

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

LC 85

In the Matter of

PACIFICORP dba PACIFIC POWER,

2025 Integrated Resource Plan and Clean
Energy Plan.

REDACTED ROUND II
COMMENTS OF RENEWABLE
NORTHWEST

October 9, 2025

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I. Executive Summary

Renewable Northwest (“RNW”) appreciates the opportunity to provide these Round II Comments on PacifiCorp's 2025 Integrated Resource Plan (“IRP”) and Clean Energy Plan (“CEP”). In these comments, RNW expands on the issues raised in Round I, responding to and incorporating perspectives and information from PacifiCorp and other parties, and raises new issues primarily focused on the CEP, which was submitted with insufficient time for a complete review prior to Round I.

RNW recognizes and appreciates the difficulty of integrating Oregon state policy into a system planning process that must account for a diverse set of interests and policies from six different states. However, as a defining theme, RNW remains concerned that PacifiCorp’s IRP and CEP fail to meet the minimum standards necessary to effectively plan for and address near- and mid-term customer needs in Oregon. In parallel, PacifiCorp has urgent deficiencies which must be addressed through near-term actions, including energy and reliability deficiencies on the western system and policy compliance requirements for the Western Resource Adequacy Program (“WRAP”) and Oregon’s House Bill 2021 (“HB 2021”). In these comments, RNW seeks to provide recommendations to the Oregon Public Utility Commission (“OPUC” or “Commission”) to navigate these competing challenges in ways that both facilitate PacifiCorp’s forward movement on critical resource gaps and take actions to address the foundational deficiencies within PacifiCorp’s 2025 IRP and CEP submissions.

In Round I comments, RNW elevated three primary concerns impacting near-term actions for PacifiCorp and OPUC: the need for urgent procurement to meet near-term Oregon customer needs, concerns with the unilateral removal of the Boardman-to-Hemingway (“B2H”) transmission line, and the discriminatory impacts of PacifiCorp’s proposed situs allocation construct for Oregon customers. In these comments, we build on these concerns with analysis and further policy development, including further quantitative assessment of PacifiCorp’s western reliability gaps. We further introduce three new concerns: whether PacifiCorp has adequately demonstrated continual progress towards HB 2021’s requirements, incremental procurement deficiencies resulting from PacifiCorp’s exclusion of data center load growth, and unresolved technical concerns within the CEP analysis.

For ease of Commission review, we summarize our recommendations on specific sections of the IRP and CEP below:

Boardman to Hemmingway:

1. Decline to acknowledge PacifiCorp’s removal of B2H from its preferred portfolio.
2. Direct PacifiCorp to reincorporate B2H into the base case for the 2025 IRP Update and 2027 IRP.

3. Direct PacifiCorp to actively work with the BPA to resolve the status of its transmission redirect requests and update the Commission, Staff, and stakeholders on the company's progress.

Allocation Framework:

4. Decline to acknowledge the allocation framework underlying the 2025 IRP.
5. Direct PacifiCorp to work collaboratively with Staff and stakeholders to develop a framework that properly separates system reliability costs from state-specific policy costs and ensures WRAP compliance costs are modeled and allocated system-wide. This framework should be vetted through a transparent stakeholder process and implemented before the next IRP cycle to ensure consistent application across all planning, procurement, and ratemaking activities.

Procurement Action:

6. Acknowledge Action Item 2b, which initiates the 2025 RFP.
7. Direct PacifiCorp to engage in accelerated procurement to capture the benefits of expiring federal tax credits, pursuant to EO 25-25.
8. Direct PacifiCorp to procure sufficient resources to maintain reliability on the PACW system and meet WRAP requirements for serving PACW load in the Forward Showing and Operational Program ahead of the binding 2028 deadline.
9. Direct PacifiCorp to procure sufficient resources needed for compliance with HB 2021 in 2030.

2025 Oregon Clean Energy Plan:

10. Direct PacifiCorp to provide analysis on fuel costs and market purchase costs in the HB 2021 counterfactual scenario.

II. Review of Round I Comments, Replies, and Subsequent Discussions

In Round I, RNW outlined several major concerns for further development in the proceeding, and in several cases sought further engagement from PacifiCorp on issue assessment and resolution. In parallel, OPUC Staff ("Staff") and other parties developed a range of issues, many of which paralleled or overlapped with themes raised by RNW. RNW's concerns and recommendations align closely with those of OPUC Staff.

First, RNW identified the need for significant resource development to meet Oregon customer needs and identified concerns with the ability of PacifiCorp's stated actions to achieve

this goal by 2030, recommending specific actions for PacifiCorp to close its physical reliability, compliance reliability (WRAP), and clean energy policy requirements in the 2028-2030 timeframe, as well as to take any and all actions necessary to capture expiring tax credits.¹ Underprocurement risk is significantly compounded by PacifiCorp's intentional and poorly-justified exclusion of bundled service load growth, as noted by Staff, Sierra Club, and others. While RNW appreciates the improvements PacifiCorp intends to make to its open RFPs, we remain concerned that PacifiCorp is both underestimating its total need and lacks sufficient oversight and enforcement to ensure it procures sufficient resources to meet its compliance obligations, a concern reflective of PacifiCorp's abandonment of its 2022 RFP and the protracted enforcement process that followed deficiencies in its prior CEP. While PacifiCorp faces significant noncompliance penalty risk for WRAP, it is unclear that WRAP requirements will ensure sufficient resources exist or are deliverable to PACW to ensure Oregon reliability, and there are unresolved uncertainties regarding PacifiCorp's intentions with WRAP participation. While PacifiCorp directionally agreed with RNW's concern in replies, RNW provides further development and analysis of the deficiencies and necessary action plans to achieve compliance in these Round II comments.

Second, RNW identified both substantive and process concerns with PacifiCorp's removal of Boardman-to-Hemingway, which parallel similar concerns from Staff and other parties. PacifiCorp's reply and subsequent discussions –while providing additional detail – have elevated new concerns related to both transmission and resource planning for existing and future loads. PacifiCorp's framing of B2H disposition and future potential to serve Central Oregon load centers continues to evolve with limited positive resolution for Oregon ratepayers; RNW reiterates and expands on prior recommendations in these Round II comments.

Third, RNW identified major concerns with the methodologies developed for the 2025 IRP to assign resources to specific jurisdictions, with significant discriminatory impacts to Oregon and Washington customers. These concerns parallel similar concerns raised by Staff. In its reply, and subsequent conversations, PacifiCorp maintains that the IRP is not a cost allocation exercise,² yet concedes that the modeling and data ecosystem developed within the IRP are essential components of other processes, including bid evaluation and jurisdictional allocation³. Further, the Inter-Jurisdictional Allocation Process ("IJAP") submitted following Round I comments provides no additional clarity, simply referring to the allocation of policy-driven procurement to designated states.⁴ RNW reiterates its concern that, while PacifiCorp has not provided a clear articulation of an allocation methodology to assess and allocate state policy-

¹ RNW Opening Comments, p. 26 (July 29, 2025).

² PacifiCorp Reply Comments, p. 8 (Aug. 26, 2025).

³ 2027 Integrated Resource Plan Public Input Meeting, PacifiCorp (Oct. 1, 2025), available at: https://www.pacifiCorp.com/content/dam/pcorp/documents/en/pacifiCorp/energy/integrated-resource-plan/2027-irp/PacifiCorp_2027_IRP_PIM_1.pdf.

⁴ *In re PacifiCorp Application for Approval of 2026 Inter-Jurisdictional Allocation Protocol*, Docket No. UM 2401, PacifiCorp's Application for Approval of the 2026 Inter-Jurisdictional Allocation Protocol (Aug. 1, 2025).

driven costs fairly, it has introduced an upstream, and potentially precedential, analytical framework that egregiously conflates energy and reliability needs with state policy requirements. The allocation methodology embedded in this IRP and proposed in the IJAP cannot and should not be considered the proper foundation by which PacifiCorp may plan, procure, and allocate costs to be considered just and reasonable by the OPUC.

RNW's Round I comments provided limited commentary on the 2025 Clean Energy Plan ("CEP"), which was released only a few weeks prior to Round I comments. In these Round II comments, we provide our initial review of the CEP, including a preliminary assessment of PacifiCorp's current and planned continual progress toward HB 2021 requirements, the proposed HB 2021 analytical framework, and unresolved analytical questions and concerns related to the HB 2021 portfolios and counterfactuals.

While we acknowledge the steps PacifiCorp has indicated to improve its current RFP process, such as the removal of the deliverability requirement in the upcoming RFP and the agreement to conduct a sensitivity study on the B2H transmission line, these limited improvements do not assuage RNW's broader concerns with the IRP and CEP. These comments will expand upon our initial critiques by replying directly to PacifiCorp's responses to our previous comments and demonstrating that: 1) the Company's procurement strategy remains inadequate for meeting near-term reliability needs and capturing expiring federal tax credits; 2) the removal of B2H from its preferred portfolio is a failure of proactive planning; 3) compliance costs for HB 2021 in the CEP are likely significantly overstated; and 4) its cost allocation methodology fails to distinguish procurement drivers leading it to inappropriately assign excess costs to Oregon customers in an unjust and unreasonable manner. RNW has specific recommendations for the Commission to address these four topics.

III. Addressing PacifiCorp's Near- and Mid-Term Procurement Needs

In Round I comments, RNW identified the steep procurement trajectory necessary for PacifiCorp to address procurement needs through 2030, needs exacerbated by the Company's persistent procurement delays and deferrals since the 2021 IRP. In its Round I comments, RNW identified substantial energy and reliability needs to comply with WRAP, address declining availability of market purchases, and fulfill state clean energy policy requirements in western states.

While RNW acknowledges PacifiCorp's removal of the deliverability requirement in its RFP as a positive first step, we remain deeply concerned that the Company's overall procurement strategy may be inadequate for meeting its pressing near-term needs on tight timelines. PacifiCorp's current RFP, which targets a 2029 online date, may be insufficient to address upcoming deadlines for reliability compliance and federal tax credit eligibility.

RNW is concerned that PacifiCorp’s RFP and broader procurement compliance framework lacks clear safeguards to prevent underprocurement for both reliability and clean energy needs. Regarding reliability, while WRAP (or any RA program) will require PacifiCorp to show sufficient resources (or face compliance penalties), it is unclear that its WRAP showing structure will specifically ensure sufficient reliability resources are located in or deliverable to PACW to ensure reliability in Oregon in a shortfall event. Regarding clean energy, the enforcement process is ambiguous, and PacifiCorp has faced little regulatory consequence for its delays and cancellations since the 2021 IRP. These risks are significantly compounded by PacifiCorp’s exclusion of data center load growth in Oregon, which may mask considerable incremental resource needs in coming years.

The urgency of this situation is underscored by recent directives from both the Oregon and Washington Commissions, which have instructed PacifiCorp to be prepared to conduct a second round of procurement in 2026 to align with B2H development and potential updates on Bonneville Power Administration (BPA) transmission planning reforms⁵.

To effectively manage these competing deadlines, RNW proposes that the Commission direct PacifiCorp to incorporate three specific oversight requirements for its Oregon procurement:

- 1) **Federal Tax Credits:** Pursuant to Governor Kotek’s Executive Order No. 25-25⁶, PacifiCorp should be directed to acquire projects that can capture expiring federal tax credits, requiring projects to begin construction before the end of this year or, alternatively, before the July 1, 2026, safe harbor deadline and report on both procurement progress and projects which were not selected to OPUC. These resources should either be sought and expedited through PacifiCorp’s Oregon-situs RFP or through a bilateral call akin to Portland General Electric’s approach.⁷
- 2) **Reliability Needs:** PacifiCorp should be directed to ensure it procures sufficient resources to maintain reliability on the PACW system and meet WRAP requirements for serving PACW load in the Forward Showing and Operational Program ahead of the binding 2028 deadline.

⁵ *Washington Utilities and Transportation Commission v. PacifiCorp*, Washington Commission Docket No. UE-250460 Order 02, pp. 7-9 (Sept. 2, 2025), available at: <https://apiproxy.utc.wa.gov/cases/GetDocument?docID=79&year=2025&docketNumber=250460>; *In re PacifiCorp Application for Partial Waiver of OAR Chapter 860-089, Request to Engage Independent Evaluator, and Approval of 2025 Draft RFP*, Docket No. UM 2383, Order No. 25-343, Appendix A at 10-12 (Aug. 29, 2025), available at: <https://apps.puc.state.or.us/orders/2025ords/25-343.pdf>

⁶ Or Executive Order No. 25-25 (Oct. 6, 2025), available at: <https://www.oregon.gov/gov/eo/eo-25-25.pdf>.

⁷ See Attachment B (“On July 29, 2025, PGE issued a bilateral call for renewable and hybrid resource power purchase agreements (PPAs) capable of capturing the expiring federal tax credits.”).

- 3) **Clean Energy Needs:** PacifiCorp should be directed to ensure it procures sufficient resources needed for compliance with HB 2021 in 2030 through its Oregon-situs RFP. PacifiCorp should also be prepared to pursue another round of procurement in 2026, per Commission Order 25-343.

While these requirements reflect distinct resource needs and policy constraints, they will inherently be met with shared resources as part of a blended portfolio. The reality of these overlapping needs underscores the importance of addressing multi-benefit resource cost allocation within PacifiCorp's cost allocation framework, as discussed in Section III.

This concern is amplified by the problematic exclusion of data center loads from the IRP forecast. While PacifiCorp claims this exclusion is to protect existing customers, it prevents stakeholders from understanding the system-wide costs and benefits that this additional load could provide. Excluding a large and known source of demand makes true system-wide optimization impossible by understating future transmission and generation needs, a direct contradiction of PacifiCorp's own long-held position that planning for a large, integrated system is more efficient than planning for its pieces separately.

In these Round II comments, RNW provides additional development on two critical issues related to quantifying PACW system needs. First, we elaborate on our comments on potential WRAP deficiencies caused by east-west transmission constraints, which fail to adequately distinguish between resources needed solely for reliability and those necessary to comply with state policy. Second, we discuss the impacts of PacifiCorp's ill-justified decision to remove anticipated bundled load growth from the IRP.

A. Understanding East-West Implications for WRAP Compliance

In Round I comments, RNW identified the potentiality that WRAP's Business Practice Manual ("BPM") requirements on firm transmission service could prevent PacifiCorp from submitting a single Forward Showing for both regions, and could instead require PacifiCorp to file separate showings limiting PACE resource service to PACW to the volume of resources which could be supported by firm transmission⁸. While RNW's interpretation of the WRAP BPM requirements and implications for PACW has not changed, RNW understands that PacifiCorp currently plans to file a single integrated Forward Showing.

RNW does not object to PacifiCorp making an integrated Forward Showing for PACE and PACW. However, RNW is concerned that a single showing may not be sufficient to ensure that PacifiCorp is procuring a sufficient portfolio to ensure physical reliability for its Oregon customers. Moreover, in the event that WRAP's transmission service requirements are enforced

⁸ RNW Opening Comments, p. 10.

around PacifiCorp’s known east-west transmission constraints at a later date, PacifiCorp would be deficient on its WRAP requirements.

It is worth noting that WRAP is exploring revisions to its geographic framework to align with the CAISO Extended Day Ahead Market and SPP Markets Plus participant footprint. While this change would be significant for WRAP, it is unclear that it would modify the internal transmission constraint between PACW and PACE, which is triggered not by the WRAP geographic boundaries but by the requirement that participants are able to serve their own internal load without significant transmission constraints. Moreover, this requirement reflects physical reliability risk should PacifiCorp have insufficient transmission to bring necessary reliability capacity from PACE to PACW in a shortfall event.

Section VI further explores RNW’s analysis on PACW’s shortfall.

