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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

INITIAL COMMENTS OF WESTERN RESOURCE ADVOCATES

September 25, 2025

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Western Resource Advocates (WRA) appreciates the opportunity to provide comments to the Public Service Commission of Utah (PSC or Commission) pursuant to the April 16, 2025, Scheduling Order, Notice of Technical Conference, and Notice of Public Witness Hearing regarding PacifiCorp's 2025 Integrated Resource Plan (IRP).

I. INTRODUCTION

The 2025 IRP breaks significantly from past IRPs. Rather than planning for continued single system operations, the 2025 IRP produced a plan for a bifurcated system. This is a fundamental change from the past and appears to be a component of PacifiCorp's corporate strategy, expressed in its recent 2026 Protocol filings, to "unwind" past planning and operational decisions in order to meet the differing energy policies and compliance requirements among the six states in which PacifiCorp provides electric service.[1] Indeed, by planning to meet the needs of the east and west sides of its system separately, the 2025 IRP employs an assumed cost allocation method that has yet to be fully developed, vetted, agreed upon, or approved.

The development of the 2025 IRP incorporates innovative modeling, and the IRP Team should be commended for its creativity and Herculean effort in producing a plan, under strict time constraints, that is consistent with corporate objectives while attempting to meet the competing energy policies and regulatory directives of its states. WRA recognizes these challenges and appreciates the difficulties faced by the Company in addressing the planning needs of its six states simultaneously.

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[1] *In the Matter of the Application of Rocky Mountain Power for Approval of the 2026 Inter-Jurisdictional Cost Allocation Protocol*, Docket No. 25-035-47, Rocky Mountain Power's Application and Testimony (filed August 5, 2025) [hereinafter 2026 Protocol].

However, despite our appreciation of these realities, WRA recommends that the PSC not acknowledge the 2025 IRP for the following reasons.

- From the outset, the IRP public input process did not build into its structure the opportunity for stakeholders to meaningfully review model results or provide input into the development of the Preferred Portfolio, essential components of the public input process, and PacifiCorp did not respond to public feedback or to Commission direction to adjust its proposed schedule when it had the time to do so.
- The 2025 IRP produced a plan for a bifurcated system that is not well documented and did not include a single-system, least-cost, least-risk plan against which to evaluate the costs of separately planning for the east and west sides of its system.
- The Preferred Portfolio is suboptimal. Bifurcated planning necessarily results in a suboptimal portfolio, and PacifiCorp did not select from the potential Integrated Resource Portfolios the least-cost, least-risk portfolio.
- The Preferred Portfolio may be overly dependent on market transactions, thereby continuing to expose customers to unacceptable levels of net power cost risk across the planning horizon.

Our comments are organized as follows. In Section II.A, we show that the public input process for the 2025 IRP did not comply with past Commission directives requiring "consultation"[2] and "ample opportunity for public input and information exchange,"[3] and we explain why our comments focus on the "Final IRP" rather than the "Utah IRP." In Section II.B, we discuss PacifiCorp's failure to vet or explain its construction of a geographically bifurcated resource plan and the lack of a single-system portfolio against which to evaluate the Company's Preferred Portfolio. In Section II.C, we show that bifurcated planning results in a suboptimal portfolio that misidentifies transmission need. In section II.D, we show that the Company's

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[2] *In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp*, Docket No. 90-2035-01, Report and Order on Standards and Guidelines (issued June 18, 1992) at 36 [hereinafter Guidelines].

[3] *Id.*

Preferred Portfolio is neither least cost nor least risk based on the Company's cost and risk analysis. Despite its analysis, the Company selected its Preferred Portfolio based on novel and unreliable "end effects" modeling, which we discuss in Section E. In Section F, we show that the 2025 IRP shifts costs and risks to customers. Finally, In Section III, for all of the reasons discussed in Section II, we recommend that the Commission not use the 2025 IRP as the basis of avoided cost pricing.

II. THE 2025 IRP CANNOT BE ACKNOWLEDGED

A. The 2025 IRP Public Input Process Does Not Comply with Guideline 3 or Past Commission Direction Regarding the Interpretation of Guideline 3.

The 1993 Order on Standards and Guidelines (Guidelines) for integrated resource planning sets forth the requirements for Commission acknowledgment of an IRP.[4] Guideline 3 requires that the IRP be "developed in consultation with the Commission, its staff, the Division of Public Utilities, the [Office] of Consumer Services, appropriate Utah state agencies and interested parties."[5] It requires that PacifiCorp "provide ample opportunity for public input and

[4] *Id.*

[5] *Id.*

information exchange during the development of its Plan."[6] Through its past orders, the Commission has provided guidance regarding the interpretation of Guideline 3.[7]

The 2025 IRP does not comply with Guideline 3. In conducting its 2025 IRP public input process, PacifiCorp disregarded past Commission orders regarding the meaning of Guideline 3 as well as extensive Utah stakeholder comments regarding the deficiencies of the 2023 IRP public input process.

1. ***The 2025 IRP Public Input Process Repeats the Deficiencies of the 2023 IRP Public Input Process.***

PacifiCorp held its first public input meeting of the 2025 IRP planning cycle on January 25, 2024, roughly three months prior to receiving the Commission's April 17, 2024, Order on the 2023 IRP.[8] The appendix to the accompanying slide deck for the January public input meeting included a proposed schedule with agenda items for the 2025 IRP series of upcoming public input meetings.[9] The schedule repeated the approach taken with the 2023 IRP and did not

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[6] *Id.*

[7] In its order declining to acknowledge the 2021 IRP, the Commission emphasized the importance of public input and information exchange during the IRP's development and reiterated statements it had made in its order acknowledging the 2017 IRP. *See PacifiCorp's 2021 Integrated Resource Plan*, Docket No. 21-035- 09, Order (issued June 2, 2022) at 9 ("The PSC has been clear: 'We view the IRP process as one in which parties are able to provide input and receive information on relevant issues, inputs, models, and **results**…Therefore the opportunity for all parties to examine and provide information during the IRP['s] development, rather than after the fact, is an important aspect of the IRP process.'" (emphasis added)); *see also PacifiCorp's 2017 Integrated Resource Plan,* Docket No. 17-035-16, Report and Order (issued March 2, 2018) at 7-8.

[8] *PacifiCorp's 2023 Integrated Resource Plan,* Docket No. 23-035-10, Order (issued April 17, 2024) at 30 [hereinafter 2023 IRP April Order].

[9] PacifiCorp, *2025 IRP Public Input Meeting* (January 25, 2024), at slide 34, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/PacifiCorp_2025_IRP_PIM_Jan_25_2024.pdf.

include a review of modeling results or consideration of the selection of the Preferred Portfolio ahead of filing a draft IRP in January of 2025.

As proposed, this schedule ignored past Commission direction regarding the meaning of Guideline 3, and it disregarded the extensive stakeholder comments provided to the Commission on the deficiencies with the 2023 IRP stakeholder process, which had identified a lack of opportunity to review results and provide feedback on the selection of the Preferred Portfolio as key concerns with the 2023 IRP public input process. The proposed schedule repeated these deficiencies but included a timely IRP filing.

WRA submitted a feedback form addressing the schedule on February 28, 2024, attached as WRA Exhibit 1. Our feedback encouraged PacifiCorp "**to revise the proposed schedule to include a review of modeling results well ahead of any IRP filing whether draft or final, with the opportunity to provide feedback, make requests, and review any new results within the context of a public input meeting**."[10] We further reminded the Company that "the process for selecting the Preferred Portfolio should be publicly discussed."[11] Company management initiated a private discussion the following week, but PacifiCorp did not alter its proposed schedule.[12]

[10] WRA Exhibit 1, at 3 (emphasis in original).

[11] *Id.*

[12] The Company did not provide a written response to our feedback, and, on August 27, 2025, while preparing our comments, we became aware that our feedback form had not been publicly posted and had not been included in Appendix M of Volume II. We contacted PacifiCorp, and it is now available on the website.

On April 17, 2024, the Commission issued its 2023 IRP Order with extensive commentary regarding the deficiencies of the public input process that mirrored the feedback WRA had provided to PacifiCorp six weeks earlier.

> Our direction on the interpretation of Guideline 3 has been clear. The opportunity for stakeholders to examine and provide information during the IRP development, rather than after the fact, is an important aspect of the process. The IRP is to be developed in consultation with stakeholders who must have ample opportunity for meaningful feedback and information exchange during the development of the plan and at each stage of the process. In this docket, PacifiCorp did not share its modeling results and the Preferred Portfolio, two of the most critical aspects of the IRP, with stakeholders until after it filed its preliminary IRP on April 3, 2023. This is the first time that PacifiCorp has not provided modeling result and Preferred Portfolio selections before making its IRP public…. [**P]arties did not collaborate on the most consequential aspects of the IRP – modeling results and the Preferred Portfolios – <u>before the preliminary IRP became public</u>**.… As we have said before, PacifiCorp must provide parties ample opportunity to review, analyze, and provide meaningful input at all stages of the IRP process. Moreover, this must be done with adequate time for PacifiCorp to evaluate and, as appropriate, apply that input before filing any IRP, whether preliminary or final.[13]

The Commission's direction could not have been more straightforward, and yet PacifiCorp still made no attempt to adjust its schedule to give stakeholders the opportunity to collaborate on "the most consequential aspect of the IRP – modeling results and the Preferred Portfolio[]."[14] The Company appears to have held to the view that producing a draft IRP in January, as required by the Washington Utilities and Transportation Commission, should also meet the public input requirements established by the Utah Commission, despite clear language in the Order that it would not.

