1407 W. North Temple, STE 110
Salt Lake City, UT 8416

May 31, 2022

ATTN: Regional Haze
Bryce Bird, Director
Utah Division of Air Quality
P.O. Box 144820
Salt Lake City, UT 84114-4820

Re: PacifiCorp's Public Comments on Utah's Regional Haze Second Implementation Period SIP

Dear Mr. Bird:

PacifiCorp submits these public comments in support of Utah's proposed State Implementation Plan for Regional Haze for the Second Planning Period ("RH SIP 2"), which was published by Utah for public comment on May 1, 2022. PacifiCorp supports Utah's RH SIP 2 for the reasons stated in the SIP, as well as the additional reasons stated herein.

I. PACIFICORP BACKGROUND

PacifiCorp is a regulated electric utility company headquartered in Portland, Oregon that serves nearly two million retail electric customers, including residential, commercial, industrial, irrigation and other customers in portions of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp is principally engaged in the business of generating, transmitting, distributing and selling electricity. In addition to retail sales, PacifiCorp buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants. PacifiCorp delivers electricity to customers in Utah, Wyoming and Idaho under the trade name Rocky Mountain Power and to customers in Oregon, Washington and California under the trade name Pacific Power.

As of 2021, PacifiCorp's system includes approximately 16,000 megawatts ("MW") of capacity from its existing resources. This includes 5,246 MW nameplate capacity of coal-fueled plants, 3,070 MW nameplate capacity of natural-gas-fueled plants, 2,255 MW owned wind, 1,556 MW purchased wind, 2,340 MW of purchased solar, approximately 49 MW of owned and purchased geothermal capacity, 80 MW of nameplate capacity for biomass/biogas, 1,118 MW of owned plus 280 MW of purchased hydroelectric generation, plus various levels of net metering, demand-side management, private generation, and power purchase contract capacities.[1] PacifiCorp's fleet of

[1] PacifiCorp 2021 Integrated Resource Plan ("2021 IRP"), Ch. 6.

thermal plants (coal-fired and natural gas) accounts for roughly two thirds of the firm capacity available in the PacifiCorp system.[2]

PacifiCorp is the majority owner and operator of Hunter Units 1 and 2, and the owner and operator of Hunter Unit 3 as well as Huntington Units 1 and 2. Hunter Units 1 and 2 are co-owned by Deseret Generation & Transmission ("Deseret") (an undivided 25.10% interest in Hunter Unit 2), Utah Associated Municipal Power Systems ("UAMPS") (an undivided 14.59% interest in Hunter Unit 2), and Utah Municipal Power Agency ("UMPA") (an undivided 6.25% interest in Hunter Unit 1). The Hunter and Huntington Units (together the "Utah Units") are integral and essential power generation resources for PacifiCorp's customers as well as the customers of Deseret, UAMPS, and UMPA. Moreover, the Utah Units directly employ hundreds of people and provide millions of dollars of taxes to the state of Utah and local governments.

II. THE UTAH UNITS ARE IMPORTANT TO THE STATE AND COMMUNITIES IN THEIR AREAS OF OPERATION

The Utah Units are very important to the local economies surrounding the power plants. The Hunter plant directly employs approximately 186 people, and the Huntington plant employs approximately 136, and thousands of other people are employed by industries that support the Utah Units. Emery and Carbon counties rely on the plants for a significant part of their tax and employment base. For example, PacifiCorp paid $22.6 million in property taxes to Emery County for 2021. This represented 68%, or roughly two-thirds, of the county's total property tax revenues. These revenues provide funding for the county law enforcement agency, the county governmental operations, and the Emery County School District.[3]

A new Kem Gardner study on Utah's Coal Country ("Coal Country Study") identifies Carbon and Emery counties as among the least economically diverse counties in the state.[4] There are approximately 4,000 jobs in Emery and Carbon counties in mining and other industry services.[5] Wages for plant workers are higher than the overall industrial workforce, and a unit closure would have a significant impact on wages earned in the surrounding communities. Because the communities currently rely so heavily on the Utah Units and associated mining and industry services, it is especially important to balance local interests, efficiencies, economics, and impacts

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[2] *See id*.

[3] Annual Comprehensive Financial Report, June 30, 2021, at 94, *available at* https://www.emeryschools.org/_theme/files/Business%20docs/Reports/2020-21/AFR_FY21.pdf. For example, the Emery County School District reports that approximately 70% ($1.6 million) of the district's property tax funding came from PacifiCorp in 2021.

[4] Kem C. Gardner Policy Institute, *Economic Challenges and Opportunities in Utah's Coal Country*, Max Backlund and Michael Hogue, May 2022, Table 5, *available at* https://gardner.utah.edu/wp-content/uploads/CC-BrightFutures-May2022.pdf?x71849.

[5] Utah Department of Workforce Services, *available at* https://jobs.utah.gov/wi/insights/county/carbon.html.

to people while pursuing strategies to decrease environmental impacts and grow a cleaner power system.

It is estimated that the early retirement of a single unit at the Hunter plant would result in an approximate 20-25% employee reduction. Beyond the loss of plant jobs, any unit retirement would have broader impacts to associated industry jobs serving the plants and the local community.

The Coal Country Study explains, "These two counties form a regional economy, with a shared commuter shed, shared industries, and consumer spending patterns. Together, these counties face challenges with changing economic circumstances from declining coal production and the future closures of power plants." The report finds time is a critical factor to diversify the local economies and address the expected employment declines in the natural resource/coal sector.[6] Both Carbon and Emery County have experienced population loss since 2010, a significant portion of which coincided with the retirement of PacifiCorp's Carbon power plant and the closure of its Deer Creek mine in 2015.[7]

The welfare of the affected communities, which is intertwined with and dependent upon the presence of the plants, is an important factor supporting Utah's proposed RH SIP 2 and the selection of the more flexible mass-based limits over the much more expensive and inflexible SCR requirement to meet the reasonable progress requirements of the regional haze program. As discussed below, the flexibility could well mean the difference between continued operation under the new limits or a forced early retirement.

III. EMISSIONS HAVE BEEN DECLINING AT THE UTAH UNITS

Despite incorrect claims by some commenters, data from the U.S. Environmental Protection Agency's ("EPA") Acid Rain Database[8] indicates that emissions from the Utah Units have greatly decreased since 1998, about the time the regional haze program began. The Utah Units have taken many steps proactively, including installation of control equipment starting in 2006 to comply with Utah's regional haze requirements[9] that have greatly reduced both nitrogen oxide ("NOx") and sulfur dioxide ("SO_2") emissions, which are haze-causing pollutants.

For example, in 1998, the Hunter Plant's NOx emissions were 21,841 tons per year and decreased 49% to 11,041 tons per year by 2021. Likewise, the Hunter Plant's SO_2 emissions were 7,226 tons per year in 1998 and decreased 47% to 3,848 tons per year of SO_2 by 2021. The Huntington power plant has seen similar emissions decreases. In 1998, the Huntington Plant's NOx emission were 14,122 tons per year, decreasing 53% to 6,604 tons per year of NOx by 2021. Likewise, the Huntington Plant's SO_2 emissions were 14,567 tons per year in 1998, decreasing 82% to 2,690

[6] Coal Country Study at 5.

[7] *Id*. at 5.

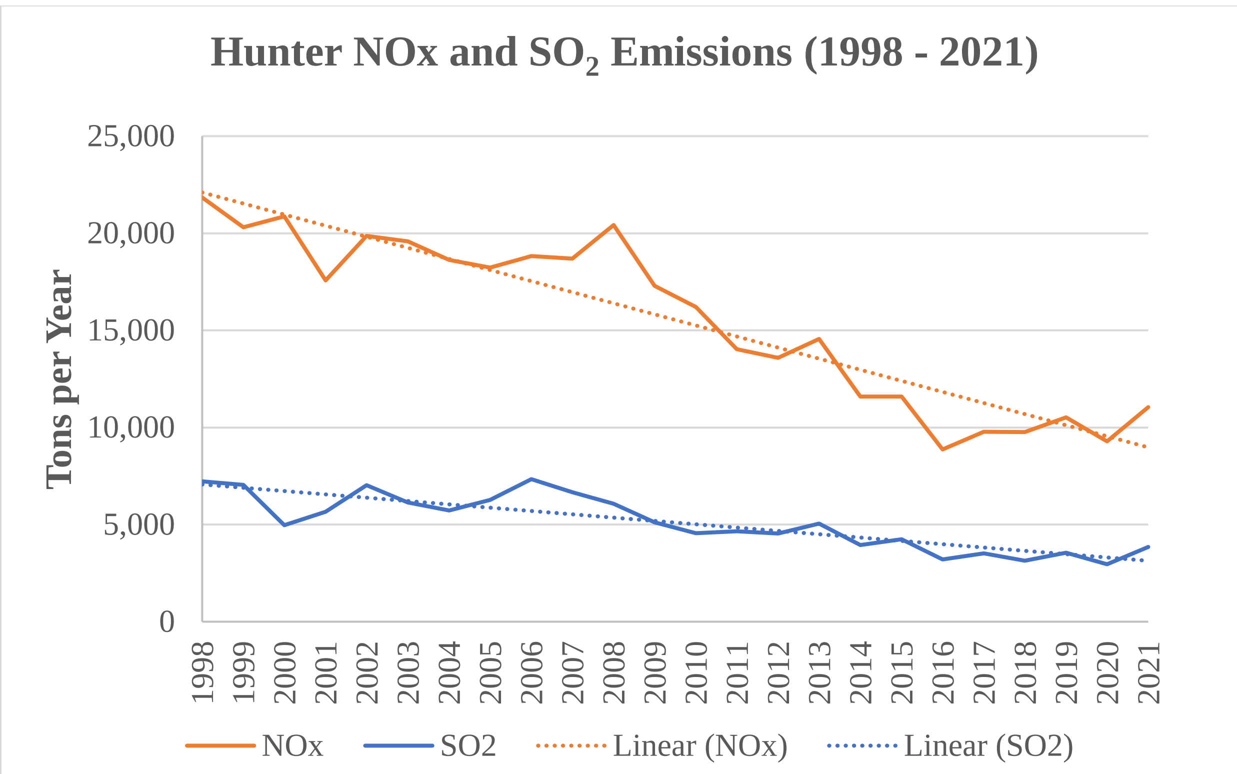
[8] *See* https://ampd.epa.gov/ampd/.

[9] Utah's regional haze requirements in the first regional haze SIP became state law before being submitted for EPA's review and approval.

tons per year of SO_2 by 2021. The graphs below represent NOx and SO_2 emissions from the Hunter and Huntington Plants between 1998 and 2021.[10]

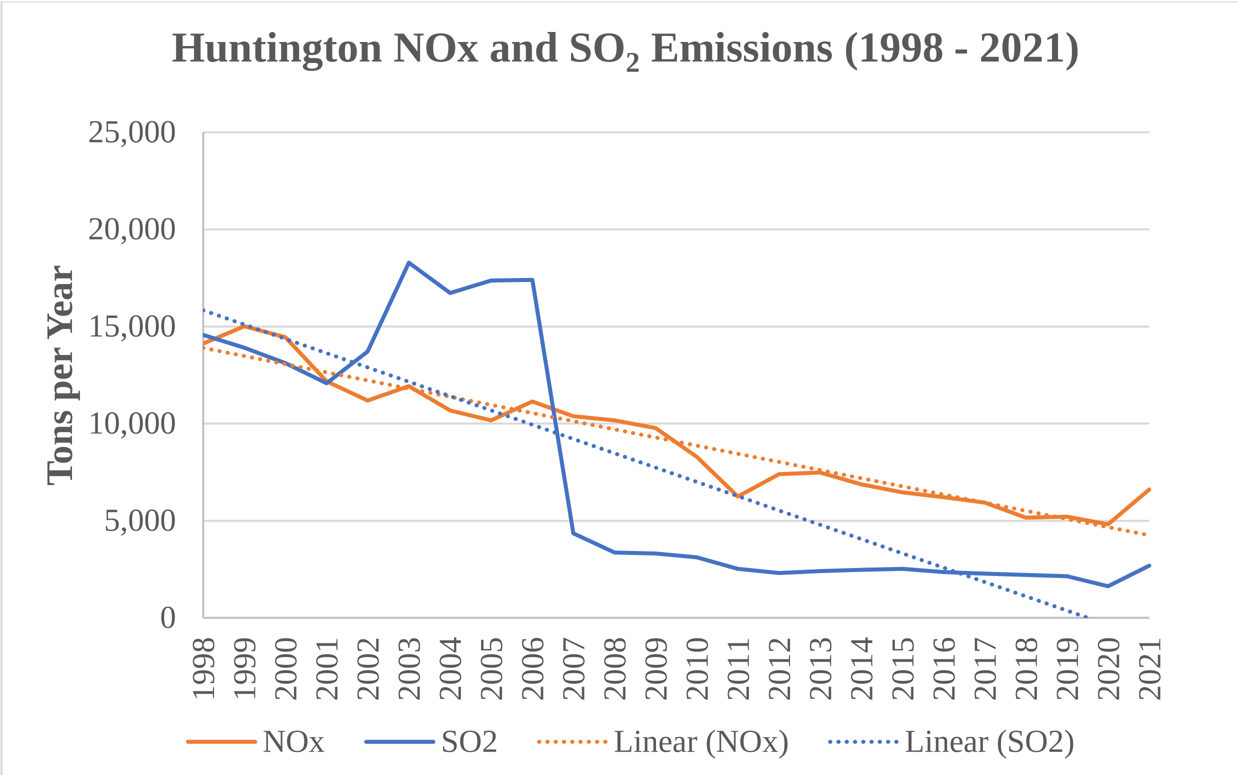
As the graphs below demonstrate, Utah's air quality program is working, and the Utah Units' impact on air quality in the general area is decreasing. While some misinformed critics have claimed the regional haze SIP for the first planning period was a "do nothing" plan, the evidence suggests that the two first planning period SIPs (one for NOx and one for SO_2) resulted in significant reductions of regional-haze causing emissions.

Moreover, Utah's NOx RH SIP for the first planning period included NOx emissions reductions due to the shutdown of the Carbon plant, and NOx-reducing combustion controls installed on all of the Utah Units. Far from a "do nothing" plan, the first planning period SIP for NOx lowered NOx emissions limits, resulted in the installation of physical NOx controls, and formalized the closure of the Carbon plant (thereby eliminating all of its emissions). Through proactive planning, PacifiCorp began these installations of the NOx combustion controls in 2006 and completed them in 2014, as required by the 2008 SIP. EPA noted that "combustion control upgrades at the Hunter and Huntington facilities have been achieving significant NOx reductions since the time of their installation between 2006 and 2014."[11]



[10] Emissions data from EPA's Acid Rain Database.

