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Public Utility Commission of Oregon
201 High St SE, Suite 100
Salem, Oregon 97301-3398

Re: Docket No. LC 68– Sierra Club Opening Comments

Please find enclosed Sierra Club Opening Comments in Docket No. LC 68. The public version of this document was filed electronically and served upon all party representatives for this proceeding via e-mail. The confidential portion of this document was served pursuant to Protective Order No. 17-292 upon all eligible party representatives via U.S. Mail.

Please do not hesitate to contact me if you have any questions or need other materials. Thank you.

Sincerely,

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BEFORE THE OREGON PUBLIC UTILITIES COMMISSION

In the Matter of IDAHO POWER COMPANY, 2017 Integrated Resource Plan	Docket LC 68

SIERRA CLUB COMMENTS
[REDACTED]

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SIERRA CLUB COMMENTS
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1. INTRODUCTION

Sierra Club appreciates the opportunity to comment on Idaho Power Company's (IPC) 2017 Integrated Resource Plan (IRP). These comments were prepared with the assistance of Avi Allison and Dr. Jeremy Fisher of Synapse Energy Economics, and they are based on examination of IPC's input assumptions, portfolio construction, and evaluation of resource options. Sierra Club participated in the 2017 IPC IRP Advisory Council and actively intervenes in utility planning proceedings in jurisdictions across the United States. In these comments, we focus on the overarching goal of achieving transparent, evidence-based resource planning that strikes a balance between low costs and risk mitigation.

2. SUMMARY AND RECOMMENDATIONS

An IRP should identify a path toward reliably satisfying future energy service demands in an economic and sustainable manner. A useful IRP contains a reasonable array of input assumptions, and fairly evaluates the costs and benefits of competing demand- and supply-side resources.

We recognize and applaud certain aspects of IPC's IRP. Specifically, this IRP explicitly acknowledges the uneconomic nature of the North Valmy coal units and includes a plan to retire North Valmy Unit 1 by the end of 2019. The IRP also accurately recognizes the importance of pursuing all cost-effective energy efficiency, and of evaluating whether it is worth investing substantial incremental capital in Jim Bridger Units 1 and 2.

However, we find that the IRP relies on a deeply flawed analytical structure, multiple analytical errors, and implausible assumptions regarding the costs and benefits of continuing to operate the Bridger units. Ultimately, IPC's IRP appears to be persistently biased in favor of maintaining the Bridger units despite the economic challenges that they currently face.

Our review indicates that the most serious flaws in the IPC IRP include:

- **Lack of portfolio optimization.** IPC chose not to use any capacity expansion models in this IRP, instead manually determining each portfolio it analyzed. IPC's claim that its portfolio design enables it to asses alternative Bridger and Boardman to Hemingway (B2H) investments in a fair fashion is misleading and inaccurate. Instead, the Company's portfolio construction scheme renders virtually useless its comparative assessment of the value of alternative Bridger retirement options. Furthermore, IPC's portfolio design all but ensures that the IRP does not select a least-cost, least-risk plan.

- **Selection of illegal portfolio.** Half of the portfolios evaluated in this IRP, including the selected portfolio, do not comply with current regulatory requirements. IPC's proposed plan banks on convincing regulatory agencies to allow it to continue to operate Bridger Units 1 and 2 without selective catalytic reduction (SCR) technology well beyond the date at which SCR retrofits are currently required. The Company's assessment of an "alternative compliance" pathway for Bridger is not equivalent to the rigorous Regional Haze alternatives evaluated—and discussed extensively with regulators—for the Boardman, Centralia, or San Juan generating stations.

- **Understated costs of retrofitting Jim Bridger Units 1 and 2 with SCR.** Under the portfolios in which IPC installs SCR on the Bridger units, the IRP mistakenly fails to account for any fixed costs incurred at the Bridger plant beyond 2034. The economic assessment contained in the IRP also relies on a calculation error that artificially reduces the cost of the lowest-cost SCR retrofit scenario. In addition, the SCR scenarios incorrectly fail to account for increased operations and maintenance costs associated with SCRs.

- **Deflated coal cost assumptions, paired with assumed rapid growth in market energy prices.** Integrated into the Company's analysis structure, these assumptions make the Bridger units appear to become economically viable in the long term, despite the IRP's implicit acknowledgment that these units are currently losing money on behalf of IPC ratepayers. An independent valuation of the Bridger units indicates that they are likely to remain uneconomic indefinitely. Only an unhelpful analysis structure and erroneous inputs result in the Company's finding that Bridger is economic if maintained into the 2030s.

- **Lack of evaluation of the economic status of Jim Bridger Units 3 and 4.** In commenting on and evaluating PacifiCorp's recent 2017 IRP, Sierra Club presented strong evidence that Bridger Units 3 and 4 are substantial liabilities. Yet IPC does not even consider the economic status of existing units other than Bridger Units 1 and 2 in this IRP, and it does not provide sufficient data to allow for an independent valuation of other units.

- **Low estimates of achievable energy efficiency potential.** While the IRP says the right things about pursuing all cost-effective energy efficiency, it assumes future savings that are much lower than the levels currently being achieved by IPC's cost-effective programs.

- **Inflated alternative resource cost assumptions.** IPC assumes that the levelized costs of all resources will increase at the rate of inflation. This assumption is inconsistent with recent evidence and industry expectations regarding the declining costs of technologies such as battery storage and solar.

Based on our findings, Sierra Club recommends that the Commission not acknowledge IRP Action Number 4 (planning on retirement dates of 2028 for Bridger Unit 2 and 2032 for Bridger Unit 1) and instead require IPC to re-assess Bridger Units 1 through 4. We recommend that the Commission disavow inadequate resource plans with substantial flaws and not defer the re-analysis of the Bridger plant to the next IRP. In addition, we recommend that IPC remedy each of the flaws identified above in future IRP filings.

Sierra Club's comments follow a narrowing structure: first, they discuss the overall analysis structure used by IPC. They then focus on errors and biases in IPC's input assumptions within that analysis structure. Next, they specifically focus on the economics of the Bridger plant, and discuss how the IRP mischaracterizes Bridger's economic viability. These comments conclude by critiquing the risk assessment applied by IPC.

3. THE IRP'S ANALYSIS STRUCTURE IS FLAWED

The analytical structure underlying IPC's IRP suffers from several major flaws. Most notably, IPC made little effort to identify a least-cost resource plan, and ultimately selected a portfolio that would violate current laws and regulations.

3.1. Lack of portfolio optimization reduces rigor, transparency, and usefulness of IRP analysis

Portfolio design is a critical component of any IRP analysis. The portfolio construction process establishes the universe of future resource decisions that are assessed meaningfully by the utility. Ensuring selection of a least-cost, least-risk plan typically requires that a utility consider as full a range of viable resource actions as possible. The most common and rigorous way of achieving this is through the use of an industry-standard capacity expansion optimization model. It is therefore concerning that IPC did not make any use of capacity expansion modeling in its 2017 IRP.

IPC states that it "designed the portfolio analysis for the 2017 IRP with the objective of informing the IRP's Action Plan with respect to two key resource actions: (1) SCR investments required for Jim Bridger Units 1 and 2 by 2022 and 2021, respectively, and (2) the B2H transmission line."[1] Specifically, "the portfolio design consisted of four Jim Bridger SCR investment scenarios, with three resource portfolios formulated within each scenario, resulting in 12 resource portfolios."[2] IPC refers to this portfolio design approach as a "factorial experimental design," and characterizes it as approximating a "controlled experiment" that addresses the two questions of whether to retrofit Bridger Units 1 and 2 with SCR or retire them early, and whether or not to invest in B2H.[3] The combination of these two sets of decisions are developed into the 12 different portfolios described in Figure 1.

Figure 1. Portfolios in the IPC 2017 IRP (excerpted from Table 9.3 in 2017 IRP)

Portfolio Details			
Portfolio Index (1)	Portfolio Description (2)	B2H (3)	Bridger Capacity Retirement (4)
P1	SCR invest, B2H, recips	✓	
P2	SCR invest, DR, recips, solar		
P3	SCR invest, DR, recips, CCCT		
P4	Bridger retire in 24 & 28, B2H, recips	✓	✓
P5	Bridger retire in 24 & 28, DR, recips, solar		✓
P6	Bridger retire in 24 & 28, DR, recips, CCCT		✓
P7	Bridger retire in 28 & 32, B2H, recips, CCCT	✓	✓
P8	Bridger retire in 28 & 32, DR, recips, solar, CCCT		✓
P9	Bridger retire in 28 & 32, DR, recips, CCCT		✓
P10	Bridger retire in 21 & 22, B2H, recips	✓	✓
P11	Bridger retire in 21 & 22, DR, recips, solar		✓
P12	Bridger retire in 21 & 22, DR, recips, CCCT		✓

IPC's decisions to evaluate whether to retrofit or retire Bridger Units 1 and 2, and whether to invest in B2H, are laudable. These are the sorts of major, discrete investment choices that justify focused analysis. IPC chose one reasonable way to begin such an analysis – constructing alternative portfolios under which the Bridger retirement decision and the B2H investment decision are manually set to the different alternatives under consideration. However, IPC erred when it decided to manually select not just these two major investment decisions, but *every resource investment decision in every portfolio for the next 20 years.*[4]

There are two core problems with IPC's choice to model only portfolios that it had determined entirely manually, without the aid of a capacity expansion model. First, there no evidence that any of the portfolios that IPC modeled constitute a least-cost or least-risk resource plan, as

[1] IPC 2017 IRP, p. 97.
[2] *Id.*
[3] *Id.*
[4] See IPC Response to Sierra Club's Data Request No. 1-4 (verifying that "capacity expansion modeling was not used to determine the portfolios").

required by Oregon's IRP rules.[5] Given the variety of resource types available to IPC and the two-decade length of IPC's modeling period, the number of possible resource portfolios that would meet IPC's reliability and regulatory constraints could easily number in the hundreds of thousands. A capacity expansion model is designed to rapidly sort through this enormous range of possibilities and come up with a least-cost plan that satisfies all system constraints. A human brain is not so designed. When humans—no matter how well trained and well intentioned—attempt to arrive at an optimal resource plan, the result is almost certain to be costlier and more tinged with bias than a modeled, optimized plan.

The impact of IPC's manual resource selection on its IRP conclusions may not be obvious at first glance, but the distinction between manually selected replacement resources and an optimal buildout can be substantial. For example, in a recent IRP, Tucson Electric Power Company (TEP) examined a coal retirement scenario in which coal was replaced exclusively with modular nuclear reactors.[6] TEP's conclusion that coal retirements were not viable because the portfolio costs were too high had nothing to do with the retirements, and everything to do with the extraordinary cost of modular nuclear reactors. At a lesser, but still relevant scale, IPC's replacement portfolios may include new resources that are not least-cost expansion or replacement options. Knowing the difference in cost between IPC's hand-selected options and an optimal choice is almost impossible.

