Rose Monahan (CA Bar No. 329861)
Staff Attorney
Sierra Club Environmental Law Program
2101 Webster Street, Suite 1300
Oakland, CA 94612
(415) 977-5704
rose.monahan@sierraclub.org

Attorney for Sierra Club

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of PacifiCorp's 2021 Integrated Resource Plan	Docket No. 21-035-09

Sierra Club's Opening Comments

Redacted Version

March 4, 2022

TABLE OF CONTENTS

I. Introduction and Recommendations **1**

A. Key Conclusions and Observations of PacifiCorp's 2021 IRP 4

B. Summary of Recommendations 6

II. PacifiCorp's Assumptions Regarding the Utah Community Renewable Energy Program Are Inconsistent with Utah Statute and Public Sentiment. **9**

III. PacifiCorp's Methodological Choices for Reliability and Resource Adequacy Raise Significant Concern. **12**

A. There Are Inconsistencies Between PacifiCorp's Capacity Contribution Study and the Preferred Portfolio with Respect to the Capacity Value of Solar Plus Storage, Potentially Leading to Overbuild of Coal Replacement Resources. 12

B. PacifiCorp's Application of a 13 Percent Hourly Reserve Margin to Individual Load Areas Is Not Fully Justified. 15

1. Reliability metrics 17

2. Binding transmission limits 17

C. PacifiCorp's Portfolio Development Process Included a Non-Transparent Post-Modeling "Reliability Adjustment" that Lacked Adequate Supporting Data or Analysis. 18

IV. Coal Unit Economics and Plant Retirements **21**

A. PacifiCorp Failed to Include a Unit-By-Unit Coal Analysis Consistent with the 2019 IRP. 21

B. PacifiCorp Inappropriately Assumes a Significant Share of Its Future Coal Fuel Expenditures Are "Sunk Costs" in the Form of Future Take-Or-Pay Contracts. This Assumption Significantly Constrains Any Coal Retirement Analysis Since These Costs Would Never Materialize if the Plants Retired Early. 25

1. The Jim Bridger and Huntington take-or-pay assumptions cloud PLEXOS' ability to potentially recognize significant coal fuel savings from reduced output and/or early retirements. 30

2. PacifiCorp's coal fuel pricing tier assumptions lack any clear explanation or justification. 32

C. The P02h Variant Case (Jim Bridger Units 3 and 4 Early Retirement) Is Lower in Cost than PacifiCorp's Preferred Portfolio (P02-MM-CETA). This Is True Despite Questionable Assumptions that Needlessly Inflate the Cost of the P02h Variant Case. 33

D. PacifiCorp's IRP Did Not Fully Assess the Risks Associated with the Early Exit of Its Coal Plant Co-Owners. 35

TABLE OF CONTENTS (CONT.)

E. PacifiCorp's IRP Failed to Evaluate a Feasible Scenario in Which EPA Requires SCR Installations to Comply with the Clean Air Act. 37

F. PacifiCorp's P03 Early Coal Retirement Case Is Misleading on Increased Costs (Relative to the Preferred Portfolio), as These Increases Are Partly Driven by Deficiencies and Subjective Choices in the Company's Modeling Methodology. 40

V. PacifiCorp's Expectation that it Will Receive Power from the Natrium Plant, a Novel Nuclear Technology, by 2028 Introduces Substantial Cost and Execution Risks that Were Not Adequately Addressed in the IRP. 41

VI. Risks Related to the Jim Bridger Gas Conversion 46

A. Overview of PacifiCorp's Proposed Coal-to-Gas Conversion of Jim Bridger Units 1 and 2 46

B. PacifiCorp's Proposed Gas Conversion Comes with Significant Price Risk. 47

C. The Risk of Fuel Cost Volatility Is Borne by Customers, Not Shareholders. 51

D. PacifiCorp's IRP Contains Unresolved Questions about the Coal-to-Gas Conversion Analysis. 52

E. PacifiCorp and Idaho Power Do Not Appear to Be Aligned on the Gas Conversion Proposal. 53

VII. PacifiCorp's Long-Term Resource Cost Assumptions Are Not Fully Informed by the Recent All-Source RFP Results. 54

LIST OF TABLES

Table 1. Comparison of PacifiCorp's Coal Unit Costs and Proposed Retirement Dates............ 23

Table 2. System Optimizer Results from PacifiCorp's 2019 IRP Coal Retirement Analysis 25

Confidential Table 3. Take-or-Pay Volumes (in Millions of Tons) Assumed by PacifiCorp in PLEXOS for Future Years at the Huntington and Jim Bridger Plants 27

Table 4. Net Present Value for Coal Plants With and Without SCRs.. 39

LIST OF FIGURES

Figure 1. Historic Henry Hub Prices and PacifiCorp's IRP Natural Gas Price Forecast 48

Figure 2. Henry Hub Prices Since January 2020, and PacifiCorp's Gas Price Forecast.............. 49

Figure 3. U.S. Natural Gas Production 50

LIST OF ATTACHMENTS

Attachment 1	Selected PacifiCorp Public Data Responses in LC 77
Attachment 2	Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 3.1 in LC 77
Attachment 3	Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 4.2 in LC 77
Attachment 4	UE 390, Surrebuttal Testimony of Dana M. Ralston on Behalf of PacifiCorp (PAC/1200) (excerpt)
Attachment 5	Confidential Attachment to PacifiCorp Response to CUB Data Request 1 in LC 77

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of PacifiCorp's 2021 Integrated Resource Plan	Docket No. 21-035-09

SIERRA CLUB'S OPENING COMMENTS
[REDACTED]

I. Introduction and Recommendations

Sierra Club appreciates the opportunity to comment on PacifiCorp's 2021 Integrated Resource Plan ("IRP"). These comments were prepared with the assistance of Strategen Consulting, and they are based on a review of PacifiCorp's input assumptions and analytical approach. These comments are further informed by Sierra Club's active participation in PacifiCorp's 2021 IRP public input meetings and all previous PacifiCorp IRP processes going back to 2011.

As a preliminary matter, it is PacifiCorp's responsibility to demonstrate that its plans and actions are in the public interest. Unfortunately, the Company did not meet this requirement with the 2021 IRP. As our comments show, not only has the Company modeled costs, such as the take-or-pay coal contracts, in a manner that unduly favors its coal fleet, but the Company has also omitted critical information supporting its assumptions and modeling choices that are essential for stakeholders and the Commission to adequately evaluate PacifiCorp's analyses and the resulting portfolios.

The omissions throughout the IRP are significant and represent an unacceptable risk for Utah customers. For example, (which is further described in Section III(C) below), the Company included a second nuclear plant in the P02h variant case,[1] thereby adding a significant cost to that portfolio. Despite touting its "extensive public-input process," Sierra Club only learned in November 2021, through informal conversations with the Company, that the second nuclear plant was not economically selected but rather was manually forced in to the variant case to meet a reliability need; yet, neither the IRP nor any of the Company's written analyses explain the number of hours, the time of year, or the shortfall of this purported reliability need. This information was only disclosed as a result of Sierra Club's data requests. Compounding this lack of transparency, the IRP does not describe which resources the Company considered when manually filling this unquantified reliability gap or why it determined a second nuclear plant was the best fit. Sierra Club highlights this one example to demonstrate the pervasive shortcomings of this IRP, particularly its lack of transparency concerning critical assumptions and subjective decision-making that went into the analysis and undoubtedly had significant implications for each portfolio, including the preferred portfolio.

Furthermore, it is the resolution of the State of Utah to "prioritize our understanding and use of sound science to address causes of a changing climate and support innovation and environmental stewardship in order to realize positive solutions," according to the 2018 Concurrent Resolution on Environmental and Economic Stewardship.[2] The science is clear that society must act aggressively and decisively to eliminate its reliance on fossil fuels, and yet, Rocky Mountain Power customers must pay for one of the most carbon-intensive energy mixes in the country. The Intergovernmental Panel on Climate Change has stated that human-caused

[1] Jim Bridger Units 3 and 4 Early Retirement Variant (P02h-JB3-4 Retire). PacifiCorp, *2021 Integrated Resource Plan*, Vol. I at 287-289 (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 [hereinafter "PacifiCorp 2021 IRP Vol. I"].
[2] H.C.R. 7 (2018).

emissions of carbon dioxide need to fall by 45 percent from 2010 levels by 2030, reaching "net zero" emissions by 2050 in order to have a realistic chance of limiting global warming to 1.5 degrees Celsius.[3] Indeed, even PacifiCorp implicitly recognizes this necessity by modeling nonexistent "non-emitting peaker" resources; yet, the Company continues to unduly favor its coal fleet and undervalue clean, renewable resources. Unlike utilities across the country committing to "bold vision[s]" for a "carbon-free future,"[4] PacifiCorp continues to describe its coal fleet as playing "a pivotal role"[5] and is one of the only major utilities to lack a climate action plan.

A business-as-usual approach to electric sector energy planning will ultimately result in millions of Americans losing their homes and communities to what President Biden has described as a "merciless march of ever-worsening droughts and floods, more intense fires and hurricanes, longer heatwaves and rising seas."[6] In just the past few years, Utah has experienced many of these catastrophes, including droughts, heatwaves, and mega-fires. This year alone, the wildfires in the western U.S. burned an area larger than Delaware and Rhode Island combined, impacting air quality in states as far away as Vermont and Maine.[7]

---

[3] IPCC, *Summary for Policymakers of IPCC Special Report on Global Warming of 1.5C approved by governments* (Oct. 8, 2018), *available at* https://www.ipcc.ch/2018/10/08/summary-for-policymakers-of-ipcc-special-report-on-global-warming-of-1-5c-approved-by-governments/.

[4] [4] *See, e.g.,* Public Service Company of Colorado (Xcel Energy), *Our Energy Future Destination 2030: 2021 Electric Resource Plan and Clean Energy Plan*, Colorado PUC Proceeding No. 21A-0141E, Vol. 1 at 19 of 73 (Mar. 31, 2021), *available at* https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Resource%20Plans/Clean%20Energy%20Plan/Vol_1-Plan_Overview.pdf.

[5] PacifiCorp 2021 IRP Vol. I at 15, 299.

[6] White House, *Remarks by President Biden Before the 76th Session of the United Nations General Assembly* (Sept. 21, 2021), *available at* https://www.whitehouse.gov/briefing-room/speeches-remarks/2021/09/21/remarks-by-president-biden-before-the-76th-session-of-the-united-nations-general-assembly/.

[7] Aya Elamroussi, *Wildfires have burned a combined area the size of Delaware and Rhode Island – and then some*, CNN, July 28, 2021, *available at* https://www.cnn.com/2021/07/28/weather/western-wildfires-wednesday/index.html.

The need and urgency for action cannot be overstated. The Commission can and must do more to require meaningful action from PacifiCorp to reduce emissions in accordance with current Utah policy and sound science by transitioning to a clean energy fleet. Sierra Club urges the Commission to closely scrutinize PacifiCorp's 2021 IRP and implement the recommendations below.

A. Key Conclusions and Observations of PacifiCorp's 2021 IRP

These comments are organized into the following five key subject matters:

1. Utah Community Renewable Energy Program
2. PacifiCorp's methodological choices related to reliability
3. Coal unit economics and plant retirements
4. The proposed Natrium nuclear power plant
5. The proposed conversion of Jim Bridger 1 and 2 to burn natural gas
6. Barriers to future clean energy deployment

Based on the analysis it has conducted to date on PacifiCorp's IRP, Sierra Club has developed the following set of key conclusions and observations:

Topic 1: Utah Community Renewable Energy Program

- PacifiCorp wrongly assumes that it can meet the requirements of Utah's Community Renewable Energy program with existing renewable resources

Topic 2: Concerns over methodological choices related to reliability

- There are inconsistencies between PacifiCorp's capacity contribution study and the Preferred Portfolio with respect to the capacity value of solar plus storage. This differential may be leading to overbuild of coal replacement resources.

- PacifiCorp's application of a 13 percent hourly reserve margin was not fully justified and may be overly conservative.
- PacifiCorp's portfolio development process included a non-transparent post-modeling "reliability adjustment." This step lacked adequate supporting data or analysis.

Topic 3: Coal unit economics and plant retirements

- PacifiCorp failed to include a unit-by-unit coal analysis as it had done in 2019. This essential step provides a check on the reasonableness of retirements included in its portfolio-wide analysis.
- PacifiCorp inappropriately assumes a significant share of its future coal fuel expenditures are "sunk costs" in the form of future take-or-pay contracts. This assumption significantly hampers any coal retirement analysis since these costs would never materialize if the plants retired early.
- PacifiCorp's coal fuel pricing tier assumptions lack any clear explanation or justification.
- The P02h variant, which retires Jim Bridger Units 3 and 4 before 2030, is lower in cost than PacifiCorp's Preferred Portfolio. This is true despite questionable assumptions that needlessly inflate the costs of the P02h case.
- The IRP did not fully assess the risks associated with Idaho Power's early exit from the Jim Bridger plant.
- PacifiCorp did not adequately assess the risk of a scenario in which selective catalytic reduction ("SCR") installations are required at coal units in both Utah and Wyoming.