[13] 2023 IRP April Order, *supra* note 8, at 30-31 (emphasis added) (citations omitted).

[14] *Id.* at 31.

A flurry of process activity followed issuance of the Commission's April 2024 Order which ultimately resulted in a September 2024 Order that approved the Company's August 2024 request to use the schedule it established in January.[15] However, this September Order, issued nine months after the Company first established its schedule, does not obviate the Company's responsibility to have incorporated past Commission direction in the initial setting of its schedule or to have modified its schedule following receipt of the April 2024 Order. The Company had full knowledge of past orders when it failed to incorporate Utah requirements into the schedule it set in January of 2024, or to modify its schedule when WRA submitted its feedback form in February of 2024; and it still did not modify the schedule following the issuance of the 2023 IRP Order in April of 2024. Not until the Commission issued a Process Order in July of 2024[16] that required PacifiCorp to meet firm dates and directed the Company to notify the Commission if it could not comply did PacifiCorp respond. On August 8, 2024, PacifiCorp filed a Notice stating that it could not comply with the timelines set forth by the Commission, and it requested that it

[15] In addition to the extensive commentary regarding the meaning of Guideline 4 included in the 2023 IRP April Order, the Order directed the Division of Public Utilities and invited the Office of Consumer Services and other IRP participants to file further comments regarding process. Parties filed on May 30, 2024. The Commission issued a Process Order on July 11, 2024, directing certain process changes for the 2025 and 2027 IRPs, and it directed PacifiCorp to notify the PSC if it was unable to comply. On August 8, 2025, PacifiCorp provided notice that it could not "meaningfully comply with the requirements in the Post IRP Order" for the 2025 IRP cycle. On August 21, 2024, the Commission issued an Order suspending the deadlines in the 2023 IRP April Order and requesting additional comments, which parties filed on September 4, 2024. On September 24, 2024, the Commission issued the Final Order in Docket No. 23-035-10. The Final Order approved PacifiCorp's request to use its previously established schedule for the 2025 IRP, but denied a further request to incorporate late-breaking changes.

[16] *PacifiCorp's 2023 Integrated Resource Plan*, Docket No. 23-035-10, Order (issued July 11, 2024) [hereinafter Process Order].

be allowed to follow its established schedule.[17] Indeed, by the time PacifiCorp responded in August, time to modify the schedule had run out, and in its September Order, the Commission approved PacifiCorp's request.[18]

By not incorporating an opportunity into the public input schedule to review modeling results and provide input on the selection of the Preferred Portfolio, the 2025 IRP public input process repeated the deficiencies of the 2023 IRP public input process, but with apparent intention. PacifiCorp did not provide an opportunity for collaboration on the most essential elements of the IRP planning process during the development of the Plan, and, thus, the 2025 IRP does not comply with Guideline 3.

2. *The "Final IRP" Rather than the "Utah IRP" Should be Used to Evaluate Compliance with the Guidelines.*

In the same August 2024 Notice informing the Commission that it could not comply with the Commission's July Process Order, PacifiCorp requested that it be allowed "to update the 2025 IRP for any material changes in the planning environment that may occur prior to the submission of the 2025 IRP, as long as any such updates do not delay the filing of the 2025

[17] *PacifiCorp's Notice to the Public Service Commission,* Docket No. 23-035-10 (filed August 8, 2024) at 7 [hereinafter *Company's August 2024 Notice*] ("PacifiCorp respectfully requests that the Commission allow PacifiCorp to continue with the established schedule.").

[18] *PacifiCorp's 2023 Integrated Resource Plan,* Docket No. 23-035-10, Order (issued September 24, 2024) at 10 [hereinafter 2023 IRP September Order] ("For the 2024 IRP cycle, PacifiCorp need not adhere to the deadlines set in the IRP Process Order, instead, PacifiCorp shall adhere to the schedule outlined in PacifiCorp's Notice.").

IRP."[19] In its September Order, the Commission denied this request and set a "Data Lockdown Date" consistent with the expected filing of the Draft IRP.[20]

The Draft IRP that PacifiCorp filed on December 31, 2024, was far from complete, and following its filing, PacifiCorp made fairly extensive changes to the IRP document that included errata corrections and corrections to the supply-side resources tables as well as other clarifications.[21] However in addition to these document corrections, PacifiCorp made other significant changes that altered modeling results.[22] WRA Exhibit 2 reproduces two slides from the January 22-23, 2025, IRP public input meeting presentation and three slides from the February 27, 2025, IRP public input meeting presentation that identify changes that affect modeling results. The slides from the January presentation include a note alerting Utah Stakeholders that the IRP filed in Utah would not contain "the corrections and updates listed on the slide."

Slide 15 from the January presentation, "Post-Draft Corrections," includes changes that affect relative resource costs for solar, thermal, nuclear, geothermal, pumped hydro storage, and hydrogen peaker resources. Slide 17 from the January presentation, "Refinements," identifies modeling changes that include reporting stochastic risk, removing all new (uncontracted) data

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[19] *Company's August 2024 Notice*, *supra* note 17, at 12.

[20] 2023 IRP September Order, *supra* note 18, at 5 ("Accordingly, for the 2025 IRP cycle, the PSC establishes January 1, 2025, as the Data Lockdown Date.").

[21] PacifiCorp, *2025 IRP Public Input Meeting* (January 22-23, 2025), at slides 7-13, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/January_22-23_2025_IRP_Public_Input_Meeting.pdf.

[22] *Id.* at slides 14-17; *see also* PacifiCorp, *2025 IRP Public Input Meeting* (February 27, 2025) at slides 5-9, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/February_27_2025_IRP_Public_Input_Meeting.pdf.

center load from the load forecast, updating thermal forced outage rates, and changing the online date of the Terra Power nuclear facility from 2030 to 2032, plus others. These are not minor changes.

However, the most significant shift in planning was signaled during the February 2025 public input meeting, the last public input meeting ahead of the Final IRP filing. PacifiCorp identified the siting of resources necessary to meet the environmental compliance requirements of Washington and Oregon in states other than Washington and Oregon as potentially impeding its ability to comply with these states' requirements,[23] and, in the final minutes of the last day of the meeting series (after the meeting was officially over), under the agenda topic "Stakeholder Feedback," PacifiCorp conveyed its intention to site compliance resources for Oregon and Washington on the west side.[24] One month later, on March 31, 2025, PacifiCorp filed the Final 2025 IRP, an IRP that plans for the west and east sides separately. This is an extraordinary change that was not vetted through the public input process.

To address the directive in the September Order that no modeling changes be incorporated past January 1, 2025[25] PacifiCorp included in Volume 1 of the 2025 IRP a Utah

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[23] *See* slide 5, bullet 4 of the February 27, 2025, IRP Public Input Meeting presentation, included in WRA Exhibit 2; *see also* PacifiCorp, *2025 IRP Public Input Meeting* (February 27, 2025), at approximately 13:20 of Part 2 (Meeting Recording), https://www.youtube.com/watch?v=1LXf9kzwZIs.

[24] *See* slide 39, bullet 3 of the February 27, 2025, IRP Public Input Meeting presentation, included in WRA Exhibit 2 ("[T]he final IRP will demonstrate compliance for Oregon and Washington using new resources on the West."); *see also* PacifiCorp, *2025 IRP Public Input Meeting* (February 27, 2025), at approximately 2:11 of Part 1 (Meeting Recording), https://www.youtube.com/watch?v=hkrlv2g_EBc.

[25] 2023 IRP September Order, *supra* note 18, at 5-6 ("PacifiCorp shall not make changes to the modeling assumptions used to produce the modeling results it intends to disclose on January 1, 2025. . . Any new or changing model inputs that cannot be incorporated into the modeling results disclosed January 1, 2025, must wait to be incorporated into PacifiCorp's 2025 IRP Update.").

IRP as Chapters 11, 12 and 13: Utah Executive Summary, Utah Modeling Results, and Utah Action Plan. These chapters coincide with Chapters 1, 9, and 10 of the Final IRP.

WRA appreciates the Commission's clear direction to PacifiCorp and PacifiCorp's adherence to this directive; however, given the extensive and extraordinary changes between the Draft IRP and the Final IRP, our analysis and comments focus on the Final IRP.

B. The Decision to Plan Separately for the West and East sides of the PacifiCorp System was not Publicly Vetted, and PacifiCorp Should Have Provided a System View Against Which the Costs of Bifurcated Planning Can be Compared.

The 2025 IRP breaks from past IRPs by separately planning for the west and east sides of the PacifiCorp system and by assigning fixed shares of existing and proxy resource to one of three jurisdictions: "Oregon Jurisdiction," "Washington Jurisdiction," and the "UIWC Jurisdiction" comprised of the remaining four states in which PacifiCorp serves: Utah, Idaho, Wyoming and California. This approach is consistent with PacifiCorp's corporate objective to ensure future full-cost recovery through a fixed-resource-assignment cost-allocation protocol,[26] but it is not consistent with regulatory principles or currently approved cost allocation protocols. Therefore, PacifiCorp should have developed an optimized system plan as a cost comparator.

