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VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-3398

Attn: Filing Center

Re: Docket UM 2225 – PacifiCorp's Response to OPUC Staff's Roadmap Acknowledgement and Community Lens Straw Proposals

PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) respectfully submits these comments in response to the Public Utility Commission of Oregon (Commission) Staff's Roadmap Acknowledgement and Community Lens Straw Proposals.[1]

PacifiCorp appreciates the significant effort and consensus-building that Commission and Staff have facilitated over the past year. Staff has identified several areas of agreement between the various stakeholders, and PacifiCorp believes that these efforts will lead to a faithful implementation of HB 2021.

The Company also notes that rulemaking proceedings can provide a helpful and effective vehicle to address any important and contested issues that arise in the current and future Staff Straw Proposals. Rulemakings would provide parties the opportunity to review and comment on specific proposals, and for the Commission to consider and deliberate about the complexity and nuances presented. These much narrower and discrete rulemaking proceedings could be administered concurrently and would not delay the Commission's investigation in this docket.

PacifiCorp thanks Staff and the Commission for the process to date, and recommends the following modest revisions discussed below.

I. Roadmap Acknowledgement

A. CEP Planning and Acknowledgement Horizons

PacifiCorp supports Staff's proposal on this issue, as clean energy plans (CEPs) should include analysis and annual goals over at least a 20-year planning horizon, and acknowledgement should focus on utility goals for the upcoming 2–4-year period. This aligns with existing Commission and PacifiCorp integrated resource plan (IRP) analyses and acknowledgement horizons and

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[1] *In re OPUC's HB 2021 and CEP Investigation,* Dkt. UM 2225, Work Plan Update and Straw Proposals (August 9, 2022).

would not appear to deter transmission infrastructure investment that have longer timelines beyond the 2–4-year acknowledgement horizon.

B. Annual Action Goals

PacifiCorp supports the majority of Staff's proposal on this issue. The Company intends to include resource actions based on retirements of existing resources and procurement of new resources, including where they are located, whether they are system resources or voluntary customer or community programs, and when they become operational. PacifiCorp can also study and report changes in system operations based on the preferred portfolio of resources: including how fossil-fueled and variable resources operate in portfolios with high penetrations of variable resources, potentially with high curtailments. The Company also envisions discussing community-based renewables and the small resource options we intend to model, which could include energy efficiency and demand response resources (as typically included, though not exclusively, with demand side management options).

That said, PacifiCorp requests additional guidance on several issues.

Does the Commission expect PacifiCorp to include separate annual action goals for non-emitting resources (storage, nuclear, etc.) and for renewable resources (wind, solar, hydroelectric)? At least for this initial CEP, PacifiCorp believes there is utility to report planned resources for both categories and will provide that information if the Commission believes the information could be beneficial. However, PacifiCorp recommends the Commission not require specific action goals for the initial CEP for these two categories of resources (i.e., a proscriptive megawatt target for hydroelectric resources). The Commission should provide utilities flexibility to explore various resource options and combinations to meet the decarbonization targets of HB 2021, and not create overly granular annual action goals that could prevent innovative resource portfolios. In future CEPs, the Commission could revisit whether separate annual action goals for non-emitting and renewable resources are appropriate.

How should utilities address distribution system planning (DSP) annual actions, and incorporate resiliency metrics for DSP purposes? These two issues raise timing, confidentiality, and process problems. DSP resiliency metrics are currently being developed in utility planning processes (should they focus on number of projects, outage metrics, risk metrics, etc.?). And the Commission's DSP and wildfire protection plan (WPP) processes, that could further develop resiliency metrics and DSP action plans, do not currently align with the schedule for filing initial CEPs.

Beyond timing concerns, depending on the level of DSP detail that the Commission requires utilities to include in their CEPs, there are significant confidentiality and planning issues. Certain historic and forecasted project-specific information at the DSP level can only be provided on a confidential basis, because the information could include either (a) sensitive bidding information that must be protected to preserve the competitive procurement bidding processes, or (b) customer-specific requirements that if disclosed could harm customer business interests.

To address these issues, the Commission should decline to include specific DSP annual actions for the initial CEP. This would allow the various planning processes to conclude (or align better), and to ensure the information sharing and planning concerns are adequately mitigated. If instead the Commission decides to include specific DSP annual actions in the initial CEP, it is important to provide guidance and reasonable sideboards to address the issues discussed above.

