of Idaho Power's share of the coal unit being replaced. For example, if a 100 MW coal-fired unit is retired, it is replaced with 100 MW of CCCT capacity at a Langley Gulch cost per kW. Of course, actual costs may be different, but for this Study however, we believe that using the Langley Gulch cost per kW is a reasonable assumption. The CCCT units are assumed to be located within the Idaho Power service territory.

3) **Conversion of the unit to burn natural gas** - Natural gas for Jim Bridger is assumed to be provided by a pipeline approximately two miles from the plant. Natural gas for North Valmy is assumed to be provided by a pipeline located approximately 13 miles north of the plant. The natural gas conversion capital and O&M costs used in this Study included installing a pipeline to the plant, modifications to the boiler, and changes in heat rate or capacity due to firing with natural gas instead of coal.

The following table summarizes the base alternatives that were analyzed. Included are the potential compliance deadlines for installing environmental controls and effective dates for the retirement and replacement with CCCT and natural gas conversion alternatives:

Base Alternatives	Environmental Compliance Deadline	Retire/Replace w/CCCT & Natural Gas Conversion Effective Date
North Valmy Unit #1		
Install DSI	3/31/2015	
Retire/Replace with CCCT (DSI not installed)		4/1/2015
Natural gas conversion (DSI not installed)		4/1/2015
Jim Bridger Unit #1		
Install SCR	12/31/2022	
Retire/Replace with CCCT (SCR not installed)		1/1/2023
Natural gas conversion (SCR not installed)		1/1/2023
Jim Bridger Unit #2		
Install SCR	12/31/2021	
Retire/Replace with CCCT (SCR not installed)		1/1/2022
Natural gas conversion (SCR not installed)		1/1/2022
Jim Bridger Unit #3		
Install SCR	12/31/2015	
Retire/Replace with CCCT (SCR not installed)		1/1/2016
Natural gas conversion (SCR not installed)		1/1/2016
Jim Bridger Unit #4		
Install SCR	12/31/2016	
Retire/Replace with CCCT (SCR not installed)		1/1/2017
Natural gas conversion (SCR not installed)		1/1/2017

In addition to the base alternatives, Idaho Power was directed in Order No. 12-177, issued by the Public Utilities Commission of Oregon (OPUC or Commission) in Action item 11 as follows:

> "In its next IRP Update, Idaho Power will include an Evaluation of Environmental Compliance Costs for Existing Coal-fired Plants. The Evaluation will investigate whether there is flexibility in the emerging environmental regulations that would allow the Company to avoid early compliance costs by offering to shut down individual units prior to the end of their useful lives. The Company will also conduct further plant specific analysis to determine whether this tradeoff would be in the ratepayers' interest."

In accordance with the Commission's directive Idaho Power analyzed hypothetical scenarios including compliance timing and the enhanced upgrade alternatives described below.

Compliance Timing Alternatives (CTA)

In addition to the base alternatives, Idaho Power analyzed avoiding the installation of required or reasonably anticipated emission controls by delaying the compliance requirement by five years in exchange for shutting the unit down at the end of the five year period. A negotiated delay is not an option that currently exists but the Study quantifies the financial results of these alternatives.

Idaho Power co-owns all of its coal-fired generation, and Idaho Power is not the operating partner for any of the coal-fired plants. Not being an operating partner removes flexibility that other utilities may have for regulations allowing emission totaling, substitution or reductions at one facility to compensate for lower reductions at another plant, or the option of shutting down a unit or plant in place of reductions at another plant, or delaying installation of environmental controls for a guaranteed early shutdown. As IPC is not the operating partner of Jim Bridger or North Valmy, it is highly unlikely Idaho Power would have the ability to negotiate alternative scenarios as described above.

The following table summarizes the CTA alternatives that were analyzed. Included are the potential compliance deadlines for installing environmental controls and effective dates for the retirement and replacement with CCCT and natural gas conversion alternatives:

Compliance Timing Alternatives (CTA)	Environmental Compliance Deadline	Retire/Replace w/CCCT & Natural Gas Conversion Effective Date
North Valmy Units #1 & #2		
Retire both units	12/31/2022	
Retire/Replace with CCCT (SCR & WFGD not installed)		1/1/2023
Natural Gas Conversion (SCR & WFGD not installed)		1/1/2023
Jim Bridger Units #3 & #4		
Retire both units	12/31/2020 & 12/31/2021	
Retire/Replace with CCCT (SCR not installed)		1/1/2021 & 1/1/2022
Natural Gas Conversion (SCR not installed)		1/1/2021 & 1/1/2022

Enhanced Alternatives

The enhanced upgrade alternative was included for North Valmy which takes into account the possibility of future environmental regulations that would require the installation of SCR and Wet Flue Gas Desulfurization (WFGD) for compliance. At this time, there are no regulations requiring the installation of the emission controls that are included in the enhanced upgrade alternative. Any future regulations are expected to have at least a five- year compliance period. A five- year compliance window would require any investment or replacement to be installed and in-service by 2018. The following table summarizes the enhanced alternatives:

Enhanced Alternatives	Environmental Compliance Deadline	Retire/Replace w/CCCT & Natural Gas Conversion Effective Date
North Valmy Unit #1		
Enhanced Upgrade (installation of SCR & WFGD)	12/31/2017	
Retire/Replace with CCCT (SCR & WFGD not installed)		1/1/2018
Natural gas conversion (SCR & WFDG not installed)		1/1/2018
North Valmy Unit #2		
Enhanced Upgrade (installation of SCR & WFGD)	12/31/2017	
Retire/Replace with CCCT (SCR & WFGD not installed)		1/1/2018
Natural gas conversion (SCR & WFGD not installed)		1/1/2018

Results

SAIC Individual Unit Analysis

The SAIC analysis included the following objectives:

- Review Idaho Power's assumptions for capital costs of the proposed environmental compliance upgrades, including SCR, DSI, WFGD, and other systems, as well as the costs of replacement capacity.
- Review Idaho Power's assumptions for variable costs of the proposed environmental compliance upgrades, coal replacement with CCCT's and natural gas conversion. Idaho Power provided SAIC forecasted generation output for each unit from AURORA. Idaho Power also provided plant operational data obtained from the coal unit's co-owner and operator; PacifiCorp for the Jim Bridger units and NV Energy for the North Valmy units.
- Develop cost estimates for replacing the coal units annual generation, under three natural gas and three carbon futures, with three investment alternatives: (1) installing environmental compliance upgrades, (2) retiring the unit and replacing with CCCT or (3) converting the unit to natural gas. These total costs include capital costs, O&M, decommissioning costs and unrecovered investments of the existing coal units.
- Develop a capital investment analysis allowing assets with different lengths of operation as well as different implementation dates to be compared equitably.
- Provide planning recommendations regarding the three investment alternatives.

The following table summarizes the results from the SAIC analysis. The left column groups each unit with the investment alternatives. The columns to the right show the net present value (NPV) of operating and capital costs over the twenty-year period 2013-2032 in 2013 dollars. The green highlighted cell indicates the least cost option for the unit under each scenario. SAIC's investment recommendations, which can be found in their report Coal Environmental Compliance Upgrade Investment Evaluation Section 5 Conclusions.