1. *Bifurcated Planning Required a Multi-Step Process and the Exercise of Ad Hoc Decision-Making to Ensure Portfolios Could Meet Resource Adequacy and Environmental Compliance Obligations.*

In developing the bifurcated plan PacifiCorp undertook a multi-step process. For each of the three jurisdictions, PacifiCorp first developed unique portfolios for five price-policy

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[26] *See e.g. Direct Testimony of Cindy A. Crane for Rocky Mountain Power,* Docket No. 25-035-47 (filed August 5, 2025) at lines 74-83.

scenarios[27] and ten alternative futures[28] using the combined capabilities of the optimization models within Plexos.[29] These initial forty-five[30] "Full Jurisdictional Portfolios" were developed using a similar, but refined, approach to the modeling of the 2023 IRP that produced a single-system plan.[31] Each resulted from modeling the PacifiCorp system assuming the compliance requirements of the jurisdiction considered.[32] For all three jurisdictions, these optimized Full Jurisdictional Portfolios include proxy resources located on both the west-side and east-side of the PacifiCorp system.[33]

In the next step, PacifiCorp combined the resource selections from the three jurisdictions into fifteen "Integrated Portfolios." In integrating the Full Jurisdictional Portfolios, PacifiCorp limited the location of proxy resources,[34] resulting in a bifurcated plan. Proxy resources located on the west-side of the PacifiCorp system were included only if they had been selected in either Washington's or Oregon's Full Jurisdictional simulations, and proxy resources located on the

[27] 2025 Integrated Resource Plan, Volume I, Docket No. 25-035-22 (filed March 31, 2025) at 207 [hereinafter 2025 IRP].

[28] *Id.*, Volume I, at 208, Table 8.5.

[29] *Id.*, Volume I, at 206.

[30] Fifteen portfolios multiplied by three jurisdictions.

[31] Full Jurisdictional Portfolios are developed in incremental steps using both the PLEXOS long- and short-term models. The incremental steps include an adjustment for the granularity between the models, modeled as an addition to cost, and a reliability adjustment, modeled as an addition to load.

[32] As we discuss further below, WRAP compliance was limited to the jurisdiction under consideration and was not applied to the full system. *See* WRA Exhibit 3, Response to WRA Data Requests 5.1(a) and 4.6(a). Therefore, the Full Jurisdictional Portfolios are underbuilt resulting in ad hoc additions in the integration step. This is discussed further in Section II.F.1 below.

[33] *See* WRA Exhibit 3, Response to WRA Data Request 6.1.

[34] 2025 IRP, *supra* note 27, Volume I, at 211.

east-side were included only if they had been selected in UIWC's Full Jurisdictional simulations.[35] So, east-side resources identified as optimally serving the system under Oregon or Washington compliance constraints (i.e. environmental regulations plus resource adequacy) were excluded; similarly, west-side resources identified as optimally serving the system under the UIWC constraint (i.e. resource adequacy only) were excluded from the Integrated Portfolios.

PacifiCorp next evaluated whether these initial Integrated Portfolios had sufficient energy and capacity compliance requirements. This step required assigning shares of existing resources as well as shares of proxy resources to the three jurisdictions. Existing resource shares were allocated using the "system generation" (SG) cost allocation factor for the year under consideration (with certain restrictions).[36] Existing coal-fired resource shares were removed from Washington's allocation at the end of 2025[37] and from Oregon's at the end of 2029[38] and were apparently reallocated to the UIWC jurisdiction. New east-side proxy resources were fully allocated to the UIWC jurisdiction, and new west-side proxy resources were allocated 75% to Oregon and 25% to Washington.[39]

[35] *Id.*

[36] *See* WRA Exhibit 3, Response to WRA Data Request 4.1.

[37] *See* WRA Exhibit 3, Response to WRA Data Request 2.2.

[38] *See* WRA Exhibit 3, Response to WRA Data Request 2.3.

[39] *See* WRA Exhibit 3, Response to WRA Data Request 4.1(e).

PacifiCorp then remedied the resulting compliance shortfalls by adjusting shares, adding resources,[40] and identifying transmission needed to support the selected resource additions.[41] Remedying shortfalls appears to have required considerable ad hoc decision-making[42] as well as increased cost, since cost-effective renewable resources selected on the east-side to serve Washington's and Oregon's compliance needs were necessarily relocated to less favorable sites. Finally, from these fifteen Integrated Portfolios, PacifiCorp selected a Preferred Portfolio.[43]

2. *The Development of a Bifurcated Plan was not Vetted, Well Explained, or Well Documented.*

The introduction of Jurisdictional Portfolios and Jurisdictional Shares is new to this IRP, and the approach was never vetted during the many hours of public input meetings that were held ahead of the Draft IRP filing.[44] Stakeholders first learned that PacifiCorp intended to employ a jurisdictional methodology by reviewing the Draft IRP, and the first opportunity stakeholders had to discuss it with PacifiCorp occurred during the January 2025 public input meeting following the draft filing.

However, the integration step described in the Draft IRP and discussed at the January 2025 meeting was not the approach used in preparing the Final IRP. The integration step

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[40] *Id.*

[41] *See* WRA Exhibit 4, Response to Sierra Club Data Request 2.2(b) ("This [] model run endogenously selected proxy transmission lines to serve these resources.").

[42] *See* WRA Exhibit 3, Response to WRA Data Request 4.2(c) ("PacifiCorp determined the size, location, and technology of the additional proxy resources by prioritizing the cheapest resource additions where surplus interconnection was available.")

[43] We discuss the suboptimality of the portfolio selected in Section II.D.

[44] *See* 2025 IRP, *supra* note 27, Volume II, at 85-86 for meeting agendas.

described in January 2025 did not geographically limit proxy resource locations, so the IRP remained a system plan. PacifiCorp apparently made the decision to bifurcate its planning by locating proxy resources needed for Washington and Oregon compliance on the west side and limiting UIWC resource shares to the east side sometime after the January 2025 public input meeting.

While the development of Full Jurisdictional Portfolios is fairly well documented, the integration process and the determination of Jurisdictional Shares are not. Despite the voluminous materials presented as part of the 2025 IRP,[45] less than a page of text addresses the development of Integrated Portfolios,[46] and WRA could not find an explanation for how Jurisdictional Shares were determined.[47] Thus, our current understanding stems primarily from PacifiCorp's responses to discovery questions submitted following the filing of the Final 2025 IRP. WRA Exhibit 3 provides PacifiCorp's responses to WRA's full set of data requests. WRA Exhibit 4 provides PacifiCorp's response to Sierra Club 2.2.

3. *Single System Planning, Operation, and Cost Allocation Based on Current Cost Causation are Foundational Commission Principles.*

Since the merger of Utah Power and Light (UP&L) with PacifiCorp in 1989, the benefits of single system planning and operations, and cost allocation based on current cost causation of a

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[45] Volume I is comprised of 403 pages, and Volume II is comprised of 536 pages.

[46] 2025 IRP, *supra* note 27, Volume I, at 210-211.

[47] Jurisdictional share tables are introduced and presented in Volume I. *See id.* at 220-222, Tables 9.2-9.4.

single system, have been foundational principles to the Commission's regulation of PacifiCorp.[48] Indeed, the planning and operational benefits resulting from merging the diversity of loads and resources of the two systems and the transmission reach that could be achieved through the merger were significant drivers behind the utilities' desire to merge,[49] and these benefits were the basis of the merger approvals garnered from the seven state utility commissions that had authority over the merging utilities.[50] In considering the merger application, the Utah Commission found benefits in projected reductions in net power costs, but even greater benefits from potential capacity savings.[51]

A decade later, maintaining the benefits of single system planning and operation were key considerations in Utah's willingness to participate in the initial "multi-state process" (MSP) stemming from Oregon's deregulation legislation in 1998 and to agree to pay more than a "Rolled-In" share of system costs, having adopted Rolled-In as the principle-based cost

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[48] *See 1990 Phase I General Rate Case,* Docket No. 90-035-06, Report and Order (issued December 7, 1990) at 8-16; *Adoption of An Interjurisdictional Allocation Method for PacifiCorp*, Docket No. 97-035-04, Report and Order (issued April 16, 1998) at 1-7.

[49] PacifiCorp was winter peaking, and because of its strong hydro resource that included the Mid-Columbia contracts, it had sufficient capacity but had become energy short. UP&L was summer peaking and energy long with excess coal capacity and an extensive transmission system. The merger created a utility with surplus generation and a vast transmission system.

[50] Seven state commissions approved the 1989 merger: California, Idaho, Montana, Oregon, Utah, Washington and Wyoming.

[51] *Application of Utah Power and Light Company and PC/UP&L Merging Corp. (to be renamed PacifiCorp) for an Order Authorizing the Merger of Utah Power & Light Company and PacifiCorp into PC/UP&L Merging Corp. Authorizing the Issuance of Securities, Adoption of Tariffs and Transfer of Certificates of Public Convenience and Necessity and Authorities in Connection Therewith*, Docket No. 87-035-27, Report & Order (issued September 28, 1988).

allocation method consistent with current cost causation.[52] This principled cost allocation method (referred to as Rolled-In) was reiterated in all further Utah Commission orders addressing interjurisdictional allocation methods, including the most recently approved cost allocation protocol, the 2020 Protocol.[53] While the 2020 Protocol anticipated fixing resource

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[52] *In the Matter of the Application of PacifiCorp for an Investigation of Inter-jurisdictional Issues,* Docket No. 02-035-04, Report and Order (issued December 14, 2004), at Section V. Background, page 17 of PDF (formal page numbers unavailable) [hereinafter 2004 Revised Protocol Report & Order].