Parts of the IPC's IRP verify that the Company fails to adequately recognize the fundamental importance of cost in resource planning. At one point, IPC states that the "primary goal of the IRP is to ensure Idaho Power's system has sufficient resources to reliably serve customer demand over the 20-year planning period," leaving out any mention of cost or risk.[7] Elsewhere, IPC affirms that its IRP methodology was "designed to remediate any energy or capacity deficiency over the planning period."[8] This means that IPC did not consider retirements (other than two of the four Bridger units) or resource acquisition during times of sufficiency, even if doing so would reduce system costs.

The second problem with IPC's portfolio design construct is that it undercuts IPC's ability to answer the very questions that this IRP is supposedly designed to address. A core premise of the IRP is that IPC has isolated the Bridger and B2H investment alternatives in such a way that they

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[5] Public Utility Commission of Oregon. UM 1056. Disposition: Guidelines Adopted; Rulemaking and Investigation Opened. P. 6 ("The goal of the IRP is to help identify the lowest realized cost over the planning horizon."); Appendix A, p. 1 ("The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties.")

[6] TEP 2017 IRP, page 276 and Table 24, page 283. https://www.tep.com/wp-content/uploads/2016/04/TEP-2017-Integrated-Resource-FINAL-Low-Resolution.pdf.

[7] IPC 2017 IRP, p. 3.

[8] IRP, p. 4.

can be fairly compared against each other as if through a "controlled experiment."[9] Unfortunately, this premise is plainly false. To understand why, one need only consider the left-most column of the very first table in the IRP, reproduced below as Table 1.[10] From the way that this table is constructed—and the way the factorial design is discussed throughout the IRP—one would think that Portfolios 1, 4, 7, and 10 all have very similar resource build plans, all of which are dominated by the B2H project coming online at a fixed date. After all, IPC "emphasizes that the validity of the factorial design relies on by-column and by-row uniformity."[11] Yet, the resource builds across these four portfolios are clearly substantially different from each other. To take one example, more than 30 percent of new capacity in the preferred Portfolio 7 comes from a combined-cycle combustion turbine (CCCT), whereas zero CCCT capacity is built in any of the three other B2H portfolios.[12] To take another example, 216 MW of reciprocating engine capacity is built by 2023 in Portfolio 10, whereas Portfolio 1 includes no new capacity before 2034 other than B2H.[13] Even the B2H in-service date varies across these portfolios, ranging from 2024 under Portfolio 10 to 2026 under Portfolios 1 and 7.[14]

Table 1. IPC "factorial design" portfolio structure

Treatment of Jim Bridger Units 1 and 2	Primary Portfolio Element(s)		
	B2H	**Solar PV/Natural Gas**	**Natural Gas**
Invest in SCR	P1	P2	P3
Retire Unit 1 in 2028 and Unit 2 in 2024	P4	P5	P6
Retire Unit 1 in 2032 and Unit 2 in 2028	P7	P8	P9
Retire Unit 1 in 2022 and Unit 2 in 2021	P10	P11	P12

Source: IPC 2017 IRP.

It is important to emphasize that there is no manual resource selection process that IPC could have used to adequately "control" for resource build decisions in its assessment of alternative Bridger retirement dates. The differences in retirement dates necessarily drive differences in the timing and degree of resource needs. It should be obvious that the best option for replacing retiring capacity in 2021 may be very different from the best option for replacing retiring capacity in 2032. The way to deal with these differences is not through a hopeless effort to manually impose similar-looking resource builds across different contexts. Instead, the reasonable path involves using an optimization model to determine the least-cost portfolio under each Bridger retirement scenario. Only once IPC has determined the best it can do under each

[9] IPC 2017 IRP, p. 97.
[10] *Id.*, p. 7.
[11] *Id.*, p. 7.
[12] *Id.*, pp. 99-105.
[13] *Id.*
[14] *Id.*

Bridger retirement alternative (and each B2H alternative) can it reasonably compare across alternatives. IPC's failure to even attempt to determine the least-cost plan under each Bridger retirement scenario greatly reduces the meaningfulness of IPC's comparison of these scenarios.

3.2. IPC's inappropriate application of the Clean Air Act's Regional Haze Rule leads it to select an unlawful portfolio

The Clean Air Act's Regional Haze program requires states to meet certain visibility milestones in order to restore air quality in national parks and wilderness areas by 2064. The first aspect of the program required power plants constructed between 1962 and 1977 to install Best Available Retrofit Technology (BART) to meet unit-specific emission limits. States, working with utilities, drafted implementation plans to submit to EPA for approval based on a five-factor analysis.[15] BART retrofits reduce sulfur dioxide (SO_2) and oxides of nitrogen (NO_X), which are precursors to visibility- and health-impairing particulates and ozone. In the alternative, the Regional Haze program provided states and entities the opportunity to propose emission reduction plans that are technically shown to be "better than BART," i.e., achieving visibility improvements equal to or greater than those achievable through strict implementation of BART.

In the 2017 IRP, IPC has presented four compliance pathways for Bridger Units 1 and 2 under the Regional Haze rule: compliance with the rule as promulgated through installation of SCRs in 2021/2022, or various alternative retirement dates, ranging from 2021 to 2032—just two years prior to the end of Bridger's depreciable life. IPC provides no basis or explanation for these alternatives, other than to say that they are intended to "help guide future discussions with the [Wyoming Department of Environmental Quality] in developing a [State Implementation Plan] for regional-haze compliance."[16]

IPC's alternatives for the retirement date of Bridger Units 1 and 2 aim to mimic the regional haze program's "better than BART" approach utilized at the Boardman, Centralia, and San Juan coal-fired plants—a tactic used by PacifiCorp in its 2017 IRP. However, like PacifiCorp's IRP, IPC's IRP evidences no engagement on the Company's part with the appropriate state air quality agencies or the U.S. Environmental Protection Agency (EPA) to verify that the range of retirement dates put forward in the IRP could comply with EPA's technical requirements for approvable emission limits and control technology.

Better than BART provides utilities with flexibility if they commit to retiring regulated units at a date certain (Boardman and Centralia) or retire some units at a date certain while installing lesser

[15] The five-factor analysis: (1) the costs of compliance; (2) the energy and non-air quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and, (5) the degree of visibility improvement which may reasonably be anticipated from the use of BART.
[16] IPC 2017 IRP, p. 83.

controls on other units (the retirement of San Juan 2 & 3). **In all cases, the EPA-approved alternative plans achieved the required emission reductions at the affected Class 1 areas.** Like PacifiCorp, IPC has offered an IRP with a range of alternative plans but has not offered **any** emissions or visibility analyses to support the viability of these plans. IPC's IRP then selects a plan in which one Bridger unit retires just two years prior to the end of its depreciable life, without installing any incremental emissions controls. It is unreasonable to think that such a plan represents a Better than BART alternative. Instead, it appears to reflect hopeful speculation regarding the future leniency of regulatory agencies.

A Better than BART alternative requires a careful—and highly technical— assessment of the visibility implications of foregoing near-term, unit-specific retrofits. The complete line of evidence provided by IPC that its plans are reasonable is summarized in two statements in discovery responses that describe an "informal meeting with the Wyoming DEQ [Department of Environmental Quality]" and no communications with EPA on regional haze compliance deadlines or options.[17] IPC's lack of documentation does not support the concept that anything aside from compliance with current Regional Haze requirements—as written—is reasonable. Existing law requires either retrofitting or retiring Bridger Units 1 and 2 in 2022 and 2021, respectively.

4. INPUT ASSUMPTIONS BIASED TOWARD GREATER NEED

IPC understates its near-term energy efficiency potential and baselessly assumes that many of its wind contracts will not be renewed. For these reasons, IPC's IRP likely exaggerates both the Company's need for new resources and the value of existing resources such as the Bridger units.

4.1. IPC understates its energy efficiency potential

IPC's IRP likely substantially understates the potential for energy efficiency to reduce its sales and peak load. IPC asserts that it "puts 100 percent of its cost-effective achievable energy efficiency potential in each portfolio prior to the consideration of any supply-side resources."[18] In other words, IPC uses the same efficiency trajectory in each of its IRP portfolios, and then asserts that this trajectory constitutes the maximum economically achievable quantity of efficiency savings. However, IPC's recent experience refutes the idea that the savings assumed in the IRP constitute the maximum "cost-effective achievable" level.

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[17] IPC Response to Sierra Club DR 1-7(c). "In September 2016, Idaho Power and PacifiCorp had an informal meeting with the Wyoming DEQ to discuss regional haze compliance requirements for Bridger Units 1 and 2. Idaho Power has no written communications or materials resulting from that meeting or otherwise." Sierra Club DR 1-7(d). "Idaho Power has not had any communication with the U.S. Environmental Protection Agency regarding regional haze compliance deadlines and options for Bridger units 1 and 2; therefore, no documents exist."
[18] IPC Response to Staff's Data Request No. 12.

Figure 2 compares IPC's historical efficiency savings levels to the savings levels included in the IRP. In three of the past five years, including each of the past two, IPC has achieved total incremental savings greater than 1 percent of sales.[19] IPC's savings levels have increased for each of the past three years, surpassing 1.2 percent of sales in 2016. Nonetheless, IPC forecasts a drastic drop in its efficiency savings, effective immediately. Each of IPC's scenarios assumes that total savings will plummet by more than 33 percent from 2016 to 2017, and never again reach the levels that IPC has consistently hit over the past several years.[20] The drop-off is particularly extreme for residential savings, which are forecasted to decline by about 70 percent in a single year.

Figure 2. Incremental energy efficiency savings as percentage of sales, historical and IPC forecast

Sources: Form EIA-861; IPC 2017 IRP.

Perhaps the forecasted decline in savings would be justified if IPC's current programs were not cost-effective. But that is clearly not the case. IPC's latest annual review of its demand-side management programs reports that in 2016, IPC's energy efficiency portfolio was remarkably cost-effective, with a benefit-cost ratio greater than 2.5 whether viewed from the utility, participant, or total resource perspective.[21] Only four of IPC's programs had a benefit-cost ratio

[19] U.S. Energy Information Administration (EIA). Form EIA-861. Available at https://www.eia.gov/electricity/data/eia861/index.html.
[20] IPC 2017 IRP Appendix C – Technical Appendix, pp. 9-10, 67.
[21] IPC 2017 IRP Appendix B – Demand-Side Management 2016 Annual Report, p. 27.

less than one on any of the three major benefit-cost tests.[22] Those four programs contributed less than 1.5 percent of savings in 2016.[23] In contrast, the uniformly cost-effective programs contributed more than 168 GWh of savings in 2016. This is more than 50 GWh greater than the savings assumed by IPC for 2017, and more than 25 GWh greater than the savings assumed by IPC in any single future year.[24]

Other justifications offered by IPC for the decline in projected savings are unconvincing. IPC attributes lower forecasts of cost-effective savings to lower alternative resource costs and the impact of the Energy Independence and Security Act (EISA) on lighting standards.[25] But natural gas prices, a primary driver of costs avoided by efficiency programs, have been consistently higher in 2017 than they were in 2016, when IPC's efficiency programs prospered.[26] And the next major change in the stringency of EISA lighting standards will not come until January 2020, and therefore cannot explain such a sharp decrease in savings between 2016 and 2017.[27] Furthermore, while the EISA standards may reduce the level of savings that IPC's programs can claim responsibility for, they will only improve the efficiency of electricity usage within IPC's service territory. It is unclear whether IPC's load forecast captures this effect.

