BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. LC 82

In the Matter of PACIFICORP, dba PACIFIC POWER, 2023 Clean Energy Plan and Integrated Resource Plan.	Staff Round 0 Comments

Introduction

PacifiCorp's (Company) 2023 Integrated Resource Plan (IRP) and Clean Energy Plan (CEP) provide the Company's plan to not only meet the energy needs of its six-state system, but to additionally meet Oregon policy requirements including the recent HB 2021 legislation and associated OPUC Order Nos. 22-390 and 22-446. HB 2021 creates new requirements for Oregon utilities to provide 100 percent clean energy by 2040, evaluate Community Based Renewable Energy Resources (CBRE), and to serve Oregon customers with small-scale renewable resources equal to 10 percent of PacifiCorp's Oregon aggregate electrical capacity by 2030. OPUC's Investigation into Clean Energy Plans added detailed guidance on expectations for the Company's first Clean Energy Plan.[1]

PacifiCorp was granted a waiver of the IRP Guideline requirement to file a draft IRP in Order No. 23-011. It was determined that the IRP and CEP would be filed on March 31, 2023, and an initial 60-day review process would be created to provide the opportunity for feedback on the IRP, and to allow the Company to file an IRP addendum if needed, before the traditional IRP review process began.[2]

On March 20, 2023, PacifiCorp filed a motion for extension to file its first Clean Energy Plan, citing the complexity of CEP development for its six-state system and unexpected load growth as factors that made it an undue burden to provide the CEP by March 31. On April 6, 2023, the Commission directed PacifiCorp to file its Clean Energy Plan on May 31, 2023, and start the extended review process set out in Order No 23-011. These Round 0 comments represent Staff's initial feedback on the Company's IRP/CEP filing. The Company is expected to provide a reply and potentially an Addendum by July 31, 2023, after which the traditional IRP review process will begin.

Staff thanks participants for their help developing the Clean Energy Plan guidance and expectations in Docket No. UM 2225 and looks forward to furthering the conversation about how Clean Energy Plans can be made increasingly useful and meaningful in the future.

Policy Landscape and Staff Approach

Staff's initial review of PacifiCorp's 2023 IRP/CEP will focus on big-picture questions and additional information the Company could provide in a July IRP/CEP addendum to improve its IRP/CEP. This opportunity should provide much of the same value as a draft IRP review process.

Some questions that Staff has considered in developing these comments are:

- How has the Company's CEP filing followed the guidance in Order Nos. 22-206, 22-390, 22-446, and 23-060, as well as ORS 469A.420?
- How does the Company plan to manage costs of HB 2021 while ensuring its goals are met?
- What should the Company's focus be to reach HB 2021 goals in 2030?
- How can the Company better engage with communities and stakeholders in developing future CEPs?
- How can transparency be improved in future CEPs?

[1] Docket No. UM 2225.

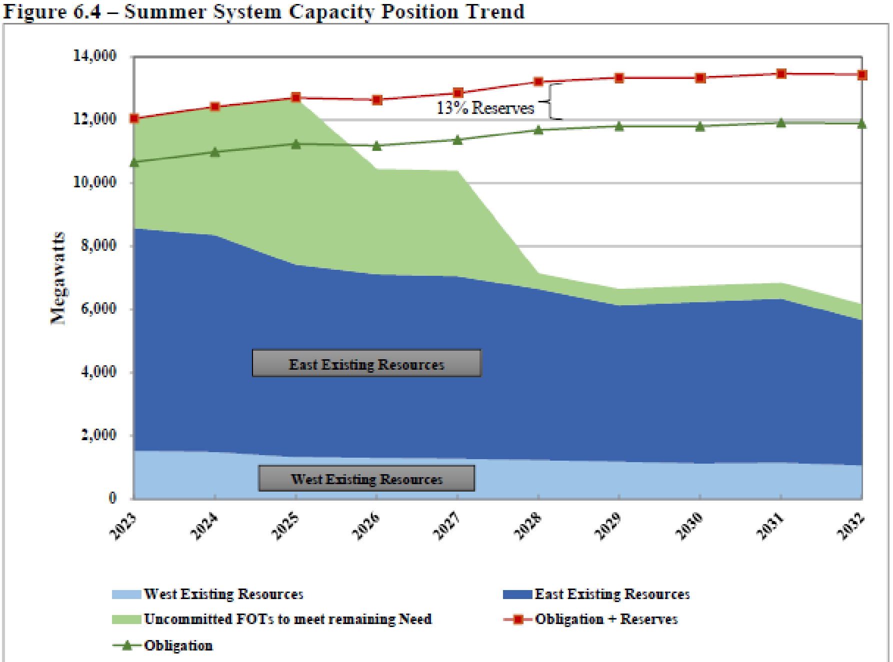
[2] Check this with the Order No. 23-011.

