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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of PacifiCorp's 2025 Integrated Resource Plan	Docket No. 25-035-22

SIERRA CLUB'S OPENING COMMENTS ON PACIFICORP'S 2025 INTEGRATED RESOURCE PLAN

Public Version

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I. INTRODUCTION

The 2025 Integrated Resource Plan ("IRP") represents a critical juncture for PacifiCorp and its Utah customers. While IRPs are constantly evolving, the decisions that flow from the 2025 IRP will impact PacifiCorp's customers for decades to come. Federal incentives for clean energy are at their peak but quickly expiring; yet, PacifiCorp has no near-term procurement plans. Having only recently completed a 2024 rate case wherein the Company requested a staggering 30% rate increase that was primarily driven by net power costs ("NPC") and the volatile fuel costs that make up NPC, the 2025 IRP represents more of the same, putting Utah customers at risk.

Rather than producing a truly least-cost, least-risk plan for Utah customers, PacifiCorp's IRP fragments planning across jurisdictions, removes critical transmission projects, and doubles down on resources with volatile fuel costs and long-term risks. The IRP's resource mix for Utah customers continues to rely heavily on fossil fuel generation—most notably the Hunter coal plant—even as evidence mounts that these resources will become increasingly uneconomic to operate. This reliance exposes Utah customers to severe risks: higher fuel and compliance costs, greater exposure to market volatility, and the likelihood of stranded asset costs as neighboring states move away from coal.

Utah needs—and the Commission should require—systemwide planning that meaningfully incorporates the lowest-cost and least-risk resources available, without artificial constraints. This requires transparent modeling, serious consideration of retiring uneconomic coal units on an appropriate timeline, and most importantly, procurement of new clean resources in the near term. Acquiring clean energy now would lock in low costs, take advantage of time-limited federal tax incentives, and deliver economic development to communities across Utah.[1] By delaying

[1] Jordan Ahern et al., *Economic Opportunities from PacifiCorp's Clean Energy Investments in Utah and Wyoming*, Current Energy Group (Mar. 2025), *available at* https://www.sierraclub.org/sites/default/files/2025-03/paceast_economicanalysisreport.pdf.

procurement, as RMP plans to do, the Company places Utah customers are unnecessary risk of both higher costs and missed opportunities.

The Commission's September 24, 2024 Order established January 1, 2025 as the "data lockdown date" after which PacifiCorp was not permitted to make changes to its modeling assumptions for the 2025 IRP. Because PacifiCorp did make significant changes to its modeling after January 1, 2025, the IRP filing presented to this Commission contains the 2025 IRP, as updated after January 1, 2025 and submitted to PacifiCorp's other jurisdictions, as well as Chapters 11-13, which represents the "Utah IRP" and does not incorporate modeling changes after January 1, 2025. Sierra Club appreciates the Commission's directives, attempting to ensure that PacifiCorp meaningfully allows for stakeholder engagement, and is concerned about last-minute modeling changes that were made between the draft and final IRP. Most notably, PacifiCorp's resource selection and jurisdictional integration methodology (described below in Section II(A)) dramatically changed between the draft (i.e. Utah) IRP and the final IRP. Nevertheless, these comments address PacifiCorp's final 2025 IRP, because the final 2025 IRP represents PacifiCorp's most up-to-date resource plans. The Utah IRP, represented in Chapters 11-13, is simply out of date.

In these comments, we demonstrate that the 2025 IRP fails to reflect systemwide least-cost, least-risk planning, that the Integrated Hunter Retire MN portfolio should have been selected as the preferred portfolio, and that near-term clean resource procurements are necessary for Utah customers. We also highlight how PacifiCorp's planning should account for the Utah Renewable Communities program and ensure that Utah customers benefit from the growing demand for affordable, reliable clean power.

We recommend that the Commission not acknowledge PacifiCorp's 2025 IRP due to the issues identified in these comments. Perhaps more importantly, however, we also recommend that the Commission provide PacifiCorp with substantive guidance, including the need for a least-cost, least-risk system-wide portfolio as well as near-term clean energy procurement. Specifically, the Commission should issue an order not acknowledging the 2025 IRP and providing guidance that:

- By the 2025 IRP Update, PacifiCorp should include, at a minimum, model two portfolios: (1) a fully optimized system-wide portfolio that includes Western Resource Adequacy Program ("WRAP") reserve margins for all states and the Boardman-to-Hemingway ("B2H") transmission line, but without Oregon and Washington's statutory requirements, and (2) a system-wide portfolio with WRAP, B2H, and Oregon and Washington compliance.
- PacifiCorp should immediately move forward on clean resource procurements for Utah and other states in order to capitalize on still available federal tax incentives.

II. THE PREFERRED PORTFOLIO DOES NOT REPRESENT A LEAST-COST, LEAST-RISK PORTFOLIO

As articulated in the Commission's Standards and Guidelines for IRPs, the purpose of integrated resource planning is to identify a portfolio of resources that can meet current and future customer electric energy needs "at the lowest total cost to the utility and its customers, and in a manner consistent with the long-run public interest."[2] The 2025 IRP does not meet this standard, primarily due to the Company's decision to introduce jurisdictional portfolios—subdividing its single system into three mini-systems—and an assumed cost allocation methodology that is not based in the current 2020 Multistate Protocol ("MSP"). This approach inherently undermines least cost planning by arbitrarily subdividing the system and eliminating the model's ability to capitalize upon regional diversity. The problems resulting from the jurisdictional portfolios and allocation methodology are compounded by the removal of the B2H transmission line, a critical transmission project linking PacifiCorp's eastern balancing authority ("PACE") and PacifiCorp's western balancing authority ("PACW"), as well as an over-reliance on market purchases and resources with volatile fuel costs in the Eastern states.

A. The 2025 IRP's Jurisdictional Portfolios and Allocation Methodology Undermine Least Cost, Least Risk Planning.

The 2025 IRP marks the first time (to Sierra Club's knowledge) that PacifiCorp has modeled its IRP not as a single, multi-state system, but as multiple mini-systems that are modeled separately, integrated without optimization, and assigned specific resources. Due to the novelty and complexity of this approach—which we are not aware of being taken by any other utility in the country serving multiple states—this section begins with an overview of the jurisdictional portfolios were modeled and the chosen allocation methodology before addressing how these modeling decisions impacted resource decisions across the system, including in Utah.

i. Overview of jurisdictional portfolios and allocation methodology used in the 2025 IRP.

For each of the jurisdictional portfolios in the IRP—UIWC[3], OR, and WA—the 2025 IRP uses a similar approach to prior IRPs, including long term ("LT") and short term ("ST") runs with reliability and granularity adjustments. However, each jurisdictional portfolio begins with a different set of assumptions. For instance, in each jurisdictional portfolio, WRAP compliance

[2] *In the Matter of Analysis of an Integrated Resource Plan for PACIFICORP*, Utah Pub. Serv. Comm'n, Dkt. No. 90-2035-01, Report and Order on Standards and Guidelines at 36 (June 18, 1992), *available at* https://pscdocs.utah.gov/electric/90docs/90203501/121607RprtOrdrStndrdsGdlnes6-18-1992.pdf (IRP Guideline 1).
[3] "UIWC," as used in the IRP, refers to Utah, Idaho, Wyoming, and California.

constraints are only applied to the load specific to that system (i.e., UIWC portfolio only models WRAP compliance for UIWC loads, etc.). Additionally, the OR and WA portfolios include fossil fuel operational constraints, while the UIWC portfolio does not.[4] Each jurisdictional portfolio is then "integrated" into a single system-wide portfolio. While the jurisdictional portfolios are optimized through PLEXOS before integration, the final integrated portfolios are not.

Integration is performed differently for different types of resources. Energy efficiency and demand response are independently determined for each jurisdiction, and "the integration step adopts the quantity from that specific jurisdiction's initial portfolio result."[5] All existing thermal resources' operational lives are determined only by the UIWC portfolio as they are all located in that jurisdiction, with the exception of the Chehalis and Hermiston gas plants which are located in Washington and Oregon, respectively.[6] Selections for new proxy resources (that are not thermal or demand-side resources), however, are determined by an integration process, which is depicted, though not detailed, in Figure 9.1 of the IRP. Integration for these resources occurs within Microsoft Excel.[7] The formulas in the workbook are the only source of full, detailed documentation for the integration process, despite it being a new and unvetted approach only implemented for this IRP cycle and not used by any other regulated entities (of which we are aware).

Each jurisdictional run has results for individual new proxy resources for each topology bubble and year. If the resource is located in the East, the UIWC value for that resource is used, regardless of whether more of that same resource was selected by the OR or WA portfolios. If the resource is in the West, the maximum of the OR and WA values is used, again, without regard for what quantity of that resource was selected by the UIWC portfolio. In this way, the 2025 IRP essentially splits PacifiCorp's system into East and West. The final integrated amount for each resource is calculated based on the difference between what the model selects as the

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[4] Specifically, the OR jurisdictional run uses a dispatch driver price (i.e., "shadow price") of $100/ton of CO2 emissions starting in 2030 applied to emissions generated by Oregon's share of gas plants, which increases by $20/ton each year until 2039. Ex. 1 (PacifiCorp Response to Oregon Public Utility Commission Staff ("OPUC") Data Request 9). Additionally, weekly generation of Oregon-allocated gas plants are capped to avoid exceeding annual emission limits. *In the Matter of PACIFICORP, dba PACIFIC POWER, 2025 Integrated Resource Plan and Clean Energy Plan*, Or. Pub. Util. Comm'n, Dkt. No. LC 85, Oregon 2025 Clean Energy Plan at 60 (June 30, 2025), *available at* https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/community/or-cep/2025_Oregon_Clean_Energy_Plan.pdf. There are also constraints in the OR portfolio to ensure procurement of small-scale clean energy resources. In the WA jurisdictional portfolio runs, a different price driver is used---the social cost of greenhouse gas.

[5] PacifiCorp 2025 IRP at 211 (Volume I).

[6] *Id*. at 234 (Volume I). The Chehalis and Hermiston Natural Gas Plants are not retired in the Preferred Portfolio. As stated in the IRP, "PacifiCorp's Chehalis and Hermiston natural gas units are subject to Washington and Oregon regulation, respectively, and a final determination of state allocations, potential operational restrictions and economics continue to be evaluated."

[7] Specifically, integration calculations were performed in the Excel spreadsheet provided in the Confidential Data Disc, "CONF_Max of Units Base MN.xlsx," which includes the formulas necessary to calculate integration from the three jurisdictional portfolios. *See also* Ex. 1 (PacifiCorp Response to OPUC Data Requests 80 and 82 (referencing integration calculations)).

maximum in the prior step (i.e., based on geography) with the maximum value from the previous year. Unless the current year's resource need is higher than the maximum resource amount selected from the previous year, no additional MWs of that resource are selected. Thus, the synergies and potential cost savings resulting from PacifiCorp's large and geographically diverse footprint are severely minimized.