- PacifiCorp's P03 Early Coal Retirement Case paints a misleading picture of increased costs (relative to the Preferred Portfolio), since these increases are partly driven by deficiencies and subjective choices in the Company's modeling methodology.

Topic 4: Risks related to the Natrium nuclear plant

- PacifiCorp's expectation that it will receive power from a novel nuclear technology by 2028 may be unrealistic and introduces substantial cost and execution risks that are not adequately addressed in the IRP.

Topic 5: Risks related to the Jim Bridger gas conversion

- PacifiCorp's planned coal-to-gas conversion of Jim Bridger Units 1 and 2 by 2024 carries significant fuel cost risk that is borne almost exclusively by ratepayers.
- The recent rise in natural gas prices has already outpaced PacifiCorp's forecast for prices in 2034, further indicating that customers may be at significant risk of higher fuel costs than what PacifiCorp has anticipated.
- If recent price trends continue, PacifiCorp's plan to burn natural gas at Jim Bridger 1 and 2 (rather than retire the units) could subject customers to additional costs on the order of $230 million present-value revenue requirement ("PVRR").

Topic 6: Barriers to clean energy development

- PacifiCorp's long-term resource cost assumptions are not fully informed by the recent all-source RFP results

B. Summary of Recommendations

Based on Sierra Club's analysis of these five topics, we make the following recommendations:

Topic 1: Utah Community Renewable Energy Program

- *Recommendation 1*: The Commission should direct PacifiCorp to revise its IRP input assumptions to ensure that a) 100 percent of the resources associated with this program are from incremental resources, b) assumed participation rates are more representative of public opinion (e.g., >50 percent).

Topic 2: Concerns over methodological choices related to reliability

- *Recommendation 2:* The Commission should direct PacifiCorp to provide more detail on the capacity value of solar plus storage assumed in each year of its model, and justify the decline in capacity value after 2030. This detail and explanation should be provided in all future IRPs.

- *Recommendation 3:* The Commission should direct PacifiCorp to define a specific reliability metric for evaluating its resource portfolios along with a specific performance target as well as clearly identifying transmission constraints impacting load area's ability to meet planning reserve margins.

- *Recommendation 4*: The Commission should direct PacifiCorp to provide the hourly results of its reliability analysis, prior to making any reliability-related cost adjustments or other portfolio refinements. The Commission should also direct PacifiCorp to identify which resources in each portfolio were added manually as part of the "portfolio refinement" step and provide a detailed justification for why that specific resource type was selected and what alternatives were considered.

Topic 3: Coal unit economics and plant retirements

- *Recommendation 5*: The Commission should direct PacifiCorp to continue conducting a unit-by-unit coal retirement analysis as performed in 2019 (but not in 2021) for the 2021 IRP and in all future IRPs.

- *Recommendation 6*: The Commission should direct PacifiCorp to conduct an additional model run in this IRP cycle that does not include any take or pay assumptions. This should become standard practice for all future IRP cycles.

- *Recommendation 7*: The Commission should require that the dispatch of coal resources modeled in future IRPs is based upon the total or "average" fuel costs over a period of 1 or more years (rather than some lower incremental value within each year).

- *Recommendation 8*: The Commission should direct PacifiCorp to evaluate the P02h variant portfolio for Washington Clean Energy Transmission Act ("CETA") compliance and assess whether it should be considered as a potential replacement for the Preferred Portfolio.

- *Recommendation 9*: The Commission should direct PacifiCorp to model a variant of its Preferred Portfolio that includes PacifiCorp absorbing Idaho Power's share of Jim Bridger plant costs from 2028-2037. PacifiCorp should also be required to compare this variant to retiring the plant by 2028.

- *Recommendation 10*: The Commission should direct PacifiCorp to model a variant of the Preferred Portfolio with SCRs installed on all relevant facilities in Utah and Wyoming. This variant should be compared to early retirement at these facilities before 2030.

Topic 4: Proposed Natrium nuclear power plant

- *Recommendation 11*: The Commission should require PacifiCorp to provide a detailed risk assessment for Natrium to be completed on time and within budget. This should include the nine items detailed in the bulleted list at the end of Section IV below. The Commission should not acknowledge the Natrium plant as part of this IRP until such an assessment is available and evaluated.

- *Recommendation 12*: The Commission should require PacifiCorp to reconcile why the variant analysis with Natrium removed leads to higher costs, even though the plant must be forced into the Preferred Portfolio.

Topic 5: Proposed conversion of Jim Bridger 1 and 2 to burn natural gas

- *Recommendation 13*: The Commission should require PacifiCorp to provide updated risk assessment of gas fuel that reflects recent price trends. This assessment should be provided as a condition of beginning any construction on the Jim Bridger conversions.

Topic 6: Barriers to Clean Energy Deployment

- *Recommendation 14*: The Commission should require PacifiCorp to revise its long-term resource cost assumptions, particularly for battery storage (standalone or paired with other resources), to better reflect the results of its 2019 all-source RFP.

II. PacifiCorp's Assumptions Regarding the Utah Community Renewable Energy Program Are Inconsistent with Utah Statute and Public Sentiment.

As this Commission is aware, and Sierra Club discussed in its comments on PacifiCorp's 2019 IRP, in March 2019, former Governor Herbert signed Utah's Community Renewable Energy Act, HB411, which allows municipalities and counties in Utah to opt into a commitment to receive a net 100 percent of all energy served from renewable resources by 2030. To qualify, communities had to adopt resolutions by the end of 2019 stating their intent to participate in the program. Twenty-three communities, including Salt Lake City, voted to become eligible by the end of 2019, representing approximately 37 percent of electricity sold by PacifiCorp in Utah.[8]

Despite the significant engagement from Utah communities, PacifiCorp's IRP did not properly detail or provide adequate assumptions regarding how it will meet the needs of the Utah Community Renewable Energy Act. First, PacifiCorp assumed 50 percent of the renewable energy used to meet the program's requirements will come from existing resources.[9] This assumption directly contradicts the plain language of the statute whose definition states that "'[r]enewable electric energy supply' means <u>incremental</u> renewable energy resources"[10] PacifiCorp does not dispute that it assumes 50 percent of the renewable energy used will be from existing resources, but rather merely stated that "there is no requirement that 100 percent of the program be met with incremental resources."[11] PacifiCorp's assertion is in direct contradiction with the plain statutory language. PacifiCorp's plan to meet the program requirements with existing renewable resources shows that the renewable energy procurement required under the program is likely to be higher than what PacifiCorp has assumed. Based on Rocky Mountain Power's participation forecast,[12] we estimate that the Company would need to acquire the

[8] Kyle Dunphey, *How Utah is Doing with its 'First of its Kind' Plan for Net-100% Renewable Energy*, Deseret News (Sept. 28, 2021), *available at* https://www.deseret.com/utah/2021/9/28/22696798/utah-climate-week-community-renewable-energy-program-salt-lake-city-ogden-sierra-club-2030.

[9] PacifiCorp Response to Sierra Club Data Request 3.1(b) in LC 77 (included in "Attach DPU 1.1-1 2nd SUPP" (all public data requests referenced in these comments are provided as Sierra Club Attach. 1)

[10] Utah Code Ann. § 54-17-902(13) (West 2019) (emphasis added).

[11] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2021 Integrated Resource Plan,* Docket No. LC 77, PacifiCorp Reply Comments at 63 (Ore. P.U.C. Dec. 23, 2021), *available at* https://edocs.puc.state.or.us/efdocs/HAC/lc77hac144535.pdf [hereinafter "LC 77 PacifiCorp Reply Comments"].

[12] Confidential Attach. to PacifiCorp Response to Sierra Club Data Request 3.1 in LC 77 (included in "Attach DPU 1.1-1 2nd SUPP CONF") (provided as Sierra Club Attach. 2).

equivalent of an additional [redacted] MW of solar by 2025 and [redacted] MW of solar by 2030 to meet the program's requirements.

Second, since this program is not included in the Company's discussion on renewable energy credit ("REC") management, it is not clear how PacifiCorp will be tracking and reporting renewable energy procured for this program relative to other procurement needs, such as meeting renewable portfolio standards ("RPS") requirements in California, Oregon, and Washington. Furthermore, PacifiCorp assumed that 50 percent of participants would elect to opt out of the program or be deemed ineligible.[13] This is an overly pessimistic assumption regarding participation rates, especially in light of the fact that recent polling indicates a significant majority of Utahans support a transition to clean, renewable energy.[14]

Accordingly, PacifiCorp's approach to the Utah Community Renewable Energy program significantly undercounted the demand for renewable resources to serve Utah customers over the long run. This in turn could stifle the pace of renewable energy additions in PacifiCorp's overall resource portfolio. Sierra Club recommends that the Commission direct PacifiCorp to revise its IRP input assumptions to ensure that a) 100 percent of the resources associated with this program are from incremental resources, b) assumed participation rates are more representative of public opinion (e.g., >50 percent). Going forward, PacifiCorp should provide additional discussion and analysis for how the program requirements will be met.

[13] Sierra Club Attach. 1, PacifiCorp Response to Sierra Club Data Request 3.1(b) in LC 77 (included in "Attach DPU 1.1-1 2nd SUPP").
[14] Western Resource Advocates, *Utah Voters Say Transition to Renewable Energy Will Help Families and Climate* (Mar. 11, 2020), *available at* https://westernresourceadvocates.org/blog/utah-voters-say-transition-to-renewable-energy-will-help-families-and-climate/.

III. PacifiCorp's Methodological Choices for Reliability and Resource Adequacy Raise Significant Concern.

Specific methodological choices PacifiCorp made in *all* of its IRP analyses may ultimately have led to a biased resource selection process and therefore raise significant concerns regarding the accuracy of each portfolio.

Sierra Club understands that certain discretionary methodological choices were made by PacifiCorp in an attempt to address purported reliability concerns. To be clear, Sierra Club understands that maintaining grid reliability is paramount and, in many cases, it is important to err on the side of caution. However, these choices are not transparent, lack supporting data and analysis, and only receive cursory explanations in the IRP documentation. It is not clear that these adjustments are necessary or the least-cost approach to meeting reliability needs.

This section details several of these reliability-related issues that warrant further investigation in this IRP, including:

- The assumed capacity contribution of solar plus storage resources;
- The application of an hourly 13 percent reserve margin at the load area level; and
- The "reliability adjustments" made to initial resource cost assumptions (i.e., post-modeling).

A. There Are Inconsistencies Between PacifiCorp's Capacity Contribution Study and the Preferred Portfolio with Respect to the Capacity Value of Solar Plus Storage, Potentially Leading to Overbuild of Coal Replacement Resources.

PacifiCorp provided a detailed capacity contribution study in Appendix K, which provided the percentage of a resource's nameplate capacity that is considered reliable for meeting system demand. This analysis relied upon the capacity factor approximation method, which the National Renewable Energy Laboratory ("NREL") determined to be the most dependable capacity contribution approximation technique. This method was applied to a portfolio similar to the Preferred Portfolio in 2030, and thus contemplates a significant amount of renewable resource penetration. The results of this study for solar plus storage are especially noteworthy since they found the capacity contribution to be on the order of 79-82 percent in the summer and 91-95 percent in the winter.[15] These values are comparable to many traditional thermal resources after accounting for forced outage rates.

PacifiCorp's capacity contribution study shows, then, that solar plus storage is a perfectly viable replacement option for retiring coal resources in lieu of proposed new thermal additions such as the Jim Bridger gas conversions or higher-cost, unproven technologies like the Natrium nuclear plant and non-emitting peaker plants. However, PacifiCorp significantly discounted solar plus storage as a viable capacity resource option in lieu of those thermal alternatives, particularly in the later years of the planning period. For instance, in the P02a-JB 1-2 No GC variant case (i.e., no gas conversion at Jim Bridger), a significant amount of costly non-emitting peakers are added starting in 2031 instead of simply adding more solar plus storage, which is cost effective. A similar result is seen in the P02e-No NUC variant case (i.e., removing the Natrium plant), which favored non-emitting peakers in the later years, rather than solar plus storage additions. In the P02h-JB3-4 Retire variant case (i.e., retire Jim Bridger 3 and 4 by 2030), an additional nuclear unit is added in 2030 instead of increasing solar plus storage deployment.

Given the relatively high cost of the nuclear and non-emitting peakers, it is unclear why these would be deployed in lieu of solar plus storage which has a relatively comparable capacity contribution according to PacifiCorp's own study. Sierra Club acknowledges that most resources

---

[15] PacifiCorp, *2021 Integrated Resource Plan*, Vol. II, App. K at 221 (Sept. 1, 2021), *available at* https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20II%20-%209.15.2021%20Final.pdf [hereinafter "PacifiCorp 2021 IRP Vol. II"]

tend to have a declining capacity contribution at higher levels of penetration, which would also be true of solar plus storage. However, PacifiCorp has provided no evidence on what those declines would be for specific resources, or evidence that such declines would be large enough to erode the value of solar plus storage as a viable alternative to thermal resources.