The SAIC results are summarized in Figure 3 below:

Figure 3. SAIC Analysis Summary Results by Scenario for the 2013-2032 Forecast Period ($2013 Millions)

Present Value Power Costs by Scenario ($2013 M)	Low Gas No Carbon	Low Gas Base Carbon	Low Gas High Carbon	Base Gas No Carbon	Base Gas Base Carbon	Base Gas High Carbon	High Gas No Carbon	High Gas Base Carbon	High Gas High Carbon
North Valmy 1 Upgrade (DSI)	$430	$405	$314	$543	$585	$493	$602	$688	$747
North Valmy 1 2015 NG Conversion	$441	$348	$196	$760	$723	$447	$1,032	$1,052	$897
North Valmy 1 2015 Retire/Replace	$455	$403	$303	$671	$661	$488	$857	$886	$811
North Valmy 1 Enhanced Upgrade (DSI+SCR+WFGD)	$604	$569	$466	$728	$764	$653	$789	$873	$920
North Valmy 1 2018 NG Conversion	$445	$353	$200	$735	$698	$422	$961	$980	$825
North Valmy 1 2018 Retire/Replace	$478	$426	$326	$684	$674	$502	$847	$877	$802
North Valmy 2 Enhanced Upgrade (SCR+WFGD)	$586	$516	$462	$687	$726	$584	$719	$795	$760
North Valmy 2 NG Conversion	$430	$294	$205	$683	$663	$354	$868	$889	$635
North Valmy 2 Retire/Replace	$486	$406	$351	$659	$660	$469	$782	$811	$668
Jim Bridger 1 Upgrade (SCR)	$538	$664	$655	$560	$707	$988	$573	$723	$1,070
Jim Bridger 1 NG Conversion	$797	$842	$636	$973	$1,039	$1,103	$1,136	$1,206	$1,342
Jim Bridger 1 Retire/Replace	$774	$851	$722	$899	$997	$1,127	$1,014	$1,116	$1,311
Jim Bridger 2 Upgrade (SCR)	$540	$650	$610	$571	$708	$929	$592	$740	$1,069
Jim Bridger 2 NG Conversion	$797	$828	$577	$1,003	$1,058	$1,068	$1,195	$1,261	$1,378
Jim Bridger 2 Retire/Replace	$787	$842	$787	$931	$1,013	$1,071	$1,065	$1,158	$1,323
Jim Bridger 3 Upgrade (SCR)	$561	$670	$570	$598	$740	$939	$617	$767	$1,087
Jim Bridger 3 NG Conversion	$822	$836	$506	$1,130	$1,185	$1,120	$1,422	$1,491	$1,568
Jim Bridger 3 Retire/Replace	$835	$861	$787	$1,051	$1,111	$1,100	$1,251	$1,322	$1,426
Jim Bridger 4 Upgrade (SCR)	$542	$628	$511	$597	$715	$798	$620	$761	$1,043
Jim Bridger 4 NG Conversion	$773	$760	$426	$1,105	$1,111	$897	$1,397	$1,439	$1,455
Jim Bridger 4 Retire/Replace	$791	$796	$787	$1,023	$1,047	$920	$1,221	$1,273	$1,332

Idaho Power Portfolio Analysis

Idaho Power utilized the AURORA model to determine the total portfolio cost of each investment alternative analyzed by SAIC. The total portfolio cost is estimated over a twenty-year planning horizon (2013 through 2032). Idaho Power used the simulated operational performance of each investment alternative relative to the existing resource under varying future natural gas price forecasts and carbon adder assumptions. Idaho Power conducted the simulation using the AURORA model. The AURORA model applies economic assumptions and dispatch cost simulations to model the relationships between generation, transmission, and demand to forecast future electric market prices. AURORA is Idaho Power's primary tool used to simulate the economic performance of different resource portfolios evaluated in the Integrated Resource Planning (IRP) process.

The fixed costs used by SAIC are incorporated into the Idaho Power Study. SAIC reviewed the fixed costs of each investment alternative and scheduled the costs annually for the various investment alternatives for the twenty-year study period. These annual costs included environmental capital investments, ongoing capital expenditures, unit replacement capital and the fixed O&M costs for the specific unit configuration. The Idaho Power Study combines the Net Present Value (NPV) of the fixed costs from the SAIC model; with the NPV of the twenty-year Aurora generated total portfolio cost to form the basis for the quantitative evaluation of the investment alternatives.

Figure 4, below, summarizes the combined NPV results of Idaho Power's Aurora analysis and SAIC's fixed costs analysis for each investment option under varying carbon and natural gas futures. The planning case (planning case carbon/planning case natural gas) is denoted in bold.

The left column groups each unit with the investment alternatives. The columns to the right show the NPV of the total portfolio costs over the twenty-year period (2013-2032) in 2013 dollars. The green highlighted cell indicates the least cost option for the unit under that scenario. The preponderance of least cost outcomes and the relative cost difference between alternatives helps determine the investment recommendation.

Figure 4. Total Portfolio Costs

Idaho Power Company
Coal Environmental Investment Modeling Results
Total Portfolio Costs (Aurora Portfolio Cost + SAIC Fixed Costs)
For the 20 year forecast period 2013-2032
NPV in 2013 $Millions

	NPV of the Total Portfolio Cost for the 3 natural gas and 3 carbon adder futures								
Investment Alternatives	NG High CO_2 $0	NG High CO_2 $14	NG High CO_2 $35	NG Low CO_2 $0	NG Low CO_2 $14	NG Low CO_2 $35	NG Planning CO_2 $0	NG Planning CO_2 $14	NG Planning CO_2 $35
Valmy 1 (V1) DSI	3,659	4,549	6,805	3,965	4,800	6,889	3,857	**4,731**	6,879
V1 2015 retire/replace with CCCT	4,079	4,800	6,637	3,922	4,623	6,543	4,032	**4,749**	6,631
V1 2015 natural gas conversion	3,869	4,681	6,775	3,920	4,722	6,786	3,927	**4,732**	6,797
V1 V2 Enhanced Upgrade (SCR & WFGD) 2018	4,275	5,167	7,388	4,580	5,372	7,439	4,474	**5,332**	7,428
V1 V2 retire/replace with CCCT 2018	4,403	5,124	6,961	4,283	4,983	6,903	4,379	**5,096**	6,978
V1 V2 natural gas conversion 2018	4,335	5,063	6,927	4,164	4,879	6,969	4,287	**5,009**	6,979
CTA - V1 V2 Enhanced Upgrade (SCR & WFGD) 2023	4,176	5,063	7,316	4,512	5,315	7,370	4,373	**5,255**	7,371
CTA - V1 V2 retire/replace with CCCT 2023	4,256	5,041	6,976	4,265	4,983	6,959	4,307	**5,081**	7,007
CTA - V1 V2 natural gas conversion 2023	4,301	5,093	7,047	4,275	5,000	7,075	4,335	**5,113**	7,108
Jim Bridger 1 (JB1) Install SCR	3,625	4,514	6,771	3,930	4,765	6,855	3,823	**4,696**	6,845
JB1 retire/replace with CCCT 2023	4,054	4,879	6,962	4,156	4,942	6,847	4,149	**4,966**	6,943
JB1 natural gas conversion 2023	4,084	4,911	7,005	4,165	4,965	6,943	4,167	**4,984**	7,012
Jim Bridger 2 (JB2)Install SCR	3,655	4,544	6,800	3,960	4,795	6,885	3,852	**4,726**	6,874
JB2 retire/replace with CCCT 2022	4,117	4,935	7,009	4,198	4,981	6,860	4,201	**5,015**	6,980
JB2 natural gas conversion 2022	4,105	4,928	7,008	4,162	4,969	6,935	4,179	**4,992**	7,009
Jim Bridger 3 (JB3) Install SCR	3,663	4,552	6,808	3,968	4,803	6,893	3,860	**4,734**	6,882
JB3 retire/replace with CCCT 2016	4,231	5,016	7,022	4,201	4,947	6,758	4,253	**5,030**	6,931
JB3 natural gas conversion 2016	4,207	4,989	7,020	4,154	4,927	6,853	4,210	**4,988**	6,969
Jim Bridger 4 (JB4) Install SCR	3,663	4,552	6,808	3,968	4,803	6,893	3,860	**4,734**	6,882
JB4 retire/replace with CCCT 2017	4,205	4,985	6,984	4,189	4,935	6,736	4,235	**5,009**	6,903
JB4 natural gas conversion 2017	4,180	4,961	6,983	4,141	4,915	6,825	4,195	**4,971**	6,934
CTA - JB3 JB4 Install SCR	3,894	4,783	7,040	4,199	5,034	7,124	4,092	**4,965**	7,114
CTA - JB3 JB4 retire/replace w CCCT 2020-21	4,895	5,576	7,351	4,539	5,209	6,785	4,742	**5,426**	7,106
CTA - JB3 JB4 natural gas conversion 2020-21	4,980	5,698	7,545	4,572	5,300	7,086	4,807	**5,512**	7,354