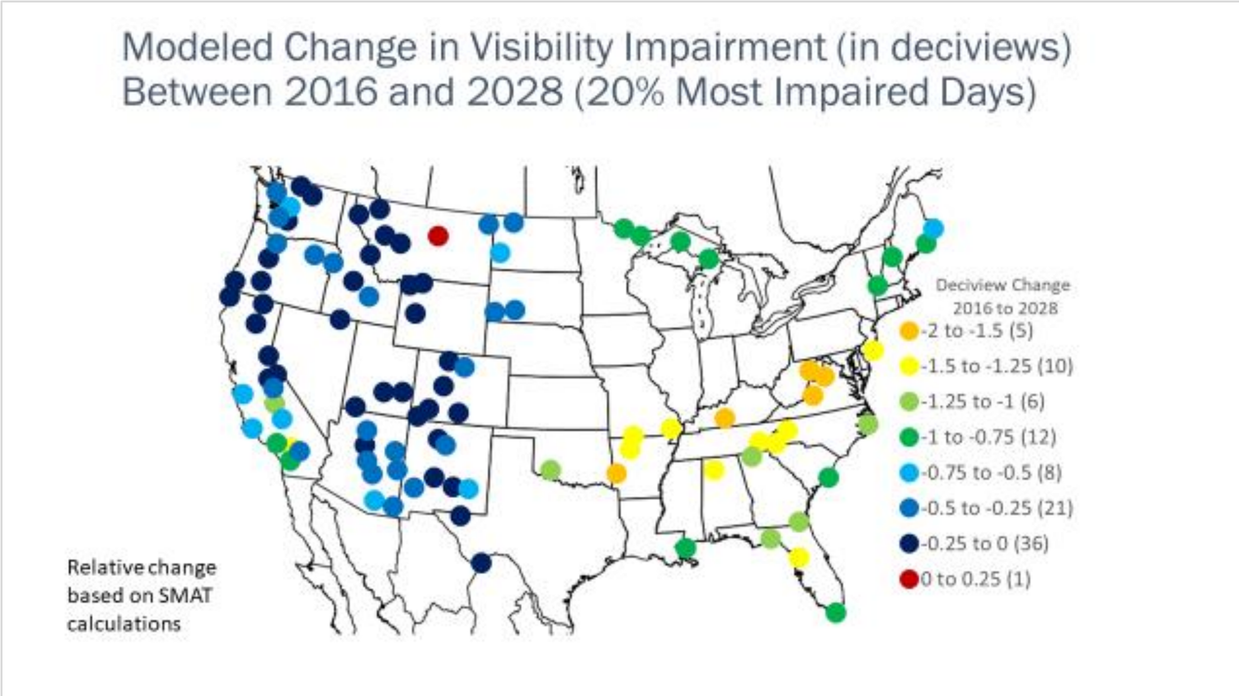
[11] Approval, Disapproval and Promulgation of Air Quality Plans; Partial Approval and Partial Disapproval of Air Quality Implementation Plans and Federal Implementation Plan; Utah; Revisions to Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze, 81 Fed. 2004, 2023 (January 14, 2016).



IV. IN THE WEST, NATURAL SOURCES AND PRESCRIBED FIRES ARE MUCH LARGER CONTRIBUTORS TO REGIONAL HAZE IN UTAH'S CLASS I AREAS THAN ANTHROPOGENIC SOURCES

Many commenters errantly ignore the largest causes of regional haze that impact Utah's Class I areas. Utah and the West are subject to very high non-anthropogenic influences, including wildfire, that dominate the formation and potential reduction of regional haze.[12] These high non-anthropogenic influences have blunted impacts from actions meant to reduce anthropogenic emissions over the past decade, and previously predicted improvements have failed to materialize. The graphic below shows that while significant anthropogenic emission reductions have occurred in the West (such as the closure of PacifiCorp's Carbon plant and NOx emissions controls installed to comply with the first planning period SIP), predicted visibility improvements in the West did not materialize. *See* Updated EPA 2028 Regional Haze Modeling Webinar Slides found at https://www.epa.gov/visibility/technical-support-document-epas-updated-2028-regional-haze-modeling (orange and yellow show the highest improvement while dark blue shows the least).

[12] EPA, Documentation for the EPA's Preliminary 2028 Regional Haze Modeling, Oct. 2017, at A122-127 (reviewed on May 26, 2022, available in EPA archives at https://nepis.epa.gov/).



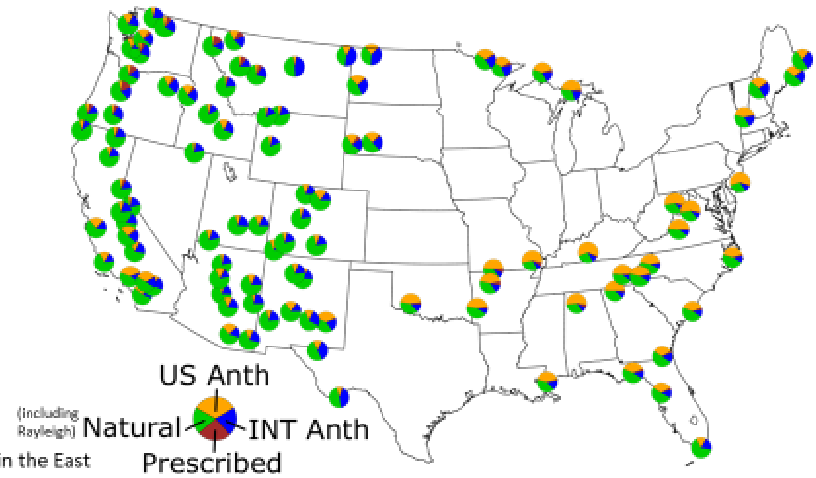
A key reason for this difference is illustrated in the next graphic below, which shows the outsized impact that natural and international emissions, as well as prescribed fire, have on regional haze visibility impairment in the West as compared to the East (note the predominance of green and blue in the western states). As can be observed from the graphic below, natural sources, followed by international sources, are the biggest haze contributors to Utah's Class I areas.

Based on EPA modeling, which analyzes the outsized impact of non-anthropogenic sources on regional haze in the West, the minimal and uncertain predicted visibility improvements from any SCR requirement is less than convincing as justification considering the huge costs. The data shows that the Class I areas addressed in Utah's SIP are actually ahead of schedule to meet the national visibility goal and projected visibility impairment is below the "glidepath" towards natural conditions.[13] Again, this supports the more cost-efficient emissions reductions required by Utah in the draft regional haze SIP.

[13] *See* Utah's draft Regional Haze SIP, Sections 8.C.1 – 8.C.5.

2028 Total Visibility Impairment Components (20% most impaired days)

2028 Visibility Impairment	Range (Mm-1)
US anthropogenic	0.98–45.68
International anthropogenic	2.88–19.33
Prescribed Fires	0.03-5.15
Modeled natural (including Rayleigh)	11.72-29.83



- Percentage of US anthropogenic higher in the East
- Percentage of natural higher in the West
- International anthropogenic contribution largest near border areas
- Prescribed fire contribution highest in the Northwest

V. SUPPORT FOR UTAH RH SIP 2

a. Utah enjoys significant discretion when administering the federal regional haze program, including when creating the RH SIP 2

Congress added § 169A to the Clean Air Act ("CAA") to address the "impairment of visibility" in Class I areas that "results from man-made air pollution." This provision of the CAA, in turn, describes separate roles for the EPA and the States.

EPA -- EPA's roles are to create a report, *see* CAA § 169A(a)(2)-(3), create regional haze regulations, *see* CAA § 169A(a)(4), provide guidelines for the States, *see* CAA § 169A(b)(1), and ensure RH SIPs submitted by the States follow the guidelines and contain the required elements. *See* CAA § 110.

States -- The States' role, which is central and intended to protect state authority and autonomy, provides significant discretion which, in turn, requires significant deference by EPA. States are required to submit a RH SIP that contains "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal." CAA § 169A(b)(2).[14] EPA is required to approve the State plan if it meets the CAA requirements. 42 U.S.C. 7410(k)(3).

Thus, the CAA mandates that states have the primary role in developing RH SIPs to protect visibility in Class I areas. Likewise, the Regional Haze Rules, 40 C.F.R. §§ 51.308 and 51.309, make clear that states have the responsibility to create and implement RH SIPs. Additionally, in

[14] The public and stakeholders participate through public hearings and the submission of comments at both the state and federal level.

issuing certain guidance on regional haze, EPA recognized the broad discretion granted to the states by the CAA. Specifically, EPA stated that "the Act and legislative history indicate that *Congress evinced a special concern with insuring that States would be the decision makers*." 70 Fed. Reg. 39,104, 39,137 (July 6, 2005) (emphasis added).[15]

The U.S. Court of Appeals for the D.C. Circuit has affirmed that EPA's role in the regional haze program is limited and that a state's role is paramount. Indeed, the Court found that the CAA "calls for states to play the lead role in designing and implementing regional haze programs." *American Corn Growers Ass'n v. E.P.A*., 291 F.3d 1, 2 (D.C. Cir. 2002). The *American Corn Growers* decision outlines the legislative history and recounts a specific agreement struck in Congress explicitly granting this authority to the states instead of allowing EPA to retain the authority: "The 'agreement' to which the Conference Report refers was an agreement to reject the House bill's provisions giving EPA the power to determine whether a source contributes to visibility impairment and, if so, what BART[16] controls should be applied to that source. Pursuant to the agreement, language was inserted to make it clear that the states—not EPA—would make these BART determinations. The Conference Report thus confirms that Congress intended the states to decide which sources impair visibility and what BART controls should apply to those sources. The [court-rejected] Haze Rule attempts to deprive the states of some of this statutory authority, in contravention of the Act." *Id*. at 8 (citations omitted) (emphasis added). Congress clearly contemplated that the states would select, using the guidance provided by EPA, all emissions controls, BART or otherwise, needed to implement the regional haze program in their respective states.

Utah has the authority and discretion under the CAA to issue the RH SIP 2. In short, the CAA anticipates that EPA will create guidance and that the states, using their discretion, will use this guidance to develop RH SIPs. PacifiCorp supports Utah's exercise of its discretion to develop the RH SIP 2.

b. The RH SIP 2 is based on the correct cost methodology

As part of the analyses employed in the RH SIP 2, Utah employed the correct methods to analyze costs, as required by statute. For example, Utah considered the appropriate cost of borrowing, reviewed and approved PacifiCorp's past cost analyses regarding SCR and SNCR controls, and determined the cost issues favored mass-based NOx emissions limits over post-combustion add-on controls due to the high costs and historical and potential future utilization projections for the units. *See* RH SIP 2, at 7.C.3 (pgs 126-132).

[15] EPA also has explained that "[i]n some cases, the *State* may determine that a *source has already installed sufficiently stringent emission controls* for compliance with other programs . . . such that *no additional controls would be needed* for compliance with the BART requirement." 64 Fed. Reg. 35714, 35740 (July 1, 1999) (emphasis added). EPA further acknowledges that, in making BART determinations, "*[s]tates* are *free to determine the weight and significance* to be assigned to each factor." 76 Fed. Reg. at 64192 (emphasis added).

[16] Best available retrofit technology ("BART"). The second planning period for regional haze requires reasonable progress analyses rather than BART.

As explained above, the regional haze program provides states, like Utah, great discretion in the development of its SIP, and that includes evaluating the cost-effectiveness of potential controls. For example, although EPA did not consider the incremental costs of "around $4,500/ton" to be prohibitive, EPA nonetheless noted "the State [of Nevada] has certain discretion in weighing cost." 77 Fed. Reg. 21,896, 21,901. Ultimately, EPA accepted Nevada's BART NOx decision for certain units and stated Nevada "is allowed to weigh the incremental cost against the incremental visibility improvement." 77 Fed. Reg. at 21,906. *See also* 77 Fed. Reg. 20,894, 20,929 (EPA states that $4,000 per ton "is still high enough that we are not prepared to change our conclusion" that North Dakota's BART determination was reasonable).

Utah's cost analysis methods are consistent with the regional haze program's goals and guidance. EPA's "2019 Guidance" encourages states to consider costs based on "complete cost data; that is, estimated values of capital costs, annual operating and maintenance costs, annualized costs, and cost per ton of emission reductions that have been prepared according to EPA's Control Cost Manual."[17]

c. An SCR requirement is likely to force retirement or conversion to an alternative fuel source.

SCR is an extremely expensive retrofit technology that was projected to cost between $142-162 million for a single PacifiCorp coal-fueled unit in 2020.[18] Adjusting these costs to 2022 dollars increases the costs by more than 10%. Moreover, it is expected SCR costs would be even higher than inflation-adjusted costs if priced out today due to supply chain issues, extended project timelines, higher metal prices, and higher supplier costs. PacifiCorp is currently working to update unit cost analysis for SCR, and PacifiCorp requests that the State consider these additional costs to construct and install SCR as further support for its analyses.

SCR is not currently an "affordable" technology for PacifiCorp's coal-fueled units based on criteria developed by the EPA guidelines for regional haze determinations[19] ("BART Guidelines"). PacifiCorp recently conducted an in-depth study that determined the high costs of an SCR requirement would lead to the forced retirement of its coal-fueled Wyodak unit in Wyoming (the "Wyodak plant"). *See Appendix A* (Wyodak Facility SCR Affordability Analysis, August 25, 2020) ("Affordability Analysis").

Much of the analyses and conclusions in the Affordability Analysis would also likely apply if an SCR requirement were imposed on the Utah Units. While the demand for electricity and market conditions in the West, as well as regulatory requirements for coal-fueled units, are continually changing and highly uncertain right now, based on internal analyses, findings by the state public

[17] EPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, at 21, Aug. 20, 2019, *available at* https://epa.gov/visibility.

[18] *See* Sargent and Lundy, Hunter Power Station NOx Control Cost Development and Analysis, April 9, 2020, at 16; and Huntington Power Station NOx Control Cost Development and Analysis, April 9, 2020, at 15-16 (attachments to PacifiCorp 4-Factor Analysis).

[19] 40 CFR Part 51, App. Y, IV.E.3.

service commissions that govern PacifiCorp's operations, and the best information currently available, it is likely that, like the Wyodak unit, the financial consequences of an SCR requirement(s) at the Utah Units would result in either early retirement or the potential of a forced conversion to a different fuel source.

There are many unit-specific factors that influence the economics of an SCR, including the life of an asset, the cost of alternatives to SCR such as retirement or conversion to an alternative fuel source, and variables such as fuel and operating costs. Like Wyodak, the Utah Units are subject to the same regulatory requirements and public service commissions, have planned retirement dates after 2035, and are part of the larger PacifiCorp energy system and dispatch processes.