[53] Approving the use of the 2010 Protocol method in a February 2012 Order, the Commission incorporated its procedural history and detailed background of inter-jurisdictional cost allocation from the 2004 Revised Protocol Report & Order (*Id.*) by reference, highlighting that "integrated system costs" were the basis of the 1989 merger of UP&L and Pacific Power, and reiterating: "[W]e find the principle-based, Rolled-In method and its current, rather than historical, cost-causation rationale, for determining Utah's revenue requirement is in the public interest." *In the Matter of the Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues,* Docket No. 02-035-04, Report and Order (issued February 3, 2012) at 18-19.

Approving the use of the 2017 Protocol method in a June 2016, Order, the Commission described "Rolled-In" this way:

> This Commission has unwaveringly sought over the years to implement a method that treats the utility system as a whole and apportions costs and revenues among PacifiCorp's jurisdictions using a cost-of-service analysis. In other words, the customers in each jurisdiction should bear the proportion of the total utility system costs those customers cause the utility system to incur. The Commission has historically referred to this as the 'Rolled-In Method' and deemed it the most suitable means for fairly apportioning costs among the jurisdictions.

In the Matter of the Application of Rocky Mountain Power for Approval of the 2017 Protocol, Docket No. 15-035-86, Order (issued June 23, 2016) at 3; *see also* additional direction at 9 ("[T]his Commission has never wavered in its conviction that a Rolled-In Method represents the most equitable manner for allocating PacifiCorp's costs.").

In a March 2017 Order the Commission stated:

shares, it punted the development of an appropriate methodology to future negotiations.[54] When MSP discussions between parties apparently stalled, PacifiCorp discontinued negotiations and informed the Commission that the Company would file a new cost-allocation methodology ahead of the December 31, 2025, expiration of the 2020 Protocol.[55] On August 5, 2025, PacifiCorp filed the "2026 Protocol."[56] The proposal fixes resource shares for Washington, but leaves the costs for the remainder of the system dynamically allocated, although PacifiCorp anticipates a

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> First and foremost, we have not deviated from our numerous prior declarations that a Rolled-In method is the appropriate cost allocation mechanism. PacifiCorp has been operating as a single, integrated whole on a least cost basis for many years. Utah ratepayers long ago compensated pre-merger Pacific Power customers for any cost advantage they enjoyed prior to the 1989 merger through the extensive merger fairness premiums (and other functionally equivalent payments) Utah ratepayers have made over nearly three decades.

In the Matter of the Application of Rocky Mountain Power to Extend the 2017 Protocol through December 31, 2019, Docket No. 17-035-06, Order (issued March 23, 2017) at 8.

Approving the use of the 2020 Protocol method in an April 2020 Order, the Commission concluded:

> PacifiCorp must recover its costs in a manner sufficient to viably operate as a fully merged and integrated system, to the benefit of all Parties …. We also recognize that during the Interim Period the 2020 Protocol implements a rolled-in method, which we have approved and adopted.

Application of Rocky Mountain Power for Approval of the 2020 Inter-Jurisdictional Cost Allocation Agreement, Docket No. 19-035-42, Order Approving 2020 Protocol (issued April 15, 2020) at 8-9.

[54] *Application of Rocky Mountain Power for Approval of the 2020 Inter-Jurisdictional Cost Allocation Agreement, Docket No. 19-035-42*, Exhibit RMP_JRS-1, 2020 Protocol (filed December 3, 2019) at Section 6.1.

[55] *In the Matter of the Application of Rocky Mountain Power to Extend the 2020 Protocol through December 31, 2025,* Docket No. 23-035-20, Rocky Mountain Power's Notice (filed July 11, 2024) ("It has become apparent to the Company that the complexities of achieving a negotiated agreement with sufficient time to seek required approvals is unlikely.").

[56] 2026 Protocol, *supra* note 1.

Phase 2 filing in which it proposes further fixing of resource shares.[57] However this method has yet to be developed, and the current application has yet to be approved.

Thus, while the 2020 Protocol anticipated fixing resource shares, and the recently filed 2026 Protocol proposes a fixed resource allocation for Washington while anticipating a second phase that further fixes resource shares, Rolled-In—i.e. cost allocation consistent with integrated system planning and operations—remains the principle for evaluating the justness and reasonableness of interjurisdictional cost allocation.

4. *The IRP Must Include Single System Analysis to Comply with the Commission's Foundational Regulatory Principles and the Currently Approved Cost Allocation Methodology.*

WRA supports PacifiCorp's goal to develop a plan that is compliant with state specific requirements. Additionally, we do not object to identifying resource shares for the purposes of demonstrating compliance with Oregon's House Bill 2021 or Washington States's Clean Energy Transformation Act. However, single system planning and operation, and cost allocation consistent with single system planning and operation, remain the standard in Utah against which all deviations must be evaluated. This requires the development of a system plan against which the costs of planning separately for the west and east sides can be compared. The 2025 IRP does not provide this comparison.

For the 2027 IRP, WRA recommends the Commission encourage PacifiCorp to prepare a system plan using a methodology that is vetted through the public input process. The

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[57] *See Direct Testimony of Rick T. Link for Rocky Mountain Power*, Docket No. 25-035-47 (filed August 5, 2025) at lines 39-75.

jurisdictional approach including the integration process presented in the Draft IRP is a potential candidate for producing a system-optimized IRP.[58] Alternatively, for future IRPs, Utah could consider using the UIWC Full Jurisdictional Portfolio as a comparator. However, for this IRP, the UIWC Full Jurisdictional Portfolio cannot be used, because, as we discuss in Section II.F.1 below, Full Jurisdictional Portfolios were modeled assuming that resource adequacy requirements pertained to jurisdictional load only, not to system load.[59] Therefore, none of the forty-five Full Jurisdictional Portfolios are WRAP compliant.

C. Planning to Meet West and East Side Compliance Requirements Separately Necessarily Results in a Suboptimal Resource Plan that Misidentifies Transmission Buildout.

PacifiCorp's decision to unwind past planning and operational decisions by planning separately for its east and west sides necessarily results in a suboptimal resource plan. Not only does separate planning result in a more costly generation portfolio, it misidentifies transmission additions, thereby deepening the suboptimality of planning through time.

As explained above, in developing the fifteen Integrated Portfolios from which the Preferred Portfolio was selected, PacifiCorp replaced the optimally-selected, cost-effective, east-side renewable resources needed to meet Oregon and Washington's compliance requirements with west-side resources. These are necessarily more costly or they would have been selected by the model optimization in the first place. And, the identification of west-side replacement resources appears to have required ad hoc judgments. When WRA asked how PacifiCorp

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[58] *See PacifiCorp's 2023 Integrated Resource Plan*, RMP Attachment A – 2025 Draft IRP Volume I (filed December 31, 2024) at 202-203 [hereinafter Draft IRP].

[59] *See* WRA Exhibit 3, Response to WRA Data Request 4.6(a).

determined the "size, location, and technology" of the added resources, PacifiCorp responded that it prioritized "the cheapest resource additions where surplus interconnection was available."[60]

However, interconnection availability doesn't appear to have guaranteed deliverability. So, to ensure these hand-selected generation resources were deliverable to load, PacifiCorp used the capacity expansion function of PLEXOS to endogenously identify the transmission projects needed to deliver the selected west-side resources to west-side loads.[61]

For this IRP, PacifiCorp identified approximately 330 miles of new west-side transmission projects, plus a new substation.

- Roughly 85 miles[62] of new transmission from the Walla Walla substation near Walla Walla, Washington to the Wine Country substation near Sunnyside, Washington to come online between 2026 and 2036.[63]

- One-hundred twenty miles of new transmission from the Fry substation near Albany, Oregon to a new substation in Deschutes County, Oregon projected to come online in 2032.[64]

- Roughly 125 miles[65] of new transmission including lines from the Fry substation near Albany, Oregon and from the Dixonville substation near Roseburg, Oregon, each connecting to a substation near Lebanon, Oregon, projected to come online in 2036.[66]

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[60] See WRA Exhibit 3, Response to WRA Data Request 4.2(c).

[61] *See* WRA Exhibit 4, PacifiCorp response to Sierra Club 2.2(b).

[62] The distance is not provided in documentation. WRA estimated this using Google Maps.

[63] 2025 IRP, *supra* note 27, Volume I, at 79.

[64] *Id.*

[65] The distance is not provided in documentation. WRA estimated this using Google Maps.

[66] 2025 IRP, *supra* note 27, Volume I, at 79.

On the east side, PacifiCorp identified a series of upgrades between southern Utah and the Wasatch Front to come online between 2026 and 2036, and a second Gateway South line projected to come online in 2036.[67]

Notably absent is completion of the Gateway West segments which would increase the transfer capability between the east and west sides of the PacifiCorp system. As discussed during the July 22, Technical Conference, PacifiCorp Generation did not allow Gateway West to be selected by PLEXOS until 2037, claiming 2037 as the earliest online date provided by PacifiCorp Transmission.