After integration, "jurisdictional shares" of each new proxy resource are assigned based on a new allocation methodology. Purportedly relying on the 2020 MSP, which is set to expire on December 31, 2025,[8] PacifiCorp made the following key assumptions:

- Resource additions are considered situs and must be able to serve requirements in their associated jurisdiction (i.e., the "situs allocation" assumptions).
- West resources are allocated with 75% to Oregon and 25% to Washington.
- The allocations remain fixed for the lifetime of the resource.[9]

None of these assumptions, nor the allocation methodology used by PacifiCorp, are specified by the 2020 MSP. Situs allocations for "state-specific initiatives" are currently contemplated under the 2020 MSP, but the 2020 MSP does not necessarily indicate that all new resources will or should be situs assigned to individual states. Furthermore, this method is not the allocation approach that PacifiCorp has taken since 2020 in prior IRPs. Even assuming that the 2020 MSP did mandate situs assignment of all new generating resources (it doesn't), the agreement will expire at the end of 2025. PacifiCorp has only recently (August 2025) filed an accompanying cost allocation proposal ("2026 Inter-Jurisdictional Cost Allocation Protocol") in Docket No. 25-035-47.

As noted in the Introduction, several significant changes were made between the Draft IRP (i.e., the Utah IRP) and the Final IRP. For instance, the first step in allocation—determining whether the resource is located in PACE or PACW—was not included in the Draft IRP. Second, the Draft IRP integrates proxy resources from the jurisdictional runs by the load share percentage and all three jurisdictions are able to influence proxy resource selections. Third, the Draft IRP does not have the same assumption that proxy resources are situs-allocated.

ii. The jurisdictional portfolios and allocation methodology resulted an IRP with significant risks for Utah.

PacifiCorp's 2025 IRP departs from long-standing industry standards in ways that compromise both reliability and affordability for Utah customers. Instead of employing its optimization software—PLEXOS—to finalize its system-wide preferred portfolio, PacifiCorp instead relies on

[8] PacifiCorp 2025 IRP at 462 (Volume II). There is also a separate Washington-specific allocation protocol, the Washington Inter-Jurisdictional Allocation Methodology (WIJAM), and PacifiCorp has a currently pending docket before the Washington Utilities and Transportation Commission to update the WIJAM.
[9] Ex. 1 (PacifiCorp Response to OPUC Data Request 34).

simple Microsoft Excel formulas to aggregate resources. This methodological choice undermines the purpose of using optimization tools like PLEXOS, which, as the U.S. Department of Energy's Office of Electricity has emphasized, is to "let optimization models optimize."[10]

The resulting portfolios fail to represent any realistic system-wide scenario. While, standing alone, the UIWC portfolio *could* have represented a system-wide portfolio without Oregon and Washington policy constraints, that portfolio omits Oregon and Washington WRAP requirements, and thus cannot stand in as a system-wide resource plan. By failing to model any system-wide portfolio, PacifiCorp's IRP is unable to inform the Company's resource planning and represents a fictional world.[11]

By not performing a realistic, thorough analysis, PacifiCorp exposes all its customers—including Utahns—to heightened risks of inaccurate long-term planning, inflated costs, and diminished financial credibility. These risks are not theoretical: PacifiCorp's credit rating was recently downgraded, in part due to disallowance of cost recovery through their Utah rate case.[12] An IRP built on flawed assumptions only compounds those concerns by eroding confidence in future investments and prudency determinations, with Utah ratepayers ultimately footing the bill through higher financing costs.

As discussed below, as a direct result of PacifiCorp's jurisdictional portfolios and allocation methodology, the 2025 IRP results in excessive resource acquisition forecasts in the West; underutilized transmission and corresponding stranded asset risks in the East; and over-reliance on volatile fuel costs in the East.

1. *The 2025 IRP's situs allocations result in excessive forecasted resources, the costs of which are likely to be shared across the system.*

The 2025 IRP's situs allocation assumptions—requiring PACE loads to be met only with PACE resources and PACW loads only be met with PACW resources—render every portfolio inherently sub-optimal. This design eliminates the fundamental efficiency of operating a multi-state system by distorting resource siting that ultimately results in over-forecasted resource needs, particularly in the West. For example, the Preferred Portfolio calls for 1,252 MW of wind in the West in 2030. Yet, the same capacity benefits could be achieved more economically in the East, where land availability is higher and wind accreditation values are over four times greater

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[10] Bruce Biewald et al., *Best Practices in Integrated Resource Planning: A Guide for Planners Developing the Electricity Resource Mix of the Future* at 63, Synapse Energy Economics & Lawrence Berkeley National Laboratory (Nov. 2024), *available at* https://www.energy.gov/sites/default/files/2024-12/best_practices_irp_nov_2024_final_optimized.pdf.

[11] The exclusion of large loads, the Boardman-to-Hemingway transmission line, and modeling of Utah Renewable Communities further divorce the IRP from reality.

[12] *Moody's Ratings downgrades PacifiCorp to Baa2; outlook stable*, Moody's Ratings, *available at* https://ratings.moodys.com/ratings-news/446629 (last visited Sept. 25, 2025).

compared to the West side of the system.[13] To achieve the same capacity benefits as the wind resource in the West, only 296 MW of wind would need to be built—a 76% reduction—which would result in corresponding cost savings.

Much of the resource additions forecasted for PACW are due to reliability requirements, not state specific policy requirements. This means that they are system, not state specific, costs and that, if historical cost allocation continues, Utah customers will be required to cover a portion of the resource costs for resources sited in PACW. Even assuming that some incremental wind in 2030 was added to meet a specific state policy requirements, Oregon and Washington state policies do not require that those incremental resources be built within PACW. As a result, PacifiCorp's 2025 IRP significantly exaggerates the needed procurements in PACW, which makes new proxy resources appear more expensive than they would be if siting decisions were instead made by identifying the least-cost location throughout the system.

Compounding the inefficiencies of situs allocation is the artificial constraint that prevents PacifiCorp from coordinating thermal resource retirements and coal-to-gas conversions in response to the system as a whole.[14] This limitation drives up costs for all customers, including Utah's, because it ignores the most economical way to integrate new clean resources with the retirement of fossil assets. When planning is done systemwide, the Company can substitute retiring thermal resources with clean energy additions at the lowest cost, rather than layering clean resources on top of an aging fleet, or asking a handful of states (Utah, Wyoming, Idaho) to accept ever larger portions of aging thermal plants. This approach enhances reliability across the system and minimizes costs, regardless of which state's policies may be driving clean resource additions.

Critically, a systemwide model does not mean that Utah customers should be asked to shoulder the cost of another state's policy. On the contrary, PacifiCorp could develop a baseline systemwide model without Oregon or Washington policy requirements (but including WRAP obligations[15]), and then compare it to a systemwide model that includes those requirements. The difference in cost would be assigned only to the states with the additional compliance obligations. This would mean two things for Utah customers: (1) cost protection, as Utah customers would not pay for incremental costs associated with Oregon or Washington compliance; and (2) system benefits, as Utah customers would still benefit from efficient resource dispatch, reduced reliance on volatile fuel resources, and mitigation of risks tied to aging coal units, such as the Hunter plant (discussed further below).

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[13] Confidential Data Disc: CONF_WRAP Values.xlsx.
[14] Other than Chehalis and Hermiston natural gas plants, see n. 6.
[15] PacifiCorp did not model any system-wide portfolio, let alone one that identified needs for WRAP compliance compared to state-specific policy initiatives.

In this way, systemwide planning is not about importing other states' policies into Utah; it is about ensuring Utah customers are protected from higher costs and unnecessary risks while taking full advantage of PacifiCorp's diverse system.

Unfortunately, the 2025 IRP does not provide the portfolios that would be necessary to evaluate a system-wide, least-cost approach. At a minimum, two portfolios are needed that were not produced: (1) a fully optimized system-wide portfolio with WRAP reserve margins and B2H (but without Oregon and Washington's statutory requirements), and (2) a system-wide portfolio with WRAP, B2H, and Oregon and Washington compliance.

2. *Integration results in under-utilized transmission and stranded asset risk for existing generators located in PACE.*

Shared transmission and generating resources across PacifiCorp's six states further supports continued system-wide IRP modeling, rather than the approach taken in the 2025 IRP. Due to the integration and allocation methodologies, energy transfers between PACE and PACW end in 2030, resulting in under-utilized transmission capacity and stranded asset risk for existing generators in the East.

Historically, significant amounts of energy have been transferred from PACE and PACW, and before integration, the UIWC jurisdictional run continues to call for transfers from PACE to PACW during the years of 2025 to 2045 of between [redacted].[16] Following integration, however, the magnitude of resources that are added to the West are so great that the transfers called for in the UIWC portfolio are no longer needed.[17] In fact, starting in 2030, PacifiCorp's model assumes zero transfers between the two balancing authorities, despite transmission capability of 1,600 MW that has been used historically and up to approximately 2,200 MW, including B2H, planned to begin in 2028. This results in underutilization of existing and projected transmission that customers across PacifiCorp's system are already paying for.

Move over, even though these transfers are not called for in the final portfolio, their removal is not mirrored in commensurate reductions in generation or resources in the East. As a result, up to [redacted] of generation that would have been transferred to the West is potentially not needed beginning in 2030, yet still produced (see circled bars in Figure 1). For context, this level of annual generation is equivalent to approximately [redacted].

[16] Confidential Data Disc: (P)_LT_25I.IR.iLT.r21.UIWC.EP.2409MN.NewWRAP.Iterator_149346 v98.9x12.xlxb.
[17] Ex. 1 (PacifiCorp Response to Sierra Club Data Request 2.5).

Confidential Figure 1. Potential Excess East-side Generation due to Integration

[redacted]

Source: Created using data from Confidential workpaper "(P)_LT_25I.IR.iLT.r21.UIWC.EP.2409MN.NewWRAP.Iterator_149346 v98.9x12.xlxb"

In other words, starting in 2030, PacifiCorp's Preferred Portfolio projects that the PACE system will have approximately [redacted] of excess capacity.

This overbuild places particular strain on coal and natural gas units with high and fixed variable costs, many of which are subject to must-take provisions. If these plants operate at lower utilization rates, their revenues will decline even as their cost obligations remain, accelerating the risk of early retirements. This could set up Utah and other PACE states to be disproportionately responsible for decommissioning costs, with Utah customers especially exposed depending on the timing of retirements.

Although new large loads could, in theory, provide replacement demand for this capacity, such customers were excluded from the IRP load forecast. In practice, many of these entities also often seek clean energy contracts and are unlikely to rely on aging, high-emission resources.[18] Based on the overbuilding of resources and inaccurate account of transfers between PACE and PACW due to integration, the 2025 IRP exposes PacifiCorp customers to a multitude of risks and uncertainties.

[18] *See, e.g., 24/7 by 2030: Realizing a Carbon-free Future*, Google Sustainability (Sept. 2020), *available at* https://sustainability.google/reports/247-carbon-free-energy/.

B. The Removal of Boardman-to-Hemingway Compounded Challenges Due to Jurisdictional Portfolios and Allocation Methodology.

