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BEFORE THE UTAH PUBLIC SERVICE COMMISSION

In the Matter of PACIFICORP, dba ROCKY MOUNTAIN POWER, 2019 Integrated Resource Plan	Docket 19-035-02

SIERRA CLUB'S OPENING COMMENTS

REDACTED VERSION

February 4, 2020

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

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SIERRA CLUB'S OPENING COMMENTS

1. INTRODUCTION AND SUMMARY

Sierra Club appreciates the opportunity to comment on PacifiCorp's 2019 Integrated Resource Plan (IRP). These comments were prepared with the assistance of Synapse Energy Economics, 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 2019 IRP public input meetings and all previous PacifiCorp IRP processes going back to 2011.

This IRP represents a step forward in many respects. PacifiCorp's coal unit assessments that identified several near-term economic coal retirements, not driven by specific capital requirements, are a particularly laudable new element of PacifiCorp's 2019 IRP. Sierra Club recognizes that PacifiCorp devoted extensive resources to conducting these assessments, to making additional modeling improvements, and to engaging stakeholders throughout the IRP process.

Nevertheless, Sierra Club remains concerned about several critical elements of PacifiCorp's IRP. Overall, Sierra Club is concerned that:

(1) PacifiCorp's decision to keep operating Jim Bridger Units 3 and 4 through 2037, rather than retiring those units in the mid-2020s, is not well supported by the evidence provided in this IRP.

(2) PacifiCorp's transmission Action Plan items are not well justified at this time. Sierra Club's specific sources of concern include:

- **The disconnect between the generation and transmission sections of PacifiCorp's Action Plan**. PacifiCorp's IRP does not commit to any specific new generation resource builds, but instead includes a plan to use an all-source request for proposals (RFP) to identify a least-cost set of generation projects. However, the IRP *does* request Commission acknowledgment of several specific transmission projects, including the $1.8 billion Gateway South line. The Company justified these transmission projects based on generation resources contained in the IRP Preferred Portfolio, resources to which the Company has not committed. If PacifiCorp's all-source RFP results in resource decisions that deviate from the IRP Preferred Portfolio, the Company's proposed near-term transmission expenditures could be rendered unnecessary.

- **Potential for lack of transparency and rigor in resource procurement decisions.** PacifiCorp's choice to make resource procurement decisions through a separate all-source RFP process raises the possibility that those decisions may not be subject to the level of rigor and transparency associated with an open and public IRP process.

- **Unnecessary resource additions under "reliability resource" methodology.** This IRP employed an unprecedented modeling approach wherein PacifiCorp added incremental resources beyond those initially selected by its capacity expansion model to ensure adequate levels of operating reserves. Unfortunately, this methodology likely resulted in far more resources than are necessary to maintain system reliability. PacifiCorp's approach arbitrarily added 500 megawatts (MW) of incremental resources beyond the reserves needs identified through its modeling. In addition, PacifiCorp overstated its calculated future operating reserves requirements, leading to further unnecessary resource additions in SO. These overstated reserves requirements increase portfolio costs, distort new resource selection, and bias the Company's analysis towards retaining existing coal units.

- **Bridger's coal mine capital costs were erroneously entered in the final Preferred Portfolio.** PacifiCorp's modeling of its Preferred Portfolio incorrectly applied the Company's own coal mine capital cost assumptions. This error caused the Company to understate the costs of its Preferred Portfolio and overstate the benefits of that portfolio relative to alternative resource plans in which the Bridger coal units retire earlier.

- **Understated coal price assumptions.** The Company's modeling assumed near-term fuel prices at the Jim Bridger coal plant that are far lower than recent historical levels. These lower fuel price assumptions bias the Company's analysis in favor of continuing to operate the Bridger coal units.

- **Failure to account for regulatory risk at Hunter and Huntington units.** There is a strong possibility that these units will be required to install selective catalytic reduction (SCR) pollution controls during the 2020s. PacifiCorp's IRP and capital spending plans do not sufficiently account for this risk.

- **Overstated solar operations and maintenance (O&M) cost assumptions.** PacifiCorp assumed solar resources will face fixed O&M costs that are approximately twice as high as industry-standard estimates. This assumption biases the Company's analysis against solar resources and in favor of existing coal units.

- **Emissions reductions in the Preferred Scenario are a function of dispatch assumptions, not retirements.** PacifiCorp asserts that by 2030, it will reduce its greenhouse gas emissions by nearly 60 percent from 2005 levels, and yet nearly half of those emissions reductions only occur after 2027, and through 2027 the majority of emissions reductions are only achieved through reduced dispatch, a purely operational assumption.

- **PacifiCorp has excluded opportunities to refinance the remaining plant balance of its existing coal fleet.** PacifiCorp's neighboring states in New Mexico and Colorado have recently enacted securitization legislation, allowing the remaining balance at existing coal plants to be refinanced upon retirement. Utah is currently considering similar legislation. If PacifiCorp were to harness such legislation, it would improve the ratepayer basis for retiring non-economic plants while minimizing impacts to PacifiCorp's bottom line. Instead, PacifiCorp elected to assume, across the board, that the utility is entitled to full recovery of and on remaining plant balance at otherwise non-economic coal plants.

Based on our review of PacifiCorp's IRP, Sierra Club makes the following recommendations:

- **The Commission should not acknowledge any transmission expenditures in PacifiCorp's Action Plan unless they are contingent on the Company's all-source RFP process identifying those expenditures as part of a least-cost resource plan.**

- **PacifiCorp's RFP process must include a level of transparency similar to the Company's IRP process.** Stakeholders should have the opportunity to participate fully in the RFP process, particularly if that process leads to resource procurement decisions that differ substantially from the IRP Preferred Portfolio.

- **PacifiCorp must better integrate an RFP process into its IRP process in future years.** Examples of such integrated processes can be found in other states, such as Indiana and Colorado.

- **The Commission should require PacifiCorp to revise its "reliability resource" methodology in its next IRP.** In addition, the Commission should not acknowledge any PacifiCorp resource decisions that are artifacts of the unnecessary "reliability resources" included in this IRP. Sierra Club's initial review suggests that, in the absence of its unprecedented reliability resource framework, PacifiCorp may have found a benefit to retiring all four Jim Bridger units by the mid-2020s.

- **The Commission should require PacifiCorp to re-evaluate the economics of each of its coal units in all future IRPs.** Given the varied and evolving economic pressures facing coal resources, it is critical that the Company continue to assess the viability of each coal unit, both on an individual basis and in combination.

- **The Commission should require that PacifiCorp's future IRP analyses**:

- Use reasonable, well-justified coal price assumptions;
- Correctly apply the Company's own Bridger coal mine capital cost assumptions;
- Quantitatively capture and evaluate reasonably foreseeable environmental compliance costs such as potential SCR requirements at the Hunter and Huntington plants; and
- Use reasonable, up-to-date cost assumptions for new resources such as solar and battery storage.

- **The Commission should investigate the potential for securitization to further reduce ratepayer costs when non-economic coal plants retire**.

2. UTAH COMMUNITY RENEWABLE ACT RESULTS STRAIN PACIFICORP PLANNED RENEWABLE COMMITMENTS

In March 2019, Governor Herbert signed Utah's Community Renewable Energy Act, HB 411, which allows municipalities and counties in Utah to opt into a commitment to receive a net 100% 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. In early 2019, it was still not clear how many communities would opt into the program outside of Salt Lake City, Summit County, and Park City.[1] However, by early January 2020, at least twenty-four (24) communities affirmatively elected to participate in the program,[2] representing a sizable fraction of Utah's demand.

In response to discovery provided as of January 2, 2020, PacifiCorp estimated the combined demand of fourteen (14) counties and cities as representing more than 70 percent of Utah's 2019 demand.[3] This value included the entire demand of Salt Lake County, rather than the unincorporated fraction of the County, which elected to meet the renewable energy goals under HB 411. However, even discounting the discrepancy, around 25 percent of Utah's load had opted into the program under those 14 communities. Since that time, another ten communities have opted into that program.