Conclusions and Recommendations

North Valmy Unit #1

North Valmy is a critical facility for the reliability of the electric system in northern Nevada.

With the exception of the installation of DSI for MATS compliance, under current and proposed regulations further environmental investment is not required for the continued operation of NV1. Installation of DSI was the lowest cost result for most of the sensitivities analyzed by SAIC. The SAIC results show installing DSI as the least cost option in six of the nine sensitivities analyzed including the planning scenario (planning natural gas/planning carbon).

The AURORA analysis, performed by Idaho Power, shows installing DSI as the least cost option in four of the nine sensitivities analyzed including the planning scenario (planning natural gas/planning carbon). The majority of scenarios not supporting the installation of DSI are the extreme low natural gas and high carbon cases which have a lower probability of occurring.

Idaho Power's conclusion is that the option to make the DSI investment represents a low cost approach to retain a diversified portfolio of generation assets including the 126 MW's of NV1 capacity for our customers benefit. The continued operation of NV1 as a coal-fired unit will provide fuel diversity that can mitigate risk associated with high natural gas prices. While noting that Idaho Power does not recommend the retire/replace with CCCT option or the conversion of the unit to natural gas, it is also important to recognize that such replacements and conversions do not happen instantaneously. Conversion to natural gas could require from three to six years for permitting, installation of the natural gas pipeline, and boiler modifications. Permitting and construction of a CCCT would require approximately four years.

Based on these results, Idaho Power recommends installing DSI and continuing to include NV1 in its generation portfolio for the 2013 IRP and future resource planning.

Figure 5 illustrates the results of the Study for installation of DSI at NV1 and Figure 6 contains a comparison of the costs of the DSI investment to the retire/replace with CCCT and natural gas conversion alternatives:

Figure 5. NV1 DSI Installation Results

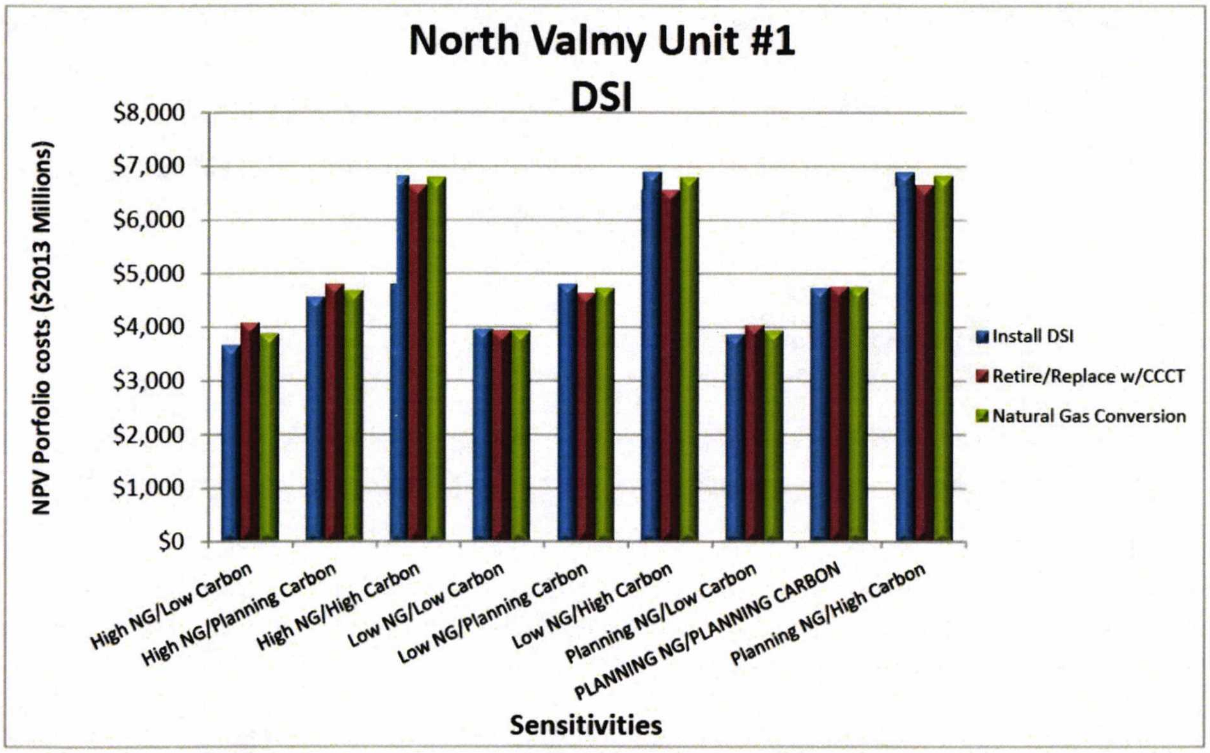


Figure 6. NV1 DSI Installation Cost Deltas

	High NG Low CO_2	High NG Planning CO_2	High NG High CO_2	Low NG Low CO_2	Low NG Planning CO_2	Low NG High CO_2	Planning NG Low CO_2	PLANNING NG PLANNING CO_2	Planning NG High CO_2
Total Portfolio Costs NPV ($ 2013 Millions)									
Install DSI	$3,659	$4,549	$6,805	$3,965	$4,800	$6,889	$3,857	$4,731	$6,879
Retire/Replace w/CCCT	$4,079	$4,800	$6,637	$3,922	$4,623	$6,543	$4,032	$4,749	$6,631
Natural Gas Conversion	$3,869	$4,681	$6,775	$3,920	$4,722	$6,786	$3,927	$4,732	$6,797
Cost Delta's by Scenario ($ 2013 Millions)									
Install DSI-Retire/Replace CCCT	(420)	(252)	168	42	177	347	(175)	(18)	248
Install DSI- NG conversion	(210)	(132)	30	45	78	104	(71)	(2)	82

North Valmy Unit #2

At this time, under current and proposed regulations, further environmental investment is not required for the continued operation of NV2. Additional analysis will be performed if future regulations require significant environmental investments in NV2.