The B2H line is the exact transmission expansion that is needed to economically site clean energy resources in the East for deliverability to the West—providing benefits to states in both balancing authorities (as described above). B2H has been planned in partnership with Idaho Power and Bonneville Power Administration ("BPA") since 2007 and is currently under construction with plans to energize as early as 2027. For years, PacifiCorp has promoted and advocated for the system-wide benefits that B2H will provide to its customers.[19] Despite this, PacifiCorp removed B2H as a transmission option in the 2025 IRP, citing "changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pocket."[20] The changed native load growth refers to uncertainty related to a new large-load customer at the Longhorn load bubble depicted in Figure 8.3 of the 2025 IRP.[21] Relatedly, because PacifiCorp has not yet obtained long-term firm transmission rights from BPA that are necessary to reach the central Oregon load areas, the currently approved transmission configuration of B2H can only serve load at the Longhorn location.

The impact of removing B2H from the 2025 IRP is that existing capacity and reliability insufficiencies are exacerbated. Without B2H, resources to satisfy PACW shortages can only be built in PACW due to insufficient existing transmission to ensure deliverability.[22] B2H is the investment needed to correct these reliability concerns, as detailed by PacifiCorp in its CPCN for the project that demonstrated B2H would deliver a net benefit well in excess of $1 billion to PacifiCorp customers.[23]

The decision also undermines cost-effective compliance with regional adequacy requirements under WRAP. Many of the near-term acquisitions called for in the 2025 IRP are not driven by state-specific clean energy policies, but by system-wide reliability obligations.[24] Under the existing MSP, such costs have historically been allocated across the system using system generation factors, and PacifiCorp anticipates using this approach for future reliability expenditures.[25] Because WRAP obligations are shared system costs, every state has a direct

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[19] *See, e.g., In the Matter of Idaho Power Company, Petition for Certificate of Public Convenience and Necessity*, Or. Pub. Util. Comm'n, Dkt. No. PCN 5, Reply Testimony of Rick T. Link, PAC/200 at 4:2 (Mar. 20, 2025), *available at* https://edocs.puc.state.or.us/efdocs/HTB/pcn5htb152050.pdf (hereinafter "Rick T. Link Reply Testimony").

[20] PacifiCorp 2025 IRP at 5 (Volume I).

[21] Ex. 1 (PacifiCorp Response to OPUC Data Request 52).

[22] PacifiCorp, *2025 Integrated Resource Plan Public Input Meeting* at Slide 39 (Feb. 27, 2025), *available at* https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/February_27_2025_IRP_Public_Input_Meeting.pdf.

[23] Rick T. Link Reply Testimony at 4:2.

[24] PacifiCorp 2025 IRP at 247 (Volume I) (Table 9.14) shows that summer reserve margins are not met until 2030. WRAP becomes binding, with penalties for non-compliance, in 2027.

[25] *See In the Matter of PacifiCorp dba Pacific Power 2025 Integrated Resource Plan*, Or. Pub. Util. Comm'n, Dkt. No. LC 85, PacifiCorp's Reply Comments at 12 (Aug. 26, 2025), *available at*

interest in ensuring that resource adequacy needs are met in the most cost efficient manner possible. Meeting capacity requirements benefits both PACW and PACE by reducing the need for expensive market purchases and/or fewer MW transfers from east to west that could then be marketed or result in variable cost savings if resources do not have to generate, producing tangible savings for all customers. Accordingly, the removal of B2H is not simply a PACW issue but directly harms PACE customers.

C. The 2025 IRP Preferred Portfolio Overly Relies Resources with Volatile Fuel Costs and Purchased Power.

The UIWC portfolio includes notable reliance on gas-fired resources and market purchases. While PacifiCorp does not forecast any new gas plants, there are several coal-to-gas conversions, including Dave Johnston units 1 and 2 and Naughton units 1 and 2, collectively representing 562 MW.[26] All current gas units are projected to continue operating indefinitely. Additionally, forecasted market purchases are significantly higher than the 2023 IRP, although PacifiCorp has limited market transactions in the 2025 IRP to energy purchases and does not rely on the market for capacity.

The Commission should scrutinize heavy reliance on gas given its inherent price fluctuations. As was demonstrated in the 2024 General Rate Case ("GRC"), gas pricing has a significant impact on customer rates. NPC—which is primarily driven by purchased power and fuel pricing—accounted for 85% of PacifiCorp's 30% rate increase request.[27] Between the 2020 GRC and the 2024 GRC, NPC increased by 87%.[28] These increases were primarily driven by the price of natural gas, which influences not only fuel for gas-fired power plants but also the cost of wholesale electricity. This underscores the importance of accurately reflecting gas prices in IRPs to ensure that resource selections are truly lowest cost and lowest risk.

A review of PacifiCorp's recent IRPs shows that gas price fluctuation has been historically under-forecasted, most notably in the 2022-2023 period which coincided with extreme weather events as well as various supply constraints, as depicted in Figure 3.8 of the Company's 2025 IRP.

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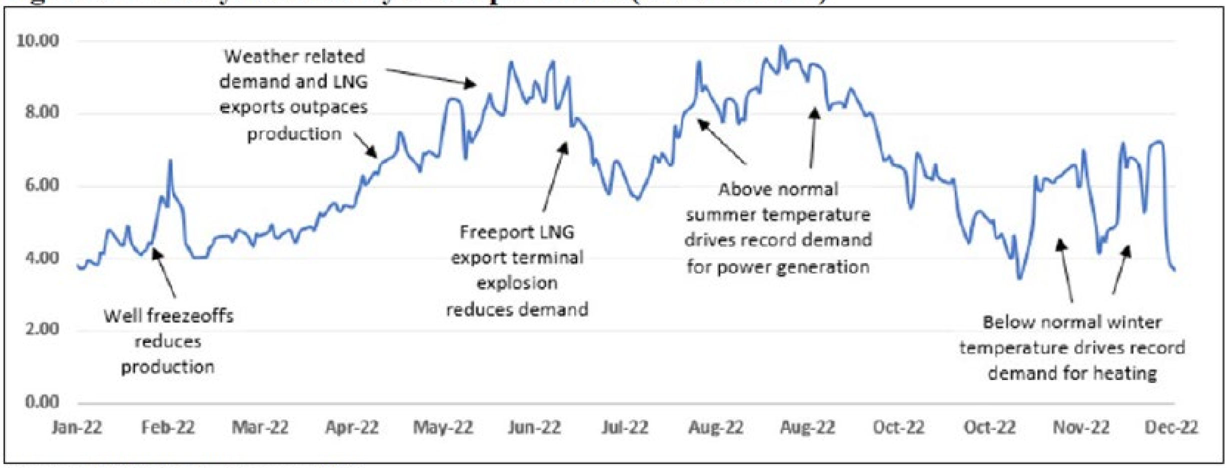
https://edocs.puc.state.or.us/efdocs/HAC/lc85hac339442027.pdf ("PacifiCorp agrees with [Renewable Northwest] that customers across all six states will share the costs of system reliability.")
[26] PacifiCorp 2025 IRP at 233 (Volume I).
[27] *Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric service Schedule and Electric Service Regulations,* Utah Pub. Serv. Comm'n, Dkt. No. 24-035-04, Direct Testimony of Joelle R. Steward at 7:143 (June 28, 2024) (Table 1), *available at* https://pscdocs.utah.gov/electric/24docs/2403504/334481DirTstmnyJoelleRStewardRMP6-28-2024.pdf.
[28] *Id.* at 7:152-158.

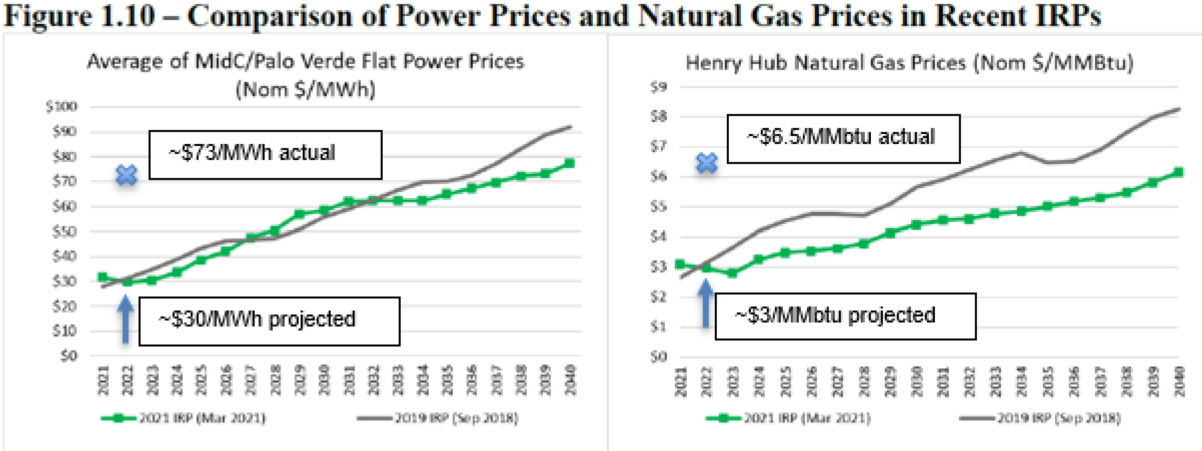
Figure 3.8 - Daily 2022 Henry Hub Spot Prices (USD/MMBtu)



Source: S&P Global, Siemens PTI

As the figure illustrates, natural gas prices in 2022 nearly reached $10/MMBtu on several occasions, while averaging $6.45/MMBtu[29] and rarely dipping below $4/MMBtu. This contrasts starkly with PacifiCorp's prior projections in the 2017, 2019, and 2021 IRPs that all included base case projections for gas prices in year 2022 that were closer to $3/MMBtu.[30] The figure below illustrates this, with the blue "X's" added to show where the actual commodity prices were versus the prior projections.