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[1] Angelique McNaughton, Summit County and Park City leaders celebrate signing of renewable energy legislation, Park Record (April 24, 2019), *available at* https://www.parkrecord.com/news/summit-county-and-park-city-leaders-celebrate-signing-of-renewable-energy-legislation/.

[2] Taylor Stevens, At least 24 Utah cities, counties pledge to use renewable energy by 2030, the Salt Lake City Tribune (Jan. 13, 2020) (Alta, Bluffdale, Castle Valley, Coalville, Cottonwood Heights, Emigration Township, Francis, Grand County, Holladay, Ivins, Kamas, Kearns, Millcreek, Moab, Oakley, Ogden, Orem, Park City, Salt Lake City, Salt Lake County, Springdale, Summit County, West Jordan, and West Valley City) As reported by the Salt Lake Tribune, January 13, 2020. https://www.sltrib.com/news/politics/2020/01/13/least-utah-cities/)

[3] Provided as Attach Sierra Club 4.1.xlsx in Oregon Pub. Util. Comm'n Docket LC 70.

We assessed if even PacifiCorp's planned renewable energy buildout would meet the anticipated needs of those communities that opted in, and found that PacifiCorp's renewable energy plans would be stretched thin by the commitments as they stand today.

In 2030, PacifiCorp's Preferred Portfolio anticipates about [redacted] percent renewable energy as a fraction of total load (including market and storage) by 2030. We assessed what would occur if Oregon, Washington, and California all opted to receive only power from non-coal resources (renewables, hydro, efficiency, markets, and gas), and if Utah's committed communities received power only from renewables, hydro, and efficiency. The remaining power was allocated to Utah's remaining customers, as well as Idaho and Wyoming. We assumed that neither Utah's remaining customers nor Idaho's customers would be satisfied receiving less than a pro-rata share of PacifiCorp's low-cost renewable energy, and that any unclaimed energy (largely coal and gas) would otherwise be allocated to Wyoming's customers, up to their demand.

Figure 1, below, shows our estimate of PacifiCorp's energy makeup in 2030 as a system, and then by jurisdiction, given current state priorities and statutes. As a whole, the system has approximately [redacted] percent renewable energy in 2030. Oregon, Washington, and California are allocated only non-coal energy (ratably), while Utah's Clean Communities are allocated only renewables, hydroelectric and efficiency (ratably), while the remainder of Utah and Idaho retain the system average mix. As a result, Wyoming is allocated more than [redacted] percent coal, and no renewable energy.

Confidential Figure 1. Energy makeup by resource type in 2030 with allocation to Utah Clean Communities.

[redacted]

This allocation leaves exactly [redacted] renewable energy above the demands of the states. If more than 25 percent of Utah's communities ultimately commit to 100 percent renewable energy, PacifiCorp's current plan would run short, or customers in the remainder of Utah, Idaho, and the western states would see a lower allocation than they currently expect.

Utah communities' commitment to rapidly adopting renewable energy and moving away from fossil fuels reflects a growing sentiment that ratepayers are looking for long-term sustainability, direct action that they can use to help address pressing climate concerns, and savings in the face of rising fossil costs and risk.

3. RFP PROCESS CONCERNS

PacifiCorp's Action Plan is the most important component of the 2019 IRP. While the Preferred Portfolio provides one vision of how PacifiCorp may meet its resource needs over the next two decades, it does not commit the Company to any particular resource choices. In contrast, the Action Plan lays out specific, near-term expenditures that PacifiCorp is committing to make, and for which the Company is seeking Commission acknowledgment.

The open-ended nature of the new generation resource section of PacifiCorp's Action Plan raises concerns. Other than a planned RFP for a small quantity of customer preference resources, the Company's only Action Plan item related to generation resource procurement involves conducting an all-source RFP process.[4] The Action Plan does not specify the need that this RFP is supposed to fulfill, the amount of resources sought, or any conditions on the term all-source.

The decision to issue an all-source RFP is not itself objectionable. However, the open-ended nature of the new resources portion of the Action Plan raises three concerns:

1. The uncertainty in the generation resource section of the Action Plan is inconsistent with PacifiCorp's request for acknowledgment of specific new transmission projects that only make sense in the context of specific renewable generation projects.
2. There is no guarantee that the RFP process will be either transparent or rigorous.
3. It is not clear which, if any of PacifiCorp's intended existing resource replacements are contingent on the outcome of an RFP process.

We discuss each of these concerns in greater detail below.

A. Disconnect between transmission and generation resource Action Plan items

Although the generation resource section of PacifiCorp's Action Plan section does not commit to any particular resource builds, the transmission section is much more specific. PacifiCorp's Action Plan seeks Commission acknowledgment of plans to construct two major new

[4] PacifiCorp 2019 IRP, Volume I, pp. 23-24.

transmission lines[5] and complete transmission reinforcement projects in four separate parts of the Company's system.[6] The most significant transmission action item in PacifiCorp's IRP is a plan to construct and place in service the 400-mile, 500-kilovolt Gateway South transmission line by December 2023. The Company estimates that this project will cost approximately $1.8 ***billion***.[7]

The problem with PacifiCorp's transmission action items is that they are tied to notional generation resources that the Company *is not* committed to developing and for which the Company has not established a tangible need.

Table 1.1 of PacifiCorp's IRP (part of which is reproduced below as Table 1) identifies the Preferred Portfolio generation resources that are associated with the near-term transmission expenditures that are included within the Company's Action Plan.[8] This table shows, for example, that the Gateway South project is designed to connect 1,920 MW of wind. Elsewhere, the IRP states that the proposed timeline for developing Gateway South "is driven by the phase-out schedule of federal production tax credits (PTCs), particularly the 2023 in-service requirement for 40 percent PTC eligibility."[9] In other words, near-term PTC availability drives the inclusion of 1,920 MW of wind included in the Preferred Portfolio, and the selection of that wind in turn is the basis for the Gateway South Action Plan item. Similarly, northern Utah transmission reinforcement projects included in PacifiCorp's Action Plan are explicitly identified as supporting Preferred Portfolio resource additions.[10]

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[5] Gateway South and Boardman to Hemingway.
[6] PacifiCorp 2019 IRP, Volume I, pp. 24-25.
[7] *Id.*, p. 8, Table 1.1.
[8] *Id.*, p. 8, Table 1.1.
[9] *Id.*, p. 74.
[10] *Id.*, p. 25.

Table 1. Near-Term Transmission Projects Included in 2019 IRP Preferred Portfolio

Year	Resource(s)	From	To	Description
2023	69 MW Wind (2023) 231 MW Solar (2024)	Within Southern UT Transmission Area		Enables 300 MW of interconnection: UT Valley 345-138 kV + 138 kV reinforcement ($8m)
2024	354 MW Solar (2024)	Within Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger 1 ($0)
2024	674 MW Solar (2024)	Within Northern UT Transmission Area		Enables 600 MW of interconnection: Northern UT 345 kV reinforcement ($30m)
2024	1,920 MW Wind (2024)	Aeolus WY	UT North	Enables 1,920 MW of interconnection with 1,700 MW of TTC: Energy Gateway South ($1,752m)
2024	395 MW Solar (2024) 10 MW Wind (2029)	Within Yakima WA Transmission Area		Enables 405 MW of interconnection: local reinforcement ($3m)

Source: PacifiCorp 2019 IRP, Volume I, p. 8.

But, critically, PacifiCorp is not committing to developing ***any*** of the generation resources from its Preferred Portfolio. If PacifiCorp's planned all-source RFP results in generation resource procurements that deviate from the IRP Preferred Portfolio, the Company's proposed near-term transmission expenditures would be unnecessary and wasteful. The Company is asking the Commission to approve billions of dollars in transmission projects on the basis of the *possibility* that PacifiCorp *might* develop generation resources that would require those transmission projects.