Finally, PacifiCorp may have used entirely different capacity contribution values than those included in its own study in Appendix K. For example, Table 9.17 shows that the installed capacity of the Preferred Portfolio includes 4,781 MW of battery storage collocated with solar by 2040.[16] Meanwhile, Table 9.18 shows a solar plus storage summer capacity contribution of only 1,811 MW (1,228 MW east, 583 MW west),[17] or a capacity contribution of approximately 38 percent as a percentage of nameplate. This is substantially lower than the 79-82 percent range from PacifiCorp's own study. Even for the year 2030, the total solar plus storage summer capacity contribution is 1,125 MW (350 MW east, 775 MW west), or approximately 66 percent of the 1696 MW of installed capacity. This capacity value of 66 percent is still far lower than the 79-82 percent range that PacifiCorp's study would suggest.

To summarize, PacifiCorp's analysis assumed capacity contributions from solar plus storage that are much lower than their own study presented in Appendix K. Even accepting the lower capacity contributions, there is a significant decline in the capacity value of this resource (i.e., from 66 percent to 38 percent) that it did not fully explain, nor did it provide any supporting analysis in the IRP. Sierra Club understands that capacity values decline with increasing resource penetration. However, it is not clear why such a large discrepancy exists between the values in Appendix K and Tables 9.17 & 9.18, especially in light of the fact that the analysis in Appendix

[16] PacifiCorp 2021 IRP Vol. I at 307.
[17] *Id.* at 309-10.

K "was performed using a portfolio that is similar to the 2021 IRP preferred portfolio"[18] and thus should have already accounted for significant solar penetration.

The assumed decline in capacity value has a significant influence on the overall resource selection process and warrants further documentation. If PacifiCorp is in fact undervaluing the capacity contribution of solar plus storage, as the analysis presented above shows, then the Company may be overbuilding capacity resources. This is especially relevant for the P03 early coal retirement cases since they include a more acute capacity replacement need. As such, any assumptions that underestimate the capacity value of solar plus storage (or any other resource) will also exacerbate the cost differential between the P02 and P03 cases. Sierra Club recommends that the Commission require PacifiCorp to provide much more detail on its assumptions for capacity contribution in the resource selection process, including any assumed decline in capacity value over time.

B. PacifiCorp's Application of a 13 Percent Hourly Reserve Margin to Individual Load Areas Is Not Fully Justified.

The 2021 IRP employed a brand-new approach to resource adequacy that differs from past practices and also differs substantially from what utilities have traditionally done. Rather than set a planning reserve margin targeted towards ensuring sufficient resources are available on the whole system during the highest peak load hour, PacifiCorp has established an *hourly* reserve margin of 13 percent that is applied to each of 15 load areas in its system topology. In addition to resource additions driven by the 13 percent margin, PacifiCorp also adds other resources in subsequent steps of its analysis to ensure resource adequacy (this is addressed in more detail in Section III(C) below).

[18] PacifiCorp 2021 IRP Vol. II, App. K at 218.

Moving towards an approach that examines a more granular timescale for the reserve margin may be sensible; as more variable wind and solar resources are added to the system, it is important to consider not only the peak load hour.

In its opening comments filed before the Oregon Commission, Sierra Club expressed concerns that the 13 percent reserve margin assumption was overly conservative, in part because it was unclear to which stages of the modeling effort this reserve margin applied. Additionally, we expressed concern over the application of the reserve margin to each individual load area since it was unclear whether this fully captured the benefits of geographic diversity.[19]

Through subsequent discovery and workshop discussions, Sierra Club believes it now has a better understanding of PacifiCorp's approach, and it is Sierra Club's current understanding that PacifiCorp's modeling process first uses the LT model to select resources to meet the minimum 13 percent hourly reserve margin. Later, PacifiCorp adds more resources to address any remaining reliability needs identified in the ST model. The ST model includes certain operating reserve requirements but does not also include the 13 percent margin. Based on this updated understanding, Sierra Club is generally less concerned than it was in its initial comments to the Oregon Commission.

However, because this is still such a novel approach, Sierra Club believes there are many outstanding questions related to PacifiCorp's new method that were not adequately addressed in PacifiCorp's IRP. In particular, Sierra Club believes there are two main issues that should be

[19] *See In the Matter of PacifiCorp, d/b/a Pacific Power, 2021 Integrated Resource Plan,* Docket No. LC 77, Sierra Club's Opening Comments at 25-27 (Ore. P.U.C. Dec. 6, 2021), *available at* https://edocs.puc.state.or.us/efdocs/HAC/lc77hac142719.pdf.

addressed on this subject, discussed below, and Sierra Club recommends that the Commission require updated information prior to an acknowledgment decision:

1. Reliability metrics

First it is not clear what specific reliability criteria PacifiCorp is using to determine whether the preferred portfolio (or any of the variants and sensitivities studied) are sufficiently reliable.

Standard industry practice would use metrics such as loss of load expectation ("LOLE"), loss of load probability ("LOLP"), or expected unserved energy ("EUE") as benchmarks for reliability performance. For example, one of the most common standards used is an LOLE of 0.1/yr, which equates to an expected loss of load of one day every ten years.

However, PacifiCorp's IRP has not provided any information on how this resource selection process, and the subsequent portfolios, perform with respect to the reliability metrics mentioned above. For each portfolio, PacifiCorp did provide values for the Energy Not Served ("ENS") expressed as "Average Annual ENS, 2021-2040 % of Average Load." However, PacifiCorp did not specify what threshold for the ENS values it considered acceptable or reliable.

Going forward, Sierra Club recommends that the PSC require PacifiCorp to define a specific reliability metric for evaluating its resource portfolios along with a specific performance target. For example, a reasonable approach could be to define any portfolio with a LOLE value <0.1/yr as being reliable.

2. Binding transmission limits

Second, while it was not initially clear from PacifiCorp's IRP, Sierra Club's understanding is that PacifiCorp allows for capacity resources in each of PacifiCorp's 15 load areas to contribute towards the 13 percent reserve margin in other load areas, if there is sufficient transmission available. While Sierra Club supports this approach, PacifiCorp has not provided much transparency around when and where these transmission limits may become binding when attempting to meet the 13 percent reserve margin target. This information is important for several reasons. First, disclosure of transmission limits would allow stakeholders to assess the reasonableness of PacifiCorp's assumptions within its own system. Second, this information would assist project developers in identifying the locations with the greatest need and opportunity for development. Going forward, Sierra Club recommends that PacifiCorp provide greater detail on when and where transmission constraints become binding (or close to binding) as the LT model selects resources to fulfill the 13 percent reserve margin requirement.

C. PacifiCorp's Portfolio Development Process Included a Non-Transparent Post-Modeling "Reliability Adjustment" that Lacked Adequate Supporting Data or Analysis.

As part of its core resource selection process, PacifiCorp applied a pre-modeling "granularity" adjustment and post-modeling "reliability adjustments." In essence, these adjustments were made to steer the resource selection process toward a certain outcome that would not otherwise be captured by the LT model (i.e., capacity expansion) due to its inherent limitations. The granularity adjustment approach may be necessary for the model to ensure the full value of resources, such as battery storage, are appropriately captured. However, in the case of the post-modeling reliability adjustment, the lack of transparency regarding what specific resource adjustments were actually made and why should raise red flags.

During an informal meeting between PacifiCorp and Sierra Club on November 30, 2021 PacifiCorp expressed that it made changes to the initial resource cost inputs used in the LT model based on reliability considerations. However, after reviewing subsequent discovery responses from the Company, it is Sierra Club's more recent understanding that PacifiCorp did not actually adjust resource costs to account for reliability. Instead, PacifiCorp hand-picked additional resources on an *ad hoc* basis in an attempt to address any remnant reliability issues after the initial LT model run was conducted. One example of this occurs in the P02h variant case where Jim Bridger was retired by 2030. There, PacifiCorp manually forced in a new nuclear plant (after Natrium) in 2030 as a "portfolio refinement" step meant to address purported reliability concerns that the Company has not substantiated. This is a fundamental and costly change to the portfolio that PacifiCorp made outside of the core portfolio optimization step. Moreover, according to a discussion with PacifiCorp representatives on November 30, 2021, PacifiCorp did not reoptimize the portfolio after taking this step. Since this additional nuclear resource was not added in other portfolios, and there is no supporting analysis that it will be needed, PacifiCorp may be overstating the cost of early Jim Bridger retirement.

Sierra Club is concerned that these adjustments represent an opportunity for PacifiCorp to "put its thumb on the scale" and steer resource selection towards a desired outcome. This risk is further exacerbated by the fact that PacifiCorp did not reoptimize the portfolio in the LT model after making these hand-picked reliability-based adjustments.

To Sierra Club's knowledge, PacifiCorp did not provide any data or information on the reliability-related resource additions or corresponding analysis of the hourly resource shortfalls in its IRP filing. However, Sierra Club did receive some of this information through follow-up data requests.

Sierra Club has since reviewed the hourly shortfalls that PacifiCorp identified between the LT and ST modeling stages. While certain shortfalls exist, it is far from clear that the resources selected to fill the reliability gaps were the best fit in all cases. For example, in the P02h variant case, which retired Jim Bridger by 2030, Jim Bridger was replaced with high-cost, nuclear resources. PacifiCorp has indicated that the nuclear resources were the best fit for replacing the plant, because it is a long duration resource that can “run around the clock.”[20] Sierra Club does not dispute that nuclear resources are long-duration, but PacifiCorp has not provided any evidence that an extremely high cost and unproven resource was the best fit for replacing Jim Bridger in 2030, as compared to other options such as longer-duration batteries (e.g. 6-8 hrs) paired with renewables. In fact, it appears that PacifiCorp limited the model’s resource selection to just nuclear or non-emitting peakers once a reliability gap reached a certain threshold. There is no evidence that longer or larger reliability gaps can and should be filled with—and only with—nuclear or non-emitting peakers.

Therefore, without more details, these adjustments may simply amount to a tool for PacifiCorp to “put its thumb on the scale” and steer resource selection towards its preferred outcome. If this is not the case, it is unclear why PacifiCorp did not provide a more thorough and detailed explanation of this critical step in its application and accompanying workpapers. Specifically, PacifiCorp should have provided:

1. A characterization of the reliability risks these adjustments are attempting to address (i.e. timing, duration, extent and frequency of reliability risks);
2. An evaluation of the ability of all resources under consideration to address these reliability needs; and,
3. Data on the specific resource adjustments that were made in each portfolio as part of this “reliability adjustment” step.

[20] LC 77 PacifiCorp Reply Comments at 17.

Sierra Club recommends that the Commission direct PacifiCorp to provide this information for the 2021 IRP and all future IRPs.

IV. Coal Unit Economics and Plant Retirements

A. PacifiCorp Failed to Include a Unit-By-Unit Coal Analysis Consistent with the 2019 IRP.

The economics of coal generation, relative to other options, has plunged in recent years. PacifiCorp has analyzed and disclosed the economics of coal plant retirements in previous IRP cycles, a practice which the Company somewhat continued in the 2021 IRP cycle; but unfortunately, it omitted important useful analyses conducted in 2019 from the 2021 IRP, particularly the unit-by-unit analysis included in Appendix R of the 2019 IRP.[21] PacifiCorp was required to pursue this unit-by-unit analysis in 2019, but absent a clear mandate, the Company unilaterally chose not to perform a similar analysis in 2021.

That 2019 unit-by-unit analysis was not only informative, but was a necessary component of a portfolio-wide approach to the modeling of coal retirements. The unit-by-unit approach provides additional information on the relative value of certain retirement decisions and also can help serve as a "check" on the soundness of the portfolio-wide results. Given the importance of a unit-by-unit analysis, it is unclear why PacifiCorp chose not to continue with this practice in this current IRP cycle, but the 2021 IRP is less informative as a result.

Instead, for the 2021 IRP, PacifiCorp's analysis only identified the most economic coal retirement dates through "endogenous" portfolio-wide modeling. The results of this endogenous selection process are similar to those in the 2019 IRP with the retirement dates left the same, or

[21] PacifiCorp, *2019 Integrated Resource Plan*, Vol. II, App. R (Oct. 18, 2019), *available at* https://www.pacificorp.com/energy/integrated-resource-plan html [hereinafter "PacifiCorp 2019 IRP"].

accelerated by a couple of years. The results also show that it is most economic to retire many of the Company's coal units prior to 2030, which is what PacifiCorp proposes in its Preferred Portfolio. Importantly, however, there are a handful of coal units that do not follow this pattern and instead remain in PacifiCorp's Preferred Portfolio through the late 2030s and early 2040s. These late retirements include the coal units at the Hunter, Huntington, Jim Bridger, and Wyodak plants.

This result is both concerning and counter-intuitive because some of the units with post-2030 retirement dates are among the costliest coal units on PacifiCorp's system on a going-forward basis. For example, the table below shows the estimated Levelized Cost of Electricity ("LCOE") to continue operating each of PacifiCorp's coal units as estimated in the 2018 Coal Valuation Study, conducted by Energy Strategies.[22] The units are ranked from highest to lowest cost and presented alongside the 2021 IRP proposed retirement dates, with the post-2030 dates highlighted in red.