Since Gateway West has been planned since 2007 when the Energy Gateway Transmission Expansion Plan was first announced,[68] the late online date is puzzling. To better understand the reasons behind its late timing, particularly since a second Gateway South line was selected in 2036, WRA submitted a data request asking a series of related questions including what remains to be completed before PacifiCorp can move Gateway West forward. PacifiCorp Transmission responded that the "outstanding tasks … will be scheduled to align with the planned in-service date as informed by the IRP."[69]

So, both sides of the functionally separated "PacifiCorp house" – Generation and Transmission – point to the other in providing the rationale for the late online date. Given these contradictions, it appears likely that corporate interests are driving the later timing of Gateway West. Instead of investments that further integrate the PacifiCorp system, provide the west-side

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[67] *Id.*

[68] *Id.,* Volume I, at 90.

[69] *See* WRA Exhibit 3, PacifiCorp response to WRA 4.8.

with greater access to low-cost renewable resources, and enhance the benefits of load and resource diversity for all customers, bifurcated planning results in bifurcated transmission additions that will increase system separation and grow more costly over time.

WRA again recommends that the Commission encourage PacifiCorp to develop an optimized single-system plan against which the costs of bifurcated planning can be compared. Sensitivities should be developed that test the potential benefits of alternative Gateway West online dates.

D. The Company Selected a Suboptimal Preferred Portfolio

To comply with Utah's IRP Standards and Guidelines, the Company is tasked with selecting as its Preferred Portfolio the set of resources that optimally balances cost and risk.[70] Rarely, if ever, does a single portfolio outperform all other candidate portfolios across *all* relevant rankings: cost (as measured by present value revenue requirement (PVRR)), risk (as measured by stochastic risk-adjusted PVRR), and environmental performance (as approximated by carbon dioxide (CO2) emissions). Like in prior IRP cycles, no candidate portfolio in the 2025 IRP ranked highest across all relevant metrics. The Company must carefully weigh tradeoffs to select the portfolio that delivers energy affordably, reliably, and responsibly.

In the 2025 IRP, several of the Integrated Portfolios performed well enough across all price-policy scenarios to warrant careful consideration as the Preferred Portfolio: Integrated Base MN, Integrated Hunter Retire MN, Integrated Base MR, and Integrated Base HH – in no

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[70] Guidelines, *supra* note 2, at 36 ("The [IRP] process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.").

particular order.[71] Out of the integrated "variant" portfolios shown, these portfolios ranked in the top four across both cost and risk metrics (PVRR and Stochastic PVRR) over the planning horizon under the "MN" price-policy scenario (i.e. the expected scenario). These portfolios' respective rankings relative to all the variants are shown in the table below, and the color scale denotes relative ranking on the metric columns among just the four portfolios shown.

Ranking Across All Candidate Portfolios MN price-policy				
Case	**PVRR Rank**	**Stochastic PVRR Rank**	**PVRR with End Effects Rank**	**CO2 Emissions Rank**
Base MN	4	2	1	9
Hunter Retire MN	1	3	3	6
Base MR	3	4	5	1
Base HH	2	1	2	4

[71] Hereinafter these portfolios are referred to without the leading "Integrated." For example, "Integrated Base MN" will simply be called "Base MN." MN refers to the price policy scenario that assumes a medium gas price and no CO2 price over the planning horizon. MR refers to the price policy scenario that assumes a medium gas price and at-risk federal environmental regulation (Clean Air Act § 111(d)). HH refers to the price policy scenario that assumes a high gas/coal price and a high CO2 price.

1. ***The Integrated Base MN Portfolio is Not the Least-Cost or Least-Risk Portfolio Under Any Price-Policy Scenario and is Outperformed by the Base HH Portfolio under every price-policy scenario.***

The Company selected the Base MN portfolio as its Preferred Portfolio. This portfolio was developed to be optimized under the MN price-policy scenario but, surprisingly, it is the fourth ranked portfolio on PVRR and second ranked portfolio on stochastic PVRR under the very price-policy scenario that it was optimized around. Three portfolios, Hunter Retire MN ($171 million less expensive), Base HH ($114 million less expensive), and Base MR ($57 million less expensive), show a lower PVRR than the Preferred Portfolio over the 21-year planning period. On a risk-adjusted basis, the Base HH portfolio has the lowest PVRR while the Preferred Portfolio is ranked second ($106 million more expensive). The Preferred Portfolio also performs exceptionally poorly on CO2 emissions under the MN price-policy scenario, ranking ninth out of 13 portfolios and emitting more than 109 million tons more than the lowest emission portfolio, the Base MR portfolio. The Base HH portfolio emitted the fourth lowest CO2 emissions and nearly 80 million tons less than the Preferred Portfolio. The Preferred Portfolio is ***neither*** the least-cost nor the least-risk portfolio over the planning horizon.

The variant studies were also modeled under the other price-policy conditions as an informative exercise. These studies are important to inform stakeholders and the Company of the relative risk or resilience of each integrated portfolio to potential fundamental policy or fossil fuel price changes (possibly at the regional, global, or federal level). The following tables show the performance of the top four portfolios under the additional three price-policy scenarios.

Ranking Across All Candidate Portfolios LN price-policy						
Case - LN	PVRR ($m)	Difference from Lowest Cost Portfolio ($m)	PVRR Rank	Total CO2 Emissions (Thousand Tons)	Difference from Lowest Emission Portfolio (Thousand Tons)	CO2 Emissions Rank
Base MN	25,226	611	5	334,470	85,630	12
Hunter Retire MN	24,959	344	2	273,675	24,835	6
Base MR	24,615	-	1	254,697	5,857	2
Base HH	24,990	375	3	248,840	-	1

Under the Low Gas/Zero CO2 (LN) price-policy scenario, the Preferred Portfolio ranked fifth in PVRR coming in $611 million more expensive than the Base MR portfolio. It ranked 12th out of 13 in CO2 emissions with 85 million more metric tons emitted than the Base HH portfolio.

Ranking Across All Candidate Portfolios HH price-policy						
Case - HH	PVRR ($m)	Difference from Lowest Cost Portfolio ($m)	PVRR Rank	Total CO2 Emissions (Thousand Tons)	Difference from Lowest Emission Portfolio (Thousand Tons)	CO2 Emissions Rank
Base MN	34,498	3,000	8	232,976	58,899	13
Hunter Retire MN	31,973	475	3	179,948	5,871	6
Base MR	31,796	298	2	180,431	6,354	2
Base HH	31,498	-	1	174,521	444	1

Under the HH price-policy scenario, the Preferred Portfolio ranked eighth out of 13 in PVRR, a staggering $3 billion more expensive than the Base HH portfolio. It also emitted the most CO2 of any variant portfolio.

Ranking Across All Candidate Portfolios SC price-policy						
Case - SC	**PVRR ($m)**	**Difference from Lowest Cost Portfolio ($m)**	**PVRR Rank**	**Total CO2 Emissions (Thousand Tons)**	**Difference from Lowest Emission Portfolio (Thousand Tons)**	**CO2 Emissions Ranking**
Base MN	**40,882**	**3,242**	**8**	**117,244**	**16,990**	**9**
Hunter Retire MN	**38,034**	**394**	**2**	**101,094**	**840**	**2**
Base MR	**38,708**	**1,067**	**3**	**117,634**	**17,380**	**11**
Base HH	**37,640**	**-**	**1**	**100,254**	**-**	**1**

Finally, under the SC[72] price-policy scenario, the Preferred Portfolio performs dismally on both PVRR and CO2 emissions. The Base HH portfolio is, again, the top ranked variant.

The Company states: "The IRP analysis is designed to define a resource plan that is least-cost, after consideration of risks and uncertainties. To evaluate resource alternatives and identify a least-cost, risk adjusted plan, portfolio resource options were developed and tested against each other."[73] Yet the Integrated Base HH Portfolio outperforms the Integrated Base MN Portfolio on a PVRR basis under *every* price-policy scenario (MN, LN, HH, and SC).[74] When balancing cost

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[72] SC refers to the price policy scenario that assumes a social cost of CO2, as required by Washington.

[73] 2025 IRP, *supra* note 27, Volume II, at 20.

[74] *See* WRA Exhibit 3, Response to WRA Data Request 3.2(a).

and risk, the Integrated Base HH Portfolio is the clear top-performing portfolio and should have been selected as the Preferred Portfolio. Under the MN price-policy scenario, the Company's Preferred Portfolio is $114 million more expensive than the Base HH portfolio and $106 million more costly on a risk-adjusted basis. Under price-policy scenarios other than MN, the differences are staggering. Even under a low gas/no CO2 price future, the Preferred Portfolio is more expensive than the Base HH. Under HH and SC price-policies, the PVRR premium for the Preferred Portfolio relative to the Base HH is $3 billion.

Portfolio risk will never be perfectly captured by stochastic risk assessment, capital cost risk, or scenario risk assessment, but the Company's selection of Base MN over Base HH exposes ratepayers to enormous tail-end risk if there are significant shifts in fossil fuel prices or federal environmental policies. Guideline 1 states that the IRP process should "meet current and future customer electric energy services needs at the lowest total cost to the utility and its customers, and in a manner consistent with the long-run public interest. The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty."[75] On any metric during the 21-year planning period (as opposed to the 26-year period with end effects discussed below), the Base HH portfolio presents a *least-regrets* choice among the available choices but was not selected.