1. Energy and Capacity Actions

Energy and Capacity Needs:

As a system, PacifiCorp expects to be short on capacity and reliant on market purchases in the near term:

Figure 6.4 – Summer System Capacity Position Trend



[3]

In the CEP update staff requests that PAC describe the degree to which this IRP/CEP's proposed energy and capacity actions, along with their proposed allocation under MSP, deviate from the previous IRP.

The IRP quantifies market reliance risk, which is an important consideration given regional resource adequacy considerations. Additionally, market purchase availability at peak times is limited in the later years of the 2023 IRP:

Table 5.8 – Maximum Available Front Office Transactions by Market Hub

Market Hub	Availability Limit (MW)				
	2023 IRP			2021 IRP	
	Short-term (2023-2027)	Long-term (2028-2042) Summer	Long-term (2028-2042) Winter	Summer	Winter
Mid-Columbia (Mid-C)	1979	500	350	500	350
California Oregon Border (COB)	424	0	250	0	250
Nevada Oregon Border (NOB)	200	0	100	0	100
4 Corners (4C)	398	0	0	0	0
Mona	325	0	300	0	300
Total	**3326**	**500**	**1000**	**500**	**1000**

[4]

[3] PacifiCorp 2023 IRP. Page 169.
[4] PacifiCorp 2023 IRP. Page 126.

Staff is interested in gaining a stronger understanding the Front Office Transactions (FOT) reflected in Table 5.8. For example, do FOTs include the potential for longer-term bilateral capacity contracts? In reply comments, PacifiCorp should include any information it has about the extent to which increasing utility participation in regional markets like EIM and EDAM is reducing the amount of capacity available for short-term bi-lateral market transactions to support capacity needs through market purchases. It seems possible that regional market participation is reducing the amount of market purchases available as FOTs on a short-term basis. Has the Company explored locking in capacity contracts on a longer-term basis in response to diminishing short-term purchase market depth?

All-Source RFP Plans:

PacifiCorp's IRP Action Plan includes a 2024 all-source RFP for resources online by the end of 2028. The draft RFP would be filed with the OPUC in Q3 2024. A small-scale RFP is also planned for late 2023, with resources operational by 2028.

Regarding the All-Source RFP, Staff requests the Company confirm whether long lead-time resources such as pumped hydro storage, with in-service dates after 2028, will be supported in the upcoming RFP. Additionally, Staff requests the Company comment on the potential to extend the in-service date of the upcoming AS RFP from 2028 to 2029, to allow for increased efficiency of procurement and potentially reduce the number of RFPs needed to meet acquisition needs.

Staff requests the updated CEP provide more details about how the small-scale RFP and how the all-source RFP and small-scale RFP will interact between each other and with the IRP/CEP. Are there any drawbacks or synergies to running two concurrent RFPs for differently sized resources?

Small Scale Renewables and Community Based Renewable Energy:

The 2023 CEP includes 490 MW of small-scale renewables (SSR) by 2030, increasing to 802 MW by 2037. The CEP indicates that there is only time for one SSR RFP before the 2030 legislated deadline. PacifiCorp's CEP shows that the Company appreciates the urgency and difficulty of procuring enough small renewables in a limited time and at the best price possible. However, Staff requests more clarity on the additional steps the Company will take to procure these resources at a reasonable cost, including steps to increase the competitiveness of the SSR RFP and the availability of CBRE resources for procurement. Will the Company provide support to RFP bidders to encourage the most robust response? Will the Company submit one or more benchmark SSR bids to encourage bidders to provide their most competitive bids? What steps might the Company take if an insufficient amount of bid capacity is received? What actions could the company take to identify key barriers to SSR and CBRE development and to enable projects that drive community benefits and help control costs, for example, interconnection and deliverability costs and timelines and the ability of community-driven projects to participate in competitive solicitations? And how quickly does the Company anticipate the CBRE Action Plan becoming a CBRE procurement? How will the Company engage communities and other partners to identify CBRE actions that drive community benefits in manner that also helps to control costs?

Additionally, Staff finds the Company's analysis of the cost and benefits associated with meeting the CEP's 10% SSR requirement a helpful starting point. To this end, updating Table 16 with a final column that captures the NPVRR of each Pathway's scenario would be helpful.

Staff also suggests the CEP be updated to include a potential range of SSR to be acquired by 2030 given policy interpretations around such items as the treatment of existing, non-RPS renewables in Oregon. While these issues will most likely not be addressed in this IRP/CEP, other policy related dockets, such as UM 2273, are exploring the landscape of Oregon's decarbonizing energy markets and providing information that informs the implications and/or interactions of various policy changes to meet the 10% SSR goal and Oregon's 100% clean mandate by 2040.