Finally, should action goals align with the acknowledgment horizon? PacifiCorp recommends the Commission consider action goals that align with the 2–4-year acknowledgment horizon (or longer as necessary for transmission resources), instead of yearly goals for the various resources and targets listed in this section. As the Commission is aware, there are significant disagreements between various stakeholders regarding the timing (when should a utility meet a target?), and type of targets (should community-based renewable projects have a larger target compared to other resources?). The transition and expansion of utility generation fleets will also be a capital and labor-intensive process that will span decades. Action goals that align with the 2– 4-year acknowledgment horizon could avoid unnecessary disputes on the interpretation of Commission "annual" goals, while also allowing utilities to focus on longer-term investment cycles with more ambitious near-term targets. This would avoid utilities and parties devoting resources to model and achieve more incremental—and likely conservative—annual or yearly targets. The Commission should adopt action goals that support robust transformation of utility generation portfolios, and multi-year goals accomplish that much better than annual goals.

C. Annual metrics for measuring the impacts of actions

PacifiCorp supports reporting total greenhouse gas emissions, based on individual fossil fuel resources, market purchases, and markets sales associated with the preferred portfolio based on then-current Oregon Department of Environmental Quality (DEQ) methodologies in an annual CEP update. PacifiCorp could also provide emissions data for certain alternative portfolios if necessary for comparison purposes. Further, the Company supports Staff's proposed process to address community impacts and benefits metrics and looks forward to working with stakeholders.

However the Commission should be aware that alternative portfolio emissions reporting could quickly become unduly burdensome: PacifiCorp evaluates hundreds, thousands, and sometimes tens of thousands of portfolios for planning purposes and requiring an additional emissions layer for each portfolio would add substantial time and resources to the process. PacifiCorp instead recommends the Commission require emissions reporting on the preferred portfolio and require only a reasonable selection of alternative portfolios to compare emissions (i.e, a high, medium, and low emissions alternative portfolios to meet HB 2021 targets). Note, PacifiCorp already reports aggregate greenhouse gas (GHG) emissions for each portfolio as a relative guide. The concern involves requiring overly detailed and granular assessments of alternative portfolio GHG emissions. Keeping a high-level assessment for all portfolios, while focusing on the preferred portfolio for more intensive emissions analysis (and a select few alternative portfolios), would ensure relevant emissions benchmarking and avoid unduly complicating the planning and reporting processes.

Staff's straw proposal also recommends that utilities annually report the estimated average electric rate impact for all portfolios that were evaluated. PacifiCorp has concerns with this metric. The IRP and CEP are resource planning tools and are not used for ratemaking purposes: they do not include the data necessary to calculate a revenue requirement that is required for rate cases, and to require utilities to provide that information as part of the IRP and CEP process would be unduly burdensome.

Without relevant cost of service information, the metric would also provide hollow information for stakeholders and would lead to a second problem: utility estimated rate impacts based on yet-to-be-procured resources, will diverge from actual rate impacts based on a utility's then-relevant revenue requirement. The Commission should avoid this unnecessary dispute between parties that misunderstand the CEP's revenue requirement metric (created for comparison and illustrative purposes), and a utility's actual and proposed revenue requirements for ratemaking purposes (required for just and reasonable rates). Additionally, HB 2021 has fundamentally revised utility cost allocation principles, and what constitutes average electricity rates for customer classes now will most likely be significantly different in the future (for low-income and historically under-represented customer classes). An estimated average electric rate metric based on current rate design principles could be misleading to the extent the Commission transitions to more equitable customer classes or rates.

Instead, PacifiCorp recommends providing the revenue requirement impact consistent with existing IRP guidelines that requires utilities to include a present value revenue requirement (PVRR).[2] The metric should also be limited to the preferred portfolio and possibly a certain limited number of alternative portfolios (aligned with the alternative emissions portfolios discussed above), and not provided for every portfolio that the Company runs.

As discussed below, PacifiCorp supports Staff's proposed process to address community impacts and benefits metrics and looks forward to working with stakeholders.

[2] *In re OPUC IRP Investigation,* Dkt. UM 1056, Order No. 07-002, Guideline 1.

D. Greenhouse gas reporting, verification, and compliance in planning (Guidance)

PacifiCorp agrees that a DEQ-verified methodology is appropriate, and that the Commission is correct to not pursue alternative greenhouse gas emissions accounting methodologies. PacifiCorp also agrees that, alongside a DEQ-verified methodology for stakeholders, reporting emissions with the granularity discussed above for annual emissions reporting on the preferred portfolio will provide stakeholders with sufficient transparency into the sources of Oregon emissions, as well as total emissions on PacifiCorp's six-state system.

PacifiCorp also notes that Washington has created an attestation process for meeting certain state decarbonization policies.[3] The Commission could consider a similar attestation process if it determines that greenhouse gas verification (or other relevant HB 2021 goals or CEP targets for that matter) becomes burdensome or problematic to implement and track. For example, given the timing issues with DEQ-verification and utility CEP annual reporting, the Commission could implement a utility greenhouse gas attestation where utilities attest that the current emissions comply with current DEQ methodologies. This would avoid the need for DEQ verification while still ensuring utility emissions accountability, though verification and Commission investigation would always be available if necessary to correct utility errors or examine contested issues.