IPC's energy efficiency forecast is ultimately based on a potential study conducted on its behalf by the Applied Energy Group (AEG). As in its previous IRP, IPC relies on AEG's estimate of "achievable potential."[28] However, evidence from the past two years indicates that AEG's "achievable potential" estimates tend to greatly understate the cost-effective savings that IPC can actually achieve. The 2015 version of AEG's potential study estimated that IPC's "achievable potential" was limited to 99 GWh in 2015, or 0.7 percent of sales.[29] In fact, IPC ended up achieving 163 GWh of savings, or 1.1 percent of sales in 2015, before going on to achieve 171 GWh of savings in 2016.[30] Figure 3 shows that these actual achieved savings levels are very similar to the values the 2015 AEG report identified as "economic potential," reflecting "the savings when the most efficient cost-effective measures are taken by all customers."[31]

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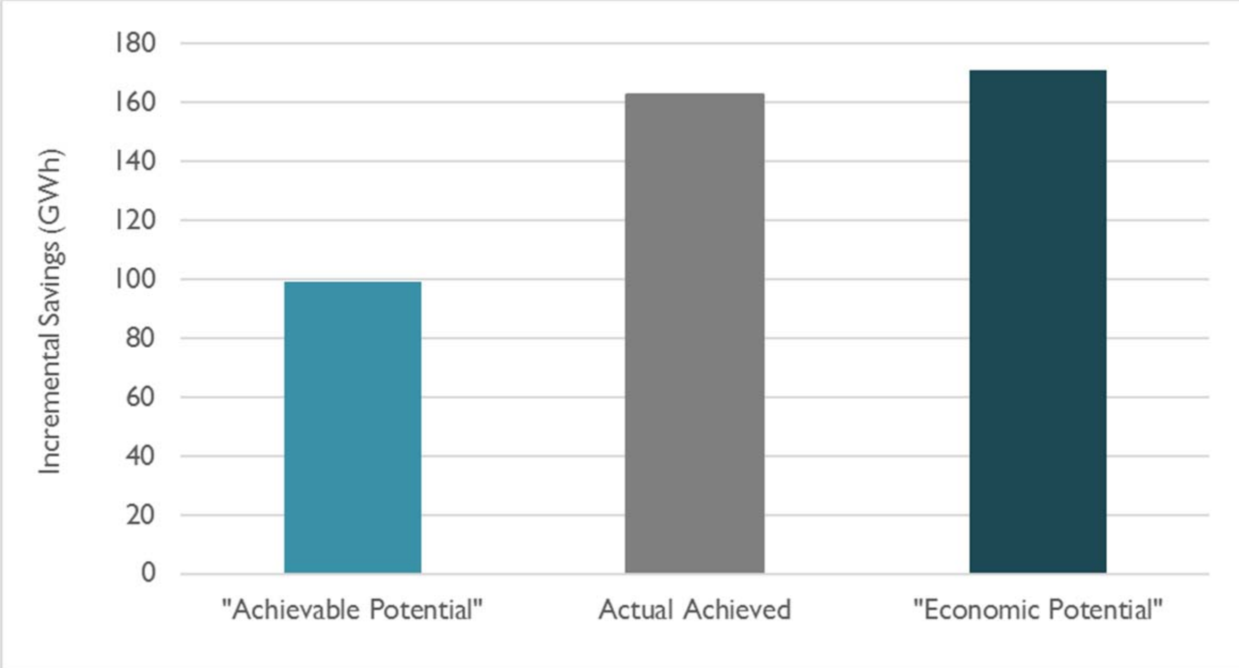
[22] *Id.* Those programs include the Fridge and Freezer Recycling Program, Home Improvement Program, Weatherization Assistance for Qualified Customers, and Weatherization Solutions for Eligible Customers.
[23] IPC 2017 IRP Appendix B – Demand-Side Management 2016 Annual Report, p. 31.
[24] IPC 2017 IRP Appendix C – Technical Appendix, p. 67.
[25] IPC Response to Staff's Data Request No. 14.
[26] EIA. Henry Hub Natural Gas Spot Price. Available at https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm.
[27] U.S. Energy Independence and Security Act. Public Law 110-140. Available at https://www.gpo.gov/fdsys/pkg/BILLS-110hr6enr/pdf/BILLS-110hr6enr.pdf; Energy Conservation Program: Energy Conservation Standards for General Service Lamps; Proposed definition and data availability. October 18, 2016. Available at https://www.regulations.gov/document?D=EERE-2013-BT-STD-0051-0079.
[28] IPC 2017 IRP, p. 50.
[29] AEG. February 23, 2015. Idaho Power Company Energy Efficiency Potential Study. P. 50. Available at https://www.idahopower.com/pdfs/EnergyEfficiency/Reports/2014_DemandSideManagementPotentialStudy.pdf.
[30] EIA. Form EIA-861.
[31] AEG. February 23, 2015. Idaho Power Company Energy Efficiency Potential Study. P. 50.

Figure 3. 2015 incremental savings, AEG projected potentials and actual achieved



Sources: Form EIA-861; AEG 2015 Potential Study.

Based on this evidence, we recommend that IPC's IRP analyses assume future energy efficiency savings that are consistent with its recent savings levels rather than assuming unjustified declines in savings. At a minimum, IPC must evaluate some scenarios in which its energy efficiency savings are consistent with "economic potential" estimates, rather than with "achievable potential" estimates that have consistently proven to be too low.

4.2. IPC assumes certain wind contracts will not be renewed

IPC has adopted an inconsistent approach in its treatment of existing energy contracts. On the one hand, the Company assumes that its Raft River Geothermal contract, expiring in 2033, is replaced. On the other hand, with respect to the Elkhorn Valley Wind contract expiring in 2027, "a replacement contract is not contemplated."[32] The Company does not explain why one contract is assumed to be renewed, but the other is explicitly not to be renewed.

IPC takes a similar approach to PURPA wind and non-wind contracts: "Idaho Power assumes all PURPA contracts, except for wind projects, will continue to deliver energy throughout the planning period, and the renewal of contracts will be consistent with PURPA rules and regulations existing at the time the replacement contracts are negotiated. Wind contracts are not

[32] IRP, p. 95.

expected to be renewed."[33] IPC includes no information suggesting that the wind turbines will be decommissioned at the time of the contract expiration, that the turbine owners have or will have contracts with other parties, or that the wind will cease to blow. It is certainly true that the wind-powered generators may not choose to sign with IPC, but that risk exists with the Raft River Geothermal plant and each of the non-wind PURPA qualifying facilities (QFs) as well.

In its IRP planning, IPC allows approximately 584 MW of wind contracts to expire,[34] but appears to ensure that the remaining 502 MW of contracted renewable-but-not-wind-fueled generators are not allowed to expire during the planning period.[35] IPC's approach is arbitrary and clearly inappropriate. The correct way for IPC to model the renewal of PURPA contracts is to assume, barring any specific evidence to the contrary, that the QF with virtually no operating costs will re-sign a PURPA contract and continue to provide the power to IPC. With respect to non-QF power purchase agreements, IPC should include the resource in a comprehensive capacity expansion modeling exercise, and then allow the optimization model to determine if re-signing the contract is part of a least-cost, least-risk portfolio.

5. WORKPAPER ERRORS BIAS IRP ANALYSES IN FAVOR OF JIM BRIDGER RETROFITS

Sierra Club's review of IPC's workpapers revealed several errors that bias the IRP in favor of the installation of SCR at Bridger. These simple analytical errors result in IPC understating the cost of its SCR installation scenarios by tens of millions of dollars.

5.1. IPC mistakenly neglected to account for long-term Bridger fixed costs under SCR scenarios

In the clearest case of analytical error, IPC did not account for any fixed costs at Bridger Units 1 and 2 beyond 2034.[36] This would be reasonable for the three Bridger scenarios in which both Bridger units retire by 2032. But under the scenario in which IPC installs SCR, the IRP is very clear that both Bridger units continue to operate through 2036.[37] Furthermore, IPC's workpapers make plain that IPC's SCR installation scenarios include generation provided by Bridger Units 1 and 2 in both 2035 and 2036.[38]

[33] IRP, p. 95.
[34] IPC currently has 101 MW with Elkhorn Valley Wind and 55% x 1115 MW = 613 MW of QF capacity under contract. The wind-powered QF capacity total drops to 130 MW by 2033 (IRP, page 95). 101 + 613 – 130 = 584 MW of expired contracts.
[35] 45% x 1115 MW = 502 MW.
[36] Attachment 5 to IPC's Response to Sierra Club Data Request No. 1-2, cells U7:V10.
[37] IPC 2017 IRP, p. 6.
[38] Attachment 3 to IPC's Response to Sierra Club Data Request No. 1-2, tabs "P1," "P2," and "P3."

To quantify the magnitude of this error, we made the simplifying assumption that Bridger Units 1 and 2 would incur the same incremental capital and fixed operational revenue requirements in 2035 and 2036 that IPC expects them to incur in 2034. Under this assumption, the additional Bridger fixed costs in 2035 and 2036 add up to a net present value (NPV) of [redacted]. This value may substantially understate the impact of IPC's error on the valuation of the IRP's SCR retrofit scenarios. This is because the SCR scenarios not only fail to account for any Bridger fixed costs beyond 2034, but they also assume a rapid tapering of incremental capital investment in the years leading up to 2034. Under IPC's modeling, incremental investment in Bridger Units 1 and 2 is [redacted] each year from 2029 through 2034, such that by 2034 investment drops to [redacted] percent below its steady-state 2029 level.[39] It is unlikely that the Bridger units would continue to be reliably operable for long with such a dwindling level of investment. It is therefore likely that a full correction to IPC's mistaken modeling of the SCR scenario Bridger retirement dates would include increased investment in all years from 2030 onward. This would amount to a value greater than the conservative [redacted] figure cited above.

5.2. IPC calculation error results in understatement of Portfolio 1 new resource costs

In a separate analytical error, IPC mistakenly under-counted the cost of the B2H transmission expenditure in Portfolio 1, but not in any other portfolios. In its initial workpapers, IPC treated the Portfolio 1 costs of B2H as commencing in 2027, even though B2H is constructed in 2026 under this portfolio.[40] After Sierra Club pointed this out in a discovery request, IPC acknowledged the error and provided updated workpapers.[41] However, IPC evidently did not update its IRP, because the Company concluded that the correction "has no impact on the relative ranking of this resource or the results of the Company's portfolio analysis."[42] Nonetheless, IPC confirmed that the correction added $11.1 million to the cost of Portfolio 1—the best-performing of the SCR retrofit portfolios.