While the outcome of the Affordability Analysis does not directly translate to the Utah Units,[20] the results of the Affordability Analysis are so dramatic that it is reasonable to project that SCR is not an affordable technology for the Utah Units and that other options such as retirement or conversion to an alternative fuel source would be the lower-cost, lower-risk option. Using the key factors identified by EPA as determining affordability and drawing from the outcome of the Affordability Analysis and the requirements for PacifiCorp as a regulated utility, PacifiCorp projects that a requirement to install SCR is likely to force the retirement or, if feasible, the conversion of each of the affected Utah Units to an alternative fuel source.

i. EPA guidelines on "affordability"

Even where a control technology is found to be cost effective, EPA's regional haze BART Guidelines allow decision makers to take a source's ability to afford the technology into account if "the installation of controls would *affect the viability of continued plant operations.*"[21] The BART Guidelines outline the circumstances where such consideration is appropriate:

> There may be *unusual circumstances* that justify taking into consideration the conditions of the plant and the economic effects of requiring the use of a given control technology. These effects would include *effects on product prices, the market share, and profitability of the source*. Where there are such unusual circumstances that are judged to affect plant operations, you may take into consideration the conditions of the plant and the economic effects of requiring the use of a control technology. Where these effects are judged to have a *severe impact on plant operations* you may consider them in the selection process, but you may wish to *provide an economic analysis that demonstrates, in sufficient detail for public review, the specific economic effects, parameters, and reasoning*. (We recognize that this review process must preserve the confidentiality of sensitive business information). Any analysis may also consider whether other competing plants in the same industry have been required to install BART controls if this information is available.[22]

[20] PacifiCorp plans to include additional analysis of SCR for the Utah Units in the 2023 IRP.

[21] 40 CFR part 51, appendix Y, section IV.E.3.1.3 (emphasis added).

[22] *Id. See also* 79 FR 33438, 33442 (2014) (EPA determination that a control technology should not be required because it was not affordable and would result in an unacceptable profit margin for the plant).

Although this guidance is specific to the selection of BART controls, the rationale applies with equal force to other regional haze controls chosen as part of a long-term strategy ("LTS"). There is nothing unique about the cost impacts of BART controls on a source as compared to LTS controls. Both analyses require considerations of costs by statute, and regulatory agencies have used similar methods when conducting cost analyses. The regional haze legislation was not intended to force units to shut down.[23] Utah considered these very types of cost issues in its development of the RH SIP 2. *See* RH SIP 2 at 127-132. Moreover, Utah appropriately exercised its discretion when it considered the various cost impacts in light of the uniform rate of progress and other visibility issues.

ii. PacifiCorp operations are governed by public service commissions and least-cost, least-risk principles

As a regulated public utility, rather than relying on the competitive market and profitability, PacifiCorp must instead meet requirements of state regulators to demonstrate prudent decision-making on behalf of its customers. The state regulators approve revenue to cover costs and a reasonable return on resource investments that they find to be prudent, and several states are subject to laws limiting recovery for investment in coal assets. PacifiCorp is required by statute, administrative regulation, and orders from public utility commissions in each of the six states where it operates to file an integrated resource plan ("IRP"). The IRP is based on a 20-year forecast and identifies the least-cost, least-risk portfolio of resources and transmission investments required to reliably serve customers.[24] The IRP also includes an action plan that sets forth the specific resource actions that PacifiCorp will take over the near-term consistent with the preferred portfolio, which can include action items to retire a high-cost asset and procure new resources. This planning process sets the stage for definitive resource decisions, which must satisfy a prudence review from state regulatory commissions. During the prudence review, state commissions assess, in part, how resource decisions affect customer rates. This planning and decision-making process applies to PacifiCorp as a regulated utility and is analogous to a review of product price, marketability, and profitability for unregulated companies. Thus, PacifiCorp must be able to demonstrate that installing an SCR would be in the best interest of its retail customers, and, therefore, would be a prudent resource decision when reviewed by its state regulatory commissions.

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[23] 79 FR 5032, 5045 (Jan. 30, 2014).

[24] *See, e.g.*, Wyo. Admin. Code 023.0002.3 § 26(a)(ii)(B); *In the Matter of Cheyenne Light, Fuel & Power Company's 2002 Res. Plan Concerning Elec. Supplies*, No. 20003-EA-02-67, 2003 WL 26620704, at *5 (July 31, 2003) ("The Commission's responsibility is to evaluate the company's selection to make certain that it has selected least cost reliable resources."); Oregon IRP Guidelines, Order No. 07-047 (risk and uncertainty must be considered, and "[t]he primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."). *See In the Matter of Pub. Util. Comm'n of Oregon Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-047, Appendix A at 1-2 (Feb. 9, 2007).

PacifiCorp routinely uses modeling tools to perform economic analyses that facilitate and support resource decisions and to show that specific resource decisions are prudent. PacifiCorp's most recent IRP was published on September 1, 2021, and filed with the public utility commissions of the states of California, Idaho, Oregon, Utah, Washington and Wyoming. The purpose of PacifiCorp's IRP is to:

> define a resource plan that is least-cost, after consideration of risks and uncertainties. To test resource alternatives and identify a least-cost, risk adjusted plan, portfolio resource options were developed and tested against each other. This testing included examination of various tradeoffs among the portfolios, such as average cost versus risk, reliability, customer rate impacts, and average annual carbon dioxide (CO_2) emissions.[25]

PacifiCorp uses complex modeling and analyses to develop an IRP that identifies a preferred portfolio and associated action plan that it must pursue to ensure the energy its customers need is available at a reasonable cost and with manageable risks, while considering customer demand for clean energy and ensuring compliance with state and federal regulatory obligations. Once these basic obligations are met, PacifiCorp uses the comparative cost, risk, reliability and emission levels of each resource to make decisions about the combination of resources, existing and new, that are necessary to achieve the plan.

Decisions about coal plants are driven in part by ongoing cost pressures on existing coal-fueled facilities as well as by declining costs for new resource alternatives.[26] Participation in the Energy Imbalance Market ("EIM") allows PacifiCorp to take real-time advantage of the least-cost energy available in the broader market, meaning that more expensive resources, even if within its own system, will not be dispatched when less expensive alternatives are available.[27]

In its most recent IRP, in 2021, PacifiCorp found that the five Utah Units subject to the RH SIP 2 would be viable least-cost and low risk assets for its customers through the end of their projected operating lives, 2036 for the Huntington units and 2042 for the Hunter units. This finding was based on the assumption that no SCR would be required for these units.

iii. Capital investment assumptions used to evaluate SCR

The determination of whether SCR is a prudent, least-cost, least risk investment is related to the remaining life of the unit requiring SCR. Because the revenue requirement from a large capital project like SCR is spread over the life of the asset in rates, these costs are treated as levelized costs in the PacifiCorp models and simulations. Standard economic modeling tools are used to determine and document how each thermal unit gets dispatched over time. Increasingly available

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[25] 2021 PacifiCorp IRP, Volume II, Appendix B (Regulatory Compliance) at 24.

[26] 2021 PacifiCorp IRP at 15.

[27] *See* 2021 IRP at 14-15. As a side note, like its coal resources, PacifiCorp only includes renewable resources in its preferred portfolio when they meet the least-cost, least-risk requirement. Renewable resources are not included simply because they meet individual state renewable portfolio requirements. *Id*. at 14.

new energy sources compete with the coal-fueled units for transmission space, capital investment, and market pricing for dispatch into PacifiCorp's system and the broader energy market. Thus, legal requirements that raise generation costs for coal-fueled units reduce their competitiveness and constrain their dispatch as other less expensive options take precedence for transmission space. This, in turn, reduces the value of these units for PacifiCorp's retail customers (analogous to "profitability").

iv. An SCR requirement will likely make coal-fueled units "unaffordable"

As the Affordability Analysis makes clear, an SCR control requirement can change a unit from a viable system asset to one that is "unaffordable" and thus subject to early retirement or possible conversion to an alternative fuel source.[28] Installation of SCR affects product prices, market share, and profitability of the affected unit to such an extent that early retirement of the unit may be the only option for PacifiCorp as a regulated utility.[29] EPA has considered "commodity price forecasting" and "cost/sales ratios," as well as other product price related issues as appropriate indicators of affordability as well as whether the cost of the controls can be passed on to customers.[30] While PacifiCorp is able to pass some costs on to consumers, as a regulated utility it must select, and justify to its regulators that it has prudently chosen, the least-cost, least-risk option for its customers. If the public service commissions find an option is not the least-cost, least risk option, or is not prudent, PacifiCorp cannot pass those costs on to its customers. This determination has been made for SCR costs in the past.[31]

v. It is not uncommon for an SCR requirement to cause unit retirement

It is not uncommon for an SCR requirement to result in retirement or repowering of a coal-fueled generation unit. Numerous other utilities facing similar economic and regulatory pressures have retired or repowered the affected units rather than install SCR. *See, e.g.*:

1. Arizona Cholla Plant, 81 Fed Reg 46852 (July 19, 2016) (required to install SCR but instead announced closure in 2020)
2. Colorado Craig Unit 1, 83 Fed. Reg. 31332 (recently announced it will shutdown by 2025 rather than install SCR)
3. New Mexico San Juan Generating Station, 79 Fed. Reg. 60978 (Oct. 9, 2014) (after a federal requirement to install SCR on all four units, settlement provides for retirement of two units and SCR on the other two)

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[28] PacifiCorp has not yet run an economic model comparison of an alternative fuel source conversion against SCR installation for the Utah Units in the current regulatory environment. However, depending upon the feasibility and costs of getting the alternative fuel to the plant, conversion can potentially be a less expensive option than SCR.

[29] 40 CFR part 51, appendix Y, section IV.E.3.1.3.

[30] 78 Fed. Reg. at 79353-54.

[31] Public Utility Commission of Oregon, Order No. 12-493 (Dec. 20, 2012) at 31-32.

4. Oregon Boardman Plant, 76 Fed. Reg. 38997 (July 5, 2011) (elected to cease burning coal by 2020 rather than install SCR as originally required by a state submittal to EPA)
5. Wyoming Dave Johnston Plant, 79 Fed. Reg. 5032 (Jan. 30, 2014) (PacifiCorp has exercised option to retire Unit 3 by 2027 rather than install SCR).
6. *See also* North Carolina BART Alternative, 81 Fed. Reg. 19519 (April 5, 2016) ("Progress Energy and Duke Energy have shut down 22 of the coal fired EGUs" subject to the BART alternative instead of installing controls to lower emissions)

While some coal-fueled units have elected to install SCR, the unaffordability of SCR and timing requirements for the PacifiCorp units differentiates them. EPA has avoided forcing a retirement under the regional haze rule: "Generally, EPA does not interpret the regional haze rule to provide us with authority to make a BART determination that requires the shutdown of a source."[32] While some facilities in the region have installed SCR, including two units at PacifiCorp's Jim Bridger facility, as illustrated by the list above, retirement or a conversion to an alternative fuel source are actually a more common result in the west than actual SCR installation.

Since PacifiCorp conducted the analysis for the Jim Bridger plant SCR installations, conditions have changed, including a dramatic increase in the amount of alternative energy resources available, both as PacifiCorp-owned resources as well as on the EIM. In addition, demands on the transmission resources relied on by the PacifiCorp units have increased dramatically, making market competitiveness even more important to ensure the viability of a unit. In the years since the Bridger SCR installations, PacifiCorp has identified many more available and affordable energy resources including wind, battery storage, incremental energy efficiency and new direct load control resources, where the large initial capital investment that would be required for an SCR could be better directed to provide net benefits for PacifiCorp customers. PacifiCorp plans to add nearly 11,000 MW of new renewable resources over the next 20-years.[33] Additionally, the 2021 IRP includes the retirement of 14 of its 22 coal units by 2030.[34]

vi. Increasing scrutiny, competition, and state laws contribute to making SCR unaffordable for a regulated utility

Over the past several years, PacifiCorp has faced increasing opposition and had costs rejected by regulators for installing pollution control equipment, including SCRs, at its coal-fueled plants. For example, in 2012, the state of Oregon denied PacifiCorp $17 million of cost recovery for BART equipment required under regional haze and cautioned the company to consider a broader range of alternatives rather than install expensive retrofit equipment on its coal plants.[35]

Many states in PacifiCorp's service area have also adopted laws and regulations that make further significant investment in coal-fueled assets difficult, if not impossible. For example, Oregon's

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[32] 79 FR 5032, 5045 (Jan. 30, 2014).

[33] PacifiCorp 2021 IRP at 89.

[34] PacifiCorp 2021 IRP at 15.

[35] Public Utility Commission of Oregon, Order No. 12-493 (Dec. 20, 2012) at 31-32.

Senate Bill 1547-B extends and expands the Oregon renewable portfolio standard ("RPS") requirement to 50 percent of electricity from renewable resources by 2040 and requires that coal-fueled resources be eliminated from Oregon's allocation of electricity by January 1, 2030. PacifiCorp would thus be unable to recover costs invested in an SCR from Oregon. California's emission performance standards ("EPS") for California-serving utilities has also resulted in a phase out of coal-fueled generation services in that state. California's EPS was mandated by Senate Bill 1368 and applies to baseload generation either owned by, or under long-term contract to a utility, which prohibits the use of coal-fueled generation after 2025. A 2019 Washington law (Clean Energy Transformation Act) sets a 2025 deadline for utilities to end all reliance on coal, and a 2045 deadline to end use of natural-gas-generated electricity. The likely inability to recover the costs of SCR in its rates or in particular states makes any SCR at the Utah Units highly likely to be unaffordable.

vii. SCR is not an affordable investment for PacifiCorp

As the above sub-sections make clear, the dollar-per-ton cost-effectiveness value for SCR does not represent all of the considerations necessary to determine whether SCR is a reasonable control that should be required at the Utah Units. As the Affordability Analysis shows, a demonstration that SCR is the least-cost, least-risk option for PacifiCorp's customers faces likely insurmountable obstacles. In addition, over the past decade, the requirement to install SCR has led to early retirement or refueling of numerous other coal-fueled generating plants in the region and across the country. External factors including increased regulatory scrutiny of investments in coal-fueled resources, state laws limiting the market for coal-fueled power and increasing competition from renewable and storage resources add to the pressures making SCR unaffordable, especially for a regulated utility. The decision to retire a coal-fueled unit rather than install SCR is not merely "a voluntary business decision[ ] that the benefits of continuing to generate electricity at the affected units were outweighed" by other factors. Instead, an early retirement decision is a regulatory necessity as continued plant operation becomes unfeasible because "the costs of [SCR] . . . [are] so onerous that the source[ ] simply could not afford them" making "the sources' decisions to cease operations . . . in essence involuntary."[36] Utah appropriately considered the future predicament that an inflexible SCR requirement would create for PacifiCorp as a regulated utility and elected to require the more flexible mass-based limits to meet the reasonable progress requirements of the regional haze program.

d. Defining a cost-effectiveness threshold is not appropriate or relevant.

PacifiCorp supports Utah's determination to not establish a cost-effectiveness threshold. As explained above, because PacifiCorp is a regulated utility, and because of PacifiCorp's significant role as an electricity provider in the western grid, a cost-effectiveness threshold is not a useful tool. First, a cost-effectiveness threshold does not take into account important considerations for a regulated utility like PacifiCorp. As EPA has acknowledged, "Generally, EPA does not interpret the regional haze rule to provide us with authority to make a BART [or other emissions control]

[36] 79 FR 33438, at 33446 (June 11, 2014).

determination that requires the shutdown of a source."[37] Here, Utah's RH SIP 2 avoids requiring controls (through stringent rate-based limits) that would potentially require the shutdown or fuel-switching of a source, and PacifiCorp supports this effort.