The Base MN portfolio ranks highest only if novel "end effects" are included for five additional years after the already-lengthened 21-year planning horizon (years 2025-2045).[76]

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[75] Guidelines, *supra* note 2, at 36.

[76] A 21-year planning horizon is a new requirement out of Washington.

Even when end effects are added, the Base MN is only $51 million less expensive over a 26-year horizon. That amount, $51 million, is not only insignificant over a 26-year planning horizon, but it is less than half of the difference between the PVRR or Stochastic PVRR between the Base MN (more expensive) portfolio and Base HH (less expensive) portfolio.

Guideline 4(d) explicitly states "PacifiCorp's future integrated resource plans will include: … A 20-year planning horizon."[77] WRA asked the Company whether end effects were required by *any* state's IRP standards and Guidelines to which the Company responded, "No. Consideration of end effects is not specifically required in the selection of the preferred portfolio."[78] In response to another WRA data request, PacifiCorp stated that "'End effects' evaluates performance of a portfolio beyond the study horizon."[79] For this and the reasons outlined below, WRA believes the consideration of novel end effects to select anything but the optimal portfolio during the planning horizon is not compliant with the Commission's Guidelines.

In response to WRA's data requests (as opposed to information published in the IRP and supporting materials), PacifiCorp justified approximating end effects outside of the planning horizon in this way: "The value of tax credits was overstated in the 2025 IRP, impacting the risks associated with the "HH" derived portfolio."[80] It goes on to explain that the ""HH" price-policy

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[77] Guidelines, *supra* note 2, at 36-38 (Guideline 4(d)).

[78] WRA Exhibit 3, Response to WRA Data Request 3.1(b).

[79] WRA Exhibit 3, Response to WRA Data Request 3.1(a).

[80] WRA Exhibit 3, Response to WRA Data Request 3.2(d)

outcomes include ***unmodeled risks not directly discussed in the 2025 IRP results.***"[81] The Company also made a conjectural statement about relative risk, claiming, "Portfolios that include more PTC resources derive a greater portion of their value from the inflated value of tax credits used in the 2025 IRP. This is why the "HH" portfolio is riskier than the "MN" portfolio."[82]

Absent perfect foresight, such a statement regarding risk can only be supported by correcting the apparent shortcomings of the Company's modeling methodology and then retesting the Base MN and Base HH portfolios under various sensitivities. As written, the statement implicitly suggests that the risk of tax credit overvaluation in the IRP is a greater risk than the PVRR or risk-adjusted PVRR differences between portfolios, despite the fact that the modeling and methods leading to those complex portfolio metrics have been developed over multiple IRP cycles in tandem with stakeholders. The end effects calculation was included ad hoc in this IRP cycle.

The Company educated stakeholders on the partial "fix" to PTC overvaluation – that the PTC value would be linearly decreased to zero in the five years prior to the end of the planning horizon – in public input meetings, but the Company has not shown through modeling that a PTC problem remains. Stated another way, the Company's statement that "the "HH" portfolio is riskier than the "MN" portfolio" only contradicts and discredits the Company's own risk-adjusted PVRR results but does not quantitatively support its position.

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[81] *Id.* (emphasis added).

[82] *Id.*

E. The Consideration of End Effects is Novel, Arbitrary, Speculative, and Lacks Robustness

The consideration of end effects is a new addition to the Company's portfolio selection methodology in the 2025 IRP.[83] To calculate end effects, PacifiCorp calculated the NPV of the revenue requirement of the final year of the planning horizon (year 21) and statically continued it for five additional years. The Company then added these "end effects" to the Stochastic PVRR of portfolios. For the 2025 planning cycle, the Company modeled an even longer planning horizon (21 years) to meet a Washington state requirement, meaning that the calculation of end effects occurs during a period from 21 to 26 years into the future.

In response to WRA's data request, the Company stated the following rationale for considering end effects:

> Calculation of end effects allowed PacifiCorp to evaluate if a portfolio performed particularly well or poorly in early years of the horizon. If a portfolio was more expensive in early years of the horizon, but much less expensive later this would be important information to consider when evaluating the risk to customers. A portfolio which was less expensive early due to tax credits could become very expensive when tax credits expire.[84]

Notwithstanding whether PTC-eligible resources were given preferential treatment, using end effects to select a suboptimal portfolio is problematic for numerous reasons, outlined below.

1. *End Effects were Only Calculated Under the MN Price-Policy Scenario, are Not a Robust Metric, and Should Not be used for Portfolio Ranking and Selection.*

In the 2023 IRP, the Company described the portfolio selection process as follows:

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[83] WRA Exhibit 3, Response to WRA Data Request 3.1(f).

[84] WRA Exhibit 3, Response to WRA Data Request 3.2(d).

> The final selection process considers cost-risk rankings, *robustness of performance across pricing scenarios* and other supplemental modeling results, including reliability and CO2 emissions data as an indicator of risks associated with greenhouse gas emissions.[85]

For the 2025 IRP the Company calculated the PVRR of every portfolio variant under every price-policy scenario, but risk-adjusted PVRR[86] and end effects were only presented under the MN price-policy scenario.[87] If end effects are to be factored into portfolio selection, then this omission means stakeholders have little sense of the Base MN portfolio's risk-adjusted performance under other price-policy scenarios in the distant future. Absent a full suite of comparable metrics, there is no "robustness of performance across pricing scenarios."[88]

The end effects metric is entirely dependent on the conditions of a single modeling year. To illustrate the potential bias introduced with this method, remember that each portfolio is run under the base load forecast, which is based on actual data from the 20-year period of 2004-2023, adjusted for numerous factors such as climate change, electrification, and customer forecasts.[89] In practice, the end effects value is based on the load forecast and corresponding system costs in only the final year, which has not been standardized to reflect a range or average of future conditions or variables. The Company provided no description of the specific modeling

[85] PacifiCorp's 2023 Integrated Resource Plan*,* Volume I, Docket No. 23-035-10 (filed April 3, 2023), at 219 [hereinafter 2023 IRP] (emphasis added).

[86] Risk-adjusted PVRR was not presented for integrated portfolio variants modeled under other price policies. 2025 IRP, *supra* note 27, Volume I, at Tables 9.35, 9.36, and 9.37.

[87] "End effects were applied to all portfolios run under the MN price-policy for a 5-year period after the study horizon, results of which can be seen in this table." *Id.* Volume I, at 260.

[88] 2023 IRP, *supra* note 85.

[89] *See* 2025 IRP, *supra* note 27, Volume II, at 5.

conditions in this model year, such as wind and solar performance or abnormal weather patterns that may be represented in the 2046 model year. Therefore, the impact of end effects is simply speculative and uncontrolled for one-off conditions.

The metric is not robust in a statistical or modeling sense and should not be used to directly compare and select portfolios. In contrast, the summary statistics (PVRR, risk-adjusted PVRR, and aggregate CO2 emissions) for candidate portfolios can be used for comparison because they are aggregated over a 21-year period and benefit from random sampling methods for weather conditions and an overall larger sample size. These metrics, as opposed to end effects, are less influenced by outliers, volatility, or conditions in any one year. By amplifying the conditions of a single year more than the other 20 years, the "end effects" metric introduces bias into the risk-adjusted PVRR metric. Selecting the Preferred Portfolio on this metric means the selection was based on an inherently biased metric.

2. ***The End Effects Calculation Gives Inordinate Weight to the Last Year of the 21-Year Planning Horizon – the Most Uncertain and Speculative Modeling Year.***

The expected accuracy of any model diminishes as the modeling horizon lengthens. Forecasting model inputs, especially policy shifts or fuel price volatility, grows increasingly uncertain the further one projects from the initial modeling period. However, the end effects calculation gives inordinate weight to a portfolio's performance in the final year of the planning horizon. The NPV from the final year is statically repeated for five more years and added to the overall risk-adjusted PVRR. The repeated year is the most distant, and thus the most uncertain year in the model.

Another problem is that the end effects calculation gives excess weight to the unadjusted modeling assumptions in the final year of the planning horizon. The Company ceases to escalate or predict electricity market prices and gas prices after 2045 (year 21). It makes no assumptions about changes in resource costs, and it makes no changes to the load forecast during this period. While none of these inputs can be predicted so far into the future with much certainty, the least credible approach may be to assume that nothing changes.

The Guidelines tacitly acknowledge uncertainty inherent in long-term planning by requiring both a 20-year planning horizon *and* a four-year action plan. Future uncertainty does not imply that models are uninformative, even if virtually guaranteed to be wrong, but it does implicitly suggest that more weight should be given to results in the early years of a planning horizon, all else equal.