E. Continual Progress and IRP cost/risk framework

The balancing of costs, benefits and risks is a core functionality of PacifiCorp's IRP modeling processes. The CEP emphasizes the importance of reducing greenhouse gas emissions, which for IRP modeling purposes can be accomplished by including greenhouse gas cost drivers in the expected case price curve. For the purposes of the CEP specifically, the Company expects the preferred portfolio to show emissions reductions over the modeled horizon to achieve the emissions reductions targets set forth in HB 2021 (whether annually or on a 2 to 4-year acknowledgement horizon, as directed by the Commission). There may be a more stairstep pattern to the reduction, as opposed to a steady year-on year reduction, as emitting resources are retired and largely replaced by non-emitting resources. However, it is also reasonable to expect that changes in load growth or other unknowable long-term planning factors can skew this trajectory. The Company believes it is important to recognize the role of the two-year planning cycle in allowing for continual updates, improvements, and course corrections. To that end, the

[3] WAC 480-100-650(3) ("On or before July 1st of each year beginning in 2023, other than in a year in which the utility files a clean energy compliance report, the utility must file with the Commission, in the same docket as its most recently filed CEIP, an informational annual clean energy progress report regarding its progress in meeting its targets during the preceding year. The annual clean energy progress report must include, but is not limited to: . . . (a) . . . an attestation for the previous calendar year that the utility did not use any coal-fired resource as defined in this chapter to serve Washington retail electric customer load.").

Company should not be penalized for the need to update its plans to continue to meet compliance targets as the future unfolds.

F. Considerations in CEP acknowledgement

PacifiCorp generally supports Staff's proposed CEP acknowledgement considerations. While considerations of how effective the Company engaged its community stakeholders could become problematic given significantly divergent stakeholder interests (decisions on how, who, and when to engage with stakeholders are not value-neutral and subject to criticism), the Company will work to address reasonable deficiencies in PacifiCorp's engagement strategies to faithfully implement HB 2021.

PacifiCorp's IRP will develop a CEP-compliant portfolio starting from an initial six-state optimization covering the Company's service territory. Emissions reporting will be used as the basis for establishing compliance with greenhouse gas reduction targets.

G. Non-Acknowledgment, partial acknowledgement, and conditional acknowledgement of the CEP, and interdependencies with IRP acknowledgement

PacifiCorp generally supports Staff's proposal and appreciates the expectation that there can be remediation steps throughout the process, without need for unnecessary punitive actions.

However PacifiCorp does not believe it is reasonable to require utilities to resubmit a revised CEP in the event of a non-acknowledged plan. Conservatively, it would take utilities 5 to 7 months to develop and submit a subsequent CEP to comply with Commission guidance. Given the overlap with IRP planning processes, this would lead to unnecessary complications and delay in implementing HB 2021. Fundamentally, IRPs and CEPs are planning documents that inform, but do not control, utility resource procurement decisions. Actual compliance with HB 2021 targets that are several years or decades in the future, and dependent on actual results from utility-specific RFPs, should be reserved for ratemaking or investigation proceedings.

If the Commission ultimately adopts a re-file policy for non-acknowledged CEPs, it should clarify that only limited facts and circumstances justify the action. For example, similar to IRP processes, the Commission should reserve the discretion to (a) acknowledge a CEP as filed; (b) acknowledge a CEP with conditions; or (c) acknowledge a CEP in general, though not acknowledge certain aspects of a plan. The Commission could then create an additional option to not acknowledge a plan in its entirety, that requires submitting a revised CEP, but only in instances of blatant or egregious instances of reasonably foreseeable future noncompliance. This would establish a high-bar standard that balances the Commission's need to monitor utility progress in complying with HB 2021, while understanding that IRP/CEPs are planning and information documents.

H. Annual update

While the Company agrees with Staff's recommendation that the IRP update include a CEP update, the expectations for the CEP update should be similarly downscaled to align with the scope of the IRP Update. An IRP update is a significantly more focused and narrow analysis that evaluates the ongoing standing of the preferred portfolio, based on a limited set of key input changes (most notably loads and prices). Metrics used in the IRP/CEP should therefore continue to be used to assess the updated portfolio resulting from the update of a narrow set of core assumptions. An IRP/CEP Update, for example, should not require a reassessment of identified community benefits and impacts, but rather should apply those same inputs and metrics to the updated preferred portfolio. The CEP update can also include DEQ emissions reports filed after the CEP was acknowledged, per Staff's recommendation.