In addition, the potential loss of PacifiCorp's dispatchable generation from even one of the coal-fired units in Utah would present significant challenges to serving PacifiCorp customers' energy needs. The Mass-Based Limits section below discusses potential reliability impacts and other reasonable progress considerations that weigh against an SCR requirement and in favor of the State's selected NOx requirement of mass-based limits. A set cost-effectiveness threshold does not allow considerations of reliability and grid stability to be weighed appropriately.

Moreover, EPA itself has avoided "bright line" cost-effectiveness thresholds, including in reasonable progress determinations. In its establishment of the first phase regional haze FIP for Montana (the State of Montana declined to create its own), EPA stated that "[w]hile the Regional Haze Rule may allow us to establish a bright line for some of the factors such as cost-effectiveness and visibility, we are not required to do so, and have not done so for this action." *See* Approval and Promulgation of Implementation Plans, State of Montana, 77 Fed. Reg. 57,864-01, 57,897 (Sept. 8, 2012). A cost-effectiveness threshold is the exception rather than the rule for EPA and most states and is not appropriate for Utah.

e. De minimus visibility impacts do not justify additional controls.

Utah's RH SIP 2 should include a discussion of whether certain controls or additional requirements will further the visibility goals of the underlying statutes.

The regional haze statute includes "visibility protection" in its title and is centered around visibility. The State of Utah has the discretion, and in fact the duty, to consider "visibility improvement" as part of its reasonable progress determinations and should do so here. In response to a strange comment objecting to visibility as a legitimate consideration in the Montana FIP, EPA explained that: ''In determining reasonable progress, CAA section 169A(g)(1) requires States to take into consideration a number of factors. [States can] take into consideration these statutory factors and any other factors that you have determined to be relevant. The potential reduction in quantity over distance (Q/D) is a factor that we consider to be relevant because the goal of the Regional Haze Rule is to improve visibility. The commenter has not cited any authority supporting the position that visibility improvements may not be considered in reasonable progress determinations and therefore has given us no basis to change our use of this factor." *See* Approval and Promulgation of Implementation Plans, State of Montana, 77 Fed. Reg. 57,864-01, 57,899 (Sept. 8, 2012). "Instead, EPA is required to consider the four statutory reasonable progress factors. In addition, EPA may consider additional, relevant factors such as visibility improvement from controls." *Id.; see also id.* at 57,902 ("As we explained elsewhere, our RP Guidance allows for consideration of additional factors such as visibility impacts or benefits. Given the large annual emissions of NOx and SO2 from Colstrip Units 3 and 4 compared to other reasonable progress

[37] 79 FR 5032, 5045 (Jan. 30, 2014).

sources, we found that it was reasonable to model the visibility benefits and consider them when evaluating controls.”).

Moreover, a requirement that controls provide some “discernible improvement” is consistent with past EPA practice. *See* 77 Fed. Reg. 24794 (0.27 dv improvement termed “small” and did not justify additional pollution controls in New York); 77 Fed. Reg. 11879, 11891 (0.043 to 0.16 dv improvements considered “very small additional visibility improvements” that do not justify NOx controls in Mississippi); 77 Fed. Reg. 18052, 18066 (agreeing with Colorado’s determination that “low visibility improvement (under 0.2 dv)” did not justify SCR for Commanche units). In Montana, where EPA issued the FIP directly, it found a 0.18 deciview improvement to be a “low visibility improvement” that “did not justify proposing additional controls” for SO_2 on the source. 77 Fed. Reg. 23,988, 24,012. While PacifiCorp acknowledges that the “visibility improvement” at an individual site does not need to reach the level of human perception, it is also not reasonable to require exorbitant expenditures that result in no real modeled, discernible improvement in visibility.

f. Dollar per deciview

Although not specifically addressed in the RH SIP 2, Utah should consider supplementing its RH SIP 2 analysis with a “dollars per deciview” approach. The dollars per deciview approach is an important and acceptable part of the regional haze analysis. For example, in its 2007 Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, EPA states that the “simple cost effectiveness estimates based on a dollar-per-ton calculation may not be as meaningful as a dollar-per-deciview calculation, especially if the strategies reduce different groups of pollutants.” *Id.* at page 5-2. Additionally, EPA has stated that “the BART Guidelines list the dollars per deciview ratio as an additional cost effectiveness metric that can be employed” as “one of several metrics that can be used to analyze cost of visibility improvement.” *See* 77 Fed. Reg. 40150, 40156 (July 6, 2012); *see also* 77 Fed. Reg. 24845, 24850 (approving South Dakota’s use of the “dollars per deciview” metric); 77 Fed. Reg. 72512, 72518 (stating the “dollars per deciview” metric is “an additional cost-effectiveness measure that can be employed along with \$/ton for use in a BART evaluation”); 83 Fed. Reg. 62204, 62233 (finding Arkansas’ analysis of reasonable progress factors, including a dollars per deciview measure, reasonable).

PacifiCorp believes a dollars per deciview (“dollar/dv”) analysis would be a useful metric to describe the cost-versus-visibility benefits associated with potential SCR retrofits on the Utah Units. The following dollar/dv values were determined using visibility impacts with the installed low-NOx burners and over-fired air (“LNB/OFA”), scrubber upgrades and baghouses on the Utah Units compared to visibility impacts with the addition of SCR. Costs associated with the installation of SCR were obtained from studies Sargent & Lundy performed for PacifiCorp. Visibility impacts to the most impacted Class I area – Canyonlands National Park – were obtained from PacifiCorp’s June 2012 BART studies completed by CH2M Hill. Application of the annualized capital and operating and maintenance (“O&M”) costs for SCR and the visibility improvement provided by SCR provide the following dollar/deciview values: \$219 million/dv for Hunter Unit 1; \$220 million/dv for Hunter Unit 2; \$249 million/dv for Huntington Unit 1; and

$298 million/dv for Huntington Unit 2.[38] PacifiCorp expects that the dollar/dv value for Hunter Unit 3 would be similar to the Hunter Units 1 and 2 values because while the visibility improvement provided by SCR on Hunter Unit 3 would likely be greater than Units 1 and 2 due to Unit 3's inherently higher LNB-controlled NOx rate, Hunter Unit 3's SCR capital and O&M costs would also be greater than the Hunter Units 1 and 2 capital and O&M costs.

EPA has found much lower dollar/dv costs to be unreasonable in Arkansas. *See* 83 FR 62204, 62230-31 (finding costs ranging from $63 to $71 million dollars/deciview to be unreasonable); *see also* 77 FR 72512, 72533 (recognizing that federal land managers, or "FLMs", "have indicated that they consider $20 million/dv to be a benchmark for average cost-effectiveness"); 77 FR 42834, 42857 (explaining that EPA's "compilation of BART analyses across the U.S. reveals that the average cost per dv proposed by either a state or a BART source is $14-$18 million. While we do not necessarily consider $14 to $18 million/dv as being a reasonable range in all cases, we note that for all of the NO_X control options [in this case], including SCR, both the $/max dv and the $/cumulative dv are well below this range."). The $219 to $298 million dollar/dv numbers highlight that requiring SCR at the Utah coal units would be an outlier due to the disparity between the high costs and very limited visibility benefit. The State should undertake similar analysis at other Utah power plants as part of the RH SIP 2 to supplement its analysis of the "cost of controls."

g. Consideration of NOx mass-based limits versus rate-based limits

The State developed a sensitivity analysis to demonstrate the impact of plant utilization on cost-effectiveness at PacifiCorp's Utah Units. The analysis indicates that lower plant utilization leads to an increase in cost effectiveness. The electricity generation industry is experiencing significant change, which increases uncertainty regarding medium to long-term operations of Hunter and Huntington.[39] As such, the State correctly determined the costs for controls were not prudent, and instead implemented NOx mass-based emission limits that conform to the Western Regional Modeling and Analysis ("WRAP") projected 2028 NOx "on the books" estimates.[40]

The State's use of the WRAP models "on the books" estimates to set emissions limits is consistent with past EPA practice. For example, in the Montana FIP, EPA said "We have stated in other actions addressing regional haze that a plan that provides for emission reductions consistent with

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[38] PacifiCorp has escalated these dollar/dv costs to 2022 dollars.

[39] Parties have requested PacifiCorp's projected capacity factors for Hunter and Huntington as contained in the 2021 IRP. However, the IRP does not contain unit-specific capacity factor projections. *See* 2021 IRP at 21. The past capacity factors for both the Hunter and Huntington plants are contained in the table in sub-section V.c above. Detailed utilization and dispatch projections are proprietary, commercially sensitive and confidential in nature since others can obtain economic value from its disclosure or use, or derive value because it is not generally known. For example, projected utilization could be used by power market participants to estimate the expected dispatch of the units, which could in turn put PacifiCorp at a disadvantage when buying or selling power. This would negatively impact PacifiCorp's customers.

[40] The Utah Units have shown a historical decrease in NOx emissions from 2000-2021.

the assumptions underlying the WRAP modeling will ensure that a State is not interfering with measures designed to protect visibility in other states. *See e.g.* 76 FR 491, 496–497 (Jan. 5, 2011). Similarly, a plan that is consistent with the assumptions underlying the modeling used to establish RPGs in a state likely will include the measures necessary to achieve those RPGs." *See* Approval and Promulgation of Implementation Plans, State of Montana, 77 Fed. Reg. 57,864-01, 57,900 (Sept. 8, 2012).

PacifiCorp supports Utah's determination for implementation of NOx mass-based emission limits at the Utah Units. Mass-based limits provide the Company with flexibility to provide reliable, safe, low-cost power to customers while ensuring reasonable progress for visibility improvements in Class I areas. Mass-based limits also best address each of the four reasonable progress factors that the State must consider when selecting regional haze control requirements. In addition to the obvious cost-effectiveness benefits, mass-based limits also provide more benefits in terms of the three remaining considerations of (1) time for compliance (mass-based limits can be implemented more rapidly than a rate-based SCR requirement); (2) energy and nonair environmental impacts (NOx mass-based limits have the ancillary benefit of reducing other emissions such as greenhouse gases (carbon dioxide), and SO_2, a haze-causing pollutant impacting Class I areas; a rate-based NOx limit would require a NOx control technology like SCR to be installed that would not limit the amount of coal burned nor control other haze-causing pollutants); and (3) mass-based limits work well with the existing useful life of the Utah Units in the most recent IRP.[41]

A rate-based limit, and the associated need to install SCR, could inadvertently lead to an increase in both other haze-causing pollutants and greenhouse gases. The installation of SCR results in a "parasitic load" (electricity consumed due to the SCR equipment that isn't distributed to customers). In other words, when SCR is installed on a coal-fueled power plant it must burn more coal to produce the same amount of electricity that can be distributed and sold to customers. Installing SCR on the two units at the Huntington plant would result in a "parasitic load" of 8.6 MW, which equates to 79,734 more tons of CO_2 per net megawatt-hour ("MWh") generated. Installing SCR on the three units at the Hunter plant would result in a "parasitic load" of 12.5 MW, which equates to 115,687 more tons of CO_2 per net MWh generated. In short, a regional haze-based requirement to install SCR at any coal-fueled unit results in more greenhouse gases being emitted per MWh, not less.

In addition to the reasonable progress factors, there will be additional challenges to meet PacifiCorp customers' energy needs if an expensive rate-based technology like SCR leads to the early retirement of even one of the Utah Units. In addition to the significant generation capacity of each unit, the units are necessary to support grid stability, transmission services, and low-cost energy during times of scarcity.

1. Generation Capacity

One of the main responsibilities of a regulated utility is to maintain the stability of the electric grid, which means preserving the ability to deliver generation right when the demand is received. In

[41] EPA requires consideration of an extended 30-year useful life for SCR. The projected useful life of the Utah Units is 14 and 20 years.

addition, maintaining stability means that enough reserve energy must be maintained in case generation or transmission capability is compromised in some manner.

Each of the Utah Units is capable of providing more than 400 MW of electricity, and replacing such capacity is not as simple as finding, for example 400 MW of solar or wind. The 2021 IRP indicated that matching the reliability benefits of 400 MW of coal fired capacity could require 800-2,000 MW of wind resources or 2,600-4,400 of solar resources, depending on location. Alternatively, 400-700 MW of energy storage resources could be required, depending on the duration that they can sustain maximum output. While mixing wind and solar resources in different locations with storage resources provides diversity benefits, it is already reflected in the values stated. As wind, solar, and energy storage become a larger portion of the Company's portfolio, their effective contributions to reliability will decline, such that more wind and solar capacity or longer-duration energy storage capacity will be required. The analysis used to develop these figures assumed all five of the Utah Units remained part of PacifiCorp's system, so the values stated are only representative of the requirements for replacing a single coal-fired facility. Transmission system investments necessary to add wind and solar resources at these levels would require significant cost and time to develop.

Sufficient electricity generation is a key component to a reliable electrical system. *See, e.g.*, North American Electric Reliability Corporation (NERC), 2022 Summer Reliability Assessment, May 2022 (finding Utah and the Pacific Northwest region are at elevated risk of an energy emergency in the summer of 2022); Wall Street Journal, Electricity Shortage Warnings Grow Across U.S., May 8, 2022 ("Power-grid operators caution that electricity supplies aren't keeping up with demand amid transition to cleaner forms of energy").

2. Grid Stability

Even if the necessary amount of renewable or other energy to replace a fossil-fueled unit were available, PacifiCorp's energy system would still be impacted if one or more of the Utah Units were retired. In addition to replacing the electricity generated by the unit, the ancillary services supporting grid stability would have to be replaced. The Utah Units each provide frequency response services that are necessary to stabilize the balance of electricity generation and load requirements. Because fossil-fuel units can quickly and reliably ramp generation up or down depending upon system needs, they play a vital role to accommodate intermittent and renewable resources, like solar and wind, while still ensuring grid stability. The frequency response required from renewable resources (FERC Order 842) can be variable in nature due to the fuel source.

Because of their vital role in accommodating renewable generation, forced early retirement of a fossil fuel unit could restrict the level of renewables that can be accommodated until adequate replacements can be constructed or purchased. Replacement resources must be tested and adequately verified to ensure that faults in the transmission system will be mitigated enough to accommodate variable sources such as renewable generation.

Fossil fuel resources also play an outsized role in providing the synchronicity needed to stabilize the electrical grid. When a fault occurs in a transmission line or transmission element, the transmission system undergoes oscillations before it stabilizes and comes to a new stable state. The inertia present in the transmission system also provides damping, which is an important factor used to stabilize the system. Fossil fuel units have significant inertia that provides damping to the system. Without replacing this inertia, a heavily loaded transmission system will have more oscillations during an outage, and this can trip other transmission elements and degrade the reliability of the transmission system.