[22] Energy Strategies, *PacifiCorp Coal Unit Valuation Study: A Unit-by-Unit Cost Analysis of PacifiCorp's Coal-Fired Generation* Fleet, (Sierra Club June 20, 2018), *available* at https://www.sierraclub.org/sites/www.sierraclub.org/files/PacifiCorp-Coal-Valuation-Study.pdf [hereinafter "PacifiCorp Coal Unit Valuation Study"].

Table 1. Comparison of PacifiCorp's Coal Unit Costs and Proposed Retirement Dates

Unit	Estimated LCOE ($/MWh)[23]	Cost Rank (Highest to Lowest)	Proposed Retirement Date (2021 IRP, w/ post-2030 highlighted)[24]	Proposed Retirement (2019 IRP)[25]
Jim Bridger 2	$ 50.43	1	2037	2028
Hayden 2	$ 49.75	2	2027	2030
Jim Bridger 1	$ 48.31	3	2037	2023
Jim Bridger 3	$ 47.60	4	2037	2037
Jim Bridger 4	$ 47.55	5	2037	2037
Hayden 1	$ 47.07	6	2028	2030
Colstrip 4	$ 42.71	7	2025	2027
Huntington 2	$ 41.54	8	2036	2036
Huntington 1	$ 41.10	9	2036	2036
Colstrip 3	$ 39.71	10	2025	2027
Hunter 1	$ 39.24	11	2042	2042
Naughton 1	$ 38.76	12	2025	2025
Naughton 2	$ 38.17	13	2025	2025
Hunter 3	$ 35.17	14	2042	2042
Hunter 2	$ 35.07	15	2042	2042
Craig 1	$ 34.77	16	2025	2025
Craig 2	$ 33.37	17	2028	2026
Wyodak	$ 31.64	18	2039	2039
Dave Johnston 4	$ 28.81	19	2027	2027
Dave Johnston 3	$ 28.80	20	2027	2027
Dave Johnston 1	$ 27.20	21	2027	2027
Dave Johnston 2	$ 26.72	22	2027	2027

[23] *Id.* at 23, Table 8.5.
[24] PacifiCorp 2021 IRP Vol. I at 137, Table 6.2.
[25] *Id.* at 299.

In particular, the Jim Bridger and Huntington plants stand out as having prolonged retirement dates that do not correspond to their high going-forward costs. This discrepancy holds true for the Jim Bridger 3 and 4 units, even though PacifiCorp plans to convert Jim Bridger 1 and 2 to burn gas.[26] A more logical result from PacifiCorp's IRP analysis would have been for these costlier units to retire sooner, presuming their costs were accurately represented in PacifiCorp's planning model.

Sierra Club recognizes that an optimal portfolio may not show a perfect correlation between LCOE and retirement date due to the complexities of modeling a large power system like PacifiCorp's. However, even when PacifiCorp did undertake a more comprehensive modeling approach to studying coal retirements, as it did in its 2019 IRP, the Company reached a very clear conclusion that early retirement of the Jim Bridger units would be beneficial to customers. In fact, the company found "there are potential customer benefits from accelerating the retirement of certain coal units, where the greatest customer benefits are associated with the potential accelerated retirement of units at the Naughton and Jim Bridger plants located in Wyoming."[27] The four Jim Bridger units ranked 1, 2, 5, and 6 out of all 22 coal units in terms of potential customer benefits were they to retire early.[28] The results of PacifiCorp's 2019 IRP coal retirement analysis from System Optimizer are shown in the table copied below.[29]

[26] *Id*. at 15.
[27] PacifiCorp 2019 IRP, Vol. II, App. R at 613.
[28] *Id*., Vol. II, App. R at 594.
[29] *Id*., Vol. II, App. R at 598.

Table 2. System Optimizer Results from PacifiCorp's 2019 IRP Coal Retirement Analysis

Table R.4 – SO Model Medium Gas, Medium CO_2 PVRR by Unit

Study	PVRR ($m)	PVRR(d) (Benefit)/Cost of 2022 Retirement
C-01 (Benchmark)	$21,897	n/a
C-02 (Colstrip 3)	$21,906	$9
C-03 (Colstrip 4)	$21,902	$5
C-04 (Craig 1)	$21,897	($0)
C-05 (Craig 2)	$21,875	($22)
C-06 (Dave Johnston 1)	$21,903	$6
C-07 (Dave Johnston 2)	$21,905	$8
C-08 (Dave Johnston 3)	$21,895	($2)
C-09 (Dave Johnston 4)	$21,916	$19
C-10 (Hayden 1)	$21,885	($12)
C-11 (Hayden 2)	$21,893	($4)
C-12 (Hunter 1)	$21,816	($81)
C-13 (Hunter 2)	$21,878	($19)
C-14 (Hunter 3)	$21,853	($44)
C-15 (Huntington 1)	$21,808	($89)
C-16 (Huntington 2)	$21,794	($103)
C-17 (Jim Bridger 1)	$21,690	($207)
C-18 (Jim Bridger 2)	$21,761	($136)
C-19 (Jim Bridger 3)	$21,800	($97)
C-20 (Jim Bridger 4)	$21,797	($100)
C-21 (Naughton 1)	$21,794	($102)
C-22 (Naughton 2)	$21,801	($96)
C-23 (Wyodak)	$21,880	($17)

Given the 2019 result, the prolonged retirement dates of Jim Bridger 3 and 4 (as well as Huntington 1 and 2) in the 2021 IRP Preferred Portfolio may in fact be the result of certain operating costs at these coal units not being accurately represented in the 2021 IRP modeling, as well as other subjective choices in PacifiCorp's portfolio selection process.

B. PacifiCorp Inappropriately Assumes a Significant Share of Its Future Coal Fuel Expenditures Are "Sunk Costs" in the Form of Future Take-Or-Pay Contracts. This Assumption Significantly Constrains Any Coal Retirement Analysis Since These Costs Would Never Materialize if the Plants Retired Early.

Several critical flaws are evident in the model input assumptions PacifiCorp developed for future coal fuel supply at coal units and the associated pricing. Chief among these flaws is the fact that PacifiCorp inappropriately assumed significant take-or-pay volumes associated with supplying coal to the Jim Bridger and Huntington units well into the future. In other words, PacifiCorp assumed in the PLEXOS model that a certain minimum volume of coal fuel must be purchased in each year for each plant by either using the fuel or by paying a penalty price for not using the fuel.[11] This means that PacifiCorp treats the minimum take quantity as a "sunk cost," even though the cost would never be incurred if the plant retired. Take-or-pay assumptions have a significant influence on both how often to run a plant and when to retire it because the existence of a take-or -pay penalty would substantially reduce—if not eliminate—the economic benefits of reducing fuel consumption (e.g., from retirement) at that plant.

The take or pay volumes for the Huntington and Jim Bridger plants are summarized in the table below for years after 2022, which was developed based on the information contained in the confidential data disk accompanying PacifiCorp's 2021 IRP.[30]

[30] PacifiCorp Confidential Master Assumptions BaseCase Workpaper PacifiCorp's 2021 IRP "Scenario Master_BaseCase 20210519_CONF.xlsx," tab "10 – Coal Cost Incremtl by Vol" (details of the take-or-pay quantities and prices) [hereinafter "Confidential Scenario Master_BaseCase Workpaper"].

Confidential Table 3. Take-or-Pay Volumes (in Millions of Tons) Assumed by PacifiCorp in PLEXOS for Future Years at the Huntington and Jim Bridger Plants

Year	Huntington (million tons)	Jim Bridger - Bridger Coal Company (million tons)	Jim Bridger - Black Butte (million tons)
[redacted]			

The large amount of assumed take-or-pay quantities is particularly problematic for the Jim Bridger fuel sources because there is currently no contract in effect that establishes any take-or-pay volumes after [redacted].[31] PacifiCorp has yet to sign a contract for the Black Butte coal supply for 2022[32] and there is no take-or-pay penalty associated with coal from Bridger Coal Company, which is PacifiCorp's affiliate mine. PacifiCorp has inappropriately assumed that future coal supply agreements to supply Jim Bridger would be required through [redacted] and that these agreements would contain provisions corresponding to its assumed minimum take volumes, without providing any supporting information.

[31] Confidential Attach. to PacifiCorp Response to Sierra Club Data Request 4.2 in LC 77 (included in "Attach DPU 1.1-2 3rd SUPP CONF") (provided as Sierra Club Attach. 3).
[32] *In the Matter of the Application of PacifiCorp (U 901 E) for Approval of its 2022 Energy Cost Adjustment Clause and Greenhouse Gas-Related Forecast and Reconciliation of Costs and Revenue*, Proceeding No. A.21-08-004, PacifiCorp (U 901 E) Brief Summary of Dates that Existing Coal Supply Agreements Are Scheduled for Renewal (Nov. 10, 2021), *available at* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M425/K516/425516818.PDF.

Sierra Club understands that for the Jim Bridger plant, PacifiCorp did not assume that it would incur any take-or-pay penalties after the plant retired. In other words, if Jim Bridger was retired in 2030, it would not incur take-or-pay penalties after that date. While this is an appropriate assumption, PacifiCorp has provided no justification for nevertheless assuming that it would have minimum take requirements for each year that Jim Bridger operates prior to retirement. By assuming that Jim Bridger will be subject to minimum-take requirements in the years before it is retired, PacifiCorp skewed the model toward (1) projecting artificially high capacity factors at Jim Bridger and (2) potentially delaying the identified optimal retirement date.

PacifiCorp asserts that it is appropriate to assume that minimum take requirements will apply if Jim Bridger is operating because the "IRP modeling is intended to reasonably represent the constraints and operating parameters faced by each resource" and take-or-pay contracts are "consistent with many of the Company's existing obligations and comparable structures are likely in future coal supply procurement."[33] PacifiCorp ignores, however, that as the owner and operator of the Bridger mine, which primarily supplies the Jim Bridger plant, the Company has *complete control* over production levels at the mine. Accordingly, any "minimum take" at the Bridger mine is set by PacifiCorp itself. Even assuming that the Bridger mine requires some base level of production to justify continued operations, PacifiCorp admitted during a public workshop with the Oregon Public Utilities Commission that *it did not evaluate an optimal supply from the Bridger mine because the Company "didn't have time to address all that."*[34] Instead, the Company used a single supply scenario from the Bridger mine without evaluating any lower production.

---

[33] LC 77 PacifiCorp Reply Comments at 22-23.
[34] LC 77, Ore. Pub. Util. Comm'n, PAC 2021 IRP Commission workshop video recording at 2:43:51-2:44:26 (MacNeil, PacifiCorp) (Jan. 13, 2022), *available at* https://www.oregon.gov/puc/news-events/Pages/default.aspx.

Not only are PacifiCorp's assumptions entirely inappropriate, but they are also at odds with its own position in recent fuel-cost recovery proceedings. For instance, in PacifiCorp's most recent fuel cost proceeding in Oregon, the Company said that the volume of coal can and should be evaluated and adjusted over a multiyear period within the IRP process. Specifically, "[c]hanges in BCC mine plans and staffing levels need to be evaluated in multiyear evaluations such as PacifiCorp's IRP and not in a one-year filing like the [Oregon fuel proceeding]."[35] Instead, PacifiCorp has taken the same approach in the IRP as its fuel proceeding modeling: the Company assumes minimum coal consumption levels throughout the planning period.

Even if one were to presume that new CSAs should be executed in the future, the volumes PacifiCorp has assumed do not have any clear rationale or justification in the IRP. For example, the Jim Bridger Black Butte take or pay volume is assumed to increase from [redacted] tons in 2023-2030 to [redacted] tons in 2031-2037, even as Jim Bridger's coal-fired output will decline.

In sum, PacifiCorp treats a large share of the coal fuel costs at Jim Bridger as a "sunk cost" in its modeling for all years the plant is online, even though these costs have not yet been incurred and might never be incurred. This means that PacifiCorp's analysis ignored a substantial portion of the fuel cost savings that would arise from dispatching Jim Bridger at lower capacity factors and may also have skewed the findings of the optimal plant retirement date. By skewing the output of Jim Bridger to be higher than necessary, PacifiCorp is also reducing the model's selection of other resource additions that could provide energy at a lower cost.

[35] *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism*, Dkt No. UE 390, Surrebuttal Testimony of Dana M. Ralston on Behalf of PacifiCorp (PAC/1200) at Ralston/32:15-16 (Ore. P.U.C. Aug. 2021) [hereinafter "PAC/1200"] (excerpt provided as Sierra Club Attach. 4).