II. Community Lens

A. Community Lens Acquisition Targets

The Company agrees with Staff's recommendation that a potential study (or studies) would be needed to determine opportunities for resiliency projects and other community-based renewable energy projects (CBREs). However, given the timeline for the first CEP and the many inputs that need to be determined prior to performing such study, the Company recommends that the potential study is neither developed nor included for the first CEP. The Company recommends using this first CEP as an opportunity to establish frameworks and processes to identify resiliency and CBRE projects with input from representatives of the community's stakeholders, and staff. Once the framework and processes are established, this would allow for a study to better inform the Company's opportunities for these projects, but also to meet the specific targets determined to meet the requirements of the CEP as well as meeting the needs of communities, stakeholders, and staff.

B. Opportunities Considered in Community Lens Potential Studies

The Company agrees with Staff's recommendation for opportunities for resiliency projects and other CBRE actions that should be developed in coordination with representatives of communities and input from stakeholders and staff. The Company will use the CEP to determine if this coordination can be implemented into existing engagement activities, or if other engagement activities are required.

C. Community Benefits Indicators

The Company generally supports Staff's initial community benefits indicators (CBI) categories, and while PacifiCorp has concerns over several of the draft CBIs advanced by the joint stakeholders (for example, requiring illegal “hire-local” provisions or unreasonable continuous reduction in greenhouse gas emissions given seasonality and load constraints), PacifiCorp will work with stakeholders to develop consensus where possible on reasonable indicators.

The Company will eventually use a robust set of CBIs in the Community Lens potential study(ies) to score IRP/CEP portfolios. However, given the limited time to work with stakeholders prior to filing initial CEPs, PacifiCorp’s first CBIs will resemble indicators used in the Company’s Washington Clean Energy Implementation Plan (CEIP), though as amended based on insights gained from the Company’s stakeholder processes in that state.

The Company also notes that it agrees with Staff’s recommendation, though from a DSP perspective, for the DSP we have represented using the Utility Community Benefits and Impacts Advisory Group (UCBIAG) to inform inputs regarding equity matters (e.g., equity metrics for screening, suggested data sources, etc.) and utilizing local engagement for input on non-wires solution (NWS) preference. The CBIs could be used to inform NWS cost/benefits between options, but the Company does not expect that the DSP would establish the CBIs, but rather would rely on them as inputs into determining NWS to address grid needs.

D. Off-setting Fossil Fuels with CBREs

Staff’s recommendations describe the core functionality of IRP modeling, in which all resource options include expected costs and impacts, including dispatch and dispatch-related costs such as fuel and emissions, as well as portfolio reliability shortfalls. Resource adequacy is modeled as reserve and load requirements and measured by an hourly-granularity reliability assessment to evaluate, and address identified shortfalls. System-wide benefits include all of the recommended elements of resource adequacy contributions, energy value, avoided GHG emissions, and avoided transmission. As transmission options are competitive with all other portfolio alternatives, the model’s native function includes avoided transmission costs in determining the optimal portfolio. Some transmission costs are included in the costs of specific resource options, where known, and this cost is also avoided if such a resource is not part of the least-cost least risk solution. Cost reporting by category is part of PacifiCorp’s existing reporting strategy and starting with the 2021 IRP includes the value of each resource option to the system whether the resource is selected or not as part of the optimal solution.

E. Resiliency-Specific Guidance

Consistent with previous Commission guidance, the Company continues to anticipate that the CEP will be included as an appendix in the 2023 IRP. Resiliency is expected to be addressed within that appendix, and as part of the larger discussion of PacifiCorp’s six-state territory. In the prior IRP, resiliency was addressed in multiple chapters, and particularly Chapter 5 – Reliability and Resiliency. For the 2023 IRP, the Company plans to maintain a similar chapter and will also address resiliency specifically in the context of the CEP with appropriate cross-referencing. Resiliency will acquire a tighter focus than in the 2021 IRP, aligned with CEP actions, including addressing community resiliency impacts.

As for the resiliency analysis and risks for the first CEP, the Company recommends that the first filing be used to determine the framework and processes for resiliency and CBRE analysis in the CEP context. There are other Company processes, such as DSP and WPP, that develop projects that indirectly address resiliency, but these processes are not specifically focused on determining resiliency opportunities in the same context as the CEP is proposing. Similarly, neither of these processes directly determine opportunities for CBREs. It is expected that a separate analysis with a different set of inputs may be required, therefore the Company recommends that this be determined and established in the first CEP with community, stakeholder, and staff feedback prior to performing such analysis.

III. Conclusion

PacifiCorp appreciates the Commission's diligent efforts in this investigation, and respectfully requests the Commission consider the comments provided above.

Sincerely,

Shelley McCoy

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PacifiCorp