Fossil-fuel units also provide the majority of the fault current necessary to protect PacifiCorp's transmission system. The fault current enables the system to distinguish between normal and abnormal conditions. The fault current triggers the protection systems for transmission that will isolate a faulted transmission element and ensure the safety and reliability of the transmission system. The premature or unplanned retirement of a coal unit would significantly reduce the fault current and would likely result in instability, but an in-depth study would be needed to determine the exact impacts. With significant reduction in the fault current, the protection settings for the transmission system would need to be readjusted to appropriately detect and isolate abnormal conditions to avoid critical breakdowns or blackout events. Such readjustments require extensive cost, study and time to engineer and construct. One option to replace the synchronicity provided by fossil fuel units is synchronous condensers. However, synchronous condensers require extensive study, years to build, and represent a major investment. Synchronous condensers also provide only partial replacement of the inertia and fault current needed. While they could help provide the reactive support that would be lost due to the retirement of a fossil-fueled unit, the exact level of replacement and their ability to serve the same inertia and fault current roles is unknown at this time. As an example, a study conducted prior to 2020 for projected retirement of a coal plant in Wyoming found that a 350 MVAR synchronous condenser would cost approximately $45-$55 million and take at least 42 months to obtain. Additional mitigation could also be required depending on study findings, and the variability of transmission interconnection presents significant uncertainties.

In summary, the additional time, costs and potential disruptions to reliability associated with an SCR requirement and the potential closure of a Utah Unit weigh heavily in favor of the mass-based limits.

3. Transmission

The amount of renewable resources, such as wind and solar, that would need to be interconnected into the existing transmission system to fill the generation currently provided by a single Utah Unit will be significant. In addition, these renewable resources may not be at the same location as the retiring fossil fuel plants, which would require additional transmission and thus additional costs and time.

In addition, the queues to access available transmission are already very crowded. For example, neighboring Wyoming has a significant potential to interconnect wind into the transmission system, but this potential is limited due to transmission constraints. The last Interconnection cluster study conducted by PacifiCorp showed that significant transmission investment is required from all new resources wishing to interconnect, including new renewable resources. These constraints often delay or prevent the planned development of new resources. Transmission constraints often require new transmission, which requires significant time to plan, receive approvals, engineer and construct.

In addition to the transmission constraints, significant upgrades of the transmission system will be required if a large fossil-fuel unit is forced to cease operating. Because fossil fuel units provide significant support in maintaining the reliability of the transmission system (as discussed above), significant upgrades will be required if even one of these units must be replaced.

As an example, when the Carbon plant closed in 2015, it was necessary to perform transmission upgrades in the form of a new Static VAR Compensator at the Mathington substation, a new phase shifting transformer at the Upalco substation, a series reactor on the Spanish Fork-Carbon 138 kV line, and multiple shunt capacitors at Mathington along with reconfiguration of several substations. These transmission upgrades cost more than $39 million and took approximately three years to complete.

The necessary upgrades to maintain reliability of the transmission system will require significant study, planning, testing, design, and construction processes.

h. Utah's proposed SO_2 rate-based limit is appropriate

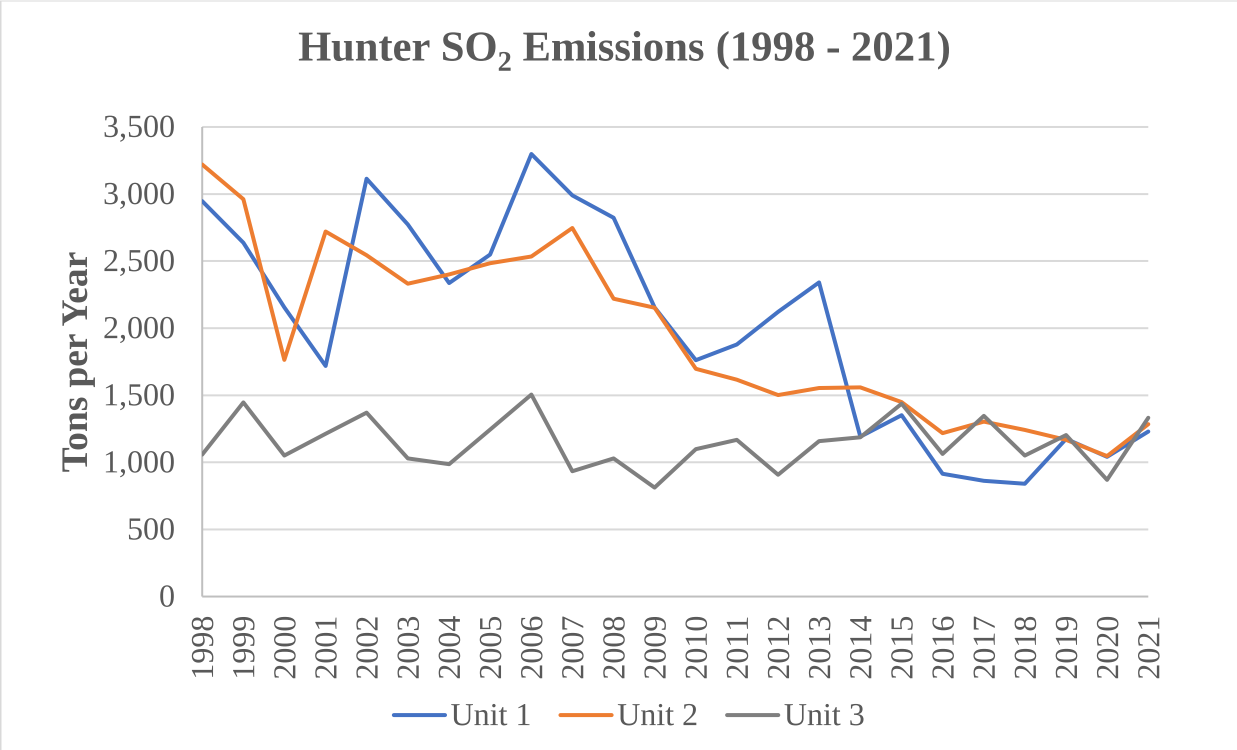
PacifiCorp supports Utah's determination of an SO_2 limit of 0.12 lb/MMBtu[42] 30-day rolling average for the Utah Units. This permit limit for the plants is the appropriate limit because the SO_2 controls at the plants: (1) are efficient and effective; (2) cannot be upgraded to become more efficient in a cost-efficient manner; and (3) align with EPA guidance recognizing that a State may forego further analysis of SO_2 controls at a plant with modern, efficient controls.

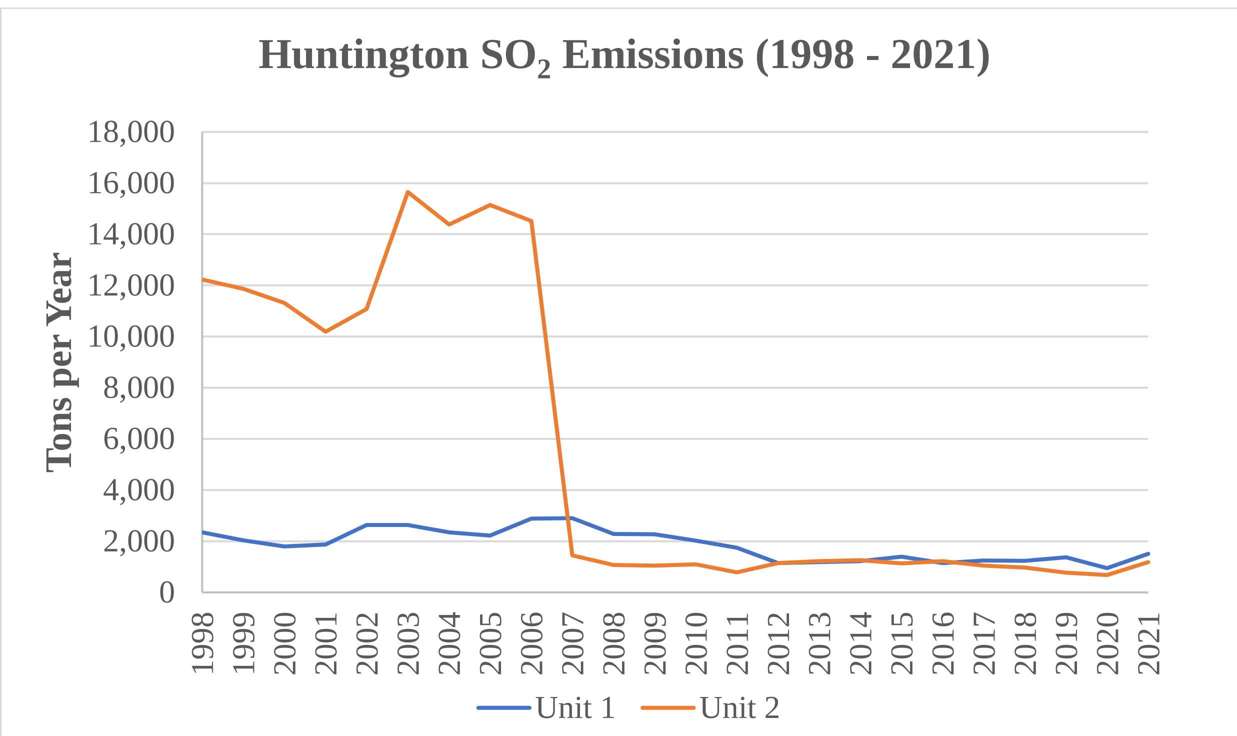
i. Hunter and Huntington have effective SO_2 controls.

The SO_2 controls at the Utah Units all have control efficiencies that surpass 90%. Each of the units at these plants is subject to a stringent SO_2 emissions limit of 0.12 lb/MMBtu through their respective Title V permits.[43] The charts below demonstrate the SO_2 emissions reduction improvements PacifiCorp has made at its Utah Units.

[42] Page 126 of Utah's RH SIP 2 references an incorrect 12 lb/MMBtu SO_2 emission limit in the UDAQ Response Conclusion SO_2 paragraph. The correct emission limit is 0.12 lb/MMBtu.

[43] Section II.B.3.b of each Title V permit contains the relevant limit.





ii. Hunter and Huntington have effective SO_2 controls.

In section 4.1.2 of its Feb. 14, 2022, feedback on Utah's RH SIP 2, the National Park Service ("NPS") incorrectly suggested that PacifiCorp and the Utah Department of Environmental Quality, Division of Air Quality ("UDAQ") should conduct a "four-factor analysis to explore potential SO_2 emission reduction opportunities for the Hunter and Huntington facilities." NPS also mistakenly asserted that PacifiCorp had provided information that the scrubbers could be upgraded to remove "over 3,000 tons/year of additional SO_2 for less than $1,000 per ton." This confusion seemed to impact the Utah Air Quality Board's discussions on April 6, 2022, and PacifiCorp wishes to clarify the issue.

The SO_2 controls at PacifiCorp's plants are running as efficiently as possible, and there are no cost-efficient upgrades available. NPS and the Utah Air Quality Board appear to be misinterpreting information provided by PacifiCorp as part of the Reasonable Progress Emission Limits ("RPELs") offered in PacifiCorp's April 21, 2020, submittal, which combined operational adjustments with incremental capital and O&M costs.

PacifiCorp's April 2020 Regional Haze Second Planning Period Reasonable Progress Analysis included proposed plantwide combined NOx and SO_2 RPELs for the Utah Units (the "2020 RP Analysis"): a 10,000 tons/year RPEL for Huntington and a 17,000 tons/year RPEL for Hunter. In the proposed RPEL determinations, which were ultimately not pursued by Utah, PacifiCorp calculated NOx emissions on a potential-to-emit basis, employing the lowest achievable lb/MMBtu emission rates for each Utah Unit, assuming an SNCR rate. Once the NOx emissions were determined for each unit (based on the SNCR rate assumption), PacifiCorp then calculated the equivalent SO_2 emission rate necessary to comply with the proposed annual RPEL. The NOx and SO_2 rates discussed in the 2020 RP Analysis are artificial rates which resulted from the RPEL calculation methodology.

The Utah Units' SO_2 pollution control equipment (scrubbers) have design rates from 0.08 to 0.10 lb/MMBtu, and the costs indicated in the 2020 RP Analysis are to optimize these rates. The design parameters were necessary to ensure compliance with the Units' 0.12 lb/MMBtu emission limits. The existing Utah Units' scrubbers cannot control to lower SO_2 emission rates. To achieve a 0.03 lb/MMBtu SO_2 rate, new scrubbers would have to be constructed at an estimated capital cost of $180 million for each unit. Similarly for the NOx rate assumed in the 2020 RP Analysis, an SNCR would be required. In contrast, the NOx and SO_2 mass-based limits in the SIP preserve the flexibility to meet the limits either with or without expensive control equipment.

iii. EPA guidance recognizes additional SO_2 controls are not required

EPA's 2019 Guidance recognizes that it "may be reasonable for a state not to select an effectively controlled source. A source may already have effective controls in place as a result of a previous regional haze SIP or to meet another CAA requirement." *See* 2019 Guidance at 22.

The 2019 Guidance provides examples which illustrate, in a non-exhaustive fashion, scenarios that may provide reasonable grounds for a State not to select a source for analysis, including when an electric generating unit has add-on flue gas desulfurization ("FGD") and meets the applicable alternative SO_2 emission limit (0.2 lb/MMBtu) of the 2012 Mercury Air Toxics Standards ("MATS") rule for power plants. *Id.* at 23. This example is consistent with the situation here. Moreover, EPA explained in the 2019 Guidance that the 0.2 lb/MMBtu SO_2 limit in the MATS rule is "low enough that it is *unlikely* that an analysis of control measures for a source already equipped with a scrubber and meeting [this] limit[] would conclude that even more stringent control of SO_2 is necessary to make reasonable progress." *Id.* at 23. (emphasis added).

Such is the case here. All of PacifiCorp's Utah coal plants have FGD installed, and each unit has a permitted limit of 0.12 lb/MMBtu for SO_2 emissions, which is significantly lower than the 0.2 lb/MMBtu SO_2 limit addressed in the 2019 Guidance. Therefore, under the applicable EPA guidance, no further SO_2 controls are needed for the Utah Units.[44]

iv. Coal Quality.

UDAQ should also consider that sulfur content varies by mine and coal seam. SO_2 emissions limits imposed on PacifiCorp must consider the potential variability of sulfur content in future coal deliveries. The Utah Units rely on a relatively illiquid coal market for fuel supply, thus any changes to SO_2 emission limits would need to account for the quality of available coal.

v. Visibility.

Finally, UDAQ has not provided any analysis or information that additional SO_2 emissions limits, as contemplated by UDAQ, will improve visibility in a cost-effective manner, or will even appreciably improve visibility in Class I areas. As explained above, UDAQ should not impose controls under the regional haze program unless there is some evidence that visibility will improve at some level. PacifiCorp is unaware of any such evidence.

i. Proposed Ozone Rule

On April 6, 2022, the EPA released a proposed revision to the Cross-State Air Pollution Rule ("2022 CSAPR") intended to address ozone transport for the 2015 ozone National Ambient Air Quality Standard. The proposed rule would require electric generating utilities in Utah, including the Utah Units, to comply with new NOx reduction requirements and a trading program with significant emission reduction requirements. As proposed, the 2022 CSAPR overlaps with the second planning period regional haze requirements. PacifiCorp is evaluating the impact of the proposed 2022 CSAPR rule on its operations and regional haze compliance in Utah. Because the proposed 2022 CSAPR and the regional haze second planning period requirements overlap for both the controlled pollutants and the controlled sources, Utah should properly account for the 2022 CSAPR, if finalized, when determining requirements for regional haze.