5.3. NPV Impact of corrections to IPC workpaper errors

Taken together, conservative corrections to the errors in IPC's workpapers amount to an NPV increase of [redacted] in the cost of Portfolio 1. This is significant because Portfolio 1 is easily the lowest-cost Bridger SCR retrofit portfolio that IPC evaluated, and it is one of the two lowest-cost portfolios that can comply with Clean Air Act requirements. In fact, under the NPV results presented in the IRP, Portfolio 1 is shown as having nearly identical total costs as Portfolio 10—

[39] PROTECTED INFORMATION - Attachment to IPC's Response to Sierra Club Data Request No. 1-2, tab "SC 2-4b - Incremental Invest."
[40] Attachment 6 to IPC's Response to Sierra Club Data Request No. 1-2, tab "Fixed Cost Streams- by Resource," cells L21:L22.
[41] Attachment to IPC's Response to Sierra Club Data Request No. 2-7.
[42] IPC's Response to Sierra Club Data Request No. 2-7(a).

the lowest-cost portfolio in which Bridger Units 1 and 2 are retired in 2022 and 2021.[43] The IRP makes it appear that the choice between retrofitting or retiring Bridger Units 1 and 2 is essentially a toss-up. However, with the corrections to IPC's workpapers, it becomes evident that retiring the Bridger units in the early 2020s is preferable to retrofitting them with SCR. Confidential Confidential Table 2 demonstrates the impact of the workpaper corrections on the cost differential between Portfolios 1 and 10.

Confidential Table 2. Net present value costs of Portfolios 1 and 10, as filed and with corrections (million 2016$)

	P1: SCR invest, B2H, recips	P10: Bridger retire in 21 & 22, B2H, recips	P10 Benefit Relative to P1
As Filed	$6,401	$6,401	$0
Bridger Fixed Cost Corrections	[redacted]	[redacted]	[redacted]
Bridger & B2H Cost Corrections	[redacted]	[redacted]	[redacted]

Note: IPC's workpapers present NPV results as in dollar year 2017. However, Sierra Club's review of IPC workpapers clearly shows that IPC discounts all cost streams back to 2016$. Sources: IPC 2017 IRP, Synapse analysis.

6. Input assumptions are consistently (and inaccurately) favorable to Bridger units

The IPC IRP analysis relies on a variety of assumptions that are generally favorable to the Jim Bridger plant. Most importantly, IPC assumes slow growth in coal prices, rapidly increasing market prices, minimal operational environmental costs, and increasing alternative resource costs. Together, these assumptions bias IPC's analysis in favor of the prolonged operation of Bridger Units 1 and 2.

6.1. IPC understates the operational costs associated with SCR controls

SCR systems are widely understood to impose costs on an affected plant that go well beyond weighty up-front construction costs. These additional costs include increases in both variable and fixed operations and maintenance (O&M) expenses.[44] Yet our review of IPC's workpapers indicates that the Company did not account for any SCR-related O&M costs in its modeling of Bridger SCR retrofit scenarios.[45] We therefore relied on technical documents published by the EPA to estimate the impact of SCR on the costs of Portfolio 1, the most cost-effective Bridger retrofit scenario.[46] We found that accounting for the fixed O&M penalties of an SCR increases

[43] IPC 2017 IRP, p. 111.

the NPV cost of Portfolio 1 by $2.4 million, and that the SCR variable O&M penalty increases the NPV cost of Portfolio 1 by $17.2 million.

Confidential Confidential Table 3 shows that, when combined with the corrections to IPC's workpaper errors, the inclusion of SCR-related O&M costs causes Portfolio 1 to become [redacted] more costly than Portfolio 10.

Confidential Table 3. NPV of Portfolios 1 and 10, as filed and with corrections including SCR costs (million 2016$)

	P1: SCR invest, B2H, recips	P10: Bridger retire in 21 & 22, B2H, recips	P10 Benefit Relative to P1
As Filed	$6,401	$6,401	$0
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Sources: IPC 2017 IRP, U.S. EPA; Synapse analysis.

6.2. IPC assumes that Bridger coal prices will decline after years of increasing

IPC assumes that the price of coal burned at the Bridger plant will decline steadily in the near term, and that it will remain below current levels throughout the study period. Under IPC's forecast, the real price of fuel at Bridger declines at an average rate of [redacted] percent per year between 2017 and 2022. Over the two decades from 2016 through 2036, the price of coal declines at an average rate of [redacted] percent per year.[47] This projected decline stands in sharp contrast to the historical growth in the price of fuel delivered to Bridger, which averaged 6.6 percent per year over the past decade, and 1.5 percent per year over the past five years.[48] IPC's projected fuel price decline is also inconsistent with the U.S. Energy Information Administration's (EIA) forecasted stability in the price of coal delivered to power plants in the

[44] See, e.g., U.S. Environmental Protection Agency. October 2001. Cost of Selective Catalytic Reduction (SCR) Application for NOx Control on Coal-Fired Boilers.
[45] Attachment 3 to IPC's Response to Sierra Club Data Request No. 1-2; PROTECTED INFORMATION - Attachment to IPC's Response to Sierra Club Data Request No. 1-2, tab "SC 2-4a – Existing."
[46] U.S. EPA. November 2013. Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model. Page 5-7. Available at https://www.epa.gov/sites/production/files/2015-07/documents/documentation_for_epa_base_case_v.5.13_using_the_integrated_planning_model.pdf.
[47] CONFIDENTIAL Attachment 2 to IPC's Response to Sierra Club Data Request No. 1-2.
[48] Attachments 2 and 5 to IPC's Response to Sierra Club Data Request No. 1-6.

Mountain region.[49] Confidential Figure 4 compares IPC's projected price of Bridger coal to alternative projections based on recent trends in Bridger's fuel price and the growth rates projected in EIA's Annual Energy Outlook (AEO) 2017.

Confidential Figure 4. Alternative Bridger coal price forecasts

[redacted]

Sources: IPC 2017 IRP Workpapers; AEO 2017.

The use of a low coal price forecast clearly favors scenarios in which Bridger continues to operate longer. Specifically, this effect makes Portfolios 1 and 7 (long-term use of Jim Bridger) look better relative to Portfolio 10 (near-term retirement).

6.3. IPC assumes that market prices will increase rapidly

While IPC expects delivered coal prices to decline, it forecasts a rapid increase in the average price of energy that it sells on the market. IPC neglected to provide market price assumptions requested in discovery, and the Company asserted that it could not report energy market

[49] EIA. Annual Energy Outlook 2017. Energy Prices: Nominal: Electric Power: Natural Gas (Region: Mountain). Available at https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2017&region=1-8&cases=ref_no_cpp~highprice~lowprice~highrt~lowrt&start=2015&end=2050&f=A&linechart=~~~~~~~~~~ref_no_cpp-d120816a.106-3-AEO2017.1-8~highprice-d120816a.106-3-AEO2017.1-8~lowprice-d120816a.106-3-AEO2017.1-8~highrt-d120816a.106-3-AEO2017.1-8~lowrt-d120816a.106-3-AEO2017.1-8&map=highprice-d120816a.3-3-AEO2017.1-8&sourcekey=0.

revenues by unit.[50] Nonetheless, we were able to use market sales, purchases, and revenue data contained within IPC's workpapers to calculate the average annual price of power sold and purchased by IPC.[51] We found that under IPC's modeling of its selected portfolio, the average real price received by IPC for its energy sales increases at an average annual rate of 3.3 percent between 2017 and 2036.

It is unclear what is driving IPC's asserted increased energy prices. Over the study period, IPC assumed that the price of natural gas delivered to its power plants will increase at an average annual rate of only 0.5 percent.[52] At the same time, the continued growth of low-marginal-cost renewables is likely to suppress power prices. And yet, IPC evidently expects the real price it receives for market sales to double over the next two decades. Confidential Confidential Figure 5 compares the growth in fuel prices assumed by IPC to the growth in average market energy prices under Portfolio 7.

Confidential Figure 5. IPC forecasted fuel and energy prices relative to 2017 Levels, Portfolio 7

[redacted]

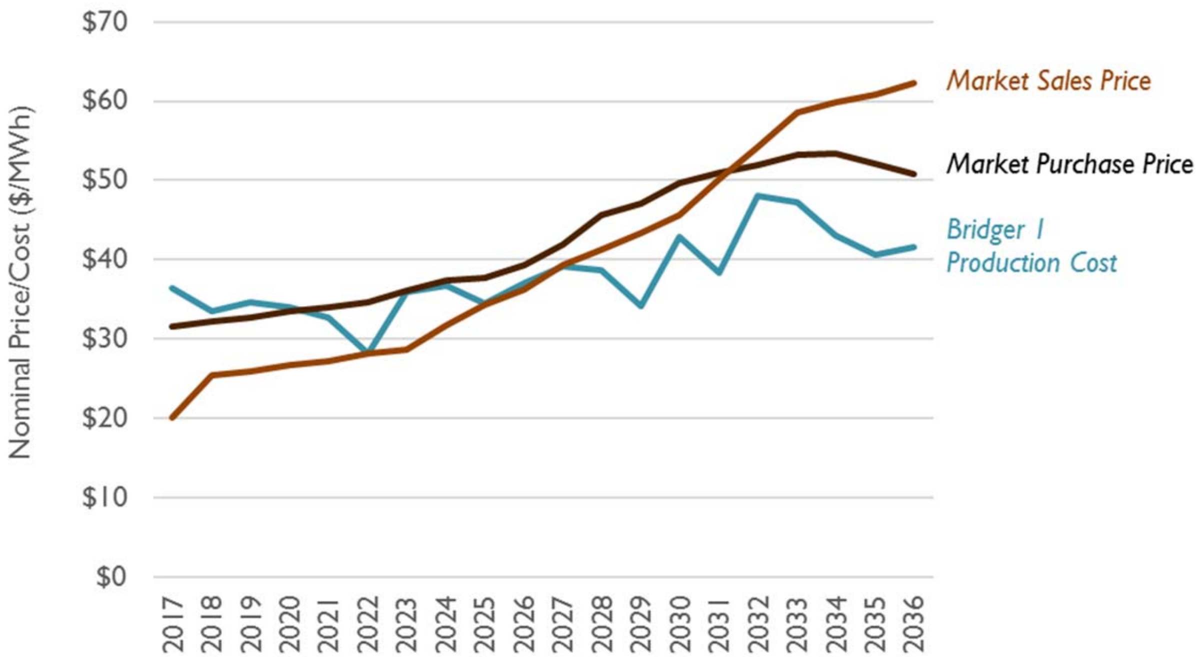
Sources: IPC 2017 IRP Workpapers.