One possible solution to this concerning disconnect is for the Commission to condition acknowledgment of PacifiCorp's transmission Action Plan items on PacifiCorp demonstrating a tangible need for transmission-connected generation resources and the all-source RFP process verifying that those items are part of a least-cost resource plan. In this way the Commission could avoid prematurely acknowledging costly near-term transmission plans that may not be warranted.

Alternatively, the Commission could decline to acknowledge the proposed transmission projects until PacifiCorp has demonstrated that those projects are part of a least-cost plan to meet specified resource needs.

Regardless of which of these approaches it pursues, the Commission should ensure that PacifiCorp's all-source RFP procurement process accounts for the incremental transmission costs associated with potential remote generation resources. Transmission expenditures included in the Action Plan should be treated as the new, incremental costs that they are, not as sunk investments for new generation resources to take advantage of at no additional cost. If local resource developers can provide lower-cost projects by avoiding incremental transmission, PacifiCorp should seek to meet its system requirements through such local resources, including distributed generation, distributed storage, and demand-side management programs.

B. Need for transparency and oversight in RFP process

PacifiCorp's 2019 IRP, and its associated Preferred Portfolio, marks the culmination of a process that involved extensive modeling and regular stakeholder engagement. While Sierra Club has concerns with some aspects of the IRP and the Preferred Portfolio, we appreciate the effort that PacifiCorp has put into its IRP analyses and the level of transparency that the IRP process has afforded. Yet, given the nature of the IRP Action Plan, the generation resource selection component of the IRP may have little, if any, bearing on PacifiCorp's future resource procurement. Instead, resources will be procured through an all-source RFP. This raises the concern that the ultimate resource selection process may be much less transparent and rigorous than the IRP.

To address this concern, Sierra Club recommends that the Commission ensure that PacifiCorp's RFP process contain a level of transparency that is similar to its IRP process. The Commission should require that PacifiCorp receive approval on the form of the all-source RFP prior to its issuance, that PacifiCorp engage an independent assessor who exclusively reports back to the Commission, and that PacifiCorp identify and explain any substantial deviations between its IRP Preferred Portfolio and the near-term resource plans that result from the RFP process.

C. Lack of clarity on whether existing resource retirement decisions would be impacted by RFP results

An important aspect of an all-source RFP is that it is meant to elicit a least-cost portfolio of resources, rather than pre-select individual technologies. A well-designed all-source RFP could identify a portfolio of new clean energy resources that costs less than the IRP Preferred Portfolio. Under such a circumstance, it is possible that the RFP results could underprice existing fossil resources more than PacifiCorp currently anticipates. However, because the RFP will be conducted separately from the IRP process, it appears unlikely that PacifiCorp's process will enable the RFP results to affect its decisions regarding existing resources. To address this concern, Sierra Club recommends that PacifiCorp's RFP resource assessments allow potential new resources to displace existing coal resources when searching for a least-cost outcome.

D. Potential for better integration of RFP and IRP processes

In the future, the Company could reduce the potential for disconnects between its IRP Preferred Portfolio and near-term resource procurement by better integrating its RFP and IRP processes. Some utilities and states have successfully adopted a process in which the issuance of an RFP is a step in the IRP process. For example, Northern Indiana Public Service Company's (NIPSCO) 2018 IRP incorporated an RFP process that revealed that renewable resource options were cheaper than some generic estimates had indicated.[11] In Colorado, regulated utilities are required to issue RFPs as part of their resource planning processes.[12]

The approaches used by NIPSCO and Colorado utilities ensure that resource options modeled in the IRP process are tied to concrete potential projects. This approach could resolve each of Sierra Club's core concerns with the RFP component of PacifiCorp's Action Plan.

During the stakeholder process, Sierra Club and other parties recommended that PacifiCorp consider issuing either a full-scale RFP or an explicit market-testing RFP to inform costs and assumptions in the IRP. If a formal RFP or market-testing RFP had been conducted as part of PacifiCorp's IRP, the Company would be more confident that its proposed near-term transmission expenditures are justified by their association with low-cost generation resource projects. Embedding an RFP within an IRP process that is already designed to solicit stakeholder feedback would also ensure a greater degree of transparency with respect to the Company's resource procurements. Finally, grounding IRP new resource cost assumptions in recent RFP results would allow for greater confidence in PacifiCorp's assessments of existing coal units relative to potential new resources.

4. PACIFICORP'S "RELIABILITY RESOURCE" MODELING APPROACH IS NOT SUPPORTED AND LIKELY RESULTS IN UNNECESSARY COSTS.

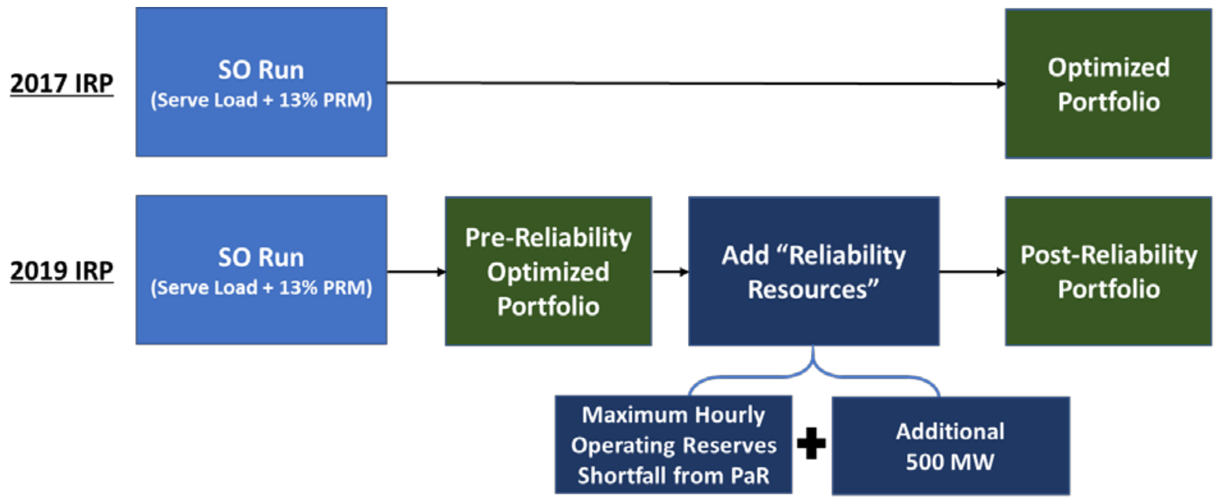
One of the most untested and impactful aspects of PacifiCorp's 2019 IRP process is the Company's new method for ensuring that its Preferred Portfolio contains enough flexible resources to maintain system reliability. As in previous IRPs, the Company made use of two models to develop and evaluate alternative portfolios: the System Optimizer (SO) capacity expansion model and the Planning and Risk (PaR) production cost model. However, the greatest difference between the 2019 IRP modeling and the modeling conducted for previous IRPs lies in the iteration between these two models.

In previous IRPs, for each scenario PacifiCorp would run SO once to create a low-cost portfolio and would then run PaR to develop detailed cost and reliability metrics for that portfolio. For the 2019 IRP, the Company still used SO to develop an initial portfolio, and still ran that portfolio through PaR, but only used its initial PaR runs for the purposes of "reliability" assessments.[13] PacifiCorp used these assessments to identify any capacity reserve shortfalls associated with the initial SO portfolio. PacifiCorp would then re-run SO, holding constant the resources selected in the initial SO run but allowing the model to add or accelerate "reliability resources" including

[11] NIPSCO, 2018 Integrated Resource Plan (Oct.2018), *available at* https://www.nipsco.com/our-company/about-us/regulatory-information/irp.
[12] 4 Colo. Code Regs. § 723-3-3616.
[13] PacifiCorp 2019 IRP, Volume II, Appendix R, pp. 609-611.

batteries, energy efficiency, gas peaking resources, and pumped storage resources.[14] The Company based the level of incremental "reliability resources" to be added in the secondary, "reliability" SO runs on the maximum hourly reserves shortfall identified through the PaR reliability assessment plus an *additional 500 MW buffer* to account for uncertainty in reserves requirements.[15] PacifiCorp used these "reliability runs" in SO to develop "reliability portfolios" that were ultimately run through PaR to develop detailed cost, risk, and reliability metrics. Figure 1 displays the core differences between the portfolio development processes used in PacifiCorp's 2017 and 2019 IRPs.