3. *If End Effects are Considered, they Must Carry Less Weight than Cost, Risk, and Environmental Risk.*

Considering the Company's modeling results, it appears that the Company chose its Preferred Portfolio based primarily on its limited, biased, and novel modeling of end effects, without giving meaningful weight to its own cost, cost-risk, and environmental-risk analysis. Environmental risk is approximated by a portfolio's CO2 (or CO2 equivalent) emissions. In its IRP, PacifiCorp acknowledges this environmental risk in no uncertain terms stating, "**The largest externality of which the Company is currently aware is the impact of greenhouse gases on the climate.**"[90] The Company adds, "The final selection process considers …

[90] 2025 IRP, *supra* note 27, Volume II, at 37 (emphasis added).

supplemental modeling results, including reliability and **CO2 emissions data as an indicator of risks associated with greenhouse gas emissions**."[91]

Ignoring the fact that the Base MN portfolio is more risky and more costly than the Base HH portfolio under the expected MN price-policy scenario, the Company evidently gave *no weight* to the fact that the Preferred Portfolio emits nearly 80 million metric tons of CO2 *more* than the Base HH portfolio. The Commission's Standards and Guidelines state: "[T]he IRP process should select resources that yield the optimal combination of costs and risks. The risk of future internalization of environmental costs must be analyzed by the Company and such risk assessment **must be incorporated in the Company's decision making and final choice of resources acquired.**"[92]

The Guidelines actually go further explaining that "all other things being equal, the Company will be expected to pursue resource acquisitions that minimize adverse environmental impacts as a method of reducing risk."[93] To comply with the Commission's Guidelines, if two portfolios perform equally on cost and risk, the Company is clearly expected to select the portfolio that poses less environmental risk. Despite this, the Company chose to model a price-policy scenario with no CO2 price and thus no proxy for the attendant risks of greenhouse gas emissions, despite stating, "[T]he single most important scenario risks of this type facing PacifiCorp continue to be government actions related to emissions and changes in load and transmission infrastructure. These scenario risks relate to the uncertainty in predicting the scope,

[91] 2023 IRP, *supra* note 85, Volume I, at 218-219 (emphasis added).

[92] Guidelines, *supra* note 2, at 18 (emphasis added).

[93] *Id.* (emphasis added).

timing, and cost impact of emission and policies and renewable standard compliance rules."[94] The Company committed egregious error in eschewing the Preferred Portfolio's environmental performance even amidst comparable cost and risk metrics.

F. The 2025 IRP Shifts Cost and Risk to Customers.

Ensuring full cost recovery is a fundamental Company objective, and this IRP appears consistent with the Company's efforts to minimize shareholder risk. Through its jurisdictionally bifurcated planning and through its treatment of large customer loads, this IRP appears to reduce cost-recovery risk for shareholders. However, the approach taken in producing this plan results in higher costs and hidden risks, including potential continued dependence on short-term market purchases. Guideline 4(h) requires PacifiCorp to evaluate the "financial, competitive, reliability, and operational risks associated with various resource options" and "identify who should bear such risk, the ratepayer or the stockholder."[95] It appears that PacifiCorp expects customers to bear all costs and risks.

1. *None of the Jurisdictional Portfolios Incorporates a System Planning Reserve Margin; All 45 Appear Underbuilt. The Final Step of Integration May Compensate for This, But Not in an Optimized Least-Cost Manner.*

PacifiCorp states that each jurisdictional simulation is a "full system optimization assuming the constraints and requirements of the jurisdiction."[96] However, this is not strictly

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[94] 2025 IRP, *supra* note 27, Volume I, at 316-317.

[95] Guidelines, *supra* note 2, at 36-39 (Guideline 4(h) requires "[a]n evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan. The Company will identify who should bear such risk, the ratepayer or the stockholder.").

[96] 2025 IRP, *supra* note 27, Volume I, at 218, Figure 9.1.

factual. In undertaking these "system" simulations, PacifiCorp did not apply a planning reserve margin to system load as it has in the past. For the 2025 IRP, PacifiCorp used Western Resource Adequacy Program (WRAP) planning reserve margins and capacity counting conventions in place of past planning assumptions. And instead of applying a 13% planning reserve margin to system load in the capacity expansion phase of modeling, PacifiCorp applied the WRAP planning reserve margin to *jurisdictional* load only. Specifically, in the simulation of each Jurisdictional Portfolio, WRAP compliance was calculated by multiplying the monthly jurisdictional load in the hour of the system peak by the monthly WRAP planning reserve margin.[97] Therefore, from a system perspective, each of the Full Jurisdictional Portfolios appears to be underbuilt and not WRAP compliant.

The extent of this shortcoming is illustrated by considering the following information that PacifiCorp used to determine and allocate shares of existing resources and the Natrium nuclear plant.[98]

- UIWC load is roughly 64% of system load,[99] so in simulating the system under UIWC requirements, a planning reserve margin was not applied to roughly 36% of system load;
- Oregon load is roughly 29.5% of system load,[100] so in simulating the system under Oregon jurisdictional requirements, a planning reserve margin was not applied to roughly 70.5% of system load;

[97] *See* WRA Exhibit 3, PacifiCorp response to WRA 4.6(b).

[98] *See* WRA Exhibit 3, PacifiCorp response to WRA 4.1.

[99] *See* WRA Exhibit 3, PacifiCorp response to WRA 4.1(b).

[100] *See* WRA Exhibit 3, PacifiCorp response to WRA 4.1(a)

- Washington is roughly 6.5% of system load,[101] so in simulating the system under Washington jurisdictional requirements, a planning reserve margin was not applied to roughly 93.5% of system load.

However, given PacifiCorp's retreat from system planning and its apparently ad hoc construction of the Integrated Portfolios, the implications of not building to a system planning reserve margin are unclear. As described above, after conducting optimized jurisdictional modeling, PacifiCorp appears to have abandoned the optimized results in favor of identifying east-side proxy resources to meet an east-side WRAP planning reserve margin, and west-side proxy resources to meet west-side compliance requirements, including a west-side WRAP planning reserve margin, without considering how the resources work together in an integrated manner.[102] Indeed, it may be that the final step of integration described above in Section II.B.1. fully compensates for the initial underbuilding, although certainly not in an optimized least-cost manner.

However, to the extent that the new approach under-represents system need or system need is addressed in an ad hoc manner that is not least cost, and to the extent that the new method does not represent a least-cost, least risk plan for customers, customers, not shareholders, will suffer the consequences through higher net-power-cost pass-throughs and higher rates than would result from an integrated approach to system planning. It is therefore imperative that

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[101] *See Id.*

[102] *See* WRA Exhibit 4, PacifiCorp response to Sierra Club 2.2(c). Sierra Club asked PacifiCorp "to detail the process that PacifiCorp is using to evaluate the integrated portfolios to ensure that the integrated model is least-cost compared to a system-level model." PacifiCorp responded that "there is no such process. It doesn't make sense to compare an integrated portfolio that is compliant with jurisdictional requirements to a systemwide model that is not, and it is highly impractical to model compliance with all jurisdictional requirements in a single systemwide model."

PacifiCorp provide the Commission and stakeholders with the information needed to develop a full understanding of the new modeling approach and its implications for least-cost, least-risk planning. In addition, PacifiCorp must provide an optimized, least-cost, least-risk, system plan that the Commission and stakeholders can use to evaluate the cost consequences of bifurcation, specifically costs associated with moving resources and addressing resulting compliance shortfalls.

2. *The Company's Removal of New Large Commercial Loads was Inappropriate and Undermines the Goals of System Planning.*

Between the filing of the Draft 2025 IRP and the Final 2025 IRP, among other unilateral decisions, the Company removed all new large commercial (data center) load from its base load forecast. The Company announced this during the January 22, 2025, Public Input Meeting by including one bullet point: "Load forecast update removes loads that fall outside of the traditional IRP planning process."[103] The public input meeting continued without substantive discussion of this significant modification. This change was given more time during the February 27, 2025, Public Input Meeting when the Company explained its justification for removing all new, uncontracted data center load. The first reason was the expectation that large load customers would build their own resources and transmission or pay for service through the

[103] PacifiCorp, *2025 IRP Public Input Meeting* (January 22-23, 2025), at slide 17, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/January_22-23_2025_IRP_Public_Input_Meeting.pdf.

arrangement of special contracts.[104] The second reason given was less a justification than simply a declaration that the Company no longer believes such loads are in the scope of IRP planning.[105] WRA disagrees. It is precisely within the scope of the IRP to pick resources the model sees as best for the system.

Confusion within the Company regarding data center load is evident. The Company claims that all new data center load in the next 12-36 months is expected to bring its own generation and transmission resources,[106] even while engaging in rulemaking that contemplates cost allocation for and terms of service for large commercial loads (Docket No. 25-R318-01). Special contracts with data centers have been included in past IRP load forecasts while transmission-only customers have not. In one venue, the Company justifies its decision to remove this load based on cost allocation arguments. In another it may claim an inability to meet

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[104] PacifiCorp, *IRP Public Input Meeting* (February 27, 2025), at approximately 1:07:05 of Part 2 (Meeting Recording), https://www.youtube.com/watch?v=1LXf9kzwZIs:

> To the question about why it's appropriate to remove data center load there's two things that we've discussed in a number of venues…One is that for the data center load that could potentially be coming in the future, the expectation is that those customers will bring their own resources and transmission, or you know, pay for those under the arrangement of special contracts.

[105] *Id.* at approximately 1:07:35:

> But more important to me as a modeler, because of that fact, you know, we need to um watch out for our customers and, you know, part of that means in the IRP which is, you know, proxy-based and involves resource selection, those resource selections that might occur under a special contract are going to occur under negotiations and whatever, you know, those particular entities are interested in doing. It's not, um, not within the scope of the IRP to pick and assign whatever resources it sees best for service to the system under those conditions, so it's very much a special arrangement. And given that that load is going to be bespoke with resources that come in with those customers, it's just not within the scope of the IRP.