It is the combination of the IRP's assumed decreasing coal prices and increasing market prices, shown in Confidential Figure 5, that makes prolonging the life of Bridger appear economically viable. Figure 6 compares the average production cost of Bridger Unit 1 to the average market

[50] Sierra Club Data Request No. 1-2(a); IPC's Response to Sierra Club Data Request No. 2-2.
[51] Attachment 3 to IPC's Response to Sierra Club Data Request No. 1-2.
[52] Attachment 1 to IPC's Response to Sierra Club Data Request No. 1-2.

energy sales and purchase prices faced by IPC under Portfolio 1.[53] This figure shows that IPC projects that the average production cost of the Bridger units will be higher than the average price at which IPC sells and purchases energy for each of the next four years. This indicates that for those years, the Bridger units will likely not earn enough revenues (or offset enough market purchases) to cover their production costs, to say nothing of their fixed costs.[54] In other words, Bridger would be losing money in the short term, and banking on low coal prices and higher energy prices over the long term to enable it to become profitable. Without the rapid recovery of market prices, Bridger would be an ongoing economic burden to IPC ratepayers.

Figure 6. IPC forecasted market energy prices and Bridger production costs, Portfolio 1



Sources: IPC 2017 IRP Workpapers.

6.4. Solar and battery storage cost assumptions are inflated

The Company's IRP relies on inflated assumptions regarding the future costs of alternative resources. This is especially the case for solar and battery storage resources. IPC's estimates of the current unsubsidized costs of these resources appear to be grounded in the widely respected

[53] Attachment 3 to IPC's Response to Sierra Club Data Request No. 1-2, tab "P1". This chart focuses on Portfolio 1 because it is the lone B2H portfolio that contains Bridger cost and generation data through the end of the study period. The production cost data for Bridger Unit 2 is nearly identical to that of Bridger Unit 1.

[54] It should be noted that it is not clear from IPC's workpapers in which hours Bridger produces, and in which hours IPC purchases and sells energy on the market. It may be that Bridger only produces in the highest-priced hours, whereas IPC engages with the market in lower-priced hours. However, it is unlikely that IPC both purchases from and sells to the market at low-priced hours.

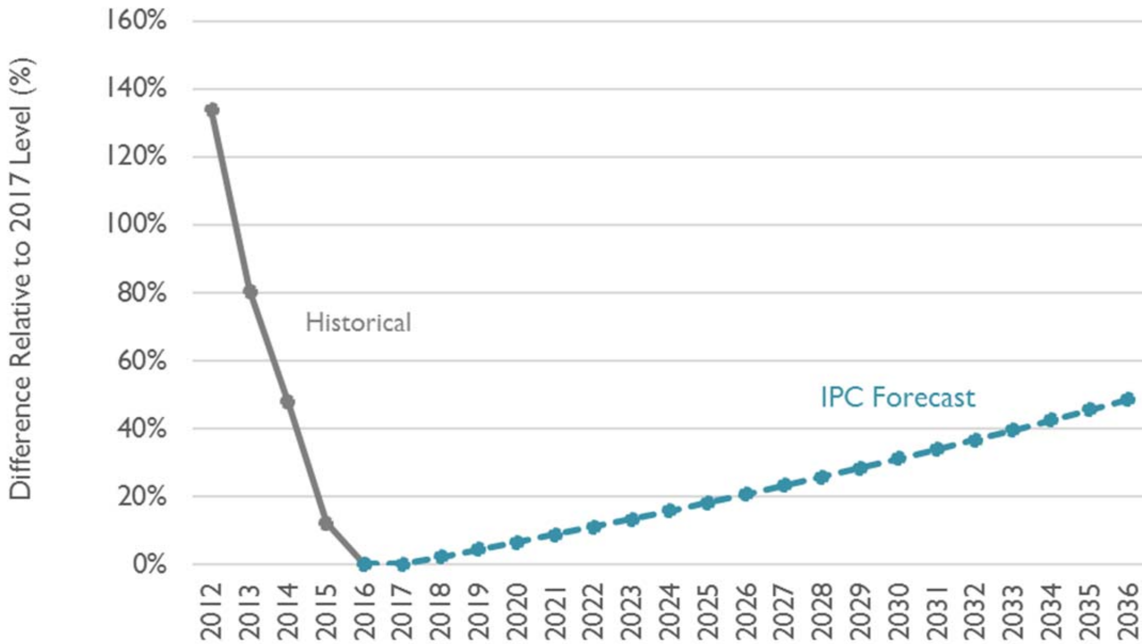
Lazard reports.[55] But, as IPC itself states, the current costs of alternative resources have little impact on the IRP, since none of IPC's portfolios include the near-term procurement of new resources.[56] What most matters in the context of the IRP are the *future* costs of alternative resources. IPC's efforts to accurately model these future costs are not adequate.

IPC's workpapers show that the Company has assumed that the levelized cost of every new resource technology under consideration will increase at an annual nominal inflation rate of 2.1 percent every year between 2017 and 2036.[57] This is equivalent to assuming that all resource costs will stay flat in real terms. Such an assumption may be reasonable for certain mature technologies that are no longer undergoing major improvements. However, it is completely unreasonable to assume that the costs of emerging technologies will increase in this way.

The recent dramatic declines in the cost of solar resources demonstrate the fallacy of IPC's cost inflation assumptions. The very Lazard report cited by IPC shows that the unsubsidized levelized cost of utility-scale solar has declined by 85 percent over the past seven years.[58] While the rate of that decline has diminished somewhat over time, utility-scale solar has nonetheless continued to get cheaper each year. Yet IPC ignores this evidence in assuming that solar costs will transition from their trajectory of decline toward one of steady increase, starting this very year. Figure 7 compares historical and IPC forecasted levelized solar costs, shown in terms of percentage difference from nominal 2017 levels. Under IPC's unjustified assumption of increasing costs, the unsubsidized levelized cost of solar would increase 13 percent between now and 2023, the first year in which solar is procured under any of the IRP portfolios.[59]

[55] IPC 2017 IRP, pp. 35, 89; IPC Response to Staff Data Request No. 59.
[56] See IPC Response to Sierra Club Data Request No. 1-11.
[57] Attachment 6 to IPC Response to Sierra Club Data Request No. 1-2.
[58] Lazard. December 2016. Levelized Cost of Energy Analysis – Version 10.0. P. 10.
[59] IPC 2017 IRP, pp. 99-105.

Figure 7. Utility-scale solar levelized costs relative to 2017 levels, historical and IPC forecast



Sources: IPC 2017 IRP Workpapers; Lazard.

IPC further erroneously overstates the future cost of solar resources by assuming that the solar investment tax credit (ITC) will have fully expired by the time that IPC would build any new solar resources.[60] While it is true that the ITC will be phased down between now and 2023, the tax credit is currently slated to remain at a level of 10 percent for all years from 2022 onwards.[61] Furthermore, the solar ITC is based on the year in which project construction starts, rather than on the in-service date. If IPC was to begin construction in 2021 on solar projects used to meet resource needs in 2023, it would benefit from a 22 percent tax credit.[62]

IPC's assumed future costs of battery storage are likely even more inflated than its solar cost assumptions. This is because most battery storage technologies remain relatively nascent, with major cost efficiency improvements likely still to come. Lazard is one of many industry observers that expects battery costs to decline steadily over the coming years. The Lazard report cited in support of IPC's battery cost assumptions projects that the cost of zinc batteries will decline at a rate of 8 percent per year over the next five years, and that the cost of lithium-energy batteries will drop by 11 percent per year.[63] In spite of this, IPC assumes that the costs of each of these technologies will increase by 2.1 percent per year (see Figure 8). While none of IPC's

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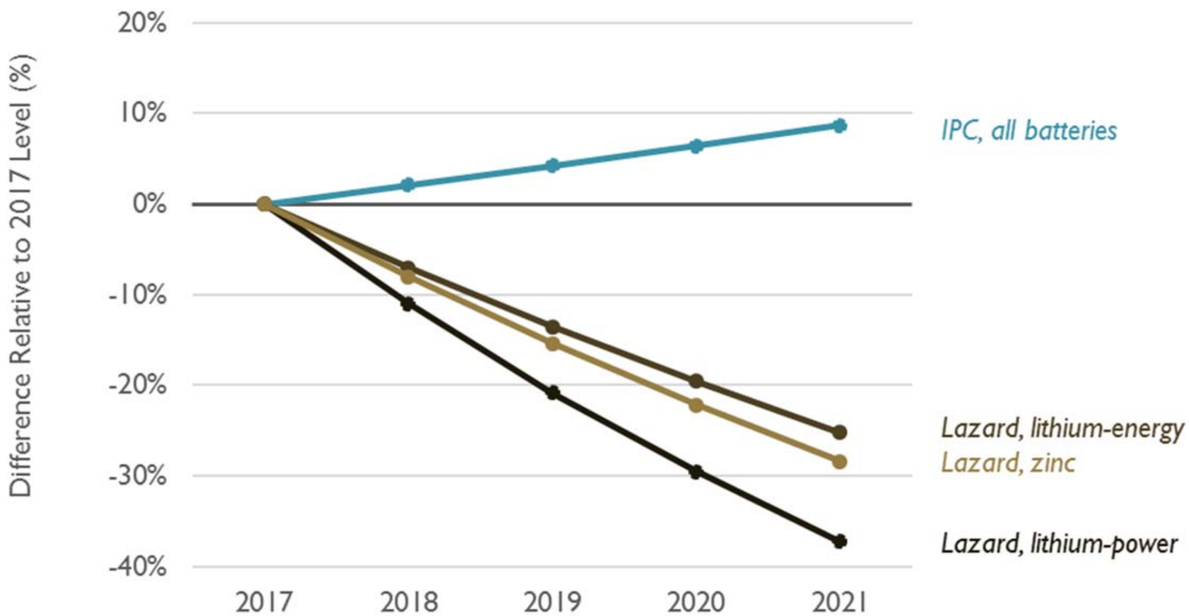
[60] IPC Response to Sierra Club Data Request No. 1-11.
[61] NC Clean Energy Technology Center. February 2017. Database of State Incentives for Renewables and Efficiency: Business Energy Investment Tax Credit (ITC). http://programs.dsireusa.org/system/program/detail/658.
[62] *Id.*
[63] Lazard. December 2016. Levelized Cost of Storage – Version 2.0. P. 20.

manually selected portfolios appear to include battery storage, a proper IRP analysis would include storage as one selectable option. It would then incorporate reasonable assumptions about the future costs of battery technologies.

Figure 8. Battery storage levelized costs relative to 2017 levels, Lazard and IPC projections



Sources: IPC 2017 IRP Workpapers; Lazard.