Figure 2. Portfolio Development Process, 2019 IRP vs. 2017 IRP



Source: PacifiCorp 2019 IRP, Volume II, pp. 609-611

Sierra Club recognizes the importance of maintaining enough flexible capacity to ensure system reliability in a high-renewables future. Sierra Club further understands that meeting energy and peak capacity requirements is not necessarily sufficient to ensure the reliability of a portfolio, particularly as ramping and other ancillary service requirements increase. However, Sierra Club is concerned that some elements of PacifiCorp's "reliability run" approach are poorly supported, will result in unnecessarily high system costs, and may have biased the Company's modeling against further economic coal plant retirements.

[14] *Id.*, Appendix R, p. 611.
[15] *Id.*, Appendix R, p. 610.

A. PacifiCorp's incremental 500 MW of "reliability resources" is not supported by the evidence provided by the Company, and appears to double-count reserve requirements.

Sierra Club's greatest concern with PacifiCorp's new, "reliability run" methodology is its inclusion of an additional 500 MW of capacity beyond any shortfalls identified through its PaR modeling runs. This 500 MW incremental requirement relied on double-counting various risks and uncertainties, is grounded in operational practice during a single historical year rather than an assessment of future needs, and amounts to an arbitrary rejection of the actual modeling and analyses that the Company conducted.

PacifiCorp claimed that the incremental 500 MW are needed "to address significant day-ahead, hour-ahead and real-time unknowns in market supply," including variances in load, thermal plant outages, and renewable generation output.[16] But the portfolios that PacifiCorp developed already account for these sorts of "unknowns" through the Company's application of a target planning reserve margin (PRM), hourly operating reserves requirements, and conservative market reliance limits.

All of the Company's SO runs incorporate a 13 percent PRM based on PacifiCorp's own PRM study.[17] The Company's PRM study was designed to identify a reserve margin that meets reliability targets at a "low reasonable cost,"[18] accounting for variability and uncertainty in future load and generation capability.[19] According to PacifiCorp, the purpose of its PRM is to "ensure that [the] . . . IRP portfolios a) meet customer load b) while maintaining operating reserves, c) meeting a one day in ten year reliability target, d) at a low reasonable cost."[20] In addition, PacifiCorp conducted a Flexible Reserve Study (FRS) to estimate the amount of reserves needed "to manage variations in load, variable energy resources (VERs), and resources that are not VERs" in each of its balancing authority areas.[21] Based on the FRS, PacifiCorp's PaR modeling applied portfolio-specific hourly reserves requirements to cover "the combined deviations of the load, wind, solar and Non-VERs on PacifiCorp's system."[22] Finally, PacifiCorp conducted its own study of regional resource availability and set strict limits on market reliance in all of its modeling runs to ensure that it would not rely excessively on uncertain market availability.[23] Thus, prior to adding the 500 MW of incremental "reliability resources" PacifiCorp has, theoretically, already accounted for "unknowns in market supply," uncertainty in regional

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[16] *Id.*, Appendix R, p. 610.
[17] PacifiCorp 2019 IRP, Volume I, p. 97; PacifiCorp 2019 IRP, Volume II, Appendix I , pp. 137-146.
[18] North American Reliability Corporation. Reserve Margin (NERC) M-1 *available at* https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx (last accessed Jan. 9, 2020).
[19] PacifiCorp 2019 IRP, Volume II, Appendix I, p. 137.
[20] *Id.*
[21] *Id.*, Appendix F, p. 77.
[22] *Id.*, Appendix F, p. 78.
[23] *Id.*, Appendix F, p. 155.

resource availability, variability and uncertainty in future load and generation capacity, variations in load and variable energy resource output, and reliability requirements. The addition of the incremental 500 MW of "reliability resources" were not justified by PacifiCorp's explanation and, as detailed below, were not supported by any of the Company's evidence.

The details of the calculations underlying PacifiCorp's incremental 500 MW capacity requirement further show that this requirement is not needed and is redundant with capacity requirements incorporated during other stages of the Company's modeling. The Company's IRP explains that the 500 MW value was calculated by rounding the sum of 295 MW representing 2018 "capacity held in reserve that is incremental to the 13 percent planning margin" and 241 MW "held in reserve to mitigate risk during peak load conditions."[24] Neither of these values are justified based on the evidence provided by the Company.

The Company states that the 295 MW value represents "capacity held in reserve," implying that PacifiCorp's operators were required to hold that amount in operational reserve to maintain the system. However, the 295 MW is derived as the difference between the amount of reserves held during a single peak hour in a historic year and the quantity of reserves associated with a 13 percent reserve margin during that hour. In other words, PacifiCorp's approach assumes that since the Company happened to have held 16 percent in reserves during the peakiest hour of a historic year, it should ensure that it maintains reserves consistent with a 16 percent reserve margin in all future years. This is a clear case of the Company disregarding its own extensive PRM and FRS analyses and supplementing its modeled requirements with additional reserve requirements based on a single hour of historical operational data. PacifiCorp's approach both implicitly rejects the Company's own 13 percent PRM assumption and does not consider the possibility that the hourly reserves requirements already applied as a result of its FRS study may be greater than 13 percent in some hours.

The Company's inclusion of the additional 241 MW to reflect "risk during peak load conditions" is even less reasonable than the 295 MW increment. PacifiCorp calculated the 241 MW quantity as the average difference between actual and forecasted loads during high-load hours in a historic year. These load variations appear to represent exactly the sort of deviations that are covered by the reserves requirements resulting from PacifiCorp's PRM and FRS analyses. In addition to being redundant with PRM and FRS requirements, these incremental 241 MW are almost certainly double-counted with the Company's application of 295 MW to account for reserves historically held during peak load times. Finally, in each of PacifiCorp's identified averaged historic year high-load hours, PacifiCorp forecasted substantially greater demand than actually materialized. Therefore, what PacifiCorp casts as uncertainty requiring incremental reserves is actually an upward bias in the Company's load forecast, which indicates that the Company may

[24] *Id.*, Appendix R, p. 611.

be holding excessive reserves during peak periods. In short, not only was PacifiCorp unlikely to be short of capacity during those hours, a core component of its "reliability resource" requirement is derived from over-forecasting demand.

Overall, there is no evidence to support PacifiCorp's decision to add 500 MW of incremental capacity requirements from a limited set of resource options to each of the portfolios it assessed. Sierra Club recommends that the Commission ignore modeling results that are artifacts of this 500 MW requirement and require PacifiCorp to revise or eliminate this aspect of its modeling in its next IRP.

B. PacifiCorp's FRS overstates the Company's future operating reserves requirements.

Besides arbitrarily adding 500 MW to its reserves requirements in a manner that is inconsistent with its PRM and FRS analyses and unsupported by the provided documentation, PacifiCorp calculated its underlying operating reserves requirements in a manner that overstated its future need for reserves. PacifiCorp's calculations misrepresent the nature of current operations within the Western Energy Imbalance Market (EIM) and do not account for known and likely developments in the EIM that would reduce PacifiCorp's need to hold operating reserves.

PacifiCorp's method for calculating its hourly operating reserves requirements involved estimating the uncertainty in generation output. PacifiCorp calculates this "uncertainty" as the historical deviation between hourly base schedules submitted to the EIM (i.e. what EIM-participating generators would be expected to output in the absence of the EIM) and the actual metered output at each generator.[25] But a substantial fraction of these deviations reflects not uncertainty but, rather, specific operational decisions to adjust unit output levels in response to real-time price signals provided by the EIM. Indeed, these deliberate, cost-saving adjustments to base schedules represent one of the core benefits of the EIM. In incorrectly assuming that all historical deviations between hourly base schedules and actual generation represent unforeseen variability rather than intentional adjustments, PacifiCorp overestimated the degree of operational uncertainty and its need for reserves to address that uncertainty.