Idaho Power recommends including NV2 in its generation portfolio for the 2013 IRP and future resource planning.

North Valmy Units #1 and #2 (Combined Analysis)

The assumption in the North Valmy Enhanced Upgrade alternative is both units are upgraded, replaced or converted to burn natural gas at the same time. The Enhanced Upgrade alternative includes installation of SCR and WFGD. Consequently, a combined investment analysis is made for both units.

Under both the SAIC and AURORA analyses, proceeding with the Enhanced Upgrade environmental investments at NV1 and NV2 are not supported. However, as there are no current or proposed regulations requiring this investment, Idaho Power recommends including NV1 and NV2 in its planning and as part of Idaho Power's generation portfolio.

Figure 7 illustrates the results of the Study for the Enhanced Upgrade at NV1 and NV2 and Figure 8 contains a comparison of the Enhanced Upgrade costs to the retire/replace with CCCT and natural gas conversion:

Figure 7. NV1 and NV2 Enhanced Upgrade Results

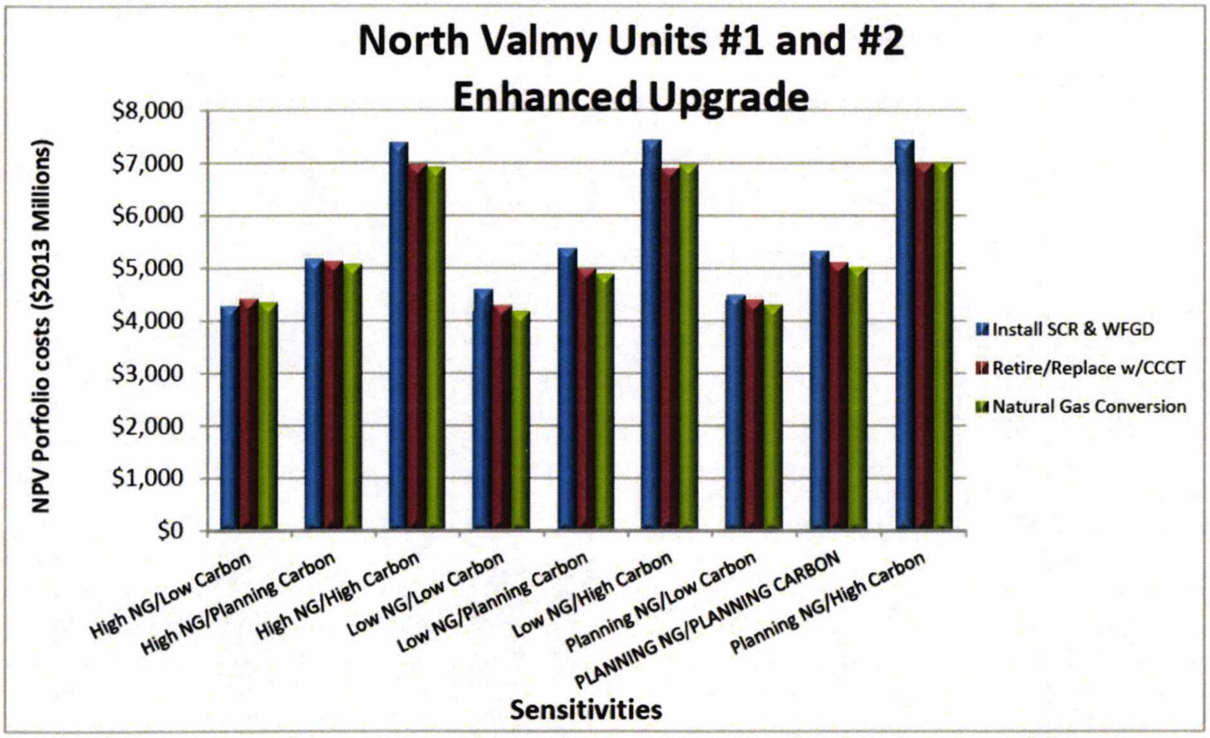


Figure 8. NV1 and NV2 Enhanced Upgrade Installation Cost Deltas

Total Portfolio Costs NPV ($ 2013 Millions)									
	High NG Low CO_2	High NG Planning CO_2	High NG High CO_2	Low NG Low CO_2	Low NG Planning CO_2	Low NG High CO_2	Planning NG Low CO_2	**PLANNING NG PLANNING CO_2**	Planning NG High CO_2
Install SCR & WFGD	$4,275	$5,167	$7,388	$4,580	$5,372	$7,439	$4,474	**$5,332**	$7,428
Retire/Replace w/CCCT	$4,403	$5,124	$6,961	$4,283	$4,983	$6,903	$4,379	**$5,096**	$6,978
Natural Gas Conversion	$4,335	$5,063	$6,927	$4,164	$4,879	$6,969	$4,287	**$5,009**	$6,979
Cost Delta's by Scenario ($ 2013 Millions)									
Install SCR & WFGD-Retire/Replace	($128)	$43	$427	$298	$389	$536	$95	**$236**	$450
Install SCR & WFGD-NG conversion	($60)	$103	$460	$416	$493	$470	$187	**$324**	$450

Additional analysis was performed using the compliance timing alternative. The results of delaying the implementation date do not support proceeding with the Enhanced Upgrade environmental investments on NV1 and NV2.

In the event additional environmental controls are required for NV1 and NV2, the compliance requirements and available control technologies will be analyzed to determine whether installing the environmental controls are the least cost/least risk option.

Figure 9 illustrates the results of the Study for the Enhanced Upgrade compliance timing alternative at NV1 and NV2 and Figure 10 contains a comparison of the compliance timing alternative Enhanced Upgrade costs to the retire/replace with CCCT and natural gas:

Figure 9. NV1 and NV2 Enhanced Upgrade Compliance Timing Alternative Results

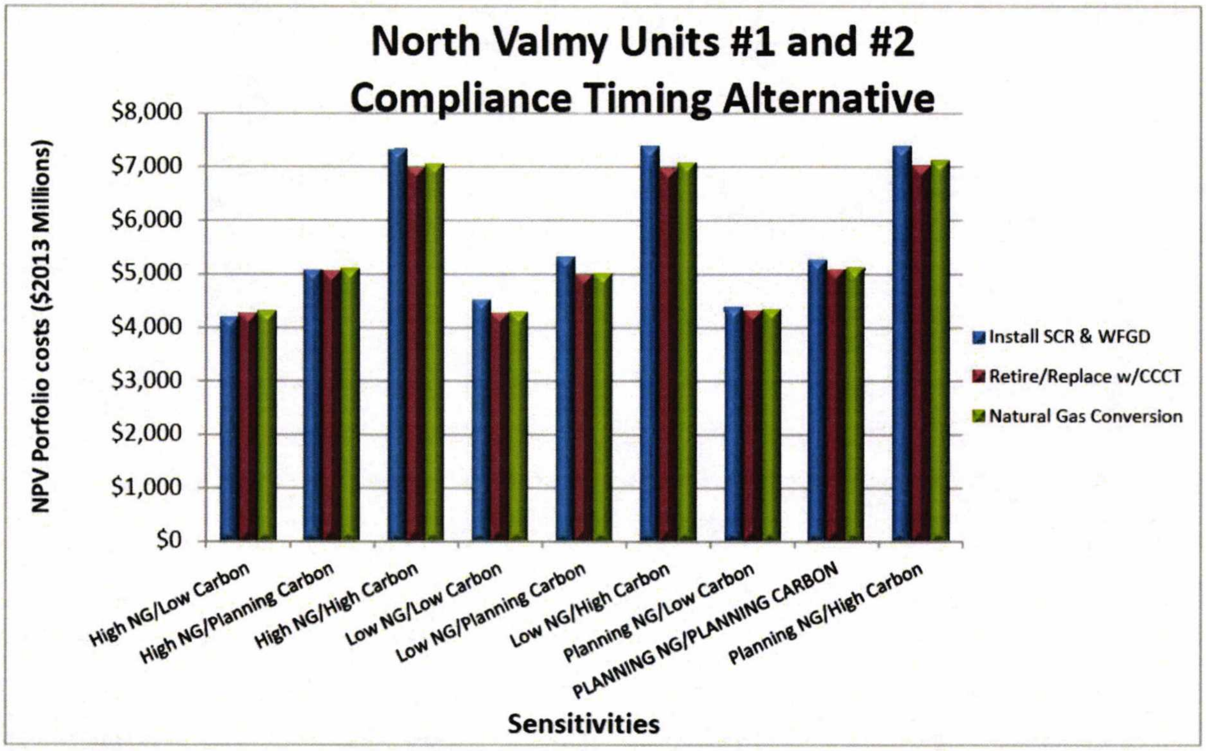


Figure 10. NV1 and NV2 Enhanced Upgrade Compliance Timing Alternative Cost Deltas

Total Portfolio Costs NPV ($ 2013 Millions)									
	High NG Low CO_2	High NG Planning CO_2	High NG High CO_2	Low NG Low CO_2	Low NG Planning CO_2	Low NG High CO_2	Planning NG Low CO_2	**PLANNING NG PLANNING CO_2**	Planning NG High CO_2
Install SCR & WFGD	$4,176	$5,063	$7,316	$4,512	$5,315	$7,370	$4,373	**$5,255**	$7,371
Retire/Replace w/CCCT	$4,256	$5,041	$6,976	$4,265	$4,983	$6,959	$4,307	**$5,081**	$7,007
Natural Gas Conversion	$4,301	$5,093	$7,047	$4,275	$5,000	$7,075	$4,335	**$5,113**	$7,108
Cost Delta's by Scenario ($ 2013 Millions)									
Install SCR & WFGD-Retire Replace	($80)	$21	$339	$248	$332	$411	$66	**$174**	$364
Install SCR & WFGD-NG conversion	($124)	($31)	$269	$237	$315	$294	$38	**$142**	$263

Jim Bridger Unit #1

Under both the SAIC and AURORA analyses, proceeding with environmental investments at JB1 is the lowest cost option for the majority of the carbon and natural gas scenarios. In the most probable scenario, the Idaho Power planning scenario which identifies a planning carbon and planning natural gas future, the environmental upgrade option is overwhelmingly the least cost option.

The installation of SCR, which is the most significant of the environmental investments analyzed, is far enough in the future to make the forecast assumptions highly speculative. As Idaho Power nears the actual SCR investment decision point, a more detailed analysis will be performed with updated assumptions.

Based on these results, Idaho Power recommends continuing to include JB1 in its generation portfolio for the 2013 IRP and future resource planning.

Figure 11 illustrates the results of the Study for installation of required environmental controls at JB1 and Figure 12 contains a comparison of the installation of required emission controls to the retire/replace with CCCT and natural gas conversion options:

Figure 11. JB1 Results

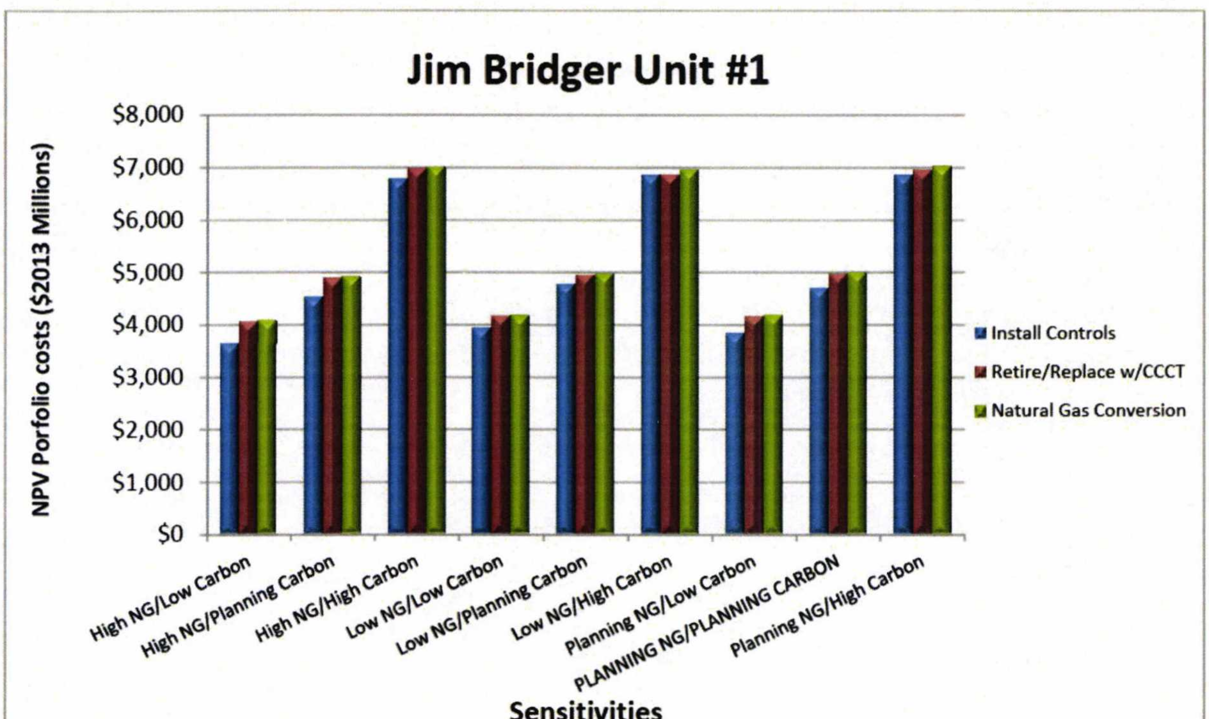


Figure 12. JB1 installation of Emission Controls Cost Deltas

	High NG Low CO_2	High NG Planning CO_2	High NG High CO_2	Low NG Low CO_2	Low NG Planning CO_2	Low NG High CO_2	Planning NG Low CO_2	**PLANNING NG PLANNING CO_2**	Planning NG High CO_2
Total Portfolio Costs NPV ($ 2013 Millions)									
Install Controls	$3,625	$4,514	$6,771	$3,930	$4,765	$6,855	$3,823	**$4,696**	$6,845
Retire/Replace w/CCCT	$4,054	$4,879	$6,962	$4,156	$4,942	$6,847	$4,149	**$4,966**	$6,943
Natural Gas Conversion	$4,084	$4,911	$7,005	$4,165	$4,965	$6,943	$4,167	**$4,984**	$7,012
Cost Delta's by Scenario ($ 2013 Millions)									
Install controls-Retire/Replace CCCT	($429)	($365)	($191)	($225)	($177)	$8	($326)	**($270)**	($98)
Install controls- NG conversion	($459)	($397)	($235)	($234)	($200)	($88)	($345)	**($287)**	($167)

Jim Bridger Unit #2

Under both the SAIC and AURORA analyses, proceeding with environmental investments at JB2 is the lowest cost option for the majority of the carbon and natural gas scenarios. In the most probable scenario, the Idaho Power planning scenario which identifies a planning carbon and planning natural gas future, the environmental upgrade option is overwhelmingly the least cost option.