7. HISTORY AND NEAR-TERM MODELING INDICATE BRIDGER IS NOT ECONOMIC

The Jim Bridger coal plant represents the largest single power plant on IPC's system. With a one-third ownership share, IPC controls 770.5 MW (gross) at Jim Bridger, or 21 percent of IPC's capacity.[64]

In 2015 and 2016, Idaho Power Company and partner PacifiCorp finished the installation of SCR equipment at Bridger Units 3 and 4 to meet obligations under the federal Clean Air Act's Regional Haze Rule. Units 1 and 2 must meet 2022 and 2021 deadlines for the installation of SCR under the same rule. While not active in IPC's dockets reviewing the decision to install SCR at Units 3 and 4, Sierra Club has been a very active stakeholder and intervenor in the economic assessment of Jim Bridger from PacifiCorp's perspective. We have engaged in IRPs since 2011, the 2012 Bridger SCR preapproval cases before the Utah and Wyoming commissions, and a 2016 rate case before the Washington Utilities and Transport Commissions (WUTC). In brief, Sierra Club established in the preapproval cases that moving forward with the

[64] IPC 2017 IRP Appendix C, pp. 110-111.

decision to retrofit Bridger Units 1 and 2 was economically risky and subject to declining gas prices, carbon risk, and potentially increasing coal prices. In a recent prudence review in Washington (WUTC UE-152253), the Commission determined that PacifiCorp had been privy to a forecast of substantially higher coal prices prior to the Company's finalization of the SCR contract for Bridger Units 3 and 4, and that such higher prices had potentially rendered the decision to retrofit imprudent. WUTC subsequently disallowed PacifiCorp's return on investment from the SCR.[65] A prudence case evaluating the 2013 decision to retrofit Units 3 and 4 has not yet come before the Oregon Commission from either IPC or PacifiCorp.

Since 2013, gas prices have remained depressed, and market prices have declined substantially—both as a function of low gas prices and a blossoming of low-cost renewable energy across the Northwest. Coal prices at the Bridger mine have increased substantially, and the Bridger plant is increasingly marginal. This is demonstrated by the collapsing capacity factor of the Bridger plant, and IPC's estimated reduction in capacity factor in the next few years (estimated at about [redacted] percent in IPC's Aurora modeling for 2018–2020).[66]

Getting the future right for Jim Bridger should be a critical part of IPC's planning, and yet the Company has provided an erroneous, misleading, and incomplete analysis of the Bridger plant in this IRP. This analysis leaves the casual reader of the IRP with the distinct impression that Jim Bridger would be economic, if only IPC weren't required to install SCRs in 2021/2022. In fact, Bridger is uneconomic irrespective of the disposition of the SCRs, an outcome shown decisively by IPC's own modeling.

7.1. IPC did not examine the economics of Jim Bridger Units 3 and 4

IPC's IRP neglects to examine the value of Bridger Units 3 and 4. Presumably, the Company determined that an examination of these units was not warranted because these units do not have impending major capital requirements. This is a first-order error. Coal plants in the United States today are often simply marginal—or fully uneconomic—due to persistently low power prices and the cost of maintaining large thermal generation. Navajo, San Juan, Four Corners, Big Brown, and Monticello are all examples of very recently announced large coal-fired power plant retirements for units that are not facing immediate compliance obligations or capital requirements. Instead, the owners and operators of those units simply determined that the continued expenditures required to keep them operational were not worth it.

Sierra Club's recent examination of PacifiCorp's 2017 IRP revealed that Bridger Units 3 and 4 were amongst the least economic in that utility's fleet. Like IPC, PacifiCorp decided not to even assess Bridger Units 3 and 4. However, unlike IPC, PacifiCorp provided sufficient information

[65] Washington Utilities and Transport Commission Docket UE-152253. Order 12.
[66] Attachment 3 to IPC's Response to Sierra Club Data Request No. 1-2.

on fixed costs to allow for an independent evaluation. IPC, on the other hand, simply assumes the ongoing operation of these units, with the incumbent assumption that the fixed costs of Bridger Units 3 and 4 are unavoidable and therefore not worthy of reporting or modeling.

It is neither reasonable nor prudent for IPC to not assess Bridger Units 3 and 4 as part of this IRP. Together these two units incur millions of dollars in capital expenses each year, are instrumental in the future of the jointly owned (and capital intensive) Bridger Coal Mine, and comprise 10 percent of IPC's generation fleet.

Without an examination of Units 3 and 4, the IPC 2017 IRP did not balance cost and risk, or approach any form of least-cost planning.

7.2. Jim Bridger will continue to be uneconomic on a going forward basis

According to the IRP, it is more economic to retain Bridger Units 1 and 2 through 2032 and 2028 (without an SCR) than to retire the units earlier (without an SCR). The implication of this is that if Bridger can avoid an SCR through negotiations with EPA, the units will remain economic. This is definitively not the case; it is based on an inaccurate economic analysis of Bridger's viability, i.e., the flawed analytical structure and erroneous model inputs discussed previously. Our review of the economics of Jim Bridger shows that the plant is highly likely to incur a net loss—under all circumstances—for IPC ratepayers.

Confidential Figure 9, below, shows a cash flow of costs at Bridger Unit 1 derived from workpapers provided in discovery.[67] This figure shows expenditures on fuel, O&M, and amortized capital in Portfolio 1, where Bridger Unit 1 continues to operate through 2036 (though IPC erroneously does not account for any fixed costs in 2035 or 2036, as discussed previously).

The figure shows the all-in cost of Bridger against the **highest possible** cost of market energy, the replacement resource for incremental energy reductions. The cash flow assessment shows that if Jim Bridger were a merchant generator, it would effectively make back just enough on the market to cover the cost of fuel—and lose substantial fixed costs. From 2017 to 2021, Bridger Unit 1 incurs a net loss of about [redacted] per year. After the installation of the SCR, annual losses rise to greater than [redacted] per year. Overall, relative to the market, Bridger Unit 1 loses [redacted] (NPV, 2016$) or [redacted]/kW.

[67] Attachments to IPC Responses to Sierra Club Data Request No. 1-2, 2-4(b), 2-4(c).

Confidential Figure 9. Bridger Unit 1 forward-going costs compared to market cost, Portfolio 1

[redacted]

The fact that Jim Bridger is a rate-regulated resource rather than a market-based generator is relatively immaterial: the utility has an obligation to serve energy with the lowest reasonable costs to its ratepayers. If IPC predicted that Bridger would eventually break out of its loss streak through an expected change in circumstances, the Company might be able to show that ratepayers are best served by holding onto the option of the resource. This is not the case. Bridger does not recover under any of the circumstances IPC itself modeled.

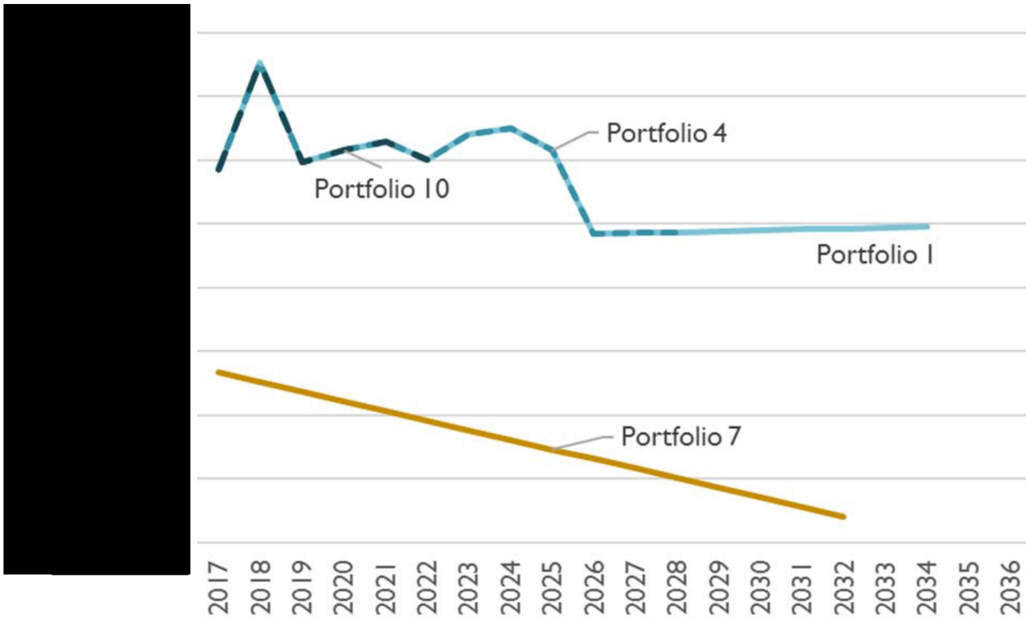
Confidential Figure 10, below, shows the same visualization of a cash-flow analysis, but for Portfolio 7. In this portfolio, Bridger Unit 1 is maintained through 2032 and no SCR is installed. There are two notable features of this graphic relative to Confidential Figure 9, above, aside from the shorter lifespan. First, Bridger Unit 1 does not incur the costs of an SCR, resulting in a substantially smaller capital cost stream (the light blue wedge). Secondly, the fixed O&M stream is substantially smaller than what is shown in Portfolio 1. As a result of these two features, the all-in cost of Bridger Unit 1 is closer to—although still above—market rates until 2028. From 2028 to 2032, Bridger appears less expensive than the market, and thus makes a small amount of margin in that time.

Confidential Figure 10. Bridger Unit 1 forward-going costs compared to market cost, Portfolio 7

[redacted]

The smaller fixed O&M for Bridger Units 1 & 2 in Portfolio 7 is almost certainly an error, as shown in Confidential Figure 11, below. The substantially smaller fixed costs in Portfolio 7 are inconsistent with all other scenarios modeled, and lower than PacifiCorp projections. It is clear that IPC expects the fixed O&M costs of each Bridger unit to remain the same across all Bridger retirement scenarios for all years in which that unit continues to operate. It is unclear how the Portfolio 7 fixed O&M error came about, but it appears to be a transcription error. While we have determined that this error likely did not impact Portfolio selection, it absolutely impacts the valuation of the Bridger units. Overall, the erroneous fixed O&M costs of Portfolio 7 appear to reduce the forward-looking costs of Bridger Units 1 and 2 by over [redacted] NPV. In the sections below, we describe our corrections for this error.