B. Addressing Excluded Load Growth Impacts on WRAP and HB 2021 Needs

Numerous parties raised concerns with PacifiCorp’s decision to exclude anticipated native load growth from data centers from its analysis. In its Reply Comments and subsequent stakeholder conversations, PacifiCorp frames this exclusion on the concept that data center loads will be served under alternative regulatory structures, asserting that “Special contracts or tariffs will determine the matching of large meter load and resources...”⁹, referencing the Oregon POWER Act as well as forthcoming policy developments to address large loads. Regardless, PacifiCorp concedes that these loads will be native, bundled customers served.

RNW understands the Oregon POWER Act to separate certain new large loads as a new customer class, with the intention of insulating other customers from cost impacts. While the Oregon POWER Act envisions some of this load being served through special self-provision structures, perhaps similar to “Clean Transition Tariff” (“CTT”) rates under development in Nevada, it neither obligates large loads to bring their own generation resources nor excludes large loads from being considered bundled load which must be planned for under the Oregon IRP process.

The Commission’s IRP Guidelines provide that “[a]t a minimum,” an IRP “must include the following elements: ... c. For electric utilities, ... identification of capacity and energy needed to bridge the gap between expected loads and resources[.]”¹⁰ The Guidelines direct an electric utility to exclude only “customer loads that are effectively committed to service by an alternative electricity supplier.”¹¹ While this language in the Guidelines was originally intended to apply to Direct Access, it may also apply to new loads entering into special contracts under the

⁹ PacifiCorp Reply Comments, p. 15.

¹⁰ *In re Public Utility Commission of Oregon Investigation Into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002, Appendix A at 4 (Jan. 8, 2007) (Guideline 4).

¹¹ Docket No. UM 1056, Order No. 07-002, Appendix A at 6 (Guideline 9).

POWER Act to the extent such contracts contemplate that a third party will provide service to the new load. However, absent evidence that a specific expected new load will be served by a third party through either the Direct Access program or a special contract, the Guidelines clearly require PacifiCorp to plan to meet these new loads.

These incremental data center loads are likely significant, and will have major implications for portfolio management as well as for compliance with WRAP and HB 2021. While some of these loads may bring their own resources, OPUC should direct PacifiCorp to integrate these loads into its resource planning process, with designated proxies intended to represent future sleeved contracts at levels to be reviewed through formal regulatory processes.

IV. Boardman-to-Hemingway (B2H)

RNW acknowledges PacifiCorp's agreement to conduct a sensitivity study on B2H as a valuable, if overdue, first step. However, a study is merely a starting point to guide decisions, and its inclusion in the 2025 IRP Update is simply too late to inform the urgent procurement decisions the company faces. The removal of a project with over \$1 billion in estimated customer benefits¹² based on a procedural delay is an unacceptable failure of proactive planning.

Therefore, RNW urges the Commission to take the following actions:

1. Decline to acknowledge PacifiCorp's removal of B2H from its preferred portfolio;
2. Direct PacifiCorp to reincorporate B2H into the base case for the 2025 IRP Update and 2027 IRP; and
3. Direct PacifiCorp to actively work with BPA to resolve the status of its transmission redirect requests and update the Commission and stakeholders on the company's progress.

RNW and other stakeholders continue to seek to engage PacifiCorp regarding its plans for B2H. At the October public input meeting, PacifiCorp provided additional clarification of its intent with B2H, indicating that it will serve bundled PacifiCorp load growth but the timeline and cost for the BPA redirect to urban load centers in PACW remains unclear. RNW is concerned that this framing implies PacifiCorp may have doubts regarding the value of B2H for existing bundled PACW customers, and is concerned that PacifiCorp was unable to provide a framework for how such an economic decision would be assessed and brought forth to regulators. As

¹² PacifiCorp 2023 IRP, p. 285 (Mar. 31, 2023), available at: https://www.pacifiCorp.com/content/dam/pcorp/documents/en/pacifiCorp/energy/integrated-resource-plan/2023-irp/2023_IRP_Volume_I.pdf.

discussed in these comments, integrated access improving PACW access to PACE resources would provide considerable value to PACW customers.

V. Evaluating PacifiCorp's Clean Energy Plan

A. Continual Progress

PacifiCorp's 2025 CEP claims it is meeting its continual progress requirements under HB 2021, achieving these primarily through a mix of non-emitting resources, coal-to-gas conversions, and storage additions, which, as it notes, do not directly achieve emissions reductions but are an important integration strategy for variable energy resources. While PacifiCorp's clean energy development has been slow, largely a function of its canceled 2022 RFP, RNW is pleased to see a significant share of solar and wind megawatts coming online in the 2024-2026 timeframe¹³. To achieve compliance with HB 2021, as well as CETA in Washington and SB 100 in California, PacifiCorp will need to build a significant quantity of new energy generating and storage resources through 2030 and beyond.

RNW provided extensive review and recommendations of PacifiCorp's continual progress in the 2023 IRP docket, LC 82, and subsequent contested case, UM 2345, and parallel analysis and recommendations in Washington's implementation of CETA. While these targets are meaningful in the model, ultimately, it will be PacifiCorp's ability to execute on these targets through solicitations, development, interconnection, and the broader work of bringing resources online that will be how its success is measured. In this CEP, PacifiCorp indicates its preliminary review of 2024 emissions achieved an 18.68% reduction from the 2010 baseline¹⁴. This leaves an additional 61.32% reduction which will be necessary through 2030. The tightness of this timeline is considerable, and will necessitate PacifiCorp's full commitment to pursuing and executing contracts through its RFP process.

RNW is continuing to review the CEP and will weigh in on the question of whether PacifiCorp has adequately demonstrated continual progress in our comments on the Staff Report. In conducting our evaluation of the company's continual progress, we look to Commission Order 24-002, where the Commission found that a continual progress determination requires a "robust weighing of costs, risks, and forecasted emissions reductions trajectories...to determine whether utility actions within the planning period are sufficient to constitute continual progress toward meeting the targets."¹⁵ RNW is currently working to "understand the tradeoffs around

¹³ PacifiCorp 2025 Oregon CEP, p. 6 (Jun. 30, 2025), available at: https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/community/or-cep/2025_Oregon_Clean_Energy_Plan.pdf.

¹⁴ PacifiCorp 2025 Oregon CEP, p. 5

¹⁵ *In re Public Utility Commission of Oregon, Investigation Into House Bill 2021 Implementation Issues*, Docket No. UM 2273, Order No. 24-002, p. 29 (Jan. 5, 2024).

practicability, emissions reductions, and costs”¹⁶ that HB 2021 requires and will provide a more comprehensive evaluation in future comments.

B. PacifiCorp’s HB 2021 Counterfactual Analysis

From a modeling perspective, RNW has conducted a preliminary review of the CEP analysis, but has had insufficient time to access the underlying CEP data files to conduct a meaningful analytical review. One of the most critical aspects of the CEP modeling is to inform the HB 2021 cost assessment using a reasonable counterfactual portfolio.

PacifiCorp’s 2025 CEP presents a counterfactual analysis to isolate the costs of HB 2021. According to the company, the net present value difference between its HB 2021 portfolio and a “No HB 2021” counterfactual is \$958 million.¹⁷ However, RNW’s review of the underlying cost summaries calls the validity of this analysis into question. Presumably, increased build costs due to HB 2021 clean energy procurement requirements would be offset by reductions in fuel costs for natural gas generation and market purchase costs. However, these presumed savings are not present in the cost summaries provided by PacifiCorp.

Comparing the cost summary files for the CEP Preferred Portfolio¹⁸ and the No HB 2021 Counterfactual¹⁹ model runs reveals surprising costs and revenues that contribute to the final present value revenue requirement (“PVR”) values presented in the CEP. First, gas generation costs appear higher in the Preferred Portfolio, driven by increased spending on fixed O&M for gas conversions. Paradoxically, the cost summaries for both the preferred CEP portfolio and the counterfactual show gas fuel *revenues* of approximately \$95 million instead of costs,²⁰ despite the IRP base case showing system-wide gas fuel costs of \$3.153 billion.²¹ Similarly, the cost of market purchases, which amounts to \$1.64 billion in the IRP base case,²² is entirely absent from both the preferred portfolio and No HB 2021 counterfactual cost summaries. Given the significance of fuel and market purchase costs in the IRP preferred portfolio, it is reasonable to assume that HB 2021 compliance would have some impact on these two cost categories. However, because PacifiCorp’s analysis appears to exclude both of these cost components, its \$958 million estimate of HB 2021’s cost may be a significant overstatement. Accordingly, we

¹⁶ Docket No. UM 2273, Order No. 24-002, p. 28.

¹⁷ PacifiCorp 2025 Oregon CEP, p. 78.

¹⁸ Public Workpaper (P)_OR Alloc ST Cost Summary - 25C.IR.ST.r21.OR.EP.2503MN.Clean110%AlwaysBind.Iterator (LT. 187421 - 187467) v.xlsb.

¹⁹ Public Workpaper (P)_OR Alloc ST Cost Summary -25C.IR.ST.r21.OR.EP.2503MN.NonComp.187535 (LT. 187535 - 187814) v10.5.xlsb.

²⁰ Public Workpaper (P)_OR Alloc ST Cost Summary -25C.IR.ST.r21.OR.EP.2503MN.NonComp.187535 (LT. 187535 - 187814) v10.5.xlsb.

²¹ Public Workpaper 02.Model Reports/IR.Integrated Runs/(P)_ST Cost Summary -25I.LP.ST.r21.1-20.EP.2409MN.Integrated.178156 (LT. 178156 - 178290) v108.4.xlsb.

²² Public Workpaper 02.Model Reports/IR.Integrated Runs/(P)_ST Cost Summary -25I.LP.ST.r21.1-20.EP.2409MN.Integrated.178156 (LT. 178156 - 178290) v108.4.xlsb.

recommend that the Commission direct PacifiCorp to provide analysis on fuel costs and market purchase costs in the HB 2021 counterfactual scenario.

VI. Allocation Issues & Stranded Assets

In our initial comments, RNW detailed fundamental flaws in PacifiCorp's new cost and resource allocation methodology, arguing that it departs from decades of precedent by improperly treating system-wide reliability investments as jurisdiction-specific, state policy costs. We demonstrated how this flawed framework creates a significant stranded capacity risk, where Oregon customers would be forced to pay for eastern system capacity that cannot be physically delivered to serve Oregon load due to binding transmission constraints, while also being charged the full cost of replacement energy and capacity to replace dwindling market purchases long relied on for PACW. Unfortunately, PacifiCorp's primary response was the procedural claim that the IRP/CEP is not a cost allocation proceeding.²³ While technically true, this response ignores how the IRP's modeling structure effectively predetermines outcomes across multiple proceedings, including the CEP and its corresponding cost cap docket,²⁴ downstream RFPs,²⁵ and potentially the 2026 IJAP proceeding.²⁶ Thus, by embedding jurisdictional constraints that link state policy-driven resource needs to specific financial responsibility, the IRP creates a cascade of predetermined outcomes that effectively allocate costs before any formal allocation proceeding occurs. If these outcomes are not "predetermined", it is at least true that the bar to overcome the assumptions embedded in improper planning and cost allocation is significantly higher. The burden must remain on PacifiCorp to demonstrate that its planning, procurement, and cost allocation proposals are in the best interests of Oregon customers and will result in just and reasonable rates.

Lacking any substantive response on the concern, RNW's understanding remains unchanged. While PacifiCorp updated certain inputs between the IRP and CEP, it maintained the fundamental allocation framework and structural constraints that drive inequitable cost assignment. This indicates that the modeling errors we are criticizing have real implications for cost allocation and other proceedings, including the HB 2021 cost cap analysis.

A. PacifiCorp's Dual WRAP Constraint Methodology Contains Systematic Errors in Reliability Planning

In our Round 2 comments, we provide further detail on PacifiCorp's dual WRAP constraint methodology and its implications for resource allocation in the Company's 2025 IRP and CEP. PacifiCorp's dual constraint methodology attempts to bridge the physical limitations of the utility's system with jurisdictional cost allocation frameworks. While RNW recognizes

²³ PacifiCorp Reply Comments, p. 10.

²⁴ See Docket No. UM 2273.

²⁵ See Docket No. UM 2383.

²⁶ See Docket No. UM 2401.

PacifiCorp's effort to address the complex intersection of WRAP requirements and jurisdictional planning, the Company's approach contains fundamental flaws that could result in unnecessary costs being assigned to Oregon customers. Our analysis demonstrates that PacifiCorp's implementation systematically understates PACW's reliability requirements while creating a framework that would inappropriately allocate system reliability costs as if they were driven by state-specific policies, while continuing to saddle those same states with shared costs for PACE system resources which they cannot physically access. This represents a significant departure from longstanding cost allocation precedent whereby reliability costs are shared systemwide.

PacifiCorp implements its WRAP constraints using a dual constraint type methodology. The first constraint type is the jurisdictional WRAP constraint (e.g., WRAP OR, WRAP WA, WRAP UIWC), which apply firm capacity requirements to each jurisdiction according to the MSP/WIJAM allocation factors. These constraints also treat PacifiCorp's transmission network as a "copper sheet," meaning they ignore the critical 1,600 MW east-to-west transmission limitation between PACE and PACW. Under this framework, Oregon is allocated its proportional share of eastern resources, independent of whether they can physically serve Oregon load, thereby creating over 1,000 MW of stranded firm capacity through 2029.²⁷ This is the "deliverability" issue referenced throughout the proceeding. It is important to note that only PACW proxy resources are eligible to satisfy the WRAP OR and WRAP WA constraints, while only PACE proxy resources can satisfy WRAP UIWC constraints²⁸.

The second constraint type is one that is based on the physical limitations of PacifiCorp's system and is represented by WRAP West. This constraint applies firm capacity requirements directly to the PACW region, accounting for actual PACE export capability limited to 1,600 MW, as fulfillment is limited to resources located within PACW less 1,600 MW assumed to be consistently available from PACE. This constraint better aligns with WRAP's requirement that participants secure 75% firm transmission for forward showings and acknowledges PacifiCorp's split across WRAP subregions (PACE in SWEDE, PACW in MidC). Again, only PACW proxy resources can satisfy this constraint.²⁹ Because there is not a W-to-E deliverability issue, the Company elected to not define a 'WRAP East' constraint in the model, which would have evaluated the physical firm capacity balance of PACE. Such a constraint, however, could be included as part of a more robust framework, as discussed by RNW further below.

In Oregon's jurisdictional model, WRAP OR and WRAP West operate simultaneously. When a system reliability need arises, the binding constraint drives procurement of new proxy resources that must be physically located in PACW due to these eligibility restrictions. Because

²⁷ RNW Opening Comments pp. 7-9 (identifying over 1000 MW in stranded capacity risk due to the problematic assumptions behind the Jurisdictional WRAP Constraint).

²⁸ Attachment A at 1 (PacifiCorp Response to OPUC Data Request 32).

²⁹ Attachment A at 2-3 (PacifiCorp Response to OPUC Data Request 136).

only PACW proxy resources can satisfy these constraints, the new reliability resources are then situs-allocated to Oregon customers.³⁰

B. RNW's Independent Analysis Reveals Systematic Errors

Rather than utilize PLEXOS's native functionality for modeling firm capacity sharing across regions, PacifiCorp elected to manually implement all WRAP-related constraints using generic constraints.³¹ This manual approach requires PacifiCorp to calculate PACE's excess seasonal firm capacity for each planning year, a complex undertaking requiring precise accounting of existing resources, load obligations, and non-generation supply resources. Errors in any of these inputs can misrepresent the company's true reliability needs and affect both the quantity and type of proxy resources selected by the model.