Figure 1.10 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs



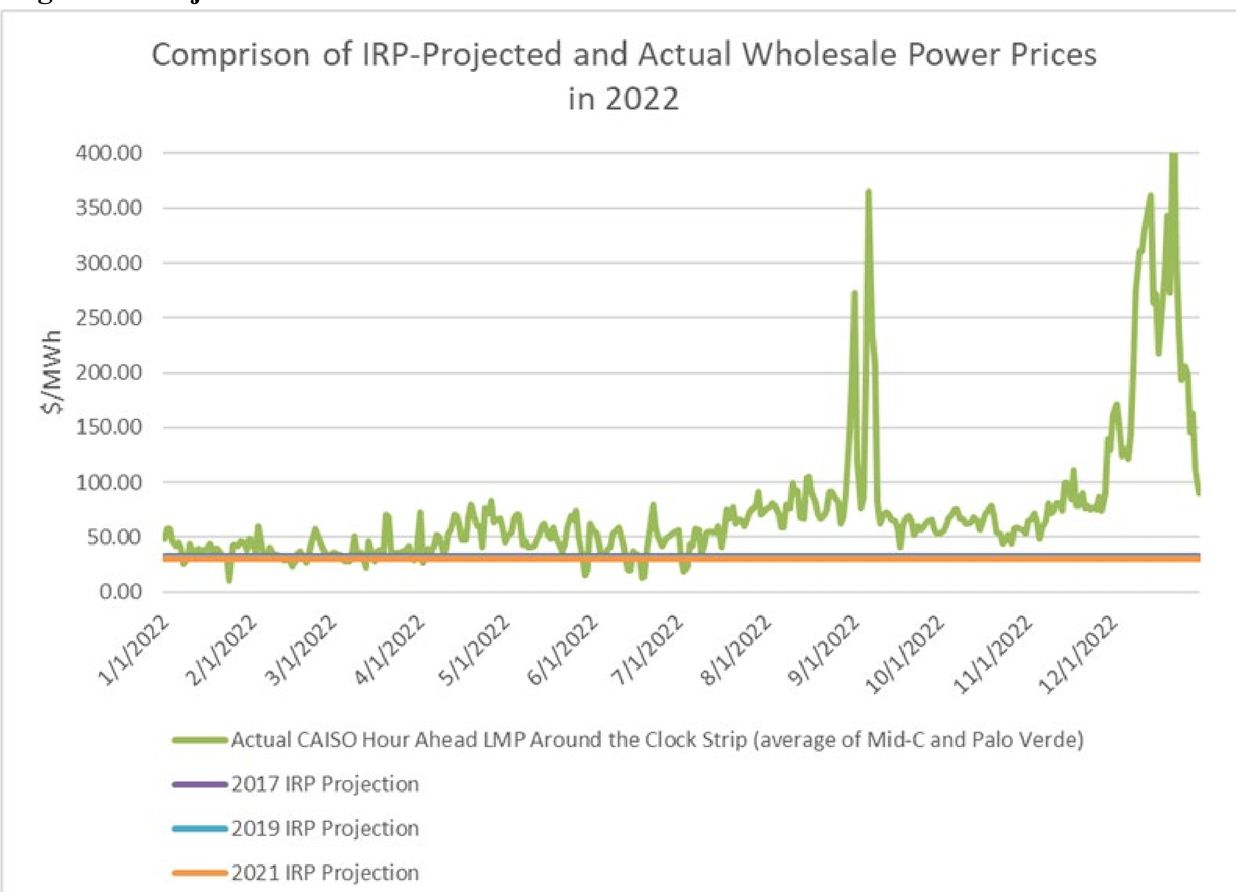
[29] Based on average of Henry Hub Spot Natural Gas Index prices in 2022 retrieved from S&P Global Market Intelligence.

[30] *See* PacifiCorp 2017 IRP at 154 (Volume I), *available at* https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2017-irp/2017_IRP_VolumeI_IRP_Final.pdf; PacifiCorp 2019 IRP at 182 (Volume I), *available at* https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf; PacifiCorp 2021 IRP at 228 (Volume I), *available at* https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf.

Thus, while some of the underlying factors that led to higher prices in 2022 may have been difficult to predict, the fact is that PacifiCorp significantly under-forecasted natural gas prices in several of its prior IRPs. Similarly, PacifiCorp's projections for wholesale power costs in 2022 were significantly lower than what actually transpired. This reflects the fact that wholesale power prices are typically driven by the marginal cost to operate natural gas generation units. Since natural gas prices had been under-forecasted in 2022, so too were wholesale power prices.

As the chart below shows, PacifiCorp's three IRPs prior to 2022 (2017, 2019, 2021) all significantly underestimated wholesale power costs in 2022. The Company's projections even just one year prior (i.e., the 2021 IRP) anticipated average wholesale power prices close to $30/MWh when in fact they averaged about $73/MWh (i.e., more than $40/MWh higher than PacifiCorp's projections). This under-forecast directly led to PacifiCorp's extraordinarily high rate request in the 2024 GRC.

Figure 2: Project versus Actual 2022 Whole Power Prices



Such significant under-forecasts of gas prices are not counter-balanced by over-forecasts in other years. Indeed, there has not been any year in recent history (or ever) where wholesale power prices were a commensurate $40/MWh lower on average than what PacifiCorp projected. For that to occur, wholesale power prices would have needed to be consistently negative throughout the year (i.e., -$10/MWh on average), which has never occurred. In fact, an examination of historical pricing in other recent years (e.g., 2023-2024), shows that PacifiCorp's prior IRP projections were also too low rather than too high, even though the discrepancy was not quite as extreme in other years as in 2022. Thus, based on this recent history, commodity prices are being systematically under-forecasted by PacifiCorp rather than over-forecasted.

Figure 3: Actual MidC/Palo Verde Flat Power Prices Versus 2021 IRP Projection

Row Labels	Actual MidC/Palo Verde Flat Power Prices[31] ($/MWh)	2021 IRP Projection[32] ($/MWh)
2022	**73.2**	**30**
2023	**52.1**	**31**
2024	**34.8**	**34**

This would mean that PacifiCorp may also be consistently underestimating NPC and thus undervaluing actions appropriate to mitigate those costs in its IRP and other planning efforts. High natural gas prices will increase PacifiCorp's NPC by increasing the cost to operate plants it owns, or increasing the cost of power it purchases from the wholesale market. This in turn drives up NPC, and subsequent customer costs, as was the case in the 2024 GRC, described above. As mentioned, this exposure to price risk tends to be asymmetric, meaning that the price spikes are not "canceled out" by price dips.

Fuel price volatility can be minimized by reducing the Company's overall reliance on thermal generation, including from both utility owned generation and market sources. To the extent that PacifiCorp invests in zero-marginal cost resources (e.g. solar and wind), it can reduce its overall exposure to these commodity price risks. To better understand the benefits of this strategy, Sierra Club performed an analysis using recent wholesale price data from 2022 and indicative 8760-hr generation profiles for wind and solar (derived from NREL data and modeling tools). This analysis shows that if PacifiCorp underforecasts wholesale prices similar to what occurred in

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[31] Based on CAISO Hour Ahead LMP Around the Clock Strip Prices (average of Mic-C and Palo Verde), retrieved from S&P Global Market Intelligence.

[32] PacifiCorp 2021 IRP at 228 (Volume I), *available at* https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf.

2022, then every 100 MW of wind would save an additional $20 million in NPC annually and every 100 MW of solar would save an additional $9 million in NPC annually. Meanwhile, even if PacifiCorp overforecasts wholesale prices by 30%, the NPC value of the wind would only be reduced by $4 million, and the solar by $2 million.

III. INTEGRATED HUNTER RETIRE MN PORTFOLIO SHOULD HAVE BEEN SELECTED AS THE PREFERRED PORTFOLIO

Due to the issues with the integration and allocation methodologies discussed above, no integrated portfolio is truly least-cost, least-risk. Nevertheless, considering the integrated portfolios from which PacifiCorp selected a preferred portfolio, the Integrated Hunter Retire MN Portfolio —which retired all three Hunter coal units by 2030—should have been selected because it was least cost and sixth lowest in emissions following the ST model results.[33] Even after the portfolio's costs were "risk adjusted" and increased by "end effects," Hunter Retire was still the third lowest cost portfolio.

As discussed below the stochastic analyses supporting the risk adjustments and end effects adjustments failed to provide meaningful insight into the relevant risks of each portfolio and further included significant input errors. Due to these shortcomings, we recommend that the Commission disregard the risk adjustments and instead compare the portfolios based on their initial relative rankings following the ST model run—which shows that Hunter Retire MN is the lowest cost portfolio. Moreover, when Sierra Club corrected errors in PacifiCorp's risk adjustment of the portfolios (discussed below), Hunter Retire MN is least cost under the deterministic present value revenue requirement ("PVRR") as well as the stochastic PVRR, even when further adjusted for end effects.

Additionally, PacifiCorp's anticipated participation in the Extended Day Ahead Market ("EDAM") will only further strain Hunter's economic viability, further supporting adoption of a portfolio that retires this plant by 2030.

For these reasons, discussed further below, the Hunter Retirement portfolio should have been selected on a purely economic basis, even before considering the additional benefits of lower emissions, lower pollutants, and progress towards Utah Renewable Communities goals.

A. Stochastic Analysis Fails to Provide Meaningful Insight and Contains Input Errors.

The stochastic analysis in the 2025 IRP focuses on risks associated with the volatility of certain inputs, including commodity prices, generation and load volatility due to weather changes, as well as the availability of thermal units. This volatility mainly impacts costs within the operating timeframe and is thus quantified through ST runs (as compared for example to the planning

[33] PacifiCorp 2025 IRP at 260 (Volume I) (Table 9.34).

uncertainty of a large load addition which would require different scenarios and investment decisions).

The stochastic analysis varies inputs based on historical data, including:

- wind generation, solar generation, and energy efficiency profiles
- hydroelectric generation
- load (mainly to reflect weather uncertainty, not load growth uncertainty)
- wholesale electricity prices
- natural gas prices (again reflecting daily variability versus deviations from the forecasted monthly averages)
- thermal unit outages

The stochastic analysis uses daily "shock" values that adjust inputs on a daily basis capturing the historical correlation of inputs.[34] However, this "stochasticity" does not capture the risk associated with inputs deviating from the Company's expectations. For example, it does not capture the risk and customer exposure to higher natural gas or coal prices. Similarly, the risk for certain resource types from increasing environmental policy at the state or federal level in the long term is not captured in this analysis.

PacifiCorp's approach of reoptimizing portfolios under these price-policy scenarios, therefore, misses the point of quantifying the costs that ratepayers will have to cover if PacifiCorp commits to a certain near-term action plan but the planning environment changes compared to PacifiCorp's expectations. A re-evaluation of all portfolios in Figure 9.34 in ST under an HH scenario (i.e., high natural gas price; high CO2 price) would be more insightful than the stochastic analysis presented. Furthermore, the stochastic analysis misses all risks associated with over- or under- forecasting load or capital costs (the build cost for each of the presented portfolio is on average 45% of the total NPVRR, with the variable cost being 6% - only part of which is the focus of the stochastic analysis, and the remaining 49% consisting of fixed costs). In short, the stochastic analysis is a seemingly complicated analysis which fails to quantify the appropriate risks, and is thus not insightful.