PacifiCorp further overstated its future operating reserves requirements by failing to account for the increased system diversity benefits that result from additional utilities joining the EIM. As PacifiCorp explained, the EIM reduces the quantity of reserves that each of its participants needs to hold by pooling variability in load, wind output, and solar output.[26] The Company used historical data to estimate that this EIM diversity benefit reduces PacifiCorp's regulation reserves

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[25] PacifiCorp 2019 IRP, Volume II, Appendix F, pp. 83, 92.
[26] *Id.*, Appendix F, p. 101.

requirements by about 16 percent.[27] But this historical benefit only accounts for the diversity provided by the electric systems that participated in the EIM in 2019. As PacifiCorp's IRP highlights, more participants are expected to join the EIM over the next three years than have joined in the entire history of the EIM to date.[28] These additional participants will bring incremental diversity benefits.[29] In not accounting for these incremental benefits, PacifiCorp overstated its future reserves requirements.

Besides adding new participants, the EIM is likely to evolve in ways that will further reduce reserves requirements in the coming decade. According to PacifiCorp, EIM participants are currently exploring the potential benefits of an extended day-ahead market (EDAM) in the west.[30] An EDAM would result in further cost reductions and increased system diversity benefits by incorporating day-ahead unit commitment and scheduling rather than just real-time scheduling adjustments.[31] Since the nature of the future EDAM is uncertain, PacifiCorp has not evaluated the implications of the EDAM for its reserves requirements.[32] Yet, while the details remain unclear, any realistic version of the EDAM would only reduce PacifiCorp's operating reserves requirements. In not accounting for these effects the Company further overstated future operating reserve requirements.

C. PacifiCorp's flawed "reliability resource" additions substantially affect portfolio costs, resource selection, and coal unit retirement decisions.

By requiring the addition of incremental capacity, the Company's "reliability resource" modeling resulted in increased costs. For example, PacifiCorp's "mid" scenario SO modeling indicates that the "reliability" version of the Company's Preferred Portfolio would result in [redacted] in incremental net present value (NPV) costs relative to the initial, "pre-reliability" version of the same portfolio.[33] Since the resources added in the "reliability run" were added to meet overstated reserves needs (including both operating reserves requirements applied within PaR runs and the 500 MW added on to the Company's calculated reserves requirements), the costs associated with many of those incremental resources are likely unnecessary.

PacifiCorp's use of overstated and poorly supported reserves requirements in its reliability runs also affects near- and medium-term resource decisions in important ways. Under the initial, "pre-

[27] *Id.*, Appendix F, pp. 101-102. ((531-635)/635) = 16 percent reduction relative to reserves requirements in absence of EIM benefit.
[28] PacifiCorp 2019 IRP, Volume I, p. 2.
[29] PacifiCorp 2019 IRP, Volume II, p. 102.
[30] PacifiCorp 2019 IRP, Volume I, p. 67.
[31] California ISO, *Extended day-ahead market issue paper* (presentation), p. 4, (Oct. 17, 2019) available at http://www.caiso.com/StakeholderProcesses/Extended-day-ahead-market.
[32] PacifiCorp Response to Sierra Club Data Request No. 3.11(d).
[33] Compare Workpaper "SO Portfolio I19-P45CNW-MMR_1909221006_CONF.xlsm", tab "PVRR Table," Cell X54 with Workpaper "SO Portfolio I19-P45CNW-MM_1909191828_CONF.xlsm", tab "PVRR Table," Cell X54.

reliability" version of the Company's Preferred Portfolio, no new gas resources are built until [redacted][34] Yet under the "reliability run" version of the Preferred Portfolio that PacifiCorp's IRP advances, the first new gas unit is built in 2026.[35]

The Company's reliability runs also have weighty implications for its coal retirement decisions. The portfolios that PacifiCorp's IRP focused on included a portfolio labeled P-45, upon which the Preferred Portfolio is based, and a portfolio labeled P-36. The key difference between these portfolios is that under P-45 one unit at the Jim Bridger plant retires in 2023, one retires in 2028, and the remaining two units continue operating through 2037, whereas under P-36 all four Bridger units retire in 2025.[36] PacifiCorp's pre-reliability, base SO runs indicated that P-36 was lower-cost than the Company's Preferred P-45 by [redacted] in NPV terms (see Table 2).[37] However, the Company's post-reliability SO runs indicated that P-36 would cost $73 million *more* than P-45 in NPV terms.[38] This [redacted] differential, which arises directly from PacifiCorp's application of overstated reserves requirements, was evidently a decisive factor in the Company's decision to pursue the near-term retirement of only one Bridger unit rather than all four units.

Table 2. NPV Revenue Requirements Under Pre-Reliability and Post-Reliability Runs, P-45 & P-36 (2018 $Million)

	P-45	P-36	P-45 minus P-36
Pre-Reliability	$21,185	$21,065	$120
Post-Reliability	$21,480	$21,553	($73)
Change	$294	$488	($194)

Source: PacifiCorp SO Output Workpapers

The role of PacifiCorp's reserves requirement assumptions in its decision to keep operating Bridger Units 3 and 4 through 2037 is further indicated by the Company's projections of those units' operations. Under the mid scenario Preferred Portfolio SO run, from 2026 through 2037 Bridger Unit 3 has an average capacity factor of about [redacted] percent and Bridger Unit 4 has an average capacity factor of about [redacted] percent.[39] It is unlikely that either unit would be able to provide sufficient energy value to offset its costs while operating with such remarkably low

[34] Workpaper "SO Portfolio I19-P45CNW-MM_1909191828_CONF.xlsm", tab "Portfolio Sum," rows 10-11.
[35] PacifiCorp 2019 IRP, Volume I, p. 12.
[36] PacifiCorp 2019 IRP, Volume II, Appendix M, pp. 360, 362.
[37] Compare Workpaper "SO Portfolio I19-P45C-MM_1908231907_CONF", tab "PVRR Table," Cell X54 with Workpaper "SO Portfolio I19-P36C-MM_1909131319_CONF", tab "PVRR Table," Cell X54.
[38] Compare Workpaper "SO Portfolio I19-P45CP-MMR_1909142325_CONF", tab "PVRR Table," Cell X54 with Workpaper "SO Portfolio I19-P36CP-MMR_1910081224_CONF", tab "PVRR Table," Cell X54. *See also* PacifiCorp 2019 IRP, Volume II, p. 159, Table K.3.
[39] Workpaper "SO Portfolio I19-P45CNW-MMR_1909221006_CONF.xlsm", tab "Capacity Factor," row 28-29.

frequency. However, PacifiCorp's new reliability resource methodology assigns greater value to these units by exaggerating the Company's need for non-variable generation resources to provide ancillary services.

5. JIM BRIDGER IS LESS ECONOMICALLY VIABLE THAN PORTRAYED BY PACIFICORP

As noted in our introduction, PacifiCorp has made substantial strides towards assessing the economic viability of its coal fleet. Like many other utilities across the country, PacifiCorp reached the conclusion that many of its existing generators are not reasonable to continue operating over the long run, or in some cases, the short run. During the development of this IRP, it rapidly became clear that Naughton, Jim Bridger, Cholla, Hayden, and Craig are economically marginal, even without additional capital risks. Despite the unprecedented attention brought to non-economic coal by PacifiCorp in this filing and process, we have remaining concerns about PacifiCorp's findings and conclusions, specifically with respect to Jim Bridger. First, we note that Idaho Power Company, a co-owner at Bridger, has now issued an exit plan for the plant that is substantially faster than PacifiCorp. Second, we identify an error in the Company's transcription of coal mine capital costs that has material impact on the Company's findings. Finally, we identify that the Company's assessment of future coal costs at Bridger is inconsistent with historical costs.