The WRAP constraints defined in PLEXOS are critical because they are one of the primary mechanisms for maintaining reliability in the Company's portfolio.³² They achieve this by forcing the Company's portfolio to have enough firm capacity to satisfy the planning reserve margin ("PRM") requirement across the entire planning horizon

As previously discussed in our Round I comments, RNW identified instances of potential inaccuracy in the model with respect to the right-hand side ("RHS") values in PacifiCorp's WRAP constraints.³³ It appeared that the company adjusted the RHS values of the WRAP West constraint by subtracting a fixed 1,600 MWs from PACW's share of coincident peak load across all months. This offset was intended to represent imports from PACE. To assess the validity of this adjustment, RNW conducted an independent analysis to calculate what the seasonal RHS values for the WRAP West constraint should be based on PacifiCorp's existing portfolio and load forecast.

Our analysis began by extracting supply and requirement values defined in PLEXOS - as provided by the public working papers³⁴ - and comparing them to the Load and Resource (L&R) tables in the 2025 IRP.³⁵ As shown in Figure 1, generation and storage values in PLEXOS align closely with Tables 6.14 and 6.15 in the IRP. This confirms that PacifiCorp's existing resources

³⁰ PACW proxy resources selected by the model are allocated 75% to OR and 25% to WA.

³¹ PacifiCorp used generic constraints to model the PRM as a monthly constraint, since the version of PLEXOS they used for the IRP only supported annual constraints. However, starting with PLEXOS v11, the software is now capable of modeling seasonal or monthly firm capacity constraints endogenously, negating the need to implement these constraints using generic constraints.

³² As discussed in previous IRP proceedings, PacifiCorp also employs an iterative procedure consisting of deploying Reliability Adjustments that bridge the Long-Term (LT) and Short-term (ST) model runs and achieve convergence when there is no hourly energy not served (ENS).

³³ See RNW Opening Comments, Attachment A.

³⁴ Public Workpaper (P)_LT_25I.LP.iLT.21.Integrated.EP.2409MN.Base IntTrans_155264 v101.1.xlsx.

³⁵ Public Workpaper (P)_Fig 6.2-6.7, Tbl 6.14-6.15, 9.12-15, 2025 IRP Final March - L&R.xlsx.

are consistently represented. However, this alignment applies only to generation and storage; our analysis of non-generation resources revealed critical discrepancies, as discussed below.

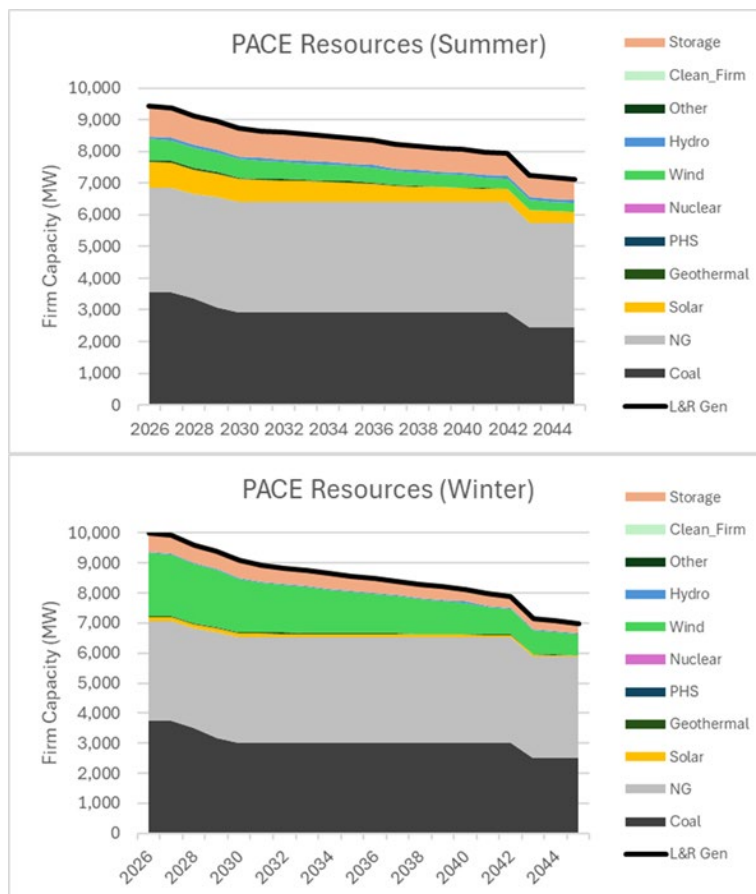


Figure 1: PACE Loads and Resources (L&R) Table (Existing Resources Only)

Next, RNW analyzed the primary components that go into defining the RHS of the constraint by examining the forecasts for load, demand response, and energy efficiency. We found that the seasonal peak load and demand response values aligned between the two sources but the schedule for existing energy efficiency revealed a large discrepancy. Figure 2 compares the values listed in L&R tables to those defined in PLEXOS across the summer and winter showings for both PACE and PACW. The largest delta appears in PACE’s summer showing. In the beginning, both schedules reflect around 100-200 MWs of existing energy efficiency. However, from that point onward, the L&R schedule escalates steadily to reach 1,600 MW of firm capacity by 2045. Meanwhile, the PLEXOS values remain essentially flat. We observed this issue in PACE’s winter showing as well, and a similar pattern was observed in PACW.



Figure 2: Comparison of Existing Energy Efficiency (EE) and Demand Response (DR) between PLEXOS and L&R Tables

Once we correct for this error, we find that PACE’s actual export capability is constrained by both the 1,600 MW east-to-west transfer limit and its own reliability obligations. Figure 3 displays PACE’s ‘Obligation,’ which consists of its share of system coincident peak load (adjusted for existing demand response and energy efficiency), grossed up by the corresponding seasonal planning reserve margin.³⁶ ‘Supply’ represents the firm capacity provided by all the generation and storage that is physically located in PACE, prior to the application of MSP allocations. The difference between Obligation and Supply represents PACE’s excess capacity that is available for export to PACW, herein referred to as ‘Length.’

The summer season (top graph) reveals that PACE’s export capability ranges from only 700-1,300 MW between 2026 and 2029, substantially below PacifiCorp’s assumed 1,600 MW in PLEXOS. By 2032, PACE faces its own reliability deficit, unable to meet load and reserve obligations with only existing resources due to load growth, portfolio changes, and declining ELCC values.

The winter season (bottom graph) presents a markedly different situation. PACE maintains excess capacity exceeding 1,600 MW through 2030, with no reliability-driven procurement needs until 2037 based on PacifiCorp’s 2025 IRP assumptions. However, even

³⁶ For Winter, RNW assumes the PRM value for January (16.8%) and for Summer we apply the value from July (14.4%).

when PACE has surplus capacity beyond 1,600 MW, transfers to PACW remain capped at 1,600 MW due to transmission constraints.

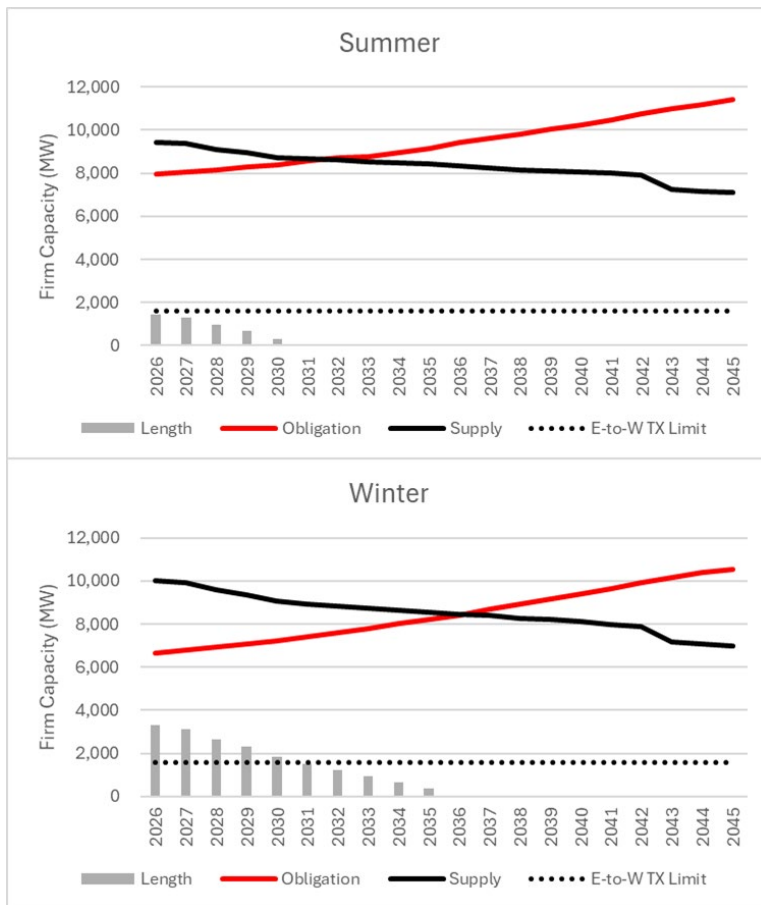


**Figure 3: PACE Firm Capacity Balance with Corrected EE Schedule
(Existing Resources Only)**

Having established PACE’s actual export capability, we next examine the impact it has on PACW. Figure 4 illustrates PACW’s corrected firm capacity balance. Similar to PACE, ‘Obligation’ represents PACW’s overall need for firm capacity, and ‘Supply’ captures all the existing generation and storage resources physically located in PACW. ‘Net Obligation’ reflects Obligation minus available PACE imports (equal to the lesser of PACE Length and 1,600 MW). PACW’s open reliability position is captured by ‘Shortfall’ and is the difference between Net Obligation and Supply.

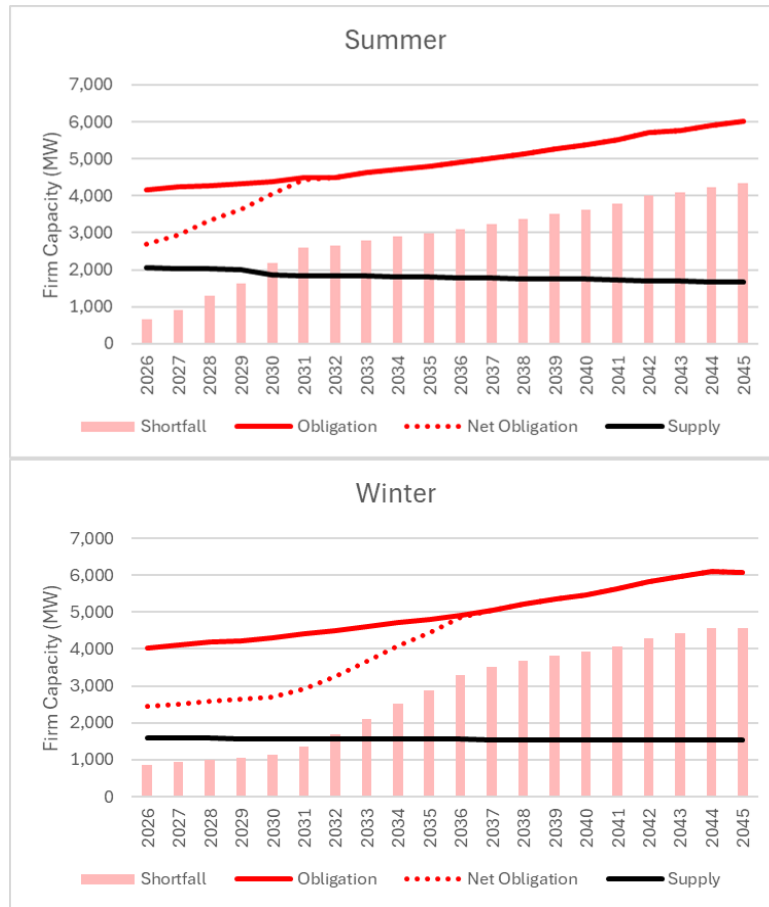


Figure 4: Firm capacity balance for PACW with the revised availability of imports from PACE

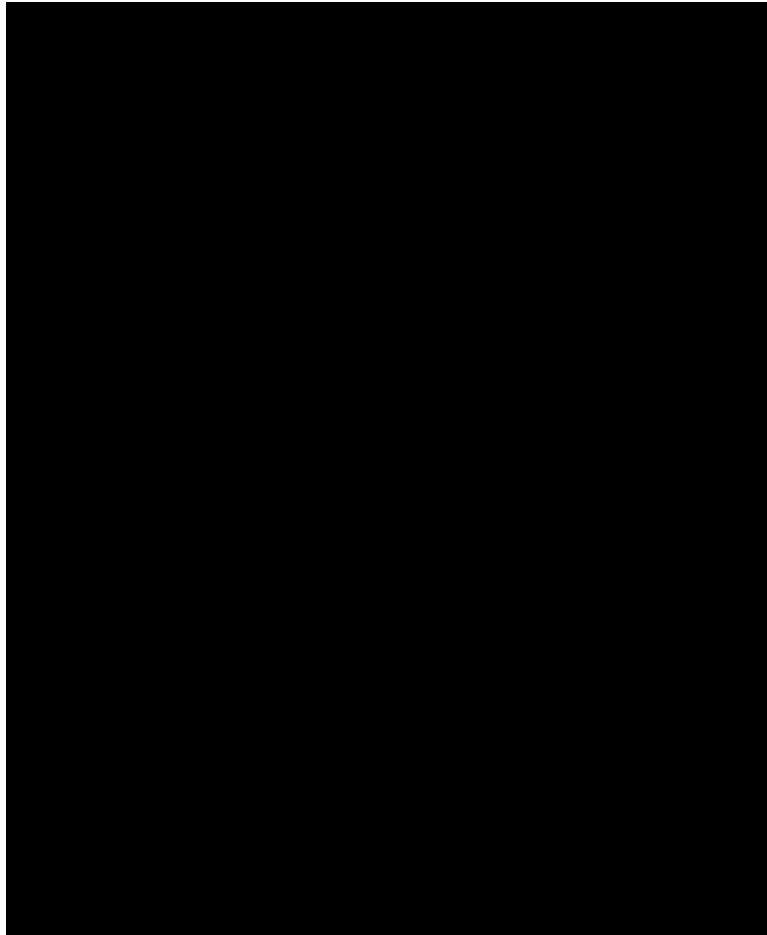
With PACW’s actual firm capacity balance now known using the corrected input values, RNW compared these requirements against the RHS values for the WRAP West constraint that PacifiCorp manually entered in PLEXOS. Figure 5 presents this comparison, plotting PacifiCorp's PLEXOS constraint values against RNW’s calculated Net Obligation for PACW.

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Without other constraints driving additional investment in new generation or storage, this underrepresentation would result in PACW having a shortfall in a firm capacity and likely produce unserved energy in the hourly ST model. This would necessitate post hoc corrections through PacifiCorp’s iterative Reliability Adjustment process.

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Figure 5: PACW L&R Balance Compared to PLEXOS (Existing Resources Only)

Despite the WRAP West constraint being systematically underrepresented, PLEXOS continues to solve without showing major reliability shortfalls because Oregon and Washington’s environmental policies incidentally drive the selection of sufficient proxy resources to mask the error. Figure 6 illustrates PACW’s capacity position after incorporating these proxy resources³⁷. As shown, environmental constraints, such as Oregon’s HB 2021, force the model to procure enough resources to cover PACW’s true reliability needs. Beginning in 2030, state-led policies drive procurement in PACW beyond what reliability alone would require. This masking effect creates a critical resource (i.e., cost) allocation problem: a portion of system reliability needs is being met by resources selected for policy compliance, which are situs-allocated to Oregon and Washington. As a result, western customers are improperly assigned higher allocations of proxy resources than necessary to maintain system-wide reliability, to the benefit of ratepayers on the east side of the system.