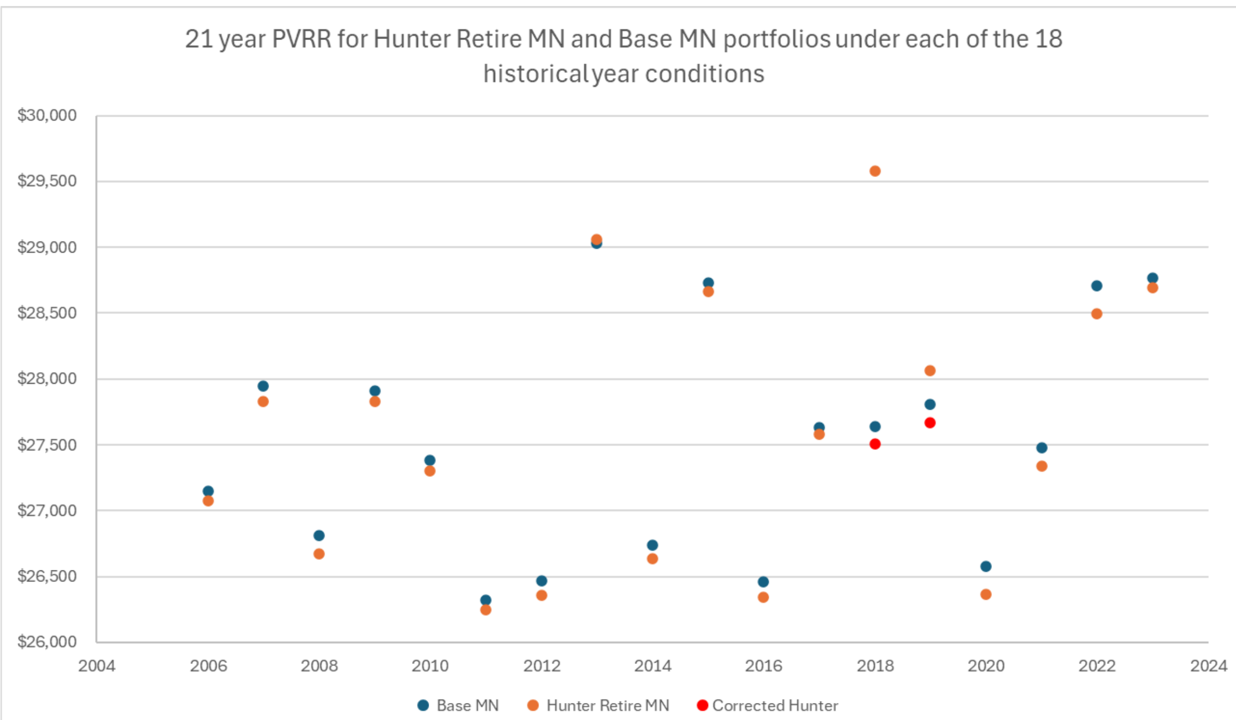
Putting aside concerns regarding the design of the stochastic analysis, the results as presented by PacifiCorp are counterintuitive. Although certain portfolios might perform better in terms of daily fluctuations—due, for example, to the existence of energy storage which can smooth out some of the price or supply/demand fluctuations—the results as a whole are not easy to interpret. Portfolios with higher renewable generation, which would be expected to be less exposed to price fluctuations, received a higher risk adjustment.

[34] PacifiCorp 2025 IRP at 149 (Volume II).

Sierra Club further investigated the numerical results and discovered a series of issues that result in an erroneous re-ranking of portfolios. The Base MN portfolio has a risk adjustment of $385 million, while the Hunter Retire MN has a risk adjustment of $703 million. These adjustments result in the Hunter Retire MN portfolio erroneously becoming more expensive than the Base MN portfolio after the risk adjustment, despite having a lower deterministic (base) PVRR.

To better understand the results of this analysis, Sierra Club investigated the output of each of the 18 historical years for each of the two portfolios (shown in Figure 4 below). Looking at the graph, it becomes obvious that the Hunter Retire MN portfolio results in lower PVRR under the majority of the historical year conditions (for the 2013 historical conditions the portfolios have very similar PVRR, while for 2018 and 2019 the results deviate more). Thus, even at this point, the conclusion remains that the Hunter Retire MN outperforms the Base MN under the majority of the simulated (historical) conditions.

Figure 4. 21 Year PVRR for Hunter Retire MN and Base MN Portfolios Under each of the 18 historical year conditions



Source: Created using data from PacifiCorp's workpapers (see Table 1) and Attach. 1 (Attachments to PacifiCorp Response to Sierra Club Data Request 5.3)

Sierra Club further investigated the issue to understand the 2018-2019 deviation. Based on this review, the Company's files appear to have significant errors. For example, the Hunter Retire MN portfolio run under the 2018 and 2019 conditions are using different portfolios (with the 2018 and 2019 erroneous portfolios containing more coal than the Hunter Retire MN portfolio), resulting in different build and fixed costs (build and fixed costs would not be expected to change in the stochastics run), as depicted in Table 1 below. Consequently, the stochastic analysis results as presented in the original filing are simply incorrect and should not be relied upon for any re-ranking of the portfolios. PacifiCorp confirmed that the runs and results were erroneous:[35]

> The 2018 and 2019 stochastic runs for the Hunter portfolio did not use the correct PLEXOS scenario to identify the proper resource selections in short-term (ST) modeling for the Hunter portfolio. The corrected stochastic runs were completed in August 2025.

PacifiCorp further states that:

> After corrections the Base MN remains the lowest PVRR portfolio. Please refer to Attachment Sierra Club 5.3 which provides copies of the public / non-confidential work papers using the corrected portfolio.

Examining the workpapers provided, it is clear that they are again erroneous, with PacifiCorp assigning $10.5 billion (NPV) of incremental transmission costs compared to the original Hunter portfolio.

Thus, the stochastic analysis remains incorrect, raising significant concerns about PacifiCorp's overall analytical and reporting processes.

Table 1: Assumed Fixed, Variable, and Build Costs for the Retire Hunter Portfolio

	Total	Fixed	Variable	Build
SR-ST.Cost.Summary.-25I.LP.ST.r21.Hunter.EP.2409MN.Integrated.Stoc2006.158824.(LT..158824.-.169094).v105.2x2006.(P).xlsb	$ 27,078	$ 13,910	$ (395)	$ 13,563
SR-ST.Cost.Summary.-25I.LP.ST.r21.Hunter.EP.2409MN.Integrated.Stoc2007.158824.(LT..158824.-.169160).v105.2x2007.(P).xlsb	$ 27,830	$ 13,910	$ 358	$ 13,563
SR-ST.Cost.Summary.-25I.LP.ST.r21.Hunter.EP.2409MN.Integrated.Stoc2008.158824.(LT..158824.-.169226).v105.2x2008.(P).xlsb	$ 26,669	$ 13,910	$ (804)	$ 13,563
SR-ST.Cost.Summary.-25I.LP.ST.r21.Hunter.EP.2409MN.Integrated.Stoc2009.158824.(LT..158824.-.169490).v105.2x2009.(P).xlsb	$ 27,832	$ 13,910	$ 359	$ 13,563
SR-ST.Cost.Summary.-25I.LP.ST.r21.Hunter.EP.2409MN.Integrated.Stoc2010.158824.(LT..158824.-.169424).v105.2x2010.(P).xlsb	$ 27,302	$ 13,910	$ (171)	$ 13,563
SR-ST.Cost.Summary.-25I.LP.ST.r21.Hunter.EP.2409MN.Integrated.Stoc2011.158824.(LT..158824.-.169556).v105.2x2011.(P).xlsb	$ 26,245	$ 13,910	$ (1,228)	$ 13,563
SR-ST.Cost.Summary.-25I.LP.ST.r21.Hunter.EP.2409MN.Integrated.Stoc2012.158824.(LT..158824.-.169622).v105.2x2012.(P).xlsb	$ 26,359	$ 13,910	$ (1,115)	$ 13,563
SR-ST.Cost.Summary.-25I.LP.ST.r21.Hunter.EP.2409MN.Integrated.Stoc2013.158824.(LT..158824.-.169688).v105.2x2013.(P).xlsb	$ 29,062	$ 13,910	$ 1,589	$ 13,563
SR-ST.Cost.Summary.-25I.LP.ST.r21.Hunter.EP.2409MN.Integrated.Stoc2014.158824.(LT..158824.-.169754).v105.2x2014.(P).xlsb	$ 26,633	$ 13,910	$ (840)	$ 13,563
SR-ST.Cost.Summary.-25I.LP.ST.r21.Hunter.EP.2409MN.Integrated.Stoc2015.158824.(LT..158824.-.169820).v105.2x2015.(P).xlsb	$ 28,662	$ 13,910	$ 1,189	$ 13,563
SR-ST.Cost.Summary.-25I.LP.ST.r21.Hunter.EP.2409MN.Integrated.Stoc2016.158824.(LT..158824.-.169886).v105.2x2016.(P).xlsb	$ 26,346	$ 13,910	$ (1,128)	$ 13,563
SR-ST.Cost.Summary.-25I.LP.ST.r21.Hunter.EP.2409MN.Integrated.Stoc2017.158824.(LT..158824.-.169952).v105.2x2017.(P).xlsb	$ 27,577	$ 13,910	$ 104	$ 13,563
SR-ST.Cost.Summary.-25I.LP.ST.r21.Hunter.EP.2409MN.Integrated.Stoc2018.158824.(LT..158824.-.170018).v105.2x2018.(P).xlsb	$ 29,577	$ 13,964	$ 2,055	$ 13,559
2018 Updated File (Sierra Club 5.3)	$ 36,930	$ 13,910	$ 32	$ 22,988
2018 Corrected File (SC correction for transmission build costs)	$ 27,505	$ 13,910	$ 32	$ 13,563
SR-ST.Cost.Summary.-25I.LP.ST.r21.Hunter.EP.2409MN.Integrated.Stoc2019.159106.(LT..159106.-.170901).v105.2x2019.(P).xlsb	$ 28,064	$ 13,852	$ 2,224	$ 11,988
2019 Updated File (Sierra Club 5.3)	$ 37,093	$ 13,910	$ 195	$ 22,988
2019 Corrected File (SC correction for transmission build costs)	$ 27,668	$ 13,910	$ 195	$ 13,563
SR-ST.Cost.Summary.-25I.LP.ST.r21.Hunter.EP.2409MN.Integrated.Stoc2020.158824.(LT..158824.-.170150).v105.2x2020.(P).xlsb	$ 26,363	$ 13,910	$ (1,110)	$ 13,563
SR-ST.Cost.Summary.-25I.LP.ST.r21.Hunter.EP.2409MN.Integrated.Stoc2021.158824.(LT..158824.-.170216).v105.2x2021.(P).xlsb	$ 27,338	$ 13,910	$ (136)	$ 13,563
SR-ST.Cost.Summary.-25I.LP.ST.r21.Hunter.EP.2409MN.Integrated.Stoc2022.158824.(LT..158824.-.170282).v105.2x2022.(P).xlsb	$ 28,495	$ 13,910	$ 1,022	$ 13,563
SR-ST.Cost.Summary.-25I.LP.ST.r21.Hunter.EP.2409MN.Integrated.Stoc2023.158824.(LT..158824.-.170348).v105.2x2023.(P).xlsb	$ 28,692	$ 13,910	$ 1,219	$ 13,563

Using the files provided in Sierra Club 5.3, and after correcting for the unjustified transmission costs, Sierra Club updated the stochastic risk adjustment for the Hunter portfolio. The Hunter Retire portfolio has the lowest deterministic PVRR (Table 9.34 of the IRP, Volume I), *and* the lowest stochastic PVRR.

[35] Ex. 1 (PacifiCorp Response to Sierra Club Data Request 5.3).

It is especially concerning that when asked to provide an explanation for these results, PacifiCorp chooses to iterate a false narrative: the response to Sierra Club 5.1. repeats that the stochastic risk adjustment for the Hunter portfolio is $703 – consistent with Table 9.34, even when recognizing that the adjustments in this Table have used inconsistent resource additions (Sierra Club 5.3).

Correcting for these errors, the Hunter Retire portfolio ranks first in terms of its deterministic PVRR, the stochastic PVRR, and the PVRR with end effects.