[44] Page 126 of Utah's RH SIP 2 references an incorrect 12 lb/MMBtu SO_2 emission limit in the UDAQ Response Conclusion SO_2 paragraph. The correct emission limit is 0.12 lb/MMBtu.

VI. CONCLUSION

PacifiCorp supports Utah's RH SIP 2 and suggests that Utah strengthen the SIP by including the additional information in these comments as part of the justification for the second planning period requirements.

Sincerely,

Kirsten Merrett

Kirsten Merrett
Environmental Technology & Policy Manager
PacifiCorp

Attachments: Appendix A – Wyodak Facility SCR Affordability Analysis, August 25, 2020

cc: James Owen – Vice President, Environmental, Fuels & Mining, PacifiCorp
Marie Durrant – Assistant General Counsel, PacifiCorp

Appendix A

Wyodak Facility SCR Affordability Analysis, August 25, 2020

August 25, 2020

PacifiCorp Wyodak Facility SCR Affordability Analysis

Draft Report

Prepared for

EPA Region 8

Affordability Analysis for Wyodak SCR Requirement

PacifiCorp has determined selective catalytic reduction equipment ("SCR") is not affordable for the Wyodak plant. A determination of SCR as best available retrofit technology ("BART") for the Wyodak plant[1] in accordance with the Clean Air Act's regional haze program has financial consequences that would result in early retirement of the unit. Due to the substantial capital costs of SCR, the associated operational and maintenance ("O&M") costs, the parasitic load imposed by the SCR, the transmission constraints within which the Wyodak plant operates, and the increasingly competitive energy markets and regulatory restrictions that govern PacifiCorp's operations in eastern Wyoming, an SCR BART determination for Wyodak has such an onerous financial impact that PacifiCorp would be forced to retire the Wyodak plant rather than install the SCR.

This report demonstrates SCR should not be required as BART at Wyodak because it is not affordable, as established by conditions in Environmental Protection Agency ("EPA") regulations, guidelines and previous BART decisions. In support of this conclusion, this report identifies the relevant parts of EPA's Guidelines for BART Determinations[2] ("BART Guidelines") that describe how to conduct an "affordability analysis", identifies the key factors EPA has applied when evaluating previous affordability analyses, and then applies those factors to the Wyodak power plant using standard economic analysis methods that are applicable to PacifiCorp as a regulated utility.

I. EPA BART GUIDELINES AND THE "AFFORDABILITY" ANALYSIS

Even where a BART control technology is found to be cost effective, the BART Guidelines allow decision makers to take a source's ability to afford a technology into account if "the installation of controls would *affect the viability of continued plant operations.*"[3] The BART Guidelines outline the circumstances where such consideration is appropriate:

> There may be *unusual circumstances* that justify taking into consideration the conditions of the plant and the economic effects of requiring the use of a given control technology. These effects would include *effects on product prices, the market share, and profitability of the source*. Where there are such unusual circumstances that are judged to affect plant operations, you may take into consideration the conditions of the plant and the economic effects of requiring the use of a control technology. Where these effects are judged to have a *severe impact on plant operations* you may consider them in the selection process,

[1] The requirement to install SCR as BART at Wyodak is currently stayed by a federal court of appeals. EPA imposed the requirement to install SCR at Wyodak through a regional haze FIP in 2014. 79 FR 5032 (2014). The state of Wyoming and PacifiCorp appealed that requirement in the Tenth Circuit Court of Appeals, and the court granted a stay of the requirement, which remains in effect. *Wyoming v. EPA*, Case No. 14-9529 (consolidated with Case Nos. 14-9530 and 14-9534) (stay order originally granted September 9, 2014). This Affordability Analysis is presented as additional evidence that SCR as BART is not appropriate for the Wyodak plant and does not contradict or waive any of PacifiCorp's arguments in the Tenth Circuit proceeding that the federal government erred in selecting SCR as BART for Wyodak.
[2] 40 CFR Part 51, App. Y.
[3] 40 CFR part 51, appendix Y, section IV.E.3.1.3 (emphasis added).

> but you may wish to *provide an economic analysis that demonstrates, in sufficient detail for public review, the specific economic effects, parameters, and reasoning*. (We recognize that this review process must preserve the confidentiality of sensitive business information). Any analysis may also consider whether other competing plants in the same industry have been required to install BART controls if this information is available.[4]

Using these guidelines, EPA has addressed the "affordability" analysis in a few cases as briefly outlined below.

II. EPA'S PAST USE OF "AFFORDABILITY" ANALYSES.

EPA has recognized the potential use of affordability analyses in several circumstances. For example, in the Wyoming regional haze rulemaking, EPA stated that Basin Electric could provide an affordability analysis that incorporated "total capital cost and total annual cost, as well as incidental increases in prices to consumers."[5] Ultimately, EPA did not accept Basin Electric's affordability analysis because it "did not provide the necessary detailed information to suggest that installing SCR at Laramie River would be unaffordable, either for the cooperative or its rate payers."[6] In the Idaho regional haze rulemaking for The Amalgamated Sugar Company ("TASCO") facility, EPA addressed the affordability analysis submitted by TASCO.[7] EPA explained that the "BART guidelines, specifically allow, but do not require, affordability to be considered when determining BART. . . . The guidelines do not require that a specific method be used to conduct an affordability analysis nor do they specify a specific standard of review."[8]

In the Washington regional haze rulemaking for Alcoa's Intalco aluminum plant, EPA used the affordability analysis to find that the subject BART control was not affordable. In the Intalco rulemaking, EPA specifically analyzed the company's "cost/sales ratio," product demand, closure of similar facilities, product prices, and profitability of the facility.[9] The analysis also took into account the difficulty of passing the costs onto customers, which could result in an unacceptable profit margin at the plant.[10] In the final rule, EPA found that the "updated analysis continues to support our determination that installation and operation of LSFO at the Intalco facility is not affordable."[11]

III. PACIFICORP AND WYODAK PLANT BACKGROUND

a. PacifiCorp

PacifiCorp is a United States regulated electric utility company headquartered in Portland, Oregon that serves 1.9 million retail electric customers, including residential, commercial, industrial, irrigation and other customers in portions of Utah, Oregon, Wyoming, Washington,

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[4] *Id.*
[5] 79 FR 5032, 5171 (2014).
[6] *Id.* at 5171-72.
[7] 76 FR 36329 (2011).
[8] *Id.* at 36334.
[9] 78 FR 79344, 79353-54 (2013).
[10] *Id.* at 79354.
[11] 79 FR 33438, 33442 (2014).

Idaho and California. PacifiCorp is principally engaged in the business of generating, transmitting, distributing and selling electricity. In addition to retail sales, PacifiCorp buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants. PacifiCorp delivers electricity to customers in Utah, Wyoming and Idaho under the trade name Rocky Mountain Power ("RMP") and to customers in Oregon, Washington and California under the trade name Pacific Power.

As of 2019, PacifiCorp's system includes approximately 10,000 MW of capacity from its existing resources. This includes 5,638 MW nameplate capacity of coal-fueled plants, 2,821 MW nameplate capacity of natural-gas-fueled plants, 2,222 MW owned wind, 1,686 purchased wind, 1,759 of purchased solar, approximately 49 MW of owned and purchased geothermal capacity, 100 MW of nameplate capacity for biomass/biogas, 1,135 MW of owned plus 89 MW of purchased hydroelectric generation, plus various levels of net metering, demand-side management ("DSM"), private generation, and power purchase contract capacities.[12]

PacifiCorp's fleet of thermal plants (coal-fired and natural gas) accounts for roughly two thirds of the firm capacity available in the PacifiCorp system.[13]

b. Wyodak

The Wyodak plant is part of the thermal fleet operated by PacifiCorp. The Wyodak plant is jointly owned by PacifiCorp and Black Hills Corporation with an undivided interest of 80% and 20%, respectively. The Wyodak plant is a single fossil steam coal unit with a net generating capacity of 335 MW. PacifiCorp owns 268 MW of that output. The boiler manufacturer is Babcock & Wilcox, and the turbine manufacturer is General Electrical. The Wyodak plant started operations in June of 1978 and is located near Gillette, Wyoming.

The Wyodak plant is not located within an RMP or Pacific Power service territory, making it one of the few units situated in that manner. The plant is in central Wyoming, east of the RMP service territory; however, Wyodak's costs are assigned across PacifiCorp's system according to a cost-allocation agreement known as the multi-state protocol. From 2011 to 2019, the Wyodak plant had an average annual capacity factor of 78.7%, which translates to delivering approximately 2.3 million megawatt-hours (MWh) of energy while burning approximately 1.8 million tons of coal per year.

The annual O&M budget for the plant is approximately $12.5 million, over half of which represents the cost of labor expense for 65 employees. This does not include the price of fuel, which is a variable cost and recovered through PacifiCorp's net power cost recovery mechanisms. Fuel is the single largest cost to operate the plant. Another $3 million is spent annually on reagents and other chemical costs used to control emissions and treat water. The remainder is used for the routine work of maintaining operating equipment in the plant. On a 4-year cycle, the plant undergoes overhauls on major pieces of equipment such as the boiler and turbine. These overhauls typically have a duration of 35 days.

[12] 2019 PacifiCorp Integrated Resource Plan ("2019 IRP"), Ch. 5.
[13] *See* PacifiCorp 2019 IRP, at 110.

The plant operates in what is referred to as automatic generator control mode, or AGC. The RMP generation desk located in Portland, Oregon, sends a signal to the plant requesting the amount of energy to be delivered to the electrical grid. That signal is typically changed on an hourly basis, but can occur more frequently. Operations personnel at the plant monitor the status of all plant equipment in support of the AGC signal. One of the main responsibilities of a regulated utility is to maintain the stability of the electric grid, which is greatly aided by delivering an AGC signal to the generating fleet. In addition, enough reserve energy is maintained in the event that generation or transmission capability is compromised in some manner.

c. Prudent Least-Cost, Least-Risk Requirements for Regulated Utilities

As a regulated public utility, rather than relying on the competitive market and profitability, PacifiCorp must instead meet requirements of state regulators to demonstrate prudent decision-making on behalf of its customers. The state regulators approve revenue to cover costs and a reasonable return on resource investments that they find to be prudent. PacifiCorp is required by statute, administrative regulation, and orders from public utility commissions in each of the six states where it operates to file an integrated resource plan ("IRP"). The IRP is based on a 20-year forecast and identifies the least-cost, least-risk portfolio of resources and transmission investments required to reliably serve customers.[14] The IRP also includes an action plan that sets forth the specific resource actions that PacifiCorp will take over the near-term consistent with the preferred portfolio, which can include action items to retire a high-cost asset and procure new resources. This planning process sets the stage for definitive resource decisions, which must satisfy a prudence review from state regulatory commissions. During the prudence review, state commissions assess, in part, how resource decisions affect customer rates. This planning and decision making process applies to PacifiCorp as a regulated utility and is analogous to a review of product price, marketability, and profitability for unregulated companies. Thus in the affordability analysis presented in this report ("Affordability Analysis"), PacifiCorp presents evidence showing it would be unable to demonstrate that installing an SCR at Wyodak would be in the best interest of its retail customers, and therefore, would not be considered a prudent resource decision if reviewed by state regulatory commissions.

PacifiCorp routinely uses the same modeling tools that inform its IRP to perform economic analysis that supports resource decisions. As such, the results of these modeling tools are used by the company to show that specific resource decisions are prudent when those decisions are reviewed by state regulatory commissions. PacifiCorp's most recent IRP was published on October 18, 2019, and filed with the public utility commissions of the states of California, Idaho, Oregon, Utah, Washington and Wyoming. The purpose of PacifiCorp's IRP is to:

> define a resource plan that is least-cost, after consideration of risks and uncertainties. To test resource alternatives and identify a least-cost, risk adjusted

[14] *See, e.g.*, Wyo. Admin. Code 023.0002.3 § 26(a)(ii)(B); *In the Matter of Cheyenne Light, Fuel & Power Company's 2002 Res. Plan Concerning Elec. Supplies*, No. 20003-EA-02-67, 2003 WL 26620704, at *5 (July 31, 2003) ("The Commission's responsibility is to evaluate the company's selection to make certain that it has selected least cost reliable resources."); Oregon IRP Guidelines, Order No. 07-047 (risk and uncertainty must be considered, and "[t]he primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."). *See In the Matter of Pub. Util. Comm'n of Oregon Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-047, Appendix A at 1-2 (Feb. 9, 2007).

> plan, portfolio resource options were developed and tested against each other. This testing included examination of various tradeoffs among the portfolios, such as average cost versus risk, reliability, customer rate impacts, and average annual carbon dioxide (CO_2) emissions.[15]

PacifiCorp uses complex analyses to develop an IRP that identifies a preferred portfolio and associated action plan that it must pursue to ensure the energy its customers need is available at a reasonable cost and with manageable risks, while considering customer demand for clean energy and ensuring compliance with state and federal regulatory obligations. Once these basic obligations are met, PacifiCorp uses the comparative cost, risk, reliability and emission levels of each resource to make decisions about the combination of resources, existing and new, that are necessary to achieve the plan.

Decisions about coal plants are driven in part by ongoing cost pressures on existing coal-fired facilities as well as by declining costs for new resource alternatives.[16] Participation in the Energy Imbalance Market ("EIM") allows PacifiCorp to take real-time advantage of the least-cost energy available in the broader market, meaning that more expensive resources, even if within its own system, will not be dispatched when less expensive alternatives are available.[17]

In its most recent IRP, in 2019, PacifiCorp found that Wyodak would be a viable least-cost and low risk asset for its customers through 2039. This finding was based on the assumption that no SCR would be required for Wyodak.[18]

IV. Financial Analysis Methodology

In order to assess the affordability of installing SCR at Wyodak, PacifiCorp conducted both an in-depth system modeling analysis and a plant-specific market-based dispatch analysis. The methodology for each of these analyses is described in this section.

a. System Modeling Methodology

As part of this Affordability Analysis, PacifiCorp conducted an assessment using a system modeling methodology consistent with the modeling methodology used to support its 2019 IRP. The 2019 IRP found that operating Wyodak without SCR through 2039 was part of the least cost, least risk option for PacifiCorp's customers. Using the 2019 IRP as a baseline, this assessment compares two theoretical cases to assess the affordability of SCR as BART at Wyodak ("SCR Comparisons"): (1) installation of SCR at Wyodak in 2024 ("SCR Installation") [19]; and (2) retirement of Wyodak in 2024 without installing SCR ("Early Retirement"). Using its

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[15] 2019 IRP, Volume II, Appendix B (Regulatory Compliance) at 22.
[16] 2019 IRP at 12-13.
[17] *See* 2019 IRP at 13. As a side note, like its coal resources, PacifiCorp only includes renewable resources in its preferred portfolio when they meet the least-cost, least-risk requirement. Renewable resources are not included simply because they meet individual state renewable portfolio requirements. *Id*. at 14.
[18] PacifiCorp 2019 Integrated Resource Plan, Vol. I, at 98-99, Table 5.2, Vol. II, App. M, at 278 (Oct. 18, 2019).
[19] While the exact date when completion of the SCR installation would be required is uncertain at this point due to on-going litigation and the court stay of the requirement, this analysis uses June 15, 2024, as the date to commence SCR installation because it roughly aligns with both the general timeframe when SCR installation could be expected

System Optimizer (SO) model and the Planning and Risk model (PaR), the company developed an economic analysis compares these options using the 2019 IRP assumptions with certain updates to reflect changes in the planning environment since the 2019 IRP was finalized (i.e., load forecast, new contracts, new legislation extending and increasing the product tax credit for new wind resources, updates to transmission inputs, and updates to market price forecasts).

