



# Oregon Citizens' Utility Board

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*Via Electronic Filing*

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**TO: Oregon Public Utility Commission**

**RE: UM 2273 - CUB Cost Cap Reply Comments**

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Below, the Oregon Citizens' Utility Board (CUB) responds to the questions raised in Oregon Public Utility Commission's (OPUC) Administrative Law Judge (ALJ) Mapes's *Memorandum* (Memo) issued on September 2, 2025.<sup>1</sup> This Memo expands upon the directives in ALJ Grant's May 27, 2025, *Notice and Memorandum*, which includes a Draft Order attached as Appendix A (Draft Order). CUB appreciates the opportunity to provide these comments.

- 1. Does ORS 469A.445 call for the Commission to issue an exemption that prevents a utility's projected obligatory compliance costs from reaching 6% of its projected revenue requirement for a year, or that relieves the utility from further compliance obligations once its projected compliance costs have reached or exceeded 6% of its projected revenue requirement for that year?**

The plain language of HB 2021 shows that the legislature intended that projected obligatory compliance costs be considered in a cost cap investigation. ORS 469A.445(4) states that when the PUC determines that an electric investor-owned utility's actual *or anticipated* investments or costs of compliance with ORS 469A.400 to 469A.457 exceed six percent of the annual revenue requirement for a year, the Commission may provide an exemption to compliance with the aforementioned statutes.<sup>2</sup> ORS 469A.445 directly mentions "forecasted costs"<sup>3</sup> and "anticipated rate impact", leading CUB to continue to conclude that the Commission can look

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<sup>1</sup> See UM 2273 –*Memorandum* (Sept. 2, 2025).

<sup>2</sup> ORS 469A.445(3)-(4) (emphasis added).

<sup>3</sup> CUB reiterates that Oregon uses future test years and forecasts rates, including non-capital costs. The Commission starts with historic costs, and then adjusts them for known and measurable changes, including forward-looking costs. Actual forecasted costs are distinguished from "speculative future costs" which are not included in rates. See CUB Opening Br., 17 (May 23, 2024).

forward at projected costs rather than just look backwards at whether compliance costs exceed or have already exceeded the revenue requirement.<sup>4</sup> CUB agrees with the draft Order that a pause in compliance obligations can only come at the end of a contested case proceeding for a section 10 cost cap determination.<sup>5</sup>

The exemption may be for more than a particular year but must be limited in duration to only the time period necessary to prevent exceedance of the cost cap and the exemption must be narrowly tailored.<sup>6</sup> Because it is narrowly tailored and of limited duration, the exemption should not be read as allowing that the emissions requirements can be ignored. One could imagine a scenario where reducing emissions by replacing a gas plant with intermittent renewables and enough batteries to meet peak demand exceeds the cost cap. However, the renewable resources without the battery would *not* exceed the cap, and eliminating the need for the gas plant outside of peak events would make meaningful progress toward meeting HB 2021 requirements. So with the battery the utility would exceed the cost cap and without the battery the utility would fail to meet that year's HB 2021 required emission reduction. Because the exemption is of limited duration and narrowly tailored, the utility will have to meet its HB 2021 requirements in the future. Because the investment in the renewable resource *without* the battery does not trigger the cost cap and makes meaningful progress towards the HB 2021 requirements, it could still be a prudent and appropriate investment. When the Commission finds that the cost cap has been reached, this relieves the utility from meeting the compliance obligation that year, but it does not mean that the utility is exempt from taking actions that make meaningful progress towards future emissions reduction as long as the utility is not breaching the cost cap.

**2. Recognizing that no forecast is perfect and that any increase in the level of detail required to support a section 10 determination comes at the expense of more lengthy proceedings, what evidence would be appropriate in a section 10 proceeding with respect to (a) costs that have already been incurred and (b) new expenditures?**

There is little doubt that this will be a continuous and difficult process. There are two parts to a section 10 determination: determining what costs generally are related to HB 2021 and determining the precise amounts that will be utilized to evaluate these costs. CUB agrees that a counterfactual of modeling costs without the emissions limits of HB 2021 is a good step in determining the set of costs that generally need to be reviewed. But Portland General Electric (PGE) and PacifiCorp both demonstrate problems with this counterfactual.