1. *The Jim Bridger and Huntington take-or-pay assumptions cloud PLEXOS' ability to potentially recognize significant coal fuel savings from reduced output and/or early retirements.*

Take-or-pay assumptions for both the Jim Bridger and Huntington plants have a significant impact on the final portfolio. Using the information from PacifiCorp's input data files, Sierra Club estimates that the costs associated with the Jim Bridger take-or-pay volume tier from the 2023-2037 period equates to an assumed coal fuel cost of approximately $[redacted] (PVRR).[36] For Huntington, the take-or-pay costs over the same period amount to $[redacted] (PVRR).[37] In other words, there is a significant amount of fuel cost savings PacifiCorp's model could potentially realize if these future take-or-pay provisions could be avoided and output at these plants were reduced, either due to early retirement or lower dispatch.

For example, if the take or pay minimum volume at Jim Bridger was reduced by 50 percent in all years, and the corresponding energy generated from coal was replaced with energy from low cost wind resources, Sierra Club estimates that this could lead to a reduction in the PVRR by approximately $[redacted].[38] Importantly, this $[redacted] represents only fuel savings and not other savings such as avoided O&M costs.

Similarly, for Huntington, there is a significant take-or-pay volume through 2029. Although PacifiCorp's current CSA at Huntington extends through 2029, PacifiCorp's analysis presumes that no events have transpired, or will transpire, that could trigger a reopener clause in the Huntington CSA. However, the Huntington CSA contains a "environmental regulations" provision[39] under which the Company can avoid minimum take requirements if changes in

[36] Calculation based on Confidential Scenario Master_BaseCase Workpaper.
[37] *Id.*
[38] This estimate is based on the following assumptions: Jim Bridger output associated with take-or-pay tier coal is reduced by 50 percent; Jim Bridger generation is replaced with Wyoming wind priced at approximately $23/MWh.
[39] UE 390, PAC/1200 at Ralston/12:14-13:11 (describing Huntington CSA environmental regulations provision).

environmental laws implicating the Huntington plant make continued operations uneconomic.[40] Stakeholders in Oregon, such as the Oregon Citizens Utility Board and the Oregon Commission Staff, have already questioned whether current environmental laws and regulations would be enough to trigger this provision, although PacifiCorp has disagreed.[41] However, environmental controls required under the Clean Air Act's Regional Haze requirements would undoubtedly constitute the type of "environmental regulations" contemplated by the Huntington coal contract. Currently, an SCR requirement at the Huntington plant remains under Clean Air Act litigation and could foreseeably be reimposed. Huntington may also be subject to additional environmental controls under the Regional Haze program's "Round 2" rulemaking, as the plant currently has no pollution controls whatsoever for nitrogen oxide ("NOx"). Utah's state implementation plan ("SIP") for Regional Haze "Round 2" is expected in July 2022, with EPA acting upon that SIP shortly thereafter. Environmental controls required under the Regional Haze rulemaking are further discussed in Section IV(E). Regardless of any environmental regulatory changes, the Oregon Public Utilities Commission has already directed PacifiCorp to "thoroughly explore the costs and benefits of contract termination or renegotiation . . . ."[42] Accordingly, PacifiCorp should have modeled a sensitivity case where the current CSA at Huntington was either nullified or renegotiated.

In conclusion, Sierra Club recommends that the Commission direct PacifiCorp to conduct an additional model run for this IRP that does not include any take-or-pay assumptions. This should become standard practice in all future IRPs. In the case of Huntington whose coal supply

[40] *Id.*
[41] *Id.*
[42] *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Order No. 21-397 at 23 (Nov. 1, 2021), *available at* https://apps.puc.state.or.us/orders/2021ords/21-379.pdf.

agreement has an extended term, the Commission should also direct PacifiCorp to remove the take-or-pay assumption after a certain date (e.g., 2025).

2. *PacifiCorp's coal fuel pricing tier assumptions lack any clear explanation or justification.*

In addition to assuming that a large volume of PacifiCorp's coal fuel supply is subject to take-or-pay agreements, PacifiCorp also makes additional assumptions regarding the incremental pricing (i.e., marginal cost) for volumes of coal fuel above the take-or-pay minimum volumes. In doing so, PacifiCorp developed a set of tiered coal prices at each plant. However, the tier volumes and their corresponding prices are not explained or justified in the IRP.

In most instances, the incremental fuel costs at the Jim Bridger and Huntington plants appear to be substantially lower than the average cost of the take-or-pay volume tier. For example, at Jim Bridger from [redacted], any coal consumed just above the take-or-pay minimum is assumed to cost [redacted] percent less in $/MMBtu than the take-or-pay volume tier.[43]

The steep drop-off in the assumed price of coal for volumes above the take-or-pay threshold (in conjunction with the take-or-pay penalties) is an inappropriate assumption that is causing PacifiCorp's model to overvalue coal at the expense of other resources. In other words, if PacifiCorp set the incremental cost of coal fuel artificially low, and it set the cost substantially lower than the average cost of coal fuel, then the planning model is likely to dispatch coal excessively over time. This will have the consequence of crowding out other resource additions which might otherwise be economically selected—particularly those with high energy value, such as high-capacity factor wind resources.

[43] Calculation based on Confidential Scenario Master_BaseCase Workpaper.

In other proceedings, PacifiCorp has indicated that it would not use incremental pricing in its IRP because the average cost of coal fuel should be used to govern long-term planning decisions, rather than some lower incremental price assumptions. For instance, in the Company's 2021 ECAC (which is the California fuel cost recovery proceeding), the Company testified that: "The Company's IRP uses a 20-year planning horizon and considers the *average coal fuel cost* in its dispatch commitment."[44] Based on that testimony, Sierra Club was surprised to learn that PacifiCorp is using an incremental pricing approach in the 2021 IRP with incremental fuel costs that deviate significantly lower from the average.

C. The P02h Variant Case (Jim Bridger Units 3 and 4 Early Retirement) Is Lower in Cost than PacifiCorp's Preferred Portfolio (P02-MM-CETA). This Is True Despite Questionable Assumptions that Needlessly Inflate the Cost of the P02h Variant Case.

As shown above, Sierra Club has significant concerns over the late retirement dates of some of PacifiCorp's coal units, particularly Jim Bridger. This concern is underscored by PacifiCorp's own analysis of the P02h variant case, which shows a risk-adjusted PVRR of $26,240 million under the MM price-policy scenario.[45] This compares favorably to PacifiCorp's Preferred Portfolio which has a PVRR of $26,343 million,[46] or about $103 million more costly than the P02h-MM case.

Sierra Club recognizes that PacifiCorp made certain adjustments to the initial P02-MM-MM portfolio to ensure that the final Preferred Portfolio (P02-MM-CETA) was compliant with Washington's CETA requirements. These changes added approximately $164 million in (PVRR)

---

[44] *In the Matter of the Application of PacifiCorp (U 901-E) for Approval of its 2021 Energy Cost Adjustment Clause and Greenhouse Gas-Related Forecast and Reconciliation of Costs and Revenue*, Docket No. A.20-08-002, Rebuttal Testimony of David G. Webb on Behalf of PacifiCorp (PAC/800) at Webb/9:16-17 (May 2021), *available at* https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2008002/3651/385112433.pdf (emphasis added).
[45] PacifiCorp 2021 IRP Vol. I at 289, Table 9.14.
[46] *Id.* at 291, Table 9.15.

costs relative to the initial P02-MM-MM portfolio.[47] However, it is not clear whether the exact same changes would also be necessary for the P02h variant to become CETA compliant. For instance, the P02h portfolio already includes 200 MW of incremental solar plus storage relative to P02-MM-MM, beginning in 2027.[48] This is roughly equal to the 160 MW of renewable plus storage resources that were added to create the P02-MM-CETA portfolio.[49] Thus, the P02h variant may already be largely, if not entirely, CETA compliant. Sierra Club recommends that PacifiCorp determine what shortfall, if any, there may be in this regard. Furthermore, Sierra Club recommends that PacifiCorp assess whether the P02h case should be considered preferable to its Preferred Portfolio.

From a pure least-cost planning standpoint, early retirement of Jim Bridger would lead to a more optimal portfolio and would be in PacifiCorp customers' interest. This conclusion would be bolstered were the take-or-pay provisions described above correctly modeled, thereby allowing even greater fuel cost savings from an early retirement. Additionally, the P02h variant includes a second nuclear unit (beyond Natrium) in the 2030 timeframe. According to a discussion with PacifiCorp's analytical team on November 30, 2021, this nuclear unit was not economically selected in the initial stage of modeling, and was later added when PacifiCorp decided it was necessary to address reliability issues. As discussed above, from the reliability data provided to Sierra Club that led to its decision to add the second nuclear unit, it appears that PacifiCorp evaluated an extremely narrow range of alternatives and it is far from clear that a nuclear plant was the best fit to meet the identified reliability gap. If a less costly set of resources could address the same reliability needs this nuclear addition was meant to cover, then it is

47 *Id.* at 261, Table 9.1; 291, Table 9.15.
48 *Id.* at 287.
49 *Id.* at 290.

conceivable the early retirement of Jim Bridger would be even more cost effective, potentially on the order of hundreds of millions of dollars (in PVRR terms), than what PacifiCorp reported in the IRP. PacifiCorp's *ad hoc* approach to addressing reliability concerns by adding resources through post-modeling "portfolio refinements," such as this nuclear unit addition, is discussed more thoroughly above in Section III(C).

D. PacifiCorp's IRP Did Not Fully Assess the Risks Associated with the Early Exit of its Coal Plant Co-Owners.

One important consideration regarding PacifiCorp's continued operation of certain coal plants is how its actions align with the actions of facility co-owners. PacifiCorp has accelerated its exit of Colstrip Units 3 and 4, which is consistent with Sierra Club's understanding of the intentions of other Pacific Northwest co-owners of the plant (e.g., Puget Sound Energy, Avista, and Portland General Electric). However, PacifiCorp has not aligned itself for other plants. In particular, in an application before the Idaho Public Utilities Commission filed in June 2021, Idaho Power stated its intention to exit its 33 percent share of the Jim Bridger plant by 2030.[50] Importantly, Idaho Power's application *did not* contemplate the gas conversions PacifiCorp proposed in its IRP filing.

Since June, Idaho Power has indicated that it intends to participate in the gas conversions but will exit from the gas units by 2034, three years earlier than PacifiCorp's planned retirement in 2037.[51] Additionally, Idaho Power now plans to exit Jim Bridger Units 3 and 4 earlier than

[50] *In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates for Electric Service Costs Associated with the Jim Bridger Power Plant*, Docket No. IPC-E-21-17, Application at 5 (June 3, 2021), *available at* https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE2117/CaseFiles/20210603Application.pdf [hereinafter "IPC Application"].
[51] Jared Hansen, Idaho Power Company, *Preliminary Preferred Portfolio* at slide 5 (Nov. 18, 2021), *available at* https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2021/2021_Preliminary_Preferred_Portfolio.pdf.

previously stated: by 2025 and 2028.[52] Whether Idaho Power's interest in Jim Bridger Units 1 and 2 continues past 2034 or in Units 3 and 4 continues past 2028 has significant implications for PacifiCorp's assumptions in the 2021 IRP regarding the cost to continue operating the plant long term. Some of the considerations are:

1. PacifiCorp should be clear on who would ultimately take ownership of Idaho Power's share of the Jim Bridger Units 1 and 2 capacity and its associated output from 2034-2037 and Units 3 and 4 capacity and associated output from 2028-2037. If PacifiCorp were to ultimately acquire or otherwise maintain control of Idaho Power's portion of the Jim Bridger plant, the Company should provide these acquisition costs and any sensitivities around them in the IRP.
2. If there are no parties interested in acquiring Idaho Power's ownership share, then PacifiCorp would still need to find a way to cover the associated operating and maintenance costs as well as incremental capital costs for major overhauls expected in 2032, 2033, 2034, and 2035. These additional costs are not adequately assessed in the IRP.
3. PacifiCorp would also be responsible for all decommissioning and remediation costs incurred after Idaho Power's exit in the 2028-2034 timeframe. PacifiCorp has not included those additional costs in its analysis.

The IRP does not address these major developments with Idaho Power and what they would mean for continued operation of Jim Bridger past 2028. In response to a discovery request asking whether PacifiCorp expects a third-party to assume ownership of Idaho Power's share, the

[52] *Id*. (indicating that all gas will come off Idaho Power's system by 2034 and all coal by 2028); Jared Hansen, *Aurora Results Update*, Idaho Power Company (Nov. 18, 2021), *available at* https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2021/2021_Aurora_Results.pdf.

Company simply stated: "PacifiCorp has not made any assumptions regarding whether or how Idaho Power Company (IPC) will handle its property."[53] At the very least, the Company could, and should, have explored sensitivities regarding whether PacifiCorp or a third party would assume ownership of Idaho Power's share of the plant.

E. PacifiCorp's IRP Failed to Evaluate a Feasible Scenario in Which EPA Requires SCR Installations to Comply with the Clean Air Act.

As PacifiCorp's 2021 IRP described in great detail, the Company's coal plants must meet certain requirements to comply with the EPA's Regional Haze Rule. This matter is especially relevant for PacifiCorp's Utah coal plants, Hunter and Huntington.