³⁷ Note that both Obligation and Net Obligation in Figure 6 differ from what is shown in Figure 5 due to PLEXOS's selection of additional load-modifying resources in both the PACE and PACW regions.

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Figure 6: PACW L&R Balance Compared to PLEXOS (with Proxy Resources)

C. Critical Implications for Cost Allocation

This mischaracterization has profound implications for future cost allocation proceedings, potentially resulting in Oregon customers paying for reliability investments that should rightfully be shared across PacifiCorp’s six-state footprint.

i. The Fundamental Problem

PacifiCorp acknowledges in its Round 1 reply comments that “WRAP requirements are not necessarily the most restrictive constraint on modeling” and that higher planning reserve margins for Oregon are “a product of all constraints included in modeling.”³⁸ While RNW agrees that environmental constraints can drive procurement beyond strict reliability requirements, this observation underscores rather than resolves the problem. Without accurate WRAP constraint values and proper modeling framework, it is impossible for any planning exercise to accurately distinguish between reliability-driven and policy-driven procurement. This distinction is essential because costs associated with system reliability resources should be shared proportionally across

³⁸ PacifiCorp Reply Comments, p. 31.

all ratepayers, whereas state-specific policy resources should be situs-allocated. PacifiCorp currently lacks the proper setup to accomplish this critical distinction.

ii. The Resource Eligibility Problem

PacifiCorp agrees that reliability costs should be shared system-wide and argues that their jurisdictional approach achieves this because the WRAP constraints are defined by each jurisdiction's share of system coincident peak.³⁹ However, this argument ignores the binding resource eligibility constraints embedded in the modeling framework. Recall, only PACW proxy resources can satisfy WRAP West and WRAP OR constraints, while only PACE proxy resources can satisfy WRAP UIWC constraints. This geographical restriction creates an inequitable outcome: if PACW resources carry cost premiums relative to PACE resources—whether due to market conditions, interconnection costs, or resource scarcity—Oregon and Washington customers bear these premiums entirely. This forced assignment violates the MSP/WIJAM framework, which allocates system costs proportionally regardless of resource location.

iii. Historical Context and Current Impact

PACW's large open position, which is the result of historical planning decisions that prioritized market reliance for western loads while building owned generation in the east, exacerbates this biased arrangement. Prior to WRAP implementation and state clean energy policies, this geographical imbalance was inconsequential because all costs were allocated proportionally based on load share and market purchase supply was robust. However, the convergence of WRAP's deliverability requirements and PacifiCorp's proposed jurisdictional framework fundamentally disrupts this precedent. Now, under the current structure, PACW customers not only face costs tied to achieving regional clean energy goals but also cost premiums associated with maintaining system reliability. While RNW acknowledges that it is appropriate and necessary to situs-allocate Oregon costs associated with CEP-related policies (e.g., SB 1547, HB 2021, etc.), the reliability component must remain a shared system cost.

To illustrate how reliability and jurisdictional clean energy policies have become intertwined, RNW analyzed the range of possible resource and cost allocation interpretations in the CEP. Figure 7 shows PACW's firm capacity balance under the MSP-WIJAM allocation framework. Here, all existing resources, from both PACE and PACW, are allocated to each jurisdiction proportionally. Critically, the MSP framework ignores all transmission constraints on PacifiCorp's system. Under this framework, there are no "imports" per se, only allocations.

Prior to 2030, PACW receives approximately 33% of each resource, with the remainder allocated to PACE (i.e., the UIWC jurisdiction). The figure clearly shows two major transitions that are driven by Oregon's environmental policies. First, in 2030, any coal in which PacifiCorp

³⁹ PacifiCorp Reply Comments p. 12.

has majority ownership rights rolls off Oregon’s rate base per the terms of SB 1547. Second, in 2040, HB 2021’s requirement for 100% GHG-free energy precludes any natural gas facilities—existing or new—from Oregon’s allocated resource stack. We can think of this allocation-based framing, rather than one based on the physical representation of the system, as one bookend.

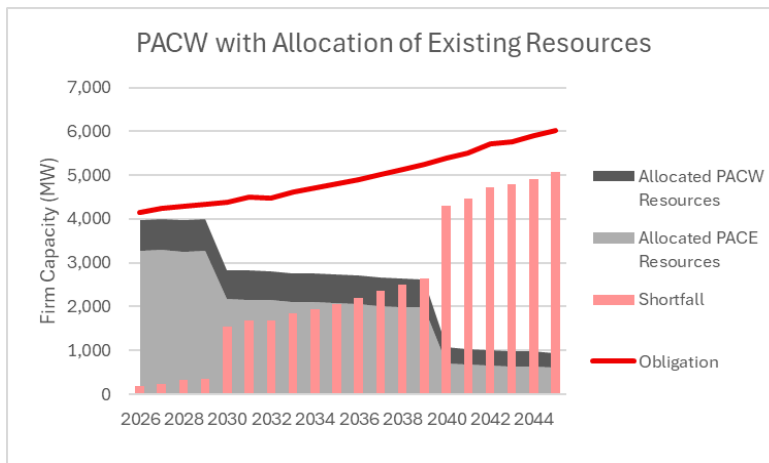


Figure 7: PACW Firm Capacity Balance Under MSP-WIJAM Allocation Framework (Existing Resources Only)

Next, we compare the PACE allocations assigned to PACW from Figure 7 against the PACE imports into PACW calculated in Figure 3. We will use the summer season as our illustrative example. Organizing the company’s existing portfolio through a physical lens, one that honors all transmission constraints on PacifiCorp’s system, provides our other bookend. Under this physical framework, PACW can only import what PACE can export, which is limited by both PACE’s length and the 1,600 MW transmission constraint.

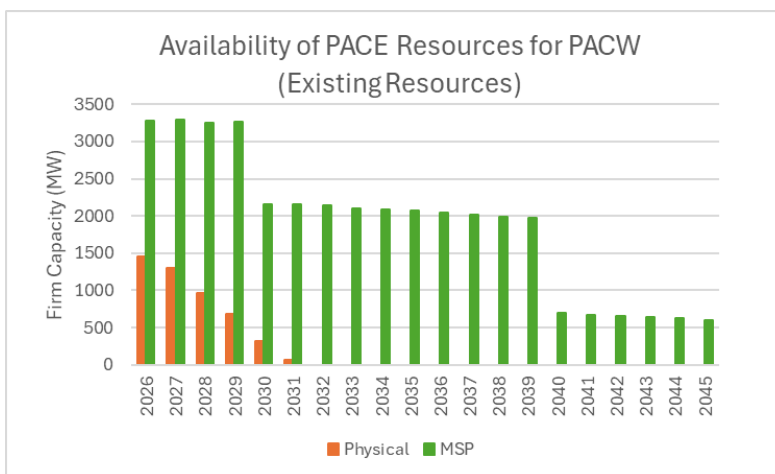


Figure 8: PACW Firm Capacity Balance Under MSP-WIJAM Allocation Framework (Existing Resources Only)

Finally, Figure 9 compares PACW’s firm capacity shortfalls under both methodologies: the physical and MSP approach. Counterintuitively, the shortfall under the physical methodology exceeds the MSP allocation shortfall, even after coal is removed from Oregon’s rate base in 2030. This occurs because the capacity stranded by transmission limitations (the difference between MSP allocation and physical deliverability) exceeds the firm capacity lost from the removal of coal. Said otherwise, transmission constraints create a larger capacity deficit for PACW than the loss of coal resources.

These bookend scenarios illustrate the critical importance of developing a robust framework that properly accounts for both transmission constraints and jurisdictional policy requirements. RNW is not advocating for either extreme position. Rather, we present this analysis to demonstrate the complexity of optimizing a system-wide portfolio across regions with diverging clean energy and GHG reduction goals. Any allocation framework PacifiCorp utilizes as part of its IRP and related proceedings must ensure fair treatment of all customers while addressing reliability and regional policy complexities that have fundamentally altered the historical planning paradigm.

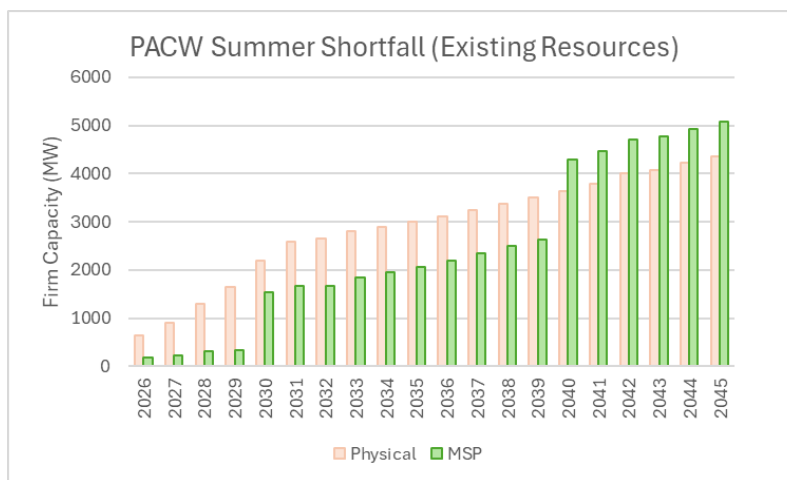


Figure 9: PACW Firm Capacity Balance Under MSP-WIJAM Allocation Framework (Existing Resources Only)

VII. RNW’s Proposed Framework for Proper Cost Allocation

The following represents a high-level conceptual framework to illustrate how proper cost allocation between reliability and policy requirements could be achieved. A fully detailed methodology will require collaborative development among PacifiCorp, Staff, and external stakeholders to ensure technical accuracy, completeness, and operational feasibility. RNW has appreciated the collaborative work that has taken place to date among that same set of parties.

To ensure fair allocation of costs between energy and reliability needs (which will be system-allocated) and state policy requirements (which will be situs-allocated), RNW proposes the following framework:

Step 1: Establish True Reliability Baseline

Determine the least-cost resources needed purely for system reliability, exclusive of state policies (clean energy mandates, emissions constraints, or technology preferences). These baseline costs will include any premiums and/or discounts that are a function of the selection of proxy resources from a particular geographic location and would be shared across all PacifiCorp customers according to the MSP/WIJAM framework.

Step 2: Identify Policy-Driven Incremental Costs

Run separate jurisdictional models with state-specific requirements activated to identify the incremental cost premium each jurisdiction incurs beyond the reliability baseline counterfactual established in Step 1. These premiums represent the true cost of state policies and would be situs-allocated to the driving jurisdiction.

Step 3: Integrated System Optimization

Conduct a final system-wide optimization with all constraints active simultaneously to determine if there are any cost savings available as a result of overlapping regional constraints.

Step 4: Allocate Cost Savings

If the integrated run from Step 3 produces any savings relative to the sum of individual policy premiums calculated in Step 2, allocate these savings proportionally to each jurisdiction, ensuring no state pays more than its standalone policy costs while all benefit from system efficiencies.

Without a clear framework separating reliability from policy-driven needs, PacifiCorp risks selecting the wrong magnitude and type of resources for its system, fundamentally distorting both planning and procurement decisions while compromising system reliability and undermining each jurisdiction's clean energy goals. This flawed approach not only undermines system optimization but creates a discriminatory cost allocation framework where certain customers, particularly in Oregon and Washington, bear disproportionate costs for resources that serve system-wide reliability needs while simultaneously addressing regional policy objectives. If left unaddressed, these allocation errors will cascade through downstream proceedings including rate cases, RFP evaluations, and future MSP negotiations, potentially resulting in billions of dollars in misallocated costs.

VIII. Conclusion and Recommendations

PacifiCorp's slow procurement action in the face of pressing needs merits bold action from Oregon's regulators. PacifiCorp's 2025 IRP and CEP, and its subsequent replies, fail to present a least-cost, least-risk path forward for Oregon customers. RNW supports the Company's ongoing efforts to fulfill its near-term needs through the Oregon and Washington situs RFPs, and encourages the Company to act swiftly to capture expiring tax credits. Its removal of the critical B2H transmission line based on a procedural delay is an unacceptable planning failure that harms Oregon customers. Most fundamentally, the IRP's flawed allocation framework creates the basis for an unjust and unreasonable outcome by conflating system reliability costs with state policy costs, creating significant stranded asset risk that Oregon customers will ultimately pay for. As explained above, RNW believes this problem is solvable. Again, we appreciate the willingness of PacifiCorp's IRP team to work with stakeholders including RNW on possible solutions. We look forward to continued work with the company to identify a modeling approach that appropriately balances achieving Oregon policy with planning for a diverse six-state system.

For the reasons detailed in these comments, RNW urges the Commission to take immediate and decisive action. Specifically, we recommend that the Commission take the following actions in regard to specific elements of the IRP and CEP:

Boardman to Hemmingway:

1. Decline to acknowledge PacifiCorp's removal of B2H from its preferred portfolio.
2. Direct PacifiCorp to reincorporate B2H into the base case for the 2025 IRP Update and 2027 IRP.
3. Direct PacifiCorp to actively work with the BPA to resolve the status of its transmission redirect requests and update the Commission, Staff, and stakeholders on the company's progress.

Allocation Framework:

4. Decline to acknowledge the allocation framework underlying the 2025 IRP.
5. Direct PacifiCorp to work collaboratively with Staff and stakeholders to develop a framework that properly separates system reliability costs from state-specific policy costs and ensures WRAP compliance costs are modeled and allocated system-wide. This framework should be vetted through a transparent stakeholder process and implemented before the next IRP cycle to ensure consistent application across all planning, procurement, and ratemaking activities.

Procurement Action:

6. Acknowledge Action Item 2b, which initiates the 2025 RFP.
7. Direct PacifiCorp to engage in accelerated procurement to capture the benefits of expiring federal tax credits, pursuant to EO 25-25.
8. Direct PacifiCorp to procure sufficient resources to maintain reliability on the PACW system and meet WRAP requirements for serving PACW load in the Forward Showing and Operational Program ahead of the binding 2028 deadline.
9. Direct PacifiCorp to procure sufficient resources needed for compliance with HB 2021 in 2030.

2025 Oregon Clean Energy Plan:

10. Direct PacifiCorp to provide analysis on fuel costs and market purchase costs in the HB 2021 counterfactual scenario.

Respectfully submitted this 9th day of October 2025,

/s/ Mike Goetz

/s/ Katie Chamberlain

/s/ Max Greene

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⁴⁰ Signatory as to redacted comments only.

⁴¹ Signatory as to redacted comments only.

Attachment A

PacifiCorp Responses to OPUC Data Requests

OPUC Data Request 32

Please describe any alternative methodologies the Company considered for construction of policy-compliant jurisdictional portfolios.

Response to OPUC Data Request 32

PacifiCorp's Draft 2025 Integrated Resource Plan (IRP) methodology for achieving policy-compliant jurisdictional portfolios allowed resources selected by a given jurisdiction to be built anywhere on PacifiCorp's system. This meant that in the Draft 2025 IRP preferred portfolio, resources necessary for individual state policy compliance allocated to the state whose policy necessitated the addition of the resources did not need to be built within that state or jurisdiction (Draft 2025 IRP, Volume I, page 2). PacifiCorp had concerns about this approach, specifically that resources selected by one jurisdiction but built in another jurisdiction would not be deliverable to the jurisdiction that selected those resources to meet its policy compliance. In the 2025 IRP, PacifiCorp revised this methodology so that in the preferred portfolio, resources necessary for individual state policy compliance were assumed to be situs-allocated and deliverable to the state whose policy necessitated the addition (2025 IRP, Volume I, page 2). For Oregon and Washington, this meant that only new resources built on the west side of PacifiCorp's system were eligible to serve requirements in those states.

For further information regarding PacifiCorp's methodologies for creating policy-compliant portfolios, please refer to PacifiCorp's Draft 2025 IRP and PacifiCorp's 2025 IRP, Chapter 1 and Chapter 8.