Table 2: PVRR and Stochastic Adjustment for Base MN and Retire Hunter MN portfolios[36]

	PVRR ($m)	Stochastic Adjustment ($m)	Stochastic PVRR ($m)	PVRR with end effects ($m)
Integrated Base MN	$ 27,233	$ 385	$ 27,618	$ 34,663
Integrated Hunter Retire MN	$ 27,062	$ 703	$ 27,765	$ 34,960
Corrected Hunter Adjustment	$ 27,062	$ 13	$ 27,075	$ 27,089

B. Hunter Will Become Increasingly Uneconomic to Operate Following PacifiCorp's Participation in the EDAM.

Not only should the Hunter plant retire by 2030 based on PacifiCorp's own modeling, but the plant will also become increasingly uneconomic following PacifiCorp's participation in the Extended Day-Ahead Market, or "EDAM."

One of the most significant developments for the electricity system in the Western US is the gradual evolution towards a regional day-ahead energy market. Once implemented, EDAM could significantly alter the operation of many dispatchable resources throughout the region, including PacifiCorp's fleet. Unfortunately, "PacifiCorp did not explicitly model participation in EDAM in its PLEXOS modeling."[37]

As a result, PacifiCorp's IRP analysis likely provides an overly optimistic portrayal of thermal resource operating costs by assuming more flexible economic dispatch of the thermal fleet than is likely to occur in reality under EDAM. To be clear, the transition to EDAM itself is likely beneficial and should still be pursued. However, in the context of the IRP, a more accurate representation of thermal resource operation under EDAM is missing from PacifiCorp's analysis.

[36] The corrected risk adjustment is derived by correcting the 2018 and 2019 runs in workpaper "(P)_Stochastic Risk Adjustment Calculator Hunter.xlsm" (Ex. 1 (Attachment to PacifiCorp Response to Sierra Club Data Request 2.16) based on the files provided in response to Sierra Data Request 5.3.
[37] Ex. 1 (PacifiCorp Response to Sierra Club Data Request 1.10).

A more accurate analysis would likely reveal that thermal resources, including the Hunter plant, are much more costly and in some cases should be retired earlier as part of the optimal solution.

PacifiCorp's modeling represents thermal resources as being economically dispatched during the vast majority of hours. However, as the Company explained, in reality only a small subset of its thermal resources are actually being configured to engage in economic bidding through the EDAM day-ahead market. Specifically, [redacted]. Despite a large share of PacifiCorp's resource portfolio not being optimized as part of the EDAM market's economic dispatch process, PacifiCorp's IRP modeling has represented these resources as such.

There are two primary reasons why PacifiCorp's actual dispatch of thermal resources (and associated costs) may exceed what the Company has modeled.

- First, some units PacifiCorp operates may be "self-scheduled" into the EDAM, meaning that their unit commitment decisions are not subject to economic dispatch and will simply run at any time PacifiCorp designates, regardless of market pricing. In such instances if the operating cost of the thermal unit exceeds the market prices, the unit will be dispatched uneconomically and PacifiCorp customers will bear excess costs relative to what the market otherwise could provide.
- Second, PacifiCorp's process for determining marginal fuel cost for bid pricing (in both EDAM and the Western Energy Imbalance Market ("WEIM")) relies [redacted]

A more accurate analysis of thermal resource operation under EDAM (i.e., with more limited economic dispatch and unit commitment) would likely reveal that thermal resources are much more costly and in some cases should be retired earlier as part of the optimal solution. This consideration is especially salient for the Hunter plant, which is proposed to operate well into the future under PacifiCorp's Preferred Portfolio. PacifiCorp's modeling, even under its overly optimistic EDAM assumptions, already suggests that an earlier retirement date for Hunter than currently proposed is the most economic option. If PacifiCorp had correctly modeled EDAM by assuming no economic bidding participation for [redacted], then this resource would have become even more costly under the Preferred Portfolio. Modeling the more accurate, higher operating cost for [redacted]

Recommendations:

- In addition to the economically optimal scenario assuming perfect economic dispatch and full fuel costs, PacifiCorp should be required to conduct modeling scenarios that reflect realistic dispatch practices under EDAM. This includes assumptions for self-scheduling and discounted fuel pricing.
- The Commission should also plan to conduct an investigation into PacifiCorp's bidding practices in the EDAM to ensure that costs to retail customers are sufficiently minimized.

IV. CLEAN ENERGY PROCUREMENT IS NEEDED PRE-2030

Even accepting that the 2025 IRP Preferred Portfolio is the least-cost, least-risk portfolio for Utah customers (it is not), the Preferred Portfolio takes a procurement approach that is both unrealistic and risky. The Company forecasts massive procurements in 2030, while neglecting earlier procurements that are critical to ensuring a low-cost, low-risk, reliable power system. This strategy is at odds with historical procurement patterns, ignores available opportunities for lower-cost resource development, underestimates needed procurement for Utah and other PACE states when the Integrated Hunter Retire portfolio is considered, and fails to capitalize upon available surplus interconnection at the Hunter plant.

A. Past Procurements Indicate that PacifiCorp's Planned Resource Acquisition in 2030 Will Be Difficult to Achieve.

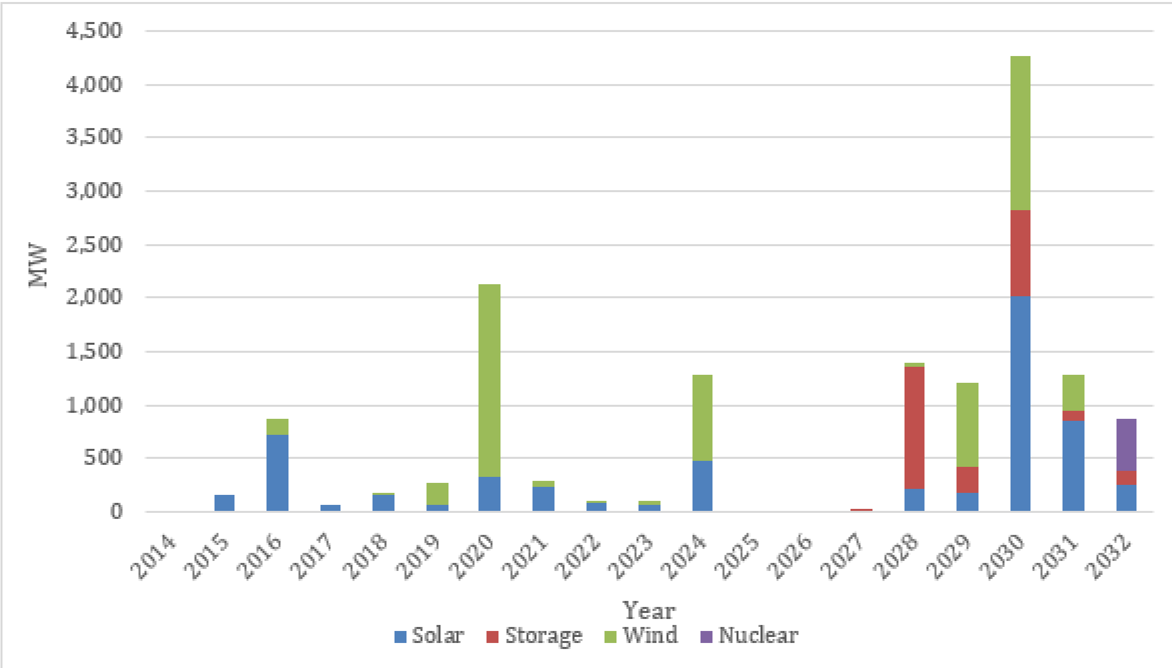
PacifiCorp's Preferred Portfolio projects a significant surge in clean energy acquisitions in 2030, well beyond anything the Company has historically achieved. As shown in Figure 3, which charts PacifiCorp's historical and projected clean energy procurements, PacifiCorp's planned additions in 2030 are more than twice the size of the Company's largest procurement year between 2014 and 2029.

The problem is compounded by the absence of any planned procurements from 2025 through 2027. Despite the significant resource needs forecast for 2028 through 2032, PacifiCorp's plan creates a three-year gap in clean energy acquisitions, followed by a sudden, concentrated procurement in 2030. This sequencing contradicts basic risk-management principles. A diversified procurement timeline would spread acquisition risks, mitigate exposure to cost spikes, and ensure a smoother integration of new resources.

Of course, these are merely modeling results of proxy resources, and PacifiCorp could opt to procure resources projected for 2030 sooner in time, as the Company has indicated it will do for Oregon-situs resources.[38] But PacifiCorp has not committed to earlier and smoother acquisition of clean resources. Indeed, PacifiCorp has repeatedly stated that it has no near-term resource needs for the PACE states and that it will not pursue a near-term RFP, despite the Preferred Portfolio indicating significant resource needs between 2028 and 2031 specifically for the UIWC states. Instead, PacifiCorp is actively choosing to defer all major procurements to 2030, thereby increasing the likelihood of higher costs and execution failures. The risks are particularly acute given the evolving regulatory landscape, intensifying competition for renewable resources and transmission development capacity, and the Company's failure to incorporate key factors into its planning, including the B2H transmission line (discussed above), the contribution of Utah Renewable Communities resources (discussed below), and the impact of future large loads.

[38] 2025 PacifiCorp IRP at 221 (Volume I), Table 9.2, n. 2.

Figure 5. Historical (pre-2025) and planned (after 2025 in Preferred Portfolio) Clean Energy Procurements



Source: Created using values provided by PacifiCorp in Sierra Club Data Request 19 and 2025 IRP Table 9.10 at 243.

B. Expiring Federal Tax Credits for Solar and Wind Energy Make Procurement of these Resources Extremely Time Sensitive.

Significant changes to federal tax incentives for clean energy further support PacifiCorp moving forward with energy acquisitions as soon as possible. The July 4, 2025 U.S. budget reconciliation bill, known as H.R.1,[39] made drastic changes to federal tax credits for renewable energy projects – particularly utility-scale wind and solar. This bill terminated key aspects of the Investment Tax Credit ("ITC") and Production Tax Credit ("PTC") for solar and wind projects; it also created barriers for projects through stricter provisions related to project construction timelines, foreign entities of concern involvement, and domestic content requirements. Where under the prior guidelines the tax credits would have extended through at least 2035, under the revised guidelines, solar and wind projects must begin construction by July 4, 2026, or be placed into service by December 31, 2027, to be eligible for the PTC/ITC.

Utah Clean Energy ("UCE") recently submitted an Expedited Investigatory Docket and Agency Action under Docket No. 25-035-52 that calls for the Commission to direct PacifiCorp to

[39] H.R.1, Pub. L. No. 119-21, §§ 70512-13, 139 Stat. 72 (July 4, 2025).

procure tax-advantaged energy generation in light of the recent passage of H.R.1.[40] Sierra Club supports UCE's request and agrees with the statements in the filing that rapid procurement of tax-advantaged resources could save ratepayers potentially billions of dollars in energy costs. Sierra Club agrees with UCE's analysis that the ITC/PTC could save ratepayers over $150 million of savings for every 100 MW of solar built and over $210 million of savings for every 100 MW of wind built.