This methodology relies on the economic analysis PacifiCorp undertakes to support prudency when making major resource decisions.

PacifiCorp relied on the same modeling tools it used to develop resource portfolios in its 2019 IRP for the SCR Comparisons. These IRP modeling tools, described further below, calculate the system present value revenue requirement ("PVRR") by identifying least-cost resource portfolios and dispatching system resources over a 20-year forecast period (2019–2038). Net customer benefits are calculated as the differential of the PVRR (PVRR(d)) between the SCR Installation and Early Retirement outcomes. The SCR Installation simulation assumes SCR is installed on Wyodak in 2024 with continued coal-fired operations continuing through 2039. The Early Retirement simulation assumes Wyodak avoids the SCR cost by retiring in 2024. In comparing the two scenarios, customers are expected to realize net benefits from the scenario with the lowest PVRR. Conversely, customers would experience increased costs from the scenario with the higher PVRR.

PacifiCorp used the SO model and PaR to develop resource portfolios for comparison and to forecast dispatch of system resources in simulations with and without the SCR requirement.

i. Description of the SO and PaR models

System Optimizer (SO)

The SO model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability and other constraints. Over the 20-year planning horizon, it optimizes resource additions subject to resource costs and capacity constraints (summer peak loads, winter peak loads, plus a target planning reserve margin for each load area represented in the model). In the event that an early retirement of an existing generating resource is assumed for a given planning scenario, the SO model will select additional resources as required to meet summer and winter peak loads inclusive of the target planning reserve margin.

To accomplish these optimization objectives, the SO model performs time-of-day, least-cost dispatch for existing resources and prospective new resource alternatives, while considering the cost-and-performance characteristics of existing contracts and prospective DSM resources. The system PVRR from the SO model reflects the cost of existing contracts, wholesale-market purchases and sales, the cost of new and existing generating resources (fuel, fixed and variable O&M, and emissions, as applicable), the cost of new DSM resources, and the levelized revenue

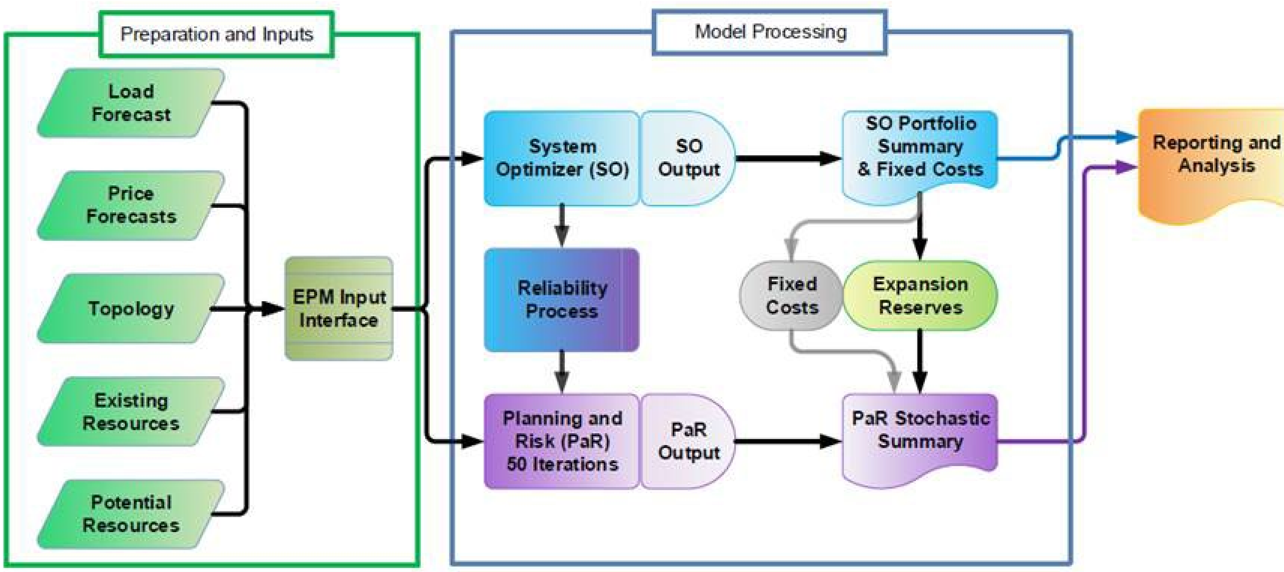
to commence if the court stay were lifted and a potential outage window at Wyodak. Use of this date in no-way indicates PacifiCorp's legal position on the appropriate date for an SCR requirement and PacifiCorp firmly maintains those positions briefed in the 10th Circuit litigation.

requirement of capital additions for existing coal resources and potential new generating resources, and costs for potential transmission upgrades.

The SO model is also used to assess additional capacity expansion resources necessary to meet reliability targets as informed by deterministic analysis conducted using PaR.

Planning and Risk (PaR)

PaR uses the same common input assumptions described for the SO model with additional data provided by the SO model results (e.g., the capacity expansion portfolio including reliability resource additions). While the SO model supplies a capacity view developing an optimized portfolio for each case, PaR is able to bring the advantages of stochastic-driven risk metrics to the evaluation of the studies while also capturing additional operational considerations that the SO model does not asses (i.e., operating reserve requirements).



PaR is used to develop a chronological unit commitment and dispatch forecast of the resource portfolio generated by the SO model, accounting for operating reserves, volatility and uncertainty in key system variables. Based on one sample week per month of the 20-year study period, PaR captures volatility and uncertainty in its unit commitment and dispatch forecast by using Monte Carlo sampling of stochastic variables, which include load, wholesale electricity and natural-gas prices, hydro generation, and thermal unit outages. PaR uses the same common input assumptions that are used in the SO model, with resource-portfolio data provided by the SO model results.

The PVRR from PaR reflects a distribution of system variable costs, including variable costs associated with existing contracts, wholesale-market purchases and sales, fuel costs, variable O&M costs, emissions costs, as applicable, and costs associated with energy or reserve deficiencies. Fixed costs that do not change with system dispatch, including the cost of DSM resources, fixed O&M costs, and the levelized revenue requirement of capital additions for existing coal resources and potential new generating resources, are based on the fixed costs from the SO model, which are combined with the distribution of PaR variable costs to establish a distribution of system PVRR for each simulation.

Historically, PacifiCorp has used the SO model and PaR to produce and evaluate resource portfolios in its IRP and to inform resource decisions (i.e. to evaluate resource bids submitted in response to request for proposals). PacifiCorp also uses these models to analyze resource-acquisition opportunities, resource retirements, resource capital investments, and system transmission projects. PacifiCorp relies on the results of these models to demonstrate to the regulating authorities in the six states where it operates that PacifiCorp is pursuing the least cost, least risk option for its customers in those states and can therefore justify its rates.

ii. The SO and PaR Models Are Appropriate Tools to Analyze the Affordability of SCR as BART

The SO model and PaR are the appropriate modeling tools for evaluating a significant capital investment such as SCR that will influence PacifiCorp's resource mix and affect least-cost dispatch of system resources. The SO model simultaneously and endogenously evaluates capacity and energy trade-offs associated with resource capital projects and is needed to understand how the type, timing, and location of future resources might be affected by the SCR requirement. PaR provides additional granularity on how the SCR is projected to affect system operations, recognizing that key system conditions are volatile and uncertain. Together, the SO model and PaR are best suited to perform a net-benefit analysis for the options of SCR installation vs. retirement of the Wyodak plant—the two possible outcomes if SCR is determined as BART. The SCR Comparison provides analysis that is consistent with the long-standing risk-adjusted, least-cost planning principles that are applied in PacifiCorp's IRP and form the basis for decisions, and subsequent prudency reviews, about what is affordable and justifiable for PacifiCorp as a regulated utility.

iii. PaR Risk Adjustment: Using PaR to Assess Stochastic System Cost Risk for SCR

The company evaluates resource-portfolio alternatives in the IRP using the PaR stochastic-mean PVRR and PaR risk-adjusted PVRR, calculated from PaR study results, to assess risks from volatility—i.e., the stochastic system-cost risk of installing SCR. With Monte Carlo sampling of stochastic variables, PaR produces a distribution of system variable costs. The PaR stochastic-mean PVRR is the average of net variable operating costs from the distribution of system variable costs, combined with system fixed costs from the SO model. PacifiCorp takes this value and uses a risk-adjusted PVRR to further evaluate stochastic system cost risk. The PaR risk-adjusted PVRR gives greater weight to the expected value of low-probability, high-cost outcomes (i.e. worst case scenarios). The PaR risk-adjusted PVRR is calculated by adding five percent of system variable costs, from the 95^{th} percentile of the distribution of system variable costs, to the stochastic-mean PVRR.

When applied to the SCR Comparison analysis, the PaR stochastic-mean PVRR represents the expected level of system costs with and without SCR installation. The PaR risk-adjusted PVRR is used to assess whether the SCR installation causes a disproportionate increase to system variable costs under low-probability, high-cost system conditions.

iv. Capital Investment Assumptions Used for the SCR Comparison

As it does when setting rates, PacifiCorp depreciated the revenue requirement from capital costs over the book life of the asset, effectively spreading the cost of capital investments over the life of the asset. Because the revenue requirement from capital projects is spread over the life of the asset in rates, these costs are treated as a levelized cost in the SO model and PaR simulations. Levelization of the capital revenue requirement is necessary in these models to avoid potential distortions in the economic analysis of capital-intensive assets that have different lives and in-service dates. This potential distortion is driven by how capital costs are included in rate base over time. The capital revenue requirement is generally highest in the first year an asset is placed in service and declines over time as the asset depreciates. Without levelization of capital revenue requirement, the SO model could inappropriately distort high-capital resource options even if those high capital alternatives would be expected to generate customer benefits over the full life of the investment.

b. Dispatch Analysis

The IRP modeling tools described above not only report system costs in the SCR Installation and Early Retirement simulations, but they also report how Wyodak gets dispatched over time. A decrease in dispatch of the Wyodak plant is a signal that the marketability of energy from Wyodak is less competitive than other system and market resources.

Dispatch rates play an important role in determining net benefits for customers, especially in the transmission-constrained area of eastern Wyoming where Wyodak is located. Increasingly available new energy sources compete with Wyodak for transmission space, capital investment, and market pricing for dispatch into PacifiCorp's system and the broader energy market. Thus impacts that raise generation costs for Wyodak reduce its competitiveness and constrain its dispatch as other less expensive options take precedence for transmission space. This, in turn, reduces the value of Wyodak for PacifiCorp's retail customers (analogous to "profitability").

V. APPLYING THE AFFORDABILITY ANALYSIS TO WYODAK DEMONSTRATES THAT SCR IS "UNAFFORDABLE"

Using the above methodologies to analyze the factors from the BART Guidelines that EPA used in the Intalco "unaffordability" determination, it is clear that an SCR BART control requirement at Wyodak would be "unaffordable" and result in the early retirement of the unit. In order to test the impact of an SCR installation requirement on the continued viability of Wyodak, as explained above, PacifiCorp introduced two alternative scenarios: (1) a required early retirement of Wyodak on December 31, 2024, to avoid installation of SCR ("Early Retirement"); and (2) installation of SCR at Wyodak on June 15, 2024 and continued plant operation through 2039 ("SCR Installation").[20]

a. Specific Application

As explained below, the IRP analysis shows that installation of SCR would affect the product prices, market share, and profitability of the Wyodak plant to such an extent that early retirement of the plant would be the only option for PacifiCorp as a regulated utility.[21] As part of its "affordability" review for the Intalco plant, EPA considered "commodity price forecasting" and "cost/sales ratios," as well as other product price related issues.[22] The Intalco analysis revealed that the source would be "unlikely to pass the cost of controls on to consumers" because "aluminum is a commodity traded on global markets" and the source had "little control over product price".[23]

While PacifiCorp is able to pass some costs on to consumers, as a regulated utility it must select, and justify to its regulators that it has prudently chosen the least-cost, least-risk option for its customers. Using these principals, the results of the affordability assessment are presented below.

i. System Modeling PVRR(d) Results

Table 1 compares the cases of Early Retirement and SCR Installation. Numbers in parentheses in Table 1 indicate cost savings to customers from early retirement, while numbers not in parentheses (if there had been any) would represent cost savings from the installation of an SCR on Wyodak in 2024.[24]

Table 1. August 2020 SO Model and PaR PVRR(d) (Benefit)/Cost of Early Retirement Assuming a 2024 SCR BART Requirement ($ million)[25]

SO Model PVRR(d)	PaR Stochastic Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
($377)	($252)	($263)

As Table 1 shows, over a 20-year period, the SCR Comparison shows that customer costs are dramatically reduced with the early retirement of Wyodak as compared to installing an SCR. This outcome is consistent through the SO model and both the PaR stochastic-mean and PaR

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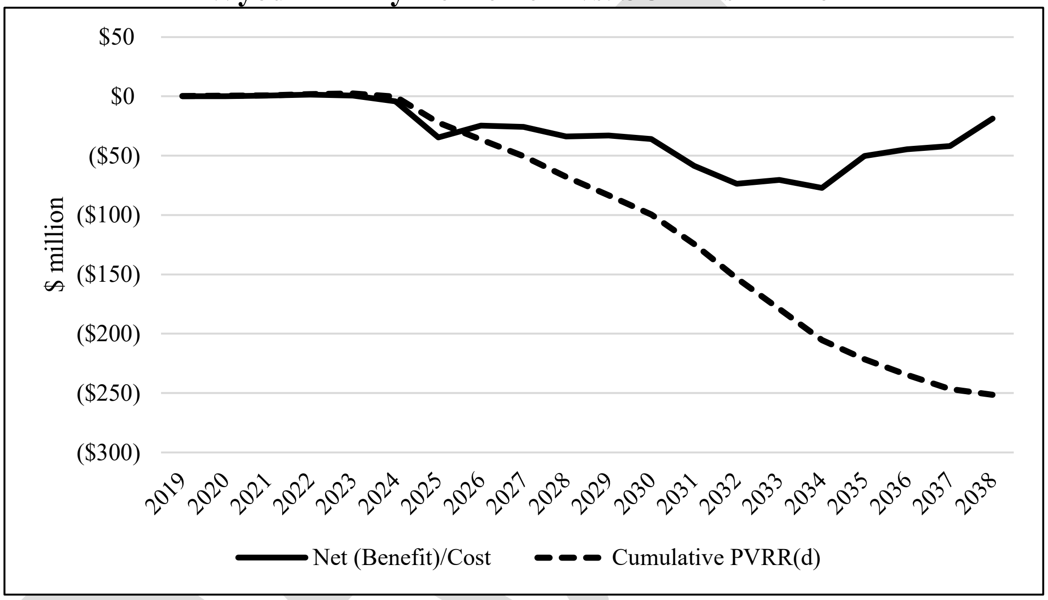
[20] See explanation in footnote 6 for the 2024 SCR installation/plant retirement dates.
[21] *See* 40 CFR part 51, appendix Y, section IV.E.3.1.3.
[22] 78 Fed. Reg. at 79353-54.
[23] *Id*.
[24] Table 1 contains the PVRR(d) results for comparison of the Early Retirement and SCR Installation scenarios. The PVRR(d) between cases with and without installation of SCR are shown for the SO model and for PaR, which were used to calculate both the PaR stochastic-mean PVRR(d) and the PaR risk-adjusted PVRR(d). The data used to calculate the updated SO model PVRR(d) and PaR stochastic-mean PVRR(d) results shown in the table are available by arrangement.
[25] The PVRR(d) benefit is reported as a net reduction to system costs, and is therefore a negative value.

risk-adjusted results. The PVRR(d) net benefits of early retirement range between a low of $252 million, when derived from PaR stochasticmean results, and $377 million, when derived from SO model results.