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<sup>4</sup> See CUB Opening Br. at 16-19.

<sup>5</sup> *Id.* at 10.

<sup>6</sup> ORS 469A.445(4).

## Costs Generally

### *PGE*

PGE's largest category of capital spending is on its distribution system. In its Distribution System Plan (DSP) it relates this spending directly to HB 2021:

PGE's commitment to decarbonization and the emissions targets established by HB 2021 sets up an imperative requiring a more dynamic system operations paradigm whereby a bi-directional system utilizes all available resources.<sup>7</sup>

PGE acknowledges that in order "[t]o meet Oregon's aggressive decarbonization requirements as set forth in HB 2021, PGE's grid must evolve to a state where systems predict the grid's next operational state and prepare system operators to anticipate, rather than react."<sup>8</sup>

It is important to recognize that these references are not limited to the direct costs of the virtual power plant (VPP), but to the ongoing investment to create a new, smarter, bidirectional power grid. While some costs associated with the VPP may be included in the Integrated Resource Plan (IRP) and the counterfactual, many of the costs are in the DSP. And because this is PGE's largest area of capital expenditure, it could be a source to offset other compliance costs. Could slowing down, or otherwise manage the timing of the investment in the distribution system's "next operational state" be a way to manage costs and avoid the cost cap?

PGE also says these costs are being made because elements of the distribution grid are nearing the end of their useful life. PGE says that HB 2021 creates an imperative and that due to HB 2021 the grid must evolve. However, CUB suspects that PGE will argue that these investments must be made with or without HB 2021.

CUB appreciates that the Draft Order states while HB 2021 compliance "may be a significant justification for the expansion of a program, an increase in the capacity of a generation project, or the like, but other drivers exist as well," they "will consider the appropriate portion of the cost or investment for inclusion in the cost cap."<sup>9</sup> Yet it is not clear what evidence would be sufficient to consider these costs as related to HB 2021. CUB agrees with the Draft Order that a review most likely will need to be determined in a fact-intensive proceeding on a case-by-case basis.<sup>10</sup>

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<sup>7</sup> UM 2362 - *In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2024 Distribution System Plan, 2024 Distribution System Plan*, 27 (Dec. 18, 2024).

<sup>8</sup> *Id.* at 29.

<sup>9</sup> UM 2273 – *Notice and Memorandum, Appx. A* (hereinafter "Draft Order"), 6 (May 27, 2025).

<sup>10</sup> See Draft Order at 12.

## ***PacifiCorp***

PacifiCorp provides a different issue with the counterfactual. PacifiCorp's IRP dispatches resources to serve its six-state system. At the same time, PacifiCorp has expanded its gas portfolio by converting its coal plants to gas. While the IRP allows Oregon's share of gas plants to dispatch differently than other states, this does not represent how gas plants operate, particularly coal plants that are converted to gas. PacifiCorp states that HB 2021 compliance will likely require Oregon to have "independent control of emitting resources."<sup>11</sup> In other words, PacifiCorp will need to allocate its greenhouse gas (GHG) emitting gas plants in a manner that allows Oregon to control dispatch of the gas plants that serve Oregon. PacifiCorp recently made a new resource allocation filing (Multi-State Process (MSP)),<sup>12</sup> but punted on this question and said that it would need to be addressed by 2030.<sup>13</sup> But without knowing the set of resources that is serving Oregon and without Oregon's ability to control the dispatch so it reflects HB 2021 constraints, it is not clear how PacifiCorp plans to meet Oregon's HB 2021 requirements. While the counterfactual would exclude coal plants as required by SB 1547 (not HB 2021), how would it allocate the remaining resources and without an allocation of those resources, how do we forecast emissions?? For example, should a Section 10 evaluation assume Oregon is assigned its traditional share of gas plants that have been converted from coal plants? These plants are relatively inefficient gas plants with long ramping times that are not well suited to function as peaking units. It is difficult to understand how a Section 10 evaluation can happen without knowing the sets of resources that are serving Oregon customers.