[106] WRA Exhibit 3, Response to WRA Data Request 7.1(e).

the specific demands of such customers. Even when discussing the removal of load between the Draft and Final IRP, one Company representative stated, "On a system basis, there's need. On an allocation basis there may also be [resource need] for the East as well. But [with] an appreciable reduction [in load], fewer resources are necessary to serve a reduced amount of load. **Is that load likely to occur? There's a pretty good chance. And hopefully it will come with enough resources to serve itself**."[107]

In its 2025 IRP Action Plan, the Company stated that continued support for Gateway West would "enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade."[108] Like the Commission's rebuke of the Company's assertion in the draft report of RAMPP II that it would be "more advantageous to over-build than under-build in the future," the Commission should again find that such "conclusions must be based on **analysis not assumptions**."[109]

Assuming all new data center load will be served with private generation is unrealistic and further separates the Company's long-term planning from reality. Of course, there is a tangible risk of stranded assets if the Company were to overbuild resources to meet load that never materializes. But risk of similar magnitude may lie in an underbuilt generation and transmission system, leading to greater reliance on market purchases, which will be increasingly volatile and tight at market hubs as other utilities grapple with similar challenges.

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[107] PacifiCorp, *IRP Public Input Meeting* (February 27, 2025), at approximately 1:19:10 of Part 2 (Meeting Recording), https://www.youtube.com/watch?v=1LXf9kzwZIs (emphasis added).

[108] 2025 IRP, *supra* note 27, Volume I, at 290.

[109] Guidelines, *supra* note 2, at 20 (emphasis added).

It is also concerning that Company gave no consideration to the diversity of load service requests in terms of size. Generally, loads greater than 10 MW are reviewed by PacifiCorp's regional business managers (RBMs) for their impact to the load forecast rather than being incorporated through a regression approach.[110] Oregon HB 3546 provides for cost allocation of loads greater than or equal to 20 MW. Utah SB 132 only governs new or expansion loads greater than or equal to 100 MW. The Company's 2026 Protocol proposes situs assignment for large load customers of 50 MW or greater. In the 2025 IRP, no new commercial data center load was included, regardless of size. It is unrealistic for PacifiCorp to deny service to *all* data centers, regardless of whether a data center requests 10 MW or 1,000 MW.

a. Removing All New Data Center Load from System Planning is Not Justified by any Rule, Statute, or Cost Allocation Argument.

The Company's unilateral decision to remove incremental data center load from IRP planning is a risky and unjustifiable dismissal of the "obligation to serve" doctrine that compels regulated and monopolistic public utilities to provide non-discriminatory service to all customers in their territory. In discovery, WRA asked the Company to disclose the tariff, legislation, rule, or regulation for each state that either mandates commercial data centers bring their own generation resources rather than take service from PacifiCorp, or ensures that all generation, transmission, and distribution costs from such loads will be directly allocated to the large customer.[111] In response, the Company confirmed that it does not have uninhibited authority to

[110] WRA Exhibit 3, Response to WRA Data Request 7.2.

[111] WRA Exhibit 3, Response to WRA Data Request 7.3.

deny new service requests from large commercial customers in any jurisdiction it serves, regardless of the reason.[112]

The heart of the issue is in the Company's overbroad characterization of all new data center load as outside of the traditional IRP planning process and the conflation between system planning and cost allocation. Traditionally, transmission-only customers, such as those in the Oregon Direct Access program, have been excluded from the IRP,[113] yet customers with individual commission-approved special contracts *are* included in the IRP load forecast, and no large commercial or industrial loads that *currently* take service under a special contract were removed from the 2025 IRP.[114] Given that both the Oregon and Utah legislation addressing service for large commercial data centers acknowledge the possibility of special contracts, it is perplexing as to why the Company automatically assumes that all data centers will bring their own generation and transmission. There are various arrangements for large commercial customers, including transmission-only service through PacifiCorp's FERC-approved Open Access Transmission Tariff (OATT), islanded behind-the-meter with private generation, private generation supplemented with utility service for reliability, interruptible service, or full utility

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[112] WRA Exhibit 3, Response to WRA Data Request 7.3(d).

[113] WY Commission Stakeholder Feedback Form, January 15, 2025, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/2025-irp-comments/2025.054_WYC_1-15-2025_with_response.pdf. Also available at 2025 IRP, *supra* note 27, Volume II, at Appendix M ("Reply: The IRP load forecast does not include transmission-only customers. The Company's customers enrolled in Oregon's direct access program are transmission-only customers and excluded from the Company's generation planning load for the IRP.").

[114] *Id. See also* WRA Exhibit 3, Response to WRA Data Request 7.2(c).

service under a tariff or special contract. Disregarding load associated with all potential large load arrangements in resource planning represents unnecessary risk for ratepayers.

b. The Company Failed to Conduct Sensitivity Analysis that would have Meaningfully Informed Stakeholders of the Risk of Overbuilding or Underbuilding Generation and Transmission Resources to Meet Data Center Load.

The Company's decision to remove all new, uncontracted-for data center load from the base load forecast may have been justifiable if the Company had also modeled a suite of load forecasts with variable but realistic levels of large commercial load. Alternative load forecasts could have informed stakeholders of the cost and relative risk of overbuilding or underbuilding. Alas, the Company performed no such analysis and instead modeled two bookend scenarios that give stakeholders no indication of the system implications of these loads. This broadbrush approach to data center load in the 2025 IRP was unnecessary and a late-breaking departure from the Company's position prior to the Draft 2025 IRP. During the September 25, 2024, Public Input Meeting, the Company stated, "It's become relevant…to do some sensitivity analysis around [data center load] above and beyond what is brought into the base load forecast."[115] The Company then listed three sensitivities including zero new data center load, maximum constrained data center load, and all-in (or unconstrained) data center load. At that time, the base load forecast included "existing data center load, incremental data center load reflecting

[115] PacifiCorp, *2025 IRP Public Input Meeting* (September 25, 2024), at approximately 3:02:30 of Part 2 (Meeting Recording), https://www.youtube.com/watch?v=_IqnbRCULBM.

expansion plans, and new load that has a high probability of being developed."[116] Three months prior to the Draft 2025 IRP, the Company had plans to model four distinct data center load scenarios, including one reflective of high probability load.

The Final 2025 IRP included only two scenarios: "zero new data center load" and "All-in data center load." In essence, the Company's base load forecast has a nearly 100% chance of underestimating large commercial load. The downstream effects include high risk on existing consumers if the Company procures expensive market products to serve the system, without safeguards on cost allocation. The "Large Metered Load Growth" scenario provides a useless bookend result representing an infeasible level of system buildout.[117] The Company acknowledged this by stating that they had *relaxed the modeling constraints* in PLEXOS that realistically limited resource selections based on construction timelines and feasibility and system cost limitations.

III. THE 2025 IRP SHOULD NOT BE USED IN AVOIDED COST FILINGS

Guideline 8 requires that the IRP be used "to evaluate the performance of the utility and to review avoided cost calculations."[118] Given the overwhelming shortcomings of this IRP, neither the Utah IRP nor the Final IRP should be used as the basis for determining avoided cost. The

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[116] *Id.* at slide 86, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/PacifiCorp_2025_IRP_PIM_September_25_2024.pdf.

[117] For example, this scenario calls for over 20,000 MW of proxy resources and enormous levels of transmission. The model selects nearly *10,000 MW* of new resources by 2028 alone. *See* 2025 IRP, *supra* note 27, at 280, Figure 9.46.

[118] Guidelines, *supra* note 2, at 40.

Utah IRP has inaccurate modeling assumptions that were significantly corrected, clarified, or refined for the Final IRP. And the Final IRP replaces full system optimization with bifurcated planning and ad hoc resource adjustments that are inconsistent with foundational rate-setting policy—i.e. "Rolled-In" cost allocation to the state. Additionally, none of the Full Jurisdictional Portfolios should be used to establish avoided cost prices because they underestimate resource adequate (WRAP-compliant) capacity expansion for the whole system. Until PacifiCorp proposes a new resource plan that is compliant with Commission rate-setting principles, the Commission should continue to use avoided costs based on the 2023 IRP Update.

IV. CONCLUSION AND RECOMMENDATION

Big decisions lie ahead, and changes in direction must be supported with sound analysis. The IRP is a primary source for understanding the cost consequence of alternative paths and must continue to provide this information. PacifiCorp has not yet proposed, and the Commission has not approved, unwinding the past benefits of single system planning and operation.

The Commission should not acknowledge the 2025 IRP for the reasons described herein. Fundamentally, the 2025 IRP represents a departure from single system, least cost/risk planning but does not provide an analytical basis for justifying such a departure. Because the 2025 IRP is not a system plan, it is not appropriate for use in setting avoided costs. PacifiCorp should provide an optimized, least-cost, least-risk, system plan that the Commission and stakeholders can use to evaluate the cost consequences of bifurcation as part of the 2027 IRP.

Dated this 25th day of September 2025.

Respectfully submitted,

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CERTIFICATE OF SERVICE
Docket No. 25-035-22

I hereby certify that a true and correct copy of the foregoing was served by email this 25th day of September 2025 on the following:

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