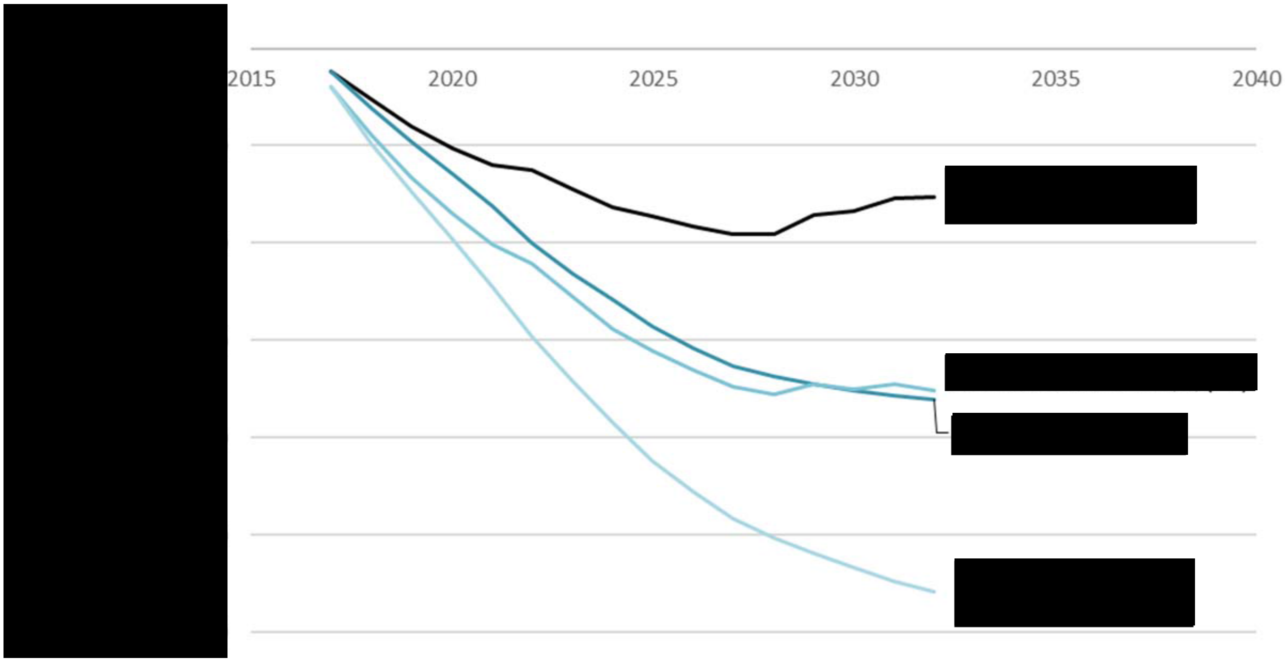
Confidential Figure 11. Bridger Unit 1 fixed O&M for Portfolios 1, 4, 10 and 7



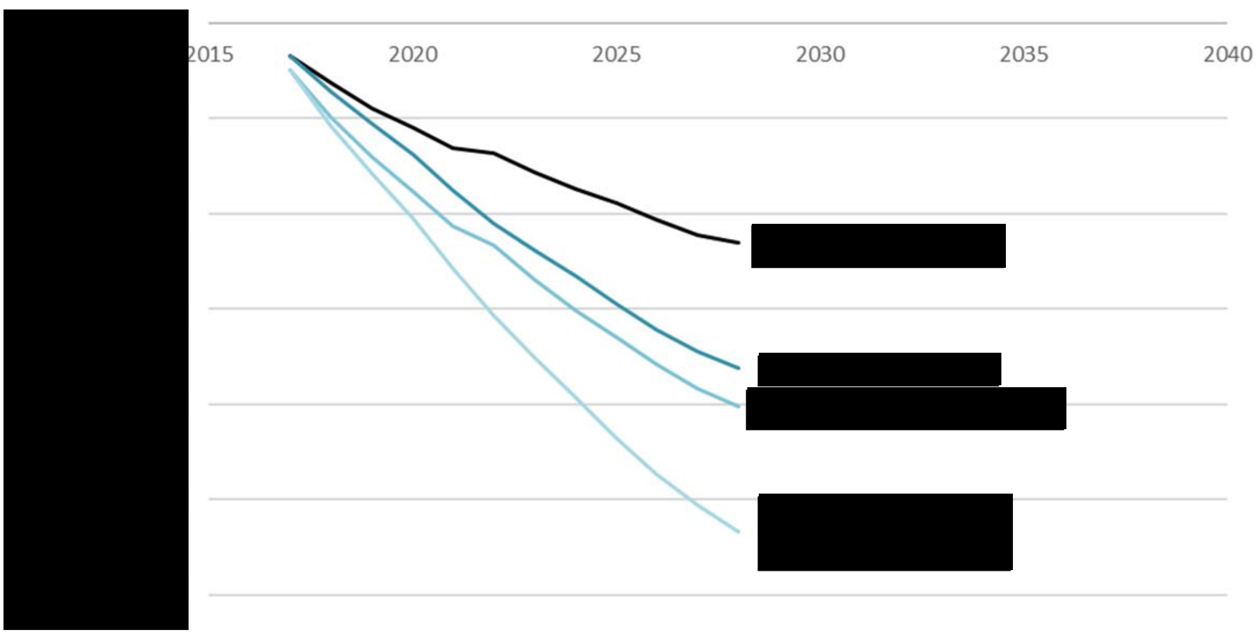
Confidential Figure 12, below, shows the cumulative present worth (CPW) of Bridger Unit 1 as modeled by IPC in "preferred" Portfolio 7 relative to the highest possible cost of energy modeled by IPC. The black line ("IPC Base") represents the accumulating value (or loss, negative) of Bridger Unit 1 through 2032. The steady drop in the black line through 2028 is indicative of ongoing losses relative to the market. The slight uptick near the end represents a small improvement relative to market in the last years of Bridger's life. Overall, IPC would estimate a market value for Bridger Unit 1 of about [redacted] (NPV, 2016$) or [redacted]/kW. Correcting Bridger's fixed O&M values to be consistent with all other portfolios results in the lighter blue line marked "Corrected FOM," and a net liability of [redacted].

We demonstrated in Section 6.2 that IPC predicts coal prices will drop in real terms from 2017 through 2034, a prediction completely antithetical to observed trends at Jim Bridger over the past decade. In addition, IPC estimated that variable O&M costs at Bridger will drop by [redacted] from 2017 to 2022 (from [redacted] to [redacted]), an assumption that is inconsistent with the operations of coal plants throughout the United States. Simply holding the cost of coal and variable O&M costs steady at 2017 levels (plus inflation) has a dramatic impact on the viability of Bridger Unit 1 in this same scenario. Accounting for both the corrected fixed O&M and flattened fuel and variable O&M costs, Bridger Unit 1 emerges as a [redacted] liability through 2032, losing value each and every year. The story at Bridger Unit 2 is no different, as shown in Confidential Figure 13, below.

Confidential Figure 12. Value of Bridger Unit 1 under Portfolio 7, as modeled and with various corrections



Confidential Figure 13. Value of Bridger Unit 2 under Portfolio 7, as modeled and with various corrections



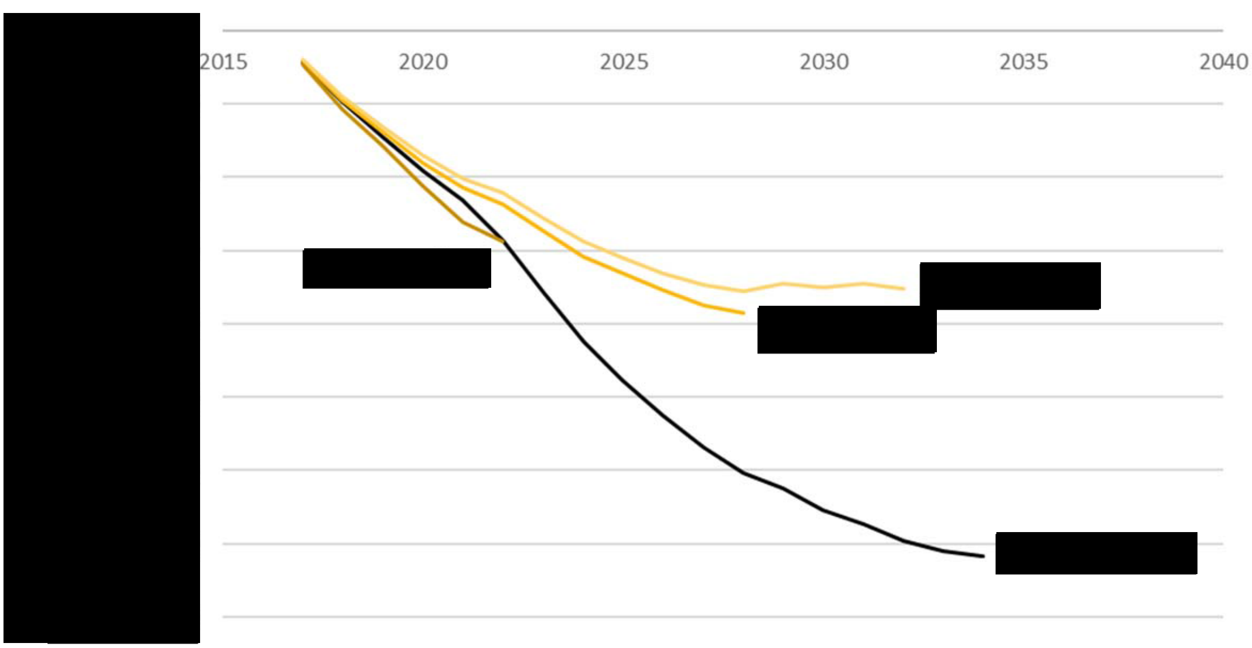
While we believe these fuel and variable O&M corrections to be valid, we do not rely on those adjustments for our basic point. The fixed O&M schedule under Portfolio 7 is clearly an error. Once this schedule is made consistent with fixed O&M costs in Portfolio 1, the IRP results are much clearer—and far more intuitive. Jim Bridger loses money each and every year that it is online—irrespective of whether it has an SCR obligation or not.

Confidential Figure 14, below, shows the value streams of Bridger Unit 1 under Portfolios 1, 4, 7, and 10—the various retirement options in which B2H is constructed. The Portfolio 1 results indicate that if, in fact, Bridger Unit 1 were required to obtain an SCR, the unit would ultimately cost ratepayers more than [redacted] above market energy procurement costs (conservatively). However, the three yellow lines are yet more useful. The close trajectories of Portfolios 10 (2022), 4 (2028) and 7 (2032) show that Bridger will continue to cost ratepayers—and the longer the units remain online, the deeper the obligations become. This means that solutions not modeled by IPC—including a 2018 or 2020 retirement or disentanglement from Bridger—would have resulted in substantial savings relative to the potential costs still yet to be incurred.