A. Idaho Power anticipates an earlier closure of Jim Bridger than PacifiCorp

On January 31, 2020, Idaho Power revised its 2019 IRP, originally submitted in June 2019. Idaho Power is a 40 percent co-owner at Jim Bridger, both in at the plant and the Bridger Coal Mine which largely supplies the plant. Both the original Idaho Power IRP and the updated IRP call for the retirement of two Jim Bridger units in the Action Plan window, in 2022 and 2026, respectively,[40] or earlier than PacifiCorp's call for closure in 2023 and 2028 respectively.

In addition, Idaho Power's amended IRP found that coal plants did not serve customers' best interests. As noted by the utility:

> *The Amended 2019 IRP also indicates favorable economics associated with Idaho Power's exit from five of seven coal-fired generating units by the end of 2026 and exit from the remaining two units at the Jim Bridger facility by the end of the 2020s.*[41]

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[40] Idaho Power 2019 IRP, Amended January 31, 2020. Table 1.2 https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2019/2019_IRPUpdated.pdf

[41] Idaho Power 2019 IRP, Amended January 31, 2020. Page 5.

PacifiCorp's Preferred Portfolio calls for the retirement of Jim Bridger units in 2023, 2028, and 2037 (two units). In contrast, Idaho Power's IRP calls for the retirement of Jim Bridger units in 2022, 2026, 2028, and 2030.

The Idaho Power 2019 IRP specifically assessed the early retirement of all four Jim Bridger units in timeframes similar to that of PacifiCorp, and a few that were faster. Idaho Power found that the fastest exit scenario, with the full closure of Jim Bridger prior to 2030, saved Idaho consumers over $80 million relative to a scenario most similar to PacifiCorp's (2022, 2026, and 2034, respectively).[42]

Idaho Power explains that while "the 2017 IRP preferred portfolio included early exits from two units at Jim Bridger in 2028 and 2032… the 2019 IRP analysis has determined it is economical to exit all four coal units early at Jim Bridger."[43]

Like PacifiCorp, Idaho Power is in possession of all relevant information about the long-term potential costs and benefits of operating Jim Bridger. Unlike PacifiCorp, Idaho Power is exposed to a much higher risk, on a proportional scale, than PacifiCorp for the continued operation of a non-economic plant. So while PacifiCorp has a regulatory incentive to seek a low cost outcome that may include various coal retirements, Idaho Power faces the very real potential that committing to operate a coal plant over the long run could have a significant impact on ratepayers.

We are concerned that PacifiCorp has potentially missed details critical to the long-term risks faced at Jim Bridger; risks that have been recognized by Idaho Power.

B. Jim Bridger's coal mine capital costs are in error in the Preferred Portfolio.

PacifiCorp used an incorrect scenario for the capital costs of the Bridger coal mine in the Preferred Portfolio, a material error leading PacifiCorp to understate the cost the Preferred Portfolio by about [redacted] in NPV terms. This same error does not appear in other scenarios that test earlier retirements of the Jim Bridger plant. As a result, the Company's selection of a later retirement date for Jim Bridger 3 & 4 is in error, and the Company has over-stated the cost to retire the whole plant earlier.

PacifiCorp's IRP modeling incorporates forecasted capital expenditures at the Bridger coal mine that is co-located with the Company's Jim Bridger coal plant. This is because, PacifiCorp

[42] Idaho Power 2019 IRP, Amended January 31, 2020. Pages 109-111. Assessment of Bridger Scenario 4 ($5,996,478,000 NPV) against Scenario 3 ($6,076,723,000 NPV) in Portfolio 16 under base planning assunptions.
[43] Idaho Power 2019 IRP, Amended January 31, 2020. Page 12.

explains, Bridger mine capital costs are recoverable from the Company's retail customers.[44] For the 2019 IRP, PacifiCorp developed several different sets of alternative Bridger coal mine retirement and capital cost assumptions. The Company selected one of the alternative Bridger coal mine plans for each resource portfolio, based primarily on the Bridger coal unit retirement assumptions associated with that portfolio.[45] Unfortunately, the Company's modeling of its Preferred Portfolio mistakenly applied Bridger coal mine capital costs associated with the wrong Bridger coal mine plan. This error caused the Company to understate the costs of its Preferred Portfolio and overstate the benefits of that portfolio relative to alternative resource plans in which the Bridger coal units retire earlier.

PacifiCorp's discovery responses indicate that its Preferred Portfolio, a variant of portfolio P-45, is associated with the Company's "Opt F Mine Plan," under which the Bridger Surface Mine closes in 2028.[46] This mine closure date is linked to the Company's assumption that Bridger Unit 2 will retire in 2028 under the Preferred Portfolio. However, PacifiCorp's modeling erroneously applied Bridger mine capital cost assumptions associated with its "Opt E Mine Plan," under which the Bridger Surface Mine closes in 2022. This mine plan is associated with portfolios in which multiple Bridger coal units retire by 2022, such as portfolio P-35.[47] It is clearly not intended to be applied to the Preferred Portfolio, in which no Bridger units retire by 2022.

Portfolio	**P-03**	**P-04**	**P-35**	**P-45**[48]
Bridger Mine Plan Name	Opt F	Opt E	Alt. Mine Plan	Opt F
Final Bridger Mine Closure Date[49]	2028	2022	2025	2028
Final Capital Year in SO Input Workbooks[50]	2027	2021	2024	**2021**

PacifiCorp's mistaken use of Opt E Mine Plan capital cost assumptions in its Preferred Portfolio modeling led it to substantially understate the costs of that portfolio. Under the Opt E Mine Plan, the Bridger coal mine [redacted] by 2022.[51] Under the Opt F Mine

[44] PacifiCorp Response to Sierra Club Data Request No. 3.28(b).
[45] Attachment "Attach Sierra Club 3.27.xlsx" to PacifiCorp Response to Sierra Club Data Request No. 3.27.
[46] *Id.*
[47] *Id.*
[48] Preferred Portfolio
[49] Attachment "Attach Sierra Club 3.27.xlsx" to PacifiCorp Response to Sierra Club Data Request No. 3.27.
[50] PacifiCorp Workpaper "CapEx Rev Req _template IRP_XX_<date>, where XX signifies portfolio number and <date> is the run date, tab "11 – Mine Capital."
[51] PacifiCorp Workpaper "CapEx Rev Req _template IRP_P34_20190530.xlsm", tab "11 - Mine Capital"; note that these values are the same as in PacifiCorp Workpaper "CapEx Rev Req _template IRP_P45_20190629.xlsm", tab "11 - Mine Capital."

Plan, Bridger coal mine annual capital costs increase from [redacted] in 2019 to [redacted] in 2020 and 2021, and the mine continues to incur new capital costs through [redacted] [52] Confidential Figure 2 displays the difference between the Opt E Mine Plan capital cost assumptions erroneously included in PacifiCorp's Preferred Portfolio modeling and the Opt F Mine Plan assumptions that the Company should have used. In total, PacifiCorp's mistaken use of Opt E Mine Plan assumptions led it to understate the cost the Preferred Portfolio by about [redacted] in NPV terms.

Confidential Figure 3. Preferred Portfolio Bridger Mine Capital Costs, As Modeled and Corrected

[redacted]

Sources: PacifiCorp "CapEx Rev Req" Workpapers

Correcting PacifiCorp's mine capital cost error by itself makes the Preferred Portfolio more costly than alternative portfolios with earlier Bridger unit retirement dates under the Company's "mid" assumptions. Table 8.4 of PacifiCorp's IRP indicates that, under medium assumptions, P-45CP is $13 million less costly than P-48CP (in which Bridger Units 3 and 4 retire in 2033 rather than 2037) and $27 million less costly than P-47CP (in which Bridger Units 3 and 4 retire in

[52] PacifiCorp Workpaper "CapEx Rev Req _template IRP_P47F_20190910.xlsm", tab "11 - Mine Capital." Sierra Club was able to verify the correct Opt F Mine Plan capital cost assumptions by reviewing the Bridger coal mine capital cost assumptions for other portfolios associated with the Opt F Mine Plan, such as P-47.

2035).[53] Both of these differentials are [redacted] than the impact of correcting PacifiCorp's Preferred Portfolio mine capital cost error.