OPUC Data Request 136

OR Jurisdictional Modeling – See the Company’s response to OPUC DR 57 that says, “Without any incremental transmission between PacifiCorp’s west and east balancing authority areas (BAA), incremental resources needed to serve load outside of Longhorn load area located in the PacifiCorp West (PACW) BAA will need to be deliverable to west-side loads.”

- (a) In the 2025 IRP, explain how the Company modeled the requirement that all new resources needed for load in PACW would need to be deliverable to PACW. Does “deliverable” to PACW mean resources cannot be located outside of PACW?
- (b) Provide a definition of “deliverable” in this context and an explanation of the modeling inputs, settings, and constraints used to implement the requirement for new resources.
- (c) How is a new resource determined to be “needed to serve load” in the PACW BAA?

Response to OPUC Data Request 136

- (a) The Company notes that the excerpt from its response to OPUC Data Request 57 quoted by in this data request does not specifically refer to modeling in the 2025 Integrated Resource Plan (IRP) and is more applicable to the Company’s Oregon Situs request for proposals (RFP). Based on the foregoing clarification, the Company responds as follows:

In its 2025 IRP, PacifiCorp required that proxy resources allocated to Oregon and Washington be physically located within the West balancing area authority (BAA) by only counting proxy resources in the West towards Oregon and Washington compliance. Therefore, yes, in the context of the 2025 IRP, it is assumed that “deliverable” to the West BAA means that resources must be physically located in the West.

- (b) “Deliverability”, as used here, describes the ability of a given resource’s output to flow across transmission lines and sink at a point within the West BAA. In the context of the aggregated topology used in the 2025 IRP, all proxy resources physically located in the West are assumed to be deliverable to West loads, and no proxy resources physically located in the East are assumed to be deliverable to West loads. In PLEXOS, this is modeled by only crediting West-side proxy resources with contributions towards Washington’s annual Clean Energy and Transformation Act (CETA) targets and the energy side of Oregon’s House Bill (HB) 2021 compliance.
- (c) The Company assumes that this question refers to modeling in the 2025 IRP. Based on the foregoing assumption, the Company responds as follows:

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

Part of the core functionality of the PLEXOS model is to identify the most cost-effective resource mix to serve load. While a new resource may be selected by the PLEXOS model for economics, i.e. not strictly necessary to serve load in a given hour, the core functionality of the PLEXOS model is to minimize costs while optimizing for constraints. Removing a new resource selected by the model may result in unserved energy shortfalls or compliance shortfalls with state compliance requirements.

Attachment B

**PGE 2025 Bilateral Call for Renewable and Hybrid
Resource Power Purchase Agreements**



Portland General Electric

2025 Bilateral Call for Renewable and Hybrid Resource Power Purchase Agreements

Date: July 29, 2025

Response Due Date: September 3, 2025, 11:59 PM



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1. Introduction

Portland General Electric Company (PGE) is seeking the potential purchase of renewable energy and associated products through bilateral agreements. PGE is sending this 2025 Bilateral Call for Renewable and Hybrid Resource Power Purchase Agreements (PPAs) ("Bilateral Call") in a targeted effort to secure cost-effective, reliable, tax credit-eligible resources that support resource adequacy, strengthen the company's long-term energy supply portfolio, and advance the state's clean energy goals.

PGE is not engaging in a Request for Proposal (RFP) for these resources as this Bilateral Call is designed to take advantage of a time-sensitive opportunity to procure resources eligible for federal energy tax credits under the H.R.1 - One Big Beautiful Bill Act (OBBB). Considering the OBBB's construction commencement deadlines, PGE views this as a critical window to potentially capture tax credit value that reduces customer cost and enhances competitiveness of resources. Running this bilateral process alongside the 2023 and 2025 RFPs reflects a modern, portfolio-based procurement strategy. PGE will evaluate progress in this bilateral process as well as the 2025 RFP to determine total energy and capacity procurement to meet customer needs. At this point, we are not anticipating modifying any of the 2025 RFP targets for resource additions. Our aim is to strengthen PGE's ability to deliver reliable, affordable and clean energy under tight timelines and complex market dynamics.

PGE seeks renewable resources with commercial operation dates no later than December 31, 2028, to meet identified energy and capacity needs beginning in 2029. Projects should have a clear, viable path to interconnection and delivery.

Should any bilateral negotiations resulting from this process lead to executable agreements for major resources that trigger Oregon's Competitive Bidding Rules (OAR 860-089), PGE would seek a waiver from Oregon's Competitive Bidding Rules to facilitate timely contracting and realization of customer benefits.

PGE provides the following information to help better define the types of projects that could satisfy PGE's immediate needs through this bilateral process.

2. What We Are Seeking

PGE is seeking one or more of the following resource types:

- Renewable-only energy (must be Oregon RPS eligible)
- Renewable energy paired with storage (must be Oregon RPS eligible)

PGE *strongly prefers and encourages* Sellers to pair all renewable energy resources with co-located storage solutions. Standalone storage resources are not being sought in this bilateral process.

3. Other Criteria

PGE is looking for projects that meet the following criteria:

- **Commercial Operation Date (COD):** No later than December 31, 2028
- **Transmission:** Seller has the obligation to procure long-term firm transmission service for the term of the project no later than twelve (12) months prior to the scheduled Commercial Operation Date of the resource. Failure to procure transmission service and provide evidence of such procurement to PGE by such date will result in termination.
 - Long-term firm transmission service includes long-term firm and conditional firm bridge, number of hours or system conditions
 - Transmission service must have a delivery point of BPAT.PGE. PGE will not accept delivery at PacifiCorp West, Pelton Round Butte or Colstrip
 - PGE will consider projects with varying amounts of long-term transmission service based on the nameplate capacity of the resource(s). Please specify the type and quantity of long-term transmission procured or intended to be procured for the project in the Executive Summary requested in Section 5.
- **Interconnection:** Seller must demonstrate a clear and achievable path to interconnection to ensure COD by no later than December 31, 2028. Please provide a summary of the plan to achieve interconnection in the Executive Summary requested in Section 5.
 - Resources located on PGE's system must be studied for Network Resource Interconnection Study (NRIS)
- **Price:** As part of this Bilateral Call, PGE is providing an indicative term sheet in Appendix A outlining the terms and conditions that PGE expects to form the basis of negotiations. Sellers are encouraged to submit projects aligned with the term sheet. PGE is asking for Sellers to submit pricing for which they are able to execute definitive agreements thereunder.

4. Transaction Structure

PGE seeks resources through Power Purchase Agreements (PPA) only.

Seller may propose any term for the PPA, not to exceed thirty (30) years.

5. Response Requirements

Each response must include:

1. Executive summary of the resource including but not limited to:
 - Resource description, technology, and location
 - Plan to achieve interconnection:
 - Interconnecting utility, queue #, studies received to date, expected timeline for remaining studies, affected system study status (if applicable), etc.
 - Transmission plan for the project:
 - If TSR's are already obtained, please provide the respective TSR #s. If service is conditional firm, please provide a brief narrative of when the service is expected to convert to firm
 - If TSR's are still in study, please provide detail to the status of study
 - If TSR's are not submitted, please provide a narrative to obtain transmission, including type of transmission and quantity
 - Site control status
 - Permitting status and schedule
 - Resource development timeline and milestones
 - Plan to capture tax credits including start of construction or placed in service requirements
 - Description of entity expected to provide supporting credit requirements
2. Resource Generation Information
 - Please provide a P50 8760 generation profile for the generating resource(s) (please do not include any shaping from any associated battery storage, or please provide any shaping analysis in a separate file or tab)
3. Completed Non-Disclosure Agreement (NDA). No changes to the NDA will be accepted. See Appendix B and word version for submittal that will be provided separately. *PGE will return a countersigned copy to counterparty within fifteen (15) business days.*

6. Schedule

Milestone	Date
Bilateral Call Sent	July 29, 2025
Responses Due	September 3, 2025
PGE Analysis ¹	September 5, 2025, to September 26, 2025
PGE Notifies Sellers to Move Toward Bilateral Negotiations	October 3, 2025
Contract Execution	No later than December 31, 2025

Note:

- This schedule is tentative and is subject to change based on the quantity and quality of responses received.
- PGE clarifies that its Structuring and Origination team will be reviewing responses received as part of this process. These individuals represent PGE's long-term procurement commercial team, and some of these individuals are also on the benchmark team for the 2025 RFP. However, these individuals will **not** review responses received as part of this PPA process until after they submit benchmark bids to the 2025 RFP.

7. Submission Instructions

Responses must be submitted electronically to:

✉ **PPA_2025@pgn.com**

Please use the subject line: **"2025 PGE Bilateral PPA - [Resource Name]"**

All responses must be received by the deadline listed in Section 6. Late responses may not be considered.

All responses must include the four elements requested in Section 5.

¹ PGE may contact the Seller to request additional information necessary to complete its analysis.

8. Additional Information

PGE recognizes responses are submitted on a non-binding basis, but PGE will not be accepting changes to response pricing during the course of this process.

This Bilateral Call is not, and shall not be construed to be, an offer by PGE. PGE is not bound to execute an agreement with, or purchase any products from, any Seller as a result of this Bilateral Call. No binding commitment shall arise for either party under this process until and unless the parties execute definitive agreements that become effective in accordance with their terms.

Each Seller shall be solely responsible for all costs it incurs in preparing to participate in, participating in, or responding to this Bilateral Call.

PGE reserves the right to:

- Move forward with bilateral negotiations, if any, at its sole discretion.
- The right to reject any and all responses, and any portion of a specific response for any deviation from what PGE seeks.
- The right to waive any immaterial non-conformity in any response received.
- The right to prioritize responses that are most likely to overcome, in PGE's discretion, development and delivery risk.
- The right to award a contract to a Seller based on a combination of price, a quantitative and qualitative assessment of portfolio fit, and post-proposal negotiations.
- Modify the schedule.
- Request clarifications or additional data.

Questions may be submitted via email to Kori Mead at korissa.mehdikhan@pgn.com.

9. Appendices

9.1 Appendix A – Term Sheet

Note: The following represents a summary of certain material terms and conditions for Sellers to PGE's 2025 Bilateral Call for Renewable and Hybrid Resource Power Purchase Agreement (PPA). The following is not an exhaustive list of all material terms, nor does it purport to comprehensively express PGE's expectations for any of the terms herein mentioned. Full-form, definitive terms will be set forth in the definitive PPA that will be executed by the parties should PGE pursue bilateral negotiations.

Buyer:	Portland General Electric Company
Seller:	[Name of Seller]
Description of Facility:	A [XX] MW_{AC} [type of technology] generating facility (the "Generating Facility"), [which includes a [XX] MW / [XX] MWh co-located hybrid battery energy storage facility (the "Storage Facility")], located in [name of County] County, in the State of [Name of State]. The Generating Facility and the Storage Facility are collectively referred to herein as the "Facility."
Generating Facility Nameplate Capacity:	[For solar resources: ____MW_{AC} / ____MW_{DC}] [For non-solar resources: ____MW_{AC}]
Storage Facility Nameplate Capacity:	[XX] MW _{AC} .
Guaranteed Storage Capacity for Storage Facility:	[XX] MW_{AC} for [XX] hour discharge. In no event shall the Guaranteed Storage Capacity be less than 95%.
Generating Facility Net Available Capacity:	The full (maximum) net energy the Generating Facility is capable of delivering to the interconnecting Balancing Authority Area continuously for at least sixty (60) minutes, which is equivalent to the Generating Facility Nameplate Capacity Rating of the Generating Facility's generating unit, less station service (parasitic power and electrical losses) and inverter limitations, expressed in MW _{AC} .

<i>Product:</i>	The Product includes the following: 1. Energy: All electric energy, expressed in MWh, generated and/or discharged by the Facility; 2. Environmental Attributes: any and all claims, credits, benefits, emissions reductions, offsets and allowances, however named, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water or otherwise arising as a result of the generation of electricity from the Facility, regardless of whether or not (i) such environmental attributes have been verified or certified, (ii) such environmental attributes are creditable under any applicable legislative or regulatory program, or (iii) such environmental attributes are recognized as of the Effective Date or at any time during the Delivery Term; 3. Capacity Attributes: Any current or future attribute, as may be currently defined or otherwise defined in the future, including but not limited to a characteristic, certificate, tag, credit, ancillary service or attribute thereof, or accounting construct, associated with the electric generation capability and capacity of the Facility or the Facility's capability and ability to produce or curtail energy, including any attribute counted towards any current or future resource adequacy or reserve requirements. Capacity Attributes are measured in MW. Capacity Attributes do not include: (i) any production tax credits, investment tax credits, or any other tax credits, deductions, or tax benefits associated with the Facility, or (ii) any state, federal, local, or private cash payments, grants, or costs relating in any way to the Facility or the electric power output of the Facility; 4. Storage Capacity: All rights and products and attributes associated with the maximum dependable operating capability of the Storage Facility to be charged with, store and discharge electric energy; and 5. Ancillary Services: All ancillary services, products and other attributes, defined in Section 3 of the Portland General Electric Company Pro Forma Open Access Transmission Tariff, if any, that may be obtained from the Facility.
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<i>Specified Amounts</i>	The amount of Facility Output generated by the Generating Facility that Seller is expected to deliver to Buyer at the Delivery Point for each monthly period during the Delivery Term. The Specified Amounts for each month shall be consistent with a generation profile associated with a 50% probability of exceedance forecast for the Generating Facility using industry standard methodology.
<i>Delivered Energy Quantity</i>	The sum of the Energy delivered to Buyer by or on behalf of Seller to the Delivery Point each hour during the Delivery Term as represented on the final e-Tag.
<i>Excess Energy Quantity</i>	The Delivered Energy Quantity in excess of 105% of the Specified Amount.
<i>No Sales to third parties:</i>	Seller shall sell one hundred percent (100%) of the Facility capability and Facility Output to Buyer and may not sell any Energy, Storage Capacity, Capacity Attributes, Environmental Attributes or any other Facility capability to any other party or purchaser, unless such sale is expressly allowed by the PPA. <u>"Generating Facility Output"</u> means all electric energy, less station service (parasitic power and electrical losses), if any, all as measured at the Facility Meter.
<i>Delivery Term:</i>	No less than [(XX)] contract years after the Commercial Operation Date. In no event shall Delivery Term exceed thirty (30) years.
<i>Interconnection Point:</i>	The Facility shall interconnect to [XX substation]. Seller shall be responsible for all costs of interconnecting the Facility to the Interconnection Point.
<i>Delivery Point:</i>	PGE scheduling point [BPAT.PGE or PGELOAD] PGE will not accept delivery at PacifiCorp West, Pelton Round Butte or Colstrip.
<i>Commercial Operation Date:</i>	The date on which the total Nameplate Capacity of both the Generating Facility and Storage Facility is fully operational and reliable, and the Facility is fully interconnected, fully integrated, and synchronized with the transmission system.