The installation of SCR, which is the most significant of the environmental investments analyzed, is far enough in the future to make the forecast assumptions highly speculative. As Idaho Power nears the actual SCR investment decision point, a more detailed analysis will be performed with updated assumptions.

Based on these results, Idaho Power recommends continuing to include JB2 in its generation portfolio for the 2013 IRP and future resource planning.

Figure 13 illustrates the results of the Study for installation of required environmental controls at JB2 and Figure 14 contains a comparison of the installation of required emission controls to the retire/replace with CCCT and natural gas conversion options:

Figure 13. JB2 Results

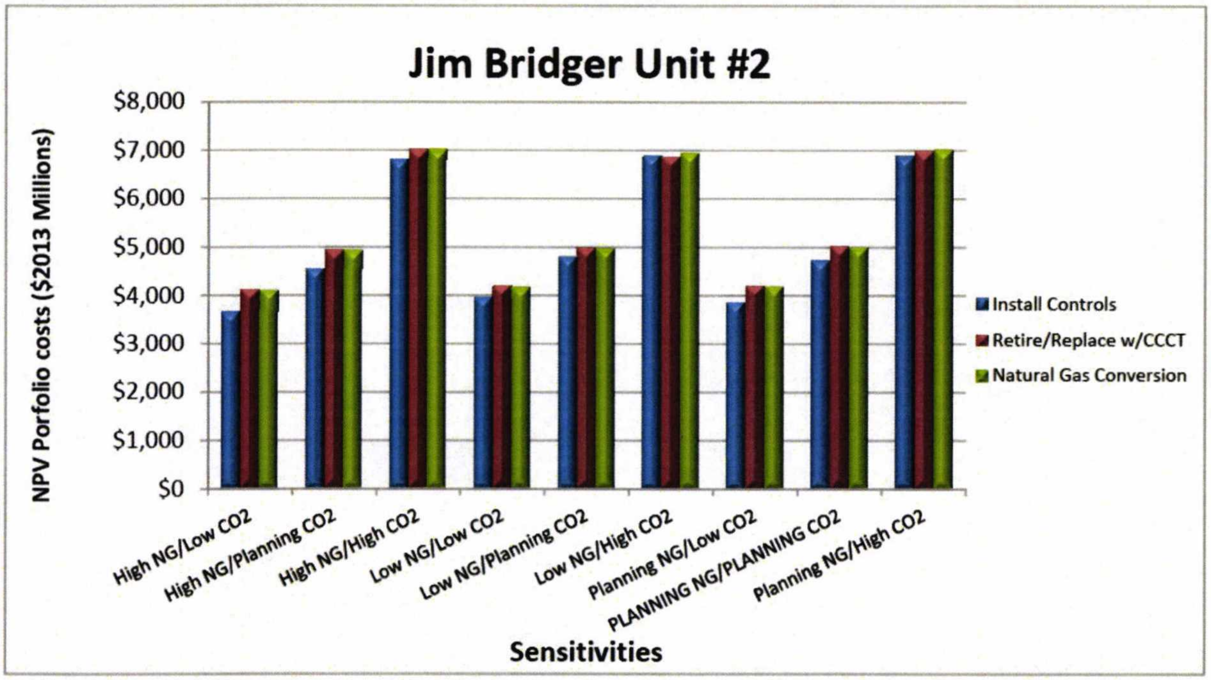


Figure 14. JB2 installation of Emission Controls Cost Deltas

Total Portfolio Costs NPV ($ 2013 Millions)									
	High NG Low CO_2	High NG Planning CO_2	High NG High CO_2	Low NG Low CO_2	Low NG Planning CO_2	Low NG High CO_2	Planning NG Low CO_2	PLANNING NG PLANNING CO_2	Planning NG High CO_2
Install Controls	$3,655	$4,544	$6,800	$3,960	$4,795	$6,885	$3,852	$4,726	$6,874
Retire/Replace w/CCCT	$4,117	$4,935	$7,009	$4,198	$4,981	$6,860	$4,201	$5,015	$6,980
Natural Gas Conversion	$4,105	$4,928	$7,008	$4,162	$4,969	$6,935	$4,179	$4,992	$7,009
Cost Delta's by Scenario ($ 2013 Millions)									
Install controls-Retire/Replace CCCT	($462)	($391)	($209)	($238)	($187)	$25	($349)	($289)	($105)
Install controls-NG conversion	($450)	($384)	($208)	($202)	($174)	($50)	($327)	($266)	($135)

Jim Bridger Unit #3

Under both the SAIC and AURORA analyses proceeding with environmental investments at JB3 is the lowest cost option for the majority of the carbon and natural gas scenarios. In the most probable scenario, the Idaho Power planning scenario which identifies a planning carbon and planning natural gas future, the environmental upgrade option is overwhelmingly the least cost option. Based on these results Idaho Power concludes that making the environmental investments in JB3 is the most prudent action and provides the lowest cost and least risk option.

Based on these results, Idaho Power recommends proceeding with the installation of all identified environmental controls (including SCR) and continuing to include JB3 in its generation portfolio for the 2013 IRP and future resource planning.

Figure 15 illustrates the results of the Study for installation of required environmental controls at JB3 and Figure 16 contains a comparison of the installation of required emission controls to the retire/replace with CCCT and natural gas conversion options:

Figure 15. JB3 Results

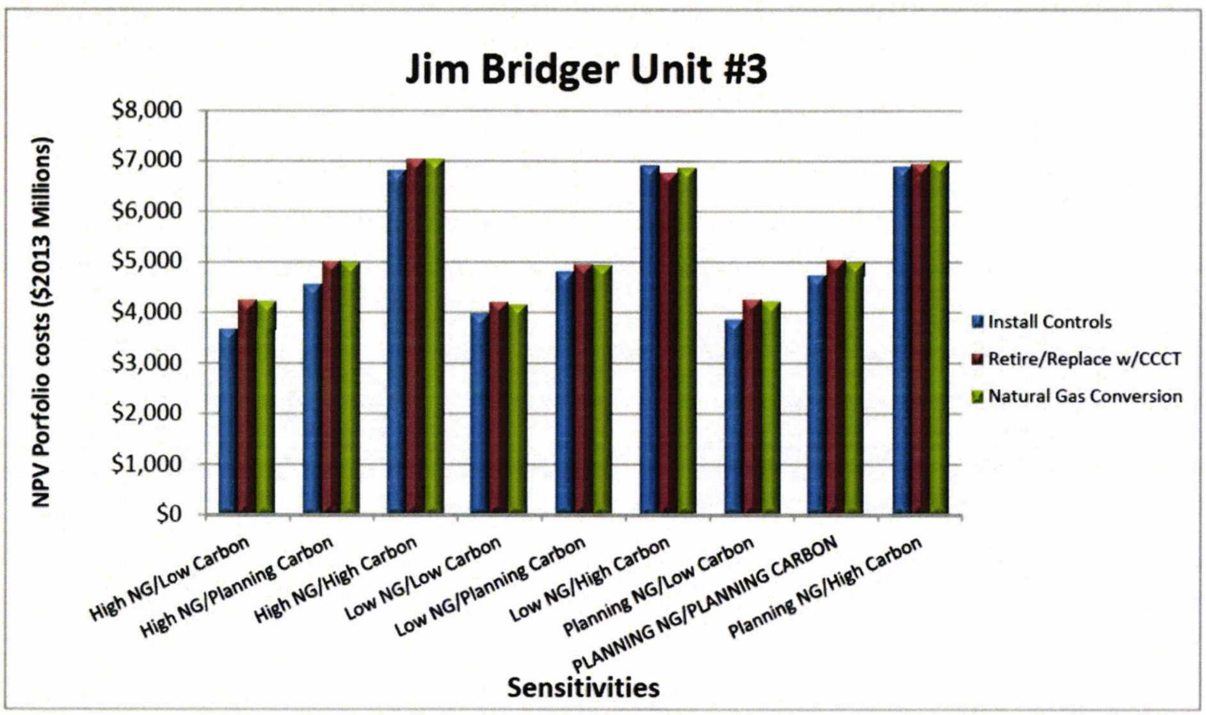


Figure 16. JB3 installation of Emission Controls Cost Deltas

Total Portfolio Costs NPV ($ 2013 Millions)									
	High NG Low CO_2	High NG Planning CO_2	High NG High CO_2	Low NG Low CO_2	Low NG Planning CO_2	Low NG High CO_2	Planning NG Low CO_2	**PLANNING NG PLANNING CO_2**	Planning NG High CO_2
Install Controls	$3,663	$4,552	$6,808	$3,968	$4,803	$6,893	$3,860	**$4,734**	$6,882
Retire/Replace w/CCCT	$4,231	$5,016	$7,022	$4,201	$4,947	$6,758	$4,253	**$5,030**	$6,931
Natural Gas Conversion	$4,207	$4,989	$7,020	$4,154	$4,927	$6,853	$4,210	**$4,988**	$6,969
Cost Delta's by Scenario ($ 2013 Millions)									
Install controls-Retire/Replace CCCT	($568)	($464)	($214)	($233)	($144)	$135	($393)	**($296)**	($49)
Install controls-NG conversion	($544)	($437)	($211)	($186)	($124)	$39	($350)	**($254)**	($87)

Jim Bridger Unit #4

Under both the SAIC and AURORA analyses proceeding with environmental investments at JB4 is the lowest cost option for the majority of the carbon and natural gas scenarios. In the most probable scenario, the Idaho Power planning scenario which identifies a planning carbon and planning natural gas future, the environmental upgrade option is overwhelmingly the least cost option. Based on these results Idaho Power concludes that making the environmental investments in JB4 is the most prudent action and provides the lowest cost and least risk option.

Based on these results, Idaho Power recommends proceeding with the installation of all identified environmental controls (including SCR) and continuing to include JB4 in its generation portfolio for the 2013 IRP and future resource planning.

Figure 17 illustrates the results of the Study for installation of required environmental controls at JB4 and Figure 18 contains a comparison of the installation of required emission controls to the retire/replace with CCCT and natural gas options:

Figure 17. JB4 Results

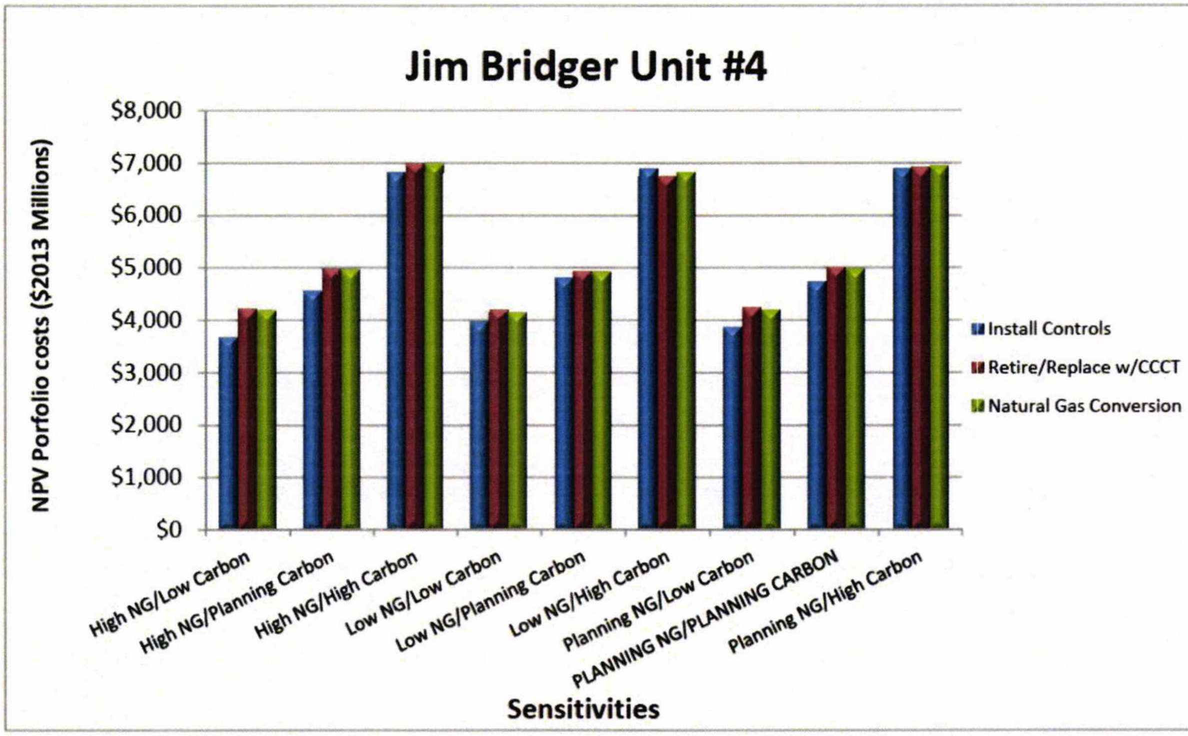


Figure 18. JB4 installation of emission controls Cost Deltas

Total Portfolio Costs NPV ($ 2013 Millions)									
	High NG Low CO_2	High NG Planning CO_2	High NG High CO_2	Low NG Low CO_2	Low NG Planning CO_2	Low NG High CO_2	Planning NG Low CO_2	**PLANNING NG PLANNING CO_2**	Planning NG High CO_2
Install Controls	$3,663	$4,552	$6,808	$3,968	$4,803	$6,893	$3,860	**$4,734**	$6,882
Retire/Replace w/CCCT	$4,205	$4,985	$6,984	$4,189	$4,935	$6,736	$4,235	**$5,009**	$6,903
Natural Gas Conversion	$4,180	$4,961	$6,983	$4,141	$4,915	$6,825	$4,195	**$4,971**	$6,934
Cost Delta's by Scenario ($ 2013 Millions)									
Install controls-Retire/Replace CCCT	($542)	($433)	($175)	($221)	($132)	$157	($375)	**($275)**	($21)
Install controls- NG conversion	($518)	($409)	($175)	($173)	($112)	$68	($335)	**($237)**	($52)

Jim Bridger Units #3 and #4 (Combined Analysis)

The assumption in the compliance timing alternative is both JB3 and JB4 are not upgraded and are replaced or converted to burn natural gas with a five year delay. Consequentially, a combined investment analysis is made for both units.

As shown in the figure above, the results of the compliance timing alternative still support the installation of emission controls on JB3 and JB4.