Correcting the Company's mine capital cost error also makes the Preferred Portfolio less cost-effective relative to all other alternative portfolios. These include Portfolio P-36, in which all Bridger coal units retire by 2025.

C. Bridger's future fuel prices are understated

The Company's fuel price assumptions constitute another aspect of PacifiCorp's IRP that is unreasonably biased in favor of the continued operation of the Bridger coal units. For this IRP, PacifiCorp developed a different set of Bridger fuel price assumptions for each portfolio. Under the Company's preferred P-45 portfolio, PacifiCorp assumed that average delivered fuel prices at the Bridger plant would be [redacted] per million British thermal units (mmBtu) in 2019, would remain below [redacted] per mmBtu in every year through 2027, and would remain below [redacted] per mmBtu through 2033.[54] According to data reported by PacifiCorp to the U.S. Energy Information Administration (EIA), these fuel cost assumptions are far below recent historical values.[55] Confidential Figure 3 shows that the weighted annual average of delivered coal prices at the Bridger plant was greater than $2.80 per mmBtu in each year from 2016 through 2018. Through the first 10 months of 2019, Bridger delivered prices averaged $2.74 per mmBtu, [redacted] percent higher than PacifiCorp's 2019 assumption.

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[53] PacifiCorp 2019 IRP, Volume I, p. 232.
[54] CONFIDENTIAL Workpaper "SO Portfolio I19-P36CP-MMR_1910081224_CONF", tab "StaMoFuel."
[55] U.S. EIA, Form EIA-923, pp. 3 (Boiler Fuel Data) and 5 (Fuel receipts and Costs), *available at* https://www.eia.gov/electricity/data/eia923/.

Confidential Figure 4. Bridger Delivered Fuel Price, P-45 Projected vs. Historical

[redacted]

Sources: Form EIA-923; PacifiCorp Workpaper "SO Portfolio I19-P36CP-MMR_1910081224_CONF"

Besides projecting near-term prices that are lower than recent levels, PacifiCorp optimistically projects that the growth rate of coal prices will be far lower than historical levels. During the decade from 2009 through 2018, annual average delivered coal prices at the Bridger plant increased by 99 percent in nominal terms. Yet PacifiCorp projects that delivered Bridger coal prices will [redacted] *in nominal terms* during the decade from 2019 through 2028.

The Company's unreasonably low Bridger fuel price assumptions understate the cost of continuing to operate the Bridger units. These assumptions therefore bias the Company's analysis in favor of continuing to operate those units.

6. SCR RISKS AT HUNTER AND HUNTINGTON PLANTS

PacifiCorp's coal unit economic analyses marked a step forward from past IRPs. However, these analyses, and the subsequent portfolios, did not capture some of the major regulatory risks facing the Company's coal units. This is particularly true in the case of potential pollution control retrofits at PacifiCorp's Hunter and Huntington coal plants.

In 2016 the U.S. Environmental Protection Agency (EPA) issued a final rule under the Clean Air Act's regional haze regulations that required the installation of SCR controls at Hunter Units 1 and 2 and Huntington Units 1 and 2 by August 2021.[56] Rather than install the controls, PacifiCorp sued EPA over the requirements and the 10th Circuit Court of Appeals stayed implementation of the rule pending resolution of the litigation. That case is still pending. In the interim, the state of Utah has submitted to EPA a revised state plan that would roll back the SCR requirement at all four units. At this juncture, EPA must evaluate the science to verify whether the agency somehow erred in its 2016 rule by requiring the SCRs.

Importantly, it would be difficult for EPA to lawfully reverse itself and negate the SCRs at Hunter and Huntington, because the legal, technical and scientific record shows that SCR retrofits **are extremely cost effective per agency metrics**. EPA estimated the costs of SCR to range from $2,380 to $2,563 per ton of oxides of nitrogen (NOx) removed.[57]

These estimates are much lower than other EPA-approved SCRs at coal units in the west where EPA required SCR under the regional haze program. For example, in its Arizona rule, EPA found SCR costs to be reasonable for Cholla Units 2, 3, and 4 at $3,114 to $3,472 per ton of NOx removed, for Apache Units 2 and 3 at $2,275 to $2,908 per ton, and for Coronado Unit 1 at $2,405 per ton.[58] For Colorado's Hayden Station Units 1 and 2, EPA relied on average cost-effectiveness estimates of $3,385 per ton and $4,064 per ton.[59] For Wyoming, EPA found SCR to be the Best Available Retrofit Technology (BART) at units for which costs greatly exceeded the cost for SCR on PacifiCorp's Utah units. EPA found SCR costs of $4,424 to $4,461 per ton (in 2008 dollars) to be reasonable for Laramie River Station Units 1-3.[60] SCR costs of $4,036 per ton (in 2008 dollars) were deemed reasonable for Wyodak.[61] SCR costs of $2,635 per ton (in 2008 dollars) were deemed reasonable for Dave Johnston Unit 3,[62] and SCR costs of $3,469 per ton (in 2008 dollars) were determined to be reasonable for Naughton Unit 3.[63]

Therefore, should the current EPA reverse course and try to change its prior regulatory approach at the Hunter and Huntington units, it could end up doing so *only temporarily* because it is indisputable that these two coal plants degrade air quality at some of the country's most iconic national parks: Capitol Reef National Park, Canyonlands National Park, Arches National Park,

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[56] PacifiCorp 2019 IRP, Volume I, p. 46.
[57] *See* Proposed Rule, Utah Regional Haze, 81 Fed. Reg. 2004, 2,035, 2,039, 2,042, 2,046 (Jan. 14, 2016); Final Rule, Utah Regional Haze, 81 Fed. Reg. 43,894 (July 5, 2016).
[58] Proposed Rule, Arizona Regional Haze, 77 Fed. Reg. 42,834, 42,856-57, 42,860, 42,862-42,863 (July 20, 2012); Final Rule, Arizona Regional Haze, 77 Fed. Reg. 72,512 (Dec. 5, 2012).
[59] Proposed Rule, Colorado Regional Haze, 77 Fed. Reg. 18,069 (Mar. 26, 2012); Final Rule, Colorado Regional Haze, 77 Fed. Reg. 76,871 (Dec. 31, 2012).
[60] Final Rule, Wyoming Regional Haze, 79 Fed. Reg. 5,032, 5,039-40 (Jan. 30, 2014).
[61] *Id*. at 5,044, 5,046.
[62] *Id.* at 5,042, 5,045.
[63] *Id.* at 5,043, 5,045.

Bryce Canyon National Park, Zion National Park, Grand Canyon National Park, Black Canyon of the Gunnison Wilderness, Flat Tops Wilderness Area, and Mesa Verde National Park. And while the current EPA may not require SCR installation at Hunter or Huntington, it remains highly likely that these two plants will face SCR requirements at some point within the coming decade.

PacifiCorp is dismissive that any future EPA will continue to require SCR retrofits in any meaningful timeframe. In response to a discovery request, PacifiCorp stated that it did not anticipate that the installation of SCR would be required on Hunter or Huntington prior to 2028, and that the units would be "re-evaluated" after 2029.[64] This view woefully understates the economic risks facing these units.

As described, the potential for SCR requirements at the four Hunter and Huntington units remains a substantial economic risk. PacifiCorp's workpapers indicate that SCR requirements would result in NPV capital costs greater than [redacted] (in 2018 dollars) at each of these units.[65] The Company's analysis indicates that installing SCR at all four units would require about [redacted] in NPV capital expenditures. In addition, SCR systems at these units would result in incremental operations and maintenance (O&M) costs.[66]

Yet, PacifiCorp's IRP did not seriously evaluate the economic risks associated with potential SCR requirements at the Hunter or Huntington units. In every IRP portfolio but one, Huntington Units 1 and 2 were assumed to retire in 2036 and Hunter Units 1 and 2 were assumed to retire in 2042.[67] The only portfolio in which the units were provided an earlier retirement date was a single scenario assessing the retirement of all coal-fired units by 2030.[68] Similarly, the only case for which PacifiCorp assumed SCR requirements at the Hunter and Huntington units was the Regional Haze Reference Case. Since this case was never compared to a case in which units retire earlier rather than installing SCR, its only value is in establishing the obvious fact that SCR requirements result in increased system costs.