<i>Scheduled Commercial Operation Date:</i>	[Date]. In no event shall the Scheduled Commercial Operation Date be later than December 31, 2028. If the Commercial Operation Date is not achieved on or before the Scheduled Commercial Operation Date, Seller shall pay Delay Damages to PGE from and after the Scheduled Commercial Operation Date up to, but not including, the first to occur of (i) the date on which the Facility achieves the Commercial Operation Date, and (ii) the Guaranteed Commercial Operation Date. <u>"Delay Damages"</u> for any given day are equal to (A) (i) \$150 per MW of Nameplate Capacity of the Generating Facility per day beginning on the first day after the Scheduled Commercial Operation Date through the 30th day after the Scheduled Commercial Operation Date, (ii) \$250 per MW of Nameplate Capacity of the Generating Facility per day beginning on the 31st day after the Scheduled Commercial Operation Date through the 60th day after the Scheduled Commercial Operation Date, and (iii) \$350 per MW of Nameplate Capacity of the Generating Facility per day beginning on the 61st day after the Scheduled Operation Date through the actual Commercial Operation Date or the Guaranteed Commercial Operation Date, whichever occurs first, <i>plus, if applicable</i>, (B) for each day beginning on the first day after the Scheduled Operation Date through the actual Commercial Operation Date or the Guaranteed Commercial Operation Date, whichever occurs first, the product of (i) the Guaranteed Storage Capacity, expressed in kW, multiplied by (ii) the quotient of (a) the Storage Facility Contract Price in the first contract year (in \$/MW/month) divided by (b) 30.4. For the avoidance of doubt, the Scheduled Commercial Operation Date shall not be extended for any reason other than for Force Majeure and shall be capped at 180 days of extension.
<i>Guaranteed Commercial Operation Date:</i>	The date that is one hundred eighty (180) days after the Scheduled Commercial Operation Date. Buyer shall have the right to terminate the PPA if the Commercial Operation Date is not met by the Guaranteed Commercial Operation Date and Seller shall pay Buyer damages in the amount

	of \$200kW of Nameplate Capacity for each of the Generating Facility and Storage Facility.
<i>Contract Price:</i>	The Contract Price shall be the sum of the Generation Contract Price and the Storage Contract Price. The Generation Contract Price shall be \$(XX)/MWh. The Storage Contract Price shall be \$(XX)/ kw-mon. For the avoidance of doubt, the Contract Price is firm. Adjustments to Contract Price are not permitted for any reason, including but not limited to, a change in law, a change in tax law, tariffs, etc.
Change in Importation Law	Means the occurrence, after the Effective Date, of (i) any delay, investigation, seizure, withhold release order or other measure implemented under an Anti-Forced Labor Law; or (ii) any Law implementing new or amended regulations of imports such as, but not limited to, tariffs or changes in the interpretation thereof or import quotas and the interpretation thereof; including for each of clauses (i)-(ii) any laws, rules, regulations, guidelines, comments, petitions, investigations, proceedings or actions in connection therewith. If such Change in Importation Law requires Seller to incur costs, net of any offsetting benefits related to such Change in Importation Law, that can be reasonably estimated to be in excess of \$15/kw of Generation Nameplate Facility Capacity and Storage Facility Nameplate Capacity in the aggregate over the remaining Term that (a) would not already be recovered or recoverable by Seller or otherwise accounted for under this Agreement, or (b) Seller cannot otherwise mitigate using commercially reasonable efforts, then upon Seller's written notice to PGE, which shall be delivered no later than thirty (30) days after passage of the legislation or issuance of the executive order, and in any event no later than the two hundred and forty (240) days prior to Scheduled Commercial Operation Date (which will include evidence reasonably sufficient for PGE and clear documentation, subject to PGE's reasonable satisfaction, to validate such Change in Importation Law and Seller's estimate of the aggregate impact), PGE may do any of the following within thirty (30) days of receiving such evidence, <i>in its sole discretion</i>:

	1. send notice to Seller declining to enter into negotiations to amend the Agreement; 2. send notice to Seller requesting to enter into good faith negotiations preserving the benefit of the bargain for all Parties under the Agreement; or 3. request Seller to prepare an amendment to this Agreement, amending only the Fixed Price to reflect the Change in Importation Law. Should PGE decline to enter into negotiations to amend the Agreement, PGE shall have the right to terminate the Agreement and Seller shall pay Buyer a termination payment of \$100/kw of Generating Facility Nameplate Capacity and Storage Facility Nameplate Capacity.
Change in Tax Law	If, due to any change in federal income tax law (including regulations or administrative guidance) enacted, promulgated, or interpreted within twelve (12) months after the Effective Date, the amount, timing, or availability of the Investment Tax Credit (ITC) or the Production Tax Credit (PTC), is reduced, delayed, eliminated, or otherwise adversely affected with respect to the Project, Seller shall provide written notice to Buyer within thirty (30) days of such impact and shall have the right to terminate the Agreement and shall not result in any termination fee, penalty, or other compensation payable by the terminating Party, except for payment of undisputed amounts due for services or energy delivered prior to the termination date.
Permitted Extension - Interconnection and Permit Delay	Means a day-for-day extension to the Scheduled Commercial Operation Date, not to exceed sixty (60) days in aggregate, due solely to (i) Seller's inability to obtain, due to delay's beyond Seller's reasonable control, [insert permit], as required to enable Seller to build or operate the project, or (ii) interconnection delays experienced by the Transmission Provider that is beyond Seller's reasonable control. Seller must provide written notice to PGE within ten (10) business days following the occurrence of any events (i) - (ii) with reasonable documentation substantiating such claim.
Permitted Extension - Change in Importation Law	Means a day-for-day extension to the Scheduled Commercial Operation Date, not to exceed sixty (60) days in aggregate, due solely to Change in Importation Law. Seller must provide written

	notice to PGE within ten (10) business days following the occurrence of such event with reasonable documentation substantiating such claim.
<i>Market Index Price:</i>	The EIM real-time pre-dispatch nodal price for the Delivery Point. In the event Buyer is participating in an organized market other than the EIM, then the Market Index Price will mean the Locational Marginal Price associated with the Pricing Node or Aggregate Pricing Node for the Delivery Point within such organized market.
<i>Market Index Settlement Price:</i>	The production-weighted sum of the Market Index Price for each hour during the delivery month.
<i>Test Energy:</i>	For the Generating Facility: Generating Facility Test Energy means energy generated by the Generating Facility prior to achieving the Commercial Operation Date. Seller may elect to sell Generating Facility Test Energy to its transmission provider, to a third-party or to an organized market via its transmission provider's system. Seller shall be entitled to any and all compensation received from its transmission provider or any third-party or organized market for such Generating Facility Test Energy. Otherwise, Seller shall Schedule in accordance with the Scheduling Procedure and deliver Generating Facility Test Energy to Buyer in order to complete Start-Up Testing of the Generating Facility. In such case, the parties shall coordinate in good faith to Schedule deliveries of Generating Facility Test Energy to Buyer that minimizes the burden to each of the parties, and Buyer shall receive the Generating Facility Test Energy. The price for such Generating Facility Test Energy received by Buyer shall be 50% of the Market Index Settlement Price and Seller shall pay any costs or additional expenses that are required for Buyer to receive the Generating Facility Test Energy, including but not limited to reimbursement for negative pricing and any necessary capacity costs or reserves costs. For the Storage Facility: Prior to the Commercial Operation Date, Seller shall schedule and complete a storage capacity test. Thereafter, at least once per year, Seller shall schedule and complete a storage capacity test. Buyer may require a storage capacity retest at any time during the Delivery Term. The Parties shall coordinate all storage capacity

	tests in good faith to minimize the burden to each of the Parties. Buyer may witness all storage capacity tests of the Facility. Seller is responsible for all costs of Charging Energy used in any Storage Capacity Test prior to Commercial Operation. Buyer shall pay for the Charging Energy used to charge the Facility in connection with the first storage capacity test during any contract year after Commercial Operation. All other costs related to a storage capacity test, including costs for Charging Energy for subsequent storage capacity tests in the same contract year (unless such subsequent retest is initiated by Buyer), shall be borne by Seller.
<i>Transmission Requirements:</i>	For Off-System Facilities: Seller shall pay for and maintain eligible Long-Term Transmission, for a minimum of (XX)% of the Generating Facility Net Available Capacity, for delivery of Energy from the Facility's point of interconnection/point of receipt (POR) identified in the interconnection agreement to the Delivery Point for the entire Delivery Term, commencing on the Commercial Operation Date. The Assignment Reference for the transmission service requests (TSRs) that will be dedicated to this resource(s) is: - [PROVIDE TSR #s] These TSRs represent a total of [XX] MW and will have a point of receipt of [NAME]. The Point of Delivery is BPAT.PGE. If Seller is providing Long-Term Transmission that is a Conditional Firm product, all upgrades, costs and changes in transmission service are the responsibility of Seller. If BPA terminates Seller's Conditional Firm service during the term of the agreement, Seller shall notify PGE within five (5) business days, and PGE shall have the right to terminate the agreement. Seller shall not have the right to terminate service, without the consent of PGE, otherwise. Seller may deliver up to (XX)% of the Generating Facility Net Available Capacity on short-term transmission. Curtailment or a transmission provider's cancelation of conditional firm reassessment transmission service shall not be a Force Majeure event. If the reassessment service is terminated or the number of curtailment hours is increased, default and failure to perform

	provisions in the PPA would be triggered and the full responsibility of the seller. If Seller is participating in a BPA TSEP process, which includes completing any and all actions necessary to keep the transmission service request(s) in an active OASIS status, Seller has the commercial obligation to participate in and fund all requirements in the TSEP process necessary to be granted long term firm or conditional firm bridge if those are the services elected. Seller shall be responsible for making all arrangements and paying all costs related to transmission, including but not limited to Ancillary Services costs required to deliver the Product(s) to the Delivery Point. For the avoidance of doubt, any energy not delivered to the Delivery Point, except for Buyer Economic Curtailment subject to Buyer Economic Curtailment Allowance, will be noncompensable curtailment. For On-System Facilities: PGE must be able to designate the Facility as a network resource and Seller must have requested NRIS interconnection for Facility Output. In such case, Buyer will be responsible for all costs associated with the delivery of Facility Output to PGELOAD.
<i>Buyer Economic Curtailment</i>	Means curtailment directed by PGE when (a) the Mid-C Day-Ahead Price is negative or (b) the PGE External Load Aggregation Point (ELAP) price in a California Independent System Operator Real-Time Pre-Dispatch (RTPD) market interval is negative. <u>"Buyer Economic Curtailment Allowance"</u> means Buyer Economic Curtailment for the first 2% of the annual Specified Amount for each calendar year will be noncompensable. Any Buyer Economic curtailment above 2% of the annual Specified Amount for each calendar year shall be compensable.
<i>Generating Facility Forecasting:</i>	Seller shall provide Buyer with: (i) a rolling generation forecast, updated hourly, for the next fourteen (14) days, (ii) a rolling generation forecast for five (5) minute and fifteen (15) minute intervals, updated every five (5) and fifteen (15) minutes respectively, for the next 24 hours, and (iii) an updated hourly generation forecast ninety (90) minutes prior to each delivery

	hour for the balance of the delivery day ("Generation Forecast"). Each Generation Forecast shall be performed by a third-party forecasting agent that is mutually agreed to by Buyer and Seller ("Forecasting Agent"). At Buyer's request, Seller will cause the Forecasting Agent to provide Buyer with an application program interface from which Buyer can access raw forecasting files. Seller shall ensure that the Forecasting Agent provides Buyer real-time access to information and forecasts concerning the Facility's availability status.
<i>Charging Energy:</i>	During the Delivery Term, Buyer shall be responsible, at its sole cost, for supplying all Charging Energy (as measured at the Storage System metering point) necessary to charge the Storage Facility to supply the discharge schedule (defined in the Scheduling Procedure).
<i>Generating Facility Scheduling:</i>	Seller shall schedule and deliver Generating Facility Energy to Buyer at the Delivery Point commencing on the Commercial Operation Date and continuing through the end of the Delivery Term. Seller's Generating Facility Energy delivery may not intentionally exceed the Generation Forecast plus discharge Energy. For each day during the Delivery Term, Seller shall comply with the following scheduling procedure with respect to the Generating Facility: (a) Seller shall communicate to PGE's Pre-schedule Desk, as directed by PGE, the Generating Facility's Generation Forecast to be delivered at the Generating Facility Delivery Point for the Pre-Scheduling Day(s) by 5:00 a.m. PPT of the customary WECC Pre-Scheduling Day for each day during the Delivery Period; (b) Seller shall communicate to PGE's real time desk via API, or as otherwise directed by PGE, Generating Facility Energy deliveries consistent with the Generation Forecast no later than ninety (90) minutes prior to the flow hour] and (c) Seller and PGE agree that the intent of these scheduling procedures is for Seller to schedule and deliver Generating Facility Energy that resembles actual generation from the Generating Facility for each hour.

	Seller shall not schedule any Generating Facility Energy to be delivered to PGE pursuant to this Agreement using a Dynamic or Pseudo-Tie e-Tag as such terms are defined and used by NERC. Seller may make adjustments to the Pre-Scheduled Generating Facility Energy scheduled from the Generating Facility each hour in Real-Time ("Real-time Adjustments"). If Seller elects to make Real-time Adjustments, Seller will: (a) communicate to PGE's Real-time Desk, as directed by PGE, its intent to adjust the Pre-Scheduled Generating Facility Energy no later than seventy-five (75) minutes prior to the flow hour; and (b) submit and receive approval of e-Tag adjustment no later than seventy-five (75) minutes prior to the flow hour. Seller will make all NERC e-Tag adjustments. Seller's e-tag shall match the adjustment communicated to PGE pursuant to <u>Section (a)</u>. Seller shall be responsible for any costs, charges, or fees associated with deviations to the e-tag after seventy-five (75) minutes prior to the flow hour. In the event that the regional market design, balancing authority, reliability entity or regulatory entity (e.g., PGE Transmission, BPA, WECC, NERC, RC West, FERC) causes or otherwise reasonably requires Buyer's scheduling practices, or the resource's participation in a regional market, to change after the Effective Date, Buyer and Seller shall meet and mutually agree on updated Scheduling Procedures within thirty (30) days after written notice to Seller of such proposed change. Seller shall not unreasonably withhold agreement to proposed changes to the scheduling practices.
<i>Storage Facility Scheduling:</i>	Buyer shall arrange all scheduling services necessary to ensure compliance with NERC operating policies and criteria, Transmission Provider OATT requirements, including Western EIM requirements, and any other applicable guidelines. Prior to the implementation and applicability to the Storage Facility in any energy market, to the extent scheduling is required now or in the future, Buyer shall schedule all Discharging Energy and Charging Energy in accordance with NERC operating policies and criteria, Transmission Provider OATT requirements and any other applicable guidelines.