Figure 19 illustrates the results of the Study for the installation of controls compliance timing alternative at JB3 and JB4 and Figure 20 contains a comparison of the compliance timing alternative costs to the retire/replace with CCCT and natural gas conversion options:

Figure 19. JB3 and JB4 Compliance Timing Alternative Results

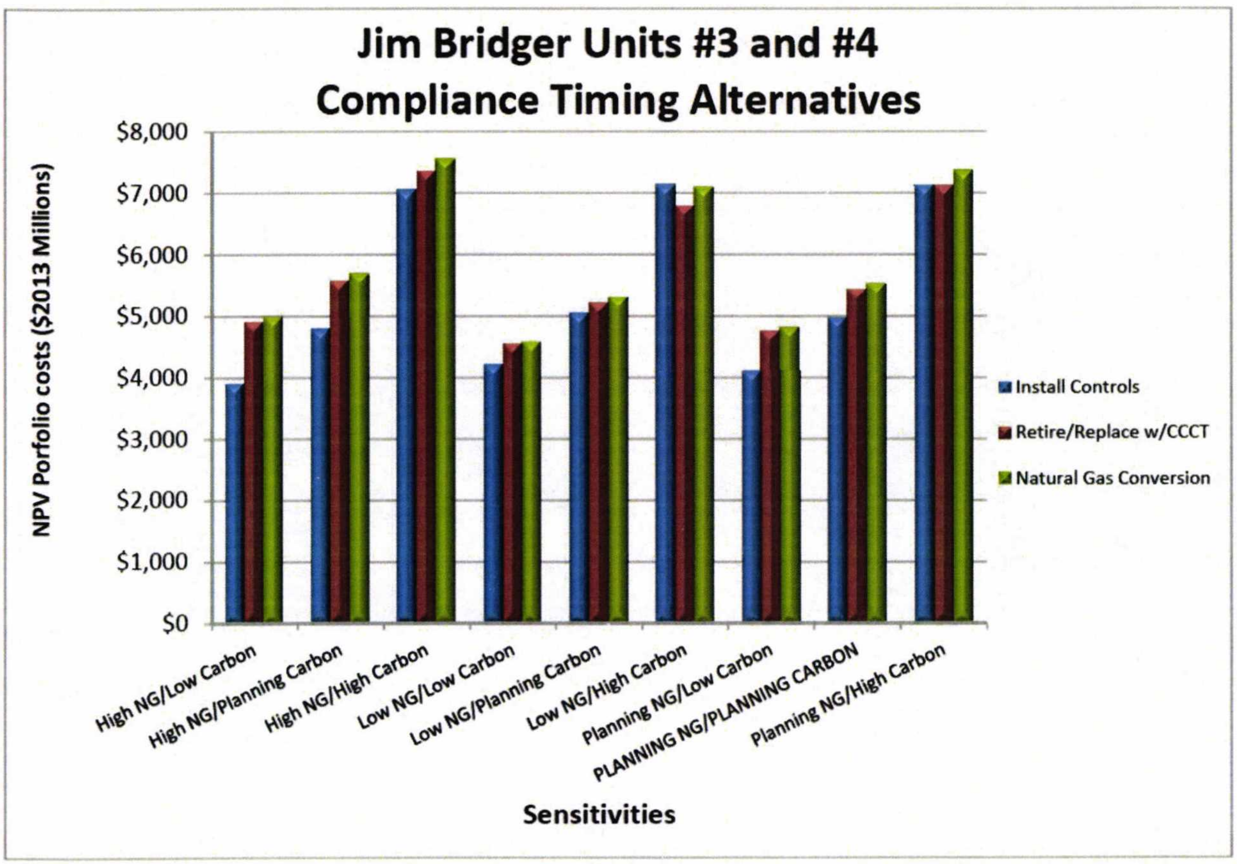


Figure 20. JB3 and JB4 Compliance Timing Alternative Cost Deltas

	High NG Low CO_2	High NG Planning CO_2	High NG High CO_2	Low NG Low CO_2	Low NG Planning CO_2	Low NG High CO_2	Planning NG Low CO_2	**PLANNING NG PLANNING CO_2**	Planning NG High CO_2
Total Portfolio Costs NPV ($ 2013 Millions)									
Install Controls	$3,894	$4,783	$7,040	$4,199	$5,034	$7,124	$4,092	**$4,965**	$7,114
Retire/Replace w/CCCT	$4,895	$5,576	$7,351	$4,539	$5,209	$6,785	$4,742	**$5,426**	$7,106
Natural Gas Conversion	$4,980	$5,698	$7,545	$4,572	$5,300	$7,086	$4,807	**$5,512**	$7,354
Cost Delta's by Scenario ($ 2013 Millions)									
Install controls-Retire/Replace CCCT	($1,001)	($793)	($312)	($339)	($175)	$339	($650)	**($460)**	$8
Install controls-NG conversion	($1,086)	($915)	($505)	($373)	($266)	$38	($715)	**($547)**	($240)

Review Process and Action Plan

The objective of this Study is to ensure a reasonable balance between protecting the interests of customers, meeting the obligation to serve the current and reasonably projected future demands of customers, and complying with environmental requirements, while recognizing that the regulatory environment is uncertain. In a commitment to honor these goals Idaho Power intends to perform systematic reviews, similar to this analysis, whenever certain triggering events occur. These triggering events include:

- A significant change in the current state of environmental regulation
- A significant change in the estimated cost of anticipated environmental controls
- Within a year of committing to a major environmental upgrade
- Whenever Idaho Power files an Integrated Resource Plan

In conclusion, this Study shows the economics of incremental environmental investments is highly dependent upon the assumptions for both natural gas and carbon adders. This Study highlights the challenge in making investment decisions today in the face of significant uncertainties. Despite these uncertainties, certain environmental control equipment investment decisions must be made in the near-term. Idaho Power will continue to work with regulatory agencies and stakeholders to analyze these major investment decisions prior to commitment and implementation.

Attachment 5

Confidential Attachment 1 to IPC Response to Sierra Club Request No. 22

ICL/SC Attachment 5 contains confidential information subject to the protective agreement in Case No. IPC-E-21-17 and has been served upon the Commission and eligible parties.

Attachment 6

Confidential Attachment 3 to IPC Response to Sierra Club Request No. 28

ICL/SC Attachment 6 contains confidential information subject to the protective agreement in Case No. IPC-E-21-17 and has been served upon the Commission and eligible parties.

Attachment 7

Confidential Attachment 1 to IPC Response to Sierra Club Request No. 24 – Bridger Coal Price Forecast

ICL/SC Attachment 7 contains confidential information subject to the protective agreement in Case No. IPC-E-21-17 and has been served upon the Commission and eligible parties.

Attachment 8

Confidential Attachment 2 to IPC response to Sierra Club Request No. 28 – JB Coal Aurora Vectors

ICL/SC Attachment 8 contains confidential information subject to the protective agreement in Case No. IPC-E-21-17 and has been served upon the Commission and eligible parties.

Attachment 9

RMI Jim Bridger Analysis

Attachment 9 is an Excel spreadsheet and is being provided as a separate attachment.

CERTIFICATE OF SERVICE

I hereby certify that on this 27th day of April 2022, I delivered true and correct copies of the foregoing **JOINT COMMENTS OF SIERRA CLUB AND IDAHO CONSERVATION LEAGUE** to the following persons via the method of service indicated below.

Electronic mail only (see Order 35375)

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