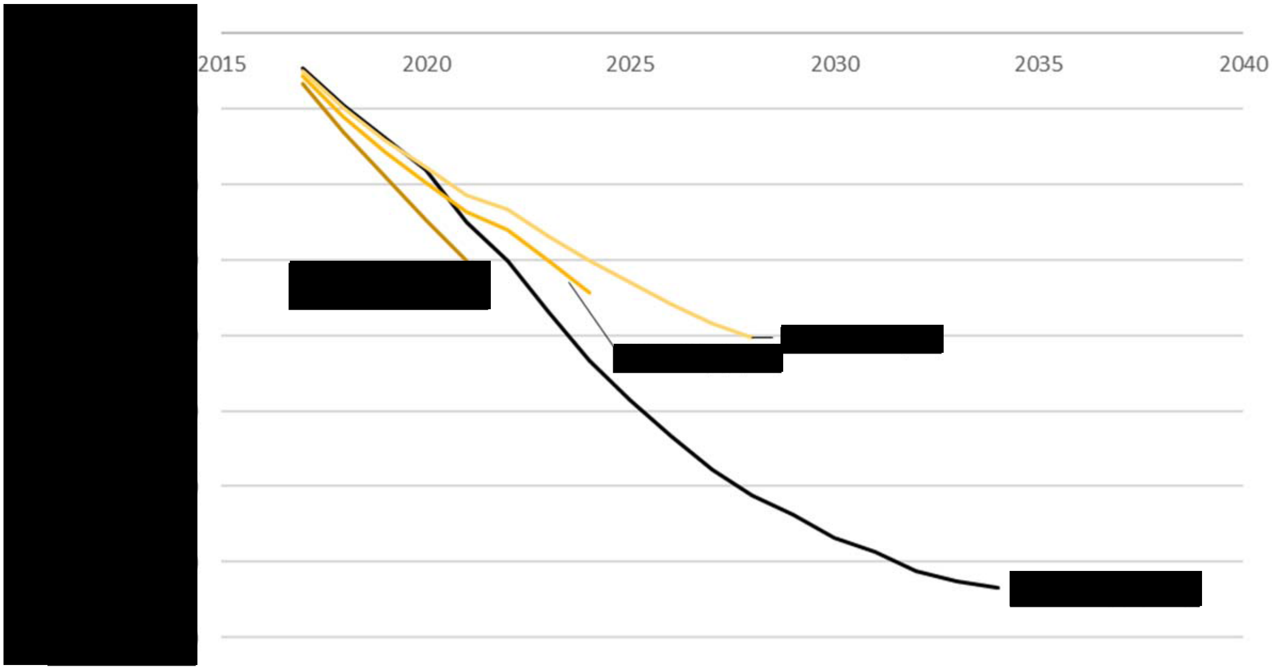
These results show that Portfolio 7 is **not** the least-cost or least-risk resource plan available to IPC, and of the portfolios modeled by IPC, Portfolio 10 should result in the least cost to consumers.

Confidential Figure 15 shows nearly identical results for Bridger Unit 2.

Confidential Figure 14. Value of Bridger Unit 1 under various portfolios, with correction to fixed O&M in Portfolio 7



Confidential Figure 15. Value of Bridger Unit 2 under various portfolios, with correction to fixed O&M in Portfolio 7



8. IPC RISK ANALYSES ARE POORLY APPLIED

Finally, the comments below address IPC's risk analysis structure. As an initial matter, a risk analysis is a method of testing and stressing a model result. In this case, it tests the different resource portfolios created by IPC. However, if those portfolios are not optimal, or are based on biased or incorrect input assumptions or analysis structures, the risk analysis is meaningless. Nonetheless, these comments can still inform future risk analyses performed by IPC.

Risk analyses are often run through a stochastic, or randomized, modeling framework. They can help a utility understand the risks associated with different resource portfolios. Better understanding the risk profile associated with different portfolios can be influential because "the goal of the IRP is to identify the mix of all available resources that provide an adequate supply of energy at the least cost and risk to the utility and its customers."[68] An effective stochastic analysis (1) identifies key inputs, (2) identifies the statistical properties those inputs will exhibit in future years, and (3) analyzes the levelized cost of various portfolio strategies under a variety of outcomes for the key inputs.

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[68] Public Utility Commission of Oregon, "Frequently Asked Questions – General Integrated Resource Plan (IR) Information," accessed October 23, 2017. Available at: http://www.puc.state.or.us/admin_hearings/IRP-FAQs.pdf.

IPC identifies three variables for stochastic analysis "based on the degree to which there is uncertainty regarding their forecasts and the degree to which they can affect the analysis results (i.e., portfolio costs):" natural gas price, customer load, and hydroelectric variability. [69] IPC did not identify coal prices as a variable worthy of stochastic analysis.

8.1. Natural gas prices

IPC models natural gas prices as a "log-normal distribution adjusted upward from the planning case gas price forecast."[70] A log-normal distribution may be an appropriate distribution for natural gas prices, and the year-to-year variability value of 0.6 may also be reasonable (although historical values in the pre-hydrofracking 1997–2007 era may fail to correctly capture year-to-year variation). However, an appropriate stochastic analysis of natural gas price would allow for prices to climb or fall. Rather than capture results associated with unexpectedly low gas prices as well as unexpectedly high prices, the IPC stochastic analysis has "natural gas prices adjusted upward from the planning case to capture upward risk in natural gas prices."[71] This technique captures the downside risk of building more natural gas generation, but it makes no attempt to quantify the risk that a decision to continue operating the Bridger plant will be a poor one due to unexpectedly low gas prices. By introducing statistical bias to the distribution function, IPC fails to correctly measure risk. The correct way to model natural gas prices in a stochastic analysis is to select a distribution wherein the median aligns with the forecasted gas price trajectory.

8.2. Customer load

IPC modeled customer load with a normal distribution, and with the distribution median aligned with the planning case load forecast. IPC implemented the stochastic analysis with randomly sampled customer consumption in 2017, but it then applied an identical growth rate for each of the 100 samples for years 2018–2036. It is an absurd notion that on the one hand IPC cannot predict next year's load to within 30 percent, but on the other hand it is absolutely certain of the year-on-year growth for each year between 2018 and 2036. There is considerable risk associated with customer load in future years, and that risk is highly dependent on the load growth rate. This is a value which IPC makes no attempt to model stochastically. The correct way to model customer load growth is similar to how IPC modeled both natural gas prices and hydroelectric variability—with random walks in which both (a) there is year-to-year variation, the result of random fluctuations of weather and other factors, and (b) there is systemic variation of the trajectory of the random walk, to represent the uncertainty surrounding the rate at which long-

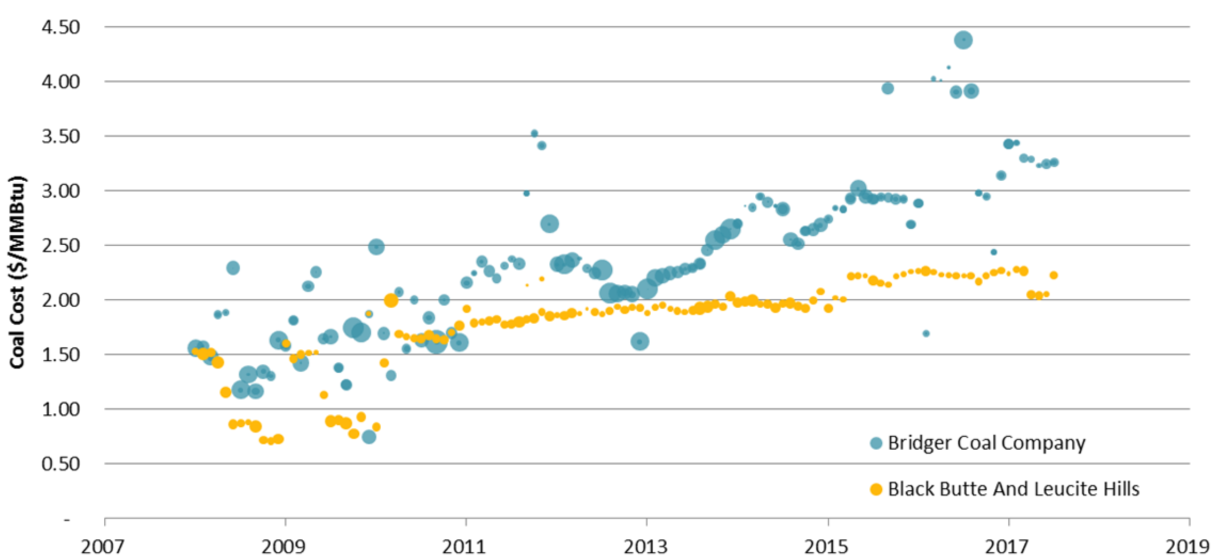
[69] IRP, p. 114.
[70] IRP, p. 114.
[71] IRP, p. 114.

term load is growing. By not taking a stochastic approach to year-on-year load growth, IPC has failed to correctly model the risk associated with its load growth forecasting.

8.3. Coal prices

Inexplicably, IPC did not include the uncertainty of coal prices in its stochastic analysis. Jim Bridger is supplied by Black Butte and Bridger Mine. Historically, Black Butte has served approximately one-third of Bridger's requirements, while Bridger Mine has served the remainder from an older surface mine and a newer underground mine. Bridger Mine is owned by Bridger Coal Company, a wholly owned subsidiary of a PacifiCorp and IPC partnership. Despite being a mine-mouth facility with regulated utility ownership, the cost of coal from Bridger Mine has been anything but predictable over the last decade, as shown in Figure 16, below.[72] Coal quality problems at the underground mine have led to a continuous re-allocation and long-term planning process. Recently, PacifiCorp reported that an expensive longwall miner had been extensively damaged during operations,[73] causing another delay in mining activities. Overall, the cost of coal procured for Bridger plant has varied substantially over time.

Figure 16. Coal deliveries to Jim Bridger plant



Source: EIA Form 923, compiled 2008-2017.

[72] Figure maps each coal delivery reported to EIA Form 923. The size of each dot is proportional to the quantity (tons) of fuel delivered. Note that since 2010 Bridger Coal Company reports the all-in cost of coal, equivalent to the wholesale cost of the coal, rather than just the "cash cost" (i.e. not including capital).

[73] See Oregon Docket UP 354. Page 2-3. "Due to unforeseen events and deteriorating geological conditions, the Joy longwall system lost its advancement capabilities, and BCC stopped using it in October 2016 because the equipment could no longer be safely restored to operation. BCC was able to recover miscellaneous components from the Joy longwall system, including the mine-owned shearer that was in production at the time."

IPC should have included coal prices in its stochastic analysis. The correct way to model the coal price stochasticity is very similar to the correct way to model gas price stochasticity—with a log-normal or similar distribution wherein the median of the distribution aligns with the forecasted coal price trajectory. The variability of the price should reflect all of the risks associated with the mine detailed above.

8.4. Lack of portfolio response to stochastic variation

In calculating the costs of each of the 12 studied capacity buildouts in each of 100 different iterations, IPC locks in the capacity procurement—even in the latter years. While this preserves IPC's ability to consistently compare outcomes across the same set of portfolios, the outcomes it compares are not useful. For example, in cases where the stochastic iteration of customer load grows more slowly than in the forecast, IPC continues to procure generating assets on the same *a priori* schedule, despite those resources no longer meeting a required need. The resulting comparison informs the reader that one imprudent procurement costs less than another imprudent procurement. This provides no information about the risks associated with ensuring the ability to reliably serve customers in a prudent manner. The correct way to implement the stochastic analysis is to allow a capacity expansion model to select the most cost-effective resources that ensure reliability in each of the 100 different iterations. The procured portfolios would be different, which is a sensible result for an experiment where the inputs are altered.

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Respectfully submitted,

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BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

In the Matter of IDAHO POWER COMPANY, 2017 Integrated Resource Plan	Docket LC 68

CERTIFICATE OF SERVICE

I hereby certify that on this 31st day of October, 2017, I caused to be served the foregoing Sierra Club Opening Comments upon all party representatives on the official service list for this proceeding via electronic mail. The public version of this document was served upon parties via email, and the confidential portion of this document was served pursuant to Protective Order No. 17-292 upon all eligible party representatives via U.S. Mail.

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