	Seller shall communicate to Buyer's Pre-schedule Desk the Storage Facility's hourly availability for the Pre-Scheduling Day(s) by 05:00a.m. PPT of the customary WECC Pre-Scheduling Day for each day during the Delivery Term. Seller shall communicate to Buyer's Real-time Desk any changes to the Storage Facility's hourly availability, Unplanned outages and any reduced Storage Facility Operating Restrictions as a result of an unplanned outage. Format and content of the daily report shall be subject to review and approval by Buyer. Unless otherwise specified by superseding policies or procedures of the System Control Center, Seller shall, by 06:00 a.m. PPT on each day, submit a good faith estimate of the hourly Storage Facility availability for the next seven (7) days. If, at any time following submission of a good faith estimate, Seller becomes aware of any change that alters the values previously provided to Buyer, Seller shall promptly notify Buyer of such change or predicted change.
<i>Market Event</i>	If at any point during the Delivery Term, an alternative market design is implemented in which the Buyer, at its sole discretion, elects to participate in the Storage Facility in an energy market or no longer participate in (a "Market Event"), such as the California Independent System Operator's (CAISO) Extended Day-Ahead Market (EDAM), and such Market Event materially changes the interconnection, delivery and scheduling requirements in the PPA, the parties shall cooperate in good faith to amend the PPA, at the least possible cost to the parties. The parties acknowledge that at the time of the agreement, PGE plans to join CAISO EDAM and that the EDAM market is still under development. PGE will work to incorporate any known changes to scheduling requirements within in the PPA at the time of execution, but additional changes may be necessary to conform with final market design.
<i>Reliability Entity Curtailment:</i>	Buyer shall not be liable to Seller if curtailment of Energy is due to the action of a Reliability Entity and such action shall not be considered a Force Majeure.
<i>Storage Capacity Guarantee:</i>	If the Storage Capacity for the Storage Facility is determined during a Storage Capacity Test to be less than the Guaranteed

	Contract Storage Capacity, Seller shall pay to Buyer as liquidated damages for such deficiency an amount determined by <u>multiplying</u> (i) the number of months since the last Storage Capacity Test (including the month in which the most current Storage Capacity Test was completed) by (ii) Fifty percent (50%), by (iii) the Storage Contract Price (adjusted to \$/MW/month (<i>multiplied by 1,000</i>), <u>multiplied by</u> 125% by (iv) the difference between the Guaranteed Contract Storage Capacity and the Storage Capacity as determined during the most recent Storage Capacity Test until such deficiency is cured ("Guaranteed Contract Storage Capacity Adjustment"). It will be an event of default if the Storage Contract Capacity, as determined by the most recent storage contract capacity test, is less than the Guaranteed Storage Contract Capacity, during two (2) out of three (3) consecutive years during the Delivery Term.
<i>Actual Round-Trip Efficiency:</i>	The round-trip efficiency for each contract year is calculated as a percentage, based on the amount of MWhs of energy used to charge the Facility and the amount of MWhs of energy discharged from the Facility, as measured by the Storage Facility meter at the Interconnection Point.
<i>Guaranteed Round-Trip Efficiency:</i>	Ninety percent (90%) for all contract years during the Delivery Term. It will be an event of default if the Round-Trip Efficiency is less than the Guaranteed Roundtrip during two (2) out of three (3) consecutive years during the Delivery Term.
<i>Guaranteed Round-Trip Efficiency Adjustment:</i>	If during any contract year during the Delivery Term, the Actual Round-Trip efficiency for such contract year is less than the Guaranteed Round-Trip Efficiency, the Seller shall pay the Buyer the following amount: (i) the charging energy for the months since the last Storage Capacity Test (including the month in which the most current Storage Capacity Test was completed), multiplied by Guaranteed Round-Trip Efficiency, less

	(ii) (the charging energy for the months since the last Storage Capacity Test (including the month in which the most current Storage Capacity Test was completed), multiplied by Actual Round-Trip Efficiency, less, multiplied by (iii) (the average day-ahead Intercontinental Exchange Mid-C Physical Peak (bilateral) or Mid-C Physical Off-Peak (bilateral) indices, weighted by the count of hours in each index during which Charging Energy was supplied by Buyer to the Point of Delivery.
<i>Maximum Annual Discharge MWh:</i>	Buyer may discharge a maximum of [MWhs] per year, subject to the Storage Facility Operating Limits and Parameters.
<i>Daily Dispatch Limits:</i>	Full Charging limits (if any): [XX] times per day Full Discharging limits (if any): [XX] times per day Partial Charging limits (if any): [XX] times per day Partial Discharging limits (if any): [XX] times per day
<i>Other Operating Limits and Parameters:</i>	[Seller to describe all applicable operating limits on dispatch of the Storage Facility, if any]
<i>Guaranteed Storage Facility Monthly Availability:</i>	Seller guarantees the Storage Facility availability shall be no less than 95% annually during the Delivery Term. It will be an event of default if Seller fails to meet the Guaranteed Storage Annual Availability during two (2) out of three (3) consecutive years during the Delivery Term, Buyer may terminate the PPA.
<i>Guaranteed Storage Facility Availability Adjustment:</i>	If the Storage Facility has Actual Availability in a contract year less than the Guaranteed Availability, then Seller shall pay Buyer liquidated damages in the amount equal to the product of: (a) the positive difference between the Guaranteed Availability and the Actual Availability, multiplied by (b) the Storage Capacity during the contract year, multiplied by (c) the Storage Contract Price (adjusted to \$/MW/month), multiplied by (d) twelve (12) months ("Guaranteed Availability Adjustment").

<i>Grid Charging of Storage Facility:</i>	If the Storage Facility is capable of receiving charging energy from the Generating Facility and in the form of grid energy and Buyer elects to provide charging energy from a source other than the Generating Facility, including grid energy (i) Buyer will be responsible for all costs relating to the charging of the Storage Facility from a source other than the Generating Facility, including the cost of energy and associated carbon costs used to charge the Storage Facility and (ii) the Parties will amend the PPA to the extent necessary so that Generating Facility Energy delivered by Seller to the Delivery Point is fully paid for by Buyer (unless Buyer is otherwise not required to pay for such Generating Facility Energy hereunder).
<i>Failure to Deliver Generating Facility Output:</i>	If Seller fails to deliver Generating Facility Output or the associated Environmental Attributes, including Bundled RECs, and such failure is not excused by Force Majeure, or by Buyer's breach of the PPA, Seller shall owe Buyer an amount as calculated below: (a) Seller shall owe Buyer an amount for such deficiency equal to the positive difference (if any) of the applicable Market Index Settlement Price minus the Generation Contract Price <i>multiplied by</i> the positive difference (if any) of the ninety percent (90%) Specified Amount for the applicable monthly On-Peak and Off-peak period minus the Delivered Energy Quantity delivered during that monthly On-Peak and Off-peak period; and (b) Seller shall owe Buyer any penalties or fines imposed by a Reliability Entity as a result of Seller's failure to deliver Generating Facility Output; and (c) Seller shall owe Buyer an amount for such deficiency should the replacement energy procured by Buyer as a result of Seller's failure to deliver the Generating Facility Output results in incremental Carbon Emissions costs to PGE; and (d) Seller shall owe Buyer an amount for such deficiency should the replacement energy procured by Buyer as a result of Seller's failure to deliver the Generating Facility Output results in incremental ancillary services; and

(e) Seller shall be obligated to settle any shortfall in the delivery of Environmental Attributes as follows:

For the avoidance of doubt, failure to deliver Facility Output associated with any curtailment event, except if by Buyer breach or Buyer Economic Curtailment, shall not relieve Seller for the obligation to deliver the Specified Amounts.

Seller shall, within one hundred twenty (120) days after the end of the shortfall month, deliver an equivalent amount of Qualifying Replacement RECs that are generated in the same calendar year; or

If Seller elects not to deliver an equivalent amount of Qualifying Replacement RECs under subpart (i) and Buyer elects in its sole discretion to purchase Qualifying Replacement RECs, Seller shall owe Buyer the price that Buyer pays for Qualifying Replacement RECs; or

If Seller elects not to deliver an equivalent amount of Qualifying Replacement RECs under subpart (i) and Buyer does not elect, in its sole discretion, to purchase replacement bundled RECs under subpart (b), Seller shall owe Buyer the Qualifying Replacement REC Price identified by Buyer multiplied by the number of Bundled RECs Seller failed to deliver.

"Reliability Entity" may include, without limitation, NERC, WECC, the Balancing Authority, Transmission Provider, regional transmission organization, independent system operator, reliability coordinator or any other entity that has, or that may have in the future, (i) responsibility over the reliability of the bulk power system and (ii) by virtue of such responsibility the legal authority to affect the operations of the Facility or delivery of the Product.

"Qualifying Replacement RECs" means environmental attributes (including renewable energy credits and renewable energy credit reporting rights) that are delivered to Buyer bundled with energy produced simultaneously by a generating source that (A) is an Oregon Renewable Portfolio Standard eligible renewable energy resource, (B) produces environmental attributes (including renewable energy credits and renewable energy credit reporting rights) of the same type and quality as Environmental Attributes

	(including Bundled RECs and REC Reporting Rights), (C) is located in [Oregon or Washington], and (D) achieves commercial operation after the Commercial Operation Date. <u>"Qualifying Replacement REC Price"</u> means the price for Qualifying Replacement RECs as determined by taking the lower of two dealer quotes representing a live offer to sell Qualifying Replacement RECs for the entire quantity of Bundled RECs that are being replaced and subtracting the value of the energy component of such quantity (as specified in the applicable dealer quotes) of such Qualifying Replacement RECs.
<i>Monthly Settlement and Invoice:</i>	All invoices shall be due on the tenth (10th) day of each month and payable on or before the later of the twentieth (20th) day of each month, or the tenth (10th) day after receipt of the invoice or, if such day is not a Business Day, then on the next Business Day. The payment for all Products shall be the sum of the Energy Payment and Storage Capacity Payment. The <u>Energy Payment</u> for each month during the Delivery Term is equal to the sum of: (a) hourly Delivered Energy Quantity, each up to 105% of the Specified Amount for such month, multiplied by the Generation Contract Price; plus (b) hourly Excess Energy delivered to the Delivery Point multiplied by the lesser of (i) [93%] of the Market Index Price, or (ii) [75%] of the Generation Contract Price; plus (c) Buyer Economic Curtailment, subject to Buyer Economic Curtailment Allowance, multiplied by the Generation Contract Price. The <u>Storage Capacity Payment</u> for each month during the Delivery Term will be equal to: (a) the Storage Facility Contract Price multiplied by the Contract Storage Capacity, less (b) the Guaranteed Availability Adjustment for such year, if any, less (c) the Guaranteed Round-Trip Efficiency Adjustment for such year, if any, less

	(d) the Guaranteed Contract Storage Capacity Adjustment, if any, less (e) Storage Facility Test Energy costs that Seller is responsible for.
<i>REC Transfer:</i>	Seller shall transfer all RECs generated by the Facility during each month of the Delivery Term to Buyer via WREGIS pursuant to the timelines in WREGIS Operating Rules.
<i>Operations and Maintenance:</i>	Seller shall not schedule any non-emergency maintenance that reduces the energy generation and/or storage capability of the Facility, as applicable, by more than ten percent (10%) during the months of June through September, unless (i) such outage is required to avoid damage to the Facility, (ii) such maintenance is necessary to maintain equipment warranties and cannot be scheduled outside the months of June through September, (iii) such outage is required in accordance with prudent electrical practices, or (iv) the parties agree otherwise in writing. Seller shall provide its outage schedule no later than September 1st of each year preceding such outage(s). The outage schedule for each Contract Year shall not exceed 240 hours.
<i>RPS Compliance:</i>	Seller shall ensure the Facility obtains Oregon RPS Certification within ninety (90) days of the Commercial Operation Date and shall maintain such certification during the Delivery Term.
<i>Labor Requirement:</i>	All project labor must comply with the requirements of Oregon House Bill 2021, as applicable. Union labor must be utilized for major construction activities related to the Facility and must include a Project Labor Agreement requirement in any related executed Engineering, Procurement and Construction Agreements. The labor group that constructs and maintains the Facility must have policies in place that are designed to limit or prevent workplace harassment and discrimination. Additionally, such labor group must have policies in place that are designed to promote workplace diversity, equity and inclusion of communities who have been traditionally underrepresented in the renewable energy sector including, but not limited to,

	women, veterans and Black, Indigenous and People of Color, with an aspirational goal of having at least fifteen (15) percent of the total work hours performed by individuals from those communities.
<i>Buyer Conditions Precedent:</i>	Buyer's obligations shall be conditioned and will become effective only upon the occurrence of each and every one of the following conditions: (i) if necessary, receipt of approval of the waiver under OAR 860-089 from the Oregon Public Utility Commission, in form and substance satisfactory in Buyer's sole discretion; and (ii) written approval of the PPA by Buyer's Board of Directors.
<i>Seller Conditions Precedent:</i>	[List Seller Conditions Precedent, if any]
<i>Security Requirements:</i>	Within thirty (30) days after the Effective Date of the PPA, Seller shall deliver development security to Buyer in an amount equal to \$125/kW of Generating Facility Nameplate and \$125/kW of Storage Facility Nameplate Capacity and shall maintain such development security until the Commercial Operation Date. On or before Commercial Operation Date, Seller shall deliver delivery term security to Buyer in an amount equal to \$100/kW of Generating Facility Nameplate and \$100/kW of Storage Facility Nameplate Capacity and shall maintain such delivery term security through the end of the Delivery Term. Within five (5) Business Days following any draw by Buyer on the delivery term security, Seller shall replenish the amount drawn such that the delivery term security is restored to the full amount. All security shall be in the form of cash or a letter of credit from a Qualified Institution as defined below and in a form reasonably acceptable to Buyer. <u>"Qualified Institution"</u> means a major U.S. commercial bank or a U.S. branch office of a major foreign commercial bank which is acceptable to PGE, organized under the laws of the United States (or any state or political subdivision thereof) with such bank having shareholders' equity of at least \$10 billion (U.S. Dollars) and a Credit Rating of at least A- by S&P or A1 by Moody's, or an insurance company with assets of \$2 billion or greater, an A.M.

	Best financial strength rating of an A or greater and authorized to issue surety bonds in the state in which the project will be located. On a case-by-case basis PGE will accept banks that do not meet the above criteria as Qualified Institutions if they have received an endorsement from an institution that does meet the criteria in the Qualified Institution definition.
<i>Termination Settlement Amount:</i>	In the event the PPA is terminated due to an event of default, the non-defaulting party shall calculate the Settlement Amount. The defaulting party shall pay the Settlement Amount to the non-defaulting party. The Gains or Losses resulting from the termination of the PPA shall be determined by calculating the amount that would be incurred or realized to replace or to provide the economic equivalent of the remaining payments or deliveries in respect of the PPA. The Gains or Losses shall be calculated for a period equal to the remaining Term ("Settlement Period"). The quantity of Energy in each month of the Settlement Period associated with Generating Facility shall be equal to Specified Amount for such month under the PPA as of the time the calculation is made. The storage capacity in each month of the Settlement Period shall be equal to the Storage Contract Capacity as of the Termination Date. <u>"Settlement Amount"</u> means the Losses or Gains, and Costs, expressed in USD, which the non-defaulting party incurs as a result of the termination and liquidation of the PPA. If the non-defaulting party's Costs and Losses exceed its Gains, then the Settlement Amount shall be an amount owing to the non-defaulting party. If the non-defaulting party's Gains exceed its Costs and Losses, then the Settlement Amount shall be zero dollars (\$0). The Settlement Amount shall not include consequential, punitive, exemplary or indirect or business interruption damages. <u>"Gains"</u> means, with respect to a party, an amount equal to the present value of the economic benefit to it, if any (exclusive of Costs), resulting from the termination of its obligations with respect to the PPA determined in a commercially reasonable manner.

	<u>"Losses"</u> means, with respect to a party, an amount equal to the present value of the economic loss to it, if any (exclusive of Costs), resulting from termination of its obligations with respect to the PPA determined in a commercially reasonable manner. <u>"Costs"</u> means, with respect to a party, brokerage fees, commissions and other similar third-party transaction costs and expenses reasonably incurred by such Party in entering into new arrangements which replace the PPA and all reasonable attorneys' fees and expenses incurred by a Party in connection with enforcing its rights under the PPA. Costs shall not include any expenses incurred by such Party in either entering into or terminating any arrangement pursuant to which it has hedged its obligations.
Aggregate Limitation of Liability	Unless expressly provided in the PPA, a Party's liability shall be limited to direct actual damages only, which direct actual damages shall be the sole and exclusive remedy and all other remedies or damages at law or equity are waived. Except as expressly provided for in the PPA, neither party shall be liable for consequential, incidental, punitive, exemplary, or indirect damages, lost profits or other business interruption damages, by statute, in tort or contract, under any indemnity provision or otherwise.
<i>Assignment:</i>	Neither party may assign the PPA without prior written consent of the other party, which consent may not be unreasonably withheld or delayed.
<i>Other Standard Contract Terms and Conditions to be included in the PPA:</i>	The PPA will include additional terms and conditions that are usual and customary in transactions of its nature.
<i>Confidentiality:</i>	This Term Sheet and all information exchanged during negotiations of the PPA are confidential, subject to the Non-Disclosure Agreement between Buyer and Seller dated [Date].