Notably, resource needs projected in the 2025 IRP could have previously been acquired—and with use of the federal tax incentives—had PacifiCorp not canceled its 2022 all-source request for proposals ("RFP") and foregone a 2024 all source RFP. Instead of correcting for its past inaction and costly delays, PacifiCorp is issuing RFPs only for Oregon and Washington resource needs, ignoring the resource needs of Utah and other PACE states. This is despite the fact that PacifiCorp's Preferred Portfolio calls for 1,412 MW of wind and solar through 2031 for PACE states. If PacifiCorp fails to move forward quickly on these resource acquisitions, they will still be needed, but will cost at least 30% more, if not more, as evidenced by UCE's analysis. For these reasons, the Commission should use its evaluation of PacifiCorp's IRP to provide guidance to the Company that moving forward with an RFP for Utah and other PACE states would be in the best interest of customers.[41]

C. Integrated Hunter Retire MN Portfolio Provides Additional Support for Near-Term Clean Energy Procurements.

While PacifiCorp's Preferred Portfolio itself demonstrates a need to move forward with clean energy procurements in the very near term, the Integrated Hunter Retire MN Portfolio provides further justification. As discussed above, the Hunter Retire Portfolio should have been selected as the Preferred Portfolio because it presents lower costs and risks than the Base MN case. Under that portfolio, PacifiCorp would need an additional [redacted] MW of clean energy resources through 2030 to replace the 1,100 MW of nameplate capacity at the Hunter units. Strikingly, more than 95% of those proxy resource additions are deferred until 2030—mirroring the same problematic concentration of acquisitions in the Preferred Portfolio. Confidential Table 3 compares the new proxy resource selections through 2030 for the two portfolios.

Confidential Table 3. Proxy Resource Selections Through 2030 in Base MN and Hunter Retire MN Portfolios

	Base MN (MW)	Hunter Retire MN (MW)	Difference (MW)

[40] *Utah Clean Energy's Request for Expedited Investigatory Docket and Agency Action*, Utah Pub. Serv. Comm'n, Dkt. No. 25-035-52, Request, *available at* https://pscdocs.utah.gov/electric/25docs/2503552/341280Rqst8-29-2025.pdf.

[41] *Id.*

Renewable – Small Scale Solar	320	[redacted]	[redacted]
Renewable - Utility Solar	2,092	[redacted]	[redacted]
Renewable - Small Scale Wind	0	[redacted]	[redacted]
Renewable - Wind	2,267	[redacted]	[redacted]
Renewable - Battery, < 8 hour	1,689	[redacted]	[redacted]
Renewable - Battery, 8-23 hour	3	[redacted]	[redacted]
Renewable - Battery, 24+ hour	511	[redacted]	[redacted]
Storage - Other	0	[redacted]	[redacted]
Total	**6,562**	[redacted]	[redacted]

Source: Calculated using confidential workbooks CONF_Max of Units Base Hunter 3.13.xlsx and Source: CONF_Max of Units Base MN.xlsx for the years 2025 through 2030.

These additional resource needs underscore the importance of pursuing near-term acquisitions that would diversify procurement and reduce risk. Spreading procurement across the coming years would smooth out the buildout trajectory, provide greater certainty to developers, and lessen customer exposure to market volatility. This point becomes even more critical if, in the 2027 IRP, PacifiCorp confirms the 2030 retirement date for Hunter. With only three years remaining to replace 1,100 MW of capacity, any delay in procurement would leave the Company with little time to prepare, forcing rushed and costly acquisitions. Acting now avoids that risk and positions the system for a more orderly and cost-effective transition.

D. Surplus Interconnection Is Especially Promising at the Hunter Site.

Near-term clean energy procurement is further justified in order to take advantage of available transmission interconnection at the Hunter plant. Even without retirement of the coal units, the Hunter site should have valuable surplus interconnection (i.e., transmission rights that are unused when the coal plants are not generating at their full capacity). When asked, PacifiCorp indicated that the Hunter plant does not have any surplus interconnection available.[42] Yet, over the past seven years, Hunter's capacity factor has averaged to approximately 60%, with significantly lower capacity factors since 2023. This means that surplus interconnection of around 40% of the plant's overall nameplate capacity may be available.

Interconnection availability is one of the largest bottlenecks for development of new energy projects across the West. Developers routinely face long wait times and escalating costs to secure

[42] Ex. 1 (PacifiCorp Response to Sierra Club Data Request 5.4).

transmission capacity. By contrast, PacifiCorp already controls interconnection rights at Hunter, meaning that new projects sited in this area could move forward on a much faster timeline and at considerably lower cost to ratepayers. Leveraging this already-built infrastructure avoids the years-long delays, permitting hurdles, and high costs associated with developing new transmission, making the Hunter site one of the most advantageous locations for near-term energy resource procurement.

If Hunter's capacity factor continues to decline, or the plant is fully retired in 2030, there would be up to 1,100 MW of interconnection available for new resources. The time and cost savings of siting new renewable resources at the Hunter site was not directly included in the IRP modeling. Had they been included, these benefits would have made the Hunter Retire MN portfolio even more attractive.

V. PACIFICORP SHOULD ACCOUNT FOR RESOURCES ACQUIRED IN SUPPORT OF THE UTAH RENEWABLE COMMUNITIES PROGRAM IN ITS IRP

The Utah Renewable Communities ("URC") program represents one of the most significant near-term drivers of clean energy development in Utah; yet, PacifiCorp's 2025 IRP inexplicitly assumes zero participation. By overlooking this program, PacifiCorp disregards resources that will unquestionably be added to its system, thereby distorting the IRP's forecast of system needs and overstating reliance on existing high-cost, high-emission resources such as the Hunter plant.

URC enables participating local communities to procure renewable resources to achieve "net-100% renewable electricity" goals by 2030. Currently, there are 19 participating communities including some of the largest population centers in the state such as Salt Lake City and Ogden. The participating communities have recently issued a Request for Proposals ("RFP") for new renewable resources that are between 2-300 MW and can achieve a commercial operation date no later than December 31st, 2029.[43] Initial RFP bids were due on July 10, 2025 and a final selection expected in December 2025. According to the RFP documentation, "The [URC] Agency anticipates that the Initial Short List will represent approximately 500 MW of aggregate capacity" but the final amount could be more or less.[44]

While there is some uncertainty regarding the final participation rates of the URC program, one thing is certain: participation will not be zero. Yet in the 2025 IRP, in all portfolios, PacifiCorp "did not designate any resources in the 2025 IRP preferred portfolio or the Utah 2025 IRP preferred portfolio for the Utah Renewable Community Program."[45]

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[43] Utah Renewable Communities RFP Website, *available at* https://www.urc2024rfp.com/ (last visited Sept. 25, 2025).
[44] *2024 Utah Renewable Communities Request for Proposals "2024 URC RFP" Program Renewable Resources* at 20, Utah Renewable Communities (May 22, 2025), *available at* https://www.urc2024rfp.com/s/URC-Solicitation-Narrative-upd0521.pdf.
[45] Ex. 1 (PacifiCorp Response to Sierra Club 1.11).

By ignoring resources that will be available on PacifiCorp's system through the URC program, PacifiCorp's 2025 IRP ignores the benefits that these resources will bring. This could mean that the 2025 IRP assumes energy and capacity needs from either existing or new proxy resources that, in reality, will be met by the URC resources. As a result, the 2025 IRP may be over-forecasting reliance on resources such as the Hunter plant, that PacifiCorp's modeling already suggests should be reduced or retired. Sierra Club recommends that PacifiCorp update its planning assumptions to include 500 MW of additional URC-designated renewable resource additions by 2030.

VI. CONCLUSION

Sierra Club appreciates the opportunity to provide comments and recommendations to the Commission regarding PacifiCorp's 2023 IRP. Sierra Club looks forward to collaborating with the Commission, PacifiCorp, and all other parties to this proceeding.

Respectfully submitted,

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DOCKET NO.: 25-035-22

SIERRA CLUB'S OPENING COMMENTS ON PACIFICORP'S 2025 INTEGRATED RESOURCE PLAN

EXHIBIT 1
PUBLIC DATA REQUEST RESPONSES

Sierra Club Data Request 1.10

As stated in Chapter 7, page 178 of the 2025 IRP, "The economic opportunities are expected to be enhanced by the EDAM, relative to current operations, but it is unclear how the EDAM will compare to the IRP model's hourly balancing optimization of market purchase and sales volumes against static hourly market prices".

(a) Please clarify whether EDAM participation is explicitly modeled by PacifiCorp in the PLEXOS ST model runs.

(b) Please provide a description of how EDAM was presented in the Company's modeling

(c) Does PacifiCorp plan to offer any generations into EDAM as "self-scheduled" units rather than economic bids? If so, which units would this apply to and how is this represented in the IRP modeling?

Response to Sierra Club Data Request 1.10

PacifiCorp notes that the majority of this data request specifies Chapter 9 or "final IRP" results. The company has interpreted this to mean that the entire data request is directed at the final IRP results as represented in Chapter 8 through 10, and not Utah IRP outcomes as represented in Chapter 11-13.

(a) PacifiCorp did not explicitly model participation in EDAM in its PLEXOS modeling. Participation in organized markets like EDAM provides flexibility and access to alternative supplies from other utilities. In the 2025 IRP, PacifiCorp represented the economic opportunities of market transactions by allowing market purchases up to transmission limits in the vast majority of hours: except for the most constrained hours on the top five load days in each peak season, when market purchases are set to zero (4 pm to 12 am in the summer and 4 am to 8 am and 4 pm to 12 am in the winter). To the extent that resources are available across the broader footprint, they would be available to assist PacifiCorp in meeting its requirements. PacifiCorp must meet certain balancing and flexible resource requirements in both the Western Energy Imbalance Market (WEIM) and the EDAM and the top five load day restrictions help to ensure that sufficient resources are available. As part of the iterative portfolio development process, the reliability adjustment acts to increase resource selections to cover shortfalls, which would be much more likely during periods when markets are not available. The availability of market purchases outside of the constrained hours may result in somewhat higher reliability than PacifiCorp could achieve without access to organized markets.

(b) Please refer to PacifiCorp's response to subpart (a).

(c) PacifiCorp may submit economic bids or self-schedules for generation for participating units into EDAM depending on the needs of a given day. As stated in subpart (a), PacifiCorp does not explicitly model participation in EDAM in its PLEXOS modeling. A list of PacifiCorp units that may participate in EDAM is provided in Attach Sierra Club 1.10 CONF, which is a list of participating and non-participating resources in the EIM. As part of the EDAM implementation, all EIM participating and non-participating resources PacifiCorp will be converted to participate in EDAM with the ability to be economically bid or self-scheduled into EDAM depending on the needs of a given day. In addition to the administrative conversion process of non-participating units, as part of the EDAM onboarding process, PacifiCorp is working on enabling the following units to engage in economic bidding: Hunter 1 & 2 , Gadsby 1 & 2, and Dave Johnston 1 & 2. As submitting Economic Bids is a form of market participation where the market can dispatch a resource up or down depending on market prices relative to the resource's economic bid price, certain resources are not physically able to be dispatched up and down due to being a run of river hydro resource or a contracted resource. If a scheduling coordinator wishes for a resource not to be dispatched by the market, they can submit a Self-Schedule, which is awarded not based on economics.