In recent years the regional haze requirements in Utah have been hotly contested. In June 2016, EPA issued a final rule ("2016 FIP") requiring PacifiCorp to retrofit Hunter Units 1 and 2 and Huntington Units 1 and 2 with SCRs by August 4, 2021. The Trump administration withdrew the 2016 FIP and replaced it with a FIP that required no controls whatsoever at the four BART units. In response, Sierra Club and other organizations filed a petition in the Court of Appeals for the Tenth Circuit challenging the Trump FIP. That appeal is pending.

Outside of Utah, other plants are subject to SCR requirements to meet regional haze requirements, including Jim Bridger Units 1 and 2 and Wyodak. SCR installation was required at Jim Bridger Unit 2 by the end of 2021, and is required at Unit 1 by the end of 2022. Although Wyoming's Governor issued an emergency order to allow Unit 2 to operate in violation of the Clean Air Act through April 2022, the federal EPA has recently announced that it intends to

[53] Sierra Club Attach. 1, PacifiCorp Response to Sierra Club Data Request 3.2(a) in LC 77 (included in "Attach DPU 1.1-1 2nd SUPP").

maintain the SCR requirements on both units.[54] Despite PacifiCorp having to comply with the Clean Air Act's regional haze rule at some point, it steadfastly refuses to take this risk seriously, and chose to omit this very real possibility in its IRP analysis, even as a sensitivity case. PacifiCorp's malfeasance not only threatens significant harm to the reliability of the grid, to workers at the Jim Bridger plant, and public health in Utah and other states but violates this Commission's IRP guidelines, which state that "the risk of future internalization of environmental costs must be analyzed by the Company and such risk assessment must be incorporated in the Company's decision making and final choice of resources acquired."[55]

To put the potential impact in perspective, Strategen considered the cost of installing SCRs at each of the coal plants mentioned above. Based on the values reported in Energy Strategies' 2018 PacifiCorp Coal Unit Valuation Study,[56] the incremental cost of these environmental controls could be on the order of $753 million in NPV terms as shown in the following table.

---

[54] 87 Fed. Reg. 2571 (Jan. 18, 2022), *available at* https://www.govinfo.gov/content/pkg/FR-2022-01-18/pdf/2022-00777.pdf. Since the federal EPA issued this notice, PacifiCorp and the State of Wyoming entered into a consent decree which would allow PacifiCorp to avoid installation of SCRs at Jim Bridger units 1 and 2. However, the EPA was not a party to this consent decree and has not acquiesced to its terms. Accordingly, the private agreement between PacifiCorp and Wyoming has no impact on federal requirements.

[55] *In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp*, Docket No. 90-2035-01, Report and Order on Standards and Guidelines at 20 (June 18, 1992), *available at* https://pscdocs.utah.gov/electric/17docs/1703516/297578AttACorrCommDPU10-25-2017.pdf.

[56] PacifiCorp Coal Unit Valuation Study.

Table 4. Net Present Value for Coal Plants With and Without SCRs

Plant - Unit	**Net Present Value (millions, $)**		
	Without SCR	*With SCR*	*Difference*
Hunter 1	$ 1,263	$ 1,402	$ 139
Hunter 2	$ 849	$ 913	$ 64
Huntington 1	$ 1,510	$ 1,470	$ 149
Huntington 2	$ 1,321	$ 1,386	$145
Jim Bridger 1	$ 1,241	$ 791	$ 80
Jim Bridger 2	$ 711	$ 912	$ 88
Wyodak	$ 824	$ 910	$ 88
Total			$ 753

For comparison, the difference between the P02-MM Preferred Portfolio and the P03-MM Early Retirement Portfolio, which retired all of PacifiCorp's coal plants by 2030, is $1,697 million (risk adjusted),[57] meaning that a $753 million increase in the PVRR equates to more than 44 percent of this difference. In other words, if SCR-related costs are ultimately required but PacifiCorp could avoid these costs through early retirement, then the difference in costs between the P02 and P03 cases becomes much smaller in magnitude. In fact, using PacifiCorp's own IRP analysis as a starting point, Sierra Club estimates the impact of early coal retirement in terms of total PVRR increase could be as little as 3 percent (versus 6 percent if SCRs are not considered). Under the high gas price scenario (HH), this difference declines even further and could be as little as <1 percent, meaning the cost difference between the P02 case if SCRs are required and the P03 case could be almost negligible. This is especially relevant in light of the recent and dramatic increase in gas prices, which shows that the HH scenario may be closer to reality than the MM scenario.

[57] PacifiCorp 2021 IRP Vol. I at 261, Table 9.1.

In summary, SCR requirements will at some point be required under the Clean Air Act. At that time, the early retirement case becomes roughly equivalent from an economic standpoint to the current preferred case, depending on the price-policy scenario.

F. PacifiCorp's P03 Early Coal Retirement Case Is Misleading on Increased Costs (Relative to the Preferred Portfolio), as These Increases Are Partly Driven by Deficiencies and Subjective Choices in the Company's Modeling Methodology.

Overall, PacifiCorp's IRP analysis finds that the P03 early coal retirement cases are costlier than the P02 cases. One exception occurs when the true social cost of carbon is applied. Under that condition, the P03 case is the least cost option from a PVRR perspective.

Importantly, even when a social cost of carbon is not applied, PacifiCorp's analysis could be exaggerating or overestimating how early retirements under the P03 cases would drive higher costs relative to the P02 cases. Instead of early retirements being the key driver of these costs, a large portion of the higher P03 costs may simply arise from methodological choices PacifiCorp has made that bias replacement resource selection towards a costlier portfolio than necessary.

One such methodological choice was PacifiCorp's overly restrictive decision on the types of potential replacement resource options it considered in the IRP selection process. For example, the main difference in incremental capacity between the P02-MM and P03-MM cases through 2030 is two resources: 1) solar plus storage and 2) non-emitting peakers. It is evident from the model assumptions and model results that the non-emitting peakers are a relatively expensive resource to build and operate (i.e., ~$374/MWh levelized cost using PacifiCorp's assumptions)[58] and their inclusion may be one of the driving factors of the higher P03 costs. Since gas additions are excluded (aside from the Bridger conversions), it appears that the

[58] PacifiCorp 2021 IRP Vol. I at 183, Table 7.2.

primary options for resources with high capacity value are limited mainly to the non-emitting peaker and nuclear additions, both of which are expensive. Indeed, both nuclear and non-emitting peaker additions feature prominently in the variant analyses and are often the main drivers of cost differences between the variants and the base case.

Through informal discussions, PacifiCorp indicated that it views resources like the non-emitting peakers as “placeholders” for resources that will be needed far into the future. However, they are still assigned a cost that is included in the PVRR calculation and is evaluated on an equal footing with nearer term resource additions. Thus, inclusion of non-emitting peakers and nuclear plants, even as indicative “placeholders” for the distant future, can still substantially skew the PVRR results and lead to misleading conclusions about the relative cost of portfolios like P03-MM.

If PacifiCorp had instead included more resource options with high capacity value beyond those two choices, then the results would differ substantially, and the cost differential of the P03 cases versus the P02 cases would not be as dramatic. Some of these additional resource options might include: 1) advanced load response measure with fewer operating limits than traditional demand response; 2) managed EV charging and V2G; 3) offshore wind; 4) longer duration storage resources; or 5) alternative configurations for hybrid resources (e.g., solar plus battery storage with five- or six-hour durations, versus PacifiCorp’s identified four-hour duration).

V. PacifiCorp’s Expectation that it Will Receive Power from the Natrium Plant, a Novel Nuclear Technology, by 2028 Introduces Substantial Cost and Execution Risks that were Not Adequately Addressed in the IRP.

PacifiCorp’s analysis of the Natrium advanced nuclear reactor raises numerous concerns. First, and most significantly, PacifiCorp has stated on numerous occasions that the Natrium nuclear plant was "exogenously" included in the model, a fancy way of saying that it was not economically selected by the model. By definition, this means that removing the Natrium unit should lead to a lower overall portfolio cost. However, the variant case where Natrium was excluded (P02e) leads to an *increase* in portfolio costs. This presents a logical inconsistency that would only make sense if PacifiCorp were applying other changes to the variant case. Given these discrepancies, PacifiCorp should provide a more detailed explanation of how Natrium can be both economic and non-economic.

Second, PacifiCorp has failed to meaningfully evaluate the various risks surrounding an untested, highly controversial energy source, including Natrium's permitting, regulatory, financial, operational, environmental, and technical risks. PacifiCorp has either downplayed or failed to acknowledge each of these. This lack of information and the absence of rigorous analysis for a new, untested technology should cause the Commission significant pause, and ultimately result in a non-acknowledgement, as PacifiCorp lack of analysis surrounding the Natrium plant and other proxy nuclear resources in the IRP contravenes the Utah IRP Guidelines which require "[a]n evaluation of the financial, competitive, reliability, and operational risks associated with various resource options."[59]

To begin, the Natrium project faces significant regulatory hurdles. The Company acknowledged that Natrium is "a first of a kind sodium fast reactor" and that there may be Nuclear Regulatory Review "challenges."[60] Yet, when asked about the project's permitting requirements, PacifiCorp implied that some portion of these risk factors would essentially be

[59] Standards and Guidelines for Integrated Resource Planning for PacifiCorp, Utah Jurisdiction 4(h) (included as Attachment A to Report and Order on Standards and Guidelines in Docket No. 90-2035-01), *available at* https://pscdocs.utah.gov/electric/17docs/1703516/297578AttACorrCommDPU10-25-2017.pdf.
[60] Sierra Club Attach. 1, PacifiCorp Response to Oregon Citizens' Utility Board ("CUB") Data Request 3 (included in "Attach DPU 1.1-1 3rd SUPP").

outsourced to its partner (TerraPower), saying that the Company and TerraPower "will comply with all federal, state and local permitting requirements[,]" but "it is premature to provide an exhaustive list of permitting requirements or timelines at this time."[61] Additionally, PacifiCorp does not appear to have a current plan for disposal of nuclear waste. When asked about the construction or availability of federally licensed storage facilities for nuclear waste that would be generated from Natrium, PacifiCorp responded that it "has no further information on this topic" but expects some, unidentified independent storage to be federally approved at some unidentified, later date.[62] The IRP omitted any potential regulatory delay or denial; instead it assumed the Natrium plant will smoothly proceed through the regulatory process. This assumption imposes significant risk on the entire Preferred Portfolio, as certain resource planning decisions in the 2020s appear to hinge upon Natrium's completion.

Next, PacifiCorp's modeling assumes that the federal government will ultimately fund approximately [redacted] of the total capital costs, or approximately $[redacted].[63] The U.S. Department of Energy has currently awarded TerraPower $80 million through its advanced reactor demonstration program.[64] Over the next seven years, the Department plans to invest a total of $3.2 billion in this program, with industry partners providing matching funds.[65] This means that PacifiCorp hopes to secure nearly [redacted] of the total available federal funding for a single nuclear project. Notably, these estimates, while already large, assume that the Natrium plant will

[61] Sierra Club Attach. 1, PacifiCorp Response to Sierra Club Data Request 4.5 (included in "Attach DPU 1.1-1 3rd SUPP").
[62] Sierra Club Attach. 1, PacifiCorp Response to CUB Data Request 6 (included in "Attach DPU 1.1-1 3rd SUPP").
[63] Confidential Attach. to PacifiCorp Response to CUB Data Request 1, tab "Capital Cost" (included in "Attach DPU 1.1-1 3rd SUPP CONF") (provided as Sierra Club Attach. 5).
[64] *U.S. Department of Energy Awards TerraPower $80 Million to Demonstrate Advanced Nuclear Technology*, TerraPower (Oct. 13, 2020), *available at* https://www.terrapower.com/doe-natrium-demonstration-award/.
[65] Office of Nuclear Energy, *U.S. Department of Energy Announces $160 Million in First Awards under Advanced Reactor Demonstration Program*, Energy (Oct. 13, 2020), *available at* https://www.energy.gov/ne/articles/us-department-energy-announces-160-million-first-awards-under-advanced-reactor.

be built on time and on budget. The IRP does not contain any analysis of potential cost overruns, despite the fact that nearly all nuclear projects in the U.S. have been plagued by astronomical cost overruns,[66] or any contingency plan in the event that the federal funding does not materialize. While there have been assurances that TerraPower will assume the risk of cost overruns and delays,[67] to date, PacifiCorp has not presented any agreements with TerraPower to this effect or otherwise provided any evidence that customers will be protected.