9.2 Appendix B - Non-Disclosure Agreement

Provided separately in word

Mutual Confidentiality Agreement

This Mutual Confidentiality Agreement (the "**Agreement**"), effective as of [redacted] (the "**Effective Date**"), is entered into by and between [redacted], a [state of incorporation] [entity type] having its principal place of business at [redacted] and Portland General Electric Company ("PGE"), an Oregon corporation having its principal place of business at 121 SW Salmon Street, 1WTC1301, Portland, Oregon 97204 (together, the "**Parties**", and each, a "**Party**").

WHEREAS, in connection with participating in *PGE's 2025 Bilateral Call for Renewable and Hybrid Resource Power Purchase Agreement (PPA)* (the "**Purpose**"), the Parties desire to share certain information that is non-public, confidential or proprietary in nature.

NOW, THEREFORE, in consideration of the mutual covenants, terms and conditions set forth herein, the Parties agree as follows:

1. Confidential Information. Except as set forth in Section 2 below, "**Confidential Information**" means all non-public, internal, confidential or proprietary information disclosed on or after the Effective Date, by either Party (a "**Disclosing Party**") to the other Party (a "**Recipient**") or its affiliates, or to any of such Recipient's or its affiliates' employees, officers, directors, partners, shareholders, agents, attorneys, accountants or advisors (collectively, "**Representatives**"), whether disclosed orally or disclosed or accessed in written, electronic or other form or media, and whether or not marked, designated or otherwise identified as "confidential," which may include:

(a) all information concerning the Disclosing Party's and its affiliates', and their customers', suppliers' and other third parties' past, present and future business affairs including, without limitation, finances, customer information, supplier information, products, services, organizational structure and internal practices, forecasts, sales and other financial results, records and budgets, and business, marketing, development, sales and other commercial strategies;

(b) the Disclosing Party's unpatented inventions, ideas, methods and discoveries, trade secrets, know-how, unpublished patent applications and other confidential intellectual property;

(c) all designs, specifications, documentation, components, source code, object code, images, icons, audiovisual components and objects, schematics, drawings, protocols, processes, and other visual depictions, in whole or in part, of any of the foregoing;

(d) any third-party confidential information included with, or incorporated in, any information provided by the Disclosing Party to the Recipient or its Representatives; and

(e) all notes, analyses, compilations, reports, forecasts, studies, samples, data, statistics, summaries, interpretations and other materials (the "**Notes**") prepared by or for the Recipient or its Representatives that contain, are based on, or otherwise reflect or are derived from, in whole or in part, any of the foregoing.

Any Confidential Information disclosed orally shall be clearly identified as such by Disclosing Party at the time it is disclosed.

2. Exclusions from Confidential Information. Except as required by applicable federal, state or local law or regulation, the term "Confidential Information" as used in this Agreement shall not include information that:

(a) at the time of disclosure is, or thereafter becomes, generally available to and known by the public other than as a result of, directly or indirectly, any violation of this Agreement by the Recipient or any of its Representatives;

(b) at the time of disclosure is, or thereafter becomes, available to the Recipient on a non-confidential basis from a third-party source, provided that such third party is not and was not prohibited from disclosing such Confidential Information to the Recipient by a legal, fiduciary or contractual obligation to the Disclosing Party;

(c) was known by or in the possession of the Recipient or its Representatives, as established by documentary evidence, prior to being disclosed by or on behalf of the Disclosing Party pursuant to this Agreement; or

(d) was or is independently developed by the Recipient, as established by documentary evidence, without reference to or use of, in whole or in part, any of the Disclosing Party's Confidential Information.

3. Recipient Obligations. The Recipient shall:

(a) protect and safeguard the confidentiality of all such Confidential Information with at least the same degree of care as the Recipient would protect its own Confidential Information, but in no event with less than a commercially reasonable degree of care;

(b) not use the Disclosing Party's Confidential Information, or permit it to be accessed or used, for any purpose other than the Purpose, or otherwise in any manner to the Disclosing Party's detriment;

(c) not disclose any such Confidential Information to any person or entity, except to the Recipient's Representatives who:

(i) need to know the Confidential Information to assist the Recipient, or act on its behalf, in relation to the Purpose or to exercise its rights under the Agreement;

(ii) are informed by the Recipient of the confidential nature of the Confidential Information; and

(iii) are subject to confidentiality duties or obligations to the Recipient that are no less restrictive than the terms and conditions of this Agreement; and

(d) be responsible for any breach of this Agreement caused by any of its Representatives.

4. Additional Confidentiality Obligations. Except as otherwise permitted by this Agreement or required by applicable federal, state or local law or regulation, neither Party shall, nor permit any of its Representatives to, disclose to any person:

(a) that the Confidential Information has been made available to it or its Representatives, or that it has inspected any portion of the Confidential Information;

(b) that discussions or negotiations may be, or are, underway between the Parties regarding the Confidential Information or the Purpose, including the status thereof; or

(c) any terms, conditions or other arrangements that are being discussed or negotiated in relation to the Confidential Information or the Purpose.

5. Security. Recipient will maintain and comply with administrative, technical and physical safeguards that are designed to protect the security and integrity of the Confidential Information, including in connection with any transfer, communication, remote access or storage of the Confidential Information as permitted or required under this Agreement. Recipient will immediately notify the Disclosing Party of any unauthorized disclosure or use of the Disclosing Party's Confidential Information.

6. Legally Required Disclosure. Any disclosure by the Recipient or its Representatives of any of the Disclosing Party's Confidential Information pursuant to applicable federal, state or local law, regulation or a valid order issued by a court or governmental agency of competent jurisdiction or in response to a data, information or discovery request issued in a proceeding before a court or governmental agency of competent jurisdiction (a "**Legally Required Disclosure**") shall be subject to the terms of this Section 6 (Legally Required Disclosure). Prior to making any such Legally Required Disclosure, the Recipient shall provide the Disclosing Party with:

(a) to the extent reasonably possible and not prohibited by law, written notice (no less than three (3) business days prior to making the disclosure) of such requirement so that the Disclosing Party may seek, at its sole cost and expense, a protective order or other remedy; and

(b) reasonable assistance, at the Disclosing Party's sole cost and expense, in opposing such disclosure or seeking a protective order or other limitations on disclosure.

If, after providing such notice and assistance as required herein, the Recipient remains subject to a Legally Required Disclosure, the Recipient (or its Representatives or other persons to whom such Legally Required Disclosure is directed) shall disclose no more than that portion of the Confidential Information that such Legally Required Disclosure specifically requires the Recipient to disclose. Recipient shall not be in breach of this Agreement or liable to Disclosing Party for any disclosure made pursuant to this Section 6 (Legally Required Disclosure).

Notwithstanding anything to the contrary in this Agreement, PGE may disclose Confidential Information regardless of whether the Confidential Information is formally requested

and without notice to the Disclosing Party to the Oregon Public Utility Commission (“OPUC”) pursuant to any protective order(s) that may be issued by the OPUC.

7. Return or Destruction of Confidential Information. At any time during or after the term of this Agreement, at the Disclosing Party's written request, the Recipient and its Representatives shall promptly return to the Disclosing Party all copies, whether in written, electronic or other form or media, of the Disclosing Party's Confidential Information, or destroy all such copies and certify in writing to the Disclosing Party that such Confidential Information has been destroyed; provided, however, that Recipient may keep copies of the Confidential Information for legal compliance, systematic backup or archival purposes, and will hold such copies subject to the terms of this Agreement. In addition, the Recipient shall also destroy all copies of any Notes created by the Recipient or its Representatives and certify in writing to the Disclosing Party that such copies have been destroyed; provided, however, that Recipient may keep copies of the Notes for legal compliance, systematic backup or archival purposes, and will hold such copies subject to the terms of this Agreement.

8. Term and Termination. The term of this Agreement shall commence on the Effective Date and shall expire five (5) years from the Effective Date. Either Party may terminate this Agreement for any reason by giving the other Party written notice thirty (30) days before the effective date of such termination. Notwithstanding anything to the contrary herein, each Party's rights and obligations under this Agreement shall survive any expiration or termination of this Agreement for a period of two (2) years from the date of such expiration or termination, even after the return or destruction of Confidential Information by the Recipient.

9. No Representations or Warranties. Neither the Disclosing Party nor any of its Representatives make any representation or warranty, expressed or implied, as to the accuracy or completeness of the Confidential Information disclosed to the Recipient hereunder. Neither the Disclosing Party nor any of its Representatives shall be liable to the Recipient or any of its Representatives relating to or resulting from the Recipient's use of any of the Confidential Information or any errors therein or omissions therefrom.

10. No Transfer of Rights, Title or Interest. Each Party hereby retains its entire right, title and interest, including all intellectual property rights, in and to all of its Confidential Information. Any disclosure of such Confidential Information hereunder shall not be construed as an assignment, grant, option, license or other transfer of any such right, title or interest whatsoever to the Recipient or any of its Representatives.

11. No Other Obligation. The Parties agree that neither Party shall be under any legal obligation of any kind whatsoever, or otherwise be obligated to enter into any business or contractual relationship, investment, or transaction, by virtue of this Agreement, except for the matters specifically agreed to herein. Either Party may at any time, at its sole discretion with or without cause, terminate discussions and negotiations with the other Party, in connection with the Purpose or otherwise and may pursue a similar purpose without the involvement of, or liability to, the other Party.

12. Remedies. Each Party acknowledges and agrees that money damages might not be a sufficient remedy for any breach or threatened breach of this Agreement by such Party or its

Representatives. Therefore, in addition to all other remedies available at law (which neither Party waives by the exercise of any rights hereunder), the non-breaching Party shall be entitled to seek specific performance and injunctive and other equitable relief as a remedy for any such breach or threatened breach, and the Parties hereby waive any requirement for the securing or posting of any bond or the showing of actual monetary damages in connection with such claim.

13. Limitation of Liability.

(a) No Consequential or Indirect Damages. IN NO EVENT SHALL EITHER PARTY OR ANY OF ITS REPRESENTATIVES BE LIABLE UNDER THIS AGREEMENT TO THE OTHER PARTY OR ANY THIRD PARTY FOR ANY CONSEQUENTIAL, INCIDENTAL, INDIRECT, EXEMPLARY, SPECIAL OR PUNITIVE DAMAGES, INCLUDING ANY DAMAGES FOR BUSINESS INTERRUPTION, LOSS OF USE, REVENUE OR PROFIT, WHETHER ARISING OUT OF BREACH OF CONTRACT, TORT (INCLUDING NEGLIGENCE) OR OTHERWISE, REGARDLESS OF WHETHER SUCH DAMAGES WERE FORESEEABLE AND WHETHER OR NOT THE BREACHING PARTY WAS ADVISED OF THE POSSIBILITY OF SUCH DAMAGES.

(b) Maximum Liability. IN NO EVENT SHALL EITHER PARTY'S AGGREGATE LIABILITY ARISING OUT OF OR RELATED TO THIS AGREEMENT, WHETHER ARISING OUT OF OR RELATED TO BREACH OF CONTRACT, TORT (INCLUDING NEGLIGENCE) OR OTHERWISE, EXCEED TWO MILLION DOLLARS (\$2,000,000). THE FOREGOING LIMITATIONS SHALL APPLY EVEN IF THE NON-BREACHING PARTY'S REMEDIES UNDER THIS AGREEMENT FAIL OF THEIR ESSENTIAL PURPOSE.

14. Governing Law, Jurisdiction and Venue. This Agreement shall be governed by and construed in accordance with the internal laws of the State of Oregon without giving effect to any choice or conflict of law provision or rule (whether of the State of Oregon or any other jurisdiction) that would cause the application of laws of any jurisdiction other than those of the State of Oregon. Any legal suit, action or proceeding arising out of or related to this Agreement or the matters contemplated hereunder shall be instituted exclusively in the federal courts of the United States or the courts of the State of Oregon in each case located in the city of Portland and County of Multnomah, and each Party irrevocably submits to the exclusive jurisdiction of such courts in any such suit, action or proceeding and waives any objection based on improper venue or *forum non conveniens*. Service of process, summons, notice or other document by mail to such Party's address set forth herein shall be effective service of process for any suit, action or other proceeding brought in any such court.

15. Attorney Fees. In the event that any Party institutes any legal suit, action or proceeding, including arbitration, against the other Party to enforce the covenants contained in this Agreement, the prevailing Party in the suit, action or proceeding shall be entitled to receive in addition to all other damages to which it may be entitled, the costs incurred by such Party in conducting the suit, action or proceeding, including reasonable and actual attorneys' fees and expenses and court costs.

16. Notices. All notices, requests, consents, claims, demands, waivers and other communications hereunder shall be in writing and shall be deemed to have been given: (a) when delivered by hand (with written confirmation of receipt); (b) when received by the addressee if

sent by a nationally recognized overnight courier (receipt requested); (c) on the date sent by facsimile or e-mail of a PDF document (with confirmation of transmission) if sent during normal business hours of the recipient, and on the next business day if sent after normal business hours of the recipient; or (d) on the third day after the date mailed, by certified or registered mail, return receipt requested, postage prepaid. Such communications must be sent to the respective Parties at the addresses set forth on the first page of this Agreement (or to such other address that may be designated by a Party from time to time in accordance with this Section).

17. Survival. Any terms and conditions contained in this Agreement which, by their nature, are intended to survive the expiration or termination of this Agreement, shall survive expiration or termination of this Agreement, including, but not limited to: Section 12 (Remedies); Section 13 (Limitation of Liability); Section 14 (Governing Law, Jurisdiction and Venue); Section 15 (Attorney Fees); and Section 16 (Notices).

18. Entire Agreement. This Agreement constitutes the sole and entire agreement of the Parties with respect to the subject matter contained herein, and supersedes all prior and contemporaneous understandings, agreements, representations and warranties, both written and oral, with respect to such subject matter. This Agreement may only be amended, modified or supplemented by an agreement in writing signed by each Party hereto.

19. Severability. If any term or provision of this Agreement is invalid, illegal or unenforceable in any jurisdiction, such invalidity, illegality or unenforceability shall not affect any other term or provision of this Agreement or invalidate or render unenforceable such term or provision in any other jurisdiction.

20. Counterparts. This Agreement may be executed in counterparts, each of which shall be deemed an original, but all of which together shall be deemed to be one and the same agreement. A signed copy of this Agreement delivered by facsimile, e-mail or other means of electronic transmission shall be deemed to have the same legal effect as delivery of an original signed copy of this Agreement.

21. Assignment. Neither Party may assign any of its rights hereunder without the prior written consent of the other Party. Any purported assignment in violation of this Section shall be null and void. No assignment shall relieve the assigning Party of any of its obligations hereunder. This Agreement is for the sole benefit of the Parties hereto and their respective successors and permitted assigns and nothing herein, express or implied, is intended to or shall confer upon any other person or entity any legal or equitable right, benefit or remedy of any nature whatsoever under or by reason of this Agreement.

22. Waivers. No waiver by any Party of any of the provisions hereof shall be effective unless explicitly set forth in writing and signed by the Party so waiving. No waiver by any Party shall operate or be construed as a waiver in respect of any failure, breach or default not expressly identified by such written waiver, whether of a similar or different character, and whether occurring before or after that waiver. No failure to exercise, or delay in exercising, any right, remedy, power or privilege arising from this Agreement shall operate or be construed as a waiver thereof; nor shall any single or partial exercise of any right, remedy, power or privilege hereunder

preclude any other or further exercise thereof or the exercise of any other right, remedy, power or privilege.

IN WITNESS WHEREOF, the Parties have executed this Agreement to be effective as of the Effective Date.

Portland General Electric Company



By: _____

By: _____

Name: _____

Name: _____

Title: _____

Title: _____

Date: _____

Date: _____