On the costs of small-scale renewables, Staff would like to see a supply side resource table that lists the cost assumptions for these resources, and requests the Company provide this information either in an Addendum to the CEP or in workpapers provided in Docket No. LC 82.

Portfolio Modeling

PacifiCorp provided a CEP that attempts to estimate the incremental cost to Oregon of meeting HB 2021 requirements. The CEP portfolio adds Oregon's 10 percent small-scale renewables requirement to the IRP preferred portfolio. However, it is unclear whether the CEP portfolio is an optimized portfolio, or whether it is a portfolio that locks in the resources from the IRP Preferred Portfolio and then adds additional resources to meet HB 2021. Staff expects that an optimized portfolio would best represent the actual costs to Oregon of HB 2021 because it would reflect the optimization the Company should be expected to do, instead of adding 490 MW of small-scale renewables to an already sufficient portfolio. Finally, Staff finds that if PAC is modeling CBRE as additional instead of as part of an optimized portfolio, this approach may potentially be counter to the direction in ORS 469A.415(4)(d) in that the cost and opportunities of CBREs were meant to be offsetting to fossil fuel generation and not additional to existing or new fossil fuel generation selected by PAC's model. Staff requests the Company respond in Reply Comments about whether the IRP resources are locked into the CEP portfolio, and if so, why. If they are locked in, then Staff requests a sensitivity portfolio where all proxy resources are available for selection by the model, not just small-scale renewables.

2. Emission Reductions

PacifiCorp's 2023 CEP shows two pathways to HB 2021 compliance. Each pathway includes additional small-scale renewables to meet Oregon's 10 percent target as an addition to Oregon's share of system resources in the IRP.

Staff appreciates the options provided by the Company in the CEP regarding emissions reductions pathways. Staff and participant comments in the 2023 IRP review process should be able to help provide additional pathways to meeting HB 2021 requirements. Goals could include reducing costs to Oregon ratepayers and increasing the consistency of GHG emissions reductions year over year (currently, emissions increase in 2027.)[5] Cost reduction options are especially interesting, given the substantial expected NPVRR cost of about $268 million for Oregon customers associated with small-scale renewable procurements. The allocation methodology of thermal resources to Oregon will play a significant role in meeting the HB 2021 targets. PacifiCorp suggested excluding converted coal-to-gas units from Oregon's energy mix. However, the converted gas units' higher dispatch costs may cause them to be dispatched less often and as a result to have lower emissions than the rest of the Company's thermal fleet.

[5] See UM 2225, Order No. 23-060, 2-14-23, page 5 and 6.

Maintaining Oregon's access to dispatchable resource that are less likely to dispatch is an approach to GHG reduction that deserves some discussion.

One requested point of clarification is the difference in NPVRR of the CEP portfolio between the Company's CEP and Data Template filings. The CEP shows a CEP Portfolio NPVRR cost of $11,810, whereas the data template shows a CEP Portfolio NPVRR cost of $12,204 for Pathway 1. Staff requests a response from the Company in Reply Comments.

Much like Staff's Round 0 comments on PGE's first CEP, Staff seeks to understand how PacifiCorp will allocate its emissions between retail load and wholesale markets for purposes of HB 2021 compliance. The CEP states that market sales of power will be "removed by proportionately subtracting it across the utility's overall resource mix for that year."[6] Staff has two questions about this statement. 1) Does this mean that market sales will be assigned an emissions factor equal to the utility's average emissions throughout a given year, and then GHG emissions from market sales will be removed from Oregon's annual reported GHG emissions at that rate? And 2) How are system market sales assumed to be allocated to Oregon in the CEP?

Regarding Table 16 of PacifiCorp's CEP, both Pathway 1 and Pathway 2 result in significant cost increases, including an increase of about $300 million to $350 million in 2040-2042. Staff requests the revised CEP include an explanation of the drivers of cost increases in 2030-2039 and 2040-2042 in both Pathways.

Figure 1.8 in the 2023 IRP shows that Demand Response quantities throughout the planning timeframe have decreased significantly since the 2021 IRP, while efficiency has stayed approximately the same.[7] Staff would like to note that the current IRP/CEP analysis does not reflect the capabilities of energy efficiency and demand response to offset potential HB 2021 cost increases for Oregon. Efficiency would help reduce Oregon emissions, making targets easier to meet. It would also reduce Oregon's requirements for small-scale renewables under HB 2021, a significant cost driver in the CEP. It does not appear that the Conservation Potential Assessment or portfolio modeling in the 2023 IRP/CEP are reflective of the increased value of efficiency and demand response to Oregon customers. Staff looks forward to a thorough conversation with PacifiCorp, IRP participants, and Energy Trust of Oregon about updating avoided costs and the amount of Oregon conservation potential to reflect those resources' full value.

Finally, for context, it is worth noting that:

- 2022 emissions may not be available until after the first round of comments
- 2023 and 2024 emissions are poised to be the highest on record for PAC since 2015.