The lack of inclusion of earlier retirement dates for Hunter Units 1 and 2 or Huntington Units 1 and 2 in any of PacifiCorp's IRP portfolios, or even in any of the "stacked retirement" cases that the Company evaluated in the earlier stages of its IRP process, may be a result of the findings from PacifiCorp's initial, unit-specific coal economic analyses. These assessments indicated that,

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[64] PacifiCorp Response to Sierra Club Data Request 5.20(a) and (b).
[65] PacifiCorp Workpaper "SO Input_Existing coal cost_IRP_P02F_20190724.xlsx," tabs "Hunter 1," "Hunter 2," "Huntington 1," and "Huntington 2," row 15.
[66] U.S. EPA, *Documentation for EPA Base Case v.5.13 Using the Integrated Planning Mode*l, p. 5-7 (Nov. 2013), *available at* https://www.epa.gov/sites/production/files/2015-07/documents/documentation_for_epa_base_case_v.5.13_using_the_integrated_planning_model.pdf.
[67] PacifiCorp 2019 IRP, Volume II, Appendix M.
[68] Portfolio P-15, designated "Retire All Coal by 2030".

for each of these Hunter and Huntington units, continuing to operate the unit would provide a net benefit of between $0 and $31 million relative to retiring the unit in 2022.[69] But these analyses did not account for *any SCR* requirements. And the relatively small benefits found under these analyses are far lower than the cost of an SCR.

If the Hunter or Huntington units do face SCR requirements in the 2020s, earlier retirement would likely be an economically preferable compliance option to installing pollution controls. And if PacifiCorp were to conclude that accelerated retirement is the lower-cost approach, it should promptly phase down life-extending capital expenditures at these units. However, for now, the Company is evidently planning to continue to spend at Hunter Units 1 and 2 and Huntington Units 1 and 2 as though they will continue to operate through at least the mid-2030s. The Company's workpapers indicate that it plans to spend more than [redacted] on runrate capital at each of these units over period from 2019 through 2035.[70] In addition, the Company's investment plans for each of these units include at least one year with more than [redacted] in runrate capital expenditures between 2020 and 2023.[71] Such investment levels may not be advisable in light of the SCR risks facing the Hunter and Huntington units.

Sierra Club recommends that the Commission require PacifiCorp to more rigorously factor in the regulatory risks facing the Hunter and Huntington units in its next IRP. While it was reasonable for PacifiCorp to exclude some uncertain compliance costs from its initial unit-specific economic coal assessments in this IRP, the Company should have quantitatively evaluated the implications of likely and potential requirements for the economic viability of its units. In particular, the Company should have evaluated whether its planned ongoing capital expenditures are reasonable in light of regulatory and other economic risks facing its units.

More generally, Sierra Club recommends that the Commission require PacifiCorp to conduct unit-specific and stacked coal retirement assessments as part of its next IRP. In the current rapidly evolving market environment, in which coal plants face a wide range of economic and environmental challenges, it is critical that the Company continue to assess the viability of its coal units. Sierra Club views the coal retirement decisions resulting from this IRP as a first step, rather than a final plan, in PacifiCorp's transition to a cleaner resource mix.

7. SOLAR COST ASSUMPTIONS DO NOT REFLECT INDUSTRY-STANDARD ESTIMATES.

Sierra Club is concerned that the solar resource fixed O&M assumptions used in PacifiCorp's IRP modeling were unreasonably high. The Supply Side Resource table contained in the IRP includes an assumption that solar resources will face fixed O&M costs of around $22 per kW-

[69] PacifiCorp 2019 IRP, Volume II, p. 599.
[70] Workpaper "CapEx Rev Req _template IRP_P45_20190629.xlsm," tab "7 - Runrate Plant CapEx."
[71] *Id.*

year.[72] This assumption are approximately double those indicated by industry-standard sources such as Lazard's levelized cost of energy reports and the National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB) reports. Lazard's latest analysis estimates utility-scale solar fixed O&M costs to be between $9 and $12 per kW-year.[73] NREL's 2019 ATB estimates 2019 solar fixed O&M costs of about $13 per kW-year, with costs declining in real terms over time.[74]

Since PacifiCorp is not committing to particular new generation resources at this time, its higher cost assumptions may not directly affect the resources it builds. The Company's all-source RFP should reveal the actual costs of developing new solar resources within PacifiCorp's service territory. However, the IRP O&M cost assumptions *do* affect the coal unit retirement decisions that PacifiCorp is making in this IRP. This IRP has established solar (typically paired with storage) as a least-cost replacement resource in the Company's service territory. Thus, the Company's unreasonably high solar fixed O&M cost assumptions likely biased the Company's analysis against the selection of further coal retirements. This is another reason that the Company must re-evaluate the economics of its coal units, using up-to-date alternative resource assumptions informed by recent RFPs, in its next IRP.

8. NEAR TERM EMISSION REDUCTIONS ARE DRIVEN BY DISPATCH, NOT PORTFOLIO CHANGES.

PacifiCorp crows that its resource plan will "dramatically reduce its greenhouse gas emissions over the next 20 years," stating that "by 2030, PacifiCorp will have reduced greenhouse emissions by nearly 60 percent from 2005 levels."[75] However, through 2027, the majority of emissions reductions from today are forecast to be driven by *dispatch decisions*, not by changes to PacifiCorp's portfolio. Unlike resource build and retirement decisions, dispatch decisions are subject to the whims of fuel prices, the construction of long-term fuel contracts, the actions of neighboring utilities, state and federal policies, and PacifiCorp's decisions to enter or withdraw various generating units from the EIM. In contrast, the impact of PacifiCorp's plans to retire specific units and replace those units with non-emitting generation can easily be assessed. It is misleading for PacifiCorp to claim substantial near-term emissions reductions from this IRP. Coal-fired units that PacifiCorp has previously forecasted would reduce generation and emissions have not hewed to PacifiCorp's prior projections.

A review of PacifiCorp's workpapers indicates that the Company estimated CO_2 emissions of [redacted] tons in 2019, and anticipates those emissions falling to [redacted] tons by 2027, a

[72] Range from $21.14 to $22.35/kW-year. PacifiCorp 2019 IRP, Volume I, p. 133.
[73] Lazard, *Lazard's Levelized Cost of Energy Analysis – Version 13.0* p. 16 (Nov. 2019), *available at* https://www.lazard.com/perspective/lcoe2019.
[74] NREL, ATB: Utility-Scale PV (2019), *available at* https://atb nrel.gov/electricity/2019/index.html?t=su.
[75] PacifiCorp 2019 IRP, Volume I, p. 4.

reduction of [redacted]. However, of the [redacted] of emissions reductions over the next decade, nearly [redacted] percent (or [redacted] tons) are achieved through downward dispatch of the Company's coal fleet.

If the Company were to retain today's level of dispatch, we would anticipate only an [redacted] reduction in emissions through 2027. While the IRP sets an expectation of emissions reductions, it would not lead to meaningful reductions in near- to mid-term greenhouse gas emissions. The real reductions in PacifiCorp's plan only occur after the retirement of Dave Johnston and Colstrip in 2027, and Jim Bridger 2 in 2028.

We recommend that in review of this and future IRPs, the Company and Commission conduct a backwards-looking assessment to determine if emissions reductions driven by dispatch decisions are meaningful.

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Respectfully submitted,

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STATE OF UTAH

Public Service Commission

In the Matter of PacifiCorp's 2019 Integrated Resource Plan	Docket No. 19-035-02

CERTIFICATE OF SERVICE

I CERTIFY that on February 4, 2020, a true and correct copy of the foregoing Redacted Sierra Club Opening Comments was served upon the following parties via electronic mail and the confidential version was served on eligible parties via Federal Express 2-Day Mail.

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