Confidential information is provided subject to Public Service Commission of Utah (UPSC) Rules R746-1-601–606.

25-035-22 / Rocky Mountain Power
June 30, 2025
Sierra Club Data Request 2.5

Sierra Club Data Request 2.5

Load and Resource Balance - Please refer to Tables 9.12 through 9.14. Please advise why are there zero MW for 'Transfers' between East and West after 2029 in both summer and winter portfolios? Was this result due to imposed modeling constraints for emission and/or RPS compliance?

Response to Sierra Club Data Request 2.5

Referencing PacifiCorp's 2025 Integrated Resource Plan (IRP), the Company responds as follows:

There are no transfers between East and West after 2029 in Table 9.12 through Table 9.14 because both the East and the West have sufficient capacity to meet the total obligation plus reserve margin in every year.

Sierra Club Data Request 2.16

Stochastic Analysis - Please refer to page 202, which lists five Stochastic Portfolio Performance Measures. Please provide the numerical values of these measures for each portfolio examined.

Response to Sierra Club Data Request 2.16

Please refer to Attachment Sierra Club 2.16 which provides files containing the stochastic calculator for all variants.

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Attachment to PacifiCorp Response to Sierra Club Data Request 2.16, "(P)_Stochastic Risk Adjustment Calculator Hunter.xlsm" has been provided in Excel format

25-035-22 / Rocky Mountain Power
September 23, 2025
Sierra Club Data Request 5.3

Sierra Club Data Request 5.3

Stochastic Analysis - Please refer to following two public workpapers: (i) SR-ST.Cost.Summary.-25I.LP.ST.r21.Hunter.EP.2409MN.Integrated.Stoc2018.158824.(LT..158824.-.170018).v105.2x2018.(P).xlsb; and (ii) SR-ST.Cost.Summary.-25I.LP.ST.r21.Hunter.EP.2409MN.Integrated.Stoc2019.159106.(LT..159106.-.170901).v105.2x2019.(P).xlsb.

(a) Please confirm that these two spreadsheets include portfolios that differ from the Hunter Retire portfolio.

(b) If confirmed, please explain why and provide the same analysis (Stoc2018, Stoc2019) for the Hunter Retire portfolio.

(c) If not confirmed, please explain the differences in fixed costs and capacities between the portfolio in each of the spreadsheets and the Hunter Retire portfolio.

Response to Sierra Club Data Request 5.3

(a) Confirmed.

(b) The 2018 and 2019 stochastic runs for the Hunter portfolio did not use the correct PLEXOS scenario to identify the proper resource selections in short-term (ST) modeling for the Hunter portfolio. The corrected stochastic runs were completed in August. After corrections the Base MN remains the lowest PVRR portfolio. Please refer to Attachment Sierra Club 5.3 which provides copies of the public / non-confidential work papers using the corrected portfolio.

(c) Not applicable.

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Attachments to PacifiCorp Response to Sierra Club Data Request 5.3, "(P)_ST Cost Summary -25I.LP.ST.r21.Hunter.EP.2409MN.Integrated.Stoc2018.158824 (LT. 158824 - 206767) v2.4" and "(P)_ST Cost Summary - 25I.LP.ST.r21.Hunter.EP.2409MN.Integrated.Stoc2019.158824 (LT. 158824 - 206745) v2.4" have been provided in Excel format

Sierra Club Data Request 5.4

Surplus Interconnection at Hunter Site - Please provide information about the following related to interconnection potential at the site of the existing Hunter coal plant (Units 1, 2, and 3):

(a) Please provide the amount of surplus interconnection capacity currently available.

(b) Please advise if the Green River Energy Center or any other in progress or planned energy project will use any of the current surplus interconnection and, if so, how much and when.

(c) Please confirm the amount of interconnection rights that would be available if the three Hunter coal units were to retire.

Response to Sierra Club Data Request 5.4

(a) There is none.

(b) Please refer to the Company's response to subpart (a) above. There is no surplus interconnection to use. The Green River Energy Center will use its own interconnection and does not rely upon surplus interconnection capacity from any other project.

(c) Surplus interconnection requires an active interconnection to be surplus to. Therefore, if Hunter units were to retire there would be no surplus interconnection possible from those units.

OPUC Data Request 9

What is the shadow carbon price used to influence emitting resource dispatch in Oregon?

Response to OPUC Data Request 9

Please refer to PacifiCorp's 2025 Integrated Resource Plan (IRP), Volume II, page 500. A model driver dispatch price was applied to the emissions generated by Oregon's share of gas plants. No shadow carbon price was applied to any emissions generated by resources that were not allocated to Oregon. The model driver dispatch price applied to the emissions generated by Oregon's share of gas plants started at $100 per ton ($/ton) in 2030 and increased by $20/ton each year until 2039, when it was $280/ton.

OPUC Data Request 34

The section on Portfolio Integration describes that “in this way, resource allocations are fixed based on jurisdictional selections in the year in which they are built and do not change over time” (p. 211). Explain why a fixed resource allocation is more efficient than a dynamic resource allocation based on economic and load factors.

Response to OPUC Data Request 34

In the integration process, a fixed allocation of the quantity of a proxy resource selected in an individual year is necessary. As an example, if 200 megawatts (MW) is built and is shared 150 MW for Oregon and 50 MW for Washington, these 200 MW would be split 75 percent to 25 percent for the balance of the horizon. If an additional 200 MW are built and are split 100 MW each for Oregon and Washington, those 200 MW would be split 50 percent to 50 percent for the balance of the horizon. This means that Oregon would have 250 MW of the resource, and Washington would have 150 MW of the resource. Once a state procures MWs of a resource that specifically contribute to their requirements it is unlikely that state would rescind their ownership in a unit.

Because all new resources are considered situs to each state by their need it is not feasible to assume that a situs resource would somehow become shared over time. Situs allocations are allowed within the existing 2020 Multi-State Process Inter-Jurisdictional Cost Methodology (2020 Protocol). While different allocation strategies may be possible if two or more jurisdictions mutually agree, PacifiCorp’s 2025 Integrated Resource Plan (IRP) does not assess alternative allocation strategies.

OPUC Data Request 52

Boardman to Hemingway – Refer to Figure 8.3 of the 2025 IRP. Please explain which load pockets PacifiCorp still expects to be served by B2H, and which ones cannot be served with B2H any longer. Please identify which specific transmission rights presented in the figure PacifiCorp would need to redirect to serve identified load pockets.

Response to OPUC Data Request 52

In PacifiCorp's 2025 Integrated Resource Plan (IRP), the Boardman-to-Hemingway (B2H) transmission line does not have any incremental west-to-east transfer capability that can be used to facilitate serving west-side load that is included in the 2025 IRP load forecast. The B2H transmission line is currently capable of serving potential new large load, that is not in the 2025 IRP load forecast, generally represented by the Longhorn load bubble as depicted in Figure 8.3 of the 2025 IRP. PacifiCorp continues to work with the new large load customer on a service agreement that captures incremental resource and transmission costs triggered by the new load, which includes the B2H transmission line.

In PacifiCorp's 2021 IRP, PacifiCorp expected to redirect certain long-term firm (LTF) transmission rights on the Bonneville Power Administration (BPA) system to have a point of receipt at the Longhorn substation and points of delivery on the west side of PacifiCorp's transmission system at Alvey, Albany, Santiam, McNary and Pendleton. These points of delivery (POD) are included in the Willamette Valley, Southern Oregon, and Walla Walla load bubbles shown in Figure 8.3 of PacifiCorp's 2021 IRP.

In the fall of 2022, BPA notified PacifiCorp that the redirect requests mentioned above would need to be studied in the BPA cluster study process. At that time, BPA had already started its 2023 cluster study process. Consequently, PacifiCorp anticipated that the requests would be studied in the 2024 cluster study process. The 2024 cluster study process was never started and was ultimately cancelled in July 2023. In June 2024, BPA distributed a notice that its 2025 cluster study process would begin in June 2025. The 2025 cluster study process was never started. In February 2025, BPA distributed a notice that its cluster study process had been paused and that it was considering transmission planning reforms. The redirect requests remain in study status.

PacifiCorp's IRPs are publicly available and can be accessed by using the following website link:

Integrated Resource Plan

OPUC Data Request 80

Jurisdictional Modeling – Please provide an explanation, with a written equation and example, for how incremental additions are allocated to each jurisdiction in the Preferred Portfolio when all three jurisdictional portfolios select a non-zero quantity of the same resource in the same year.

Response to OPUC Data Request 80

For a narrative description and numerical example of PacifiCorp's integration process used to develop final integrated portfolios from initial jurisdictional portfolios, please refer to Chapter 8 (Modeling and Portfolio Evaluation) of PacifiCorp's 2025 Integrated Resource Plan (IRP), Volume I (pages 210-211).

Given concerns related to the deliverability of resources to the state whose policy necessitated the resource addition, the selection of proxy resources on the West was determined jointly by the Oregon and Washington jurisdictional portfolios, and the selection of proxy resources on the East was determined by the initial jurisdictional UIWC portfolio. For proxy resources selected in Oregon and Washington, PacifiCorp assumed a fixed share of 75 percent and 25 percent respectively, excepting only resources identified as necessary for achieving compliance with a particular state's needs. Oregon and Washington were not eligible to share in proxy resources selected outside of Oregon and Washington. A numerical example where both Oregon and Washington select a non-zero quantity of the same resource in the same year is given in Table 8.6 (Portfolio Integration Resource Example) of PacifiCorp's 2025 IRP, Volume I. A detailed breakdown of the 2025 IRP preferred portfolio integration is provided in confidential work paper: 25IRP WP 03-31 Filing (Confidential).1/Model Reports/Integration/CONF_Max of Units Base MN.xlsx.

OPUC Data Request 82

Jurisdictional Modeling – For each year, please provide the MW allocation of each incremental resource addition in the Preferred Portfolio to each jurisdiction.

Response to OPUC Data Request 82

Please refer to Tables 9.2-9.4 in Chapter 9 of PacifiCorp's 2025 Integrated Resource Plan (IRP) which present the jurisdictional shares of incremental resource additions by resource type and year from the 2025 IRP preferred portfolio. Note that for the purposes of informing procurement processes, a given resource selection may represent one or more actual projects, and the location is similarly considered proxy.

A detailed breakdown of the incremental resource additions allocated to each jurisdiction in the 2025 IRP preferred portfolio is provided in confidential work paper: 25IRP WP 03-31 Filing (Confidential).1/Model Reports/Integration/CONF_Max of Units Base MN.xlsx. Specifically, refer to tab "Max Gen Units", columns BP:BR and tab "Max Bat Units", columns BH:BJ.

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of PacifiCorp's 2025 Integrated Resource Plan	Docket No. 25-035-22

CERTIFICATE OF SERVICE

I certify that on August 26, 2025, a true and correct copy of the foregoing Sierra Club's Opening Comments on PacifiCorp's 2025 Integrated Resource Plan was served upon the following as indicated below:

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