## **Specific Costs**

Once we know the investments and costs to be examined in the Section 10 proceeding, there is a need to forecast the specific costs. The regulatory process has a variety of ways to forecast costs, so this is not an unusual area.

However, there are some things that make this difficult. The IRP looks at the utility net present value revenue requirement (NPVRR) over 20 years, but the revenue requirement during individual years can look much different for a utility-owned asset in rate base as compared to a power purchase agreement (PPA). While the 20-year NPVRR is similar, the cost in individual years is different and the cost cap seems to apply to specific years. If we begin the counterfactual during the IRP – before we know the specifics of the resource – CUB

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<sup>11</sup> LC 85 - *In the Matter of PACIFICORP, dba PACIFIC POWER, 2025 Integrated Resource Plan and Clean Energy Plan*, PacifiCorp's 2025 Integrated Resource Plan, 787 (Mar. 31, 2025).

<sup>12</sup> See UM 2401 - *In the Matter of PACIFICORP, dba PACIFIC POWER, Application for Approval of 2026 Inter-Jurisdictional Allocation Protocol*, Application (Aug. 1, 2025) (hereinafter PacifiCorp MSP Application).

<sup>13</sup> UM 2401 – PacifiCorp MSP Application at PAC/200/Link/17.

recommends that we look at both options: a utility build and a PPA. If one causes rates to exceed the cost cap but the other one does not, then it tells us which procurement strategy should be used to meet HB 2021 within the cost cap.

For resources that already exist, modeling based on weather normalized operations would seem to be a reasonable simplifying assumption in a manner similar to current power cost forecasts.

**3. How should the Commission address power costs, which often represent roughly 50% of the annual revenue requirement, in developing projected annual revenue requirements for use as the denominator of the cost cap calculation?**

Power Costs are part of rates and include the cost of the fossil fuels that produce the carbon emissions. Power costs must be included in the denominator. Generally, CUB believes utilities should use a weather normalized dispatch much like is done in power cost forecasting proceedings. This would not capture a circumstance where cost cap could be triggered by a low net present value (NPV) due to mild weather throughout the West shrinking NVP and lowering the denominator. But in that case, if the cost cap would not have been tripped if the weather normalized power costs were used, the Commission can view the higher costs as being triggered by unusual weather, not by HB 2021 compliance costs.

**4. In light of the opportunity for significant complexity when determining the numerator and denominator, should the Commission adopt simplifying assumptions to make timely section 10 determinations more feasible? Which elements of the calculation could benefit from simplifying assumptions while allowing the Commission to effectively achieve the balance between climate goals and affordability articulated in the legislation?**

The Commission should make simplifying assumptions where necessary, but where possible, those assumptions should be based on known and approved methodologies. As mentioned above, the Commission should use the weather normalized dispatch and fuel prices methodology that currently is used to set power cost rates. We should assume normal hydro conditions and expected dispatch from existing renewables. When projecting the cost of new capital investments, the Commission should assume the currently authorized rate of return, even though it will be recalculated with the utility requests cost recovery.

**5. Parties have proposed starting section 10 proceedings at various points in the planning and procurement process. Please provide an illustrative timeline for how an IRP/CEP, RFP, and section 10 proceeding would best align.**

CUB believes a process could begin on a preliminary basis during the IRP but would have to be updated to reflect what the bids and resources that come into the RFP process.

CUB appreciates the opportunity to review draft order and to offer these comments and looks forward to continuing to work on implementation.

Respectfully submitted,

*/s/Bob Jenks*

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