Connected, Natrium's technical design itself raises cost concerns. Unlike past nuclear projects, Natrium requires a highly enriched uranium, known as "high-assay low-enriched uranium" ("HALEU"). PacifiCorp is assuming it will obtain a domestic supply for HALEU;[68] however, such fuel is currently only produced for commercial purposes in Russia.[69] In light of the ongoing war and humanitarian crisis in the Ukraine, increasing the United States' energy reliance on Russia should raise obvious concerns. Some trade press estimate that it will take at least seven years to develop a U.S. based market.[70]

Fuel availability further raises questions on impacts to local, fence line communities. For example, the White Mesa mine in southwestern Utah, which is the only operating conventional uranium mine in the U.S., has caused documented environmental damage to the surrounding indigenous communities. Further development of uranium production in the U.S. to fuel plants

[66] *See, e.g.,* Timothy Gardner and Nichola Groom, *Some U.S. Cities Turn Against First Planned Small-Scale Nuclear Plant*, Reuters (Sept. 2, 2020), *available at* https://www.reuters.com/article/us-usa-nuclearpower-nuscale/some-u-s-cities-turn-against-first-planned-small-scale-nuclear-plant-idUSKBN25T30E (noting that the NuScale nuclear project's projected cost of $6.1 billion has risen from $3.1 billion in 2017).
[67] *Project Details*, Wyoming Advanced Energy, *available at* https://wyomingadvancedenergy.com/project-details/ (last visited Mar. 3, 2022).
[68] Sierra Club Attach. 1, PacifiCorp Response to CUB Data Request 4 (included in "Attach DPU 1.1-1 3rd SUPP").
[69] Matthew Bandyk, *Nuclear reactors of the future have a fuel problem*, Utility Dive (Aug. 30, 2021), *available at* https://www.utilitydive.com/news/nuclear-reactors-of-the-future-have-a-fuel-problem/604707/.
[70] *Id.*

such as Natrium could similarly result in harmful consequences for nearby, local communities. Yet, PacifiCorp has not considered and disclosed these issues.

Finally, operating any nuclear plant comes with significant operational risks. In addition to having minimal information on its waste management strategy, PacifiCorp does not appear to have begun planning to operate the plant. For example, regarding training personnel, PacifiCorp has only indicated that it is "currently evaluating the overall strategy for operations and maintenance."[71] Notably, the IRP does not contain any analysis evaluating the risk that the plant—a first of its kind demonstration project that has never operated on a commercial scale—may suffer from operational difficulties during its early years.

Sierra Club recommends first that the Commission not acknowledge the Natrium plant. Non-acknowledgement will make clear that PacifiCorp's pursuit of this unproven, risky, and expensive technology is a risk to be borne by shareholders, not ratepayers. Additionally, the Commission should require significantly more information from PacifiCorp concerning its nuclear plant, including:

1. A detailed explanation of how Natrium can be both non-economic (and thus requiring hardwiring into PLEXOS) and economic (removing the Natrium plant from the model increasing costs to the system) is essential to understanding this resource;
2. A detailed explanation of anticipated radioactive waste storage options;
3. A detailed explanation of anticipated federal, state, and local permitting requirements, with key milestones with anticipated dates; this should also explain who is responsible (i.e., PacifiCorp or Terrapower) for achieving licensing and permitting milestones;

[71] Sierra Club Attach. 1, PacifiCorp Response to CUB Data Request 9 (included in "Attach DPU 1.1-1 3rd SUPP").

4. A detailed accounting of estimated costs, including various scenarios forecasting potential cost overruns and lack of federal funding support;
5. Greater explanation on the plant's anticipated fuel supply, with contingency plans if a domestic market is not available by 2028;
6. A detailed explanation of PacifiCorp's operating plans, including safety, worker training, and worker transition;
7. A clarification of whether this project would be a purchase power agreement ("PPA") arrangement or a PacifiCorp-owned resource. If it is a PPA, PacifiCorp should provide a detailed explanation for what protections will be in place for its customers regarding any project denials, delays or cost overruns;
8. A contingency plan for meeting resource needs if the plant is still in the planning or construction phase in 2028; and,
9. A detailed explanation, with documentation, on how PacifiCorp will protect itself and ratepayers from unforeseen cost overruns and delays.

VI. Risks Related to the Jim Bridger Gas Conversion

A. Overview of PacifiCorp's Proposed Coal-to-Gas Conversion of Jim Bridger Units 1 and 2

PacifiCorp's planned coal-to-gas conversion at Jim Bridger Units 1 and 2 by 2024[72] carries significant risk that is borne almost exclusively by ratepayers. Specifically, the Company's overly optimistic fuel cost forecasts combined with its artificial limitation on the types of capacity resource alternatives explains why the Company found the conversion to be economical. In reality, the Company has not adequately explained the details of the conversion.

[72] PacifiCorp 2021 IRP Vol. I at 24.

The Company's analysis of the conversion's impact on the preferred portfolio is examined in its variant run that excluded the gas conversion.[73] In its analysis, the Company concluded that the portfolio without the conversion is $477 million higher, or $469 million on a risk adjusted basis.[74] The Company claims that the project is cost-effective primarily because it has low capital costs relative to the alternative resource.

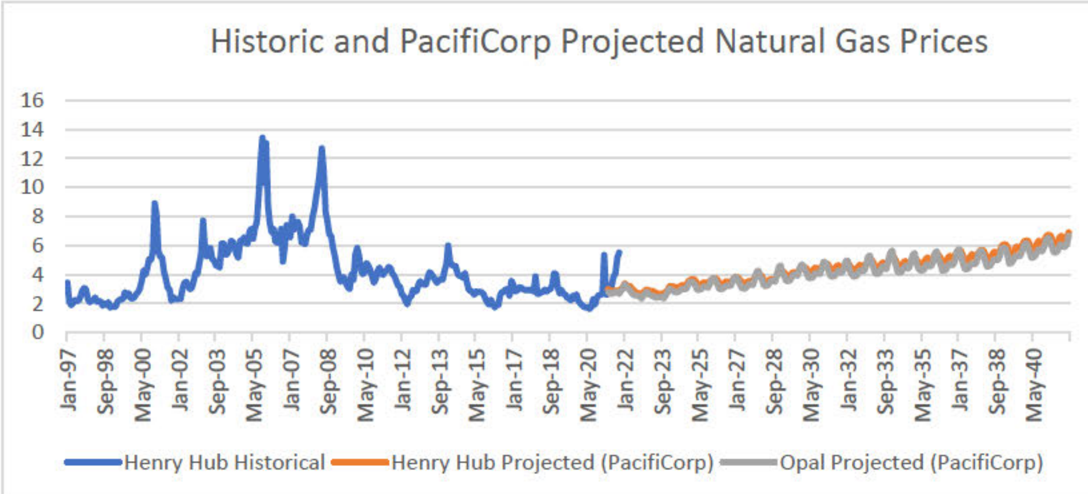
B. PacifiCorp's Proposed Gas Conversion Comes with Significant Price Risk.

Historically, the price of natural gas has been linked to crude oil prices, where both commodities' prices rose and fell together.[75] However, beginning in 2011, gas prices dropped, primarily due to the domestic shale fracking, and became relatively stable. A low, stable gas price was the norm for a decade. Consequently, we saw a dramatic shift in the electric sector as generation shifted from coal to fracked gas and then renewables.

PacifiCorp's IRP forecast expects these low prices to continue for the entire planning horizon. As shown in Figure 1, PacifiCorp's forecast for Henry Hub natural gas prices begins in April 2021 at just under $3/MMBtu, slowly rise to $4 in 2029, $5 in 2034, and ultimately top off at just under $7/MMBtu by 2041.[76]

[73] Variant P02a-JB1-2 GC.
[74] PacifiCorp 2021 IRP Vol. I at 270, Table 9.7 (comparing no conversion to P02-MM-MM portfolio).
[75] Peter Hartley et al., *The Relationship Between Crude Oil and Natural Gas Prices*, James A. Baker III Inst. for Pub. Policy at 8 (Nov. 2007), *available at* https://www.bakerinstitute.org/media/files/Research/c4d76454/ng_relationship-nov07.pdf.
[76] The most likely natural gas hub for the Jim Bridger plant is Opal, which closely mirrors Henry Hub but is usually 5-10 percent cheaper.

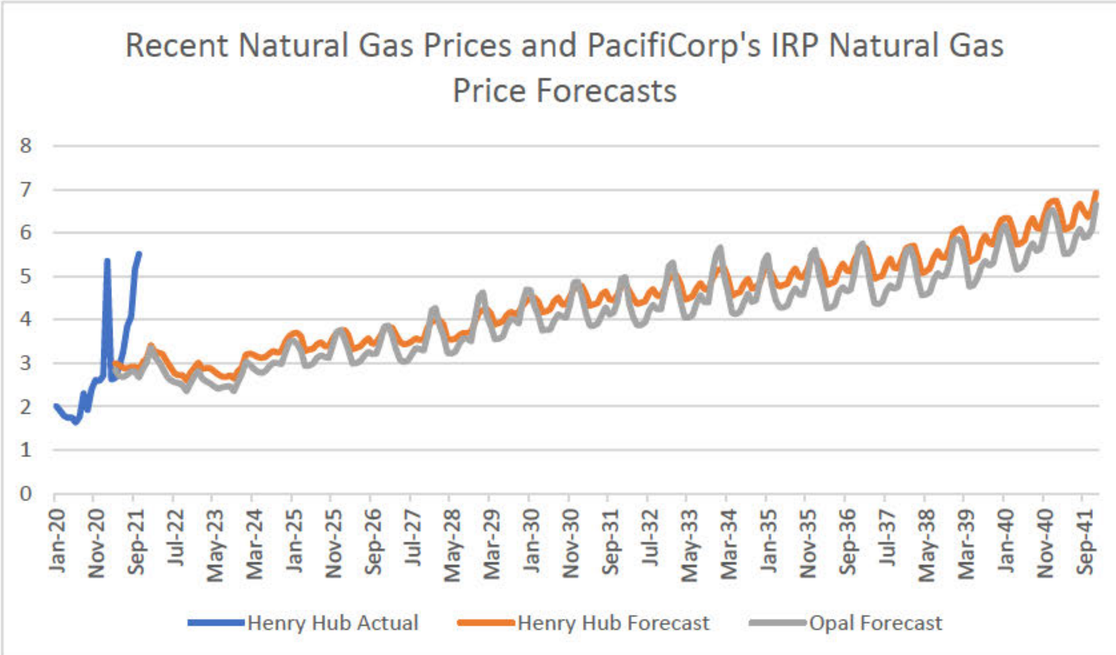
Figure 1. Historic Henry Hub Prices and PacifiCorp's IRP Natural Gas Price Forecast



However, gas prices have nearly doubled in the past year alone.[77] Prices rose sharply in February 2021 after the Texas winter storm, dropped quickly, but then immediately started a persistent climb in March 2021 until today. Because PacifiCorp had to lock in its gas price forecast as an input for its IRP in early 2021, we can track the Company's forecast to actual gas prices. Since April 2021, actual gas prices have significantly increased relative to the Company's forecast. In October 2021, the Henry Hub price for gas was \$5.51/MMBtu, nearly double the Company's forecast of \$2.84/MMBtu.

[77] Talmon Joseph Smith, *Winter Heating Bills Loom as the Next Inflation Threat*, The New York Times (Nov. 8, 2021), *available at* https://www nytimes.com/2021/11/08/business/economy/home-heating-prices-winter html?utm source=Sailthru&utm medium=email&utm campaign=Issue:%202021-11-08%20Utility%20Dive%20Newsletter%20%5Bissue:37856%5D&utm term=Utility%20Dive.

Figure 2. Henry Hub Prices Since January 2020, and PacifiCorp's Gas Price Forecast

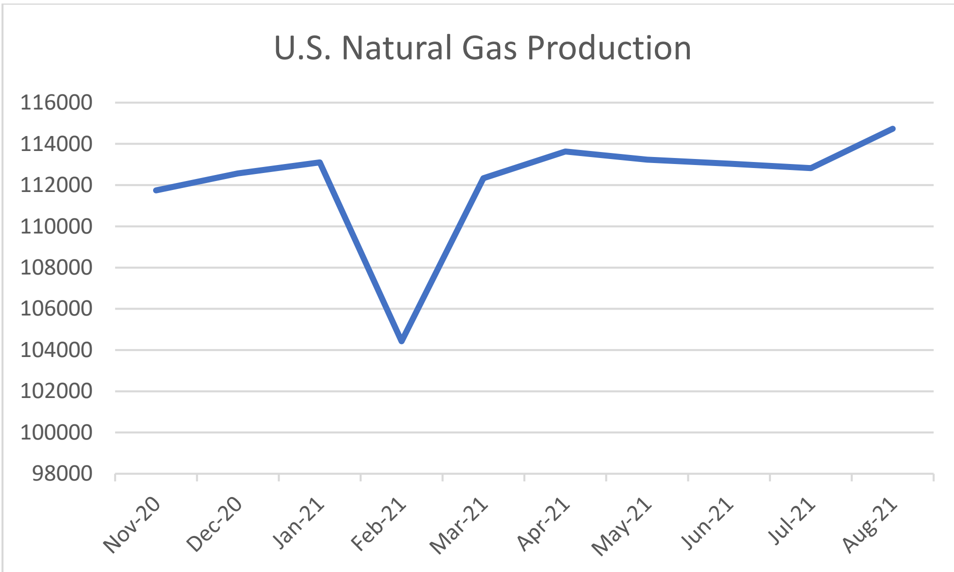


This year's dramatic increase in gas prices may be a relative blip and prices could decline once again; however, there is also a real chance high prices could persist as a "new normal." PacifiCorp is optimistic that prices will revert to their historic low. According to the IRP, as of June 30, 2021, gas futures show a high price of \$3.17/MMBtu, which is a "signal-to-drill" and will incent drillers to chase production efficiency and continue to drive down prices.[78] PacifiCorp continued that "[t]he North American natural gas supply curve continues to flatten as production efficiencies expose an ever-increasing resilient, flexible, and low-cost resource base."[79]

[78] PacifiCorp 2021 IRP Vol. I at 44.
[79] *Id.* at 46.