Figure 1 presents the annual changes in stochastic mean PVRR(d) over the 20-year study period, illustrating that the benefits of early retirement as compared to the installation of SCR begin immediately upon retirement, reaching more than $50m in 2027, nearly $100m in 2030, and culminating in the full $252m net benefit reported in Table 1 in 2038.

Figure 1. PaR Annual Cumulative Stochastic-Mean PVRR(d)
Wyodak Early Retirement vs. SCR Installation



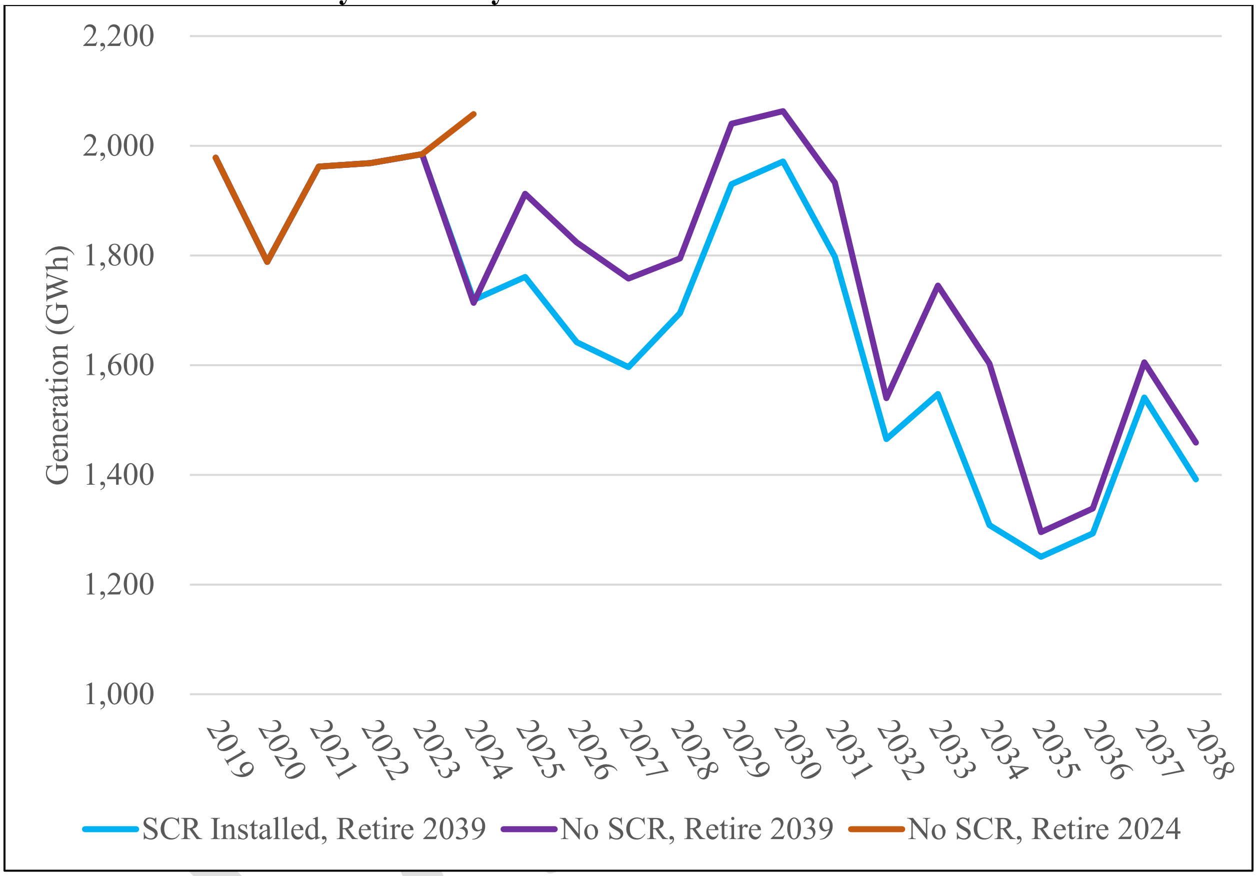
All of these results indicate that if PacifiCorp were to install SCR at Wyodak, its customers would lose between $252 to $377 million dollars in net benefits that would be gained by retiring Wyodak instead. The losses would begin immediately and increase over time. The large margin between the options of early retirement and installation of SCR indicate the only reasonable choice for PacifiCorp is the early retirement alternative. Installation of SCR would not be considered prudent by state regulatory commissions. In other words, the economic effects of requiring SCR affect the viability of the continued operation of Wyodak. The results in Table 1 and Figure 1 demonstrate that SCR is unaffordable, and regulators, customers, and environmental groups would rely on these results to oppose any attempt by PacifiCorp to recover costs for installing an SCR at Wyodak.[26]

[26] It is important to note that PacifiCorp's 2019 IRP results demonstrated that operating Wyodak without SCR through 2039 provides the least-cost, least-risk option for its customers.

ii. Dispatch Analysis Results

Figure 2 below shows that if SCR is installed and Wyodak continues operation through 2039, dispatch of Wyodak would drop by approximate 7% yearly on average.[27]

Figure 2. Wyodak Dispatch Comparison (2019-2038)
Wyodak Early Retirement vs. SCR Installation



The steady and significant reduction in dispatch of Wyodak if SCR is installed demonstrates that Wyodak would become less marketable as a system resource in comparison with other options available to PacifiCorp. State regulators are unlikely to find SCR installation to be a prudent decision with these reduced dispatch rates, forcing PacifiCorp to retire the unit to enable investment in other resources with lower costs and risks for its customers.

b. System Modeling and Dispatch Results Summary

EPA's BART Guidelines allow consideration of economic elements that "*affect the viability of continued plant operations*".[28] In EPA's evaluation of other commercial facilities' affordability analyses, it has looked at product price, market share, and profitability as the appropriate

[27] Some of the reduced dispatch may be driven by other portfolio differences other than Wyodak itself. However, these differences arise in the respective scenarios where SCR Installation or Early Retirement of Wyodak are the only changes to the model.
[28] 40 CFR part 51, appendix Y, section IV.E.3.1.3 (emphasis added).

economic elements to demonstrate affordability. Because PacifiCorp is a regulated utility, the equivalent economic elements that affect the viability of continued plant operations are demonstrating prudent decision making and selection of the least-cost, least-risk option for its customers. As the above analyses demonstrate, a requirement to install SCR at Wyodak would be unaffordable due to impacts on all of these factors.

In the Intalco "affordability" review, EPA determined that if the subject BART controls were required, "its profits, per-ton and overall, could be reduced to unacceptable levels by LSFO that would likely lead to a business decision to close the facility."[29] Similarly, the systemic modeling and dispatch analysis of the SCR Comparison demonstrate that the requirement to install SCR at Wyodak leads to the regulatory necessity for PacifiCorp to retire Wyodak as the most prudent decision for its customers due to the significant net benefits gained by retiring rather than installing SCR.

VI. EXTERNAL CONSIDERATIONS

a. The "Severe Impact" of SCR Requirements on Other Regional Facilities

The BART guidelines provide that where an analysis of the affordability factors demonstrate a "severe impact on plant operations," then EPA and/or the state may consider this information when choosing the BART control and limit.[30] As the analysis above confirms, requiring a SCR at Wyodak as BART would lead PacifiCorp to retire the Wyodak unit.

Across the country, it is not uncommon for a determination of SCR as BART to result in retirement or repowering of a coal-fired generation unit. Numerous other utilities facing similar economic and regulatory pressures have retired or repowered the affected units rather than install SCR. *See, e.g.*:

i. Arizona Cholla Plant, 81 Fed Reg 46852 (July 19, 2016) (required to install SCR but instead announced closure in 2020)
ii. Colorado Craig Unit 1, 83 Fed. Reg. 31332 (recently announced it will shutdown by 2025 rather than install SCR)
iii. New Mexico San Juan Generating Station, 79 Fed. Reg. 60978 (Oct. 9, 2014) (after a FIP requirement to install SCR on all 4 units, settlement provides for retirement of 2 units and SCR on the other 2)
iv. North Carolina BART Alternative, 81 Fed. Reg. 19519 (April 5, 2016) ("Progress Energy and Duke Energy have shut down 22 of the coal fired EGUs" subject to the BART alternative instead of installing controls to lower emissions)
v. Oregon Boardman Plant, 76 Fed. Reg. 38997 (July 5, 2011) (elected to cease burning coal by 2020 rather than install SCR as originally required by the state submittal to EPA)
vi. Wyoming Dave Johnston Plant, 79 Fed. Reg. 5032 (Jan. 30, 2014) (PacifiCorp has exercised option to retire unit 3 by 2027 rather than install SCR).

[29] 78 FR at 79354.
[30] 40 CFR part 51, appendix Y, section IV.E.3.1.3.

While some coal-fired units have elected to install SCR, the unaffordability of SCR at Wyodak differentiates it from these units. As EPA has acknowledged, "Generally, EPA does not interpret the regional haze rule to provide us with authority to make a BART determination that requires the shutdown of a source."[31] As indicated in this analysis, a BART determination of SCR for Wyodak would result in just such a shutdown requirement. While some facilities in the region have installed SCR, including two units at PacifiCorp's Jim Bridger facility, as illustrated by the list above, retirement or conversion to natural gas are actually a more common result than actual SCR installation.

In the time since the analysis for the Jim Bridger plant SCR installation was conducted, conditions have changed, including a dramatic increase in the amount of alternative energy resources available both as owned resources as well as on the EIM. In addition, demands on the transmission resources relied on by Wyodak have increased dramatically, making market competitiveness even more important to ensure the viability of the plant. In the years since the Bridger SCR installations, PacifiCorp has identified many more available and affordable energy resources including wind, battery storage, incremental energy efficiency and new direct load control resources, where the large initial capital investment that would be required for an SCR could be better directed to provide net benefits for PacifiCorp customers. The 2019 IRP indicates the addition of nearly 11,000 MW of new renewable resources over the 20-year planning period through 2038, and includes the retirement of 16 of its 24 coal units by 2030.[32]

b. Increasing Scrutiny, Competition, and State Laws Contribute to Making SCR Unaffordable for a Regulated Utility

Over the past several years, PacifiCorp has faced increasing opposition and had costs rejected by regulators for installing pollution control equipment, including SCRs, at its other plants. For example, in 2012, the state of Oregon denied PacifiCorp $17 million of cost recovery for BART equipment required under regional haze and cautioned the company to consider a broader range of alternatives rather than install expensive retrofit equipment on its coal plants.[33]

The viability of coal-fired electrical generating units in PacifiCorp's fleet is also subject to increasing competition from other available energy resources. For example, "[c]hanges in how PacifiCorp has been operating these [coal-fired] assets (i.e., by lowering operating minimums) has allowed the company to buy increasingly low-cost, zero-emissions renewable energy from market participants, which is accessed by our expansive transmission grid."[34] Wyodak and other coal-fired plants must compete in a market with new and lower cost renewable energy and storage options. In fact, due to "ongoing cost pressures on existing coal-fired facilities and dropping costs for new resource alternatives, of the 24 coal units currently serving PacifiCorp customers, the preferred portfolio includes retirement of 16 of the units by 2030 and 20 of the units by the end of the planning period in 2038."[35] Wyodak (without an SCR requirement) was

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[31] 79 FR 5032, 5045 (Jan. 30, 2014).
[32] 2019 IRP page 209.
[33] *See* Public Utility Commission of Oregon, Order No. 12-493 (Dec. 20, 2012) at 31-32.
[34] PacifiCorp 2019 IRP, at 12.
[35] *Id.*

not one of the units identified for retirement in the 2019 IRP. As shown in this report, the requirement to install SCR would change that.

Many states in PacifiCorp's service area have also adopted laws and regulations that make further significant investment in coal-fired assets difficult, if not impossible. For example, Oregon's Senate Bill 1547-B extends and expands the Oregon renewable portfolio standard ("RPS") requirement to 50 percent of electricity from renewable resources by 2040 and requires that coal-fueled resources be eliminated from Oregon's allocation of electricity by January 1, 2030. PacifiCorp would thus be unable to recover costs invested in an SCR from Oregon. California's emission performance standards (EPS) for California-serving utilities has also resulted in a phase out of coal-fired generation services in that state. California's EPS was mandated by Senate Bill 1368 and applies to baseload generation either owned by, or under long term contract to a utility, which prohibits the use of coal-fired generation after 2025. A 2019 Washington law (Clean Energy Transformation Act) sets a 2025 deadline for utilities to end all reliance on coal, and a 2045 deadline to end use of natural-gas-generated electricity.[36]

VII. CONCLUSION

As discussed in this report, SCR at Wyodak is not affordable. PacifiCorp's system modeling methodology and dispatch analysis indicate installing SCR would significantly burden PacifiCorp's customers and reduce net benefits from the Company's system, leading to insurmountable evidence that would prevent a demonstration of prudency or that SCR is the least-cost, least-risk option for PacifiCorp's customers. In addition, over the past decade, the requirement to install SCR has led to early retirement or refueling of numerous other coal-fired generating plants in the region and across the country. And external factors including increased regulatory scrutiny of investments in coal-fired resources, state laws limiting the market for coal-fired power, and increasing competition from renewable and storage resources add to the pressures making SCR unaffordable, especially for a regulated utility. The decision to retire Wyodak rather than install SCR is not merely "a voluntary business decision[ ] that the benefits of continuing to generate electricity at the affected units were outweighed" by other factors. Instead, the Early Retirement decision is a regulatory necessity as continued plant operation becomes unfeasible because "the costs of [SCR] . . . [are] so onerous that the source[ ] simply could not afford them" making "the sources' decisions to cease operations . . . in essence involuntary."[37] A BART requirement for SCR at Wyodak is not affordable and should not be required by EPA.

[36] Wyodak is not included in PacifiCorp's Washington resources.
[37] 79 FR 33438, at 33446 (June 11, 2014).