3. Community Lens, CBRE Actions, & CBIs

PacifiCorp's CEP describes the actions the Company has taken around Community Based Renewable Energy pursuant to HB 2021. These actions include an assessment of CBRE potential from existing or forecasted projects, and an action plan detailing the Company's next steps. The

[6] PacifiCorp 2023 CEP. Page 75.
[7] PacifiCorp 2023 IRP. Page 17.

CBRE potential study is considered a placeholder to be improved upon in collaboration with stakeholders in the near term. CBRE targets are expected to be developed as part of this process.[8]

Order No. 22-390 includes Staff expectations that the first CEP should include annual targets for CBREs. However, in the 2023 CEP these are not yet developed. They Company does include a plan to develop annual targets in the near term.

The Company's Interim Community Benefit Indicators were developed with input from stakeholders including the Joint Advocate Group. The CEP includes a mapping of PacifiCorp's Interim CBIs to some of the CBIs recommended by Joint Advocate Group. However, it is not clear how PacifiCorp chose which recommended CBIs to adopt. Order No 22-390 states that the Company is expected to report in its CEP about how input was incorporated, and why certain input was not incorporated. The CEP does not make it clear why some CBIs were adopted by the Company and others were not. Staff requests the Company provide explanation regarding why it prioritized the CBIs that it did, and why some were not selected.

Finally, the intention of portfolio CBIs expressed in Order No. 22-390 is that they should be ***reflected in*** IRP portfolio scoring.[9] PacifiCorp's portfolio CBIs are: Increasing Energy from Non-emitting Resources and Reducing CO2 Emissions to meet HB 2021 Targets. It's unclear how PacifiCorp's IRP or CEP portfolios would be affected by considering these portfolio CBIs.

4. CEP Action Plan

PacifiCorp notes that the Interim CBIs still needs to receive stakeholder input and currently do not inform the company's final CBRE potential study and action plan.[10]

Staff seeks a better understanding of when the interim CBIs will be finalized and how this timing will relate to any proposed RFP for SSR and CBRE resources. Staff also suggests updating the CEP Action Plan to go beyond refining CBIs to include describing how they impact resource decisions and portfolio evaluations.

5. Other Resource Strategy Implications

Staff requests more discussion of the Company's participation in the Western Resource Adequacy Program (WRAP). It is Staff's understanding that the Company will be assigned an amount of capacity that it is responsible for maintaining under the WRAP. Will that assigned amount allow the Company to lower its capacity need in the IRP and rely on the WRAP sharing process? Is there any analysis or discussion that will help parties better understand how the current IRP Action Plan might

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[8] PacifiCorp CEP. Page 45.

[9] Order No 22-390. Page 39.

[10] Order No. 23-060 called upon utilities to in their CEPs how resource choices appropriately balance cost, risk, and the pace of greenhouse gas emissions reductions, and community impacts and benefits.

impact PacifiCorp's position in the WRAP or their engagement in ongoing design elements, and/or how the implementation of the WRAP could influence this or future Action Plans.

Finally, Staff reminds the Company of the guidance provided in Order No. 22-446 to consider, quantitatively where possible, the following questions in the CEP.[11] Staff appreciates the Company's efforts to identify key HB 2021 compliance hurdles and offer a discussion of its options to address these key barriers in the form of the emissions reduction pathways analysis. While the IRP and CEP analysis provided may be helpful in answering these questions, Staff requests the Company provide greater narrative around the following questions in Reply Comments.

- What low regrets near term actions does the utility expect would perform relatively well, if implemented, regardless of future uncertainties in technology, demand, and regional developments?
- What near term actions that the utility considered might have large negative long term consequences (in terms of cost, risk, GHG emissions, or community impacts or benefits) under one or more future technology, demand, or regional development scenarios?
- What are the critical junctures at which the utility's plan would materially change and what indicators will the utility use to identify whether those junctures are approaching?
- What are the critical dependencies for the utility to successfully execute its long term plan? What are the critical dependencies for the utility's plan to achieve the desired outcomes in terms of cost, risk, GHG emissions, and community impacts or benefits? What might be the implications of one or more of those critical dependencies failing?
- What critical barriers need to be addressed to implement the utility's long-term plan? Which of these barriers can be addressed by the utility or the Commission and which of these barriers are out of the utility's or the Commission's control? Which of these barriers would need to be addressed in the next 5-10 years? The utility should include a plan for addressing those barriers identified in the 5-10 year time frame, including direct actions that can be taken by the utility and opportunities to coordinate with other involved entities.

This concludes Staff's Round 0 comments.

Dated at Salem, Oregon, this 30th of June, 2023.

/s/ ***Rose Anderson***

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Rose Anderson
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[11] Order No. 22-446. Page 16.