However, even as gas prices reached and then exceeded $3.17/MMBtu in 2021, rather than incentivizing drillers to chase production as PacifiCorp predicted, domestic fracked gas production has remained relatively flat since November 2020.[80]

Figure 3. U.S. Natural Gas Production



The domestic and international gas markets continue to evolve. European and Asian gas prices are higher than normal as demand outpaces supplies.[81] The United States is not immune to this global dynamic and, in fact, has much more international exposure now due to LNG expansion.[82] The cost of financing new fossil fuel projects, like fracked gas wells, and the distribution system for carrying that gas, is increasingly costly relative to alternative opportunities, like renewable

[80] *Monthly Crude Oil and Natural Gas Production*, U.S. Energy Info. Admin. (Nov. 30, 2021), *available at* https://www.eia.gov/petroleum/production/#ng-tab. The drop in February 2021 was caused by the Texas Winter Storm.
[81] Frederico Carita, LevelTen Energy, *A Perfect Storm: Understanding the European Energy Crisis* (Oct. 28, 2021), *available at* https://www.leveltenenergy.com/post/europe-energy-crisis.
[82] Victoria Zaretskaya, U.S. Energy Info. Admin., *U.S. liquefied natural gas exports grew to records highs in the first half of 2021* (July 27, 2021), *available at* https://www.eia.gov/todayinenergy/detail.php?id=48876.

generation.[83] Fossil fuel company shareholders are demanding higher returns after a decade of relatively low growth of returns.[84]

Based on our initial analysis, if gas prices held at $5/MMBtu in 2021 and increased at 3 percent annually until 2037,[85] PacifiCorp customers would spend an incremental $230 million on fuel costs during the plant's operation horizon from 2024-2037.

The purported economic benefits of the coal-to-gas conversion is further diminished upon closer scrutiny of PacifiCorp's other variant assumptions, as we will address in subsection (D).

Sierra Club does not purport to know future gas prices. However, we are well aware of the risks associated with investing in a long-term resource with an unknown long-term fuel cost relative to an alternative resource, such as renewables paired with storage, which has no fuel cost risks whatsoever. If the recent prices become "the new normal" then we are currently experiencing natural gas prices that PacifiCorp did not anticipate until 2034.

C. The Risk of Fuel Cost Volatility Is Borne by Customers, Not Shareholders.

As demonstrated above, there is significant risk associated with relying on a fossil fuel resource with variable, uncertain fuel costs, and that risk falls squarely on customers. In Utah, fuel costs are initially set through rate cases, with "true-ups" approved through the Energy Cost Adjustment Mechanism ("ECAM"). Utah customers pay 100 percent of the difference between base fuel costs set in the rate case and adjustments through the ECAM, meaning that PacifiCorp has no incentive to ensure that projected fuel costs established in a rate case track actual fuel

---

[83] Tim Quinson, *Cost of Capital Spikes for Fossil-Fuel Producers*, Bloomberg Green (Nov. 9, 2021), *available at* https://www.bloomberg.com/news/articles/2021-11-09/cost-of-capital-widens-for-fossil-fuel-producers-green-insight.

[84] Matt Egan, *US oil companies are in no rush to solve Biden's gas price problem*, CNN Business (Nov. 10, 2021), *available at* https://www.cnn.com/2021/11/10/energy/oil-gas-prices-joe-biden/index html?.

[85] PacifiCorp's forecast for Opal, the most likely gas hub for the Jim Bridger plant, increases 3.89 percent on average between 2024-2037.

costs. In other words, PacifiCorp can adjust its forecast annually in the ECAM, and thus can track the upward trajectory of costs, thereby limiting the Company's risk exposure when considering a long-term investment decision like the gas conversion. Neither the ECAM nor any other regulatory mechanism would have the utility share in the costs and benefits of its gas price forecast over the long-term. PacifiCorp would not assume that type of risk for its shareholders, but it is demonstrating its willingness to assign that risk to its customers.

We are especially concerned given that there is an abundant choice of alternative, clean capacity resources that do not carry this inherent fuel cost risk.

D. PacifiCorp's IRP Contains Unresolved Questions about the Coal-to-Gas Conversion Analysis.

In addition to the concerns raised above, the IRP does not provide a description of the plant nor the capital projects that the Company plans to undertake in order to convert Jim Bridger Units 1 and 2 to gas. The Company's action item for the conversion consists of five, broad steps that provide little meaningful detailed information.[86] The Company does not provide any explanation in the IRP on the expected fuel source, the type of permitting that must be completed, or if the converted units would be classified as a new or existing source for purposes of environmental compliance.

The Company also refers to the converted units as "peakers," but does not explain if the plant will operate as combustion turbines or will maintain and use the existing boilers. The Company's workpapers only compound the confusion by including multiple, disparate heat rates, which suggests two very different technologies. In one confidential workpaper, the Company

[86] *See* PacifiCorp 2021 IRP Vol. I at 24.

appears to use heat rates of [redacted] and [redacted] Btu/kWh for Jim Bridger 1 and 2 respectively,[87] and in another workpaper the heat rates are listed as [redacted] and [redacted].[88] Which heat rate, or rates, the Company uses as an input in its models has a tremendous impact on the outcome of the model run. But the IRP fails to provide any of this critical information.

Finally, as discussed in Section IV(F), the results of the No Gas Conversion variant that finds the conversion economical may be a result of PacifiCorp's overly restrictive number of potential replacement options in its IRP selection process. The No Gas Conversion variant includes over 600 MW of non-emitting peakers from 2031-2037, a future resource that is still speculative. But the Company limited its IRP capacity resource options to non-emitting peakers and nuclear additions, both of which are expensive, thus driving up the cost of replacing the gas conversion. The Company then used the results of the variant, based on the speculative costs of speculative resources, as justification for converting Jim Bridger Units 1 and 2 to gas. As discussed in Section IV(F), if PacifiCorp had included more resource options with high-capacity value beyond nuclear and non-emitting peakers, then the variant results could differ substantially.

E. PacifiCorp and Idaho Power Do Not Appear to be Aligned on the Gas Conversion Proposal.

As noted above, PacifiCorp does not appear to be appropriately coordinating with its co-owner of the Jim Bridger facility, Idaho Power. Idaho Power has publicly set a company goal to be 100-percent clean energy by 2045, and, as noted, has taken steps to accelerate the Jim Bridger depreciation schedule no later than December 31 2030.[89] However, just a few months after

[87] Confidential Plexos Inputs Workpaper accompanying the PacifiCorp 2021 IRP Application "Plexos Inputs – 2021 IRP 091021_CONF.xlsx".
[88] Confidential Jim Bridger Gas Conversation Master Assumptions Workpaper accompanying the PacifiCorp 2021 IRP Application "JB1+2_NGCv20210519 CONF.xlsx" tab "15 - Refuel CapEx".
[89] IPC Application at 1.

making its depreciation filing, Idaho Power and Idaho Commission Staff filed a joint motion requesting a suspension of the procedural schedule and discovery "to allow Movants the opportunity to assess this case in light of new developments that may impact the operation of the Jim Bridger Power Plant."[90] Those "new developments" turned out to (1) continued regulatory uncertainty regarding Regional Haze requirements at the plant and (2) PacifiCorp's announced gas conversions for Units 1 and 2. Idaho Power's filing indicates that PacifiCorp may not be coordinating its plans with its co-owner.[91] In addition to the questions raised above regarding cost and liability assumptions, this is concerning as PacifiCorp's conversion plan is fast-paced. The Company states that it intends to initiate the conversion process by finalizing an employee transition plan by the end of Q2 2022 and finalize close-out existing permits, contracts, and other agreements by the end of 2023. These plans appear aggressive, considering the various challenges, and PacifiCorp's lack of transparent communications and coordination with Idaho Power.

VII. PacifiCorp's Long-Term Resource Cost Assumptions Are Not Fully Informed by the Recent All-Source RFP Results.

PacifiCorp's assumptions regarding the cost of new clean energy resources are a key driver of its IRP portfolio results—particularly over the long term after it constructs the 2019 RFP finalist projects While many of PacifiCorp's cost and performance assumptions are

---

[90] *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 Motion to Suspend Procedural Schedule at 1 (Oct. 1, 2021), *available at* https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE2117/Company/20211001Joint%20Motion%20to%20Suspend%20Procedural%20Schedule.pdf.

[91] *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, Amended Application and Motion to Set Schedule (Feb. 16, 2022), *available at* https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE2117/CaseFiles/20220216Amended%20Application%20and%20Motion%20to%20Set%20Schedule.pdf.

consistent with other recent public data, some assumptions, as described in this section, are unsupported.

PacifiCorp retained Burns & McDonnell Engineering Company ("BMcD") to evaluate various renewable energy resources in support of the development of the 2021 IRP and associated resource acquisition portfolios and/or products. According to the Company, the resulting 2020 Renewable Resources Assessment and Summary Tables[92] provide a high-level comparison of technical capabilities, capital costs, and O&M costs that are representative of renewable energy and storage technologies. PacifiCorp made additional adjustments on some of the cost and performance parameters to reflect the Company's own experience and assessment.

PacifiCorp's assessment is fairly comparable with the most recent (2021) Annual Technology Baseline ("ATB") report by the National Renewable Energy Lab ("NREL") with the exception of battery storage cost estimates, which differ significantly. For example, PacifiCorp assumed that a 4-hour Li-Ion battery, that is available in 2021 and has a commercial operation year of 2023, has a capital cost of $1,820/kW, while NREL's ATB predicts $1,281-1,351/kW for 2021 installations and $1,070-1,275/kW for 2023 installations.[93] Similarly, PacifiCorp assumed a capital cost of $4,622/kW for an 8-hour battery, while NREL's ATB projects the cost to be $2,318-2,444/kW in 2021 and $1,937-2,307/kW in 2023. PacifiCorp's higher cost assumption combined with other flawed assumptions and modeling choices, such as the capacity contribution of hybrid solar plus storage assets (as discussed above in Section III(A)) and the low gas prices (as discussed above in Section VI), caused underinvestment in clean energy and storage technologies in the Company's optimized portfolios.

[92] PacifiCorp 2021 IRP Vol. II, App. M.
[93] NREL ATB estimates are expressed in $2019, but were adjusted to $2020 for a consistent comparison (using a 2.5% inflation assumption).

Regardless of how PacifiCorp developed its technology cost assumptions, it is problematic that these assumptions may not match the reality of actual project costs as informed by the recent all-source RFP bids. When PacifiCorp delayed its IRP filing from April to September, one of the justifications it provided was that the additional time would allow the Company to utilize the results of its all-source RFP for the modeling. That way, the most up-to-date market data could be reflected in the supply side resource cost assumptions and modeling. PacifiCorp included cost information for the specific projects resulting from the 2019 RFP to be deployed in the 2021-2024 timeframe, but did not necessarily use that information to inform its forecasts going further into the future, and instead reverted back to the BMcD forecast.

PacifiCorp confidentially provided some information on the 2019 project bids,[94] but it is still possible to develop a high-level comparison of the recent project cost data to PacifiCorp's future forecast. Focusing on the workpaper for the Dominguez I project (a 200MW/4hr battery energy storage system with a projected commercial operation date of mid-2024), the estimate for "All Fixed Costs With Network Upgrades" is [redacted]/kW for the first full year of operation (2025) escalating at [redacted] per year. In contrast, in Table 7.2 Total Resource Cost for Supply-Side Resource Options 21 IRP, PacifiCorp assumes a total fixed cost of $223.65/kW for 50MW/4hr Li-Ion battery.[95] This confirms that there is a significant discrepancy between PacifiCorp's model assumptions going forward and real-world project cost data it has recently received. Sierra Club recommends that PacifiCorp revise its long-term resource cost

[94] Unfortunately, values in the project-specific workpapers were hard coded and it is not fully transparent how their values were used to inform the final selection of resources.
[95] PacifiCorp 2021 IRP Vol. I at 177. in reference to this workpaper "3_0003_Dominguez_BSA_200MW_200_4H_UT_15YR_2024_2_A_B+F_IRPDataFix CONF.xlsx"

assumptions, particularly for battery storage (stand alone or paired with other resources), to better reflect the results of its RFP as it had promised in requesting a delay.

Dated: March 4, 2022

Respectfully submitted,

/s/ Rose Monahan
Rose Monahan (CA Bar No. 329861)
Staff Attorney
Sierra Club Environmental Law Program
2101 Webster Street, Suite 1300
Oakland, CA 94612
(415) 977-5704
rose.monahan@sierraclub.org

Attorney for Sierra Club